

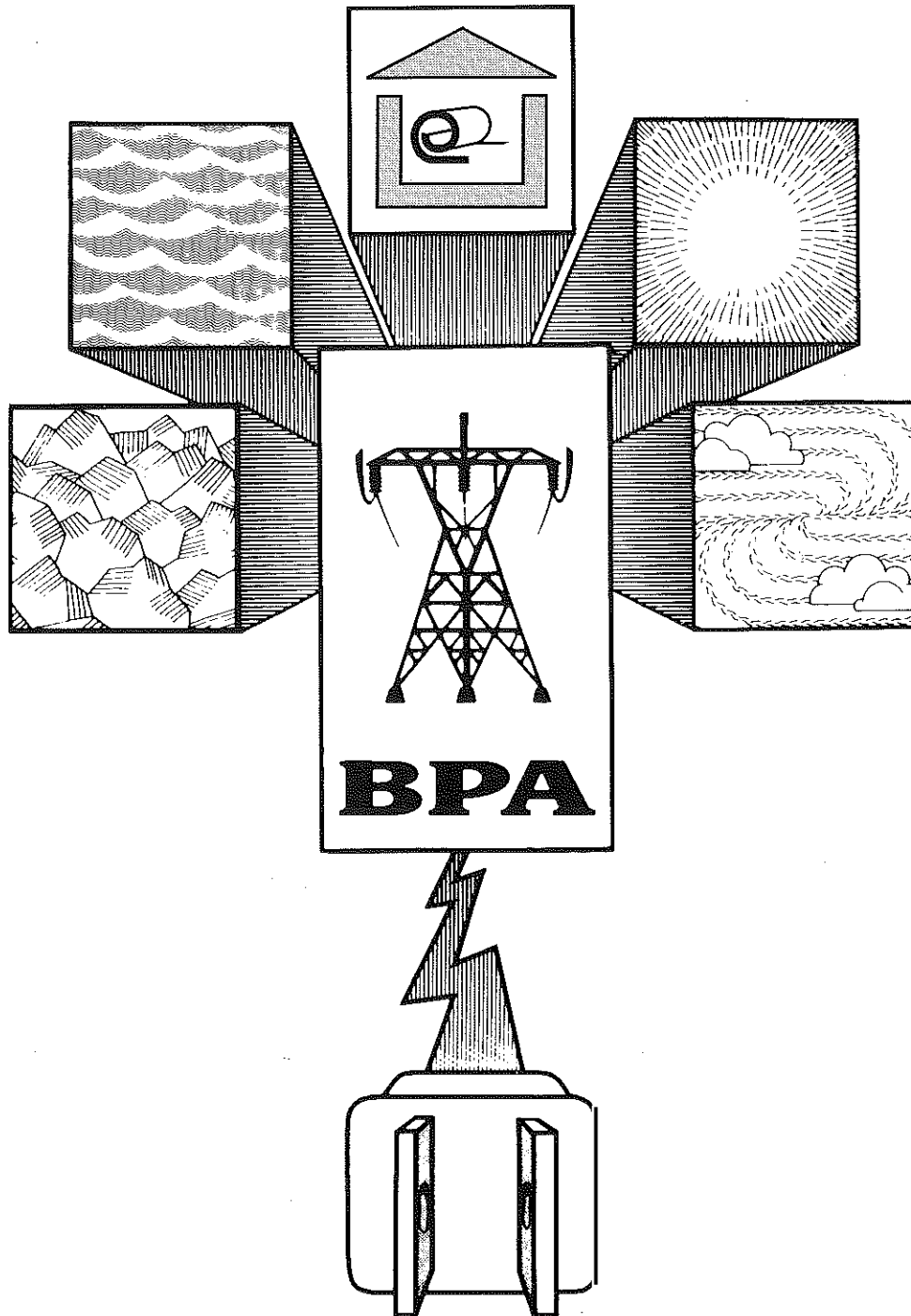
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Final Environmental Impact Statement Resource Programs

DOE/EIS

Volume 1: Environmental Analysis

February 1993



U.S. Department
of Energy

Bonneville
POWER ADMINISTRATION

**Resource Programs
Final Environmental Impact Statement**

Volume 1: Environmental Analysis

**Bonneville Power Administration
February 1993**

**Resource Programs
Final Environmental Impact Statement
(DOE/EIS-0162)**

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

Title of Proposed Action: Resource Programs

States and Provinces Involved: Washington, Oregon, Idaho, Montana, Wyoming, California, Nevada, Utah, New Mexico, Arizona, British Columbia

Abstract: Every two years, BPA prepares a Resource Program, which identifies the resource actions BPA will take to meet its obligation to serve the forecasted power requirements of its customers. The Resource Programs Environmental Impact Statement (RPEIS) is a programmatic environmental document that will support decisions made in several future Resource Programs. Environmental documents tied to this EIS may be prepared on a site-specific basis.

The RPEIS includes a description of the environmental effects and mitigation for the various resource types available in order to evaluate the trade-offs among them. It also assesses the environmental impacts of adding thirteen alternative combinations of resources to the existing power system.

The alternatives represent the range of actions BPA could take to meet its load obligations. Each of the alternatives allows BPA to meet the almost 5,000 average megawatt load increase that could occur with high load growth, or an equivalent need for resources caused by a combination of load growth and any future loss of resources. In the No Action Alternative, resources are not acquired to meet load. The Status Quo Alternative depicts resource acquisitions based on least-cost planning. The Base Case Alternative reflects BPA's decision to include quantifiable environmental costs in its resource planning, and is the benchmark against which all of the other alternatives are compared. The remaining alternatives all emphasize the estimated supply of a particular resource type: Emphasize Conservation Alternative, Emphasize High Conservation (which includes an additional amount of conservation that has not been confirmed), Emphasize Cogeneration, Emphasize Combustion Turbines, Emphasize Nuclear (which includes the partially completed Washington Nuclear Projects 1 and 3), Emphasize Coal (conventional coal), Emphasize Clean Coal (fluidized bed combustion and coal gasification technologies), Emphasize Fuel Switching (customers switch from electricity to natural gas for some applications), and Emphasize Imports (which includes imports from California and British Columbia). Other options, such as emerging technologies and load management, are also considered.

The Emphasize Conservation Alternative has been identified as the Preferred Alternative because it was shown to be the most cost-effective and environmentally responsible.

The Draft EIS was mailed to over 1,500 agencies, groups, and individuals (see Chapter 8). Public comments were received during a 45-day comment period, during which a public meeting was held in Portland on June 16, 1992. The Final EIS includes the public comments and responses.

To request additional copies of the EIS please contact:

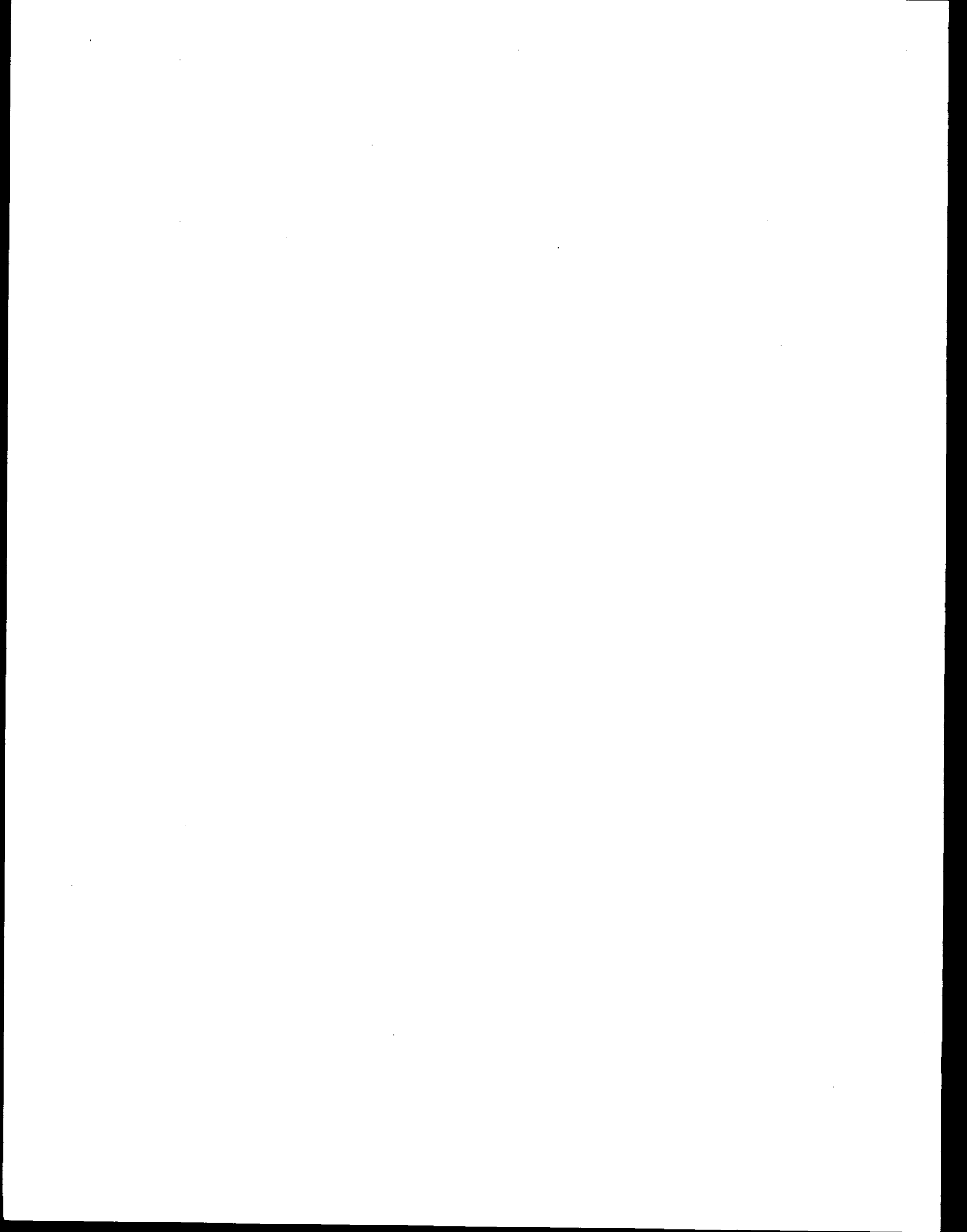
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Copies may also be obtained by calling BPA's tollfree document request line:
1-800-622-4520

For information on DOE NEPA activities contact: Carol M. Borgstrom, Director, Office of NEPA Oversight, EH-25, U.S. Department of Energy, 1000 Independence Avenue, SW, Washington, DC, 20585, (800) 472-2756.



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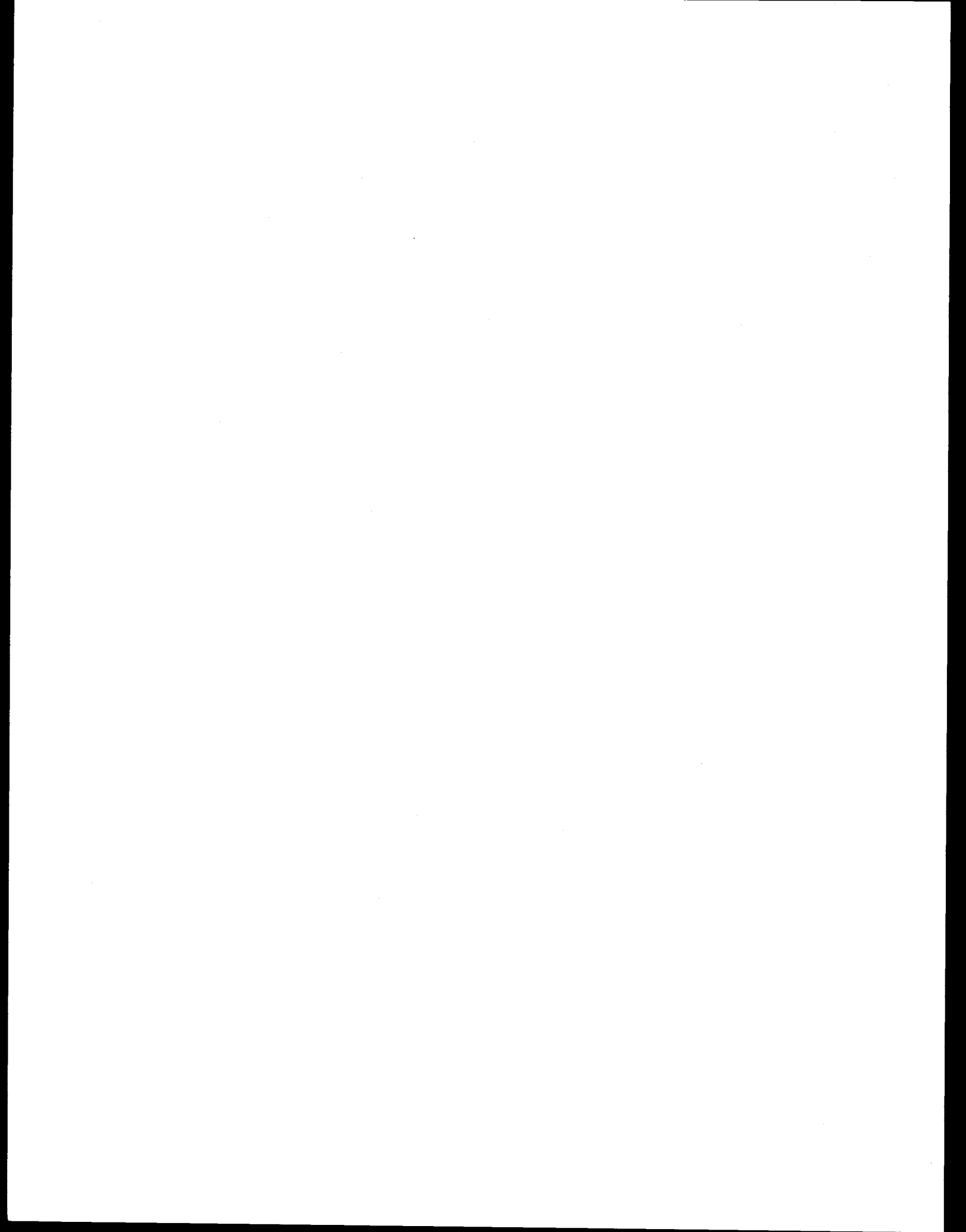
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Resource Programs Final Environmental Impact Statement

Summary

THE UNIVERSITY OF CHICAGO PRESS

CHICAGO, ILLINOIS 60607

1974

1975

1976

Summary

Resource Programs Final Environmental Impact Statement

Background

The Bonneville Power Administration (BPA) is the largest power marketing agency within the U.S. Department of Energy. BPA's primary service area is the Pacific Northwest, including Oregon, Washington, Idaho, and western Montana. The Bonneville Project Act of 1937 (Project Act) established BPA as the marketing and transmission agent for power produced by the Bonneville Dam. Today BPA markets power from 31 Federal dams and two nuclear plants in the Pacific Northwest and has built one of the largest and most reliable transmission systems in the United States. Almost half of all the power used in the Northwest comes from BPA, and BPA provides about three-fourths of the region's transmission capacity.

BPA markets wholesale electric power to several customer groups inside and outside the region. Within the region, BPA customers include four groups: Preference Customers, Direct-Service Industries (DSIs), Investor-Owned Utilities (IOUs), and Federal agencies. BPA also sells or exchanges power with utilities in California and Canada. BPA uses revenues from the sale of power and transmission services to recover the costs of operating the system, to repay the Federal investment in the system, and to back the financing of new power generation and transmission facilities, conservation measures, and fish and wildlife enhancements.

The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) was enacted in response to the need for coordinated planning and development of the Pacific Northwest's power supplies. Under the Northwest Power Act, BPA is authorized to acquire conservation and the output of additional generating resources to meet the future needs of its customers. The Northwest Power Act also created the Northwest Power Planning Council (the Council) which includes representatives from the four Pacific Northwest States. The Council developed a 20-year Northwest Power Plan to ensure that the region has

adequate and reliable energy at the lowest cost. BPA relies on the Council's guidance in the Power Plan to provide the long-range context within which BPA's own resource planning takes place. This Resource Programs Environmental Impact Statement (RPEIS) is part of the planning being done to assure that BPA will be able to meet its loads in a cost-effective and environmentally sound manner.

BPA's Resource Program

Every two years, BPA prepares a Resource Program, which describes the actions BPA will take to meet the power requirements of its customers. In developing a Resource Program, BPA prepares load forecasts in cooperation with the Council. A range of five forecasts (low, medium-low, medium, medium-high, and high) is prepared to reflect uncertainties about future load growth. Next, a range of load/resource balances is prepared by comparing the energy capability of the existing Federal system resources to the range of projected Federal system energy loads over the next 20 years. In a parallel process, BPA and the Council develop new resource supply forecasts.

Under the 1990 long-term medium forecast, the Federal system was in load/resource balance, with sufficient resources to meet BPA's needs for the rest of the decade. Under the 1991 long-term medium forecast, the Federal system was 400 to 500 aMW in deficit in the near term and would require 800 aMW by the year 2000. Total public utility load growth averaged 3.1 percent annually from 1983 through 1990. However, the actual level of future loads is not known. If demand grows faster or if resources do not perform as expected, BPA could face a deficit. Under high load growth, BPA could have almost 5,000 average megawatts (aMW) of additional load to meet by the end of its 20-year planning period.

In addition to these projected energy loads, changes in the operations of the hydroelectric system to increase fish survival may reduce the capacity of the Federal system. The need to replace capacity to meet peak loads may become an increasingly important goal of BPA's future Resource Programs. To continue to meet its obligations, BPA needs to plan for the acquisition of additional resources now.

Purpose of and Need for Action

Need

BPA needs to acquire sufficient new resources to meet electricity deficits caused by growing customer loads.

Purpose

The purposes of this action are to:

- ◆ Ensure that BPA can meet its contractual obligations to supply cost-effective electric power as requested by its customers--taking into account potential environmental consequences when making any decisions to acquire resources to meet those loads;

- ◆ Assure consistency with BPA's statutory responsibilities, including the Northwest Power Act, while taking into consideration the Council's Power Plan and its Fish and Wildlife Program; and
- ◆ Restore and enhance environmental quality and avoid or minimize possible adverse environmental effects.

Scope of the EIS

The RPEIS is a programmatic document that addresses broad issues associated with resource acquisitions. The EIS evaluates the environmental trade-offs among generic resource types and the cumulative effects of adding various combinations of these resources to the existing system. Although supplements may be necessary, the RPEIS is intended to be broad enough to support Records of Decision for several Resource Programs. Following the identification of actions in each Resource Program, proposals will be made to acquire specific conservation or generating resources. Separate site-specific environmental documents will be prepared, as necessary, to evaluate the impacts of those acquisitions. These site-specific documents will be tiered to the RPEIS.

Many of the potential environmental effects of acquiring and operating new resources are site-specific. BPA recognizes its responsibilities to evaluate these potential impacts and to take action to protect, enhance, and restore the environment. Therefore, these environmental impacts are acknowledged in the RPEIS and will also be considered in the site-specific documents that will be tiered to this EIS.

Resource Types

Before analyzing the actions BPA could take to meet the underlying need, the RPEIS evaluates the environmental effects of generic resource types and potential mitigation measures for each. Current supply curve analysis indicates that the following resource types could be available to meet future load growth through 2010:

- ◆ conservation (including the commercial, residential, and industrial sectors)
- ◆ renewable resources (including hydropower, geothermal, wind, and solar power)
- ◆ efficiency improvements
- ◆ cogeneration
- ◆ combustion turbines
- ◆ nuclear power
- ◆ coal (including conventional coal and clean coal technologies).

A relative comparison of principal environmental impacts of each resource type is shown in Figure S-1.

Other means of meeting load, such as fuel switching from electricity to natural gas for some applications, energy imports, and efficiency improvements, are also evaluated. Emerging technologies that could become commercially available

within the planning period, and several types of load management, have been included as well.

Figure S-1
Selected Environmental Impacts of Conservation and
Generation Resource Operations

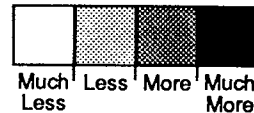
Resource	Relative Impact										
	SOx (tons/aMW)	NOx (tons/aMW)	TSP (tons/aMW)	CO (tons/aMW)	CO2 (tons/aMW)	Water Consumption (acre-FT/aMW)	Thermal Discharge (mmBTU/aMW)	Land Use (acres/MW)	Direct Cost (mills/kWh)	Environmental Costs (mills/kWh)	Hydro System Operations Impact
Conservation											1
Eff. Imps											
Hydro											
Geothermal											
Wind											
Solar											
Cogeneration ¹⁾											
CTs											
Nuclear											
Coal											
Clean Coal											

Note: Fuel Switching not shown because comparable data are not available, but generally has low impact in all areas.

1) Natural gas fired cogeneration assumed

2) "More" means a more negative impact to capacity

3) Capacity value of conservation varies considerably among conservation measures, from positive to negative



Conservation

The Northwest Power Act prioritizes new resources to be acquired for the region. The first priority is conservation, which reduces the need to build new generation. Conservation in commercial and residential buildings consists of increasing energy use efficiency by upgrading or retrofitting existing buildings and by designing new buildings to be as energy efficient as warranted. The largest potential for energy savings is in lighting and heating measures. Proper handling and disposal of fluorescent light ballasts and lamps from commercial buildings can prevent the hazards associated with polychlorinated biphenyls and mercury. Although changes to the heating, ventilation and cooling systems may affect air quality inside commercial buildings, energy-efficient designs can be installed such that indoor air quality is not affected adversely.

Residential conservation includes a wide variety of measures to reduce electricity use in single family homes, multi-family dwellings, and manufactured homes. Conservation programs promote retrofitting existing homes to make them more energy efficient and employing construction techniques in new homes to tighten the structure, thus reducing air infiltration and heat loss. Of primary concern has been the effects of the reduction in indoor air quality, especially from radon and formaldehyde, on human health. These impacts were evaluated in previous documents: The Expanded Residential Weatherization EIS (DOE/EIS-0095F, 1984) and the Final Environmental Impact Statement on New Energy-Efficient Homes Programs (DOE/EIS-0127F, 1988). Avoiding certain building materials and products is effective mitigation for formaldehyde. Many radon mitigation techniques are available. However, more recent studies have shown that there is no direct correlation between house tightening and radon levels.

Industrial and agricultural sector conservation measures include high efficiency motors, motor speed controls, energy efficient motor rewinds, heat recovery equipment, insulation, lighting, energy management systems, power factor improvements, and irrigation efficiency improvements.

Since these measures do not alter the mechanical processes in such a way as to substantially affect waste streams, and because industrial applications are highly regulated, minor, if any, environmental impacts are likely.

Renewable Resources

Second priority is given to renewable resources. Four renewable resources are under consideration: hydroelectric power, geothermal, wind, and solar power.

Hydroelectric facilities vary greatly in size and can be run-of-river dams, storage reservoirs, or small projects such as the addition of turbines to existing pipe or ditch systems. Environmental impacts include the alteration of surface water and stream habitat. Water temperature, water quality, and stream flow may be affected. Dams may block migration of fish, such as salmon, and alter wildlife habitat. However, the Protected Areas amendments adopted by the Council help protect critical fish and wildlife habitat.

Geothermal energy taps heat available within the earth's core. The most likely locations in the Northwest for geothermal development are in southeastern Oregon and southern Idaho and in the high Cascades of southern Oregon. The three principal types of geothermal conversion technologies used in power generation are dry steam, flash, and binary cycle plants. The major environmental impacts associated with geothermal energy are contaminants from geothermal steam

(particularly hydrogen sulfide), waste heat, degradation of water quality, and solid waste. However, mitigation measures are available to minimize these impacts.

Almost 40 locations in the Northwest have been identified as having potential for commercial development of wind sites. The environmental impacts are associated with siting the wind turbines, which are usually grouped together in wind parks. These wind parks require the development of large tracts of land, and some of the best sites in the region are in scenic areas along the Pacific coast and in the Columbia River Gorge. Wind parks may pose a hazard to birds from striking the turbine blades. Noise and electromagnetic interference are also potential impacts. Many of these siting impacts can be mitigated.

The best potential solar site in the Northwest is in southeastern Oregon. Solar energy can be captured by solar thermal plants, which convert heat energy into electricity through a turbine-generator, and by photovoltaic cells, in which the sun's radiation is converted directly into power. Solar energy is characterized by daily and seasonal variations. Because solar radiation is diffuse, large tracts of land are required for developing commercial-sized solar thermal sites, and land use is also a major impact of photovoltaic systems. In addition, the industrial processing of the photovoltaic materials uses hazardous chemicals, but they are generally highly regulated.

Cogeneration

The Northwest Power Act gives third priority to high efficiency resources such as cogeneration, in which electric power is generated from an existing heat-producing industrial operation. A variety of fuel types, including natural gas, coal, and biomass, can be used in cogeneration; however, for modeling purposes in this EIS, cogeneration was assumed to be gas-fired. The environmental effects depend largely on the type of fuel used; plant emissions would be similar to any combustion facility using these fuels. Because cogeneration plants satisfy thermal energy as well as electricity needs with a single energy source, there is less overall pollution than if separate energy sources were used.

Thermal Resources

Combustion turbines, or CTs, are based on the same technology as jet engines. A combined cycle combustion turbine couples a CT with a steam plant to generate power very efficiently. CT designs are simple, reliable, and relatively easy to site. CTs that use natural gas are relatively clean burning. Although oxides of nitrogen (NO_x) tend to be a problem because of the high combustion temperatures, the NO_x emissions can be controlled. Carbon dioxide, which is a greenhouse gas, and waste heat are also produced. Noise can be a problem, especially in an urban setting, but silencing packages are available.

Another possible thermal resource choice is the completion of Washington Nuclear Plants 1 and 3. In these pressurized water reactors, nuclear fission is used to produce steam, which turns a turbine-generator to produce electricity. Both plants are sited on large tracts of land. Environmental impacts from operating a nuclear plant include thermal discharge, water consumption, release of airborne radioactive materials, and release of waterborne chemical pollutants. Radioactive waste disposal continues to be an issue. Long-term storage proposals have met considerable public opposition and some technological questions remain unsolved.

Conventional coal plants are a traditional thermal resource with a well-established technology. Coal is burned to boil water and produce steam. The steam then

turns a turbine, which generates electricity. A large amount of domestic coal is available to the Pacific Northwest. The impact of greatest environmental concern from coal generation is air pollution. Emissions include oxides of sulfur and nitrogen (SO_x and NO_x), which contribute to acid rain, and carbon dioxide, which has been implicated in global warming. Although there are ways to scrub exhaust gases to reduce SO_x and NO_x , there currently is no effective way to mitigate CO_2 pollution. Coal combustion also releases particulates, and coal plants require large quantities of cooling water. Several clean coal technologies, including fluidized bed combustion and coal gasification, have higher thermal efficiencies and produce fewer emissions compared to conventional coal.

Alternatives

Key Assumptions

The high load growth forecast was used in the analysis to identify maximum environmental effects. A combination of load growth plus the loss of existing or planned resources could mean that BPA will have to acquire as many resources as under the high forecast. However, high load growth is considered unlikely, and as a result, the more expensive resources needed under high growth conditions are not expected to be acquired in the 20-year study period.

The estimated costs for each resource type in this analysis were based on the 1990 Resource Program. Some resource costs have since changed. The effects of shifts among relative costs of the different resources comprise a major element of the economic analysis that will be part of each future Resource Program.

Environmental externalities are the economic costs and benefits that are not directly borne by the party causing the environmental effect. BPA is required by the Northwest Power Act to include quantifiable environmental externalities in determining a resource's total system cost for BPA's planning and acquisition activities. The Northwest Power Act also directed the Council to develop, as a guide to BPA, a methodology for quantifying environmental costs. In developing estimates of environmental costs and benefits, BPA has followed the methodology proposed by the Council.

A technical work group was formed in November 1990 to review the methodology and information used by BPA for the estimates of environmental costs and benefits developed for the RPEIS. The work group, which included representatives from public and investor-owned utilities, state and Federal agencies, independent power producers, interest groups, and private citizens, met throughout the development of this EIS.

BPA's environmental cost estimates focus on the effects of operating generic resources on atmospheric visibility, human health risks, forests, crops, materials, and on land and water. Three airborne pollutants are analyzed—sulfur oxides, oxides of nitrogen, and particulate matter. The effects of carbon dioxide emissions were initially included. It was determined that the uncertain scientific evidence concerning the effects of CO_2 preclude placing a value on the effects of CO_2 emissions. BPA recognizes, however, that some states and utilities have placed a cost on CO_2 emissions based on existing studies, and BPA has included CO_2 in the non-cost analysis of air quality impacts of each alternative.

The potential environmental costs associated with radioactive emissions from a catastrophic nuclear event are not estimated or included in this analysis. The environmental costs for nuclear plants cited in the document consist only of estimates associated with land and water use impacts for all large thermal plants.

It was also assumed that BPA and the IOUs planned separately. None of the IOU load growth was placed on BPA; all of the load growth of the generating public utilities (GPUBs) was. In addition, it was assumed that BPA's contracts with utilities and the DSIs were renewed in 2001 without major changes.

In the past, BPA has focused on planning to meet energy deficits because, historically, the Northwest hydropower-based system has been relatively capacity-abundant. However, in the future, as the region acquires more conservation, renewable, and thermal resources, and as the operations of the hydroelectric system change to increase fish survival, the capacity attributes of new resource acquisitions may become increasingly important.

In this EIS, it is assumed that when the Canadian Entitlement sale to U.S. utilities expires, its energy and capacity will be returned to Canada. Other options (such as repurchasing all of the Entitlement, or its capacity or energy elements) are also possible.

Development of the Alternatives

Thirteen alternatives were developed to represent the range of actions BPA could take to meet its load obligations. The resource acquisitions proposed in future Resource Programs are expected to fall within this range. With the exception of No Action, each alternative is made up of a combination of resources that allows BPA to meet the almost 5,000 average megawatt load growth projected under the high forecast, or an equivalent need for resources caused by a combination of load growth and possible loss of resources. The Integrated System for Analysis of Acquisitions (ISAAC) was used to simulate resource acquisitions and operations. A resource stack (a least-cost ordering of resources available to meet load growth) was used as input to the model. Variations of the resource stack were developed for each alternative. For comparison purposes, in the Final EIS, a set of resource additions to serve expected (medium) loads was identified.

Description of the Alternatives

Under the No Action Alternative, the underlying need for energy to meet the growing loads of BPA customers would not be met. There would be an increased emphasis on conservation and on more efficient use of existing generating resources. Efficiency improvements and interregional exchanges would be pursued, as well as fuel switching to natural gas or wood. Although the environmental effects associated with the large-scale development of thermal resources would be avoided, there would be degradation of air quality from wood burning, and water quality and land use impacts from changes in population dispersion and numerous small generating facilities. Socioeconomic impacts could be major.

In the Status Quo Alternative, resource acquisitions continue on the least-cost planning course set in the 1990 Resource Program. Resources are acquired based

on minimizing system costs, without including quantifiable external environmental costs. The primary difference between this alternative and the Base Case Alternative is that coal is acquired and operated instead of some geothermal and cogeneration.

The Base Case Alternative reflects BPA's decision to include quantifiable environmental costs in resource planning, and is the benchmark against which all of the other alternatives are compared. Under this alternative, resources would be acquired based on minimizing total system cost, including quantified external costs. Since the Base Case Alternative was developed specifically to minimize total system costs, it is the least-cost alternative, with the exception of the Fuel Switching and High Conservation Alternatives. Both fuel switching and the conservation resources included in the High Conservation Alternative were assumed to be relatively inexpensive and to have fairly low environmental costs. However, neither of these types of resources were included in the Base Case because neither has yet been confirmed as to cost or availability. The Base Case Alternative is, in essence then, the least-cost alternative.

The remaining alternatives were developed by placing the available supply of the emphasized resource at the top of the stack of resources developed for the Base Case Alternative, after nondiscretionary conservation.

Because of its relatively low cost, all of the available conservation is already at the top of the resource stack in the Base Case Alternative. Therefore, the Emphasize Conservation Alternative and the Base Case Alternative are the same.

In the Emphasize High Conservation Alternative, additional conservation resource potential was assumed for residential refrigeration, residential freezers, other residential appliances, new commercial buildings, and industrial facilities (excluding aluminum smelters operated by direct-service industrial customers of BPA). This additional achievable potential is based, in large part, on the 1990 analysis of the regional energy conservation resource potential by the Natural Resources Defense Council and the Northwest Conservation Act Coalition.

In the Emphasize Renewables Alternative, the renewable energy resources (hydropower, geothermal, wind, and solar) available to BPA were moved to the top of the Base Case resource stack and acquired first.

For the Emphasize Cogeneration Alternative, cogeneration resources were moved to the top of the Base Case resource stack. For the purpose of modeling environmental impacts, cogeneration was assumed to use natural gas because gas is the fuel used for most new cogeneration. However, a variety of fuel types--including biomass and municipal solid waste--can be used in cogeneration.

In the Emphasize Combustion Turbines Alternative, all of the available combustion turbine resources were moved to the top of the Base Case stack. Because CTs are already near the top of BPA's resource stack and because the alternatives are modeled against future high load growth, all of the available CTs were acquired in the Base Case by 2000. Therefore, moving the CTs to the top of the stack did not change the average megawatts of resources acquired or operated in 2000 or 2010; thus this alternative is identical to the Base Case.

The partially completed Washington Nuclear Projects (WNP)-1 and -3 were placed at the top of the resource stack in the Emphasize Nuclear Alternative. The major difference between this alternative and the Base Case Alternative is that

both nuclear plants are acquired and operated by 2000 and almost no cogeneration or CT resources are operated.

In the Emphasize Coal Alternative, the conventional coal resources available to BPA were moved to the top of the resource stack. The major difference from the Base Case is that coal replaces nuclear plants in 2000 and in 2010, coal replaces some renewables, cogeneration, and CTs.

In the Emphasize Clean Coal Alternative, the amount of high technology coal, including fluidized bed combustion and coal gasification, available to BPA was moved to the top of the resource stack. In 2000, clean coal replaces a nuclear plant, and in 2010, clean coal replaces some renewables, cogeneration, and CTs.

Fuel switching from electricity to natural gas for some applications is a means of reducing load and an option now being pursued by some Pacific Northwest utilities. In the hypothetical program modeled for the Emphasize Fuel Switching Alternative, BPA would pay the costs involved in bringing gas lines near residential areas and subsidize conversion from electric to gas.

In the Emphasize Imports Alternative, an estimated supply of imports was moved to the top of the resource stack. These imports were modeled as gas-fired CTs--two-thirds new and one-third existing. It was assumed that half of the imports were from Canada and half were from the Pacific Southwest. In addition, the imports from Canada were assumed to be available all year and the imports from the Pacific Southwest were shaped into the September through April period.

Because of the long lead time to plan for and build resources, large amounts of resources are not acquired in any of the alternatives before the mid-1990s. It is assumed that extra-regional purchases of firm power can be made on a short-term basis to meet the near-term loads. The year 2000 was chosen to represent the mid-term and 2010 to represent the long-term. BPA resource acquisitions and operations in 2000 and 2010 for all the alternatives (excepting No Action) are presented in Tables S-1 through S-4.

Table S-1
New Resource Acquisitions - 2000

Resource Types (in aMW):	Alternatives											
	Status Quo	Base Case	Conservation	High Conservation	Renewables	Cogeneration	CT's	Nuclear	Coal	Clean Coal	Fuel Switching	Imports
Conservation	477	477	477	815	477	458	477	404	441	452	477	197
Effic Imp	134	134	134	134	134	134	134	114	134	134	134	133
Renewables	60	105	105	60	716	49	105	46	49	60	105	0
Cogen	140	260	260	260	140	1380	260	10	170	140	260	0
CT's	1046	1046	1046	1046	698	349	1046	349	698	698	1046	0
Nuclear	813	813	813	0	0	0	813	1619	0	0	0	0
Coal	0	0	0	0	0	0	0	0	1127	0	0	0
Clean Coal	0	0	0	0	0	0	0	0	0	806	0	0
Fuel Switching	0	0	0	0	0	0	0	0	0	0	241	0
Imports	0	0	0	0	0	0	0	0	0	0	0	2000
Total	2670	2835	2835	2315	2163	2370	2835	2542	2619	2290	2263	2330
Load/Resource Balance	397	562	562	44	-107	99	562	272	345	16	-10	60

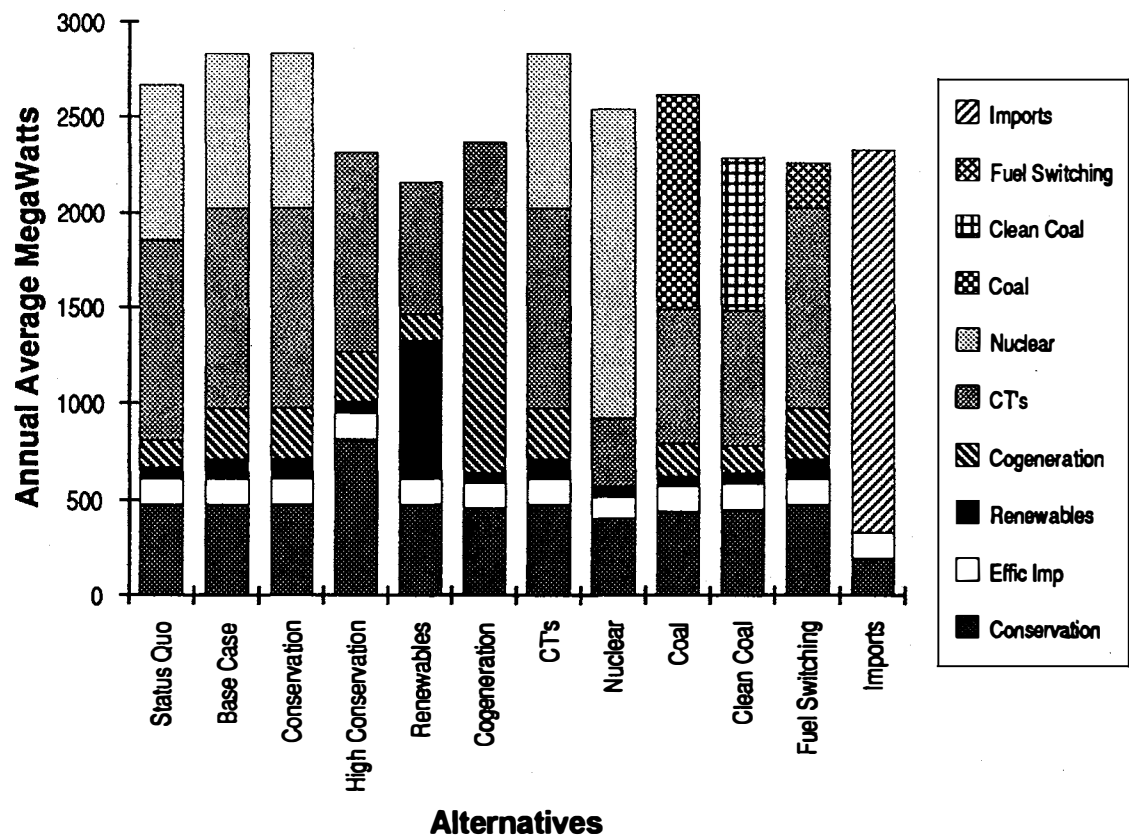


Table S-2
New Resource Acquisitions - 2010

Resource Types (in aMW):	Alternatives											
	Status Quo	Base Case	Conservation	High Conservation	Renewables	Cogeneration	CT's	Nuclear	Coal	Clean Coal	Fuel Switching	Imports
Conservation	1033	1033	1033	1881	1033	1029	1033	1011	1029	1033	1033	858
Effic Imp	134	134	134	134	134	134	134	134	134	134	134	134
Renewables	367	480	480	349	967	405	480	412	314	213	367	60
Cogen	390	840	840	400	490	1380	840	930	340	280	430	120
CT's	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046
Nuclear	1619	1619	1619	1619	1619	1819	1819	1619	1619	1619	1619	0
Coal	563	0	0	0	0	0	0	0	1127	0	0	0
Clean Coal	0	0	0	0	0	0	0	0	0	1286	0	0
Fuel Switching	0	0	0	0	0	0	0	0	0	0	556	0
Imports	0	0	0	0	0	0	0	0	0	0	0	3000
Total	5152	5152	5152	5429	5289	5813	5152	5152	5609	5611	5185	5218
Load/Resource Balance	55	55	55	333	193	517	55	56	512	514	89	124

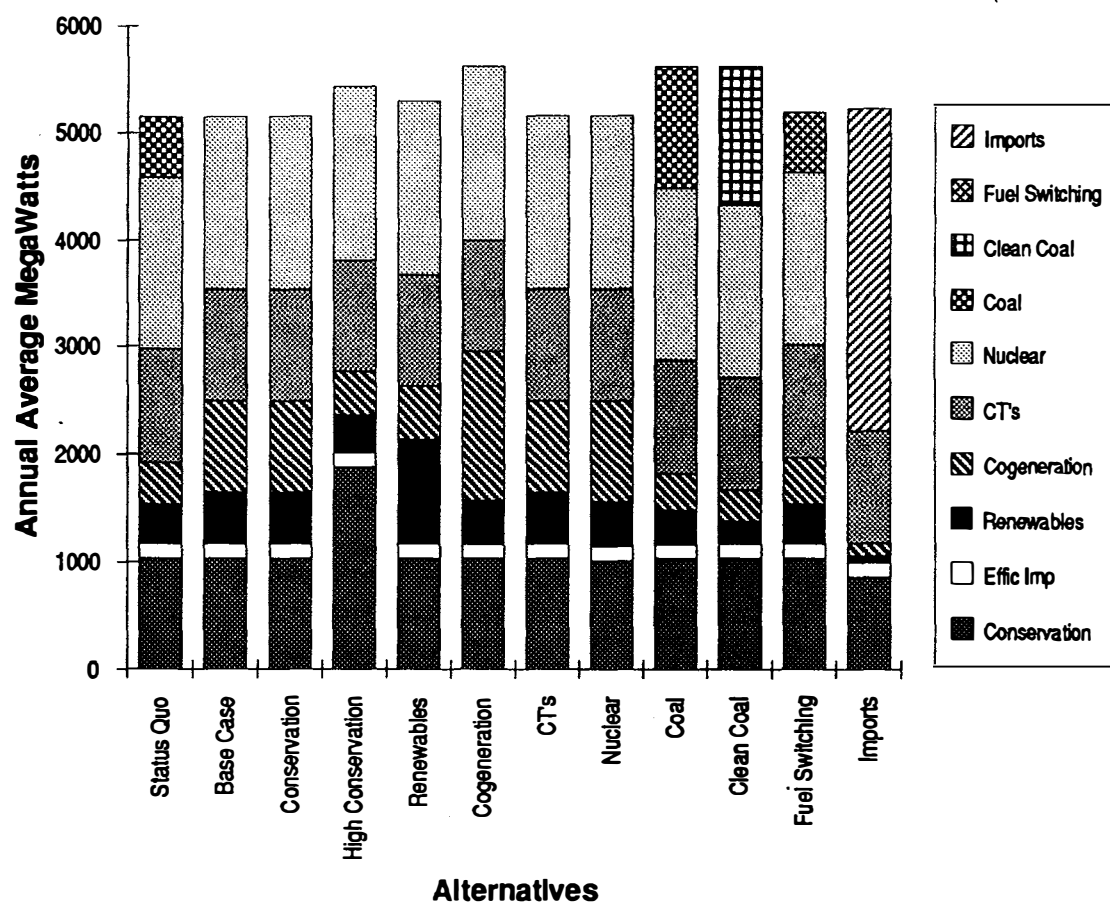


Table S-3
New Resource Operations - 2000

Resource Types (in aMW):	Alternatives											
	Status Quo	Base Case	Conservation	High Conservation	Renewables	Cogeneration	CT's	Nuclear	Coal	Clean Coal	Fuel Switching	Imports
Conservation	477	477	477	815	477	458	477	404	441	452	477	197
Effic Imp	134	134	134	134	134	134	134	114	134	134	134	134
Renewables	60	105	105	60	716	49	105	46	49	60	105	0
Cogen	140	260	260	260	140	1380	260	10	170	140	260	0
CT's	185	140	140	277	185	70	141	35	109	176	283	0
Nuclear	813	813	813	0	0	0	813	1619	0	0	0	0
Coal	0	0	0	0	0	0	0	0	958	0	0	0
Clean Coal	0	0	0	0	0	0	0	0	0	697	0	0
Fuel Switching	0	0	0	0	0	0	0	0	0	0	241	0
Imports	0	0	0	0	0	0	0	0	0	0	0	681

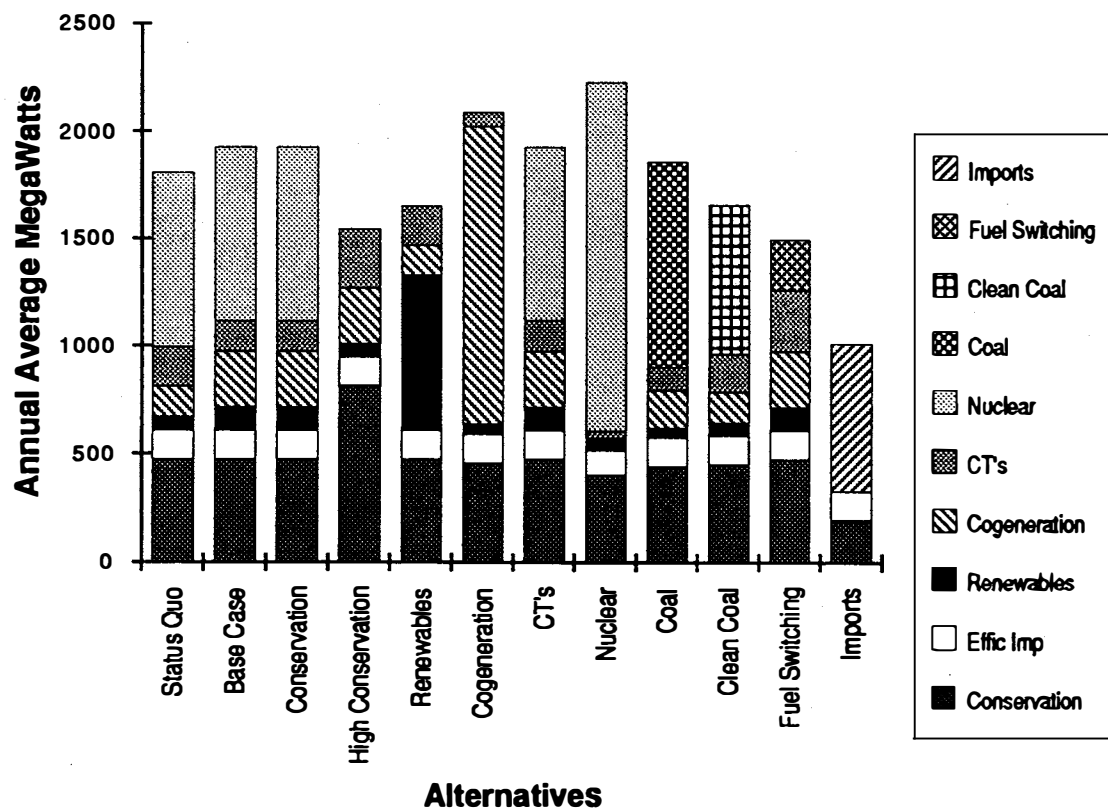
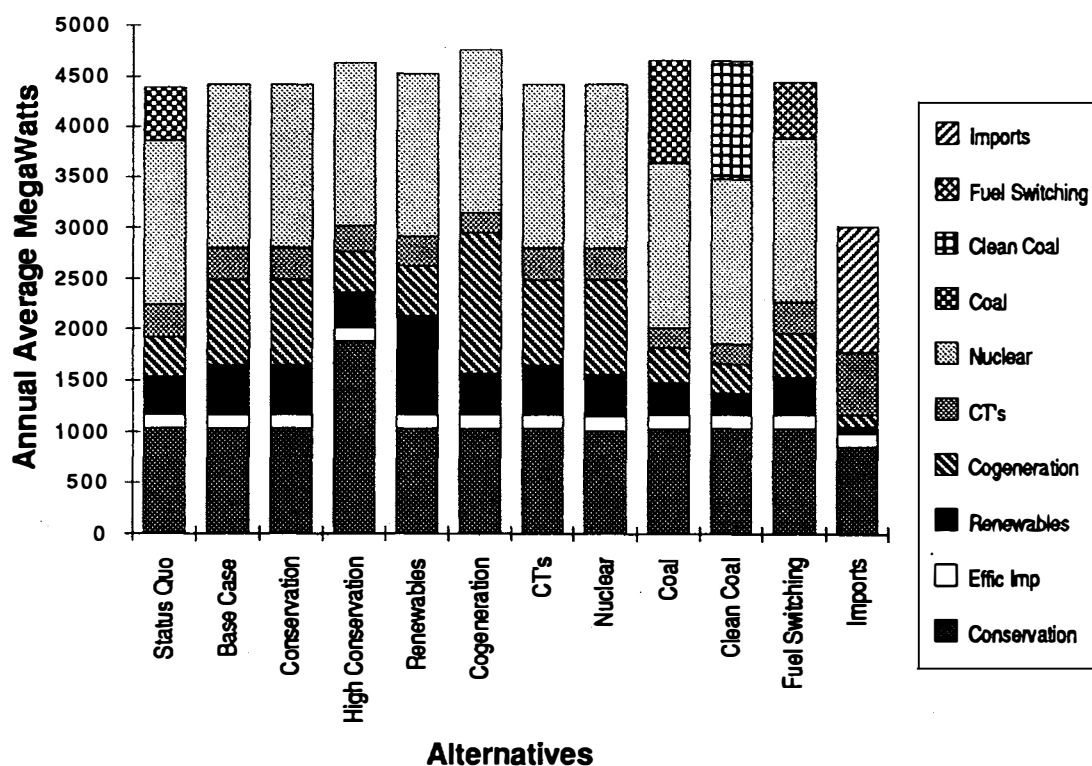


Table S-4
New Resource Operations - 2010

	Alternatives											
Resource Types (in aMW):	Status Quo	Base Case	Conservation	High Conservation	Renewables	Cogeneration	CT's	Nuclear	Coal	Clean Coal	Fuel Switching	Imports
Conservation	1033	1033	1033	1881	1033	1029	1033	1011	1029	1033	1033	858
Effic Imp	134	134	134	134	134	134	134	134	134	134	134	134
Renewables	367	480	480	349	967	405	480	412	314	213	367	60
Cogen	390	840	840	400	490	1380	840	930	340	280	430	120
CT's	315	316	316	253	290	198	316	315	200	198	305	613
Nuclear	1619	1619	1619	1619	1619	1619	1619	1619	1619	1619	1619	0
Coal	534	0	0	0	0	0	0	0	1032	0	0	0
Clean Coal	0	0	0	0	0	0	0	0	0	1176	0	0
Fuel Switching	0	0	0	0	0	0	0	0	0	0	556	0
Imports	0	0	0	0	0	0	0	0	0	0	0	1235



Environmental Effects of the Alternatives

Except for the No Action Alternative, all of the alternatives are compared to the Base Case Alternative. Since most of the potential impacts from conservation measures could be mitigated, the comparison of alternatives focused on impacts to air quality, water quality and use, and land use from the operation of the new generating resources acquired.

The potential for each alternative to affect the operation of the hydro system was also examined. Scenarios were developed to determine which characteristics--magnitude, monthly shape, displaceability, and load resource balance--of adding new resources have the greatest potential to affect hydro system operations. The System Analysis Model (SAM) was then used to simulate operation of the system for each scenario. The hydro system operation studies showed that the resource characteristics that most affect hydro system operation are resource shaping throughout the year and the load/resource balance. In general, the greater the amount of shaping and the greater the amount of surplus, the greater the potential for effects on hydro system operations. The hydro system analysis scenarios were then compared to the alternatives. Alternatives were also compared in terms of the amount of capacity they provide overall, as determined by comparing the ratio of the total capacity of all the resources in each alternative with the total energy provided.

The potential environmental impacts of the alternatives compared to the Base Case are summarized on the following pages in Figure S-2 for 2000 and in Figure S-3 for 2010. The system costs of the various alternatives are also compared.

Other Considerations

The alternatives analyzed in the RPEIS were modeled to assess the cumulative impacts of adding different combinations of resources to the existing system. Therefore, the cumulative impacts of actions taken to meet the underlying need have been addressed.

In addition, all of the alternatives involve trade-offs between short-term uses of man's environment and the maintenance and enhancement of long-term productivity. As new resources are acquired in the region to meet BPA's need, short-term and long-term impacts will occur to the affected environment. All alternatives in the study are expected to have short-term impacts from the building or installation of new resources, noise from construction and operation of large generating units, soil erosion, displacement of wildlife, disruption of habitat, and altered land use. Socio-economic impacts are expected in the short-term from the increase in work force required during construction of large generating units. In the long-term, impacts could occur to air quality, land use from mining, and water consumption and thermal discharge from thermal generating plants.

In every alternative, resources which use fossil fuels or other nonrenewable resources are operated. Even the alternatives that emphasize conservation and renewable resources include thermal resources, and nonrenewable resources are required for the construction of the generating facilities, for the renewable resources, and for the materials used in the various energy conservation measures.

Therefore, every alternative involves the irreversible or irretrievable commitment of resources.

In addition, controversy involving the environmental trade-offs among the various resource types is expected.

Figure S-2
Selected Environmental Impacts of Operations of Resource Alternatives Compared to the Base Case Alternative - 2000

POTENTIAL EFFECT	BASE CASE	ALTERNATIVE									
		Status Quo	Conservation	High Conservation	Renewables	Cogeneration	CTs	Nuclear	Coal	Clean Coal	Fuel Switching
SO ₂	9 tons										
NO _x	1,800 tons										
TSP	9 tons										
CO	300 tons										
CO ₂	1.24 million tons										
Water Consumption	17,000 acre-ft										
Thermal Discharge	52 million MMBtu										
Land Use	1,900 acres										
Direct Cost ¹⁾	Base case										
Environmental Cost ¹⁾	Base case										
Hydro System Operations	800 aMW large thermal with maintenance; no shaped import										
Capacity Contribution	Base case										

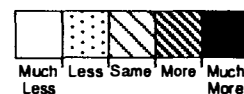
¹⁾ Relative expected present value over entire study period



Figure S-3
Selected Environmental Impacts of Operations of Resource
Alternatives Compared to the Base Case Alternative - 2010

POTENTIAL EFFECT	BASE CASE	ALTERNATIVE									
		Status Quo	Conservation	High Conservation	Renewables	Cogeneration	CTs	Nuclear	Coal	Clean Coal	Fuel Switching
SO ₂	26 tons										
NO _x	5,100 tons										
TSP	26 tons										
CO	700 tons										
CO ₂	3.7 million tons										
Water Consumption	48,000 acre-ft										
Thermal Discharge	151 million MMBtu										
Land Use	3,900 acres										
Direct Cost ¹⁾	Base case										
Environmental Cost ¹⁾	Base case										
Hydro System Operations	1600 aMW large thermal with maintenance; no shaped import										
Capacity Contribution	Base case										

¹⁾ Relative expected present value over entire study period



Preferred Alternative

BPA's preferred alternative is the Emphasize Conservation Alternative. System and environmental costs are low. Environmental impacts from conservation are minimal. This alternative is cost-effective and environmentally responsible; only the High Conservation Alternative has lower costs and fewer environmental impacts. However, there is some concern about the cost-effectiveness, reliability, and commercial availability of the high conservation resources. If the supply of the additional conservation potential was confirmed and it became cost-effective, the High Conservation Alternative would be preferred.

Relationship to the Columbia River System Operation Review

The Corps of Engineers, Bureau of Reclamation, and Bonneville Power Administration are jointly preparing a System Operation Review (SOR) EIS on the operation of the Columbia River hydropower system. The SOR EIS will include extensive analyses of the effects of alternative hydro system operations on the multiple uses of the hydro system. These multiple uses include navigation, flood control, recreation, hydropower generation, fish (both resident and anadromous), wildlife, cultural resources, and irrigation.

The RPEIS assumes current operating practices and constraints on the hydro system for all alternatives. In the SOR EIS, however, those constraints will be removed and alternative operations which accommodate the river uses in different ways will be analyzed. Upon completion, the SOR EIS will provide additional information on the environmental effects of changes in hydro system operations. If an alternative in the SOR EIS causes a reduction in hydropower operation or capability, the RPEIS will provide information on the potential replacement resource(s) and their environmental impacts.

Changes in the Final Environmental Impact Statement

The Draft Resource Programs EIS was released for public review during the summer of 1992. Comments received by letter or in the public hearing held June 16, 1992, were used to revise and update data and analyses of the EIS (public comments and BPA's responses are contained in Volume III of the Final EIS). In addition, a number of revisions were made in the Chapter 3 material describing each resource type, and in Chapter 4 and the Summary, to assure consistency with the modeling and analysis in Chapter 5. Additional information about the capacity aspects of each resource type and alternative has been added, and the material on conservation and its impacts has been reorganized.

Purpose of and Need for Action

Chapter 1

1. The first part of the document is a letter from the President of the United States to the Congress, dated January 3, 1862. It is a very long letter, and it contains a great deal of information about the state of the country at that time. It is a very important document, and it is one of the most interesting documents in the collection.

Chapter 1

Purpose of and Need for Action

1.1 Purpose of and Need for Action

Need

The Bonneville Power Administration (BPA) needs to acquire sufficient new resources to meet electricity deficits caused by growing customer loads.

Purpose

The purposes of this action are to:

- ◆ Ensure that BPA can meet its contractual obligations to supply cost-effective electric power to its customers—taking into account potential environmental consequences when making any decisions to acquire resources to meet those loads;
- ◆ Assure consistency with BPA's statutory responsibilities, including the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), which requires consideration of the Northwest Power Planning Council's (Council) Conservation and Electric Power Plan and Fish and Wildlife Program;
- ◆ Restore and enhance environmental quality and avoid or minimize possible adverse environmental effects.

Scope

The Resource Programs Environmental Impact Statement (RPEIS) is a programmatic document that is intended to be broad enough to support decisions for several years. Before analyzing the actions BPA could take to meet the underlying need, the RPEIS evaluates the environmental effects of generic resource types and potential mitigation measures for each. Then a range of alternatives is considered. Except for No Action, each of these alternatives is comprised of a combination of resource types. The analysis in the EIS focuses on the environmental impacts of adding these combinations of resources to the

impacts despite uncertainty in future load growth and in the availability of existing resources, each of the alternatives will allow BPA to meet its obligations under high load growth.

The RPEIS covers broad issues associated with resource acquisitions. It evaluates the environmental tradeoffs among generic resource types and the cumulative effects of adding these resources to the existing system. Subsequent site-specific environmental analyses tiered to this programmatic EIS will be undertaken on actual resource acquisitions.

1.2 BPA's Role as a Power Marketing Agency

The Bonneville Project Act of 1937 (Project Act) established BPA as the marketing and transmission agent for power produced by the Bonneville Dam (16 U.S.C. 832a(a)). Through subsequent delegations within the Executive Branch and ultimately through statute, BPA was given the additional responsibility to market power from 31 Federal dams in the Columbia River Basin and certain thermal resources (16 U.S.C. 838f and 839a(10)). BPA uses revenues from the sale of power and transmission services to recover the costs of operating the system, to repay the Federal investment in the system, and to back the financing of new power generation and transmission facilities, conservation measures, and fish and wildlife enhancements.

In response to an increasingly pressing need for coordination in planning and developing the region's power supplies, Congress, on December 5, 1980, enacted Public Law 96-501, the Northwest Power Act. Under the Northwest Power Act, BPA is authorized to purchase generating capabilities of future resource additions and integrate them into the Federal power system. At the same time, this statute created an obligation for BPA, if requested, to serve the load growth of its utility customers to the extent each utility did not serve its own load. Thus, the Northwest Power Act created a long-term supply obligation on BPA at the same time that BPA was granted authority to acquire resources.

The Northwest Power Act also authorized the states of Idaho, Montana, Oregon, and Washington to enter into an interstate compact for the purpose of long-range region-wide power planning and the protection of some specific shared resources. This legislation created and directed the Northwest Power Planning Council to develop both a 20-year regional Power Plan, and a program to protect, mitigate, and enhance the fish and wildlife affected by hydroelectric development in the Columbia River Basin.

The Power Plan sets goals and objectives for BPA and other regional energy interests. It also provides guidance to BPA and the long-range context within which BPA's own planning takes place.

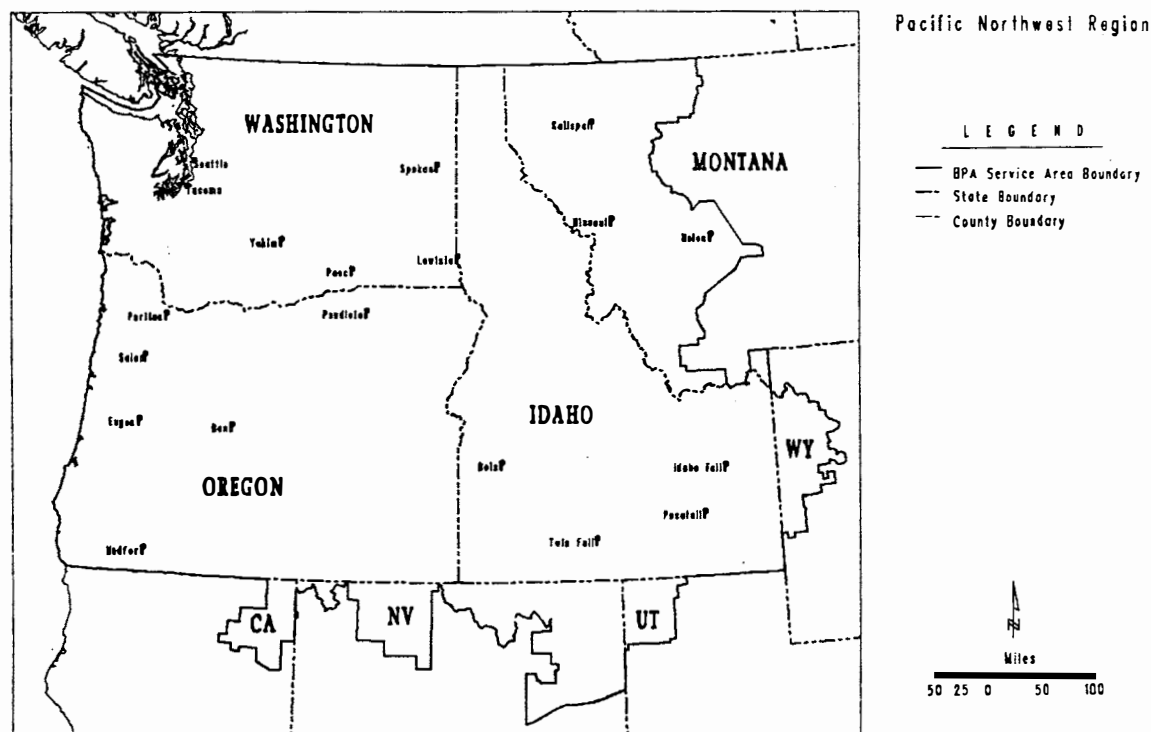
In assuring the region an adequate, efficient, economical, and reliable power supply, the Northwest Power Act encourages conservation and efficiency in the use of electric power and development of renewable resources in the Pacific Northwest. The Plan gives the following priorities to resources that are cost-effective:

1. Conservation;
2. Renewable resources (such as hydro, geothermal, solar, and wind);

3. Generating resources using waste heat or of high fuel conversion efficiency (such as cogeneration); and
4. All other resources (e.g., nuclear, coal, combustion turbines).

Today, BPA is the largest power marketing agency within the Department of Energy. Congress has defined BPA's primary marketing area as the Pacific Northwest Region, encompassing the States of Washington, Oregon, and Idaho, as well as the State of Montana west of the Continental Divide and certain other border areas (16 U.S.C. 839a(14)). (See Figure 1-1).

Figure 1-1
BPA Service Area

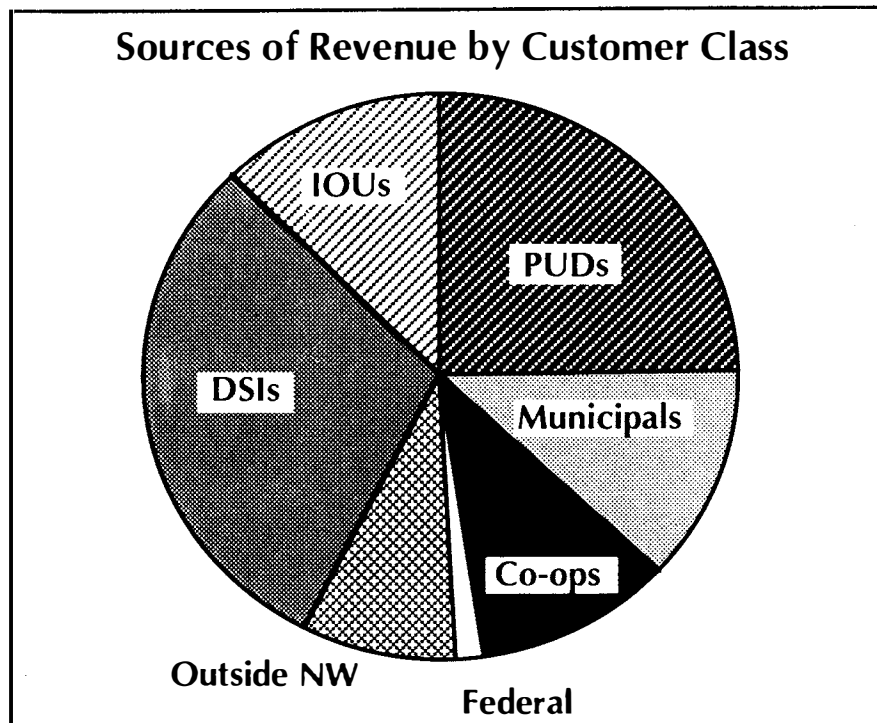


BPA markets wholesale electric power under various rate schedules to several customer groups inside and outside the region (see Figure 1-2). Within the region, BPA customers include four groups:

- ♦ **Preference Customers** - public bodies and cooperatives that, under the Project Act and the Northwest Power Act, enjoy statutory priority for available power, including BPA's surplus power. BPA is required to meet their loads as requested.
- ♦ **Direct-Service Industries (DSIs)** - large industries (such as aluminum smelters) that purchase power directly from BPA rather than from a utility. The Northwest Power Act gave the DSIs rights to initial, 20-year power contracts, and authorized BPA to offer additional, follow-on contracts as prescribed by law; however, the DSIs do not have preference status.

- ◆ **Investor-Owned Utilities (IOUs)** - although they are nonpreference customers, the Northwest Power Act requires BPA to serve the load growth of IOUs upon request with minimum notice as required under their power sales contracts.
- ◆ **Federal agencies** - BPA is authorized -- but not required -- to serve the needs of requesting Federal agencies.

Figure 1-2
BPA Sales by Customer Class



BPA Sales and Revenues for FY 1990

Customer Class	Energy Sales (MWh)	Total Revenues (\$000)
Municipalities (39)	10,786,135	\$ 234,841
Public utility districts (28)	20,517,725	469,650
Cooperatives (56)	9,377,114	204,519
Federal agencies (6)	1,169,170	24,563
Investor-owned utilities (8)	7,734,230	239,260
Aluminum industry (8)	25,525,463	578,591
Other direct service industries (8)	1,489,405	35,686
Total Pacific Northwest Sales (153)	76,599,242	1,787,110
Sales Outside Pacific Northwest (20)	8,576,923	158,244
TOTAL (173)	85,176,165	\$1,945,354

Under provisions of the Northwest Power Act and the Pacific Northwest Regional Preference Act of August 31, 1964 (Public Law 88-552), BPA may sell surplus power not needed in the region to entities outside the region. Presently, BPA sells power to public bodies, Federal agencies, and 14 IOUs outside the Pacific Northwest region, primarily in California.

Transmission System

BPA owns and operates a high voltage transmission system comprising approximately three-quarters of the bulk transmission capacity in the Pacific Northwest. BPA uses this transmission capacity to deliver power to its customers and makes transmission capacity available to other utilities.

The Federal transmission system is comprised of 14,779 miles of high voltage transmission lines, 387 substations, and other related facilities. BPA transmits its power and provides wheeling and other power services to its customers over this system. Included in this transmission system are BPA's portions of the Pacific Northwest/Pacific Southwest Intertie (Intertie), which consist of three high voltage transmission lines with a combined capacity of about 6,300 megawatts, and associated facilities that interconnect the electric systems of the Pacific Northwest and Pacific Southwest. BPA owns approximately 80 percent of the portions of the Intertie located north of California and Nevada. The Intertie provides the primary bulk transmission link between the two regions. BPA and certain Northwest and California utilities are planning to add 1,600 megawatts to present Intertie capacity by November 1993.

BPA's transmission system also includes an interconnection with British Columbia. This interconnection has a nonfirm capability of 2,300 megawatts and allows the Pacific Northwest and British Columbia to undertake many mutually beneficial arrangements. BPA has connections east of the region as well.

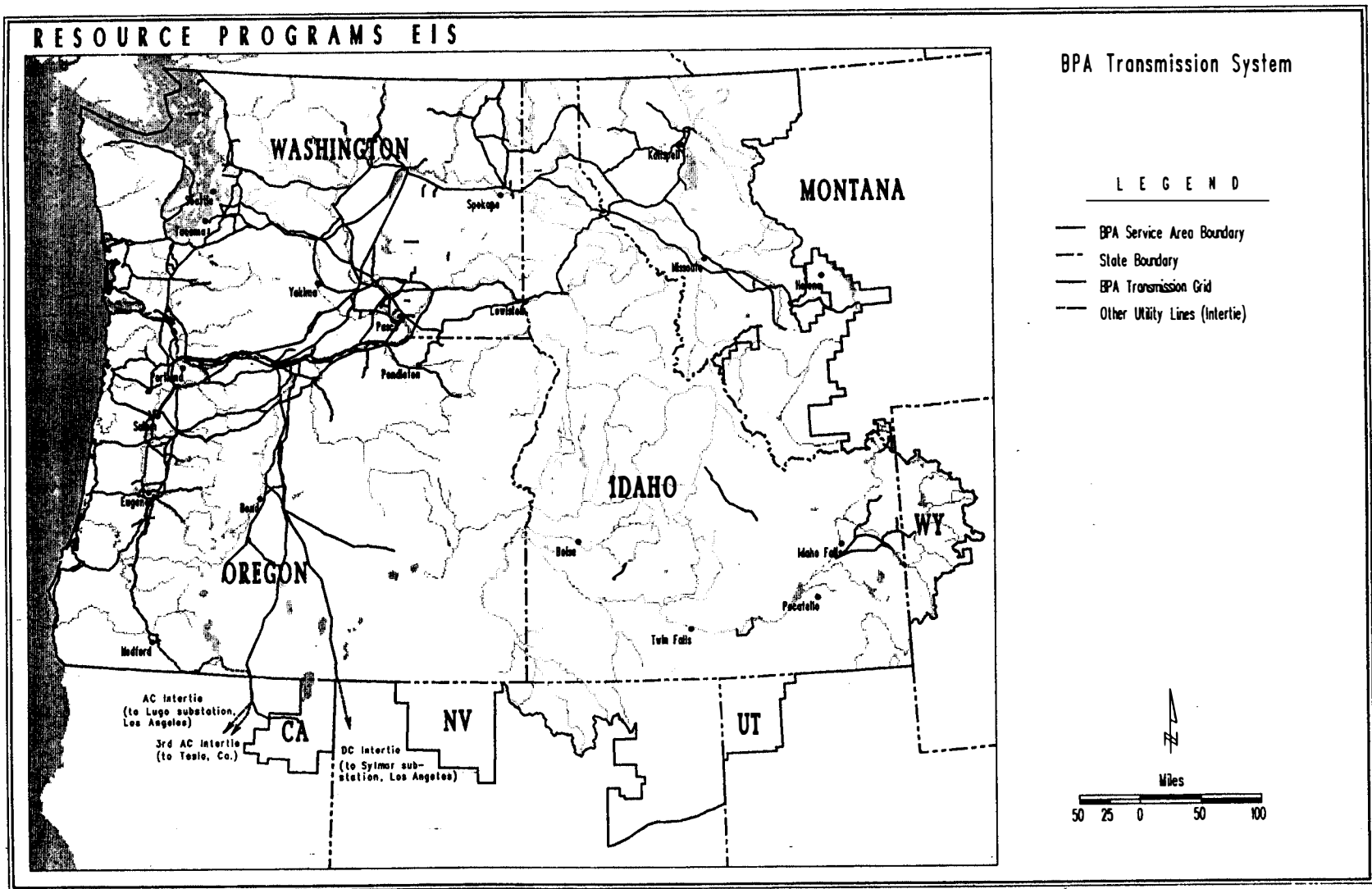


Figure 1-3
BPA Transmission System

1.3 BPA's Resource Program

Every 2 years, BPA prepares a Resource Program that communicates how BPA proposes to meet its expected load obligations. For each Resource Program, alternatives composed of different combinations of energy resource types from BPA's resource stack are examined. (The resource stack is the list of resources, ordered generally by cost, forecast to be available to meet electric power needs. See Chapter 4, section 4.1.) BPA's planning model relies on this resource stack in simulating resource acquisitions and serves as a basis for BPA's resource planning decisions.

BPA relies on the Northwest Power Planning Council's most recent Power Plan to provide the long-range context within which BPA's own planning takes place. In developing a Resource Program, the guidance in the Power Plan is translated into specific near-term actions with associated budgets.

BPA prepares load forecasts used in the Resource Program jointly with the Council. A range of forecasts is prepared to reflect uncertainties about future load growth. Next, a range of load/resource balances is prepared by comparing the energy capability of the existing Federal system resources to the range of projected Federal system loads over the next 20 years. In a parallel process, BPA and the Council develop new resource supply forecasts to plan acquisition of cost-effective resources as needed to meet load growth and to facilitate program design.

Under the 1990 long-term medium forecast, the Federal system was in load/resource balance, with sufficient resources to meet BPA's needs for the rest of the decade. However, in the 1991 long-term medium forecast, the Federal system was 400 to 500 average megawatts (aMW) deficit in the near-term and would require 800 aMW by the year 2000. The actual level of future loads is not known. If demand grows faster or if resources do not perform as expected, BPA could face a deficit. Under high load growth, BPA could have about 5,000 aMW of resource need to meet by the end of its 20-year planning period.

In addition to these projected energy loads, changes in the operations of the hydro-electric system to increase fish survival may reduce the capacity of the Federal system. The need to replace capacity to meet peak loads may become an increasingly important goal of BPA's future Resource Programs (see section 1.4, Capacity).

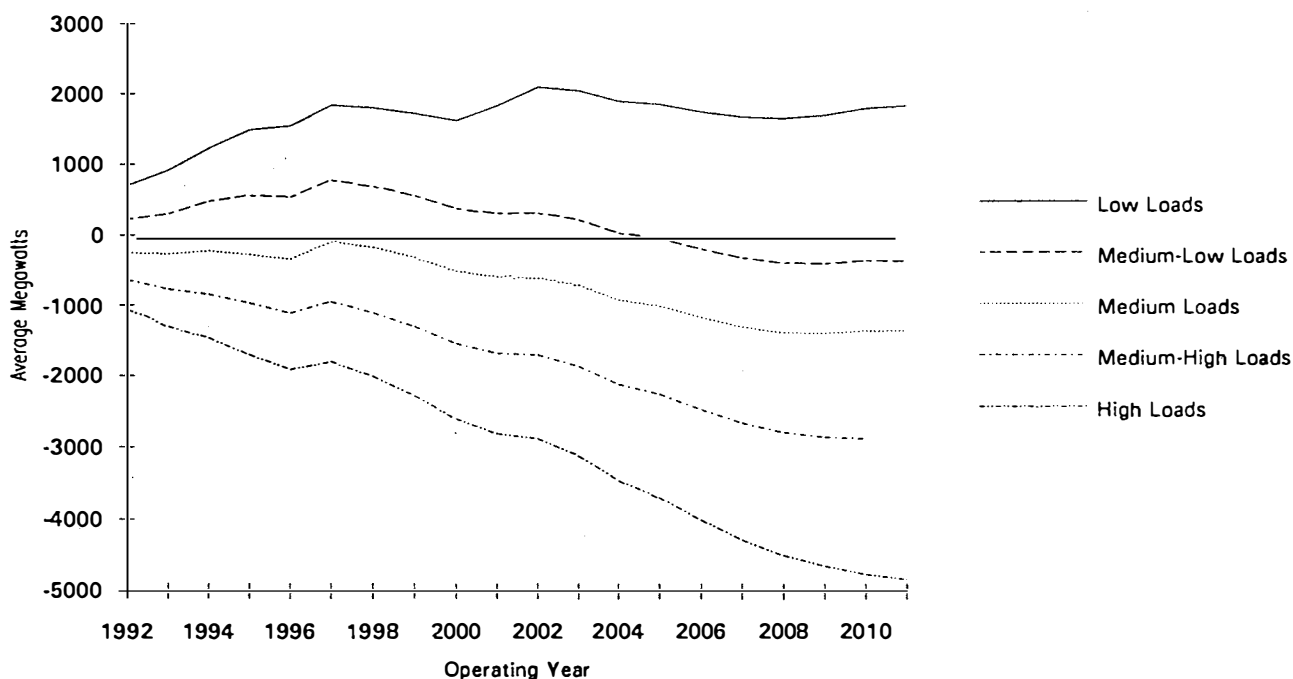
This Resource Programs EIS is part of the planning being done to assure that BPA will be able to meet its loads in a cost-effective and environmentally sound manner. The RPEIS focuses on the environmental tradeoffs among the various resource types (such as conservation, renewables, nuclear, or coal), and the impacts of adding various combinations of these resources to the existing system. These combinations of resources represent the range of alternatives that could be included in future Resource Programs.

Although supplements may be necessary in the future, the analysis in the RPEIS is intended to be broad enough to support several Resource Programs, beginning with the 1992 Resource Program. BPA plans to use the RPEIS (along with the results of additional analyses) to support these Resource Programs. The Resource Programs will also clarify and make more specific the decisions made in the ROD on this EIS. Following the identification of actions in each Resource Program, specific resource acquisitions will be proposed. Separate site-specific environmental analyses will be undertaken to evaluate the impacts of those

acquisitions. The RPEIS will be incorporated by reference into each site-specific environmental document prepared for a resource acquisition.

Although costs are analyzed in this document, resource costs are expected to change over time. Shifts among relative costs of the different resources will be incorporated in each Resource Program. Subsequently, just as site-specific environmental analyses will be prepared for proposed acquisitions, specific economic analyses will also be prepared to document resource cost-effectiveness at the time of the acquisition decision.

Figure 1-4
Federal Firm Energy Surpluses/Deficits
Assuming No Resource Acquisitions



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

1.4 Capacity

Capacity is the amount of power that can be produced by a generator (or generation system) over an instant or a defined period of high demand (e.g., winter days). In the past, BPA has had a surplus of capacity because the hydroelectric system was developed to utilize most of the high flows that generally occur each spring. When generation additions were evaluated, economic analysis indicated benefits to installing additional generators on existing dams to maximize use of the spring high flows. Any excess nonfirm power that was produced was marketed to the Southwest or used to displace more expensive Northwest resources. New

resources that were added to the Federal system to meet energy needs also brought capacity to the system.

In the long-term, BPA tries to plan toward load/resource balance for both energy and capacity. In the shorter-term, BPA's strategy is to market surplus capacity and acquire resources for their energy.

Recent changes in hydroelectric system operations to enhance fish survival have required storing additional water January through March each year, reducing the capacity of the hydroelectric system during those months. The additional stored water is released during the spring and summer to support downstream anadromous fish migration, potentially increasing capacity during that period. However, additional capacity has little value in the Pacific Northwest during the spring and summer because loads are lower than during the winter peak load season. Additional capacity available in the spring and summer has been sold, when available, to the Southwest.

Some current proposals to modify hydroelectric operations to increase fish survival, such as spilling water instead of generating during the spring runoff, and operating reservoirs at or below minimum pool levels, would reduce the capacity available for marketing to the Southwest or for displacing expensive Northwest resources.

BPA has begun to reexamine the amounts and characteristics of capacity on the combined Federal system. As a result of this reexamination, the capacity characteristics of conservation and generation resources (including imports and exports) may become increasingly important elements in the evaluation of future BPA energy resource acquisitions.

1.5 Relationship to the Columbia River System Operation Review

The Corps of Engineers, Bureau of Reclamation, and Bonneville Power Administration are jointly preparing a System Operation Review (SOR) EIS on the operation of the Columbia River hydro system. The SOR EIS will allow the three Federal agencies to make decisions on (1) adopting a System Operating Strategy (SOS), (2) renewing the Pacific Northwest Coordination Agreement (PNCA), (3) renegotiating five Canadian Entitlement Allocation Agreements, and (4) developing a means to periodically review and update the SOS. The SOR EIS is scheduled for completion in late 1993 or early 1994.

The SOR will focus primarily on 14 Federal projects: 5 storage projects and 9 run-of-river projects on the mainstem Columbia and Snake Rivers and several major tributaries. Alternatives to be evaluated will range from No Action and Status Quo to a variety of new operations that accommodate the river uses in different ways. The impacts of alternatives to all uses, including navigation, flood control, recreation, hydropower generation, fish and wildlife, irrigation, and other purposes, will be evaluated. An extensive public involvement process will allow the entire region to participate in formulating the alternatives to be considered and the techniques for determining impacts.

Balancing the multiple uses of the Federal hydro facilities in the Columbia River Basin could affect hydroelectric power production. If the SOS adopted causes a reduction in hydropower operation or capability, resources will need to be

acquired. The SOR EIS will rely upon the RPEIS to provide information on resource acquisitions.

As part of the development of a multiple-use operating strategy for the hydro system, the SOR EIS will evaluate the trade-offs between power and nonpower uses. Major changes in Columbia River system operations are being considered. However, the analysis in the RPEIS of the effects of adding resources to the existing system is based on current constraints and operating requirements. Upon completion, the SOR EIS will provide additional information on the environmental effects of changes in hydro system operations.

1.6 Incorporation By Reference

Several environmental documents prepared for various BPA conservation programs are incorporated by reference. All of these documents are available for inspection through BPA's Public Information Office.

EA on Approaches for Acquiring Energy Savings in Commercial Sector Buildings (DOE/EA-0513), September 1991. BPA proposed three approaches: (1) targeted acquisition, (2) billing credits, and (3) competitive acquisition to encourage utilities to design and offer regional conservation resources to acquire savings in the commercial sector. The potential environmental effects associated with the installation of energy conservation measures in new and existing commercial buildings were considered. Specific environmental requirements were developed for all three approaches to assure proper installation of measures and avoidance of impacts.

Final EIS on New Energy-Efficient Homes Programs (DOE/EIS-0127F), August 1988. BPA had implemented marketing and financial incentive programs and was in the process of implementing a surcharge policy to encourage the construction of new energy-efficient homes that complied with the Model Conservation Standards developed by the Northwest Power Planning Council. In this EIS, BPA proposed giving builders and consumers more flexibility by increasing the options for protecting indoor air quality in its new homes programs. A broad menu of options, making up 11 pathways, was examined. Although many pollutants were assessed qualitatively, the analysis focused on the relationship between ventilation rates and concentrations of radon and formaldehyde.

Direct Service Industry Options Final EIS (DOE/EIS-0123F), April 1986. BPA proposed to implement one or more options to reduce load fluctuations and revenue uncertainty resulting from its electrical service to 10 aluminum smelters and its other direct service industrial customers. One of the options, the aluminum smelter Conservation/Modernization Program, consisted of on-site modifications and retrofits to improve the production efficiency of the aluminum smelters. The EIS analyzed the environmental impacts of these aluminum smelter conservation measures.

The Expanded Residential Weatherization Program Final EIS (DOE/EIS-0095F), August 1984. BPA proposed to expand its Residential Weatherization Program, which had excluded certain types of residences from receiving air infiltration-reducing (tightening) measures--storm windows and doors, wall insulation, caulking, weatherstripping, and electrical switchplate and outlet

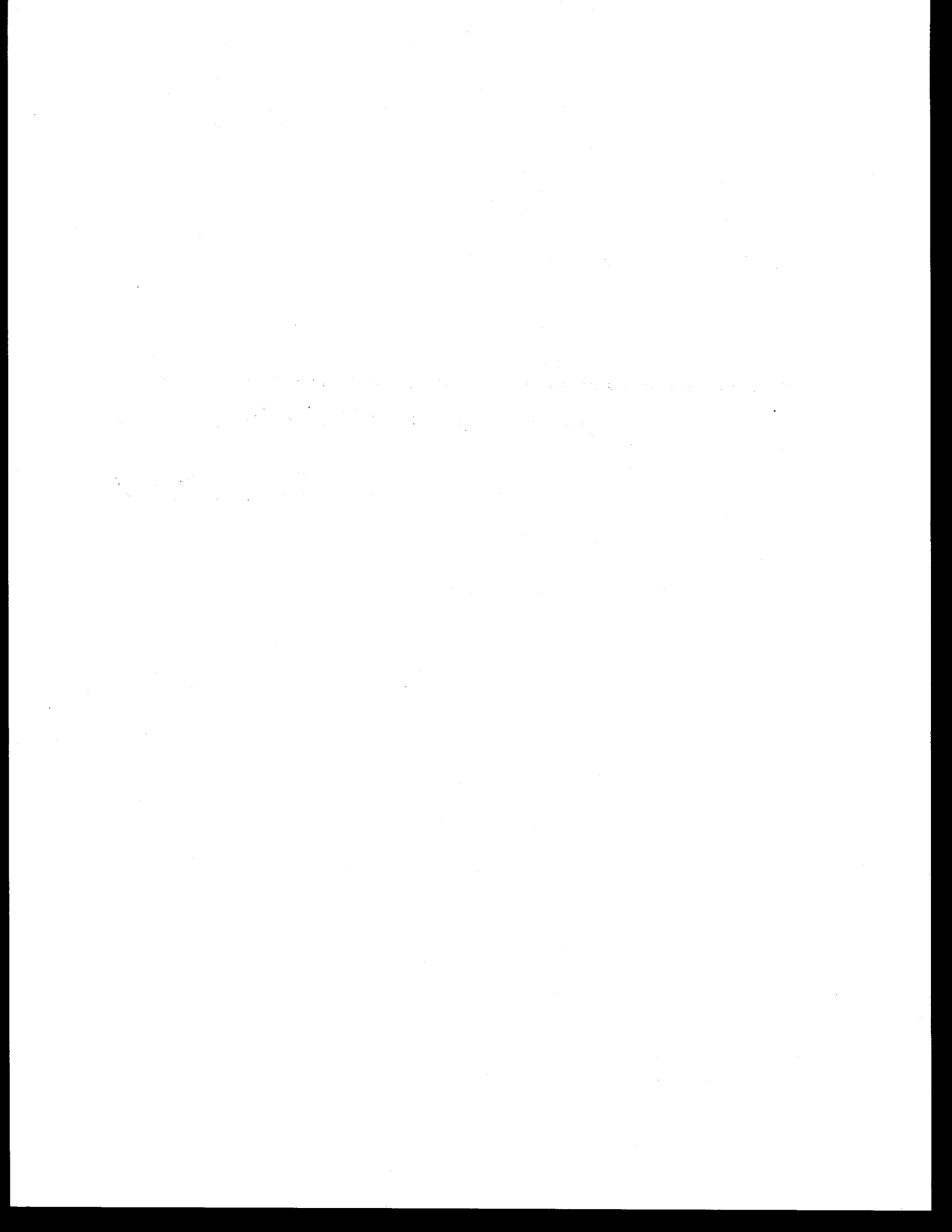
gaskets. This EIS evaluated the effects of five alternative actions. The major effects examined were indoor air quality, public health, energy, and socioeconomic and institutional changes.

EA on Energy Conservation Opportunities in Commercial-Sector Facilities in the Pacific Northwest (DOE/EA-0187), August 1982. In this EA, BPA considered a program that would make funds available to commercial building owners and institutions for energy audits and financing of cost-effective retrofits in their buildings. Three energy conservation programs were compared: (1) a new conservation program (the no-action alternative); (2) a program that did not specify limits regarding air quality (the unrestricted program); and (3) a conservation program that required the maintenance of certain air quality criteria within buildings (the restricted program).



Affected Environment

Chapter 2



Chapter 2

Affected Environment

The study area includes:

- ♦ BPA's service area, which covers the States of Idaho, Oregon, and Washington; the State of Montana west of the Continental Divide; and small portions of the States of Wyoming, Utah, Nevada, and Northern California (collectively referred to as the Pacific Northwest); and
- ♦ The Canadian Province of British Columbia.

In addition, areas in eastern Montana, north-central Nevada, and southwestern Wyoming surrounding coal plants that serve the Pacific Northwest; the State of California; and the States of Nevada, Arizona, Utah, and New Mexico (collectively referred to as the Inland Southwest or ISW) are studied for socioeconomic and power system concerns.

The area potentially affected by the alternatives under consideration is very broad. Therefore, the descriptions in the following sections focus on those aspects of the affected environment necessary to understand and compare the alternatives. Since this is a programmatic document that looks at the effects of adding alternative combinations of generic resource types to the existing system, attention has been concentrated on describing the existing power system and the social and economic relationships between the Pacific Northwest, British Columbia, California, and the Inland Southwest. The interrelated aspects of the natural and physical environment have also been described with particular attention to the Pacific Northwest. Resource development in California and the Southwest would be so limited and site-specific that a review of natural resource issues in these areas would not be useful at this programmatic level.

Appendix A contains supplemental data on the topics covered in this chapter.

2.1 Social and Economic Considerations

2.1.1 Geography and Land Use

Pacific Northwest

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

The Pacific Northwest includes all or portions of three physiographic provinces: Northern Rocky Mountain, Columbia Plateau, and Pacific Mountain system. Major features include the Columbia and Snake Rivers, the Puget Sound and Willamette Valley plains, and the Coast Range, Cascade, and Rocky Mountains. These features define the climate, vegetation, transportation, and development patterns of the region.

Half the region is covered by forest (primarily Douglas fir or varieties of pine), most densely west of the Cascade Range. Rangeland occupies substantial areas in the Snake River and Rocky Mountain regions. Agricultural lands are located primarily on the Columbia River Plateau, along the Snake River, and in the Willamette Valley. About two-thirds of the land in the region is publicly owned, enabling the development of multiple use land programs and extensive recreational opportunities. Land managers include the Federal Government (including the U.S. Forest Service, Bureau of Land Management, Department of Energy, and Department of Defense), state and local governments, and Indian tribes. The rest of the land is privately owned.

The Cascade Range, which runs north-south, divides Oregon and Washington into two unequal and widely different climatic regions. Coastal climate is mild and wet, with only occasional extremes of temperature. East of the Cascades, most of the precipitation occurs in the winter in the form of snow, and summer months are hot and dry.

Idaho experiences a wide variation in climate. Pacific Ocean air brings temperate climate to the northern third of the state, while high mountains on the eastern border tend to block cold air from Montana and Wyoming.

Elevations of the Pacific Northwest range from sea level to 14,410 feet at Mt. Rainier in Washington.

Beginning in southeastern British Columbia, the Columbia River flows south and west for 1,214 miles to the Pacific Ocean. From the point it passes into the State of Washington to its mouth, it drops steadily for 748 miles. The Snake River, which is 1,038 miles long, begins in northwestern Wyoming. It flows west and north, forming part of the borders between Oregon and Idaho and between Idaho and Washington. Part of that border is the nation's deepest canyon (Hell's Canyon).

In southern Washington, the Snake River joins the Columbia and they flow west and north, forming the border between Oregon and Washington. The rivers flow through extensive wilderness, scenic, and recreation areas. The rivers pass through irrigated agricultural area in the plateaus east of the Cascade Mountains

and through the Cascade and Coast Mountain Ranges on their way to the Pacific Ocean.

California and the Inland Southwest

California is mostly part of the Pacific Mountain System physiographic region, although portions of southeastern California are part of the Basin and Range province.

The Southern Cascade Mountains and the Sierra Nevada form California's backbone, a barrier the length of the state that is crossed in only a few places. Elevations reach over 14,000 feet above sea level at Mt. Whitney and Mt. Shasta. The majority of the mountain ranges trend north-south and exert major influences on the climate of the region, with extremes in several areas.

To the west of this barrier lies the Great Valley and the California Coast Ranges. The valley contains the major population centers and is a high-value agricultural area, heavily irrigated. The Coast Ranges, mostly lower than 5,000 feet, support commercial forestry, grazing, and specialty crops such as wine grapes.

To the east of the Cascades and Sierra barrier are the parts of California in the Basin and Range province. It is a semi-desert to desert region of plateaus, basins, plains, and isolated mountain ranges.

The Inland Southwest includes some of the driest portions of the United States. Physiographically, the region is in the Basin and Range, the Colorado Plateau, and portions of the Southern Rocky Mountain provinces. Topographically, the region encompasses the lowest and some of the highest elevations in the continental United States. The Colorado River Basin is the major drainage for the region, rising on the Continental Divide and ending at the Pacific Ocean. It contains major multipurpose dams, such as Hoover Dam, which provide electric power, water supplies, and recreation areas. The land is fairly arid, except for the Rocky Mountains, which are moderately wet. The area tends to be water-limited, with most precipitation occurring in the mountains. Land use includes mining and mineral processing, cattle ranching, and farming. Since much of the land is arid, agriculture is dependent upon irrigation, although dry farming is practiced in portions of New Mexico.

British Columbia

The geography and land uses of British Columbia, like the Pacific Northwest, center on river systems. Columbia Lake, the source of the Columbia River, is situated 2,664 feet above sea level in the Canadian Rocky Mountains in southeastern British Columbia. The river flows north, then turns sharply to flow south to the international border, for a total of 459 miles and a drainage area of 39,550 square miles in Canada. Near the border, it is joined by the Kootenay River, which begins in the Canadian Rockies, proceeds south into Montana and Idaho (where it is the Kootenai), then returns north into Canada before joining the Columbia. The Peace River, which also begins in the Canadian Rocky Mountains in eastern British Columbia, flows north and east into Alberta, eventually emptying into the Arctic Ocean. Regulation of these river systems by dams has reduced seasonal flow variations and, on the Columbia, reduced the occurrence and severity of floods. Dams on the rivers also produce power.

In general, land uses in British Columbia include forestry, mining, and mineral processing, as well as some cattle ranching and tourism. Since much of the terrain

is mountainous, there is little arable land. The forest industry dominates the western portion; the eastern reaches include a broader mix of uses, such as agriculture, forestry, mining, oil and gas, and transportation. British Columbia's waters produce a rich harvest of fish, including salmon. Water resource uses also include recreation, transportation, and power production.

2.1.2 Population

Pacific Northwest

In the Pacific Northwest, population centers around Seattle/Tacoma (WA), Portland/Vancouver (OR/WA), Eugene/Springfield (OR), Spokane (WA), and Boise/Nampa/Caldwell (ID). Estimates indicate that the population in Washington grew from about 4.13 million in 1980 to about 4.87 million in 1990, a 17.9 percent net increase and an annual rate of growth of 1.7 percent. The population of Oregon increased from about 2.63 million in 1980 to an estimated 2.85 million in 1990, an 8.2 percent net increase and an annual growth rate of 0.8 percent. The population in Idaho grew from 945,000 to about 1 million, a 6.9 percent net increase and an annual growth of 0.7 percent. The population of western Montana grew from 294,500 in 1980 to approximately 303,300 in 1990, nearly a 3 percent net increase and an annual growth rate of 0.3 percent.

California and the Inland Southwest

In California, population is centered around Los Angeles, San Diego, San Francisco, San Jose, and Sacramento. The much smaller population of the Inland Southwest is clustered in the Salt Lake City, Phoenix, Tucson, Albuquerque, Santa Fe, Las Vegas, and Reno metropolitan areas. The population of the region as a whole is 36,264,000, with 29,473,000 in California (California State Department of Finance, Demographic Research Unit).

British Columbia

Population in British Columbia is centered around Vancouver, Victoria, and a few smaller centers. The population of the province has grown from approximately 2.5 million in 1976 to about 3 million in 1990 (Canadian Consulate General, Office of Tourism). British Columbia Hydro and Power Authority (BC Hydro) has projected a population growth of about 1.6 percent on an annual basis through 1999 and 1.3 percent per year for the following 10 years.

2.1.3 Industry/Economic Base

Pacific Northwest

Over the past 10 years, the economy of the Pacific Northwest has evolved from resource-based to more diversity, with growing trade and service sectors. In 1980, resource-based industries accounted for 30.9 percent of manufacturing employment; by 1990, their share had fallen to 27.2 percent. High technology industries (aerospace, electronics, and scientific instruments), have grown in share over the last decade from 33.7 to 38.6 percent of total manufacturing. Overall, the manufacturing share of the regional economy was 19.4 percent in 1980 and fell to 17.3 percent by 1990.

The lumber and wood products industry still plays an important role in the region's economy, with 3.1 percent of the total regional employment, but this sector has

declined from a decade ago, when it accounted for 4.4 percent of total employment. Food processing has fallen from 2.5 percent of total employment in 1980 to 2.1 percent in 1990. This loss of employment share has been due to an increase in the relative size of the employment base and productivity gains brought on by plant upgrades and other efficiencies. Transportation equipment, primarily Boeing, has remained at nearly 4 percent of total employment over the last decade, and the electronics industry has remained at about 3 percent of total employment. Energy-intensive aluminum production is economically important to the region, but the level of employment in this sector is relatively small (below 0.7 percent of total employment in 1990).

While the manufacturing share fell over the decade, the nonmanufacturing share of total employment rose from 80.6 to 82.7 percent. A rise in wholesale and retail trade and services accounts for most of the gain. Employment in trade grew from 24.1 percent of total employment in 1980 to 24.7 percent in 1990. The services sector grew from 18.8 percent of total employment in 1980 to 23.4 percent in 1990. The region's growing trade with California and the Far East also broadened the economic base.

Twenty-five percent of U.S. exports to Asia and 30 percent of all U.S. exported goods are handled through Pacific Northwest ports. In fact, the Ports of Seattle and Tacoma are the fourth and sixth largest ports in the world, respectively.

The advantage of low-cost energy relative to other areas has strengthened the region's economic base. Due to the availability of natural gas from Canada and the region's hydro base for electricity, the Pacific Northwest has a long-term energy advantage. On average recently, the region's electricity prices ran 40 percent lower than the national average and natural gas prices were 16 percent less.

The region still can be hard-hit by high interest rates and their dampening effect on housing, which is the biggest source of demand for the region's lumber and wood products. However, more diversity and efficiency in industries in the region means more resistance to severe fluctuations now than in the past. Continued high levels of international trade should help offset the negative impact of periodic national business cycles, and the nonmanufacturing service sector of the region's economy is expected to continue to grow faster than total employment.

California, with over 29 million people (more than 10 percent of the nation's total population) represents an important market for the Pacific Northwest. The tourism industry, fueled by the scenic coast, Columbia River Gorge, and Hells Canyon, provides economic stimulus in less populated regions and helps stimulate activity in the service and trade sectors. Agriculture also is a substantial industry in the region, employing about 276,000 in 1990, down from about 285,000 in 1980. The decline in agriculture employment is part of the shift toward a less resource-dependent economy, and also is due to growing productivity in the farm sector.

California and the Inland Southwest

California has a rich endowment of natural resources, amenities, and climate. The state is a major source of the nation's fruits and vegetables. Its agricultural sector ranks first in the nation in cash value and produces virtually every crop grown in temperate zones. Lumber production is second only to Oregon, and its mining production ranks among the top three states. Employment in manufacturing industries is the leading source of personal income, followed by government, wholesale and retail trade, and service occupations. The entertainment industry, although it has declined somewhat since WWII, is still a significant part of the state's economy, while tourism is one of the fastest growing sectors.

The economy of the Inland Southwest is based on mining and ore processing, manufacturing, services, agriculture, and tourism.

British Columbia

The economy of British Columbia as a whole, and especially the areas through which the Columbia and Peace Rivers flow, is heavily resource based. Forestry, mining, and mineral processing industries are important sources of income and employment. In many cases, these industries rely on the river system either for power or transportation. The river systems also are closely tied to another important economic base--tourism and recreation (Envirocon 1986). Petroleum and natural gas production also are important to the economy.

There is abundant hydroelectricity, natural gas, and coal to serve the needs of both domestic and export customers (B.C. Ministry of Energy, Mines, and Petroleum Resources). However, high unemployment (currently 8.3 percent, seasonally adjusted) has resulted from economic dependence on natural resources (Labor Force Annual Averages, 1990, 71-220). Nonetheless, with an ample and diverse energy supply, a carefully developed infrastructure, and easy access to world markets, British Columbia is poised for future development.

2.1.4 Existing Power System

Pacific Northwest

Hydro projects produce about two-thirds of the total electricity used by the Pacific Northwest. There are 58 major hydroelectric dams, including 31 Federally owned dams with a combined capacity of approximately 22,000 MW (see Appendix A, Figure A-1 and Table A-1). 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 streamflow varies from month to month and from year to year according to weather and other natural conditions. In normal years and years of heavy run-off, water is readily available to produce electricity needed in the Pacific Northwest; when streamflow is down, additional water is released to maintain required flows. In an average year, 16,400 aMW of hydropower is produced and in the critical period the hydro system produces about 12,400 aMW.

The amount of run-off in the system is highly variable. The average annual run-off is about 134 million acre-feet (MAF), but it has varied from about 78 MAF to

193 MAF. The monthly mean natural streamflow at The Dalles, Oregon, ranges from 40,000 cubic feet per second (cfs) in winter, to 600,000 cfs in the spring.

The total usable storage capacity of the Columbia River system is about 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 Pacific Northwest and BC Hydro coordinate operation of the hydro system to increase flexibility and to enhance power production.

Coordination of the Pacific Northwest 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, Corps of Engineers (U.S. Department of the Army) are designated the U.S. Entity for the Treaty. The Canadian Entity is the Chairman of BC Hydro. Under the Treaty, Canada constructed three storage dams in British Columbia. The total usable Canadian storage at Mica and Arrow, on the Columbia River, and Duncan, on the Kootenay River, was to be 15.5 MAF. The United States was allowed to construct 5 MAF of storage at Libby Dam on the Kootenai River.

The three Canadian storage dams enabled downstream U.S. projects to produce up to an additional 2,800 MW of dependable capacity. Canada's 50 percent share of the increase in downstream power benefits from the Treaty became known as the Canadian Entitlement. Since there was no market in British Columbia for this Treaty power, the rights to the Entitlement were sold to the United States, with the proceeds of the sale used to construct the three Canadian storage projects. The Entitlement belongs to the BC government and the Canadian Entity is responsible for implementing its return.

The term of the sale was 30 years, based upon the operational dates of the Canadian projects. The Canadian Entitlement is estimated to represent 550 MW of usable energy and 1,250 MW of capacity when it reverts to British Columbia during the period 1998-2003. The return obligation extends through the term of the Treaty and the earliest the Treaty could expire is 2024. BPA currently plans for the return of the Entitlement, depicting it as a load in the load/resource balance studies.

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 5 MAF of usable storage at Mica. BC Hydro and BPA have signed a Non-Treaty Storage Agreement, which captures some additional efficiencies due to diversities in loads, resources, and run-off patterns.

Few sites remain in the Pacific Northwest that could effectively accommodate major hydroelectric development. As more power is required, other ways to produce power have been added to the power base. In addition to the hydroelectric system, electricity for the region is also produced at 14 coal units and two commercial nuclear plants. (See Appendix A, Table A-2, for a listing of major Northwest thermal power plants.)

The Pacific Northwest 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 (See Section 2.1.5).

California and the Inland Southwest

Half of California's generating capacity consists of oil- and gas-fired power plants. Next is hydro (about 20 percent), followed by nuclear, coal, geothermal, and cogeneration. Investor-owned and municipal utilities, the California Department of Water Resources, and the Western Area Power Administration (a Federal power marketing agency) can together generate 45,000 MW with their systems.

The peak load demands of the Pacific Northwest and California occur at different times. The Pacific Northwest peak demands occur in the winter, while California's peak demands occur in the summer. During the summer, the hydro-based Pacific Northwest and BPA systems tend to have excess capacity which could be used to help meet California's summer peak demands. In a similar manner, California's thermal-based system tends to have excess capacity in the winter. This excess capacity could be used to help the Pacific Northwest meet its winter peaks. There is a natural fit between the two systems, and there are benefits that each can provide the other. Full use of both systems could reduce the need for new resources. BPA currently has several seasonal energy and capacity/energy exchange contracts in effect with a number of California utilities.

The Inland Southwest 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 Inland Southwest's total capacity could be transferred on a firm basis to supply export power to California and other areas in the summertime (Western Systems Coordinating Council, April 1991).

British Columbia

BC Hydro, a provincial crown corporation, was established to generate, transmit, and distribute electricity. It serves almost 1.3 million customers in an area containing over 92 percent of British Columbia's population. Remote communities which are not integrated into BC Hydro's transmission system are served by small local generating plants. West Kootenay Power Ltd., a private utility, serves approximately 98,000 customers directly or through wholesalers in the south-central interior of British Columbia.

Hydroelectric generation accounts for approximately 90 percent of all electricity production. The only major thermal plant is a natural gas facility on Burrard Inlet near Vancouver, B.C. The Burrard plant is capable of producing up to 912 MW of nominal capacity and 630 aMW of energy. In the past, the plant output was restricted to 0 MW over winter peak with about 360 aMW of energy, as a result of the gas supply assumed at that time. 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.

2.1.5 Energy Conservation

Conservation of electric energy in the Pacific Northwest has been actively pursued for the past decade. The key areas of activity have been in the residential, commercial, industrial, and agricultural sectors. Energy conservation programs are generally categorized as acquisition programs, capability development, technical assistance, or research, development, and demonstration (RD&D). The primary purpose of an acquisition program is to purchase energy savings to help meet BPA's load obligations. If the purpose of a program is to develop and test administrative systems, incentives, quality and cost control procedures, and delivery approaches, that effort is considered capability development. Some programs are designed to support energy conservation through education and information-sharing activities. Those efforts are considered part of a technical assistance program. RD&D projects examine specific applications of new or revised technology and theories through highly structured investigation or experimentation.

Conservation resources have been captured through a variety of approaches, including codes and standards, BPA or utility-designed programs, and new approaches relying on retail, utility, and other third-party program design and implementation. In its new approaches, BPA is trying to clearly communicate the minimum standards, requirements, and conditions under which it will purchase resources. Other third-party program design and operations, such as billing credits, competitive bidding, and targeted acquisitions, were initiated by BPA for testing in 1990.

Table 2-1 lists the existing programs being operated by BPA in the region. Many utilities in the region are also operating programs within the four end-use sectors.

Table 2-1
Current Conservation Programs Administered by
the Bonneville Power Administration

Name	Type	Sector	Target Market
Energy Smart Design	Acquisition	Commercial	All Commercial Buildings All Technologies
Targeted Acquisition	Acquisition	Commercial	All Commercial Buildings
Energy Savings Plan	Acquisition	Industrial	All Manufacturing
Major Plants Test	Acquisition	Industrial	Large Customers
Weatherwise	Acquisition	Residential	All Existing
Super Good Cents	Acquisition	Residential	New Residential
Appliance Efficiency	Acquisition	Residential	New Appliances
Residential Construction Demonstration Project	RD&D	Residential	All Technologies
NW Energy Code Program	Acquisition	Residential	New Homes
Billing Credits	Acquisition	All Sectors	Utilities
Competitive Acquisition	Acquisition	All Sectors	General
Lighting Design Lab	Technical Assistance	All Sectors	Designers/Architects/Engineers
Electric Ideas	Technical Assistance	All Sectors	General
State Technical Assistance Program	Acquisition	All	General
Chain and Franchise Pilot	Acquisition	Commercial	Multi-sited Businesses

2.1.6 Demand For Power

Pacific Northwest

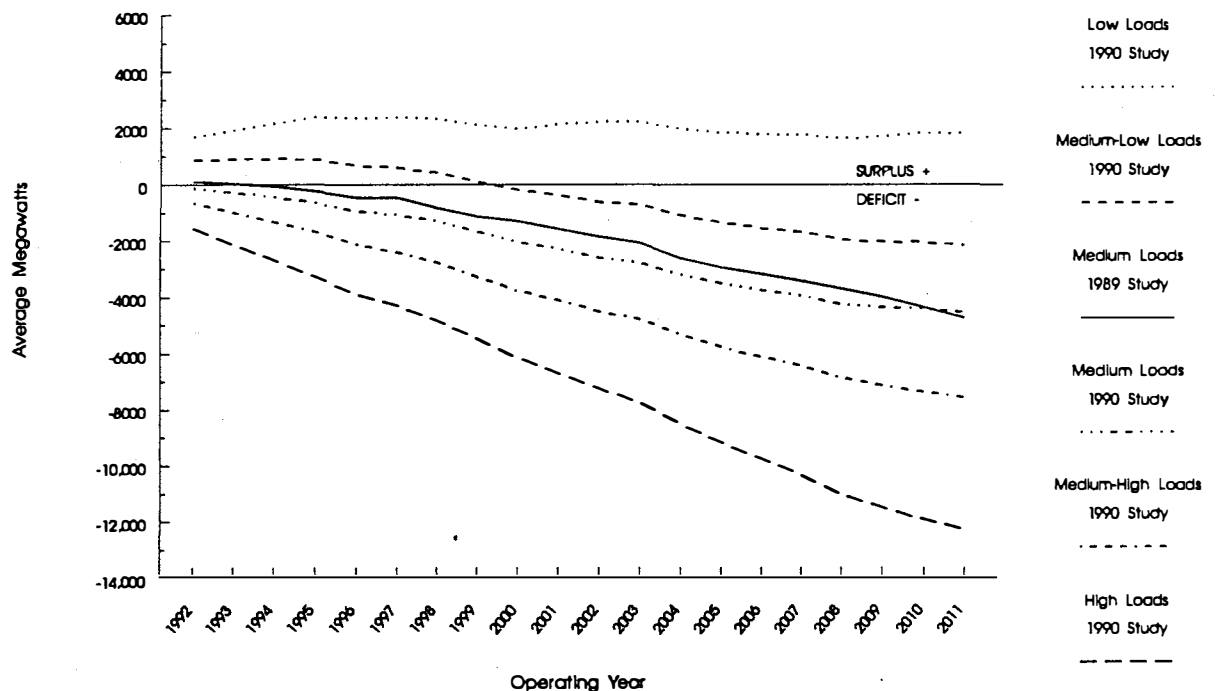
Electric loads within the Pacific Northwest vary according to geographic location and season. The Puget Sound-Willamette Valley region, where two-thirds of the population lives, uses the largest amount of electricity, most of it in winter for heating. East of the Cascades, the difference between winter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

Industrial users account for roughly 40 percent of electric consumption, commercial users for 20 percent, and residential users for over 30 percent. Over time, the region's hydro-based power has become much less expensive than power from fossil fuels, which are used more in other regions. As a result, residential customers rely more on electricity for space and water heating. Although the region uses much less fossil fuel than the rest of the country, residential customers in the region use twice as much electricity for end uses.

Slightly less than half of Pacific Northwest loads are served by BPA, which markets power from U.S. Army Corps of Engineers and Bureau of Reclamation dams and two nuclear facilities: Washington Public Power Supply System Plant No. 2, and a share of the Trojan plant. The public utilities and investor-owned utilities (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 (see Chapter 1) 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, however, 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 in the future, 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, the medium, medium-high, and high forecasts place the region in deficit conditions throughout the 20-year study period. (See Figure 2-1.)

Figure 2-1
Regional Firm Energy Surpluses/Deficits
Assuming No Resource Acquisitions



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

California and the Inland Southwest

State-wide peaking electricity demand in California in 1990 was 45,710 MW. Roughly 90 percent of this demand was from three investor-owned utilities and the two largest municipally-owned utilities.

The California Energy Commission (CEC) Electricity Report 90 forecasts that, between 1989 and 2009, statewide peaking electricity demand is expected to grow by about 2.3 percent annually, while energy loads are expected to grow at 1.8 percent. Individual growth rates projected for the large investor-owned utilities range from 2.2 to 2.6 percent annually for peak, and 1.7 to 2.4 percent for energy.

Individually, Pacific Gas and Electric (PG&E) expects to require 200 MW of capacity by 1999, increasing to 2,570 MW by 2009, and Southern California Edison (SCE) expects to need 1,200 to 1,800 MW by 2001. San Diego Gas and Electric (SDG&E) has the most immediate need, requiring additional capacity in 1991 to meet its reserve requirement. By 2001, SDG&E projects a need for 1,513 MW. By 2009, this need could increase to 2,300 MW.

In the Inland Southwest, 1989 load was approximately 9,884 MW. Since total generating capacity is far greater than load in this region, this part of the Southwest is expected to be surplus over the next 20 years.

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, but only 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.

2.1.7 BPA Power Rates

BPA provides electric power to its preference public utility customers, to direct service industrial (DSI) customers (primarily aluminum smelters), and to other regional and extra-regional customers. Electric power produced by both public and IOU-owned dams in the Pacific Northwest is relatively inexpensive; thus BPA's wholesale power and IOU retail rates have traditionally been low relative to wholesale rates in the rest of the United States. Electricity use per customer is higher than the U.S. average, while the overall electricity cost per customer is close to the national average.

BPA provides a rate mechanism that equalizes, at the wholesale level, the rate paid by residential and small farm consumers of investor-owned utilities with the rates charged the public-owned utilities. (The investor-owned utilities' systems include much more thermal generation than does the Federal base system; hence, their average rates are higher.) This rate mechanism is known as the Residential Energy Exchange. Between 1979 and 1983, rates in the Pacific Northwest rose rapidly. These rate increases were due primarily to the inclusion of costs of the Washington Public Power Supply System's Nuclear Plants 1, 2, and 3, and, to a lesser extent, by programs mandated by the Northwest Power Act. These programs include costs of the Residential Exchange Program, costs of fish and wildlife programs, and Conservation Program costs. Since 1984, rates have been

relatively stable in nominal terms and have declined in real terms after adjusting for inflation.

2.1.8 Cultural Resources

Cultural resources are the nonrenewable evidence of human occupation or activity as reflected in any district, site, building, structure, artifact, ruin, object, work of art, architecture, or natural feature that was important in human history at the national, state, or local level. Cultural resources that could be affected by BPA actions are located throughout the study area.

Recognizing that implementation of conservation programs could affect historic buildings, BPA entered into several programmatic agreements that outline specific procedures to protect the cultural resource values of these buildings.

BPA actions that affect the operation of the existing power system can also affect cultural resources. Changes in hydro system operations can cause changes in reservoir levels at the five Federal storage reservoirs on the Columbia and Snake Rivers: Grand Coulee (Lake Roosevelt), Libby (Lake Koocanusa), Albeni Falls (Lake Pend Oreille), Hungry Horse, and Dworshak. Numerous archeological and historic sites, especially Indian burials and ancient habitations, are known to exist within the reservoir areas and many sites remain to be discovered. BPA has a programmatic agreement with several responsible agencies that provides for consultation and mitigation (see Chapter 6, Section 6.4).

Further discussion of the region's historical development and cultural heritage is contained in Appendix A, Section 1.

2.2 Natural Resources Environment

2.2.1 Air Quality

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 (NO_x), particulates, hydrocarbons, ozone, carbon monoxide (CO), and lead. Of these, particulates, SO₂, and NO_x 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. In addition to these common pollutants, combustion generating plants may also emit heavy metals, radionuclides, and hazardous compounds. Generating technologies and their associated emissions are discussed in Chapter 3. The detailed air quality information and data used in this analysis are contained in Appendix B.

New thermal generating plants are expected to be located in Oregon, Washington, California, Montana, the Inland Southwest and British Columbia, Canada.¹

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 air quality standards and those for Washington, Montana, Oregon, and Idaho are shown in Table 2-2. A comprehensive list of all Federal nonattainment areas in the study area, classified by pollutant, is contained in Appendix A.

Air quality over British Columbia is generally in the "good" to "fair" ranges, with only occasional episodes of air pollution in the "poor" range and no episodes in the "very poor" range. (Greater Vancouver Regional District Air Monitoring System, 1988.) Emissions of carbon monoxide and nitrogen oxides make up the majority of pollutants in urban areas, while particulate matter from wood-burning appliances makes up the bulk of air pollution in rural areas.

California air quality standards are not included in Table 2-2 because they vary greatly among jurisdictions. Air quality itself is also highly variable. California has Class I airsheds as well as those, such as the Los Angeles basin, which often have difficulty complying with standards.

¹Information 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.

Table 2-2
Federal and Pacific Northwest Air Quality Standards

Pollutant	National Primary	National Secondary	Washington	Montana	Oregon	Idaho
PM10						
Annual Arith Mean	50 ug/m ^{3a}	50 ug/m ³	50 ug/m ³	50 ug/m ³	50 ug/m ³	50 ug/m ³
24-Hour Average	150 ug/m ³	150 ug/m ³	150 ug/m ³	150 ug/m ³	150 ug/m ³	150 ug/m ³
Sulfur Dioxide						
Annual Average	0.03 ppm ^b	0.02 ppm		0.02 ppm	0.10 ppm	0.03 ppm ^b
24-Hour Average	0.14 ppm		0.10 ppm	0.5 ppm ^e	0.50 ppm	0.14 ppm
3-Hour Average		0.50 ppm		0.5 ppm ^e		
1-Hour Average			0.40 ppm ^c	-		
Carbon Monoxide						
8-Hour Average	9 ppm	9 ppm	9 ppm	9 ppm	9 ppm	9 ppm
1-Hour Average	35 ppm	35 ppm	35 ppm		35 ppm	35 ppm
Ozone						
1-Hour Average ^d	0.12 ppm	0.12 ppm	0.12 ppm	0.12 ppm ^e	0.12 ppm	0.12 ppm
Nitrogen Dioxide						
Annual Average	0.053 ppm	0.05 ppm	0.05 ppm	0.05 ppm	0.053 ppm	0.053 ppm
Lead						
Quarterly Average	150 ug/m ³				150 ug/m ³	150 ug/m ³
Hydrogen Sulfide						
1-Hour Average	0.05 ppm ^e					0.05 ppm ^e

^a micrograms per cubic meter

^b parts per million

^c 0.25 ppm not to be exceeded more than two times in any 7 consecutive days.

^d Not to be exceeded on more than 1 calendar day per year.

^e Not to be exceeded more than once per year.

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 individually 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 Pacific Northwest found that, in the summer of 1984, 15 regional haze events occurred (Core et al. 1987). However, 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. Burning of high-sulfur coal is not permitted in Oregon. In Washington and Oregon, SO_2 is typically not a problem. 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.

Oxides of Nitrogen

Nitrogen dioxide (NO_2) 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 NO_2 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. A properly designed and operated combustion process is the best means of controlling CO emissions.

Automobiles are a primary source of CO . Thus, nonattainment areas tend to be located in business districts and at 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 tend to be 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 EPA, carbon dioxide (CO₂) is a gas associated with the widespread use of fossil fuels, such as coal, oil, natural gas, and other carbon-based fuels, including wood. Industrial processes and deforestation also contribute to increasing CO₂ levels. It is believed that increasing concentrations of CO₂ in the atmosphere may cause global climate change because of CO₂'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 as much as 7 degrees Fahrenheit in the next 50 years. 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 CO₂ 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.

The Potential Climatic Impacts of Greenhouse Gas Emissions

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 higher global surface temperature than would occur if the earth did not have an atmosphere. Except for 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 ultraviolet 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 CO₂ sink, absorbing approximately 40 percent of all CO₂ created by fossil fuel combustion. However, this absorption process is little understood, and the ultimate carrying capacity of the oceans for CO₂ is not known.

It has been established through the use of ice cores and atmospheric testing that the concentration of CO₂ in the atmosphere is higher than it has been in the last

160,000 years, the result of increased CO₂ emissions from industrialization. The rate of global CO₂ emission increased steadily by 4.6 percent per year until 1973, then declined to a 2.3 percent rate of increase per year. The U.S. is the leading emitter of CO₂; the former USSR is second. The more developed countries are reducing their per capita emissions, while the developing nations with rapidly growing populations are now responsible for the major increases in CO₂ emissions.

Partly because the Pacific Northwest relies heavily on hydropower, it is low on the national ranking for CO₂ 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 Pacific Northwest could dramatically increase its amount of CO₂ emissions in the future.

Many models of the greenhouse effect show global increases in temperatures of 1.2 to 1.3 degrees Celsius (°C) due to doubling of CO₂ concentrations. Because of the many variables involved, there is uncertainty surrounding this issue. There seems to be a pattern that CO₂ 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 °C. Regional patterns are difficult to gauge and would vary depending upon location.

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

2.2.2 Water

River Uses

The two major Northwest rivers, the Columbia and the Snake, are very different now from when the region was first settled by non-Indian 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 and recreation, improve navigation, and produce electricity. The hydroelectric projects are operated to accommodate fish, wildlife, and recreation needs as well as power. Today there are 31 hydro projects in the Columbia River Basin, including five major Federal storage reservoirs--Libby, Hungry Horse, Albeni Falls, Grand Coulee, and Dworshak. The locations of Federal and non-Federal Columbia Basin hydroelectric projects are provided in Appendix A, Figure A-1.

The sometimes competing multiple uses are considered by the hydro project owners and operators (the Corps of Engineers 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 Corps of Engineers 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 Pacific Northwest, Federal hydro projects provide numerous opportunities for recreation at the storage reservoirs and the areas downstream. Boating, swimming, water skiing, and fishing are typical water-related 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 hydro system.

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

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 556,800 acres. Only about half of this project's authorized capacity has been completed; environmental impacts from further development of the Project are currently being assessed in another environmental impact statement.²

The Grand Coulee Reservoir provides irrigation for the Columbia Basin Project. Most of the water for the Project—about 1.3 million acre-feet 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 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 Corps of Engineers 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, as well as a major contributor to the region's economy. At those reservoirs whose authority includes

²Bureau of Reclamation, 1989. *Draft Environmental Impact Statement: Continued Development of the Columbia Basin Project, Washington*. Bureau of Reclamation, Pacific Northwest Region, Boise, Idaho.

supplying water for navigation, a portion of the storage capacity is set aside to ensure that specified flows are maintained for that purpose.

Water Quality and 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. In general, the Pacific Northwest enjoys excellent water quality, but stringent protection is required. 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 Clean Water Act requires states to establish designated uses for which each body of water in the state must be maintained (Novick 1991). The state must also establish pollution level criteria to maintain the designated use. In addition, the EPA has established regulations that require at a minimum that, where attainable, all designated uses specify that water is fishable or swimmable. Listed later in this section are water bodies that currently supply major thermal power plants.

Idaho - Idaho has about 32,000 miles of streams and rivers and 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 - Montana has over 50,000 miles of streams and rivers, almost 750,000 acres of lakes, and 2 million acres of wetlands. About 13,000 miles of Montana streams and about 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 - Oregon has over 90,000 miles of rivers and streams that cross or border the state, 6,000 lakes and reservoirs, and 21 major estuaries on 362 miles 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. Oregon's lakes total a surface area greater than 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 131,844 acres, freshwater wetlands are estimated to cover 30,000 acres. Little is known about the water quality in these areas.

Washington - Washington has about 40,000 miles of rivers and streams, with an additional 346 miles of boundary rivers. The state has over 60,000 acres of lakes and reservoirs, 165 miles of coastal shoreline, about 3,000 square miles of estuaries, 400,000 acres of freshwater wetlands, and over 1,100,000 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 Pacific Northwest.

Yellowstone River - This river supplies water via pipeline to Castle Rock Reservoir, which supports a warm water fishery and supplies the water for the Colstrip coal plant, near Forsyth. 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, Montana, area. Precipitation and run-off in the area are low. (MDHES 1990).

Green River - The 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 1,763 cfs. Minimum discharge occurs in the winter (688 cfs in February 1984).

Skookumchuck River - The Skookumchuck River, regulated by Skookumchuck Dam, supplies water to the Centralia coal plant. It is a typical Cascade Mountain stream with a full complement of resident and anadromous salmonids (chinook, coho, and chum salmon; steelhead; and cutthroat trout) which use the area near the plant for spawning. The Skookumchuck is not listed as being water quality limited.

Columbia River - Carty Reservoir, filled with water pumped from the Columbia River, 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, and to the Trojan nuclear plant near Rainier, Oregon.

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. (WSDOE 1990, and ODEQ 1990.)

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

2.2.3 Vegetation

The northwest United States is among the more diverse regions of North America. This region includes wet coastal and dry interior mountain ranges, miles of coastline, interior valleys, basins, and high desert plateaus. Moisture, temperature, and substrate vary greatly, as does the vegetation.

In the Pacific Mountain System, Douglas fir forests dominate the native vegetation from the coast to about 5,000 feet of the moist western slopes of the Cascades. The drier east side of the Cascades supports yellow pine/lodgepole pine forests.

The forests of the western Cascade Mountains comprise the most densely forested region in the United States. These forests represent the maximal development of temperate coniferous forests in the world in terms of extent and size. The climax forests of this area are almost totally dominated by coniferous species. Generally, conifers are pioneer species—species that first populate an area, but which give way after many years to hardwood or mixed forest. However, in much of this region, this pattern is reversed, with hardwood trees such as red alder or bigleaf maple west of the Cascades playing an initial role in the vegetative succession. A second feature of this forest is the size and longevity of the dominant species. The climax forests found by the pioneers were comprised of trees several feet through at the base, several hundred feet-tall, and several centuries old. Much of this forest is now second growth—forests that have grown up where virgin forests once stood. Forestry, clearing for agriculture and other development, and wildfires have removed much of the original forest.

Prairies are an important feature of the landscape south of Washington's Puget Sound. The occurrence of prairie indicates the area has been free of forest for many years. The origin and continued occurrence of the prairies stems from soil type and frequent burning. The soil is gravelly, derived from glacial outwash material coupled with low summer precipitation. The frequent burning resulted from natural causes, native human populations, and the early European settlers. Since settlement, the extent of these prairies has been rapidly diminishing as a result of invasion by Douglas fir trees and other native plants. The reforestation of these areas is probably due to fire protection and changing management of the land.

The Columbia Plateau physiographic region covers much of Washington and Oregon east of the Cascades and most of southern Idaho. The area is arid to semi-arid, with low precipitation, warm to hot summers, and cold winters. The region is dominated by shrubs and grasses. Juniper is an invading species. Forest vegetation is generally confined to areas with more than 15 inches of annual precipitation, and in the higher elevations.

Much of this area has been changed by wildfire and grazing. The two dominant native shrubs are sagebrush and rabbit brush. Both are fire-sensitive and can be eliminated from an area for decades by fire. The major perennial grasses are

bunch grass and fescue. Neither is adapted to heavy grazing. Two alien species that are well adapted to the region and were able to invade areas that were burned or heavily grazed are cheatgrass and poa.

In the largely semi-arid climate of the Northern Rocky Mountains province (western Montana, northern Idaho, and northeastern Washington), native vegetation consists of larch/white pine or yellow pine/Douglas fir forests. Since European settlement, valleys such as the Flathead Valley in northwest Montana, are irrigated and farmed.

The lands surrounding the headwaters of the Columbia and Peace Rivers in British Columbia are heavily forested. Douglas fir is prominent in the Canadian Rocky Mountains, and the valley bottoms in most areas are characterized by stands of western hemlock. The upland, subalpine zone includes Englemann spruce and lodgepole pine.

2.2.4 Wildlife

The wildlife of the Pacific Northwest and Montana is diverse, including larger mammals such as bear, elk, and deer, and smaller animals such as butterflies, snails, and birds. Although all are important to the environment, some arouse special interests because of their economic and recreational value or because they are listed for protection by a state (see Appendix A) or the Federal Government.

The following discussion lists some of the important wildlife found in the Pacific Northwest.

Some of the more recreationally important wildlife of the Pacific Northwest include deer, elk, moose, pronghorn antelope, sheep, goats, and wild pigs. Many of these animals are important game species.

Many of the mammals of the Pacific Northwest are protected or are considered for protection because they have been over-harvested or their habitat has been lost to other uses. The protected list of mammals includes carnivores such as the gray wolf and the grizzly bear. It also includes whales, Columbia white-tailed deer, pygmy rabbit, shrews, squirrels, gophers, chipmunks, a mouse, voles, and bats. Not all of these mammals would be potentially affected by power plant development.

Besides mammals, Pacific Northwest wildlife includes a diverse bird population. Recreationally important birds include pheasants, geese, ducks, quail, and grouse. Many species have protected status with a state or the Federal Government. Protected birds include pelicans, Aleutian Canada goose, peregrine falcon, sandhill crane, eagles, and the spotted owl.

Reptiles, amphibians, molluscs, and insects are also part of the diverse wildlife of the Pacific Northwest. Many are protected or are being monitored for protection. The protected list includes several turtles, butterflies, beetles, snails, salamanders, and snakes.

Wildlife in the Canadian portion of the study area includes large populations of elk and deer, as well as mountain goats in higher elevations. Predators include the timber wolf, black and grizzly bears, and cougars. The Peace River area supports raptors, including bald eagles, hawks, and falcons.

2.2.5 Anadromous Fish

Columbia River Basin

The Pacific Northwest supports a large number of anadromous fish (species that migrate downriver to the ocean to mature, then return upstream to spawn). The principal anadromous fish runs in the Columbia Basin are chinook, coho, and sockeye salmon, and steelhead trout.

These fish are an important resource to the Pacific Northwest, both for their economic value to the sport and commercial fisheries, and for their cultural and religious value to the region's Indian Tribes and others.

The development of dam and reservoir projects on the Columbia and Snake Rivers and tributaries has reshaped the natural flows of these rivers. The use of storage reservoirs to capture runoff for later release results in reduced flows during the spring and early summer, when juvenile salmon and steelhead are migrating downstream to the ocean. Water velocities have also been reduced as a result of the increased cross-sectional area of the river due to run-of-river projects. These changes have slowed juvenile fish migration, exposing juvenile salmon and steelhead to predation and disease and impairing their ability to adapt to salt water when they reach the ocean. Additional mortality occurs as fish attempt to pass each dam on their downstream migration to the ocean.

Flow: Flow plays an important part in moving juvenile fish downstream to the ocean. In 1982, the Northwest Power Planning Council established a specific volume of water, known as the water budget, to increase river flows during the April 15 through June 15 period. This coincides with the peak out-migration of spring fish (predominately yearling chinook, steelhead, and sockeye), which depend on adequate river flow, particularly velocity, for a successful migration. The Federal hydro system is operated to provide this water each year.

Not only is flow important for moving juvenile fish downstream past the dams, but flow is an important component of insuring successful spawning and emergence of fall chinook on Vernita Bar (a gravel bar used by spawning fall chinook, located in the Hanford Reach of the Columbia River, downstream from Priest Rapids Dam). In 1988, BPA and the mid-Columbia operators signed a long-term Vernita Bar Agreement, which specifies protection requirements for fall chinook spawning, incubation, and emergence on Vernita Bar.

Spill: Until adequate bypass systems are installed at all the dams, spill remains a necessary means of moving juvenile fish past dams. Planned fish spill now includes the negotiated Spill Agreement, as well as a restricted operation at Bonneville Dam by the Corps. Planned spill also includes spill levels specified by the Federal Energy Regulatory Commission for non-Federal projects. Planned spill does not include overgeneration spill (water which is spilled because there is no market for the energy it would produce) and is not changed as a result of the resource additions. Planned fish spills are met under all water conditions.

Threatened and Endangered Species

In 1978, the National Marine Fisheries Service (NMFS) initiated, under the Endangered Species Act, a status review to determine whether various salmon populations in the Columbia River might be eligible for listing as threatened or endangered species (43 Federal Register 45628, October 3, 1978). One of the stocks reviewed at that time was the Snake River fall chinook salmon (Irving and

Bjornn 1981). NMFS ceased to pursue listing options because of optimism for improved salmon populations that would result from conservation measures following passage of the Pacific Northwest Power Planning and Conservation Act in 1980.

On March 29, 1990, the Shoshone-Bannock Tribe of Idaho petitioned NMFS to list Snake River sockeye salmon as a threatened and endangered species under the Endangered Species Act (ESA). On June 7, 1990, NMFS received a petition from Oregon Trout, a special interest advocacy group, with co-petitioners, to list Snake River fall chinook salmon and to designate critical habitat under the ESA.

In the winter of 1991, pursuant to the ESA, NMFS designated the Snake River sockeye salmon as endangered. And, in the Spring of 1992, NMFS designated the Snake River spring and summer chinook salmon (as a single species) and Snake River fall chinook as threatened.

NMFS, the Federal agency responsible for developing the Recovery Plan for Columbia Basin salmonid stocks listed under the ESA, appointed a Recovery Team comprised of regionally recognized fishery scientists. This NMFS Recovery Team produced a pre-decisional draft document on sockeye salmon on September 27, 1992, and will produce a draft Recovery Plan on all three listed species (Snake River sockeye, fall chinook and spring/summer chinook salmon) by 1993. Also, the Northwest Power Planning Council, BPA, other agencies, tribes, and numerous interested parties have participated in the development of a plan for river operations and other measures designed to protect and enhance these salmon.

In 1992 the Columbia River Federal Hydropower System was deemed to cause no jeopardy to the listed species by NMFS. A biological assessment is being prepared for 1993 hydropower operations.

The Council's Fish and Wildlife Program provides a regional framework for enhancement efforts for depleted salmonid stocks in the Columbia basin. This program includes developing a plan for the conservation and recovery of endangered and threatened species, including the conservation of genetic diversity of naturally spawning stocks, and increasing the run size of adult salmonids throughout the basin. Proposed amendments to the council's program include measures to develop management goals, escapement objectives, and rebuilding schedules for specific population units.

BPA is taking several new steps to protect anadromous fish. The major features of these ESA operations to protect salmon include:

- ◆ Increasing spring flows in the Columbia and Snake Rivers
- ◆ Operating four lower Snake River reservoirs and John Day Reservoir on the Columbia River at reduced elevations
- ◆ Increasing flows in the snake River in the summer for juvenile passage and in the fall for temperature control
- ◆ Increasing spill in the Snake River in the spring and summer
- ◆ Conducting numerous studies, activities, and projects

Other River Systems

Other Northwest river systems contain runs that include spring and fall chinook, coho, chum, pink salmon, and steelhead trout. As with some Columbia River

anadromous fish stocks, many coastal and Puget Sound populations are severely depleted, largely due to habitat degradation or excessive harvest.

2.2.6 Resident Fish

Resident fish are freshwater fish that live and migrate within the rivers, streams, and lakes of Washington, Oregon, Idaho, and western Montana. A few species that were originally anadromous but are now landlocked are included with the "resident" fishes.

Production in Reservoirs

A number of Federal reservoirs support substantial resident fish populations. Reservoirs whose resident fish would be most affected by changes in hydro operations are Hungry Horse and Lake Koocanusa (behind Libby Dam) in northern Montana, Grand Coulee in central Washington, and Dworshak in Idaho. Common game fish species in Hungry Horse include westslope cutthroat trout, Dolly Varden, and mountain whitefish. Common game fish species in Libby Reservoir include western cutthroat trout, rainbow trout, Dolly Varden, and kokanee salmon. Grand Coulee supports an economically valuable recreational fishery for walleye and rainbow trout. Sport fish caught in Dworshak include kokanee salmon, rainbow trout, and smallmouth bass.

Production in Streams

The Kootenai River below Libby Dam and the Flathead River below Hungry Horse Dam support important populations of resident game fish. These include kokanee in the Flathead River system, and westslope cutthroat trout, rainbow trout, and Dolly Varden in the Kootenai River. The kokanee that spawn in the Flathead River system below Hungry Horse migrate upstream from Flathead Lake. Currently, this population of kokanee is in decline. Montana Department of Fish, Wildlife, and Parks (MDFWP) has developed a mitigation plan for the Flathead River system that includes rebuilding the kokanee population as one of its major components.

Threatened and Endangered Species

Some of the resident fish of the Pacific Northwest are threatened, endangered, or of special concern to the management agencies charged with protecting these species. Recently, three environmental groups petitioned the United States Fish and Wildlife Service (USFWS) to protect the bull trout in five Northwest states. No action has taken place on the petition as yet. In June 1992, the Idaho Conservation League petitioned the USFWS to list the Kootenai River White Sturgeon under the Endangered Species Act. The cause of the decline is attributed to the construction and operation of Libby Dam. The USFWS has until June 1993 to act on the petition. In an attempt to avoid a listing, a technical work group has been formed to develop a plan that will satisfy both the petitioner and the USFWS.

2.2.7 Protected Areas

The Northwest Power Act directs the Council to develop a "program to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and

habitat on the Columbia River and its tributaries."³ Large habitat losses have occurred in the Columbia River Basin as a result of hydroelectric and other development. The Council has estimated that 4,600 stream miles of salmon and steelhead habitat have been lost (a 30 percent decline), not including losses of resident fish and wildlife habitat.⁴ Significant habitat losses have also occurred in other areas in the region, and these losses have played an important role in declines of regional fish and wildlife populations. The Council is required to consider fish, wildlife, their habitat, and other environmental factors in developing its regional power plan.⁵

Past mitigation efforts have not been able to compensate fully for the effects of hydropower and other development. The loss of anadromous fish habitat beyond the Hells Canyon complex on the Snake River is a significant example. In addition, recent listings by the NMFS of several stocks of anadromous fish as threatened or endangered underscore the need to protect remaining habitat. Disagreements among and between the public, fishery biologists, Federal, state, and local agencies, and Indian tribes over the possible effects of development, and the likelihood that mitigation may be successful, have been common. These disagreements add to developer costs and utility rates, and leave the region less certain about its ability to develop new resources quickly when needed.

To protect the critical fish and wildlife habitat that remains, to avoid expensive and divisive disputes over hydropower development in sensitive fish and wildlife areas in the region, and to reduce costs and uncertainties in the region's ability to meet its power needs, the Council embarked on a process 10 years ago to study areas where development would have substantial and irreversible adverse effects.

In 1987, the Council adopted the goal of doubling salmon and steelhead runs within the Columbia River Basin. As part of the strategy for meeting the doubling goal while protecting valuable fish habitat from damage caused by hydropower development (thus preserving an environment for wild and naturally spawning fish), the Council, on August 10, 1988, approved Protected Areas amendments to the Fish and Wildlife Program and Power Plan. In brief, the final rule adopted a single standard of protection for all Protected Areas: because Protected Areas represent the region's most valuable fish and wildlife habitat, hydropower development should not be allowed in Protected Areas, but should be focused in other river reaches. The final rule does not apply to projects existing or licensed as of August 10, 1988. In addition, the rule provides for developers to seek an exemption from the Council for a project with "exceptional fish and wildlife benefits."

The Council's Power Plan identifies the amount of new hydropower the region can count on to be developed in the next 20 years. Because projects proposed in Protected Areas are less likely to be built, the region's "supply curves" do not count on new hydro being developed in them.

³16 U.S.C. §839b(h)(1)(A).

⁴See *Council Staff Compilation of Information on Salmon and Steelhead Losses in the Columbia River Basin*, p. 89 (March 1986).

⁵16 U.S.C. §839b(e)(2).

During the Council's rulemaking, staff examined the impacts of designating Protected Areas on projects for which a preliminary permit, license, or exemption was active at the Federal Energy Regulatory Commission (FERC). That analysis showed that out of 387 active projects, 241 (62 percent) would be affected by a Protected Area designation. Of the 241 affected projects, 123 were located within the Columbia River Basin (848 MW, 448 aMW), and 118 were located outside the Basin (682 MW, 366 aMW). Total potential foregone was 1,530 MW of capacity and 814 aMW of energy. On the other hand, 146 projects (38 percent) were unaffected by Protected Area designation, representing 1,780 MW of capacity and 917 aMW of energy (1,546 MW, 795 aMW within the Basin and 234 MW, 122 aMW outside the Basin). The mileage now protected represents less than 15 percent (44,000 miles) of the Northwest's rivers and streams.

The primary purpose of Protected Areas is to direct developers to the least environmentally sensitive sites. However, Protected Areas designations are not static. Depending on future energy needs and other potential new supplies, Protected Areas designations can be modified.

The region's current hydropower supply curves, developed jointly by BPA, the Council, and the States in 1989, show an "upper bound" of regional potential at 910 aMW of new hydro available outside of Protected Areas at a cost of less than 6.0¢/kWh (levelized in 1988 dollars), with the amount of "likely developable" hydro outside of Protected Areas at 410 aMW. From 1988 through 1990, 237 MW (or about 100 aMW) of new hydro capacity was installed in the region outside of Protected Areas, well on the way to meeting projections of available supply.

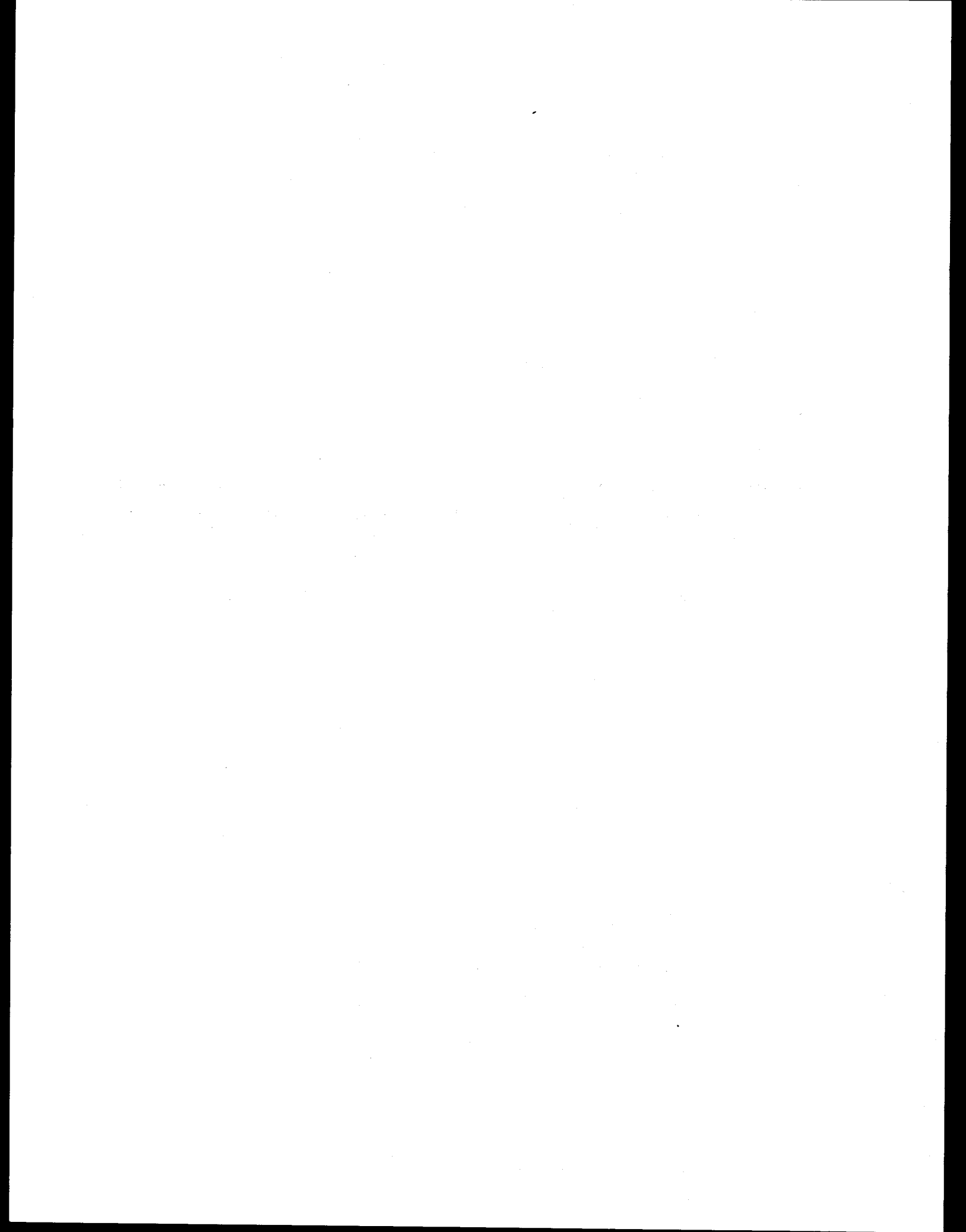
On May 17, 1988, BPA adopted its Long-Term Intertie Access Policy (LTIAP) governing provisions for use of BPA's Intertie with California. Protected Areas within the Columbia River Basin were adopted as the fish and wildlife protection mechanism in the LTIAP. The policy provides for decreasing utilities' access to the Intertie if they develop or acquire the output from a new hydro project located in a Protected Area. The Council has recommended that BPA adopt a similar policy with respect to Protected Areas outside the Columbia River Basin.

In addition, the Council has stated that new hydroelectric resources should not be acquired within Protected Areas--whether inside or outside the Columbia River Basin.

Since August 1988, FERC has not issued a license or exemption that conflicts with the Protected Areas amendments. As of January 1991, FERC has had few new applications for licenses in Protected Areas, although FERC has granted preliminary permits on sites located within Protected Areas.

Alternative Resource Types

Chapter 3



Chapter 3

Alternative Resource Types: Description, Environmental Effects, and Mitigation Measures

This chapter describes the potential environmental effects and mitigation for the resource types available for meeting load. The cost and supply projections for these conservation and generating resources are also included. The detailed assumptions and model inputs used for each resource type in Chapters 4 and 5 are included in the supply curves that are contained in Appendix D. With the exception of nuclear, all of the resource types described are generic resources. Data presented for the Final EIS in this chapter have been revised in response to comments on the Draft EIS and for consistency with assumptions used in Chapters 4 and 5.

Figure 3-1 compares the resource types against each other for several important environmental impacts. The impacts of each resource are described in more detail in the remainder of this chapter.

3.1 Conservation Resources

Conservation includes a wide range of methods to save energy and capacity in the commercial, residential, industrial, and irrigation and agriculture sectors.

Conservation programs can provide both capacity and energy savings. Each program needs to be evaluated as to how it may impact the load. Some conservation programs reduce load only during off-peak hours and would have little or no capacity savings. Other conservation programs provide load reduction primarily during peak hours and would provide substantial capacity savings.

A simple way to evaluate capacity savings from conservation programs is to compare the ratio of load reduction during peak hours to the total load reduction multiplied by the monthly energy savings. Detailed examples of capacity calculation for conservation programs have been developed for Billing Credits at BPA.

The potential environmental effects of conservation programs vary considerably. Figure 3-2 provides an overview of the pathways for environmental impacts; the following sections describe impacts by individual sector.

Figure 3-1
Selected Environmental Impacts of Conservation
and Generation Resource Operations

Resource	Relative Impact										
	SOx (tons/aMW)	NOx (tons/aMW)	TSP (tons/aMW)	CO (tons/aMW)	CO2 (tons/aMW)	Water Consumption (acre-FT/aMW)	Thermal Discharge (m mBTU/aMW)	Land Use (acres/MW)	Direct Cost (mills/kWh)	Environmental Costs (mills/kWh)	Hydro System Operations Impact
Conservation											1a
Eff. Imps											
Hydro											
Geothermal											
Wind											
Solar											
Cogeneration ^{1j}											
CTs											
Nuclear											
Coal											
Clean Coal											

Note: Fuel Switching not shown because comparable data are not available, but generally has low impact in all areas.

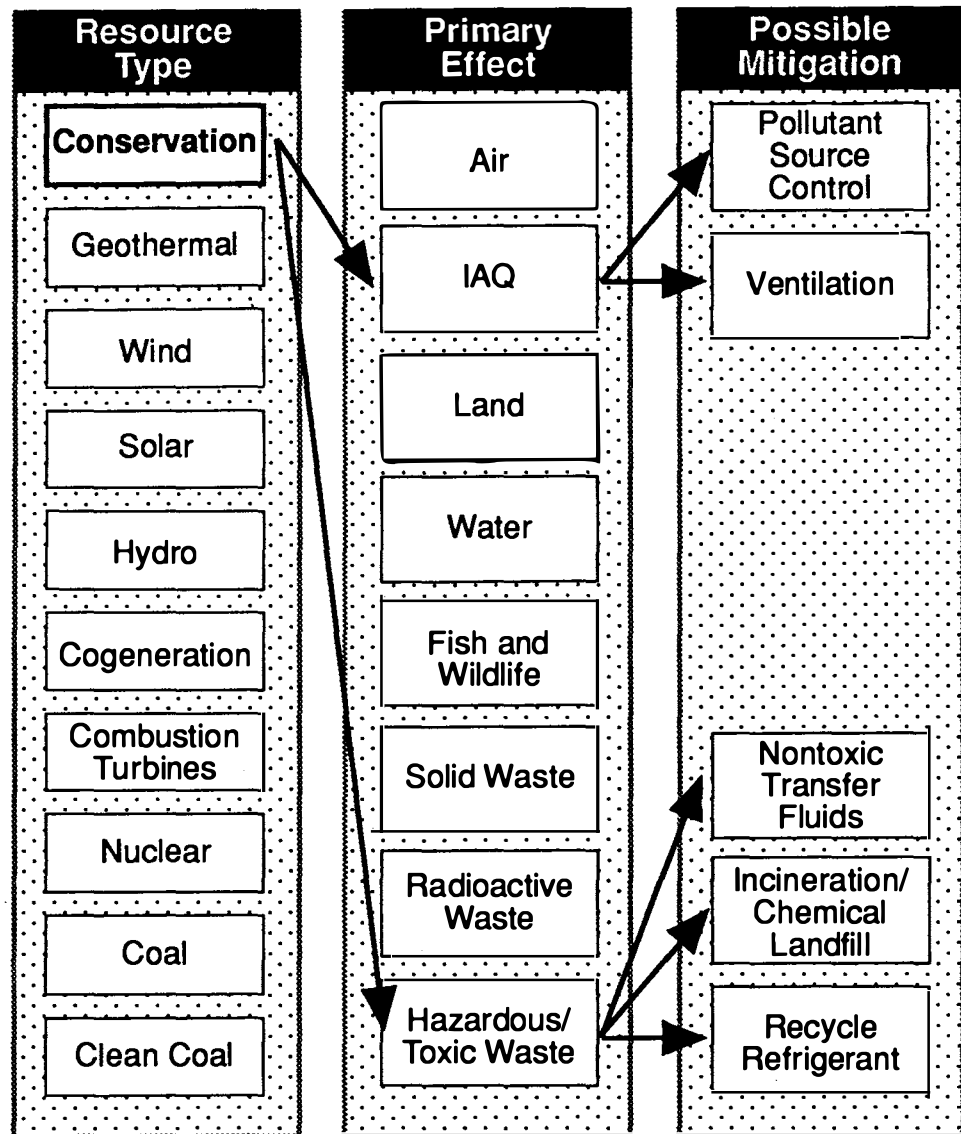
^{1j} Natural gas fired cogeneration assumed

^{2j} "More" means a more negative impact to capacity

^{3j} Capacity value of conservation varies considerably among conservation measures, from positive to negative

Much Less	Less	More	Much More

Figure 3-2
Environmental Effects and Mitigation - Conservation



General Environmental Impacts

Indoor air quality has been the principal environmental impact of concern for energy conservation. The quality of the air inside a house or building is influenced by the sources of airborne pollutants (either from outside or within the building), as well as interaction between pollutants themselves, the building's internal environment (temperature, humidity, ventilation rate, biological contaminants), and any cleaning or filtration of either the internal or external air. Internal sources

of pollutants include building materials and furnishings (e.g., paint, adhesives, furniture, and carpet), and activities within a building, such as photocopying or cooking.

People may spend as much as 90 percent of their time indoors. That time is spent in buildings with increasingly tight envelopes (the building's floors, walls, ceilings, and roof, including openings such as doors, windows, and other gaps).

Human health may be affected by indoor air quality. Effects include cancer, Legionnaire's disease, headaches, eye/nose/throat irritation, nausea, sensitivity to odors, dizziness, neurotoxic symptoms such as difficulty in concentrating, skin irritation, and odor and taste complaints.

Some of the impacts to human health may be caused by inadequate ventilation; microbiological contamination from dampness or from a building's chillers or humidifiers, or toxins released by those organisms; materials released by biocides used to control growth organisms; lighting levels; noise; naturally occurring radon gas; or some combination of these factors. Some studies have determined that improved ventilation could eliminate most indoor air quality problems. Others have concluded that a combination of factors governs.

Most existing homes and buildings potentially have indoor air quality problems. Many were built before any standards or regulations for indoor air quality existed. In most studies, naturally ventilated buildings exhibit the lowest prevalence of problems but are least efficient in energy conservation. Air quality in so-called "tight" homes and buildings, on the other hand, may be dominated by the building's ventilation system and the activities of the building's occupants.

Other environmental concerns include release of CFCs, disposal of potentially hazardous materials removed from existing buildings during conservation remodels, or retrofits (see 3.1.1); and preservation of the character of historic buildings receiving conservation improvements, discussed below.

Chlorofluorocarbons (CFCs). Chlorofluorocarbons are one member of the halocarbon family; chemically stable compounds derived from common hydrocarbons such as methane, ethane, and propane. The halocarbons also include hydrogenated chlorofluorocarbons (HCFCs) and hydrogenated fluorocarbons (HFCs). CFCs, the most commonly used of the halocarbons, are primarily employed in refrigeration, air conditioning, packaging, and insulation, and as solvents and aerosol propellants. CFCs are nontoxic, nonflammable, noncorrosive, and extremely stable. CFCs include most of the best refrigerant fluids available today, as well as the foaming agents in low-density insulation materials. However, it was discovered in the 1970s that CFCs released into the atmosphere eventually reach the upper stratosphere. There they are broken down by ultraviolet radiation, releasing free chlorine or bromine atoms, which destroy the ozone layer. The ozone layer absorbs and scatters ultraviolet rays from the sun, protecting the earth from excessive exposure to their harmful effects. A decrease in the ozone layer is suspected to have negative biological effects, including increased incidence of skin cancer and eye cataracts.

Not long after their effect on the ozone layer was discovered, scientists discovered that CFCs were also contributing to the greenhouse effect. The greenhouse effect results when infrared radiation emitted from the earth is trapped by the atmosphere, causing the earth's climate to increase in temperature. Studies indicate that CFCs account for about one-fifth of the global warming effect.

In July 1992, the Clean Air Act Amendments of 1990 came into effect, controlling the recycling, recovery and disposal of all CFC refrigerants. There is also a ban on HCFCs for use in new equipment by 2015, a 100-percent ban on HCFC production by 2030, and guidelines for government procurement policies on CFC equipment. Along with these Federal initiatives, state governments, including Oregon and Washington, have considered CFC legislation of their own. The banning of polystyrene foam food containers from Portland, Oregon, restaurants further demonstrates the growing regional interest in controlling CFCs.¹ Conservation programs that involve retrofits or installations of air conditioning, refrigeration, rigid foam insulation, or other potential emitters of CFCs must comply with the Clean Air Act and the 1990 Amendments. In addition, BPA may have to consider the environmental impacts of CFC substitutes and replacements, such as ammonia.

Historic Preservation. Buildings of potential historical, architectural, or cultural significance, including buildings more than 45 years old, potentially could be affected, or have their significance reduced or ruined, by the application of energy conservation measures. The ECM could affect the appearance of either the building exterior or interior, if the interior is significant. The inclusion of uncharacteristic features, design, materials, colors, or equipment (if visible) could potentially degrade the value of a significant building. Adding vestibules or awnings, inappropriate fixtures, wrong-colored materials such as caulking, nonperiod equipment such as timeclocks and thermostats, inappropriate windows or doors, and insulation treatments that are obtrusive are examples of actions that might conflict with the significance of a building, depending on the measure and how it is installed.

Recognizing that implementation of BPA's conservation programs could affect historic buildings, BPA entered into an agreement to protect the cultural resource values of such buildings. In 1983, BPA, the Advisory Council on Historic Preservation, and the State Historic Preservation Officers of California, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming signed Programmatic Memoranda of Agreement that specified procedures for ensuring that BPA's energy conservation programs were consistent with historic preservation values and that the review requirements of the National Historic Preservation Act were fully satisfied.

Current Legislation. BPA first entered the arena of indoor air quality at a time when no legislation or regulation existed. Now EPA and the states are developing laws and standards. BPA's programs strive to be consistent with and to complement these efforts.

The EPA has begun a multi-year effort to look at the cost implication of a number of indoor air quality control strategies. Several program initiatives are underway

¹Marseille, T.J., and Baechler, M.A. September 1990. *Chlorofluorocarbon Environmental Issues Related to Conservation Acquisition in Commercial Buildings*. PNL-7503, Pacific Northwest Laboratory, Richland, Washington.

within the EPA to improve utilization of the Toxic Substances Control Act (TSCA) and the Federal Insecticide, Fungicide, and Rodenticide Act, as amended (FIFRA) statutes (see Chapter 6) and to integrate them within the broad framework of indoor air exposures.

Since 1989, the budget of the Indoor Air Division, the group responsible for EPA's indoor air policy and programmatic activities, has grown substantially. The President's FY 1992 budget would enhance the Agency's ability to focus on these indoor air quality research areas: health effects; source assessment and control; building studies and methods; risk assessment; and development of a biocontaminant control program.

Indoor Radon Abatement Act of 1988 (IRAA). Several key authorities in IRAA expired in 1991 and additional discussion is anticipated on this topic. EPA and the states are taking the lead in setting standards, developing codes, and establishing monitoring and mitigation requirements.

In fulfilling its responsibilities under IRAA, EPA has several activities under way or in various stages of completion:

- ♦ Conducting national surveys in homes, Federal buildings, and schools to characterize radon exposure levels.
- ♦ Providing grants to states to establish and enhance their radon programs.
- ♦ Operating four regional training centers to train states and the private sector on the latest advances in diagnosing, mitigating, and preventing radon entry in buildings.
- ♦ Operating two voluntary proficiency programs that evaluate radon contractor capabilities and provide lists of qualified firms to states and consumers.
- ♦ Developing model construction standards that will prevent radon entry in new buildings.
- ♦ Recommending that all levels below the third floor of a building be tested for radon, and that appropriate corrective measures be taken.

Proposed Legislation. Several proposals have been put before the state and/or Federal legislative bodies that deal with further regulation of indoor air quality. EPA and the states are playing a strong role in mitigating any potentially harmful health effects of radon. BPA's programs have been designed to complement any mitigation requirements imposed by state or Federal legislation.

In the fall of 1991, comprehensive indoor air quality legislation was put before the U.S. Senate (S. 455; S. 792) and the House of Representatives (H.R. 1066; H.R. 1693; H.R. 1793). S. 792, the Indoor Radon Abatement Reauthorization Act of 1991, was intended to expand the original legislation in a number of areas.

H.R. 1793 was intended to ensure that amounts paid for home improvements to mitigate radon gas qualify for a tax deduction. H.R. 1693, the National Radon in Schools Testing Act of 1991, amends the Toxic Substances Control Act and requires local education agencies to submit radon test results to the governor, who must submit a report to the EPA. Provisions similar to S. 792 have also been introduced in the House. Because of the persistent introduction of new bills in both the House and the Senate concerning indoor air quality, it is highly likely that further Federal and state action can be expected. H.R. 3258, introduced in 1992

and approved in committee, is designed to improve the accuracy of radon testing products and services and create a commission to increase public awareness of radon, to provide grants to state-run radon programs, and to reauthorize EPA's radon programs.

HR 1066, an indoor air bill sponsored by Rep. Joseph Kennedy (D-MA) that was scheduled for U.S. House of Representatives committee action in September 1992, was postponed for consideration until the 1993 session. The bill calls for the U.S. Environmental Protection Agency to research the sources and health effects of indoor air contaminants. It would also mandate ventilation rates of 20 cubic feet per minute (cfm) for each occupant of a public building and 60 cfm for each occupant who smokes.

3.1.1 Commercial Sector Conservation Resources

Program Description

Conservation in commercial buildings consists of increasing energy use efficiency. Each facet of a building's design, construction, operation, and maintenance can affect its energy efficiency. Opportunities for conservation or increased energy efficiency in existing buildings may be via either upgrades of single features or systems, such as lighting, or through renovations, remodels, or major retrofits, where the interior of a building may be gutted and entirely new mechanical, electrical, or structural features are installed. New buildings are designed to be as energy efficient as is warranted.

The commercial sector conservation resource consists of 11 generic building types including large and small office buildings, large and small retail buildings, restaurants, elementary and secondary schools and colleges, warehouses, grocery stores, health care facilities, lodging facilities, and a miscellaneous category. Office and retail buildings account for the largest share of energy use, since they make up the biggest share of commercial building floor space. The largest potential for energy savings is in lighting and heating measures.

BPA completed two Environmental Assessments (EAs) of conservation in commercial sector buildings ("Approaches for Acquiring Energy Savings in Commercial Sector Buildings," September 1991 and "Energy Conservation Opportunities in Commercial Sector Facilities in the Pacific Northwest," August 1982). Both EAs resulted with BPA issuing Findings of No Significant Impact for specific commercial sector conservation programs. On July 7, 1992, BPA categorically excluded from further NEPA review the regionwide application of the energy conservation measures evaluated and approved in the September 1991 EA ("Acquire energy savings through the regionwide application of proven Energy Conservation Measures to commercial sector buildings").

These NEPA documents list specific proven ECMs that may be installed in new and existing commercial buildings. BPA also developed specific environmental requirements for the ECMs in a document entitled "Commercial Environmental Requirements" (CERs). The CERs ensure effective mitigation of any adverse effects to the human environment resulting from the proven ECMs. All of BPA's commercial conservation programs must comply with the CERs prevailing at the time of installation. The CERs are periodically updated to incorporate new information relevant to the potential environmental impacts of ECMs and to allow for modifications or additions to the list of proven ECMs. The decisions resulting

from these NEPA documents will continue unless new information warrants a change in the decisions.

Energy Conservation Measures

Energy-consuming end uses within these building types include lighting, power systems, building shell (envelope), heating/air conditioning, ventilating, refrigeration, domestic water heating, and other uses including "plug loads" such as task lighting and personal computers. A complete list of ECMs is included in Appendix C.

Lighting Measures. Lighting measures provide light or illumination for the various needs within (or outside of) a building. Lighting measures consist of fixtures, ballasts, lamps, reflectors, and lighting controls. Fixtures, or luminaires, hold all of the components. Fixtures may incorporate the most advanced design of reflectors, getting the most light produced by a fixture to the object, area, or task needing light. Ballasts, if needed, may be magnetic, hybrid, or electronic, the latter being the most efficient. Ballasts provide starting current for and limit current flow to fluorescent lamps, while consuming some power themselves. Lamps are the light source and they may be incandescent, fluorescent, high-intensity discharge (mercury vapor, metal halide, or high-pressure sodium) or low-pressure sodium. Lighting systems are designed and analyzed for the most efficient layout, use, and control. Daylighting, the use of natural daylight, is another strategy to conserve energy by limiting the use of artificial lighting.

Power Systems. In power systems, conservation measures consist of actions such as disconnecting lightly loaded transformers, replacing transformers, upgrading to higher voltage systems, use of appropriately sized motors, use of variable speed drives, and controls of these devices.

Building Envelope. Envelope measures consist of insulation in a building's ceiling, walls, floors, foundation, crawl space, or slab. Infiltration measures such as weatherstripping or caulking also are considered envelope measures. Some door and window technology also falls into this category and affects the efficiency of the building shell energy use.

Heating/Air Conditioning. These measures affect a building's cooling systems, equipment, and controls. High-efficiency equipment, alternative cooling systems, insulation of equipment, control of systems, and variable air volume systems might all be used to conserve energy in a commercial building.

Ventilation. Ventilation affects a building's equipment and/or its use because it affects air uptake and circulation, and the control of the system. Sensors, the amount of air used, and circulation equipment such as fans, dampers, or air destratification devices are examples of energy conservation measures.

Refrigeration. Conservation measures dealing with refrigeration include efficient equipment for the production and movement of chilled water or refrigerant such as pumps, compressors, chillers, exhaust heat recovery, and variable speed drives, as well as systems for control of the equipment.

Domestic Hot Water. These measures provide better insulation of equipment, alternative heating systems, and controls.

Operating Characteristics and Capacity Contribution

Impacts of commercial conservation programs on capacity depend on the types of energy-consuming equipment present within commercial buildings and their operating schedules. These two factors vary depending on the type of building and whether it is a retail store, office, school, or other type of facility. Generally, the greatest opportunities for conservation programs are indoor lighting and heating-ventilation-and-cooling (HVAC) systems, which usually consume the most electricity in commercial buildings. The electricity demands of these two end uses are generally regarded as major contributors to load at the time of system peak demand. Therefore, conservation programs directed toward them should reduce peak demand. Peak savings have typically been estimated as being equal to energy savings.

Environmental Effects and Mitigation

The potential environmental effects associated with installing energy conservation measures in commercial buildings and suggested mitigation techniques are summarized below.

Table 3-1
Commercial Conservation Measures
and Their Impacts

Measure	Effect	Impact or Concern
Lighting Systems	Replacement or installation of equipment	PCBs, mercury, glare, safety
Power Systems	Replacement with high-efficiency equipment	None expected
Building Envelope	Insulation, windows, doors, infiltration measures	UFFI, asbestos, IAQ
Heating, Ventilation, and Air Conditioning	Efficient equipment, operational changes, insulation, controls, operation	Chemicals, CFCs, IAQ
Refrigeration	Controls, equipment, operation	CFCs
Domestic Hot Water	Insulation, operation	Toxic transfer fluids

Lighting Systems

High-pressure sodium (HPS) lamps are an extremely bright source of light. They can offer a highly efficient and long operating life in selected indoor applications. Although lighting technology is rapidly changing, there are still some environmental concerns associated with the use of HPS indoors. They include glare, which can cause annoyance or affect visual performance; stroboscopic ("flicker") effect, in which rapidly moving objects may appear to be stationary; and color distortion. These effects are related primarily to safety. There are no known long-term health effects. Low-pressure sodium (LPS) lighting produces monochromatic light (yellow or gold tint), which distorts color such that it is not recommended for indoor use.

Proper installation of HPS mitigates the effects. Glare can be reduced or eliminated through proper placement of the lights, and by use of either a refractor

lens or other HPS lamps that have been specifically designed for mounting at low heights. Other types of supplementary task light can be used to help reduce or eliminate reflected glare. In work areas where flicker could present a safety hazard, HPS lighting should use three-phase power and luminaires that produce overlapping illumination. By wiring each adjacent luminaire on a separate phase, the stroboscopic problem can be reduced or eliminated. Earthtone colors with a dull or matte finish can be used on surfaces to improve color rendition. However, if critical, color-dependent tasks are involved, HPS lighting should not be used. Any signs or signals conveying health and safety information (e.g., exit or caution signs) can be illuminated independently by other light sources such as incandescent, fluorescent, or metal halide.

As energy-efficient lighting programs gain in popularity, the risk of contamination at landfills increases with the increased disposal of used lamps. Recent studies suggest that the lead solder used in the base of lamps, because of its highly toxic nature, may cause most lamps to be classified as a hazardous waste.² The quartz arc tubes in mercury vapor and metal halide lamps contain small amounts of mercury, ranging from 20 milligrams in a 75-watt lamp, up to 2,500 milligrams in a 1,000-watt lamp. In addition, all fluorescent lamps contain mercury. A 4-foot fluorescent lamp typically contains 35 to 50 milligrams of mercury, well above the Federally regulated level of 20 milligrams. According to Fred Bryant of Mercury Technologies Inc., Benicia, California, it takes 10,000 4-foot fluorescent lamps to yield 1 pound of mercury. Only a few teaspoons of mercury can poison a lake for centuries.³

Both mercury and lead are highly toxic and poisonous to living organisms. Mercury and lead poisoning can lead to chronic renal failure. Chronic exposure to or ingestion of practically any heavy metal, such as mercury or lead, may lead to multiple abnormalities to the nervous system. Concern is growing about the ground and water contamination that may result as municipal landfills continue to accept lighting refuse.

In addition to the threat of used fluorescent lamps contributing to ground contamination by lead and mercury, fluorescent light ballasts manufactured prior to 1978 may contain polychlorinated biphenyls (PCBs). PCBs are a probable human carcinogen suspected of causing excess risk of liver cancer in humans by ingestion, inhalation, or skin contact. Prior to 1979, PCBs were widely used as coolants in electrical equipment, including the capacitors used in fluorescent light ballasts. The capacitors in those fluorescent ballasts contain 1 to 2 ounces of near-pure PCBs. If the ballast fails, the capacitor may break open, allowing the PCB oil to leak. Under the Toxic Substances Control Act of 1976, leaking ballasts must be disposed of either through high-temperature incineration or in an

²Options for Handling Noncombustion Waste, Revision 1, Electric Power Research Institute report SG-7052-Rev. 1, prepared by Mittelhauser Corporation, Laguna Hills, CA, April 1992, pg. 3-7.

³Tracy, Jim. *Hidden Cost of Relamping*, *Home Energy - Trends in Energy*, May/June 1992, p.10.

EPA-approved chemical waste landfill. Disposal of small quantities of non-leaking fluorescent ballasts containing PCBs is not Federally regulated, but EPA, Region 10, has developed and adopted a policy for disposal of five or more PCB-laden light ballasts. The EPA has published a fact sheet, "PCBs in Fluorescent Light Fixtures," which provides basic guidelines for handling and disposing of ballasts containing PCBs. The EPA is also currently reviewing its methods for testing the potential hazards caused by the disposal of used fluorescent lamps. As of January 1992, EPA had no specific regulations on disposal of lamps.

Building Envelope

Urea formaldehyde foam insulation (UFFI) has, in the past, been used to insulate buildings. UFFI contains gaseous material and releases residual-free formaldehyde as it ages. This may contribute to adverse health effects for building occupants. However, formaldehyde-containing products are no longer available and have been replaced with such products as cellulose with fire-retardants. Tightening of the building envelope may lead to changes in indoor air quality. The primary impacts or concerns are UFFI, asbestos, and radon in apartment buildings.

Insulation or other construction materials in some buildings may contain asbestos. Asbestos fibers are very small (less than 10 microns long), very strong, and very resistant to heat and chemicals. Since they are so resistant, they are also extremely stable in the environment. They do not evaporate into the air, dissolve in water, or disintegrate over time. Intact and undisturbed asbestos materials do not pose a health risk. However, the adverse health effects resulting from exposure to airborne asbestos fibers are well documented. Asbestos is a known carcinogen and can lead to other respiratory ailments. Stringent Federal, state, and local waste disposal procedures and regulations govern asbestos disturbance and removal. Removing or altering building structures that contain asbestos must be done in compliance with those laws and regulations.

Fiberglass insulation used in commercial ductwork may increase worker and occupant exposure to synthetic fibers. It is not clear if such exposure is linked to health effects. (Baechler, et al., *Environmental Effects and Mitigation for Energy Resources*, 1990.)

BPA's existing commercial IAQ procedures require that apartments be monitored for radon prior to installing ECMs that may affect air quality. If more than 5 percent of the total number of monitors installed in a building have radon levels of 5 picoCuries per liter (pCi/l) or greater, the building does not qualify for ECMs affecting natural ventilation. However, many new state and Federal requirements, laws, standards, and codes regulate indoor air quality and recent studies indicate there is no direct correlation between the tightening of a building envelope and radon levels (*Radon and Remedial Action in Spokane River Valley Homes*, USDOE/BPA, 1987). Thus, BPA may elect to drop radon monitoring of apartment buildings as a requirement in future commercial programs. For more information on radon, refer to section 3.1.2.

Heating, Ventilation, and Air Conditioning Systems

Changes to the heating, ventilation, and air conditioning systems may affect air quality inside buildings. Various pollutants are released within any commercial building on a continuing or intermittent basis. Indoor pollutants can originate from objects within a building, from building materials, from indoor activities of

building occupants, or from building occupants themselves. Outdoor air pollutants enter buildings through mechanical ventilation systems or through infiltration. A reduction in the flow of outside air into a building may cause these pollutants to accumulate at levels that could cause health problems for building occupants.

In a 1991 EA (*Approaches for Acquiring Energy Savings in Commercial Sector Buildings*, DOE/BPA-0513), BPA used the American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Standard 62-89, "Ventilation for Acceptable Indoor Air Quality," as a basis for proposing programs. This standard is the heating, ventilating, and air conditioning nationwide industry consensus standard for ventilation air in commercial buildings. BPA incorporated this standard into the Commercial Environmental Requirements document.

Because local and state building codes do not generally require compliance with ASHRAE 62-89, BPA should approve the ventilation design of new buildings and inspect mechanical ventilation systems in existing buildings for compliance with the standard. Furthermore, some existing buildings do not have mechanical ventilation systems and are naturally ventilated. These buildings must comply with local and state building codes and, at a minimum, should meet the Uniform Building Code (UBC) ventilation requirements. The UBC requirement provides ventilation standards in those localities that do not include ventilation requirements as part of their building codes.

Some types of projects (e.g., direct application geothermal or groundwater heat pumps) may involve the use of subsurface resources and could impact water and soil quality. For example, groundwater heat pumps could contaminate groundwater or soil if toxic heat transfer fluids leak or accidentally discharge. However, non-toxic solutions are available. Ground source heat pumps draw heat from the soil, causing the ground to freeze sooner than would be expected under normal conditions.

Various Federal, state, and local regulations govern the use of subsurface resources. Those regulations are intended to minimize the impacts on land and water. Letters of coordination and/or approval from appropriate agencies can be obtained through consultation prior to installing any energy conservation measure that could affect subsurface resources.

Domestic Hot Water Systems

Some types of commercial ECMs (i.e., solar domestic water heating systems or water source heat pumps) require the use of transfer fluids. These fluids, such as ethylene glycol, may be toxic and could contaminate the groundwater or soil if leaks or accidental discharges occur.

Substituting non-toxic transfer fluids for the toxic fluids can eliminate concern for contamination. In addition, some state or local codes may prohibit the use of certain toxic transfer fluids. Consequently, local code officials should be contacted prior to installing energy conservation measures that require the use of transfer fluids.

Supply Forecast

To effectively evaluate commercial energy conservation, BPA evaluated the effects of a mix of energy conservation measures (ECMs) and the amount of

equipment that would be replaced by the installation of a new technology, given forecasts of regional electricity savings potential. To accomplish this, BPA supplied a base case forecast to Battelle Pacific Northwest Laboratory, which developed a tool called ECMMIX.

Basically, ECMMIX selects energy conservation measures until a specified megawatt target is achieved. The model estimates the number of ECMs and the amount of replaced technology that corresponds to a particular forecasted regional savings potential. The savings rate per thousand square feet, adjusted by fuel share sensitivities and line-loss credits, is multiplied by the prototypical building floor size, resulting in a savings rate per building type. Regional savings potential then is converted to kilowatt-hours. The kilowatt-hours, divided by savings rate per building, yields an estimate of the number of buildings corresponding to the savings potential. The number of ECMs, applied to the number of buildings, yields an estimate of the number of ECMs needed to achieve the forecasted savings potential. This also yields the number of ECMs replaced as each ECM is installed. For the purposes of this model, ECMs also are categorized by timing opportunity, e.g., whether remodel, renovation, lost opportunity, or discretionary. Lost opportunities correspond to ECMs that can only be adopted during construction or when a building undergoes major renovation or remodeling. Discretionary opportunities can occur at any point in the life cycle of an existing structure.

Table 3-2
Conservation Resource Supply for
Commercial Sector Program

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) ¹	BPA Supply by 2010 (aMW)
New Buildings	601	222
Existing Buildings - Discretionary	158	84
Existing Buildings - Lost Opportunity	149	72

¹ Achievable conservation potential under the 1989 final high load forecast.

Table 3-3
Conservation Resource Supply
for Commercial Sector Program
Under High Conservation Alternative

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) ¹	BPA Supply by 2010 (aMW)
New Buildings	1,760	650
Existing Buildings - Discretionary	158	86
Existing Buildings - Lost Opportunity	149	67

¹ Achievable conservation potential under the 1989 final high load forecast.

Cost

The projected costs for the commercial conservation programs under all alternatives analyzed in this RPEIS are contained in Table 3-4.

Table 3-4
Conservation Resource
Regional Cost¹ for Commercial Sector Program

Program (Sector/Sub-sector)	Cost per MW ² (1988\$) (000)
New Buildings	\$1,876
Existing Buildings - Discretionary	\$2,876
Existing Buildings - Lost Opportunity	\$2,737

¹ Figures represent the regional costs of conservation, which are the sum of BPA, utility, and customer expenditures. These figures represent costs over the life of the programs (see Table D-7, Resource Lifetimes, Volume 2: Appendices of the Draft Environmental Impact Statement - Resource Programs, March 1992).

² Includes a 7.5 percent transmission line loss credit. Cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources. Operating costs are included in the cost of installation, as are administrative costs for BPA and utilities.

3.1.2 Residential Sector Conservation

Program Description

Residential conservation involves implementing a wide variety of approaches to promote reduced electrical consumption in both new and existing residences. Conservation programs for new homes provide incentives and/or assistance to construct residences that meet or exceed the current energy codes and standards. Conservation programs for existing residences promote retrofitting homes with specific measures to make them more energy efficient. Some conservation programs may also promote the use of energy-efficient appliances and devices. The residential sector conservation resource includes single family dwellings, multifamily dwellings, manufactured homes, and mobile homes. BPA's residential conservation programs currently operate according to two final Environmental Impact Statements and associated Records of Decision (RODs).

Energy Conservation Measures

When retrofitting existing homes, weatherization measures such as ceiling insulation, floor insulation, storm windows, unfinished-wall insulation, duct insulation, storm doors, caulking, weatherstripping, clock thermostats, dehumidifiers, and electrical outlet and switchplate gaskets can be installed.

Conservation measures in energy-efficient new homes are installed through various construction techniques that tighten the building structure to reduce air infiltration and heat loss. These include many of the weatherization materials described above.

Beyond building envelope measures, there are numerous other measures that can be installed in residential structures. Other conservation measures are grouped into the following general categories: lighting, other appliances, space heating, and solar devices.

Operating Characteristics and Capacity Contribution

Conservation programs that reduce electrical energy consumption in the residential sector tend to result in corresponding reductions in peak loads. Typically, reductions in peak are assumed to be equal to the reductions in energy use.

Residential programs - space and water heating measures: These two end uses are major contributors to system peak demand. Residential programs are primarily directed at improving space and water heating efficiency, and therefore are beneficial in reducing peak loads and increasing capacity.

Residential programs - lighting and appliances. Programs that promote energy efficient appliances and lighting efficiency also reduce loads at the time of system peak. However, the capacity contribution from conservation in these end uses is less than the contributions from space and water heating programs.

Environmental Effects and Mitigation

The environmental effects of conservation measures are largely beneficial. Yet, to some extent, virtually all conservation measures may have effects on the environment which are adverse or undesirable.

BPA published the *Final New Energy-Efficient Homes Programs* EIS in August 1988 and filed a ROD in the Federal Register on February 23, 1989. The EIS analyzed various construction techniques for saving energy and mitigating the resulting decreased indoor air quality. Environmental mitigation requirements include: exhaust fans for kitchens and bathrooms, designated air supplies for combustion appliances, information on indoor air quality, Housing and Urban Development (HUD) product standards for formaldehyde emissions from structural board materials, and the offer of radon monitoring and radon source control (called the Radon Package). The Radon Package allows a builder one of two basic approaches: 1) construct the house to include specified foundation treatments, or 2) forego those measures and assume responsibility for requiring radon monitoring in the house after construction.

BPA published the *Final Expanded Residential Weatherization Program* EIS in August 1984 and issued a ROD in the Federal Register on October 18, 1984. The EIS analyzed options to expand the existing BPA Residential Weatherization Program to make "house tightening" measures available to all electrically heated homes in the BPA service area. BPA decided to adopt mitigation strategies to reduce the risk of adverse human health effects resulting from decreased indoor air quality. The mitigation strategies include: giving program participants (residents) information on indoor air pollutant sources and practical steps for reducing concentrations, giving program participants options for having their homes monitored for radon concentrations, and partially subsidizing the installation of a proven mitigation device if radon concentrations exceed 5 picocuries per liter.

Conclusions from the two residential sector EISs and other relevant information are summarized in Table 3-5 and in the discussion below.

Lighting

Compact fluorescent lights may break more often than incandescent bulbs when being installed or from lamps falling over, and breathing the gases contained inside these bulbs may be hazardous. All fluorescent lamps contain mercury and lead, which are highly toxic. Disposal of fluorescent lamps in municipal landfills by

individuals is allowed by current regulations. However, concern is growing about the soil and water contamination that may result. EPA is reviewing its methods for testing potential hazards caused by the disposal of used fluorescent lamps. (See Section 3.1.1, above.) Potential contamination from disposal of large quantities of fluorescent lamps can be reduced by using handling procedures in accordance with hazardous waste regulations. The problem of disposing of ballasts containing radioisotopes can be avoided by using electronically-ballasted lights, which do not use radioisotopes for starting. Low-pressure and high-pressure sodium and metal halide bulbs last longer than standard bulbs, thus reducing the waste stream.

Table 3-5
Residential Conservation Measures and Their Impacts

Measure	Effect	Impact or Concern
Building Envelope		
Insulation Ceiling, attic, walls, floors, ducts	Reduces energy requirements	Asbestos, CFCs
Infiltration Measures Storm and thermal windows and doors, caulking, weatherstripping	Reduces energy requirements	IAQ
Ventilation Systems	Heat recovery concerns	IAQ
Energy Use Efficiency Compact fluorescent lights, energy-efficient appliances (e.g., refrigerators, freezers, etc.)	Reduces energy requirements	None
Heating System Efficiency Hydronic pipe insulation, clock & other energy-saving thermostats, heat pumps	Reduces energy requirements	None
Water Heating Efficiency Water heater wraps, low-flow showerheads, pipe insulation, exhaust air heat pumps, thermostats	Reduces energy requirements	Scalding
Solar	Reduces energy requirements	Battery handling when used for residential systems

Building Envelope

Tightening measures to reduce the air exchange rate in residences may cause increased indoor air pollution concentrations, thus increasing the risk of adverse health effects to the occupants. However, measures such as insulation, clock thermostats, and dehumidifiers have little or no effect on indoor air quality. BPA prepared an EIS in 1984 (*The Expanded Residential Weatherization EIS* [DOE/EIS-0095F]) and an EIS in 1988 (*Final Environmental Impact Statement on New Energy-Efficient Homes Programs* [DOE/EIS-0127F]) to examine the potential environmental effects of implementing residential weatherization and new homes programs for all electrically heated homes in the region. Major effects examined pertained to indoor air quality and human health.

The primary concerns focused on radon and formaldehyde. Other indoor pollutants, such as respirable suspended particulates (RSP), combustion gases, household chemicals, moisture, and microorganisms, also raised concerns, but

review of the scientific literature indicated insufficient information to accurately quantify the health effects of these pollutants.

Scientists have found that formaldehyde can cause severe short-term health effects, although these effects are not quantifiable and sensitivity among exposed persons differs. The key health effects for indoor air pollutants are lung cancer from exposure to radon, and nasal cancer from formaldehyde.

Most formaldehyde impacts can be mitigated by simply avoiding building materials or other products that contain urea formaldehyde glues or adhesives.

Radon. Radon comes primarily from uranium-bearing soil. Entry into homes is predominantly caused by natural forces such as pressure gradients, wind, and air temperature, not by house tightening techniques, as was postulated in the 1984 EIS.

There are many new state and Federal requirements, laws, and standards regulating indoor air quality. Thus, from BPA's perspective, monitoring for radon may no longer be necessary as a program requirement in tracking potential environmental impacts. The extent of BPA's responsibility due to its weatherization programs is also questionable, as studies have revealed that there is no direct correlation between house tightening and radon levels (*Radon and Remedial Action in Spokane River Valley Homes*, USDOE/BPA, 1987). Indoor radon levels depend on several other factors that do have direct correlations, including air temperature, atmospheric pressure, wind direction, source concentration, soil permeability, and soil moisture content. As radon levels are now recognized as source-driven, house tightening and weatherization are not the determining factors.

Many new radon mitigation techniques have become available since the preparation of BPA's 1984 and 1988 EISs.

Although all alternative construction techniques (pathways) described in the 1988 Final EIS required a radon package for new homes, which included the offer of radon monitoring to all households, it also included the option of installing measures (a ventilated crawlspace and/or a gravel base under a concrete slab floor) for more effective mitigation of radon if the homeowner chose. Those new homes for which builders did not install these measures for post-construction source control require monitoring for radon.

The effectiveness of mitigation methods may vary, due to daily or seasonal changes in environmental factors or in the operation of the building and mechanical systems within it. These mitigation methods usually lower indoor radon levels; however, the final time-averaged concentration is not always predictable. Of the mitigation techniques studied over the past several years, five basic radon control techniques are considered to be the most effective. These techniques are:

- ◆ Subsurface ventilation
- ◆ Passive stack ventilation
- ◆ Block wall ventilation
- ◆ Air-to-air heat exchanger

- ♦ Basement overpressurization
- ♦ Caulking of cracks and openings

As described below, each of these techniques can be effective when applied under appropriate conditions and radon concentrations. Source control and the other methods rely on either mitigation after the fact or a combination of source and concentration dilution to achieve results.

Subsurface Ventilation. Subsurface ventilation has the potential to be the most effective when a building is on a concrete foundation or basement slab. Basic subsurface ventilation consists of one or more ventilation pipes installed through the subfloor and into the ground under the foundation and extending to the outside of the building. The result is an unrestricted ventilation hole coupling the ground with the outside air. A small air pump is typically attached to the ventilation pipes to provide either a negative or positive pressure gradient between the interior building space and the subfoundation perimeter. This technique is intended to prevent the migration of radon gas into the building space. If the initial interior concentration of radon is kept to a minimum, further mitigation should not be necessary. Test results to date show that a significant reduction of indoor radon concentrations can be achieved through proper subsurface design.

Passive Stack Ventilation. This ventilation system is very similar to the active systems previously described, with the exception of the mechanical pump. On a passive system, natural pressure gradients and existing "stack effects" are the driving forces for providing a negative pressure flow out of the ground under the concrete slab. The overall effectiveness of passive stack ventilation has not yet been fully determined. BPA, the Environmental Protection Agency, and the Washington Department of Health are beginning a study to determine its actual effectiveness. This technique is expected to offer some reductions in radon in homes.

Block Wall Ventilation. Block wall ventilation is a technique used when concrete building blocks are used for basement or structural walls. The interior cavities of the blocks are used as ventilation sinks. An active system is installed such that air is removed from the block cavities. This technique, if properly designed and controlled, results in varying success as a mitigation tool.

Air-to-Air Heat Exchangers. Air-to-air heat exchangers are limited to situations where the indoor radon concentration is not extreme. Because most of these systems are designed to provide a maximum of 0.5 air changes per hour, mitigation of high levels of radon would not be effective. Basement installations are one of the most effective applications of air-to-air heat exchangers. When a basement can be isolated from the remaining building by closing doors and sealing cracks, fairly effective mitigation can be achieved by ventilating only the basement area. Typically, if the lowest level of a building can be mitigated properly, the remainder of the building will be similarly affected.

Basement Overpressurization. Basement overpressurization is a variation of subsurface pressurization in which the basement area, rather than the subfloor ground area, is pressurized. This technique has shown positive results, but the basement must be isolated and closed off or the technique is overridden.

Caulking. Caulking of cracks and openings has very limited application and mitigation effect. If the initial concentration of radon is low, this technique may

prove to be the most cost effective. If radon levels are moderate to high and other circumstances are present, caulking and sealing may not prove reliable. It would, however, be a complementary technique for a more active approach, such as basement overpressurization.

Although weatherization activities do not appear to be determining factors in residential radon levels, BPA continues to monitor radon legislation.

Appliances

Some of BPA's conservation programs promote the use and development of energy-efficient appliances and devices. Appliances such as refrigerators and freezers, and water heaters or condensation dryers employing a heat pump may contain chlorofluorocarbons. CFCs are known depleters of the ozone layer and contribute to global warming if released into the atmosphere. For a more complete discussion of CFCs, see section 3.1.

Space Heating

Integrated hot water/space heat systems can experience backdrafting in units that do not use power venting or sealed combustion. Air-to-air heat exchangers can cause moisture-related problems, including mold, mildew, and wood decay, when they fail to exhaust humidity to the outdoors. Such recapturing of humidity can allow the transfer of dissolved pollutants (such as formaldehyde) to the incoming air.

Possible effects associated with backdrafting can be eliminated by using power venting or sealed combustion in integrated combustion appliances. Heat exchangers that are properly installed with units that are not oversized for the house eliminate many of the problems of moisture retention and backdrafting. Improving thermal distribution systems in homes can help to reduce or eliminate pressure imbalances and improve indoor air quality, energy consumption, and comfort.

Exhaust air heat pumps can increase the potential for backdrafting and increased radon entry into the home where radon is a problem. Air-source heat pumps pose environmental problems to the earth's ozone layer when their refrigerants are allowed to escape. High-efficiency models have been found to be the source of odors in the home. Variable-speed models can cause moisture problems by maintaining different temperatures in different areas of the house if not operated properly.

Scrubbing the fan coils of high-efficiency heat pumps with bleach can remove house odors associated with these units; however, care must be taken to ensure bleach fumes do not affect the indoor air. Refrigerants used in heat pumps should be recycled properly to avoid escape into the atmosphere.

Solar

Solar access in itself has minimal adverse environmental effects. The major environmental impact of residential photovoltaic (PV) systems involves the batteries; handling of the acidic electrolyte contained in these batteries can have adverse health effects. Proper care and disposal of PV batteries is essential to avoid accidents and environmental damage.

Well-designed passive solar houses should have no major adverse environmental impacts, but active systems may pose problems, depending on the kind of heat

storage material used. Mold and mildew can grow on storage racks and be distributed throughout the house via a forced air system. Noxious or harmful outgassing can also occur. Materials for storage bins must be selected with care to avoid those that might enhance mold and mildew growth or cause health hazards.

Supply Forecast

Table 3-6 contains the estimate of total residential conservation achievable by 2010 for all alternatives except the High Conservation Alternative.

Table 3-7 contains the projected total supply under the High Conservation Alternative.

Table 3-6
Conservation Resource Supply
for Residential Sector Programs

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) ¹	BPA Supply by 2010 (aMW)
Existing Single Family Weatherization	102	62
Existing Multi-Family Weatherization	36	9
New Single-Family MCS	260	144
New Multi-Family MCS	37	12
Water Heaters	345	152
Refrigerators	106	43
Freezers	38	16

¹ Achievable conservation potential under the 1989 final high load forecast.

Table 3-7
Conservation Resource Supply
for Residential Sector Programs
Under High Conservation Alternative

Program (Sector/Sub-sector)	Total Supply by 2010 (aMW) ¹	BPA Supply by 2010 (aMW)
Existing Single Family Weatherization	102	62
Existing Multi-Family Weatherization	36	9
New Single-Family MCS	260	144
New Multi-Family MCS	37	12
Water Heaters	345	152
Refrigerators	343	115
Freezers	105	45
Other Appliances ²	700	270

¹ Achievable conservation potential under the 1989 final high load forecast.

² For the High Conservation Alternative, this sector (sub-sector) includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation alternatives.

Cost

The projected costs for BPA's residential conservation programs for all alternatives analyzed in this EIS except the High Conservation Alternative are

contained in Table 3-8. Projected costs under the High Conservation Alternative are contained in Table 3-9.

Table 3-8
Conservation Resource Cost
for Residential Sector Programs

Program (Sector/Sub-sector)	Cost per MW ¹ (1988\$)(000)
Existing Single Family Weatherization	\$6,842
Existing Multi-Family Weatherization	\$6,750
New Single-Family MCS ²	\$7,826
New Multi-Family MCS ²	\$7,127
Water Heaters	\$1,523
Refrigerators	\$1,682
Freezers	\$2,040

¹ Includes a 7.5 percent transmission line loss credit. Cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources.

² These measures are expected to have a 70-year life, compared to a typical life of 20 years for the other measures.

Table 3-9
Conservation Resource Cost
for Residential Sector Programs
Under High Conservation Alternative

Program (Sector/Sub-sector)	Cost per MW ¹ (1988\$)(000)
Existing Single Family Weatherization	\$6,842
Existing Multi-Family Weatherization	\$6,750
New Single-Family MCS	\$7,826
New Multi-Family MCS	\$7,127
Water Heaters	\$1,523
Refrigerators ²	\$5,732
Freezers	\$1,498
Other Appliances ³	\$3,138

¹ Includes a 7.5 percent transmission line loss credit. Cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources.

² New savings from refrigerators are assumed to come from the more expensive advanced technologies.

³ For the High Conservation Alternative, this sector (sub-sector) includes additional achievable potential beyond that estimated for the other RPEIS alternatives.

3.1.3 Industrial Sector Conservation

Program Description

Conservation in industrial applications consists of increasing the efficiency of the energy used for a process, system, or specific application of an energy conservation measure or electro-technology. Energy-consuming end uses within industrial facilities include motors, pumps, heating-cooling, fluid handling, ventilation, lighting, space and material heating, and controls. The ECM application could be as simple as installing a single heat exchanger in a cooling

line, or as complex as a complete upgrade and change-out of an entire material-handling application where motors, pumps, friction pads, guides, and controls are redesigned.

The industrial sector conservation resource consists of 12 major categories of manufacture, based on the Standard Industrial Classification (SIC) Manual listings and BPA's listing of the 100 largest industrial electricity users served by public utilities in the region (see Appendix C, Tables C-1 and C-2).

Energy Conservation Measures

Within the industrial sector, there are currently 20 major energy conservation measures that are recognized as most useful. These measures are generally system upgrades or replacements within existing facility boundaries. BPA has individually evaluated the ECMs described below and determined them to be Categorically Excluded from further NEPA review.

High Efficiency Motors Install high efficiency electric motors, replacing existing or proposed standard efficiency motors.

Adjustable/Variable Speed Drives (ASD/VSD) Install drives to control motor speed to the appropriate load, thus eliminating the need for regulating devices such as gear reducers, belt and pulley systems, dampers, valves, flow restrictors, etc. for tailoring speed to work output.

Energy Efficient Motor Rewinds Repair and/or rebuild a failed motor. Specific tasks may include replacing bearings, wiring, insulation or other enhancements.

Heat Recovery Equipment Install equipment to transfer heat to or from a liquid or gas and to or from an existing or proposed process which will offset electric or other fuel use.

Thermal Storage Install equipment to store energy in the form of hot or cold fluids or mass to provide heating or cooling capacity for later use in a process.

Insulation Install insulation to reduce heat transfer in a process (excludes asbestos products).

Process Heat Equipment Install equipment or make efficiency improvements to process heating or heat distribution systems.

Compressed Air Systems Install efficiency improvements such as humidity controls, compressor changeouts, improved sequencing controls, piping upgrades, reduction of air leaks, and unloaders to existing or proposed compressed air systems.

Lighting Replace or upgrade existing or proposed lighting systems to reduce electrical energy use and maintain or improve light levels and quality.

Energy Management Systems Reduce the energy consumption of systems by optimizing control of fluid flows, material handling, and controlled variables such as temperatures, pressures, scheduling and sequencing.

Material Handling Upgrade material handling systems efficiency by replacing pneumatic conveyors with mechanical systems, installing high efficiency motors, installing adjustable speed drives or other measures.

Power Factor Improvement Install capacitors to improve power factor and reduce line losses.

Cooling Tower Conversion Install modifications to cooling towers to improve efficiency, such as conversion from counterflow to cross flow, installation of 'Strainer Cycle' operation to provide direct cooling, installation of high efficiency motors, ASDs or other fan or pump control systems.

Pumps and Fans Replace, rebuild or modify fans, compressors, blowers, pumps, impellers or fluid conveyance systems with energy saving units.

Distribution Transformers Replace existing or proposed transformers with high efficiency transformers.

Dehumidifiers Replace an existing or proposed electric dehumidification system with a more energy efficient system.

Furnace Upgrades Replace existing furnaces with more energy efficient furnaces.

Water Recycle Processes Upgrade existing water recycle or reclaim processes to conserve electrical energy. The upgrade must not increase the waste stream.

Refrigeration Systems Replace existing or proposed mechanical refrigeration processes or their components with systems or components of higher energy efficiency. They may include more efficient compressor systems, motors, controls, heat exchangers, oil cooling, auto purgers, larger condensers, and refrigerant upgrades. All refrigerants removed must be recovered and recycled in accordance with the Clean Air Act Amendment of 1990.

Customer System Efficiency Improvements General transmission improvements including transformer replacement, conductor replacement, and insulator additions and replacement.

Conservation Linked to Cogeneration

Cogeneration is the simultaneous production of electricity and useful heat energy from a single fuel source. Many industrial sites generate electricity in a power plant and use the cogenerated steam for industrial processes, such as drying. In other cases, commercial sites such as hospitals, laundries, or universities use waste heat or steam for space heating, water heating, and even absorption cooling applications.

Since passage of the Northwest Power Act, various interests, including some of BPA's customers, have requested that BPA develop processes to acquire "small" generating resources, particularly cogeneration. As a result, BPA may consider linking cogeneration with conservation efforts at large industrial plants. At a minimum, large industrial customers may receive audits for cogeneration potential as part of their conservation audits. This would enable BPA to build a knowledge of plant-specific cogeneration capability. BPA may also consider adding cogeneration as an incentive to the industrial conservation programs.

For additional information about cogeneration, see section 3.2.2.1.

Operating Characteristics and Capacity Contribution

Industrial facilities in the Pacific Northwest, especially the large aluminum and pulp and paper plants, tend to operate constantly throughout the day, therefore

yielding flat electricity consumption patterns. Typically, these plants also operate constantly throughout the year. Conservation programs in the industrial sector generally improve the efficiency of the operating equipment and reduce electricity consumption evenly across all hours of operation, which includes the time of system peak demand. The peak savings achieved through industrial programs is assumed to be equal to the energy savings.

Environmental Effects and Mitigation

Most of the measures discussed above do not alter the current mechanical processes in a way that affects the immediate quality of any waste streams. Therefore, they impose little or no foreseen environmental impacts. Due to the diverse nature of the industrial sector, new energy conservation measures may be developed which could have impacts that may alter an existing waste stream or introduce a new waste stream.

BPA recognizes the environmental concerns and future needs relative to industrial energy impacts. However, in most applications, no negative impact would be realized because the action would take place under a highly regulated structure of Federal, state, and local laws and regulations. The ECMs, in many cases, have a positive impact by reducing the need for new generation or enhancing the efficiency of the process, which can result in reduced emissions.

In most industrial applications, there is sufficient regulation to deal with the environmental impacts that would be associated with the industry base located in the BPA service area. Tables 3-10 and 3-11 list the major regulating agencies in BPA's service territory and their jurisdictions.

Table 3-10
Environmental Regulatory Agencies in BPA's Service Territory

United States Environmental Protection Agency	EPA
Idaho Department of Health and Welfare	IDHW
Montana Department of Health and Environmental Sciences	MDHES
National Institute for Occupational Safety and Health	NIOSH
Mine Safety and Health Administration	MSHA
Oregon Department of Environmental Quality	ODEQ
Oregon Occupational Safety and Health Administration	OOSHA
Occupational Safety and Health Administration	OSHA
Washington Department of Labor and Industries	WDLI
Washington Department of Ecology	WDOE

Supply Forecast

The total regional supply of industrial conservation measures is projected to be 407 aMW (BPA's share would be 191 aMW) by 2010 under all alternatives except the High Conservation Alternative. Under the High Conservation Alternative, the total regional projected supply is 508 aMW.

Cost

The cost of BPA's industrial conservation program under all alternatives analyzed in this EIS is \$1,927 per megawatt. This cost includes a 7.5 percent transmission line loss credit. The cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources.

Table 3-11
Jurisdiction of Regulatory Agencies

	Idaho	Montana	Oregon	Washington
Air Emissions	IDHW	MDHES	ODEQ	WDOE
Discharges to Surface Water	EPA	MDHES	ODEQ	WDOE
Discharges to Ground Water	IDHW	EPA	ODEQ	WDOE
Hazardous Waste Management	IDHW	MDHES	ODEQ	WDOE
Mine Safety & Health	MSHA	MSHA	MSHA	WDOE
Occupational Health & Safety	OSHA, NIOSH	OSHA, NIOSH	OOSHA, NIOSH	WDLI, NIOSH

3.1.4 Irrigation and Agricultural Conservation

Program Description

Energy efficiency improvements in the irrigated agriculture sector consist of measures that reduce the electrical energy requirements for irrigating crops. BPA's irrigated agriculture programs provide incentives to irrigators for specific ECMs. BPA also encourages and assists irrigation research proposals. Most projects are designed to optimize water use and thus make efficient use of energy.

Energy Conservation Measures

Energy conservation measures include low-pressure sprinkler irrigation, drip irrigation, high-efficiency motors, nozzle replacement, well modifications and treatment, mainline upgrades, adjustable speed drives, pressure relief and bypass, low/high-angle discharge, and flow adjustment.

Operating Characteristics and Capacity Contribution

Conservation programs in the agricultural sector are directed toward reducing the electricity required in the pumping of water onto fields. The pattern of electricity

use in this sector usually begins in the morning, continues fairly constantly throughout the day, then drops off in the evening, although some program efforts have attempted to promote watering later in the day. However, agricultural electricity use peaks in the spring and summer, versus winter for the system peak demand. Therefore, the energy saving results of conservation programs in this sector tend not to affect peak winter demand.

Environmental Effects and Mitigation

This sector of the conservation resource consists of several energy-related measures that are routinely practiced and considered environmentally benign. These measures have been addressed and researched to assess the local environmental impacts that might be associated with them. BPA-sponsored research projects such as the "Evaluation of Very Low Pressure Sprinkler Irrigation and Reservoir Tillage for Efficient Use of Water and Energy" (1988) suggest that the environmental impacts associated with most of the energy conservation measures result in a net positive environmental impact in that reductions in both energy and water consumption are realized and equipment life is extended. The primary negative impact results from a change in water droplet size from such measures as nozzle change-out, pressure adjustment, and angle discharge. In some cases, this change could increase the rate of soil erosion with its attendant impacts on water quality in a given area. However, through proper placement and equipment sizing, and the usage of a variety of tillage practices to enhance infiltration, any change in soil erosion can be kept at a minimum and, in some cases, improved. In cases where efficient sprinkler systems replace traditional flood and furrow irrigation, erosion is generally reduced. Table 3-12 lists the energy conservation measures implemented and their associated impacts.

Table 3-12
Irrigation Measures and Their Impacts

Measure	Effect	Potential Impact or Concern
Low-Pressure Sprinkler Irrigation	Droplet and spray change	Erosion
Drip Irrigation	Soil moisture concentration	No impact
High-Efficiency Motors	Reduced energy consumption	No impact
Nozzle Replacement	Droplet size, decreased radius	Erosion
Well Modifications and Treatment	Increase pumping capacity	Land use
Mainline Upgrading	Improved distribution efficiency	No impact
Adjustable Speed Drive	Reduced energy, demand, water usage	No impact
Pressure Relief and Bypass	Reduced energy and water usage	No impact
Low/High-Angle Discharge Flow Adjustment	Spray impact angle Water flow rate	Erosion Erosion

Supply Forecast

The total supply of irrigation and agricultural conservation is projected to be 35 aMW by 2010 under all alternatives analyzed in this EIS (BPA's share would be 14 aMW). This is considered to be the total achievable conservation potential under the 1989 final high load forecast.

Costs

The cost of BPA's irrigation and agricultural conservation program is projected to be \$1,648 per megawatt under all alternatives analyzed in this EIS. This cost includes a 7.5 percent transmission line loss credit. The cost per unit includes administrative costs, in 1988 constant dollars, associated with acquisition of conservation resources.

3.2 Generating Resources

The availability of a resource at various costs is estimated in BPA's supply curves. This section contains the supply curve (cost and supply) projections for generating resources in the Pacific Northwest that are used in this EIS analysis. They are not projections of what will be constructed, but rather, they are generic forecasts of the types and costs of resources that are assumed to be available for development. Information for each resource is organized by a description of the technology, its operating characteristics, costs, environmental effects and mitigation, and a supply forecast. Costs are given in 1988 dollars.

Transmission Cost Adjustment

All generating resources not directly applied to a load must be connected to transmission and distribution lines. This interconnection, as it is called, can be expensive, particularly if a resource addition is located far from transmission facilities or if local facilities are fully utilized. Transmission, or lack thereof, can affect the cost-effectiveness of a generating resource, so transmission costs are estimated for all generating resource types.

To make an accurate estimate of the transmission cost associated with integrating a particular resource, transmission planners need to know the capacity, location, and operating characteristics of that resource. Since this information is not available in sufficient detail at the planning level, a more general approach has been used here. For this analysis, a cost factor was added to each resource in a way that recognizes that resources far from load centers are more costly to integrate than resources near load centers. This approach to accounting for transmission cost also recognizes resources that can take advantage of surplus capacity in existing facilities.

For transmission cost estimating purposes, resources are divided into five location categories: resources sited west of the Cascade Mountains, resources east of the Cascades but within BPA's existing network, resources east of the BPA network, resources in Canada, and resources in California.

In the existing Northwest power system, the major load centers are located west of the Cascades and are centered around Seattle and Portland, the region's two largest population centers. The largest load growth is in the Seattle area. For this analysis, greatest load growth is assumed to continue west of the Cascades.

Transmission capital cost estimates were developed for each of the five location categories and converted to unit costs. Table 3-13 summarizes these cost estimates. These transmission capital cost adjustments are applied to generic resources. They are embedded in the total capital cost figures reported in this section. The transmission adjustment for the coal resources is based on the same methodology but was applied based on the prorated mileage relative to Colstrip, Montana. Operating and maintenance costs for additional transmission are not included in the transmission cost adjustment.

Table 3-13
Transmission Capital Cost Adjustments
for Generation Resources
(1988\$)

Zone	Cost (\$/kW)
West of Cascades	0
East of Cascades	120
East of BPA Network	410
California	0 ^a
Canada	0 ^a

^a Resources from California and Canada are assumed to be system sales, which would compete with Northwest resources. Consequently, no transmission adjustment is applied to these resources.

3.2.1 Renewables

3.2.1.1 Hydropower

Technical Description

Water power is one of the oldest, simplest forms of energy. In its modern form, the potential energy of water is released as it drops through a turbine to generate electricity. Water is piped to the turbine through a "penstock," starting at the "forebay" or entrance to the penstock. Available energy is proportional to the elevation difference between the forebay and the turbine blades. This height is often referred to as feet of "head."

Hydroelectric projects can have large dams associated with them to store water and create head, or they may be "run-of-river" plants, which use a smaller dam (or diversion) to take a portion of a river's flow out at a high elevation, drop it through a penstock and turbine, and release it at a lower level. The large majority of the potential projects are small run-of-river designs. It is also possible to install small turbines in existing pipe or ditch systems.

Long-range planning is based on the firm energy capability of the hydro system. The firm hydro energy capability is the amount of power produced by these regional hydro resources in the worst low-water period--called the critical period--recorded for the Columbia River Basin. The energy produced by the region's hydro projects during the critical period is calculated using the generation average for the period September 1928 through February 1932. The regional hydro system generates approximately 12,400 aMW of firm energy under critical water conditions.

Nonfirm Resources

Resource planning uses critical water flows to compute the region's and the Federal system's firm hydro energy. The regional hydro system, however, has historically experienced precipitation levels that produce greater than critical period flows. This excess water is used to produce nonfirm energy.

Planning does not include nonfirm energy in the loads and resources balance.

Nonfirm energy increases regional resources by about 3,800 aMW annually when averaged over 50 years of historical water flows. The Federal share of this nonfirm energy is about 2,400 aMW based on 50 years of data. Nonfirm energy is even larger for both systems when based on 102 years of historical water flows.

Operating Characteristics and Capacity Contribution

The amount of water behind the dam, precipitation levels, loads in the service area, and regional coordination of hydro operations affect the operation of hydro projects. Hydro projects provide both energy and peaking capabilities, which depend on the number of turbine units, streamflows, water storage, and the elevation of the dam. Streamflow estimates are based on existing records of such information as the drainage areas above the site, precipitation, and local ground water conditions. Hydrologic conditions vary greatly over the region and even within basins and sub-basins. In the west, winter storms produce immediate high flows, and in the east, flows are predominantly from melting snow in the spring. Hydro projects typically have availability factors of 85 to 90 percent. Capacity factors of 50 percent are typical.¹

Hydro projects have poor to excellent dispatchability and a widely varying match with natural load shape, especially seasonally. Hydro is generally good for capacity, but can vary widely depending on the natural streamflow shape and restrictions on operational flexibility. Projects on streams without dependable summer flows make no contribution to firm summer capacity. Projects restricted to a constant discharge around the clock make only the same contribution to capacity as would a baseload plant.

Costs

The cost projections shown in Table 3-14 are either supplied by potential developers or calculated by an algorithm (Hydropower Analysis Model-HAM) contained within the Pacific Northwest Hydropower Data Base and Analysis System (NWHS). This algorithm uses individual developer estimates if they are available from permit and license applications. When consistent estimates are not available, the model develops a cost estimate from the physical characteristics contained in the application. All of the cost estimates are then aggregated into generic cost categories, i.e., Hydro-1, -2, -3, and -4.

¹1986-1990 *Generating Availability Report*, North American Electric Reliability Council (NERC), August 1991, p. 118.

Table 3-14
Costs and Supply - Hydroelectric Power
(1988\$)

	Hydro-1	Hydro-2	Hydro-3	Hydro-4
Capital Cost (\$/kW)				
EAST ^a	1,179	1,448	1,951	2,336
WEST ^a	1,059	1,328	1,831	2,216
O&M Cost				
Fixed (\$/kW-yr)	21.00	27.00	37.00	44.00
Variable (mills/kWh)	0	0	0	0
Real Levelized Costs (mills/kWh)				
EAST ^a	21	27	36	42
WEST ^a	20	25	35	43
Nominal Levelized Costs (mills/kWh)				
EAST ^a	45	57	77	89
WEST ^a	43	53	75	91
REGIONAL SUPPLY (aMW)				
EAST ^a	45	57	77	89
WEST ^a	43	53	75	91
BPA SUPPLY (aMW)				
EAST	11	14	19	22
WEST	11	13	19	23

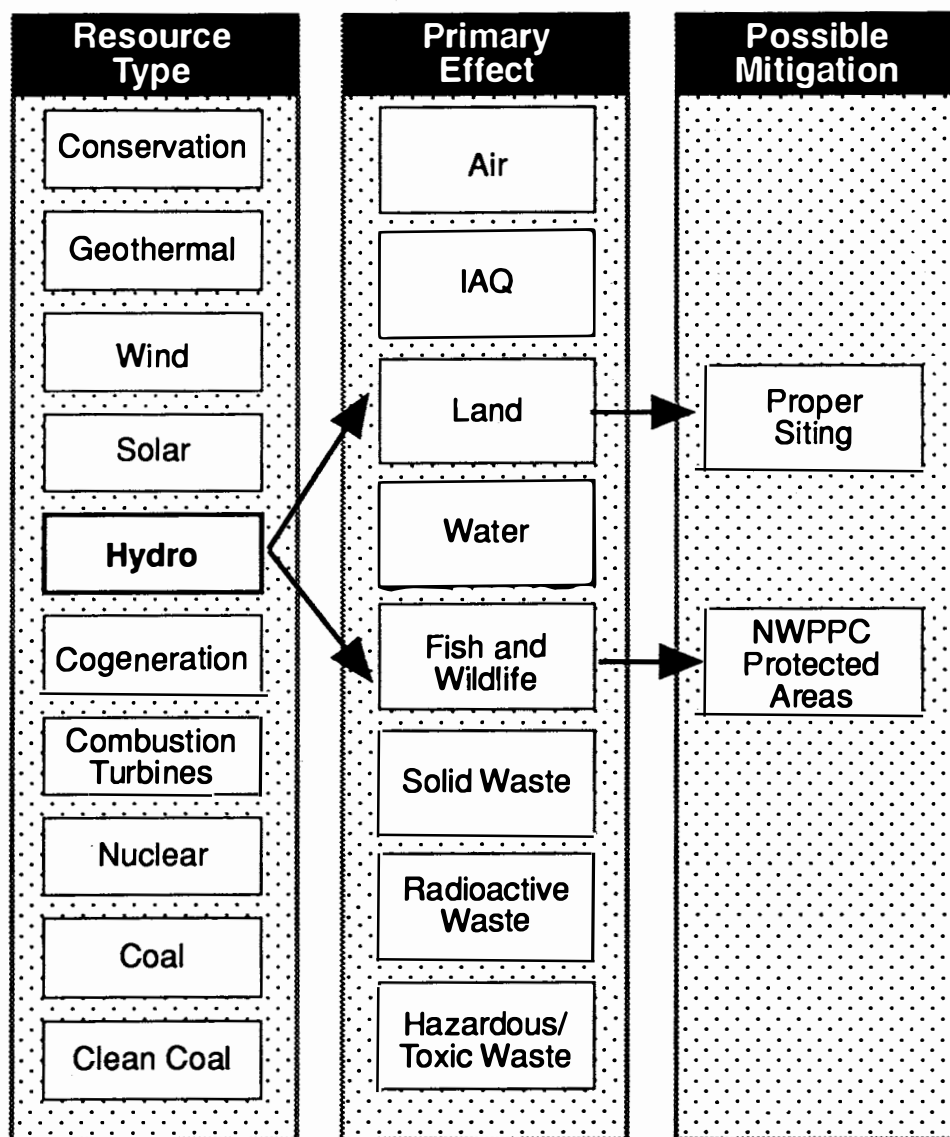
^a The regional potential is split between the east and west side on a 60/40 ratio. The portion that is located on the east side receives a capital cost adder that reflects the transmission cost adjustment.

Environmental Effects and Mitigation

The impacts of hydroelectric development vary greatly from project to project. Impacts include effects on land use, wildlife, aesthetics, and impacts associated with construction (Figure 3-3). Although a single, small project may have only a small effect, it is necessary to consider the cumulative effects if a number of projects are developed on the same river or stream.

There are no emissions of greenhouse gases or particulates, and only small quantities of solid wastes are generated by hydroelectric plants. However, impoundment of a river or stream alters the surface water and habitat, and may block migration of fish. Protection of critical fish and wildlife habitat is accomplished via the Protected Areas amendments to the Northwest Power Planning Council's Fish and Wildlife Program and Power Plan. Among other environmental safeguards, these amendments state that, "...because Protected Areas represent the region's most valuable fish and wildlife habitat, hydropower development should not be allowed in Protected Areas, but should be focused in other river reaches." (See Chapter 2, Section 2.2.7.) None of the potential projects considered for the region are located in the Northwest Power Planning Council's Protected Areas, thereby limiting projects that might have irreversible impacts on anadromous fish populations.

Figure 3-3
Environmental Effects and Mitigation - Hydroelectric Power



A hydroelectric project that has an impoundment (the capability to store water) associated with it generally has a more severe impact than a run-of-river project. This is especially true for large impoundments (greater than 100 acres). Most of the sites in the data base used to develop the potential for the region are smaller run-of-river projects with no, or limited, impoundments.

Hydroelectric plants with greater than 30 MW of capacity may be either run-of-river dams or storage reservoirs, and are usually located on mainstream rivers or major tributaries. Projects of less than 30 MW capacity are typically located on small tributary streams. Often, the smaller streams have a higher gradient and provide sufficient head to operate turbines without the need for a large reservoir.

Supply Forecast

The procedure to generate regional estimates of supply uses the cooperatively developed Pacific Northwest Hydropower Supply (NWHS) Model. The model uses data from the NWHS model on cost, capacity, and output, combined with regional environmental information from the Northwest Environmental Data Base. The procedure used to develop estimates of potential hydropower resource capability for this EIS involves several steps:

1. Sites that are located in the Northwest Power Planning Council's Protected Areas were screened out.
2. Even projects passing this screen could have environmental problems that may preclude development. In addition, the technical characteristics of many of these sites have not been fully explored, leading to the possibility that development may not be feasible for engineering, environmental, or economic reasons. To account for these factors, probabilities of completion were assigned, based on the stage at which the project stands in the regulatory process (permit pending to license granted), the layout of the project (diversion to canal), the status of the waterway structure (undeveloped to existing), and the value of the environmental resources at the site which would be impacted by development.
3. These probabilities (ranging from 20 to 95 percent) were applied to the capacity and energy potential of each project to obtain its probable contribution. The probable contributions of individual projects were then summed to obtain the regional potential.

This method produces a statistical estimate of the expected developable hydropower without the need to determine if specific individual projects should be developed--a determination that would be inappropriate, given the limited information available on a specific project and stream reach.

Table 3-14 summarizes the results of this regional projection of supply.

It is important to remember that, even though a specific project is included in the estimate of potential, this does not mean the site will or will not be developed. This methodology is intended to provide a macro assessment of the potential in the area. The presence or absence of a specific project has a minor effect on the overall projection for the small hydro resource.

Table 3-15
Potential Annual Routine Environmental Impacts
Per Average Megawatt of Hydroelectric Power^a

Potential Impacts	Generation
Air Pollutants	None
Water Quality Impacts	
Consumption (acre-ft)	Water use is not consumptive.
Thermal Discharge	No thermal discharge.
Other Impacts	Warm reservoir water from increased surface area, reduced shading, and slow water movement may exceed fish temperature tolerance; reduction in dissolved oxygen could impact fish and encourage algal blooms. Air entrained in water flowing through generators or over spillways can cause gas supersaturation, which can be lethal to fish; sediment collection behind dams can alter river substrate and impact invertebrate population; fish and wildlife can be stranded, lose habitat, or have migration routes blocked by hydro development.
Land Effects	
Acreage Requirements	Depends on site and technology.
Other Impacts	Large hydroelectric projects require vast amounts of land for reservoirs and large dams alter natural landscapes; storage reservoirs may change seasonal water levels and can result in unattractive and unproductive beach areas; recreational opportunities are altered by water impoundment and loss of free-flowing water; opportunities for fishing, sailing, and boating may be developed, while rafting would no longer be available
Waste Streams	Limited to office and maintenance activities.
Employment^b	
Construction (employee-years per MW capacity)	9.3
Operations (employees per MW capacity)	0.3
Occupational Safety and Health Impacts Per MW Capacity	Not available in literature.

^a Unless otherwise indicated, these generic descriptions are taken from: Baechler, M.C., D.H. Fickheisen, and P.L. Hendrickson. 1990. *Environmental Effects and Mitigation for Energy Resources*. PNL-SA-18087, prepared by Pacific Northwest Laboratory for the Bonneville Power Administration, Portland, Oregon.

^b See sources and calculations in Appendix F to the Draft EIS.

3.2.1.2 Geothermal

Technical Description

Geothermal energy taps heat available within the earth's core. Heat, water, and permeable rock, found in combination, are the requirements for a hydrothermal resource for power generation. Generally, wherever tectonic plates abut, there is the potential for geothermal resources. Here, the earth's mantle is relatively thin and fault systems give way to earthquakes and volcanoes; magma from the earth's core protrudes close to the surface, bringing geothermal heat with it. High-temperature gradients found in drilling, in hot springs and geysers, and in certain kinds of geologic formations and geochemistry, provide evidence that hydrothermal systems exist beneath the earth's surface.

The biggest problem with developing geothermal resources is finding the resource. Drilling to depths of 10,000 feet or more may be required to locate a production well to bring geothermal steam or fluid to the surface, where it can be processed through a power plant. Prospecting for high-quality geothermal reservoirs is financially risky and expensive.

There are three principal types of geothermal conversion technologies used for power generation: (1) dry steam, (2) flash, and (3) binary cycle plants. In dry steam systems, the geothermal resource is a gas at temperatures in excess of 350°F. High-pressure geothermal steam is drawn up through wells as a gas and goes directly through a turbine; then it condenses to a liquid to be injected back into the reservoir.

In flash systems, the geothermal resource is found as a pressurized liquid brine at temperatures greater than 350°F. Because the resource is a fluid under high pressure, it must be "flashed" or depressurized to a gas state before it can be processed through a turbine. When geothermal fluid flashes, only a portion of the liquid becomes steam; the rest remains as a high-pressure liquid. Depending on the temperature and pressure of the brine as it leaves the well head, geothermal fluid may be flashed twice in sequence to maximize the "quality" or proportion of steam possible from the fluid.

Binary systems extract heat from geothermal fluids that have relatively low temperatures, less than 300°F. A binary system must use another working fluid besides the geothermal brine (such as butane, iso-butane, or pentane) that has a low boiling point compared to water. In a binary system, there is the geothermal loop, a working fluid loop, and a cooling loop. All three are separate and do not mix. The geothermal loop imparts heat to the working fluid in an evaporator, where the working fluid boils to a gas. The hot gas expands through a turbine generator. Finally, the cooling loop runs through a heat exchanger and condenses the working fluid. Binary systems have used geothermal resources with temperatures as low as 177°F.

The temperature and pressure of the resource dictate the choice of technology employed at a particular geothermal site. All geothermal technologies are mature, and geothermal energy is used worldwide. Active geothermal regions in the U.S. include The Geysers, with about 2,000 MW on-line, and the Imperial Valley and Glass Mountain in California, as well as the Basin and Range geologic province covering parts of Utah, Nevada, and Idaho.

Typically, geothermal plants are sited in 20 to 50 MW units, but modular systems as small as 5 MW have been developed. One advantage of small-scale modular

units is that they can be used to help evaluate a reservoir's characteristics while generating power.

Operating Characteristics and Capacity Contribution

Geothermal power is generally operated as a baseload energy source. These projects typically have availability factors of 85 to 90 percent and capacity factors of 70 to 75 percent. Geothermal power is generally considered to be baseloaded because, due to constraints of well dynamics, these resources are generally not amenable to rapid fluctuations in output. However, in some cases, such as some units at The Geysers, units can be operated to follow load.

Because geothermal resources are usually operated as baseload plants, they provide roughly the same contribution to capacity as any other baseload plant (e.g., comparable to coal plants). To the extent that they are more reliable and that outages can be planned, they would be slightly better.

Costs

In this EIS, the cost data for the geothermal resource is derived from the Northwest Power Planning Council's *Staff Issues Paper 89-36, Geothermal Resources*. This data reflects a range of geothermal conversion technologies at sites with defined geothermal resources. Costs would be expected to vary depending on site-specific conditions. Table 3-16 shows costs for two categories of geothermal energy. GEO-1 represents a pilot plant (10 to 30 MW) in the high Cascades. GEO-2 represents the potential in the Basin and Range geologic province. Basin and Range development has already occurred and future development in this area has less uncertainty associated with it than does the Cascade resource.

Table 3-16
Costs and Supply - Geothermal
(1988\$)

	GEO-1	GEO-2
Capital Cost (\$/kW)	2,785	2,920
O&M Cost		
Fixed (\$/kW-yr)	102.00	95.00
Variable (mills/kWh)	2.7	1.4
Real Levelized Costs (mills/kWh)	74	42
Nominal Levelized Costs (mills/kWh)	148	84
Supply (aMW)		
Region	27	390
BPA	27	390

Environmental Effects and Mitigation

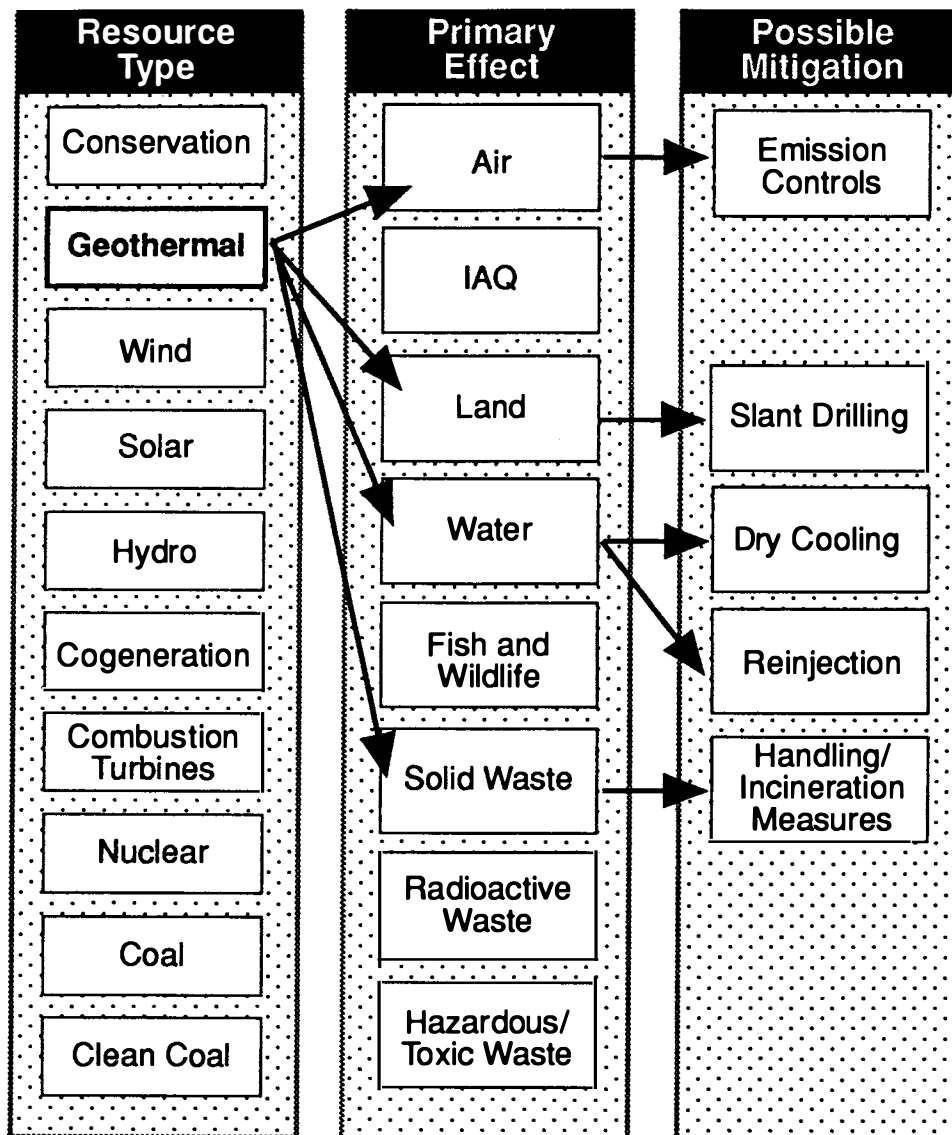
Depending on the kind of conversion technology and the size of the facility, geothermal resource development can have environmental impacts (Figure 3-4). Environmental impacts are described for binary, flash, or dry steam systems. The impacts from all three types are similar, and the flash system is the most likely to be used. (See Table 3-17.) Plant size, siting, and operation and maintenance practices also affect the magnitudes and kinds of impacts that may be expected.

Many of these impacts, however, can be mitigated, and geothermal energy can provide a reliable, relatively clean generation alternative.

Geothermal energy conversion requires processing large quantities of fluids and gases. Dry steam systems, and flash steam systems to some extent, introduce non-condensable gases into the environment, particularly hydrogen sulfide (H_2S). In small concentrations, H_2S has an unpleasant, rotten egg odor. In large concentrations, the gas paralyzes the olfactory nerves and becomes undetectable; it is lethal at high concentrations. H_2S can accumulate in low pockets and threaten plant species and wildlife. Carbon dioxide, another non-condensable gas, is also discharged into the atmosphere in significant amounts. But the concentration of CO_2 is about one-thirtieth that emitted by a coal plant per kilowatt-hour (kWh). Other contaminants from geothermal steam pose less serious hazards compared to hydrogen sulfide. In dry steam, there are small concentrations of boron, arsenic, and mercury.

Waste heat in the form of condensing steam from turbines poses another environmental concern. Large quantities of waste heat are dumped into the environment, mainly from cooling towers. Clouds of condensing steam from the towers may affect local climates, producing fog and causing a visibility hazard, especially on roads. Large quantities of cooling water are needed to operate the cooling system. Condensed steam can be used as a coolant, augmented by some additional water supply. Water needs for power generation, particularly in arid areas, may conflict with local agriculture, mining, or public consumption uses.

Figure 3-4
Environmental Effects and Mitigation - Geothermal



Water quality can be affected at a geothermal site. Brine coming to the surface from supply wells and returning through injection wells has the potential to contaminate local water tables. Most geothermal fluids are highly saline and contain trace toxic elements such as boron, mercury, lead, ammonia, and arsenic. Manganese and iron, which make water acidic, may also be found. Also, there is the potential for leakage into shallow aquifers or accidental release of brine into streams or lakes.

Waste products pose problems unique to geothermal energy. Primary among these are hazardous wastes from drilling, emission of hydrogen sulfide, and concentrated scaling from brine residue. Containment, processing, and removal of these chemicals pose risks in transportation and handling.

Another concern in geothermal operations is the maintenance of the geothermal reservoir. Normally, re-injection of the brine is practiced to help recharge fluids into the reservoir and prevent subsidence of the well field. However, injection may induce seismic activity, due to high local pressures generated by the re-entering fluid.

Like any major construction activity, the development of geothermal sites can have a major impact on local communities. There is heavy road use, erosion, disruption of local ecosystems, and noise. Some of these effects are transitory, while others are ongoing during plant operations. Energy production may require only about 20 to 100 acres for a 50-MW plant, but the exploration, drilling, construction, and operation facilities may encompass from 500 to 3,000 acres.

There are also social and economic effects of geothermal development. Rapid, intense development and the accompanying influx of new residents can tax a community's ability to provide schools, housing, and other essential services. Finally, aesthetics are a major concern. The visual impact of a well field and power plant facilities may be objectionable, especially in pristine areas such as the Cascades, where many potential geothermal sites exist.

By far the most pronounced environmental impact from dry steam and flashed steam plants is the emission of hydrogen sulfide. Mitigation measures include abatement using the Stretford process, which traps nearly 99 percent of the non-condensable H_2S emissions, reducing the compound to elemental sulfur and hydrogen. Other control methods include a hydrogen peroxide/iron catalyst process, which removes 90 to 98 percent of the hydrogen sulfide left in steam condensate. Control of well head ventilation and burning vent gas can also reduce H_2S . In binary power systems, H_2S emissions are not a problem, since the geothermal fluid remains in a closed loop.

Several mitigating measures can be taken to minimize the impacts of geothermal power production. Dry cooling towers reuse the geothermal steam as a cooling water source after it condenses, offering an alternative to the use of additional water for cooling. However, dry towers are large and expensive. Slant drilling to locate several wells from one pad reduces land impacts. Loud noise caused by steam release at wells can be muffled to avoid hearing injury to field workers. Risks associated with hazardous wastes can be minimized by employing good safety practices and accident prevention measures in transportation and handling. Some wastes can also be incinerated and rendered harmless.

In general, geothermal steam or brine chemistry, the conversion technology used, and the characteristics of the geothermal reservoir dictate the primary environmental concerns associated with a particular plant. Each site poses its own peculiar environmental problems, which must be dealt with on a site-specific basis.

Examples of potential environmental impacts from geothermal generation are shown in Table 3-17.

Table 3-17
Potential Annual Routine Environmental Impacts
Per Average Megawatt of Energy Generation of Flash
Geothermal Plants^a

Potential Impacts	Generation
Air Pollutants	
Hydrogen Sulfide (tons)	0.09 to 0.88
Ammonia (tons)	3.3 to 339.99
Methane (tons)	2.16 to 90.39
Carbon Dioxide (tons)	700.8 ^b
Arsenic (tons)	0.0075 to 0.09
Boron (tons)	0.225 to 2.28
Mercury (tons)	0 to .045
Benzene (tons)	0.43
Radon (curies)	0.21 to 32
Water Quality Impacts	
Consumption (acre-ft)	44.8
Thermal Discharge (MMBtu)^c	131,000
Land Effects^d	
Acreage Requirements	0.27 per MW capacity corrected for capacity factor (does not account for exploration)
Waste Streams (tons)	
Drilling Mud (Cubic ft)	3,622 to 7,839.75
Solids Separated from Fluids	86
Solids from Hydrogen Sulfide Abatement	3.52
Solids from Scale Removal	4.62
Employment^d	
Construction (employee-years per MW capacity)	4.1
Operations (employees per MW capacity)	0.3
Occupational Safety and Health per MW capacity	
O&M Injuries	0.008

^a 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. Specific pollutants are very dependent on the chemistry of specific geothermal resources.

^b Source: Fluor Daniel, Inc. *Environmental Data for Thermal Resources*, Prepared for BPA 1991.

^c Thermal discharge may be to air, water, or reinjection to the ground.

^d See sources and calculations in Appendix F to this EIS. Seventy-five percent capacity factor assumed.

Supply Forecast

The technology of geothermal energy is well established and demonstrated. It can, however, only be applied where a recoverable geothermal heat source exists. The only demonstrated use of geothermal energy in the Northwest is a now-defunct binary cycle demonstration plant at Raft River, Idaho.

The most likely locations in the Northwest for geothermal development are the Basin and Range province (southeastern Oregon and southern Idaho) and the high Cascades of southern Oregon. Although the high Cascades area offers the greatest potential (1,000+ aMW), it is also the most uncertain. The GEO-1 resource listed in Table 3-16 represents a 30-aMW high Cascades pilot project. GEO-2 represents 390 aMW of potential Basin and Range development. It is hoped that the high Cascades pilot project will lead to more exploration and subsequent development of the area. However, the uncertainty of the resource precludes projecting a larger supply at this time.

3.2.1.3 Wind

Technical Description

Wind turbines convert the kinetic energy of wind into electrical energy by transferring the momentum of air to the rotation of wind turbine blades or a shaft connected to a generator. There are numerous wind turbine designs and design variations, but the most common is the horizontal axis turbine, which has the axis of blade rotation oriented parallel to the ground (the blades resemble an airplane propeller). Gears step up the blade shaft rotation to a rate nearly matching the 1,800 revolutions per minute (rpm) needed to synchronize the generator, which is connected through a switchgear to a utility grid. In the horizontal axis design, the rotor blades, turbine, gears, and generator are all mounted on a bedplate or platform set atop a tower and contained within a housing as a single unit.

Engineers have devised two principal means to regulate blade speed for controlling power output: variable pitch and stall regulation. With variable pitch, a wind machine's blades adjust so that the turbine begins generating at a cut-in speed, then rises to a rated power output, and finally, holds this level until the wind reaches a cut-out speed. With stall regulation, blades are aerodynamically designed to progressively lose their lift above a certain rotation speed. Turbine housings are also designed with passive or active yaw control to rotate on a vertical axis and align the turbine in the direction of the wind.

The power available in a wind stream is proportional to the cube of the wind velocity; as the wind speed doubles, output available increases by a factor of eight. Due to wind-to-mechanical-shaft conversion inefficiencies, output from a wind turbine varies as the square of the wind speed; i.e., as the wind speed doubles, output increases four times. Because the amount of energy extracted from wind is extremely sensitive to wind speed, optimum siting of individual turbine units requires a substantial amount of data describing how wind speeds are distributed over the site, as well as over time. There is even significant variation of wind strength as tower height varies above ground. Winds aloft tend to be more stable and stronger than those near the ground. Potential sites must have average annual wind speeds in excess of 12 miles per hour at 33 feet above the ground to be considered worth developing.

Wind machines are generally grouped together into arrays at a site called a wind farm or wind park. A typical arrangement is to place turbine units in rows about 10 rotor diameters apart downwind, with adjacent crosswind turbines within the rows about 3 to 5 rotor diameters apart--although optimum siting must take terrain and the interactive effects among turbines into account. Wake disturbance and turbulence from one wind machine can severely limit the energy extracting potential of other machines downwind. Array losses due to energy extraction by upwind turbines can drop energy production as much as 15 to 20 percent in poorly sited wind parks.

Wind power technology has undergone substantial development since the early 1980s, and the technology has now reached the status of a mature industry. In California today, there are about 17,000 wind turbines operating with an installed capacity of 1,500 MW at 3 principal sites. (This is about 90 to 95 percent of the installed wind turbine capacity in the world.) California has been a proving ground for the developing wind industry. Initial problems with fatigue failures and reliability are now being addressed with better aerodynamic and structural designs and improved controls.

Operating Characteristics and Capacity Contribution

Wind power depends on the availability of wind. Despite wind's unpredictability, this renewable resource does exhibit certain patterns. Sites in the Columbia Gorge, for example, where winds are topographically and thermally induced, attain maximum availability in the spring and summer, when cooler air on the west side of the Cascades moves eastward to displace rising warmer air inland. At other sites, such as those along the southern Oregon coast and at the foot of the Rocky Mountains in Montana, winds are driven by storms, which tend to occur in winter.

Although wind cannot be counted on to meet peak loads, it can displace some energy loads. Turbine units with good mechanical design and regular maintenance have shown availability factors up to 92 to 93 percent, but they vary widely in output. Typical capacity factors for on-line units can vary widely from 10 to 35 percent, depending on the annual average wind speed and the persistence of energy-producing winds. Wind machines being installed today tend to be 100 to 300 kW units, which are lighter in weight and more efficient than their predecessors. Because of their low operating (marginal) costs, wind units are not generally operated as a dispatchable resource; instead, wind energy is used whenever it is available. Wind generation located in areas with unpredictable, gusty wind can place extra capacity demands on electrical systems, whereas wind generation in areas of regular, predominantly daytime winds (as in the interior valleys of California) are more neutral.

Costs

The cost of electricity from a wind facility is a function of the wind conversion technology cost, as well as the wind resource present at the site. The costs shown in Table 3-18 assume a capacity factor of 25 percent. Wind-1 is a compilation of those sites considered more available and accessible than those in Wind-2.

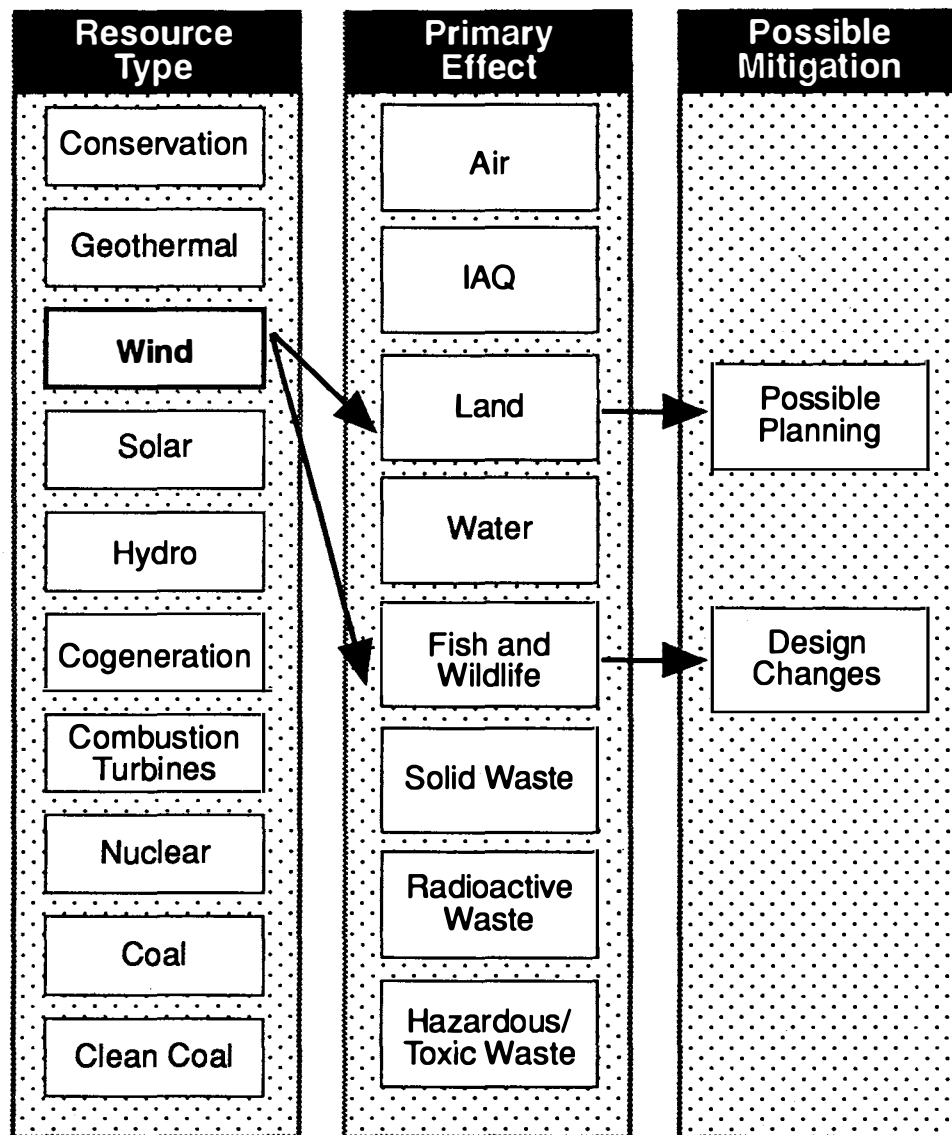
Table 3-18
Costs and Supply - Wind
(1988\$)

	WIND-1	WIND-2
Capital Cost (\$/kW)	1,158	1,250
O&M Costs		
Fixed (\$/kW-yr)	15.00	16.00
Variable (mills/kWh)	11.0	11.5
Real Levelized Costs (mills/kWh)	53	53
Nominal Levelized Costs (mills/kWh)	81	81
Supply (aMW)		
Region	261	1,241
BPA	65	310

Environmental Effects and Mitigation

Although wind energy is environmentally benign, there are some distinct environmental impacts in siting wind turbines (Figure 3-5). Wind parks of any sizable megawatt capacity require the development of large tracts of land. Only a small portion of the land would be directly occupied by turbines, roads, transmission lines, substations, and buildings. The remaining land in and around turbines could be used for livestock grazing or other non-intensive farming. Some of the best sites are in the most scenic areas along the Pacific coast and in the Columbia Gorge, where aesthetics may be an environmental concern. Furthermore, wind turbines do generate audible noise, which can be objectionable to nearby residents, and electromagnetic "noise," which can interfere with television reception. A unique potential effect is "blade flash." At certain times of the year sun may "flash" off the rotating blades, causing visual irritation to viewers.

Figure 3-5
Environmental Effects and Mitigation - Wind



Some wind sites may pose a hazard to both birds and aircraft. Some sites may be in the path of migratory birds. Secondary impacts would be caused by constructing transmission lines to bring electricity from wind sites to transmission grid connection points. By and large, siting impacts can be mitigated with good planning.

Examples of potential environmental impacts from wind generation are shown in Table 3-19.

Supply Forecast

In 1985, BPA completed a 5-year resource assessment of over 300 wind data sites in the Pacific Northwest. Of these, 39 areas were identified to have potential for future commercial development. BPA continues to gather data at five of these sites for long-term analysis. The Northwest Power Planning Council used this data, as well as technology data from California, to project regional supply. Approximately 1,500 aMW is projected as developable in the Northwest. This potential is dispersed among many areas. The largest potential is on the Blackfoot Indian Reservation surrounding Browning, Montana. This potential (approximately 3,000 MW peak, 1,000 aMW energy) is not currently considered available due to the remote location and difficulties in getting power to load centers. Preliminary evaluation of transmission constraints and cost has been completed. According to a PNUCC Study (*Blackfoot Area Wind Integration Study*, PNUCC, August 1991.) approximately \$1 billion and 10 years would be required to complete environmental studies, procure rights-of-way, and design and construct the lines needed to integrate 3,000 MW of wind resource capacity.

Table 3-19
Potential Annual Routine Environmental Impacts
Per Average Megawatt of Wind Generation

Potential Impacts	Generation
Air Pollutants	Potential electromagnetic interference and noise emissions
Water Quality Impacts	No direct impacts
Land Effects ^a Acreage Requirements	23.6 per MW capacity/corrected for capacity factor (land occupied by facilities or partially obstructed by guywires)
Waste Streams	No annual residue except office and maintenance wastes ^b
Employment ^a Construction (employee-years per MW capacity)	1.9
Operations (employees per MW capacity)	0.4
Occupational Safety and Health per MW capacity ^b O&M Injuries	35×10^{-6} to 69×10^{-6}
O&M Deaths	0 to 27×10^{-7}
Construction Injuries	8×10^{-5} to 149×10^{-6}
Construction Deaths	1×10^{-7} to 3×10^{-7}

^a See sources and calculations in Appendix F to this EIS. Twenty-five percent capacity factor assumed.

^b 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.

3.2.1.4 Solar

Technical Description

Solar Thermal. Solar thermal plants are similar to other thermal generating plants--they convert heat energy into electricity through a turbine generator. Solar energy is highly variable, both during the day and between seasons. It is not available at night, and is greatly diminished during cloudy weather. Because solar radiation is diffuse, it must be gathered and concentrated to be useful in a solar thermal system. This requires large arrays of panels with controls and mechanisms to reflect and focus the incident light and direct it to a heating unit. The heating unit of a solar thermal station has high absorptivity for trapping and retaining incident radiation, which is then transferred to a working fluid.

Collectors for solar thermal generators are characterized by large surface areas for capturing sunlight, and specific geometric shapes for concentrating the radiant energy. There are three main types of collectors: central station receivers, line-focus parabolic troughs, and point-focus parabolic dishes. In central station receivers, movable mirrors, called heliostats, track the sun and reflect the sun's energy to a central receiver mounted on a tower.

The best example of a central receiver station is the 10-MW plant in Barstow, California, which has operated since 1982. This system has 1,818 individual tracking heliostats with 766,000 square feet of reflective surface. In its operating history, the plant has produced as high as 11.7 MW of peak power, with a 10 percent capacity factor and a maximum annual output of 8,816 MWh.

Parabolic in-line troughs are the solar thermal power technology most used by utilities. The reflective trough is bent into a parabolic shape the entire length of the trough and concentrates the sun's energy along a line parallel to the parabolic trough. Along this line, receivers are run to capture the concentrated energy. Because many of these systems are designed to be stationary, elaborate tracking mechanisms and controls are not needed. Troughs are typically oriented north-to-south and lie horizontally. This configuration tends to offer the best tradeoff between maximizing capacity and keeping first costs and maintenance costs down. If energy is to be maximized instead of capacity, other orientations--such as tilting or tracking the troughs toward the sun--can be considered.

Receivers for in-line parabolic troughs are a specially coated pipe inside a glass vacuum tube. One company, Luz International--which operates the world's seven largest solar thermal plants--uses a synthetic oil as a heat transfer fluid in the pipes. The oil reaches 753°F, then runs through a heat exchanger and super heats the steam that drives a turbine generator. With this design, solar thermal conversion efficiency has improved to about 29 percent.

Point-focus parabolic dish systems are single dish units, focusing the solar energy to a single point where the receiver is located, like a flashlight reflector in reverse. Unlike the in-line troughs, the parabolic reflector must track the sun continuously on two axes. One axis allows for tracking east to west during the day; the other axis allows for tracking north to south as the sun's declination angle changes with the seasons. Because of this system's requirement for accuracy and reliability to work effectively, fabrication is difficult and expensive.

Some point-focus systems have external heat engines, such as a reciprocating Stirling, that absorb heat directly and turn generators. Others have a system of fluid lines connecting each receiver and carrying a heat transfer fluid, which in

turn is used in a turbine generator. Compared to the in-line parabolic reflectors, point-focus systems can concentrate much more energy. As of 1987, there were four point-focus reflector pilot projects testing various engine and generation technologies.

Photovoltaic. Photovoltaic cells (PVs) use the photoelectric effect to convert the sun's radiation directly into DC power. In photovoltaic cells, sunlight strikes a semiconductor material, typically a treated silicon, and frees up electrons, which generates a DC current. The DC power is then conditioned through an inverter with controls to produce AC current.

There are two main types of PV systems: flat-plate and concentrating. Flat-plate systems are usually deployed as a group of cells in stationary panels. Thus, the incident sunlight upon the cells varies markedly throughout the day and with the season as the angle of the sun's rays changes. Concentrating systems, on the other hand, track the sun throughout the day and are outfitted with lenses to concentrate the sunlight.

Photovoltaic cells are usually grouped together into waterproof modules that range from 0.1 to 2 square meters. These modules are laid out side by side in banks to form arrays. A typical PV cell produces less than 2 amperes at about 0.6 volts, or about 1.2 watts of energy. Commercial PV flat-plate cells can achieve about 12 percent efficiency in converting sunlight into electrical energy; concentrating systems have reached better than 26 percent efficiency using a single-crystal silicon material. Multiple thin-film layered cells currently under development can theoretically reach 42 percent efficiency.

Although the costs of producing PVs are decreasing and efficiencies are increasing, the technology is still very expensive. Single-layer thin film cells, the least costly to manufacture, also have very low conversion efficiency, about 4 to 6 percent. For this technology to reach wide market acceptance, analysts estimate that efficiencies would have to reach a threshold conversion level of 15 percent; laboratory versions have reached 12 percent. As more and more PVs are manufactured--there were only 30 MW produced in 1988--the industry will be able to reduce costs even further. Costs are expected to drop from a current 55 cents per kWh, down to 8 cents per kWh by 2010.

Photovoltaics are a proven technology with many applications currently in use, including calculators, range fences, and remote lighting and signaling stations. Flat-plate PVs have a free energy source, low operating and maintenance costs, minimal environmental impacts, and very high reliability. Concentrating PVs have a lower reliability because they are more complex mechanically and therefore subject to failure.

Operating Characteristics and Capacity Contribution

Solar Thermal. A solar thermal system's capacity is dependent on the sun. Solar insolation has a daily peak in early afternoon, and, of course, is not available at night. There is also seasonal variation due to the change in the sun's declination angle. Any transient cloud cover also affects the amount of energy available from the sun.

Luz's systems use natural gas as a back-up fuel to boost peak or maintain capacity during cloudy periods and late in the day. In Luz's California plants, the proportion of energy contributed by gas in a solar energy system is constrained to no more than 25 percent. If solar thermal plants were used to supply capacity, as

Luz's California plants are, the situation would be analogous to gas-fired systems backing up nonfirm hydro in the Pacific Northwest. A fossil fuel used as a back-up presents the question of whether this fuel would be better used in another application, such as space heating. Without a fuel back-up, a solar thermal station's capacity factor is diminished significantly.

For eight of Luz's Solar Electric Generating Stations, typical capacity factors range from 25 percent for a 13.8-MW plant, to 36 percent for an 80-MW plant. First costs range from \$4,500 to \$2,788 per kW for these same plants. There are about 6,000 to 8,000 square meters of collector area per MW of capacity. Luz's has an installed capacity of over 160 MW at six sites, with almost another 500 MW planned. Luz plants operate in latitudes and climates where the available insolation is much higher than that available in the Pacific Northwest. The most promising locale for solar generating plants in this region is east of the Cascades.

Solar thermal systems offer little or no dispatchability but provide a very good match with natural load shape, especially in summer. Natural gas burning can extend generation into the evening hours after sun sets. Solar thermal systems offer a very good contribution to summer capacity, and a good contribution to winter capacity.

Photovoltaics. As with solar thermal, a PV system's capacity is dependent on the sun. Solar insolation has a daily peak in early afternoon, and, of course, is not available at night. There is also seasonal variation due to the change in the sun's declination angle. Any transient cloud cover also affects the amount of energy available from the sun.

Solar radiation is very dispersed and varies significantly with latitude and climate. The average daily total solar radiation in Phoenix is about twice that of Seattle. Consequently, the most promising PV sites in the region are east of the Cascades. Although about 1 kW of solar radiation, called insolation, falls on a square meter at noon on a sunny day, a typical PV array can generate only about 120 watts per square meter. A 50-MW power installation would require about 90 acres of PV cells. This is peak capacity and does not account for diminished performance under cloudy skies or early or late in the day. PV system capacity factors for future concentrating PV plants may reach as high as 33 percent.

Photovoltaic systems offer little to no dispatchability, but provide a good match with natural load shape, especially in summer. PV systems offer a good contribution to both summer and winter capacity.

Costs

The cost estimates in Table 3-20 cover three configurations of solar thermal facilities. The solar facility with combustion turbine back-up is characteristic of the more successful California installations. The natural gas-fueled back-up tends to lower the overall cost of the facility and provides a more dependable resource.

The cost of photovoltaic cells is currently on the order of \$5,000 per peak kilowatt. Cost reductions are projected to bring cost of installed photovoltaic systems down to \$4,000 per kW. Although specific Northwest applications are possible, it is likely that solar thermal systems will remain more competitive for the foreseeable future.

Table 3-20
Costs and Supply - Solar
(1988\$)

	Sol-TR ^a	Sol-TRHTR ^a	Sol-CT ^a
Capital Cost (\$/kW)	3,009	3,099	2,485
O&M Cost			
Fixed (\$/kW-yr)	44.00	44.00	6.00
Variable (mills/kWh)	0.8	0.8	0.8
Real Levelized Costs (mills/kWh)	109	111	78
Nominal Levelized Costs (mills/kWh)	193	196	138
Supply (aMW)			
Region	22	22	42
BPA	22	22	42

^a Sol-TR is a stand-alone parabolic trough system. Sol-TRHTR is a parabolic trough with gas heater. Sol-CT is a parabolic trough with a combustion turbine backup.

Environmental Effects and Mitigation

Solar Thermal. Although the energy source for solar thermal systems is free and environmentally benign, plant siting and operations do have some environmental impacts. All turbine generators require some cooling to condense working fluids, whether the fluid be steam in central station systems, or butane, iso-butane, or pentane working fluid in a closed loop reciprocating engine. Dry cooling with air may be the heat sink of choice, but even this air must be conditioned, usually with a cooling tower or cooling pond. Ultimately, some makeup cooling water is required to cool the air. In hot, dry climates where solar thermal plants are most likely to be located, water for cooling comes at a premium.

Because of the diffuse nature of solar radiation, large sections of land are required for developing solar thermal sites, which has a localized effect on the ecology of land taken out of use.

If natural gas is used as a back-up energy source, then plant operators must reckon with the impacts of natural gas combustion. Lastly, the working fluids used in engines and turbine generators, such as oils, butane, iso-butane, or pentane must be managed and contained to prevent inadvertent escape into the environment.

Photovoltaic. Significant environmental impacts of PVs are in the industrial processing of the PV materials, where such chemicals as gallium arsenide and cadmium sulfide are used, and in the large surface areas of land required to set up a PV plant.

Examples of potential impacts from solar development are shown in Figure 3-6 and Table 3-21.

Figure 3-6
Environmental Effects and Mitigation - Solar

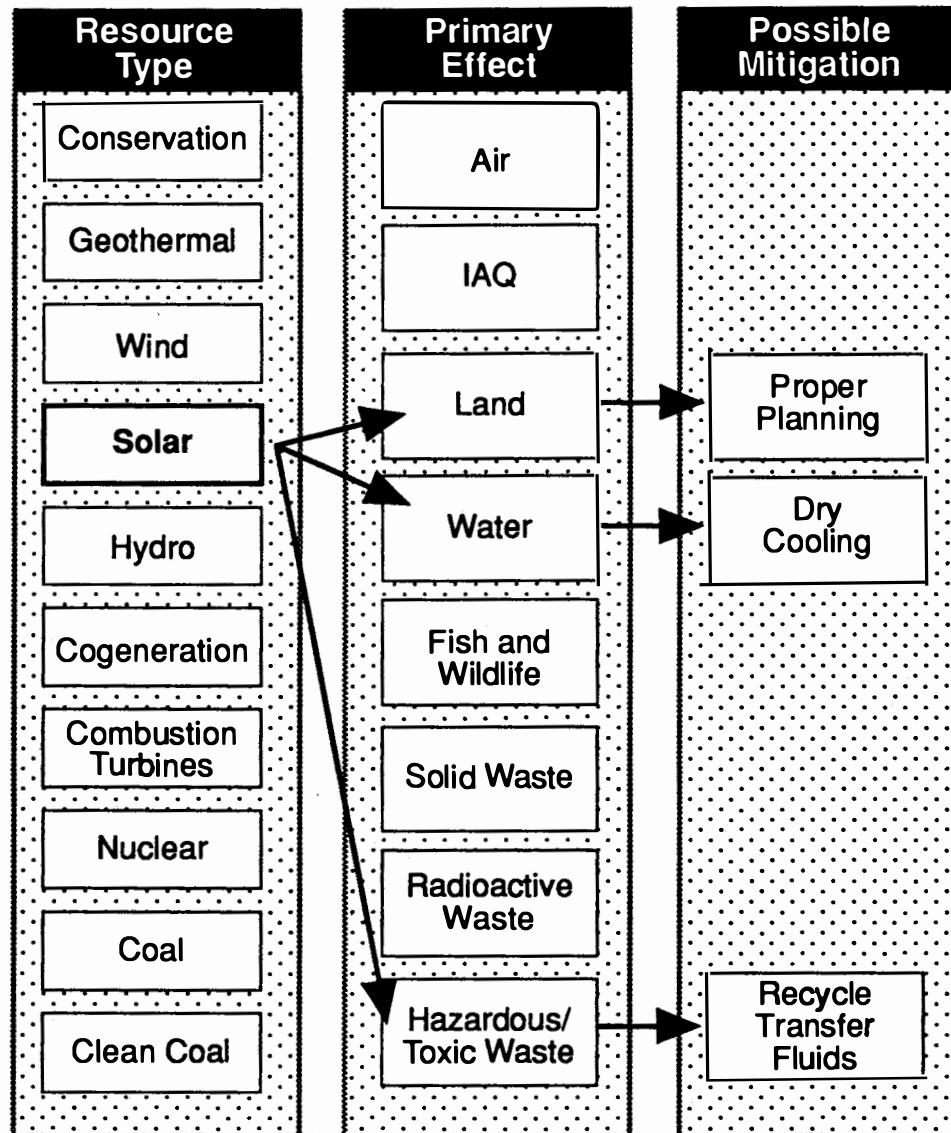


Table 3-21
Potential Routine Annual Environmental Impacts Per
Average Megawatt of Energy Generation of Central Solar
Thermal Generation^a

Potential Impacts	Generation
Air Pollutants	None
Water Quality Impacts Consumption (acre-ft)	0.39 assuming that either central tower or heat exchange fluid other than water is used. ^d
Thermal Discharge ^b (MMBtu)	23,000
Land Effects ^c Acreage Requirements	6 per MW capacity corrected for capacity factor.
Waste Streams	No annual residue except office and maintenance wastes. ^d
Employment ^c Construction (employee-years per MW capacity)	19.6
Operations (employees per MW capacity)	0.4
Occupational Safety and Health per MW capacity ^c O&M Injuries	24×10^{-6} to 28×10^{-6}
O&M Deaths	0 to 24×10^{-7}
Construction Injuries	342×10^{-6} to 1428×10^{-6}
Construction Deaths	2×10^{-7} to 28×10^{-7}

^a These examples do not include impacts from natural gas-fired combustion that may be used to firm solar-thermal generation.

^b Thermal discharge may be to air or water.

^c See sources and calculations in Appendix F to this EIS. Fifty 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 U.S. DOE. 1983. *Energy Technology Characterizations Handbook, Environmental Pollution and Control Factors*. DOE/EP-0093. Washington, DC.

Supply Forecast

The best potential solar site in the Northwest is in southeastern Oregon. However, because of its latitude, southern Oregon receives only 70 percent of the solar energy received by the best sites in the Pacific Southwest. This, along with higher avoided cost in the Southwest, will be likely to inhibit solar development in the Northwest. Consequently, only a modest quantity of solar thermal is projected for the Northwest: 80 MW capacity (22 aMW) for both the parabolic trough (Sol-TR) and the parabolic trough with heater (Sol-TRHTR), and 150 MW capacity (42 aMW) for the parabolic trough with combustion turbine backup (Sol-CT) (Table 3-20).

3.2.2 Thermal

3.2.2.1 Cogeneration

Technical Description

Cogeneration is the sequential production of more than one form of energy output from one energy source. Cogeneration is particularly well-suited to process industries, such as pulp and paper, lumber, and food processing, where large quantities of steam or heat are used for drying or to process materials and plant electric loads are high. Typically, high-pressure, high-temperature steam can be used first in an electricity generation process, then bled off from a turbine for process heat.

Cogeneration is not new. Before large central generating plants came into vogue in the 1930s, as much as 50 percent of the electricity generated in this country came from cogenerators. Historically, most cogeneration plants involved large (5 to 50 MW) units in industrial facilities. Today, cogeneration plants are as diverse as the industries and commercial applications where they are found, and the technology employed is as varied as the kinds of fuels used.

A variety of fuel types can be used in cogeneration. In wood industry plants, for example, wood waste must be disposed and is used as an energy source. Fuels for proposed cogeneration projects nationwide are as follows: natural gas, 58 percent; coal, 19 percent; and biomass, waste, and other fuels accounting for the rest. Burning municipal solid waste at garbage sites, and using the methane produced at sewage treatment plants, are two possible applications for waste fuels.

Since the Public Utilities Regulatory Policy Act of 1978 (PURPA) has encouraged independent power production, small, modular systems that can be fueled with natural gas have come into the market. These modules, rated from 4 to 20 MW, are suitable for hospitals, schools, prisons, hotels, and other small commercial and institutional establishments. Rather than the traditional boiler/turbine arrangement of larger cogeneration systems, these packaged units may employ reciprocating internal combustion engines. They are likely to use heat recovery of the exhaust gases to serve secondary energy needs--hot water, drying, space heating, refrigeration, or space cooling. Cooling applications use some of the heat recovery to drive absorption chillers.

Cogeneration technologies have reached commercial maturity and can be operated reliably with high availability and capacity factors. As electricity prices increase, a threshold is reached where it makes economic sense to operate a cogeneration plant. At mills where process heat, as well as electricity, is needed and wood residue is both a waste problem and a fuel opportunity, cogeneration can be an attractive solution. The option may not be as straightforward at a hospital or university. Fuel sources must be stable in both price and availability to induce potential cogenerators to opt for generating their own electricity.

Operating Characteristics and Capacity Contribution

Cogeneration is particularly suited to sites that have a relatively constant thermal load, which requires a stable fuel supply. For this reason, cogeneration makes a good baseload technology. Cogeneration projects have high availability factors of 85 to 90 percent.

Generally, cogeneration offers little or no dispatchability, and is a mediocre match with natural load shape generally. However, a cogeneration plant that operates only during the daytime would have a good to very good match with natural load shape, and would make a good contribution to capacity. Overall, cogeneration offers the same contribution as other baseload resources, unless the utility cannot rely on its cogeneration energy being available, which would reduce the capacity contribution.

Costs

Regional estimates of cogeneration prepared by BPA and the Northwest Power Planning Council used output of the Cogeneration Regional Forecasting Model (CRFM) as the principal source. This model matches cogeneration technologies with facility types for subregions in the Northwest. The program performs a cost/benefit analysis for a subset of the configurations appropriate for each facility type. The objective is to find the configuration, operating mode, and system size that maximizes the internal rate of return as seen by the project sponsor. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. This is then converted to a quantity of cogeneration at different sell-back prices. The price that a utility has to pay for cogeneration is treated as a cost from a supply forecast perspective. This information was reduced to four cost categories (see Table 3-22). The difference between Cogen-1 through Cogen-4 is a difference in cost only; no inference should be made regarding the type of fuel or generation technology.

Table 3-22
Costs & Supply - Cogeneration
(1988\$)

	Cogen-1	Cogen-2	Cogen-3	Cogen-4
WEST^a:				
Real Levelized Costs (mills/kWh)	30	35	40	45
Nominal Levelized Costs (mills/kWh)	60	70	80	90
EAST^a:				
Real Levelized Costs (mills/kWh)	32	37	42	47
Nominal Levelized Costs (mills/kWh)	49	57	64	72
REGIONAL POTENTIAL (aMW)	125	500	1,000	4,000

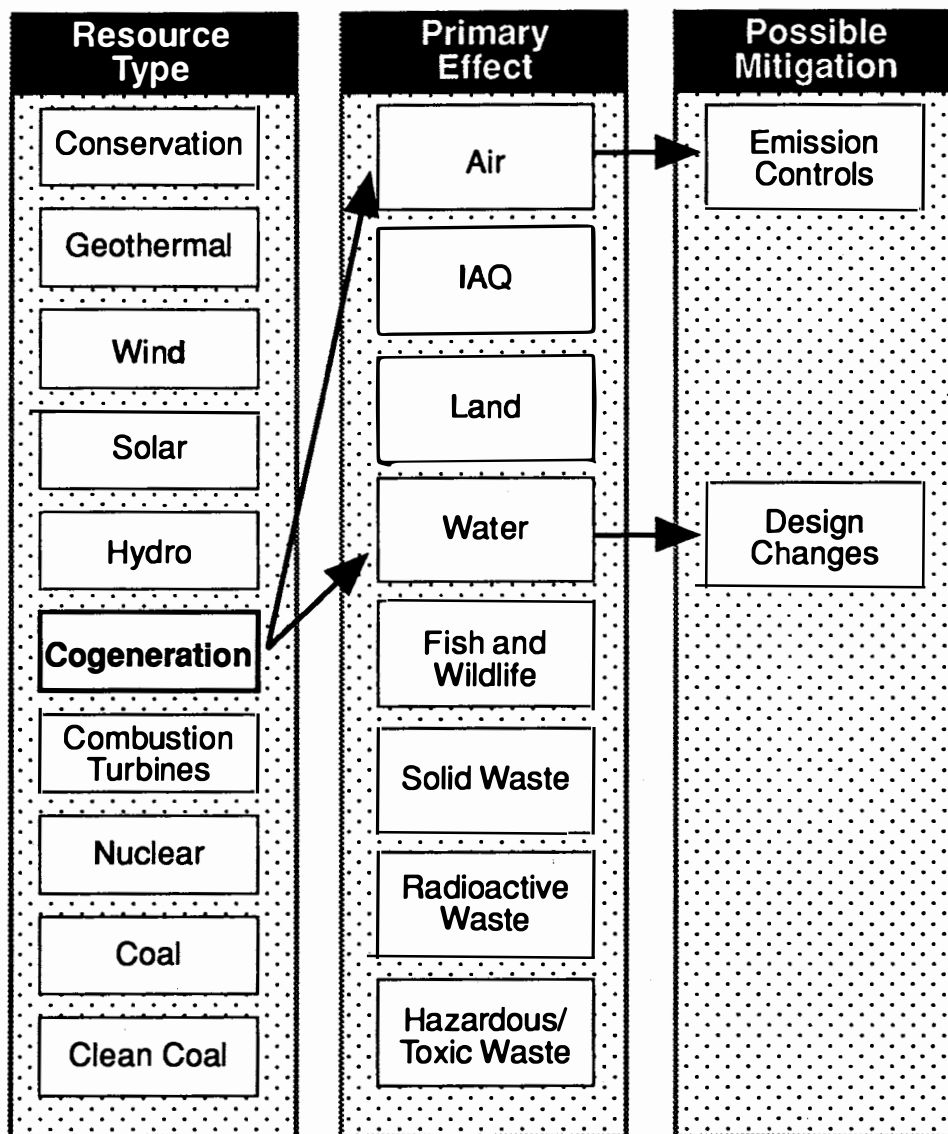
^a The cogeneration potential is assumed to be evenly split between the east side and the west side of the Cascades. This split is based on the distribution of industrial and commercial cogeneration potential as reflected in the Cogeneration Regional Forecasting Model (CRFM), which is the primary tool used by the Council and BPA to forecast the cost and availability of cogeneration potential.

Environmental Effects and Mitigation

Environmental effects of cogeneration (Figure 3-7) depend primarily on the type of fuel used. New cogeneration plants sited in the region could use a variety of fuels, but the primary fuels are natural gas, biomass, and solid waste. Natural gas is the

fuel that would most likely be used for a new cogeneration plant sited in the region.

Figure 3-7
Environmental Effects and Mitigation - Cogeneration



Plant emissions for biomass, coal, natural gas, or other fuels would be similar to any combustion facility using these fuels. Compared to large central power stations, though, emissions would be of much smaller scale and very much localized. While emissions may be less concentrated and more dispersed, however, they are likely to be found within large population areas, whereas large central power plants are often remote from population centers. Typical air emissions of natural gas-fueled cogeneration include NO_x , CO, and CO_2 .

Cogeneration plants generally use water for cooling. Cooling tower blowdown may contain trace amounts of metals or chemicals used to control algae growth, and would generally require treatment before discharge. In addition, there may be water quality impacts associated with leachate from ash or solid waste when wood mass or solid waste are used as fuels.

Because cogeneration plants satisfy thermal energy as well as electricity needs with a single energy source, there is less overall pollution than if separate energy sources were used for these purposes. Cogeneration fuel sources tend to get stretched to maximize the use of the available energy; less energy is wasted. On the other hand, multiple small units may be less efficient than a large single unit for the same level of production. This may be the case for installations that produce excess electricity beyond the amount matched to the secondary thermal load for a site. In this case, the byproduct--thermal energy--made available through cogeneration is not used as efficiently.

Another issue, sometimes overlooked, is that developing small-scale electricity supplies, such as packaged cogeneration units, may exclude the opportunity to concentrate on energy efficiency in buildings. Gains in energy efficiency are also likely to reduce pollution, since less generation and, therefore, less fuel combustion is required to meet an equivalent level of electrical service. In addition, small units may not always have pollution controls as sophisticated as may be installed on large-scale units.

Examples of potential fuel cycle impacts for solid waste and wood biomass-fueled cogeneration are shown in Tables 3-23 and 3-24. Natural gas is the fuel that would most likely be used for a new cogeneration facility in the region. Examples of potential impacts from natural gas combustion can be found in Table 3-26.

Table 3-23
Potential Annual Routine Environmental Impacts
Per Average Megawatt of Energy Generation
For Solid Waste Combustion

Potential Impacts	Generation
Air Pollutants^a	
Sulfur Oxides (tons)	15.03
Oxides of Nitrogen (tons)	77.36
Particulates (tons)	3.31
Carbon Monoxide (tons)	2.96
Carbon Dioxide (tons)	14,612 ^b
Water Quality Impacts	Undetermined, although leachate from ash and solid waste may be significant.
Thermal Discharge	Varies significantly
Land Effects^c	
Acreage Requirements	2 per MW capacity corrected for capacity factor
Waste Streams	3,018.8 tons of ash ^d
Approximately 80% of solid waste fuel is consumed -- 20% remains as ash	
Employment^c	
Construction (employee-years per MW capacity)	29
Operations (employees per MW capacity)	4.5
Occupational Safety and Health	undetermined

^a Air quality estimates taken from measured emissions of the Marion County facility in Oregon as reported in Khalil, M.A.K., T.P. Steen, R.J. O'Brien, H.T. Osterrud, T.B. Stibolt, Jr., F.P. Terraglio, and D.P. Thompson. 1988. *Health Impact Review Panel: Report on the Trash Incineration Facility Proposed for Columbia County, Oregon*. Metropolitan Service District, Portland, Oregon.

^b Estimated carbon dioxide emissions from Taylor, H.F. 1991. "Comparison of Potential Greenhouse Gas Emissions from Disposal of MSW in Sanitary Landfills vs. Waste-to-Energy Facilities." in *Municipal Waste Combustion*. Air and Waste Management Association, Pittsburgh, Pennsylvania.

^c See sources and calculations in Appendix F to this EIS. Eighty percent capacity factor assumed.

^d Andrews, J.C. 1991. "Incinerator Ash Disposal in the Tampa Bay Region." In *Municipal Waste Combustion*. Air and Waste Management Association, Pittsburgh, Pennsylvania.

Table 3-24
Potential Annual Routine Environmental Impacts Per
Average Megawatt of Energy Generation for
the Wood Biomass Fuel Cycle^a

Potential Impacts	Mining and Processing	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	Fossil-fueled equipment will release	Transport by truck or train will result in pollutants from fossil fuels.	0.57 ^f
Oxides of Nitrogen (tons)			9.94 ^f
Particulates (tons)	pollutants.		1.88 ^f
Carbon Dioxide (tons)	Reduced slash burning will improve air quality in forests.		13,183 ^f
Carbon Monoxide (tons)			18.7 ^f
Thermal Discharge (tons)			51,612.9 ^b
Water Quality Impacts			
Consumption (acre-ft)	Forest harvest may contribute to erosion.		54.3
General Effluent (acre-ft)			28.7
Thermal Discharge			Varies significantly
Land Effects^c			
Acreage Requirements	1,775 acres of 70-year-old forest needed per year to supply 25% of fuel needs; potential loss of wildlife habitat and up to 125,000 pounds of nitrogen from soil. ^e		2.63 per MW capacity corrected for capacity factor
Waste Streams			
Solid Wastes	75% of fuel expected from mill wastes ^d		108
Employment^c			
Construction (employee-years per MW capacity)			9.6
Operations (employees per MW capacity)			4.5 ^a
Occupational Safety and Health^d			
O&M Injuries	3.224×10^{-4}	4×10^{-7} to 2.6×10^{-6}	6×10^{-7} to 2×10^{-6}
O&M Deaths	2×10^{-6}	0 to 1.5×10^{-9}	5.4×10^{-9} to 4.5×10^{-8}
Construction Injuries			1.6×10^{-7} to 4.5×10^{-6}
Construction Deaths			3×10^{-9} to 1.7×10^{-8}

^a 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 this 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..

Supply Forecast

The Cogeneration Regional Forecasting Model (CRFM) was used as the primary data source for the regional estimates of cogeneration supply prepared by BPA and the Northwest Power Planning Council. The model's objective is to find the configuration, operating mode, and system size that maximizes the internal rate of return as seen by the developer. This process yields a distribution for a supply of cogeneration as a function of internal rate of return. Assumptions are made regarding penetration rates (actual decisions to install the cogeneration equipment) at different levels of return. This penetration curve is used to reduce the distribution of supply to an expected value for developed cogeneration and the results are aggregated to a regional level. Table 3-22 shows the quantity of cogeneration projected at given prices.

The output of this process is a generic planning estimate of the potential cogeneration. There is no site- or project-specific information in the output.

3.2.2.2 Combustion Turbines

Technical Description

Combustion turbines (or CTs, also called gas turbines) are the same technology used in jet engines. In the basic CT design, air enters a compressor, which packs large amounts of air into a combustor at high pressure. In the combustor, fuel is added to the air and burned, releasing heat energy and producing a high-temperature, high-pressure exhaust gas. This gas is expanded through a turbine, which powers a generator and the compressor.

Natural gas or distillate oils are the primary fuels used in combustion turbines. Gasified fuels, such as the syngas derived from coal, are also potential fuel candidates. (Gasified coal is covered under "Coal" later in this chapter.) The heat rate (or efficiency) for gas turbines is about the same as steam turbine generators. However, CT thermal efficiency is improving as the technology improves and CTs gain the flexibility of conversion to combined-cycle operation.

The inefficiency of a combustion turbine can be seen in the high temperatures of the gases discharged from the turbine. There is significant available energy in the exhaust gases, which can be recovered through a heat recovery process. One way to take advantage of this available energy is to use steam injection (which also has the benefit of reducing NO_x emissions). In a steam-injected turbine, hot exhaust gases are recirculated to heat pressurized water into superheated steam. The steam is then injected into the combustor of the turbine and mixes with compressed inlet air. The additional inlet steam helps drive the turbine.

CT efficiencies can also be improved by using multi-stage compressors with inter-cooling between stages and by operation at higher turbine inlet temperatures. Currently, turbines achieve temperatures around 2,000°F, but improvement in heat-tolerant materials can increase this limit to more than 2,300°F.

The high thermal energy in the turbine exhaust makes CTs ideal in cogeneration applications where high-grade process heat is used in addition to electricity. Another way to take advantage of the energy in the exhaust gases is to use the combustion turbine as the "topping cycle" in a combined cycle plant. (Cogeneration is covered earlier in this chapter.)

Combustion turbine technology is proven and widely used. Simple cycle CT (SCT) designs are basic, reliable, and relatively easy to site. They can be installed with minimum site renovation and preparation because they are compact and generally do not require additional equipment, such as cooling towers or elaborate fuel processing subsystems.

A combined cycle combustion turbine (CCCT) combines a combustion turbine with a steam cycle plant to generate power very efficiently. Electricity is first generated from the combustion turbine. The exhaust gases from the CT then become the heat source for raising water to steam in a steam cycle system. The combustion turbine cycle is referred to as the "topping cycle," and the steam turbine cycle as the "bottoming cycle."

Combined cycle plants are designed to maximize the thermal efficiency of a power plant by using the available energy in the combustion turbine's high-temperature exhaust gases. The key to the combined cycle is the heat recovery steam generator system, which takes the place of the steam cycle boiler. Typical steam conditions in a heat recovery steam generator are 900 to 1,000°F and 1,000 to 1,500 pounds per square inch. Instead of rejecting heat to the environment at gas turbine temperatures of more than 1,000°F, the combined cycle eliminates heat at the steam cycle condenser temperature, which is the temperature of available cooling water--approximately 50 to 70°F.

Operating Characteristics and Capacity Contribution

Combustion turbines can be operated to meet both peak and energy loads. CTs can quickly respond to load demand changes; however, maximum efficiencies are obtained when operating at design capabilities. Because of high fuel costs, CTs tend to be used at a constant rate for a limited period of time. CTs can be quickly fired up and have proved effective in meeting short-term peak loads and load fluctuations due to extreme weather conditions.

CT availability factors run 80 to 90 percent. Simple CTs operate at heat rates of 11,000 to 12,000 Btu/kWh. Combined cycle applications operate at heat rates of 7,500 to 8,500 Btu/kWh.

Combustion turbines offer very good dispatchability, which provides many options in how CTs may be operated. These options include: (1) baseload-type operations where the plant is running most of the year; (2) daily peaking, where the plant is ramped up during the day to meet peak loads, but ramped down at night, thereby reducing problems of returning energy to the Northwest hydro system; or (3) seasonal or short-term peaking, where the plant is running for a period of prolonged heavy loads (e.g., during a cold snap) or during periods of low streamflow. Each of these options would result in different amounts of energy and capacity being provided. Under baseload-type conditions, the annual energy would be produced; however, under the other options, the resulting energy would be less than the annual amount. Capacity would be provided under any of the options, but ability to react to daily or weekly load fluctuations may be greater under the second option. If it is economic and if nonfirm energy is available, CTs could be displaced under any of these options.

If operated for capacity, a combustion turbine would meet peak loads but provide less total energy throughout the year. For example, at an expected capacity factor of 50 percent, a CT could provide extra capacity in several modes. One mode would be to operate it at 50 percent per day, running at maximum during the day

and much lower at night. Another mode would be to use a CT to recharge the hydro system when it is drawn down to meet prolonged heavy loads (e.g., during a cold snap). The CT would be kept idle perhaps half of the weeks of the winter, but turned on for maximum, flat operation during cold weather, allowing the reservoirs to refill and increase their capacity effectiveness by increasing the head at each reservoir.

Costs

Cost estimates shown in Table 3-25 are based on documentation contained in a July 1988 report, *Development of Combustion Turbine Capital and Operation Cost*, prepared for BPA by Fluor Daniel, Inc. The cost of power resulting from using nonfirm energy with CTs is dependent on the amount of nonfirm energy available, the value of nonfirm energy, and the cost and availability of fuel to operate such CTs.

Table 3-25
Costs - Combustion Turbines
(1988\$)

Capital Cost (\$/kW)	
Simple Cycle	660 ^a
Combined Cycle	747 ^a
O&M Cost	
Fixed (\$/kW-yr)	
Simple Cycle	3.06
Combined Cycle	7.51
Variable (mills/kWh)	
Simple Cycle	b
Combined Cycle	b
Real Levelized Costs (mills/kWh)	c
Nominal Levelized Costs (mills/kWh)	c

^a These capital cost estimates include a \$120/kW transmission adder, which reflects siting on the east side of the Cascades.

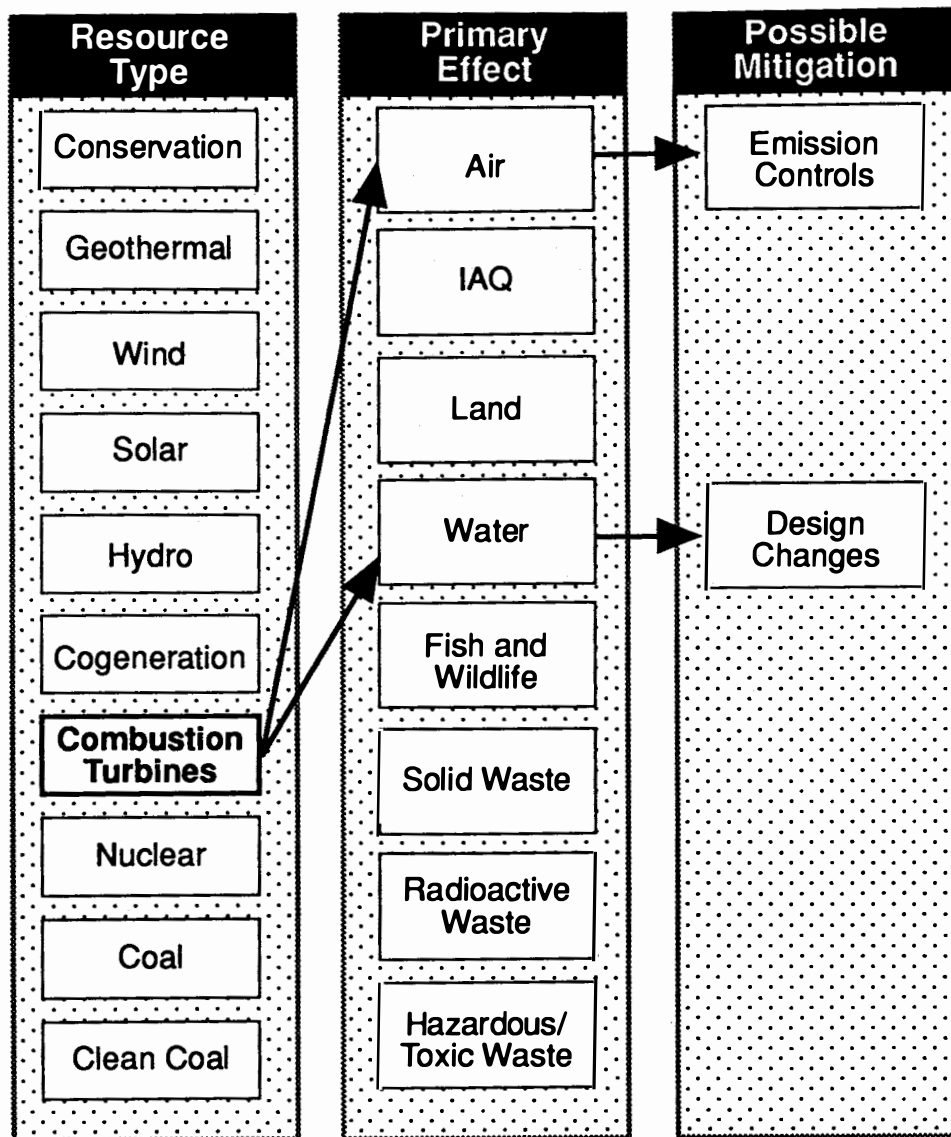
^b The variable costs have been loaded into the fixed costs.

^c Combustion turbine cost depends on how they are used. When displaced by nonfirm hydro power, combined cycle CTs have a cost of 26 to 34 mills/kWh (real).

Environmental Effects and Mitigation

The primary environmental effects of CTs are shown in Figure 3-8. CTs that use natural gas are relatively clean burning. Only NO_x emissions tend to be a problem because of the high combustion temperatures, but significantly less so than in coal combustion. NO_x can be controlled with either water or steam injection into the CT combustor, eliminating up to 80 percent of the NO_x. Water use and visible steam plumes in this case become an environmental concern, but water use can be minimized by re-using the condensed exhaust steam for steam injection.

Figure 3-8
Environmental Effects and Mitigation - Combustion Turbines



If oil fuels are used, there is some sulfur dioxide pollution. SO_x exhaust gas can be mitigated with scrubbers, which add to the cost of CTs. As in all combustion technologies, significant amounts of CO_2 , a "greenhouse" gas, and waste heat are produced. Simple cycle CTs reject waste heat directly to the atmosphere, so cooling water is not required.

Because CTs are often sited close to where gas transportation and transmission lines meet, effects on urban environments need to be considered. CT noise can be a problem. Noise levels of unsilenced CTs can run 65 to 70 decibels at 1,200 feet from an operating turbine. Silencing packages can reduce this to 51 decibels at 400 feet.

Environmental impacts for combined cycle plants are the combined impacts of waste heat boiler plants and combustion turbines. For the amount of fuel combusted, though, plant efficiencies are proportionately higher, and, therefore, the environmental impacts are proportionately less.

Examples of potential environmental impacts for the gas-fired combustion turbine fuel cycle are shown in Table 3-26.

Table 3-26
Potential Annual Environmental Impacts Per Average Megawatt
Per Year of Energy Generation for the Natural Gas-Fired
Combined Cycle Combustion Turbine Fuel Cycle^a

Potential Impacts	On-Shore Gas Extraction	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	0.95	0.0004 tons	0.03 ^d
Oxides of Nitrogen (tons)	0.056	0.266 tons	5.81 ^d
Particulates (tons)	0.0013		0.03 ^d
Carbon Dioxide (tons)			3,904.95 ^d
Carbon Monoxide			2.23 ^e
Water Quality Impacts			
Consumption (acre-ft)			3.4 ^f
Discharge	0.0058 acre-ft drilling mud		0.0081
	0.0011		
Biological Oxygen Demand (tons)	0.0074		0.651
Chemical Oxygen Demand (tons)	0.0228		
Oil and Grease (tons)	0.00006		
Chromium (tons)	0.00002		
Zinc (tons)			
Total Dissolved Solids (tons)	0.305		1.06
Total Suspended Solids (tons)			1.14
Ammonia (tons)			0.00012
Chloride (tons)	0.057		
Sulfate (tons)	0.046		
Thermal Discharge			28,800
Land Effects^b			
Acreage Requirements	.025 Permanent .032 Temporary	4.18	0.15 per MW capacity corrected for capacity
Waste Streams			
Solid Wastes (tons)	2.24 (Drill Cuttings)		undetermined
Employment^b			
Construction (employee-years)	.029	0.45	1.4 (per MW capacity)
Operations (employees per year)	.003	0.013 employees	0.1 (per MW capacity)
Occupational Safety and Health^c			
O&M Injuries	7.7×10^{-8} to 2.174×10^{-6}	1.06×10^{-7} to 1.7×10^{-7}	3.4×10^{-6} to 6.34×10^{-5}
O&M Deaths	9×10^{-10} to 2.23×10^{-8}	3×10^{-10} to 3×10^{-9}	2.5×10^{-8} to 1.1×10^{-6}
Construction Injuries			6.8×10^{-6} to 9.88×10^{-5}
Construction Deaths			2.23×10^{-8} to 4×10^{-7}

^a 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 this 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.

^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.

Supply Forecast

The quantity of combustion turbines installed is not inherently limited. Constraints that are typically discussed include ability to site and availability of fuel supply. These constraints will not impose an impediment for the first several hundred megawatts. For this EIS, 1,680 MW of CCCT capacity (1,394 aMW energy) is considered to be available to the region, of which 1,260 MW capacity and 1,046 aMW energy would be available to BPA. It is possible to initially

install simple cycle CTs that are configured for conversion to combined cycle units.

3.2.2.3 Nuclear Fission - Completion of WNP-1 and WNP-3

Technical Description

During a fission reaction, the uranium atoms (235 and 238) are split apart, forming new elements and releasing heat. The accumulation of millions of these reactions can be used to produce steam, which turns a turbine generator and produces electricity.

Commercial nuclear power plants use the steam cycle and have two basic designs: the pressurized water reactor (PWR), and the boiling water reactor (BWR). The PWR design uses three separate, sequential, heat transfer systems. The first is the reactor coolant system that circulates high-pressure hot water from the hot reactor core to the steam generator heat exchanger. The steam generator heat exchanger is the second system, where heat from the reactor coolant on the primary scale boils water on the heat exchanger secondary scale to create steam, which is then used to drive the turbines. The third system condenses the steam from the turbine and discharges the excess heat to the environment. These three systems are designed to have no fluid exchange, only heat transfers.

Boiling water reactor designs use two sequential systems. The first system circulates water through the reactor core itself, where steam is produced and then introduced directly to the steam turbines. After expanding through the turbines, the steam is exhausted to the condensers, where it is cooled and then sent back through the reactor. A separate water system brings cooling water to the condenser. In both the BWR and PWR systems, heat from the condensers is discharged to the atmosphere by evaporating water in cooling towers (mechanical or natural), which reject the heat by evaporating water.

Nuclear fission power is a proven commercial technology, with reactors on-line since the 1950s. As of early 1992, there were 111 licensed reactors in the United States, with a combined capacity of 111 gigawatts, producing nearly 22 percent of the nation's electricity.

There are only two commercial nuclear plants operating in the Pacific Northwest: the Trojan plant on the Columbia River near Rainier, Oregon, and the Washington Nuclear Power Plant (WNP-2) on the Hanford Reservation near Tri-Cities, Washington. The Trojan plant is a 1,178-MW (gross) pressurized water reactor plant in service since 1976. The 1,154-MW (gross) WNP-2 facility is a boiling water reactor plant with an in-service date of 1984.

WNP-1 is a 1,250-MW net capacity PWR commercial nuclear plant, designed by Babcock & Wilcox, located on land leased from the U.S. Department of Energy on the Federal Hanford Nuclear Reservation about 10 miles north of Richland, Washington. WNP-1 is about 65 percent completed. It has been in a preserved state since construction was suspended in 1982.

WNP-3 is a 1,240-MW net capacity PWR commercial nuclear plant, designed by Combustion Engineering, located near Satsop in Grays Harbor County, Washington. WNP-3 is about 75 percent completed. It has been in a preserved state since July 1983, when construction was suspended.

Operating Characteristics and Capacity Contribution

Nuclear plants are best operated in baseloaded mode at their rated output. Like all steam cycle plants, nuclear plants have a large start-up inertia and cannot respond quickly to changes in load demands. Most nuclear projects are available to meet capacity and energy loads for about 10 months per year. For approximately 2 months, these projects are down for maintenance and refueling. Pacific Northwest nuclear projects are typically down in the late spring. During these outages, the lost power is made up by the Pacific Northwest hydropower system, which has increased streamflows during this timeframe. Nuclear plants typically have availability factors of 60 to 70 percent, depending on project type.

Nuclear power plants offer no dispatchability and provide only a mediocre match to natural load. They provide somewhat less capacity contribution than other baseload plants because they are more subject to lengthy, unplanned outages.

Costs

As a result of public input received during review of its draft 1990 Resource Program, BPA recommended deferral of a new comprehensive study of the future of WNP-1 and WNP-3 until significant information becomes available or conditions change sufficiently to warrant a new study.

Detailed cost-to-complete-construction estimates were prepared by the Washington Public Power Supply System (WPPSS or Supply System) and its contractors in 1984. In 1986, the Supply System updated the 1984 estimates in support of BPA's 1987 Resource Strategy. Operation and Maintenance (O&M) cost estimates were also reviewed in 1986. Table 3-27 summarizes the capital and O&M cost assumptions in 1988 dollars. The Northwest Power Planning Council reviewed O&M costs for nuclear power plants for its *Draft 1991 Northwest Conservation and Electric Power Plan*. It reported that, although O&M costs escalated rapidly from 1974 to 1984, escalation has peaked and declined in later years. The Council assumes that the real rate of O&M cost escalation will decline from 3.5 percent annually in 1986, to zero percent (real) by 2000. (The Council's 1986 cost estimates are inflated to 1988 dollars for analysis purposes.)

Table 3-27
Costs - WNP-1 and WNP-3
(1988\$)

Cost	WNP-1	WNP-3
Capital Cost (\$/kW)	1,325	1,054
O&M Cost		
Fixed (\$/kW-yr)	78.85	84.15
Variable (mills/kWh)	6.75	6.75
Real Levelized Costs (mills/kWh)	35	34
Nominal Levelized Costs (mills/kWh)	67	65

A number of nuclear reactor vendors are developing enhanced or advanced reactor designs with the hope of receiving NRC certification in the 1995 to 2000 timeframe (see section 3.4.3). When BPA reviews its position on the future of the nuclear option, it will consider any new/advanced technology available at that time, as well as economics, safety and nuclear waste disposal (NRC responsibilities), and other environmental impacts.

In April 1991, the Council released its 1991 Power Plan, which included an objective to determine the cost and availability of resources in the region in the next 20 years. Such resources, among others, include Washington Nuclear Projects (WNP) 1 and 3 (the Projects). The Council recommended that BPA and the Supply System undertake the work necessary to determine how to resolve outstanding issues so that the Council can make an informed judgment in the next Power Plan (1994-96) whether to continue preserving the Projects, to construct either of the Projects if needed, or to terminate them, if appropriate.

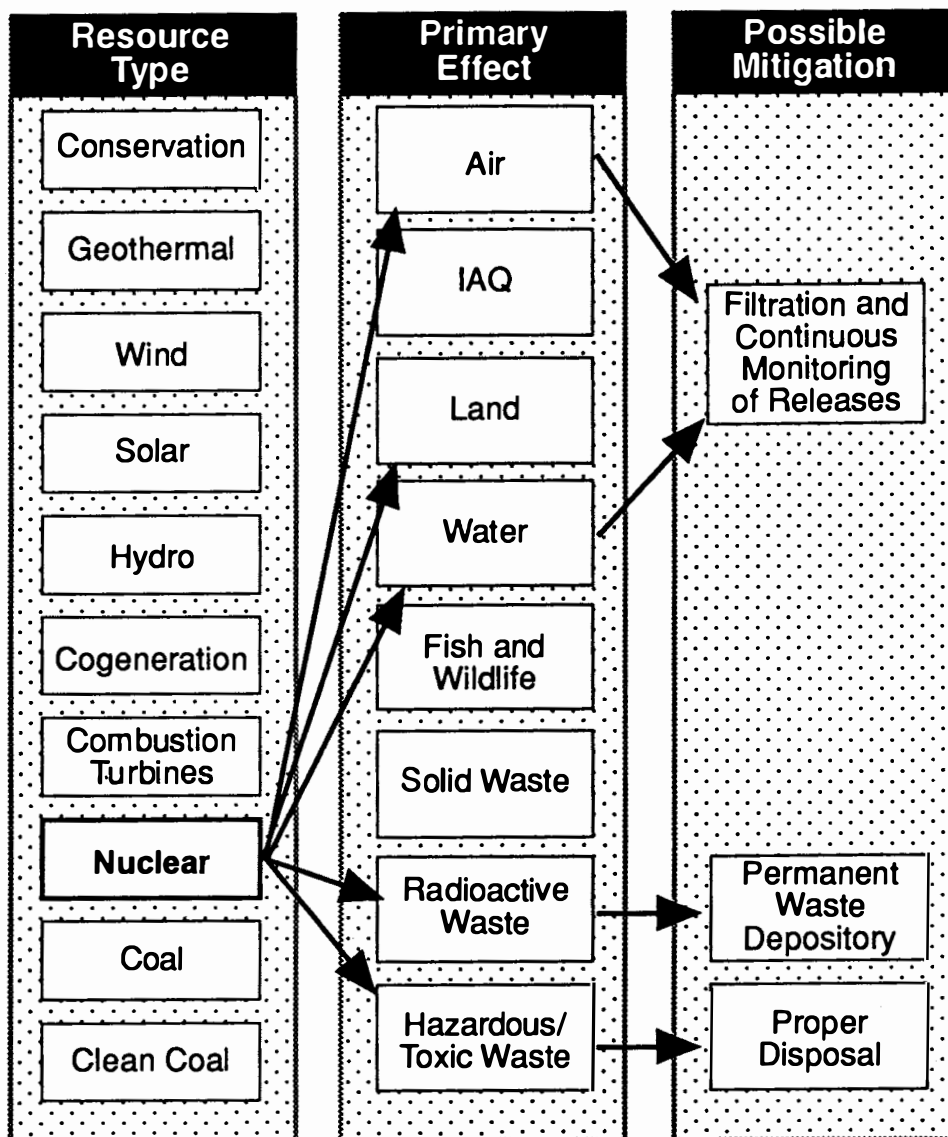
In response to the Council's recommendation, the Supply System and BPA agreed to study the viability of the Projects as resource options. Three initial areas were identified as having potentially significant impact on the viability of the Projects, namely, (1) institutional issues, (2) the NEPA process, and (3) critical path analysis:

- (1) The institutional issues include potential litigation that may impact the Supply System's ability to finance completion of the Projects. Certain Project participants have alleged that the Projects have been terminated and under existing Net Billing Agreements would not be obligated for the repayment of bonds sold to finance completion of the Projects. While BPA's General Counsel, the Supply System's Chief Counsel and the Bond Counsel to the Supply System agree that neither Projects nor the Net Billing Agreements have been terminated, there is potential for litigation to resolve the issue. BPA and the Supply System have agreed to identify potential alternatives for resolution of this issue.
- (2) BPA took the lead in addressing the NEPA process issue by hiring a consultant to conduct an independent review of the existing NEPA requirements. The draft report from the study did not identify any new issue that would be an insurmountable obstacle to completion of the Projects. It did conclude that it would likely take 2 years to complete a site-specific draft EIS, which would put the NEPA process on the critical path for a 6-year completion schedule if a decision was made now to complete either project.
- (3) The Supply System issued a task order for the architect-engineer contractors to develop a critical path analysis for a 6-year completion schedule for the Projects. The critical path analysis verified that the plants could be completed in a 6-year construction schedule and the specification and contract for the simulator is on the critical path. The simulator must be operational for operator training prior to fuel loading.

Environmental Effects and Mitigation

The environmental impacts of nuclear energy fall into the categories of mining uranium ore and fuel processing, plant construction, electricity production, and waste disposal. The primary environmental effects of nuclear power are shown in Figure 3-9.

Figure 3-9
Environmental Effects and Mitigation - Nuclear



Uranium is mined in open pits. Exploration, drilling, and blasting in mining operations can disrupt the local ecology and contaminate ground water. Radioactive uranium tailings must be disposed of properly, lest they contaminate water supplies or air quality. Land reclamation problems are similar to those of coal mining, but on a much smaller scale, since the energy content of uranium ore is of much higher density than that of coal. Miners must take precautions to avoid inhaling radioactive material, which carries the risk of inducing lung cancer or other respiratory problems (see Appendix A, Human Health Effects).

During construction, there are erosion and dust pollution impacts, and disruptions to the local economy. These are transitory and typical of large construction

projects. Since WNP-1 and WNP-3 are already more than half completed, nearby communities have already experienced many of these construction impacts.

Nuclear plants require relatively large amounts of land. A relatively small portion of the land requirement is for the plant itself and site support (e.g., WNP-3 would require 185 acres). Larger exclusion areas (1,500 acres for WNP-3 and 2,150 acres for WNP-1) have restricted access and cannot be used for agriculture or urban or industrial development. Such exclusion areas can provide open space and habitat for wildlife.

The primary impacts from operating a nuclear power plant include the release of heat and moisture from the plant cooling system, cooling tower drift, and airborne radioactive materials. Impacts related to heat rejection (e.g., water vapor plume, cooling tower drift, cooling tower blowdown) are common to all thermal power plants.

Radioisotopes are products formed as a result of uranium and plutonium fission in the reactor. These include actinides and activation products. Actinides are the isotopes of elements having atomic weights of 89 and greater. Activation products include radioisotopes formed by the neutron flux during reactor operation.

The containment building of a nuclear reactor is designed to withstand severe natural forces, especially seismic activity, so that even if pipes break, any released radionuclides will be contained. In the event of a loss in reactor cooling, there is a potential for the core to overheat; however, the primary cooling system is backed up with diverse and redundant systems to prevent this from occurring.

Gaseous radioactive effluents include fission product isotopes of noble gases--krypton, neon, and argon (the primary source of direct, external radiation emanating from a plant's effluent plume)--and carbon-14, tritium, and radioiodines. These products can be controlled through filtration and by collecting them and allowing them to decay to acceptable radiation levels before they are released. Particulates--such as the fission products of cesium and barium, activated products of cesium and barium, and activated corrosion products such as cobalt and chromium--are captured by filtration and then disposed of with solid radioactive waste.

Besides airborne gas releases, there may be some unplanned releases of particulates or waterborne radioactive materials, including fission products such as nuclides of strontium, and activation products such as sodium and manganese, and tritium.

Experience in the design, construction, and operation of nuclear power plants indicates that the average annual release of these kinds of radioactive materials and effluents typically will be a small percentage of the limits specified by Federal safety regulations. All aspects of nuclear power plants are continuously monitored to ensure that allowable limits are not exceeded.

Other potential water-related effects of nuclear power plant operation include thermal discharges, water consumption, and release of waterborne chemical pollutants. Make-up water in cooling towers tends, over time, to concentrate mineral salts and other contaminants in the coolant system. These are controlled with continuous "blowdown" to introduce fresh coolant. Blowdown can be environmentally damaging but can also be treated to remove impurities. Blowdown discharges are continuously monitored and must meet strict standards

for discharge.

Radioactive waste disposal continues to be a problem. Waste is classified as high-level, transuranic, or low-level. High-level waste has high concentrations of beta- and gamma-emitting isotopes and significant concentrations of transuranic materials, including plutonium. Spent fuel is the only reactor product that falls into this category. Reactors produce about 400 cubic feet per year of spent fuel.

Transuranic wastes have low levels of beta and gamma emissions but significant concentrations of transuranic isotopes. Transuranic wastes are produced during reactor operation, but remain contained within the fuel elements unless the cladding is breached.

Finally, low-level wastes are characterized by a low level of beta or gamma emissions and insignificant concentrations of transuranic materials. These wastes may become radioactive during normal operations. Low-level wastes include clothing, paper, spent ion-exchange resins, filters, and evaporator concentrates from isolated parts of the reactor building. Generally, these wastes are disposed of by allowing them to decay, then diluting them to acceptable concentrations that are much less than those that occur naturally. These wastes are then disposed of in a specially designed and controlled burial site.

Although operational and safety risks can be addressed, long-term disposal of high-level nuclear wastes remains an unresolved problem. In 1982, Congress passed the Nuclear Waste Policy Act making the Federal Government responsible for the ultimate disposal of high-level nuclear wastes, which include the spent fuel from power plants. There have been delays due to state resistance and management problems. To date, no long-term storage facility has been established.

Examples of potential environmental effects of the nuclear fuel cycle are shown in Table 3-28.

Table 3-28
Potential Annual Environmental Impacts
Per Average Megawatt of Energy Generation Per Year of
Generation for the Nuclear Fuel Cycle^a

Potential Impacts	Mining and Processing	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	5.2		
Oxides of Nitrogen (tons)	1.396		
Particulates (tons)	1.51		
Carbon Monoxide (tons)	0.035		
Fluoride (tons)	0.0007		
Radionuclides (curies)	4.81		
Fossil Fuel Emissions (tons)			0.076
Airborne water			3,800,000 gallons
Water Quality Impacts			
Consumption (acre ft)	.993		16
Sulfate	5 (tons)		315.00 mg/l ^b
Manganese	0.01 (tons)		28.45 µg/l ^b
Chloride	0.011 (tons)		17.75 mg/l ^b
Iron	0.17 (tons)		243.00 ^b
Selenium	0.00026 (tons)		
Calcium	0.0079 (tons)		81.55 mg/l ^b
Fluoride	0.0365 (tons)		0.76 mg/l ^b
Nitrate	0.032 (tons)		
Alkalinity as CaCO ₃			47.00 mg/l ^b
Ammonia as N	0.014 (tons)		0.08 mg/l ^b
Hardness as CaCO ₃			202.00 mg/l ^b
Magnesium			22.75 mg/l ^b
Phosphorous			0.49 mg/l ^b
Potassium			4.00 mg/l ^b
Sodium	0.015 (tons)		23.35 mg/l ^b
Total Dissolved Solids			786.00 mg/l ^b
Total Suspended Solids			12.90 mg/l ^{b, e}
Cadmium			1.61 µg/l ^b
Chromium			15.66 µg/l ^b
Copper			116.15 µg/l ^b
Lead			7.44 µg/l ^b
Mercury			1.88 µg/l ^b
Nickel			31.15 µg/l ^b
Zinc			62.35 µg/l ^b
Radionuclides (curies)	0.739		0.302 curies
Thermal Discharge (MMBtu)	954		42,000
Land Effects^c			
Acreage Requirements	0.357		2.26 per MW capacity corrected for capacity factor (includes exclusion areas)

Table 3-28, continued:

Potential Impacts	Mining and Processing	Transportation	Generation
Waste Streams			
Overburden and Tailings (tons)	8.3		
Chemical Wastes (tons)	0.79		
Radionuclides (curies)	0.130		0.0058
Employment^c			
Construction (employee-years per MW capacity)	1.078		1.8
Operations (employees per MW capacity)	0.277	0.513	0.9
Occupational Safety and Health^d			
O&M Injuries	13.8×10^{-7} to 38×10^{-7}	1×10^{-7} to 16×10^{-7}	1×10^{-7} to 16×10^{-7}
O&M Deaths	2.7×10^{-8} to 5.16×10^{-8}	0 to 1.5×10^{-9}	1.2×10^{-9} to 2×10^{-9}
Construction Injuries			21×10^{-7} to 44.7×10^{-7}
Construction Deaths			3×10^{-10} to 5.82×10^{-8}

^a 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 Concentrations in cooling water blowdown, assuming 5 cycles for WNP-1 and 6 cycles for WNP-3. Source: Washington Public Power Supply System. *Environmental Reports for Operating Licenses for WNP-1 and -3*. 1982.

^c See sources and calculations in Appendix F to this EIS. Sixty-five 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 The Supply System reports that TSS from WNP-2 have typically been less than 50 mg/l (Carl Van Hoff, letter of July 2, 1992).

Supply Forecast

For purposes of this document, WNP-1 and WNP-3 are considered to be available for completion. This is the same assumption that was used in BPA's 1990 Resource Program.

3.2.2.4 Coal

Technical Description

Conventional coal plants use the same technology as steam cycle plants fueled with oil, biomass, natural gas, or municipal solid waste. One important distinction between coal-fired plants and other steam cycle plants using these fuels is the significant effort required to process fuel, treat emissions, and dispose of wastes that are peculiar to coal.

In a conventional steam cycle coal plant, heat from coal combustion is transferred to water in a boiler. The boiler changes water under high pressure to high-temperature steam. The steam expands through a turbine, which drives a generator. After passing through the turbine, the steam is condensed to water again, then pumped back into the boiler with a feedwater pump to complete the cycle.

The same technologies used to increase efficiencies in other steam cycle plants--regenerative cycles, superheat, and reheat--are used in coal plants.

Coal deposits are found in seams. Coal comes in many varieties and grades, with varying concentrations of sulfur and ash. The coals available to the Northwest include those from the East Kootenay coal field in British Columbia, the Powder River coal field in eastern Montana and Wyoming, and the Uinta coal field in Utah and Colorado. All of these coals have low (less than 1 percent) sulfur content. Because coal is a solid, it is pulverized, then blown into special burners to fire steam boilers.

Coal technology is well established and a prominent power source worldwide. During 1988, 56.9 percent of the electricity generated in the United States came from coal plants. Coal plants are generally designed as large, centralized units, typically sized to 250 MW or more. Often, plants are located near mining sites for easy access to the fuel, but may be just as well located near large transmission lines.

Table 3-29 summarizes the surrogate sites and corresponding coal sources for the five plant sites. These sites were selected because there is current or proposed coal plant activity. They are not the only sites where a coal plant could be constructed. However, they are representative of the areas where development would be likely to occur.

Table 3-29
Assumed Coal Sites and Coal Sources

	Coal-1	Coal-2	Coal-3	Coal-4	Coal-5
Surrogate Site	Colstrip	Creston	Boardman	Thousand Springs	Western WA/OR
Coal Source	Colstrip	East Kootenay	East Kootenay	Thousand Springs	East Kootenay

Operating Characteristics and Capacity Contribution

Coal plants are designed as baseload power generators, with optimum performance at design load. Most coal plants are available to meet energy loads for about 11 months per year. For approximately 1 month per year, these projects are down for maintenance. Coal plants are not designed for short-term peaking operation. The thermal inertia of getting boilers, turbines, and condenser up to operating temperature inhibits quick response to variations in load. Coal plants typically have high availability factors of 75 to 85 percent. Capacity factors are assumed to equal 75 percent. For planning purposes, a heat rate of 10,856 Btu/kWh is assumed at design load.

Coal plants offer little dispatchability and provide only a mediocre match to natural load. They do provide a slightly greater contribution to capacity than nuclear, cogeneration, or geothermal, due to a marginally better dispatchability. A coal plant displaced for one or more months by availability of non-firm energy could be started up if extended cold weather caused a major draw-down of the hydro system. Thus, coal plants can contribute more to winter capacity than other baseload plants, but this contribution is not firm, since it could only occur when the coal plant has been idled.

Costs

Cost estimates for coal-fired resources are derived from documentation prepared for BPA's 1990 Resource Program. These costs are summarized in Table 3-30. The costs and characteristics of pulverized coal plants are composites of large and small plants. The costs are the average of the large (603 MW) and small (250 MW) twin plants.

Table 3-30
Costs - Coal
(1988\$)

	Coal-1	Coal-2	Coal-3	Coal-4	Coal-5
Capital Cost (\$/kW)	1,955	1,776	1,789	2,042	1,758
O&M Cost					
Fixed (\$/kW-yr)	25.58	29.35	30.29	31.31	31.48
Variable (mills/kWh)	3.5	3.8	3.8	3.8	3.8
Fuel Cost (\$/MMBtu)^a	0.48	1.24	1.39	1.29	1.61
Real Levelized Costs (mills/kWh)	37	44	46	48	49
Nominal Levelized Costs (mills/kWh)	73	87	91	94	97

^a Fuel costs reflect transportation to the plant site.

Environmental Effects and Mitigation

Coal generation can have substantial impacts to air, land, and water (Figure 3-10).

Among the greatest environmental concerns of coal generation are the emissions of oxides of sulfur and nitrogen (SO_x and NO_x) and carbon dioxide (CO_2). SO_x and NO_x are, to some extent, precursors of acid rain. CO_2 is thought to be a "greenhouse" gas, which may have serious environmental impacts. (See Chapter 5, section 5.2.2 for discussion of global warming.) Although there are ways to scrub exhaust gases to reduce SO_x and NO_x , there is no effective way to mitigate CO_2 pollution. The region currently has about 3,200 aMW of coal-fired generation, much without significant scrubbing capability. Adding scrubbers would reduce SO_x emissions by about 70 percent.

Coal combustion produces particulates, most of which can be removed with filters and electrostatic precipitators. Coal is also contaminated with trace amounts of heavy metals and radionuclides, such as lead, cadmium, arsenic, and radium-226, which vary with the source of coal.

If plants are sited remote from transmission grids, transmission lines must be built, and construction of power lines and substations introduces secondary environmental impacts.

Centralized thermal plants also require large quantities of cooling water to carry waste heat from plant condensers. There is a large, localized effect from a central power plant. Air quality, transportation, burner waste, ash disposal, cooling water, noise, land disruption, temporary dust and erosion impacts during construction, and local economic effects are all expected impacts.

Figure 3-10
Environmental Effects and Mitigation - Coal

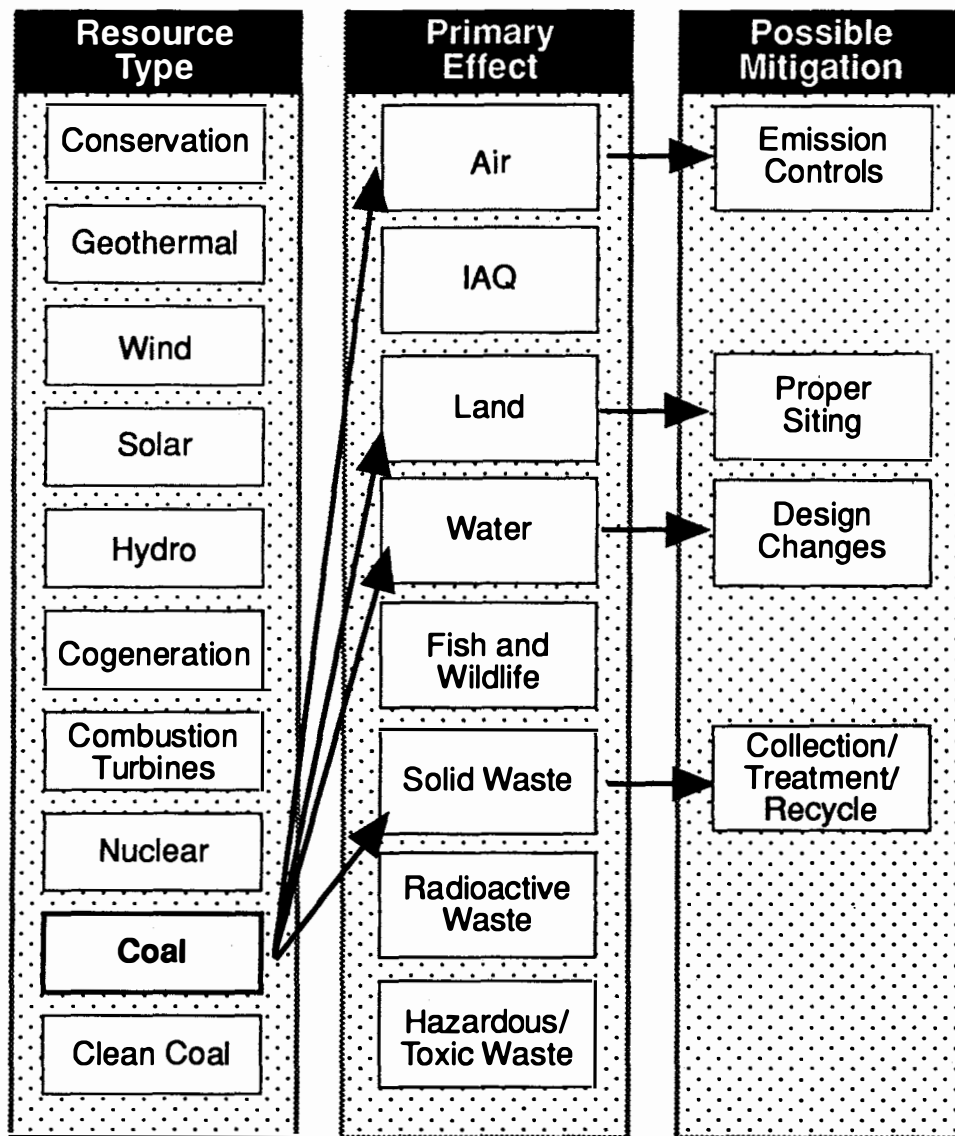


Table 3-31 presents the potential annual environmental impacts per megawatt per year of generation for pulverized coal.

Table 3-31

Potential Annual Environmental Impacts Per Average Megawatt of Energy Generation Per Year of Generation for the Coal Fuel Cycle^a

Potential Impacts	Mining and Processing	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	0.0075	0.12	9.51 ^e
Oxides of Nitrogen (tons)	0.1155	0.105	23.77 ^e
Particulates (tons)	0.006	3.36	1.43 ^e
Carbon Dioxide (tons)			9,747.6 ^e
Carbon Monoxide (tons)	0.023	0.156	1.69 ^f
Fugitive Dust (tons)	0.017	10.4	
Heavy Metals (lbs)			1.13
Radium 226 (curies)			0.000006
Methane (tons)			7.01 ^f
Water Quality Impacts			
Consumption (acre ft)			10.69
Oil and Grease (tons)			0.034
Total Suspended Solids (tons)			
Chloride (tons)			0.06
Iron (tons)			0.00002
Copper (tons)			0.00002
General Discharge (acre ft)	0.20 ^b (alkaline)		
Thermal Discharge (MMBtu)			42,000
Land Effects^c			
Acreage Requirements	0.25 per year Permanent change in landscape		1.33 per MW capacity corrected for capacity factor
Waste Streams			
Solid Wastes	1,940		
Boiler Bottom Ash			68
Boiler Fly Ash			202
Scrubber Sludge			86
Employment^c			
Construction (employee-years per MW capacity)			4.7
Operations (employees per MW capacity)	0.195	0.513	0.5
Occupational Safety and Health^d			
O&M Injuries	14.5 x 10 ⁻⁷ to 2.1 x 10 ⁻⁶		6 x 10 ⁻⁷ to 2 x 10 ⁻⁶
O&M Deaths	2.7 x 10 ⁻⁸ to 4.7 x 10 ⁻⁸		1.3 x 10 ⁻⁹ to 4.5 x 10 ⁻⁸
Construction Injuries		9 x 10 ⁻⁸ to 2.6 x 10 ⁻⁸	1.7 x 10 ⁻⁶ to 22.4 x 10 ⁻⁶
Construction Deaths		1 x 10 ⁻⁹ to 4 x 10 ⁻⁹	3 x 10 ⁻¹⁰ to 5.82 x 10 ⁻⁸

Footnotes, Table 3-31:

- ^a 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 Adapted from Argonne National Laboratory. 1988. *Energy Technologies and the Environment*. DOE/EH-0077U. U.S. Department of Energy, Washington, DC.
- ^c See sources and calculations in Appendix F to this EIS. Seventy-five 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 From BPA's emission estimates for environmental costs and planning.
- ^f Adapted from Northwest Power Planning Council. 1991. *Northwest Conservation and Electric Power Plan*, Volume II, Part II, Portland, Oregon.

Supply Forecast

The amount of coal-fired generation that could be developed at all of the surrogate sites was limited to 4,800 aMW in BPA's 1990 Resource Program. This is the same limit that was used by the Northwest Power Planning Council for its draft 1991 Power Plan. This limit is based on a qualitative assessment of the constraints surrounding the development of the coal resource. The limits are assumed to be 1,800 aMW at the Colstrip site and 750 aMW at the remaining sites. BPA's supply was assumed to be 1,200 aMW.

3.2.2.5 Clean Coal Technology - (Fluidized-Bed Combustion, Gasification)

Technical Description

Several advanced coal technologies offer better heat rates (higher thermal efficiencies) and greatly reduced emissions compared to the conventional steam cycle coal plant.

Atmospheric fluidized-bed combustion (AFBC) is an advanced coal technology that is gaining wide acceptance throughout the world. In a fluidized bed, a fluid such as air, steam, or oxygen is blown into a reactor vessel. With the help of a fluidizing agent such as sand, the fluid entrains fuel particles in its stream and bubbles or fluidizes them in the combustion zone of the reactor. This fluidizing effect promotes effective heat transfer and complete combustion. Limestone is mixed with coal in the fluidized bed to trap the sulfur. Removal of much of the sulfur with this design reduces or eliminates flue gas clean-up of the combustion gases.

Pressurized fluidized-bed combustion (PFBC) reactors are operated at high pressures; the exhaust gases can then be used to supply a combustion turbine. Typical reactor conditions may be 16 atmospheres of pressure with a bed temperature of 1,580°F. PFBC technology is now progressing to the demonstration stage, but still lags behind AFBC technology.

Coal gasification technology thermally decomposes solid coal into a high-quality gas fuel that can be burned in a combustion turbine. In gasification, the coal is

partially oxidized, producing mostly carbon monoxide (CO) and hydrogen (H₂), which are combustible gases. A subsequent acid process removes the sulfur from the gas stream and converts the reactants to hydrogen sulfide, which is easily removed. Gasification provides a clean, combustible gas, referred to as "syngas," that is nearly sulfur-free.

One of the most efficient coal combustion systems is a combined cycle plant, which uses a combustion turbine as the topping cycle and a steam cycle plant as the bottoming cycle, with a gasifier as the fuel processor. The 100-MW Coolwater plant, near Barstow, California, has successfully demonstrated this design using an oxygen-blown gasifier. Compared to an air-blown gasifier, the Btu content of syngas from an oxygen-blown gasifier is higher.

A combined cycle plant like Coolwater could be developed in stages. The first phase would be a combustion turbine, initially using natural gas or distillate oil as the fuel source. Phase two would add a steam cycle plant to take advantage of the exhaust heat from the gas turbine to generate steam for a steam turbine. Lastly, a gasification plant could be added and syngas from coal would become the final energy source.

Operating Characteristics and Capacity Contributions

Like conventional coal-fired generators, advanced design coal plants are designed as baseload power generators, with optimum performance at design load. These plants are most likely available to meet capacity and energy loads for about 11 months per year. For approximately 1 month per year, these projects are down for maintenance. They are not designed for short-term peaking operation. The thermal inertia of getting boilers, turbines, and condenser up to operating temperature inhibits quick response to variations in load. Equivalent availability factors, in percent, range from the mid 70s to the high 80s, and capacity factors generally exceed 65 percent. Capacity factors are assumed to equal equivalent availabilities for planning purposes. Fluidized bed designs have capacity factors that range from 9,800 to 10,300 Btu/kWh (9,885 Btu/kWh is assumed for this study). Coal gasification plants have heat rates under 9,500 Btu/kWh (9,270 Btu/kWh is assumed for this study).

Advanced design coal plants, like their conventional counterparts, offer little dispatchability and only a mediocre match to natural load. They are probably only slightly better than nuclear, cogeneration, or geothermal plants in contributing to capacity due to their slightly greater dispatchability.

Costs

Cost estimates for AFBC and integrated gasification combined cycle (IGCC) systems are shown in Tables 3-32 and 3-33. These plants are assumed to be located at the same surrogate sites as the conventional plants. (See Table 3-29). Fuel cost remains the same. The only change is in the capital and O&M costs.

Table 3-32
Costs - Atmospheric Fluidized Bed Combustion (AFBC)
Coal Plant (1988\$)

Cost	AFBC-1	AFBC-2	AFBC-3	AFBC-4	AFBC-5
Capital Cost (\$/kW)	2,202	1,908	1,899	2,162	1,863
O&M Cost					
Fixed (\$/kW-yr)	37.10	37.10	37.10	37.10	37.10
Variable (mills/kWh)	4.8	4.8	4.8	4.8	4.8
Fuel Cost (\$/MMBtu)	0.48	1.24	1.39	1.29	1.61
Real Levelized Costs (mills/kWh)	43	47	48	51	51
Nominal Levelized Costs (mills/kWh)	85	93	95	100	100

Table 3-33
Costs - Integrated Gasified Combined Cycle (IGCC)
Coal Plant (1988\$)

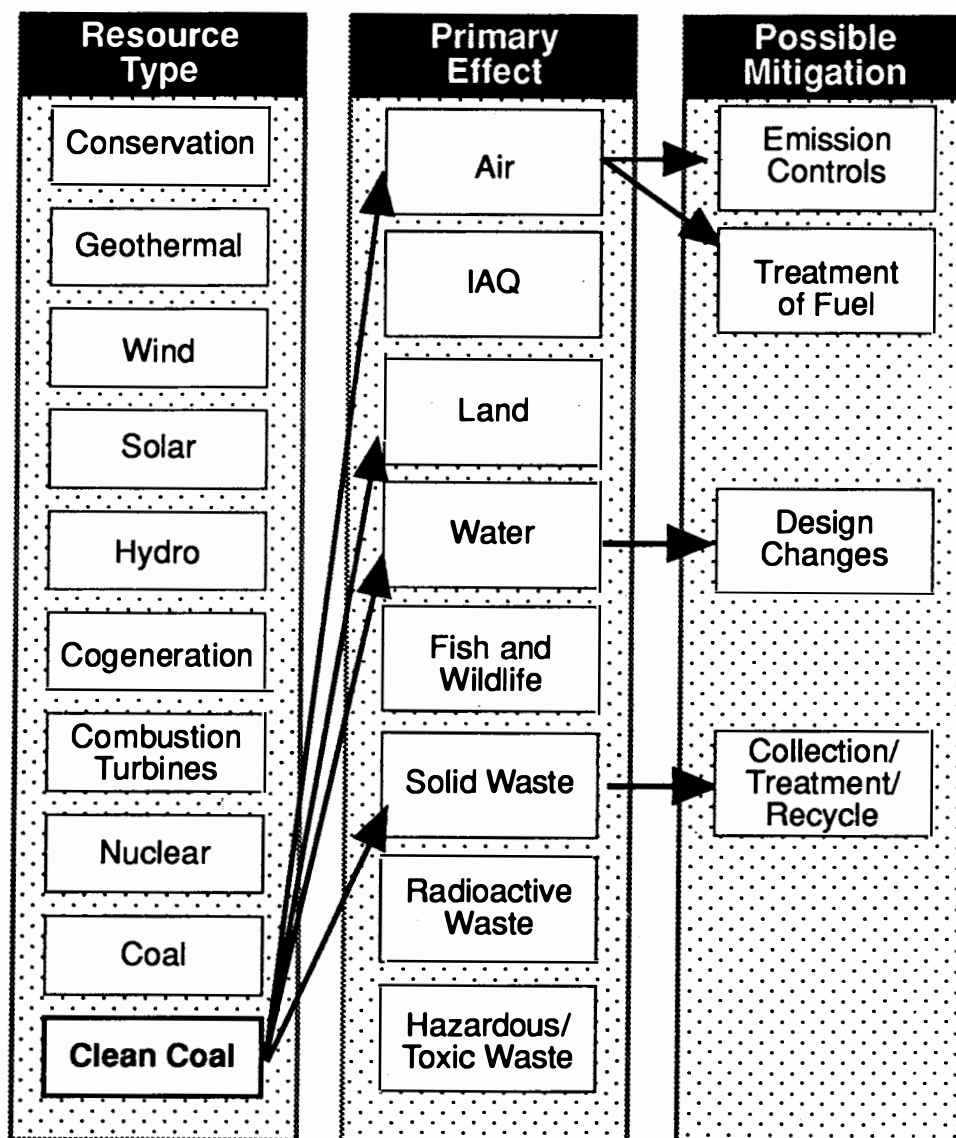
Cost	IGCC-1	IGCC-2	IGCC-3	IGCC-4	IGCC-5
Capital Cost (\$/kW)	2,570	2,276	2,267	2,539	2,231
O&M Cost					
Fixed (\$/kW-yr)	52.32	52.32	52.32	52.32	52.32
Variable (mills/kWh)	0.8	0.8	0.8	0.8	0.8
Fuel Cost (\$/MMBtu) ^a	0.48	1.24	1.39	1.29	1.61
Real Levelized Cost (mills/kWh)	41	47	49	49	51
Nominal Levelized Costs (mills/kWh)	81	93	97	97	100

^a Fuel costs reflect transportation to the plant site.

Environmental Effects and Mitigation

Because of the combustion characteristics of fluidized bed and gasifier systems, NO_x and SO_x emissions are dramatically reduced compared to conventional coal-fired plants (compare Table 3-31 with Tables 3-34 and 3-35). However, European experience with fluidized bed combustion suggests that these systems may actually produce higher NO_x concentrations than conventional coal plants. Studies are underway to investigate this concern.

Figure 3-11
Environmental Effects and Mitigation - Clean Coal



Other pollutants and emissions from advanced coal systems are similar to conventional coal. Mining, transportation, fuel handling, ash disposal, and cooling water problems are similar for both conventional and advanced coal technologies.

Tables 3-34 and 3-35 present the potential annual environmental impacts per megawatt per year of generation for the AFBC and the IGCC systems, respectively.

Table 3-34
Potential Annual Environmental Impacts Per Average Megawatt
of Energy Generation Per Year of Generation for the Atmospheric
Fluidized Bed Coal Fuel Cycle^a

Potential Impacts	Mining and Processing	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	0.007	0.109	3.46 ^e
Oxides of Nitrogen (tons)	0.105	0.095	5.8 ^e
Particulates (tons)	0.005	3.05	0.65 ^e
Carbon Dioxide (tons)			8,875.74
Carbon Monoxide (tons)	0.021	0.142	1.54 ^f
Fugitive Dust (tons)	0.015	9.46	
Heavy Metals and other trace elements (lbs)			1.13
Radium 226 (curies)			0.000006
Methane (tons)			7.01 ^f
Water Quality Impacts			
Consumption (acre ft)			16.43
Oil and Grease (tons)			0.03
Total Suspended Solids (tons)			0.06
Chloride (tons)			0.06
Iron (tons)			0.00002
Copper (tons)			0.00002
General Discharge (acre ft)	0.182 ^b (alkaline)		
Thermal Discharge (MMBtu)			42,000
Land Effects^c			
Acreage Requirements	0.228		1.58 per MW capacity adjusted for capacity factor
	Permanent change in landscape		
Solid Wastes	1,766 tons		768
Boiler Bottom Ash			
Boiler Fly Ash			
Scrubber Sludge			
Employment^c			
Construction (employee-years per MW capacity)			5.1
Operations (employees per MW capacity)	0.178	0.467	0.7
Occupational Safety and Health^d			
O&M Injuries	14.5×10^{-7} to 2.1×10^{-6}		6×10^{-7} to 2×10^{-6}
O&M Deaths	2.7×10^{-6} to 4.7×10^{-8}		1.3×10^{-9} to 4.5×10^{-8}
Construction Injuries		9×10^{-8} to 2.6×10^{-8}	1.7×10^{-6} to 22.4×10^{-6}
Construction Deaths		1×10^{-9} to 4×10^{-9}	3×10^{-10} to 5.82×10^{-8}

Footnotes, Table 3-34:

a 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 Adapted from Argonne National Laboratory. 1988. *Energy Technologies and the Environment*. DOE/EH-0077U. U.S. Department of Energy, Washington, DC.

c See sources and calculations in Appendix F to this EIS. Ninety-five 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. Taken from estimates for a pulverized coal plant.

e From BPA's emission estimates for environmental costs and planning.

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

Table 3-35

Potential Annual Environmental Impacts Per Average Megawatt of Energy Generation Per Year of Generation for the IGCC Coal Fuel Cycle^a

Potential Impacts	Mining and Processing	Transportation	Generation
Air Pollutants			
Sulfur Oxides (tons)	0.006	0.10	1.62 ^e
Oxides of Nitrogen (tons)	0.097	0.089	4.26 ^e
Particulates (tons)	0.005	3.2	0.27 ^e
Carbon Dioxide (tons)			8,323.53 ^e
Carbon Monoxide (tons)	0.02	0.132	0.15 ^f
Fugitive Dust (tons)	0.014	8.84	
Methane (tons)			7.01 ^g
Water Quality Impacts			
Consumption (acre ft)			16.26 ^g
Oil and Grease (tons)			0.034
Total Suspended Solids (tons)			0.06
Chloride (tons)			0.06
Iron (tons)			0.00002
Copper (tons)			0.00002
General Discharge (acre ft)	0.17 ^b (alkaline)		
Thermal Discharge (MMBtu)			42,000
Land Effects^c			
Acreage Requirements	0.21 per year Permanent change in landscape		0.75 per MW capacity corrected for capacity factor
Waste Streams			
Solid Wastes	1,649 tons		481.8g
Employment^c			
Construction (employee-years per MW capacity)			5.7
Operations (employees per MW capacity)	0.166	0.438	0.9
Occupational Safety and Health^d			
O&M Injuries	14.5 x 10 ⁻⁷ to 2.1 x 10 ⁻⁶		6 x 10 ⁻⁷ to 2 x 10 ⁻⁶
O&M Deaths	2.7 x 10 ⁻⁸ to 4.7 x 10 ⁻⁸		1.3 x 10 ⁻⁹ to 4.5 x 10 ⁻⁸
Construction Injuries		9 x 10 ⁻⁸ to 2.6 x 10 ⁻⁸	1.7 x 10 ⁻⁶ to 22.4 x 10 ⁻⁶
Construction Deaths		1 x 10 ⁻⁹ to 4 x 10 ⁻⁹	3 x 10 ⁻¹⁰ to 5.82 x 10 ⁻⁸

^a 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 Adapted from Argonne National Laboratory. 1988. *Energy Technologies and the Environment*. DOE/EH-0077U. U.S. Department of Energy, Washington, DC.

^c See sources and calculations in Appendix F to this EIS.

^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. Taken from estimates for a pulverized coal plant.

^e From BPA's emission estimates for environmental costs and planning.

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

^g Adapted from Ottinger R.L., D.R. Wooley, N.A. Robinson, D.R. Hodas, and S.E. Babb. 1990. *Environmental Costs of Electricity*. Oceana Publications, Inc. New York.

Supply Forecast

The potential supply of advanced coal technologies is assumed to be the same as conventional coal facilities. This limit is based on a qualitative assessment of the constraints surrounding the development of the coal resource.

The limit is assumed to be 1,800 aMW at the Colstrip site, and 750 aMW at the remaining sites. The total 4,800 aMW potential (1,200 aMW for BPA's assumed share) is considered the limit for all coal resources. Any combination of coal technologies could be used within this limit.

3.3 Other Means of Meeting Load

3.3.1 Fuel Switching

Fuel switching occurs when consumers change from electricity to another fuel, usually natural gas, for an energy end use. BPA has begun work to develop a policy regarding what role, if any, BPA should play in influencing the end-use fuel choices of consumers. In January 1992 BPA published an initial technical study of fuel switching potential in the *Draft 1992 Resource Program Technical Report*. Some Northwest utilities are implementing or considering fuel switching programs to help meet their loads. This EIS requires analysis of options that may be viewed as resources in the future. Consequently, fuel switching is included as a potential resource in this EIS.

The data and analysis presented here are preliminary only. It is important to note that the results are based on the assumption of strong load growth. This fuel switching analysis examines the case where homeowners substitute natural gas for electricity for residential space and water heating. Switching to gas reduces both peak loads and overall energy requirements for electricity. Although many new-home owners are already selecting gas, there is a potential for conversion of electric space and water heat in existing homes to gas. There is also a potential to expand the gas distribution system to reach homes that currently do not have access to gas. This analysis looks at residential fuel switching potential beyond what is expected to occur through market forces driven by the generally lower cost of heating with gas.

Industrial and commercial sectors were excluded from the preliminary analysis. Fuel choice in these sectors is specific to site, equipment, and process. Complex economic and engineering issues and data inadequacy make these market segments difficult to analyze. Exclusion of commercial and industrial fuel switching from the analysis does not mean that cost-effective fuel switching could not be achieved in these sectors. It means only that the residential sector was believed to be more amenable to a screening analysis and more likely to provide near-term fuel switching potential. BPA and others in the region are likely to investigate commercial and industrial fuel switching potential in the future through pilot studies or technical analyses.

Cost

In general, the cost of fuel switching is the difference between installing and operating new gas equipment and operating and maintaining electric equipment. The major cost categories are equipment, administrative, hook-up, and operating.

Equipment, administrative, and hook-up are collectively referred to as capital costs.

Equipment costs include the space and/or water heating equipment, including flues, venting, piping, and any required code improvements. Administrative costs represent program design, implementation, and oversight costs. These costs are set equal to 20 percent of equipment costs, which is roughly equal to BPA's experience with conservation programs. Hook-up costs are the costs of gas service drop and/or main extension and the metering equipment and installation. Operating costs are the fuel costs associated with operating the space or water heating equipment.

Table 3-36 details projected costs and aMW savings that could be achieved through available fuel switching options.

Table 3-36
Fuel Switching Estimates - 2010

Market Segments	Participating Households	Annual kWh Per Household	Capital Cost Per Household (1988\$)	Total Savings (Annual aMW) (1988\$) (A*B)	Total Capital Cost (\$M) (1988\$) (A*C)
	(A)	(B)	(C)		(A*C)
Existing CFA+WH/SD	34,574	18,300	3,840	72	133
Existing CFA+WH/ME	26,507	18,300	4,920	55	130
Existing Zonal+WH/SD	46,452	15,100	6,840	80	318
Existing Zonal+WH/ME	35,613	15,100	7,920	61	282
Existing WH Only/SD	137,321	4,500	1,320	71	181
Existing WH Only/ME	105,279	4,500	2,400	54	253
New, all space heat+WH	154,000	10,000	3,654	176	563
TOTAL	539,746			569	1,860

Existing = Existing homes WH = Water Heat CFA = Central Forced Air space heat
ME = Main Extension New = New homes D = Service Drop Zonal = Zonal space heat

Environmental Effects and Mitigation

Fuel switching may create some relatively low impacts to air quality.

Environmental impacts resulting from the construction of new gas lines would be considered in the site-specific environmental analyses prepared for a specific fuel switching proposal.

Supply Forecast

Estimates of the potential for fuel switching by market segment (see Table 3-36) were based on load forecast information combined with information on natural gas availability. Based on the aggressive policy assumptions and strong load growth required by this EIS, a potential of approximately 550 aMW was estimated to be available to BPA by 2010.

3.3.2 Energy Imports

Characteristics and Capacity Effects

BPA is exploring opportunities to serve its future deficits with interregional transactions. Both California and Western Canada have significant potential to provide energy and capacity to the Pacific Northwest: California because of its large system and load patterns which complement Pacific Northwest loads; Canada because of the extent of its gas, coal, and hydro resources. Imports from the Midwest are constrained by the capacity of the existing transmission system and the high cost, both direct and environmental, of new transmission.

BPA could purchase options on winter energy and capacity from California utilities. BPA would normally displace these purchases with nonfirm or spot purchases and/or other short-term purchases whenever economical. Firm energy and capacity options could be used as firm resources for BPA planning and may well provide a cost-effective way to cover at least part of future deficits. An impediment to these transactions is the limited supply of natural gas for electrical utility generation in California in the winter, when residential and commercial demand for gas in the Pacific Northwest is high. Fuel oil can be stored as a backup fuel supply, but this is generally more expensive, and additional fuel storage facilities could be required. The gas supply problem is likely to diminish as new pipeline capacity into California, which is currently under construction or near completion, comes on-line.

Another way of meeting BPA's winter power needs through extraregional transactions would be to enter into joint generating or conservation projects. These projects could provide winter energy and/or capacity to BPA, while providing summer capacity and/or energy to California. Various arrangements need to be explored, including, for instance, joint ownership, where BPA would control the output of the resource in the winter and a California utility would control it in the summer. From the West Coast perspective, capacity is more valuable in summer than winter due to the high value placed on it by California. The addition of nonpower constraints from the System Operation Review (SOR) and Endangered Species Act (ESA) studies could modify this. The value of nonfirm energy also varies over a wide range throughout the year depending on the amount.

Both the Pacific Northwest and British Columbia may have excess capacity available in the summer, which could be used to defer capacity additions that would otherwise be needed to serve growing Pacific Southwest summertime capacity needs. At the same time, Pacific Southwest utilities appear to have the ability to produce firm fossil-fuel-powered energy in the late fall and winter, which could be used to defer new firm energy resources that would otherwise be needed to serve growing Pacific Northwest and Canadian wintertime firm energy needs. These strategies may offer environmental benefits to both anadromous fish in the Pacific Northwest and to air quality in the Pacific Southwest.

The contribution of energy imports to system capacity depends upon the provisions of each contract. BC Hydro may be able to provide energy to the region on-peak, which would make a very good contribution to capacity during the months covered by the contract. California entities are more able to deliver energy off-peak, which would be a depletion of capacity. Nighttime import contracts would be deleterious for capacity. They might provide BPA with the option of

declining the energy in the event of nighttime minimum load problems, though the energy foregone by such a choice may have been counted on to meet firm load and would have to be replaced.

Costs

Supplies of imports from the Pacific Southwest were assumed to cost 34.4 mills per kWh (levelized 1988\$). Pacific Southwest imports were also assumed to be shaped into the fall-winter period and surplus to the needs of Pacific Southwest systems during that time. As a result, costs do not include embedded system costs, but were based on variable costs.

Canadian imports were assumed to be from Western Canada at a cost of 37.8 mills per kWh (levelized 1988\$). These imports were assumed to be built expressly to serve Pacific Northwest loads and full costs are assumed to be covered by BPA. The small difference in costs is due to low fuel costs in Canada and high efficiencies of all-new plants assumed to be built there.

Environmental Effects

If future transactions involve different resource types, their impacts would be generically described by resource types included in this document.

Air quality is expected to be the area of most environmental effect. Air quality is a problem in metropolitan areas in California, particularly the Los Angeles basin area. Summer power exports from the Pacific Northwest to California would allow dirtier plants to be displaced and could therefore improve air quality in their problem season. Winter generation to return energy to the Pacific Northwest, however, would increase emissions when the plants were operated. The net effect would likely be to improve air quality overall in sensitive areas, but it is likely that the tradeoffs would receive wide public scrutiny before such transactions became routine.

Supply Forecast

For this EIS, import resource supplies available to BPA were assumed to be 1,500 aMW from the Pacific Southwest and 1,500 aMW from Western Canada. For the Pacific Southwest, two-thirds of these resources are assumed to be newly built gas-fired CTs and one-third of the imports are expected to come from existing facilities. For modeling purposes, the imports from Canada are all assumed to come from new gas-fired CTs, although cogeneration, conservation, system sales, or hydroelectricity could also be sources. The energy resource potential in both the Pacific Southwest and Western Canada may be significantly greater than the 3,000 aMW assumed for this EIS, but actual effects would be specific to resource type, not source.

3.3.3 Efficiency Improvements

Technical Description

Hydropower efficiency improvements consist mainly of electronic 3-D cam installation on existing Kaplan hydropower turbines. These savings estimates were first described in 1985 (*Generating Resource Supply Curves*, DOE/BP/473, July 1985). Most of the turbines that could be modified are located at Corps of Engineers and Bureau of Reclamation projects. These improvements allow the

turbines to maintain optimum output by automatically adjusting blade and wicket gate position through a variety of operating heads.

Improving the Federal transmission system consists of reducing the power losses inherent in power transmission. See section 3.3.5 for a detailed technical description.

Operating Characteristics and Capacity Contribution

Efficiency improvements have the same characteristics as the resource they affect. Generation improvements simply increase the output in the same shape as the original hydroelectric resource. Transmission and distribution improvements are a function of line loadings and other factors that are difficult to project. Consequently, output of this resource is assumed to be flat.

The contribution of efficiency improvements to capacity depends on the nature of the load or resource being made more efficient. Hydro efficiencies would generally allow more generation on-peak with the same amount of water, and would increase capacity.

Costs

Hydroelectric efficiency improvements are estimated to cost less than 3 mills real (6 mills nominal). Transmission efficiency improvements are estimated to cost less than 12 mills real (24 mills nominal).

Environmental Effects and Mitigation

Efficiency improvements improve the efficiency of existing facilities. They are not known to have detrimental environmental consequences.

Supply Forecast

Hydroelectric system improvements available to BPA are projected to be 100 aMW. Federal transmission system improvements are estimated at 34 aMW.

3.3.4 Load Management

Technical Description

Demand-side management means planning and implementing activities designed to influence consumer use (demand) of electricity in ways that support meeting that load in a least-cost manner. Demand-side options can be used to support all utility system requirements for satisfying loads. The demand-side options should be compared on an equal basis with other options--combustion turbines, cogeneration, and others.

BPA has traditionally pursued conservation as the demand-side option of choice to help meet loads. The possibility of more stringent hydro system regulations, which could affect the availability of generation to meet loads (see Appendix E), has prompted BPA to begin evaluating other demand-side options. Following are the demand-side options available to BPA:

Conservation. This is the option with which the Pacific Northwest is most experienced. Conservation is typically pursued when the utility system is deficient in meeting loads in general, e.g., during all or most months and hours of the day.

Load Shifting. This is typically referred to as load management. It is used when there is a problem meeting loads during certain hours, generally peak hours, and when loads during off-peak hours are not a problem. Load management is used to shift load from peak hours to off-peak hours.

Rate Design. A marginal-cost-based rate design that sends price signals to wholesale and retail customers and could potentially reduce load growth and "shape" loads to be more consistent with marginal costs.

Peak Clipping. This is frequently thought of as curtailment. Peak clipping is typically used when there is a problem meeting loads during peak hours and there is no interest in shifting use to off-peak hours.

Flexibility. This is a concept that is used if the system requirements are dynamic and largely unpredictable. Flexibility can be implemented only if consumers are willing to respond immediately to signals from the utility.

Operating Characteristics and Capacity Contribution

The potential contribution to capacity from load management is substantial. In thermal-based systems in other parts of the U.S., load management is one of the most important ways to manage peak capacity deficits. Load shifting to decrease daytime load and increase nighttime load, whether induced by rate design or other measures, has the potential to increase the regional capacity supply significantly, though the region has little experience with the costs of such an increase.

Environmental Consequences

Demand-side options are viewed as being environmentally benign. They, in fact, can be turned to when more environmentally destructive generating options need to be displaced.

3.3.5 Customer System Efficiency Improvements

A portion of electric power is lost as it is distributed along power lines. As the load supplied by a system grows and changes character, a system that was once properly sized for economic operation becomes undersized, resulting in ever-increasing power losses. Power losses are significant because the utility has purchased the power but lost it without being able to sell it to the ultimate user. Also, the supplier must generate this power, providing the kilowatt-hours lost and the peak capacity to generate these kilowatts, along with the line capacity to transmit the power. When losses are reduced, the energy saved is available for consumers, and the total sales of power can increase without needing to generate additional power.

In the Northwest, total transmission and distribution losses are estimated to be 1,300 aMW per year. Losses for BPA customers range from as low as 2 percent, to as high as 22 percent, with the typical utility experiencing losses averaging around 8 percent. If maximum losses could be held at 5 percent, the potential savings in energy available are estimated to be 2.7 billion kWh annually. Over the last decade, BPA has gathered substantial data on losses in the Northwest and the potential for conservation of lost energy through implementation of customer system efficiency improvements (CSEIs). Research has shown a significant number of CSEIs to be well-established and cost-effective energy saving techniques for utilities.

The two principal sources of losses on a customer distribution system are the primary conductors and the service transformers. Conductor losses occur primarily because of the resistance of the conducting material (aluminum and copper) to the flow of electric current. Usually, the smaller the diameter of the conductor, the greater the resistance to the flow of electrical current. When distribution systems are designed and built, an attempt is made to achieve an economic balance between the cost of larger conductors and the cost of anticipated losses that would occur with the use of smaller conductors. The most economic size for a conductor is one that exhibits the lowest total cost.

With transformers, which change the voltage of the primary system to a voltage that can be used by the customer, losses are classified as either core (no-load) or coil (load) losses. Core losses occur continuously, independent of the load, while coil losses are dependent on the load. In both cases, the loss represents the energy lost as heat during the voltage/current transformation process. Heat reduces both the life and load-carrying capability of all transformers. Transformer core losses amount to approximately 1.4 percent of the electricity generated on a utility system. Transformers are generally selected so that initial loadings are equal to a given percentage of their nameplate rating. As customers use more power, the transformer becomes more heavily loaded and losses increase.

Seven practical methods can be used to reduce losses associated with transformers and conductors:

1. Substitute larger conductors for smaller ones. This results in lower losses for the same amount of power transmitted. Losses are proportional to peak load squared, multiplied by resistance. Larger conductors with lower resistance reduce losses proportionally.
2. Increase system voltage, which usually requires installing insulators or transformers, or adding one or more substations. This results in fewer losses, since doubling the voltage reduces the loss to one-quarter of the original value. Losses are inversely proportional to the square of the voltage.
3. Use efficient transformers in place of less efficient transformers. This lowers losses significantly. High-efficiency transformers, such as amorphous core transformers, offer a 60 to 70 percent reduction in the energy consumed by no-load losses in distribution transformer cores.
4. Improve power factors by adding shunt capacitors. This is a cost-effective and simple way to improve power factor and thus reduce active and reactive losses. Essentially, an electric power device that supplies the reactive, magnetized power required by reactive loads, shunt capacitors remove the reactive power from the distribution system, which in turn unloads the distribution lines, releases electrical system capacity, and cuts power bills. An improved power factor also increases voltage levels, which results in greater distribution efficiency and reduced transformer losses.
5. Add or balance phases. Single phase and two-phase lines have greater losses than balanced three-phase lines.
6. Add parallel feeders. This is a special type of reconductoring in which a heavily loaded feeder is split at a breakpoint some distance from the substation. The breakpoint is chosen to either split the load in half or to

supply a large spot load. Losses are reduced as the remote load is carried on a new, large conductor instead of the smaller old conductor.

7. Conservation Voltage Reduction (CVR), which involves regulating distribution voltages to reduce voltage to the consumer, is another CSEI option available to utilities with an appropriate distribution system configuration and load mix. Utilities have found CVR to be both a cost-effective conservation measure and an effective means of reducing peak load and maintaining better distribution system control.

One study sponsored by BPA estimated that approximately 380 aMW could be saved cost effectively on the Northwest systems through reconductoring, transformer replacement, and upgrading the distribution voltage from 12.5 to 34.5 kV. Additional savings of 270 aMW could be achieved through the implementation of CVR.

Environmental Effects and Mitigation

The following list of potential environmental effects parallels the list of seven customer system efficiency improvements provided above.

1. Substituting larger conductors for smaller ones would have negligible environmental impacts. Most potentially significant is a probable change in the electromagnetic field (EMF) produced by the power line. Reducing line losses would probably have little effect on EMF strength. Although the evidence is uncertain, human exposure to EMF is a public health issue. (See the Environmental Effects and Mitigation discussion in Section 3.5, Transmission, for more information on this issue.) Heavy equipment used to change conductors would cause local, temporary impacts (such as operating noise and slight vegetation damage) similar to the impacts of operating heavy equipment for maintenance.
2. Increasing system voltage would affect only previously developed substation facilities, and would therefore not affect the natural environment.
3. Replacing less efficient transformers with more efficient transformers would usually have no effect outside existing substations, so long as old transformers are retired and disposed of properly. In some cases, however, it may be best to replace an old substation with a new substation. This would cause land use impacts at the new substation site that would require site-specific environmental review. Retired transformers should be tested for PCBs and disposed of in accordance with Environmental Protection Agency federal and state regulations.
4. Improving power factors by adding shunt capacitors would have no effect outside existing substations.
5. Adding or balancing phases would probably change the EMF characteristics of the line; see discussion under (1), above. This would also cause a negligible change in the appearance of the line, including support structures (poles and crossarms), and minor impacts from heavy equipment operation.
6. Adding parallel feeders might change the EMF characteristics of the line; see discussion under (1), above. If new support structures are needed, construction impacts could also occur, and might require site-specific environmental review.

7. Conservation Voltage Reduction may have negligible effects on EMF characteristics, but would have no construction impacts.

3.4 Emerging Technologies

3.4.1 Fuel Cells

Technical Description

Fuel cells are similar to batteries; they convert the energy released in chemical reactions into electricity. Electric current passes between anode and cathode, with hydrogen gas oxidized at the anode and oxygen gas reduced at the cathode, and an electrolyte solution in between. Although one cell produces less than 1 volt, current densities in fuel cells are quite high, on the order of hundreds of amperes per square foot of electrode area. These densities are possible when groups of cells are formed into stacks to provide high power levels.

There are three major types of fuel cells under development, named for the type of electrolyte used: phosphoric acid, molten carbonate, and solid oxide. Aside from different electrolytes, a key distinction among these three cell types is their different operating temperatures. Phosphoric acid cells operate at 400°F, molten carbonate cells at 1,200°F, and solid oxide cells at 1,800°F. Waste heat energy from the chemical reactions can be used as a heat source for steam or in low-temperature bottoming cycle cogeneration. Fuel cells operate at a constant temperature and pressure, regardless of load.

Fuel cell power plants have a fuel processing system and three subsystems: a fuel stack subsystem, a power conditioning subsystem, and a balance of plant subsystem. A fuel processing system may convert natural gas or petroleum distillate into a fuel rich in hydrogen to supply the cathode. Ultimately, coal gasification may be used to generate this fuel, but catalytic reforming is the commercial process currently employed. The fuel stack subsystems generate DC electricity while removing the CO₂ and H₂O byproducts. The power conditioning subsystem converts DC to AC current and also modulates the fuel cell's power factor. The balance of plant subsystem has the controls, water and heat management, cooling, and heat recovery.

Conversion efficiencies, in theory, are near 80 percent, but in practice are reduced to about 60 percent because of parasitic losses, especially electrical resistance. Since fuel cells are a direct conversion technology, they do not suffer the efficiency penalties of other electric generation technologies, such as steam and gas turbines, that convert heat energy into electrical energy.

Operating Characteristics and Capacity Contribution

Fuel cells have excellent load-following ability; they can adjust output quickly and over a broad range. If an adequate fuel supply is available, fuel cells can also provide baseload service. Projected availabilities should be greater than 90 percent.

Costs

The projected capital cost for fuel cells is \$1,300 per kW. Fixed operation and maintenance cost is estimated to be \$5.43 per kW per year, and variable operation and maintenance cost is 9 mills per kWh. Levelized energy costs, given current

natural gas prices, would be 54 mills per kWh (real) and 83 mills per kWh (nominal). These estimates are based on forecasted operation. Fuel cells have not yet achieved these cost levels.

Environmental Characteristics

For the most part, environmental impacts of fuel cells are related primarily to the fuel type used to provide the hydrogen for the electrochemical reaction. If gasified coal is the source, sulfur removal at the gasification site will be a significant environmental concern. Waste products, including ash and contaminated effluent from gasifier cooling systems, must be treated. If water cooling systems are used to remove heat from the fuel cells, there may be some thermal pollution where the cooling water is discharged.

Supply Forecast

Although simple and compact, fuel cells have not yet reached commercial maturity. Unproven reliability and durability of the fuel cell stacks themselves, as well as relatively high manufacturing costs, have slowed commercial implementation. Therefore, fuel cells are not considered to be available for planning purposes.

3.4.2 Hydrogen

Technical Description

Hydrogen gas is a highly combustible, but environmentally acceptable fuel. Decomposing water through electrolysis is the principal means of producing hydrogen. If there were enough off-peak or surplus power available, hydroelectric energy could be used to produce hydrogen. This fuel could be used later in a combustion turbine, fuel cell, or internal combustion engine to generate electricity during peak periods.

An electrolyzer cell consists of an electrolyte, electrodes, a water porous separator, and a container. In electrolysis, a direct current is passed between two electrodes immersed in a water-based electrolyte. Water molecules dissociate into hydrogen and hydroxyl (H^+ and OH^-) ions. The hydrogen ions migrate toward the cathode and form H_2 gas while the OH^- ions migrate toward the anode. At the anode, the hydroxyl ions decompose to O_2 , giving up their hydrogen atoms to other hydroxyls which form water.

The anode and cathode electrodes are usually catalytic metals that help accelerate the reactions and therefore are a critical factor in effective electrolysis. The electrolyte is also critical because it should not react with the hydrogen and hydroxyl ions, not decompose under the voltages induced in the cell, be chemically stable, and resist pH changes. For most practical applications sulfuric acid, H_2SO_4 , meets all these criteria.

Electrolysis conversion efficiency is determined by the amount of kilowatt-hours used in electrolysis compared to the heating value (in Btu) of the hydrogen fuel. Since electrolysis is the reverse of the hydrogen combustion reaction, the theoretical maximum heating value of hydrogen would exactly equal the kilowatt-hours of electrical energy used in the electrolysis. However, parasitic loads--mainly for pumps to circulate cooling fluid, electrolyte, and gas products--account for about 5 percent of the total system energy. The rest is the electric power used

in electrolysis. Even some of the resistance heat in the cell helps induce the electrolysis reaction.

There is a net energy loss in producing hydrogen as fuel then generating electricity compared to direct hydroelectric conversion. First, the electrolysis conversion efficiency is about 80 percent; then converting the energy in hydrogen gas into electricity carries an additional penalty. Per kilowatt-hour, the electrical energy produced from a combustion turbine or fuel cell using hydrogen fuel would be about 15 to 30 percent that produced directly from a hydroelectric turbine.

Reliable technologies for electrolyzing, storing, and using hydrogen exist. The principal technical obstacle in using hydrogen for peak power is to understand the adequacy of reservoirs where the hydrogen might be stored. Underground natural gas reservoirs might be an option. Compared to natural gas, hydrogen has about one-third the energy content per cubic foot so would take about three times the storage volume required by natural gas. Two Northwest sites--Jackson Prairie, Washington and Mist, Oregon--have been identified as possible hydrogen storage reservoirs.

Pipeline or transport arrangements would be needed to move the hydrogen from storage to a combustion turbine for peak load generation. However, electrolysis generation of hydrogen only makes sense when there is surplus hydropower and the overall conversion efficiency of storing hydrogen fuel and regenerating electricity with it is economical.

Operating Characteristics and Capacity Contribution

Hydrogen as a fuel would most likely be used in CTs for peaking power. Fuel cell use of hydrogen is also a possibility. The generation profiles of either of these applications would depend on how CTs or fuel cells are used.

The idea behind hydrogen energy storage would be to produce hydrogen gas during the spring and summer months when the Columbia River system water runs high and electricity demand is low, store the hydrogen, then use it during winter peak periods as a combustion fuel in combustion turbine peaking plants.

Costs

Costs for a hydrogen electrolysis plant were developed from data obtained from the *Pacific Northwest Hydrogen Feasibility Study*, March 1991, prepared for BPA by Fluor Daniel, Inc. These costs are based on an electrolyzer-fuel cell combination. Capital cost projections are \$4,100 per kW; fixed operation and maintenance cost is \$8.26 per kW per year; variable operation and maintenance cost is 28 mills per kWh. This would yield a real levelized cost of 158 mills per kWh (242 mills per kWh nominal levelized). These cost levels were calculated assuming an input power cost of 14 mills per kWh.

3.4.3 New Nuclear Fission Technology

The nuclear industry and the Federal Government have, over the past several years, been developing advanced nuclear power plant designs. Objectives of these advanced designs include improved economics, reduction in investment risk, and improved safety. This is to be accomplished by reduced plant size, increased factory fabrication, increased reliance upon "passive" safety systems requiring no operator intervention, general simplification of design, increased safety margins,

improved maintainability, and improved operator-machine interfaces. Guiding the development of advanced designs is a philosophy of avoiding revolutionary design changes in favor of an evolutionary approach that begins with refinement of current designs.

Advanced Nuclear Plant Designs

Three generations of advanced designs are under development. "Large evolutionary" designs are based on incremental improvements to existing light water reactor designs. These plants are available for overseas order and are expected to be approved for construction in the United States in the early 1990s. "Small evolutionary advanced" designs use current light water reactor technology, but would incorporate significant downsizing and passive safety features. These designs may be available for order by the mid-1990s. "Modular advanced" designs would use non-light water reactor technology and would incorporate extreme downsizing, a high degree of modularity, and passive safety features. Modular advanced designs probably will not be available for order until the turn of the century.

Large Evolutionary Plants

Two U.S. vendors are actively developing large evolutionary advanced designs for the international market and for submittal to the Nuclear Regulatory Commission for certification. The models and vendors are General Electric's Advanced Boiling Water Reactor (ABWR), and the System 80+ by Combustion Engineering. These designs are essentially refinements of these vendors' earlier light water reactor designs. They retain the large-scale (1,200 MW capacity) and general engineering features of predecessor designs.

The Advanced Boiling Water Reactor is an evolutionary version of existing General Electric boiling water reactors such as WNP-2. Design of this plant has been underway since 1978, under the auspices of an international consortium of boiling water reactor vendors. The Advanced Boiling Water Reactor is intended to incorporate the best features of the earlier boiling water designs offered by participating vendors. Distinguishing features include a simplified coolant recirculation system, triple-redundant emergency core cooling, improved containment, and improved control and instrumentation systems. Two 1,365-MW units have been ordered by Tokyo Electric Power for construction beginning in 1991 at the Kashiwazaki-Kariwa station. Commercial operation of the first unit is scheduled for 1996 and the second unit in 1998.

The Combustion Engineering System 80+ is a refinement of the Combustion Engineering System 80 designs used at Palo Verde 1-3 and at WNP-3. Operating experience at Palo Verde is being used to guide design improvements, as is the experience of Duke Power, one of the more successful U.S. nuclear utilities. The principal design changes involve improvements to the containment building, the emergency core cooling system, a safety depressurization system, increased thermal margins, and improved control room design. The System 80+ is scheduled to be certified by the Nuclear Regulatory Commission in Fiscal Year 1992.

Because they have not yet been built or tested, the cost and performance characteristics of large evolutionary designs remain somewhat speculative. Because these plants represent refinements of current nuclear technology, actual construction costs are likely to be similar to those of the better plants recently

completed, and operating characteristics and capacity contribution would also probably be similar to existing plants.

Small Evolutionary Advanced Plants

The small evolutionary advanced nuclear power plants would represent a major departure from contemporary nuclear power plant design. Though using conventional light water reactor technology, these plants would be considerably smaller than current designs, would use greatly simplified mechanical and electrical systems, and would employ passive safety systems requiring no operator intervention for many hours following an abnormal occurrence. These designs are expected to have greatly improved performance and cost compared with contemporary designs. Performance objectives for small evolutionary designs, prepared by the Electric Power Research Institute, include 87-percent availability, a 4-year construction period, and a 60-year operating life (Stahlkopf, 1988).

Two small evolutionary advanced designs are being developed. The Westinghouse AP-600 would employ conventional pressurized light water technology in a 600-MW plant, featuring overall simplification, a passively actuated and operated emergency core cooling system, and advanced instrumentation and control systems. A 3-year construction schedule is targeted, with a 5-year overall lead time from order to commercial operation. Construction costs are estimated to be \$1,270 to \$1,500 per kW (Electrical World, 1988; Stahlkopf, et al., 1988). The AP-600 is being developed under a program jointly funded by the Electric Power Research Institute and the U.S. Department of Energy.

The General Electric Small Boiling Water Reactor (SBWR) would be based on conventional boiling light water reactor technology. This plant also would be in the 600-MW size range, and also would employ passively actuated and operated emergency core cooling. This design also is being developed under the Advanced Light Water Reactor program of the Electric Power Research Institute and the U.S. Department of Energy.

Modular Advanced Plants

Modular advanced reactors would employ alternatives to the conventional light water reactor technologies used in the current generation of commercial nuclear plants to achieve the objectives of improved performance and safety, and lower construction and operating costs. Most of the proposed designs are highly modular, with unit sizes ranging down to the 100 to 200 MW level. These small sizes would permit greater factory fabrication, better quality control, shorter construction lead time and would allow for improved containment of radioactive materials. Several design concepts envision arrays of small reactors operated by a central control room and supplying a common turbine generator to capture some of the economies of scale associated with larger plant sizes.

Examples of this generation of advanced designs include the Asea Brown-Bovari PIUS, the General Atomic Modular High Temperature Gas-Cooled Reactor, and the General Electric PRISM. These designs are currently at the conceptual stage of development. It is not expected that they would be certified for commercial use prior to 2000.

Prospects for New Nuclear Plants in the Pacific Northwest

Three generations of new nuclear power plant designs are presently under development. The most advanced of these (in the sense of schedule) are the so-

called large evolutionary advanced plants. These plants are basically refinements of existing models offered by U.S. vendors, and are expected to be certified for U.S. construction by the Nuclear Regulatory Commission by the early 1990s. There is little evidence of interest in these plants by any U.S. utility, since they would face many of the development issues faced by conventional light water commercial reactors. Though these plants might be easier to build and achieve better performance, they will retain the large size and active safety systems of current designs. Because of their investment risk, lengthy construction period, and large plant size, the Council has not included these plants in its resource portfolio.

The small evolutionary plant designs would address some of the major development issues associated with nuclear power. Cost uncertainties will likely be reduced and public acceptance might improve because of passive safety systems and improved cost and schedule certainty. Smaller plants, shortened construction time, and greater cost certainty should help alleviate investment risk. These plants might be available for commercial operation in the 2000 to 2002 period.

Finally, modular advanced designs may be certified for construction near the end of the century. These designs would further reduce investment risk by using much smaller unit sizes. Plant safety should be improved, in an absolute sense, by improved containment of radioactive materials and innovative system design. Cost reductions and greater cost certainty should be achieved by using extensive factory fabrication. Commercial units probably will not see service before 2005. There is a possibility that the Northwest might see a demonstration unit using modular advanced technology, because the U.S. Department of Energy is considering construction of a tritium production reactor with this technology at the Idaho National Engineering Laboratory. This plant could come on-line around the end of the century.

None of the advanced designs address the issue of high-level waste disposal. By providing additional on-site spent fuel storage, utilities can prolong plant operation until such time as a high-level waste repository is developed. Alternatively, the Federal Government or utilities could develop centralized monitored retrievable storage facilities for interim storage of spent fuel.

The more advanced design concepts--small evolutionary advanced plants and modular advanced plants--feature smaller unit sizes, passive safety systems, and other features enhancing their attractiveness. But there is great uncertainty with respect to the time when these plants will be available for construction. Because they are at such an early stage of development, their cost and performance characteristics also are highly uncertain. Current cost and performance estimates appear attractive, but most likely are optimistic design goals and may not be realistic. Because of these uncertainties, advanced nuclear technologies do not appear, at this time, to be reliable and available within the meaning of the Northwest Power Act and therefore are not included in the portfolio. The Council will continue to monitor new nuclear technologies and reassess them as part of future power plans.

3.4.4 Pumped Storage

Like most utility storage technologies, off-peak energy is used to "charge" or fill a reservoir, which is then discharged during peak demand periods in a cyclic

fashion. A typical pumped storage system uses a reversible pump/turbine and a reversible motor/generator. During off-peak charging, the motor drives the pump and delivers water to an elevated reservoir. During peak periods, the water is released and runs back through the reversible pump, which serves as the turbine. The turbine drives the electric motor in reverse, which works as the generator.

A modular energy storage system uses a closed pumped hydro technology. It differs from the traditional pumped storage in that it uses ground water to charge a relatively small closed system, thereby avoiding fish impacts. Since it does not depend on surface water flow, its location is more flexible than traditional hydro or pumped hydro. A typical installation would have a 100 MW capacity (twin 50 MW units) and would cost \$700 per kWh (turn-key installation).

A disadvantage of any pumped hydro system in the Northwest is that it is a net energy loser. Since the Northwest is an energy deficit region, the loss of energy makes pumped hydro systems an expensive alternative to more traditional ways of acquiring capacity (e.g., combustion turbines). Although there may be specific applications where such facilities make economic sense, such facilities are not generally considered to be a competitive resource.

3.5 Transmission

Technical Description

Development of new generation and import energy resources may require construction of new or upgraded transmission facilities to integrate with the existing transmission system, and to ensure continued reliable operation of the regional transmission system. However, until specific information is available on the size, location, and operating characteristics of proposed new resources, collateral transmission system requirements cannot be specifically known. Generally, resources located farther from load centers, especially resources east of BPA's transmission system, would require more transmission facility construction than would resources closer to load centers.

Transmission construction actions could include building new double-circuit extra-high-voltage lines, single-circuit lines, upgrading existing lines, upgrading existing substations, and constructing new substations. New lines could be located along existing transmission line corridors, or on new corridors. (See Figure 3-12.) Both the construction and operation of transmission facilities may have environmental effects. These potential environmental effects are described below and will be addressed in detail in subsequent site-specific environmental documents tiered to this EIS.

Environmental Effects and Mitigation

Land use impacts are directly related to the amount of new and existing rights-of-way affected. Building a transmission line with a new corridor would have a greater impact to residential, commercial, agricultural, and forest land because new line segments would intrude on existing land use. Agricultural land would be removed from production for tower sites and access roads, and structures could interfere with farming operations. Forest land would be removed from production for the right-of-way, line clearances, and access roads. Transmission lines may

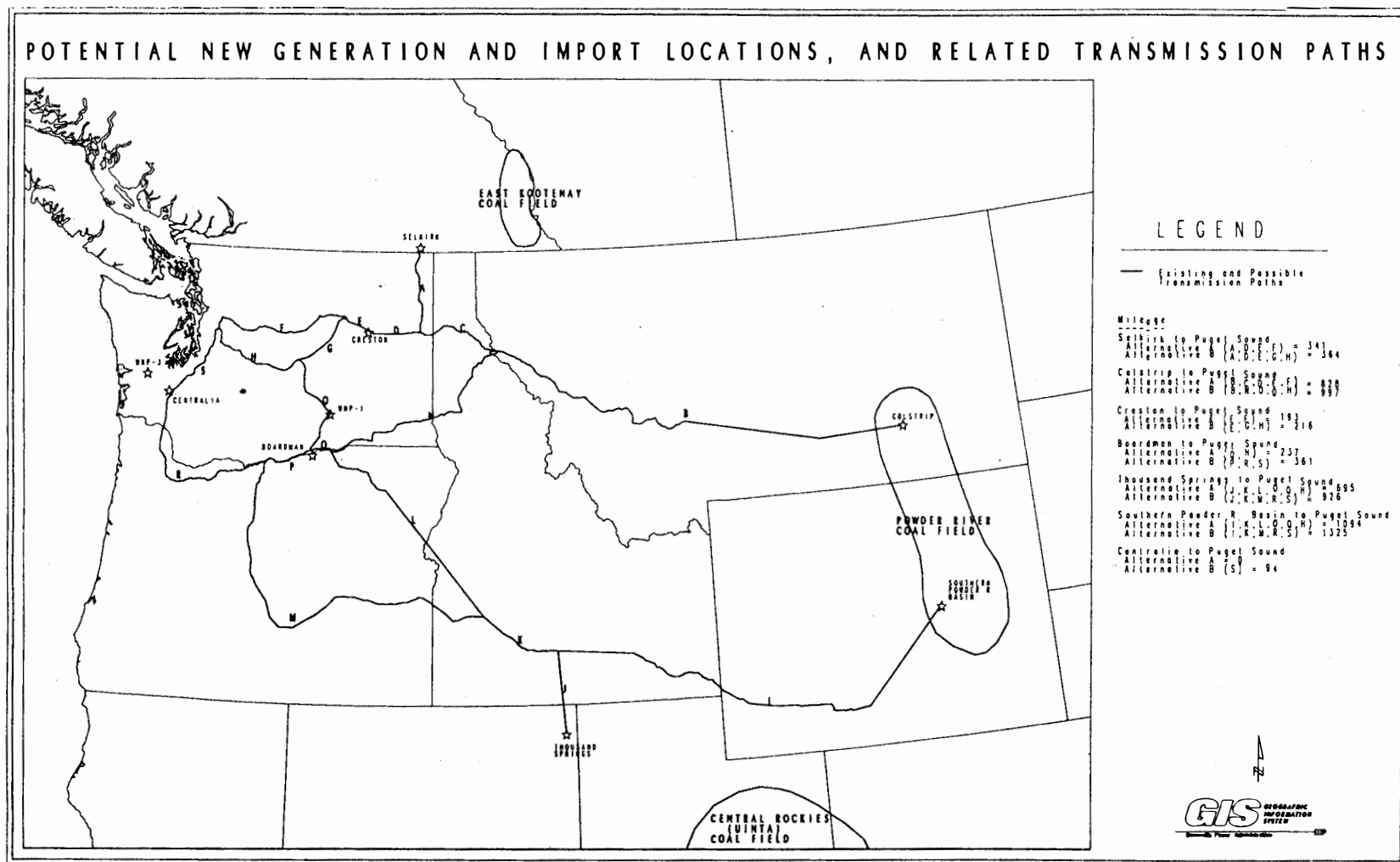


Figure 3-12

cross trails and intrude on scenic views. Many people contend that transmission lines reduce property values. A transmission line using expanded or existing right-of-way would create fewer land use impacts. Construction and maintenance may cause soil erosion. Careful siting, terraces, and other erosion control methods, and restoration can reduce erosion.

Clearing during construction and expanding existing rights-of-way can impact vegetation. Existing vegetation is removed, and vegetation composition may change. Noxious weeds may be introduced. Vegetation communities also are affected by maintenance, especially if herbicides are used. Clearing should be kept at a minimum and disturbed areas should be reseeded.

Floodplains and wetlands may be affected during construction of structures and access roads, and vegetation may be removed. Using existing right-of-way or spanning floodplains and wetlands would decrease potential impacts.

Although the increase would be short-term, clearing new right-of-way, expanding existing right-of-way, and constructing access roads can accelerate run-off and increase sediments in streams. The resulting decrease in water quality could impact fish. Culverts and hand clearing near streams can reduce potential impacts. Herbicides used to control vegetation, and oil used in capacitors at substations could contaminate ground water.

Birds may collide with the new line. However, by increasing the amount of edge habitat, species diversity may increase. Clearing may displace some wildlife and alter habitat and increase access for hunters.

Transmission lines may have visual impact. Lines could cross scenic areas, and towers may be out-of-scale with the surrounding landscape. Views would be disrupted for the long term. Careful siting, including avoiding crossings at high points, avoiding long views, placement of lines behind ridges or timber, diagonal approaches, and maximizing the use of natural screens (vegetation or terrain) can reduce visual impacts. Since transmission lines may be a hazard to aircraft, lines and towers are marked. While these markings increase safety, they may not be aesthetic.

Upgrading existing lines, constructing a new corridor, or expanding an existing right-of-way could disturb cultural resources. Construction may disturb subsurface sites, and the line may intrude visually on cultural resources. Archaeological surveys and vegetation screening may reduce impacts.

Construction vehicles create dust and exhaust emissions. Some construction debris is burned. Although these impacts are temporary, air quality may be affected. Construction and maintenance may also create noise.

Electric and magnetic fields and corona are electrical properties of alternating current (AC) transmission lines that may affect plants, animals, and people.

Electric and Magnetic Field Effects. Electric fields induce voltages and currents in conducting objects. When a person or animal insulated from ground touches a grounded object in a strong electric field, a perceptible tingling or an annoying spark discharge may occur. However, if a grounded person were to touch a large conducting object insulated from ground, a painful or harmful discharge shock could be received. For this reason, fences, irrigation systems, antennas, and other large metallic objects near the larger transmission lines are routinely grounded, as required by BPA policy and the National Electric Safety Code. It is also possible

that fields from transmission facilities could affect operation of cardiac pacemakers and cause premature detonation of explosives with electric blasting caps, and that spark discharges could ignite flammable mixtures (e.g., gasoline vapor and air). BPA publishes safety information about these possible effects in a free, non-technical booklet, *Living and Working Around High-Voltage Power Lines*.

Magnetic fields can also induce voltages in objects near transmission lines, resulting in nuisance shocks. However, techniques are available that BPA uses effectively to mitigate shocks from magnetic field induction.

Although shocks associated with electric and magnetic fields are well understood and largely controllable, questions have been raised as to whether there are long-term health effects from exposure to electric and magnetic fields. These fields induce weak currents and electric fields in people and animals. Although these currents and fields are too small to be felt, other than by hair stimulation, some scientists suggest that long-term exposures to these fields are potentially harmful and should be minimized.

Hundreds of studies have been done throughout the world. Both laboratory and field studies have been done on plants, focusing on growth and yield. Electric and magnetic fields produced by transmission lines do not appear to affect the growth of crops or other low-growing vegetation. Tree branches allowed to grow near conductors can be damaged by induced corona from strong electric fields. However, overall tree growth and survival apparently are not decreased.

Extensive field research has also been done on a variety of animals, including insects, wildlife (birds and mammals), fish, and livestock. Research to date has not shown that electric and magnetic fields have an adverse effect on behavior or health. Although various functional changes (e.g., drops in hormone levels) have been reported in exposed animals, research with laboratory animals has not shown any hazardous effects from exposure to electric or magnetic fields.

Other studies have found that these fields can also cause functional changes in isolated cells and tissues. Some scientists believe that the fields cause effects by interacting directly with cell membranes. Laboratory research to obtain the information needed to assess the biological implications of these reported effects and to understand their causative mechanisms is ongoing.

A growing number of epidemiological studies suggest an association between electric and magnetic fields and cancer. Even though the relative risks reported in these epidemiological studies are low and a cause-and-effect link has not been established, the need for long-term research to resolve this issue is universally acknowledged. Because of the uncertainty, BPA has adopted Interim Guidance as a precautionary measure. This Interim Guidance was updated in August 1992. When new transmission facilities are designed and located, the potential for long-term field exposure increases is considered a major decision factor. Such increases are avoided if practical alternatives for reducing the exposures exist. This Interim Guidance will be reassessed as new information becomes available.

Corona Effects. In addition to electric and magnetic field effects, transmission lines produce corona. Corona, the breakdown of air very near conductors, occurs when the electric field is greatly intensified at projections (such as water droplets) on the conductor. Corona is most noticeable in 500-kV and higher voltage AC lines during foul weather. Corona may result in audible noise, radio and

television reception interference, light, and production of minute amounts of ozone.

Line designs have been developed that greatly reduce audible noise levels and often corona effects. Few noise complaints are now received from persons living near BPA 500-kV lines. Although radio and television interference sometimes occurs, BPA policy requires all problems to be investigated and corrected if a BPA facility is involved. Studies have shown that the amount of ozone produced is generally not detectable above average background levels.

For additional information on either electric and magnetic field effects or corona effects, please refer to a publication available from BPA titled *Electrical and Biological Effects of Transmission Lines: A Review*.

3.6 Capacity

Capacity is the ability to produce energy upon demand. The Pacific Northwest, with its huge hydro system, has often been likened to a battery: when the wicket gates open and water is released through the turbines, electricity is generated. Shut the gates and generation ceases. Thermal-based systems build resources just to hold in reserve so they will be available to meet peaks. Many of these are low-capital-cost, high-operating-cost resources that the utilities hope they will never have to run, but which they must have available to meet reserve requirements for peak loads, resource failures, and system reliability.

The Pacific Northwest hydropower system was designed with turbines capable of capturing much more of the potential energy from the rivers than its firm energy capability. Since firm energy capability is defined as worst flow conditions, not average, the system has much more installed capacity than is required to serve its firm loads. Because of the transmission interconnections between the Pacific Northwest and British Columbia, and between the Pacific Northwest and California and the Inland Southwest, the region can often sell its excess generation as nonfirm energy, thus reducing the need for purchasing utilities to invest in resources they do not expect to operate. Such sales generate revenues to repay investments in the Federal transmission system, and to minimize BPA's rates consistent with the "prudent business practices" required by its authorizing statutes.

Overall, the west coast electric power system is a summer peaking system, with summer loads exceeding winter loads by a factor of about four. BPA's system, conversely, is largely a winter peaking system, and capacity needed to meet winter loads is underutilized in summer. Except for part of the 1980s, when the entire system was awash with new, baseload, and surplus resources, seasonal exchanges in which BPA sold summer capacity in exchange for combinations of capacity, energy, and money have been the norm. As loads in the west coast system have grown, capacity is becoming increasingly valuable, and may provide both increasing revenues to BPA and increased efficiency of the existing west coast system in the period covered by this EIS. However, recent changes in hydroelectric system operations to enhance fish survival have reduced the capacity of the Federal system during some months. The future capacity of the Federal system may be affected by decisions about system operations that result from the

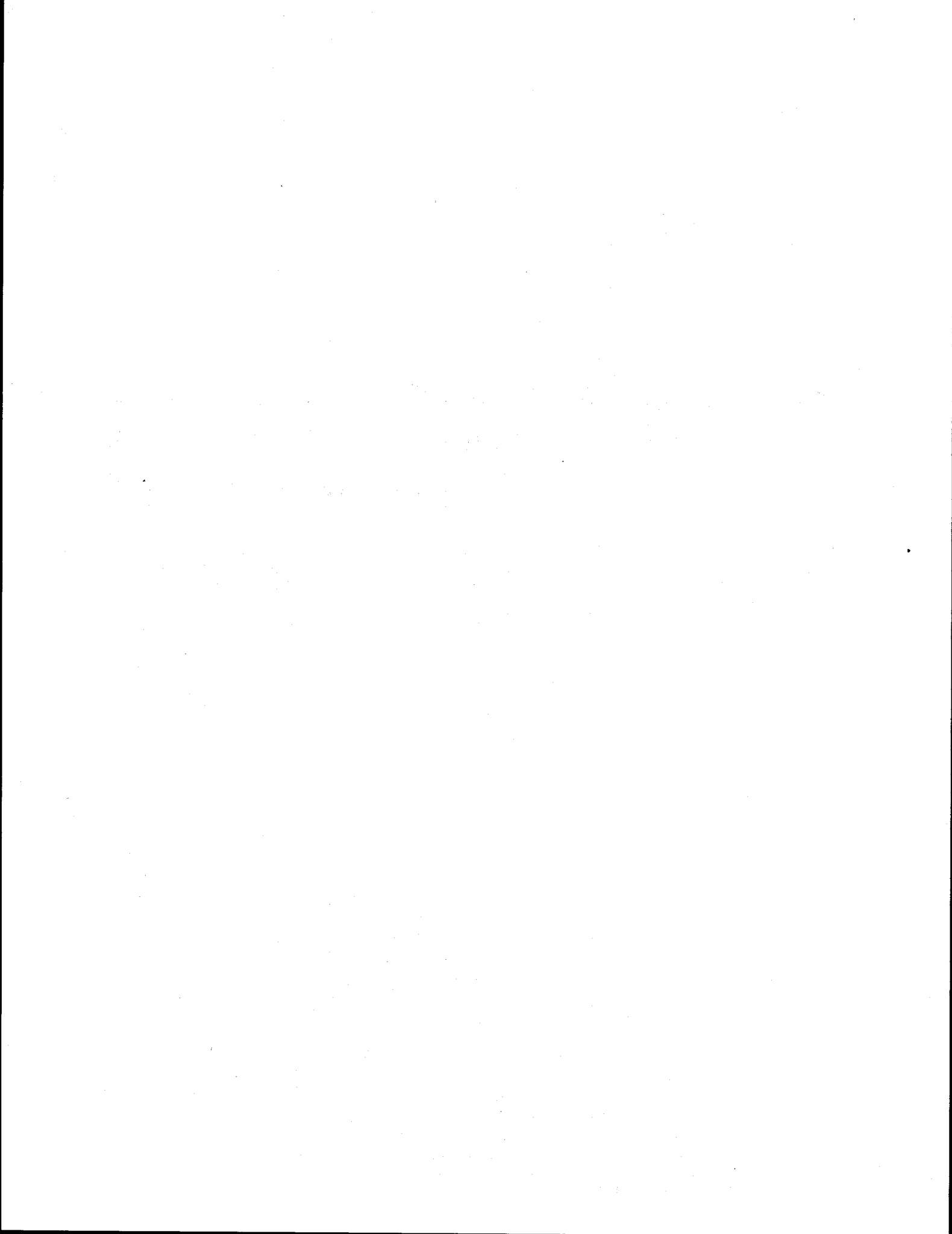
on-going System Operation Review (SOR) and Endangered Species Act planning.

Development of new resources in the Pacific Northwest may increase potential summer capacity (and energy) sales. Such transactions can have added benefits. Utilizing Pacific Northwest capacity in the summer reduces the adverse effects of generation on the vulnerable airsheds of California's metropolitan areas. When the capacity sold comes from the Pacific Northwest hydropower system, the increased flows associated with generation also speed young anadromous fish on their way to the ocean. Some of these transactions have lately been dubbed "environmental exchanges."

The planning models used in this EIS are energy models and do not take into account potential capacity impacts of resource additions. As a result, economic costs and benefits attributable to capacity are not incorporated in the economic analyses presented. A model which does incorporate capacity is being developed for resource planning at BPA, with preliminary estimates indicating that summer capacity sales potential may become a significant economic factor in future resource acquisition decisions.

Alternatives, Including the Proposed Action

Chapter 4



Chapter 4

Alternatives, Including the Proposed Action

4.1 Development of Alternatives

4.1.1 High Load Assumption

Thirteen alternatives were developed to represent the range of actions BPA could take to meet its load obligations. The resource acquisitions proposed in future Resource Programs are expected to fall within this range. Each of the alternatives comprises a combination of the individual resource types described in Chapter 3. Each alternative examined allows BPA to meet the 5,000 aMW load growth projected under the high forecast, or an equivalent need for resources caused by a combination of load growth and possible loss of resources. Analysis of the high load forecast enabled examination of maximum environmental impacts to ensure that the potential environmental effects of acquiring resources would be covered.

The ISAAC model, with its simulation of resource acquisition and operations over a wide range of uncertainty, was used to determine resource additions to the existing regional system and the economic effects of those additions. Resource stacks are used as input to the model. A resource stack is a least-cost ordering of resources available to meet load growth, and includes conservation, renewables (hydro, geothermal, wind, and solar), cogeneration, combustion turbines, nuclear, and coal. (See Chapter 3 for a discussion of the supply for each resource.) Fuel switching from electric to gas water and space heating, and energy imports from California and Canada were examined as well. In general, the stack is ordered based on cost-effectiveness, with the most cost-effective resource at the top. Variations of the resource stack were developed for each alternative. Because of supply limitations, no alternative is made up of solely one type of resource.

The resource stack for the Status Quo Alternative is based on minimizing total system costs, with no consideration of environmental costs. (See Chapter 5 for a detailed description of costs and modeling.) Reflecting BPA's commitment to incorporate environmental costs in its planning, the Base Case resource stack was developed by taking the Status Quo resource stack and reordering the resources based upon the quantified environmental costs associated with each resource.

Both the Status Quo resource stack and the Base Case resource stack are included in Appendix D. The resource stacks for the remaining alternatives were developed by placing the available supply of the emphasized resource at the top of the Base Case stack (after nondiscretionary conservation).

Once the resource stacks were developed, ISAAC was used to analyze all of the alternatives, except the No Action Alternative, in which no resources are acquired. For each of the alternatives, ISAAC acquired the resources in the order specified and operated the resulting power system. All alternatives were run to meet high load under varying (random) water conditions. In order to incorporate end effects, the study period for all alternatives was extended through August 2050. It was assumed that BPA and the investor-owned utilities (IOUs) planned separately and that none of the IOU load growth was placed on BPA. However, all of the load growth of the Generating Publics was placed on BPA. Also, it was assumed that BPA's contracts with utilities and the DSIs were renewed in 2001 with no major changes.

Regional resource acquisitions, as well as BPA resource acquisitions, were modeled. However, the alternatives represent changes in BPA actions only; actions taken by IOUs were held constant across all alternatives. It should be noted that the resource stack used in the modeling for the IOUs was based on direct costs only.

In addition to modeling resource acquisitions, ISAAC also models the operation of the resulting power system. Due to the large amount of hydropower currently used to meet loads, power system operations can vary greatly from year to year. System operations depend on each year's hydrologic condition. Currently, in years when natural runoff is extremely high, much of the load can be met with hydropower. In years when drier conditions prevail, the Northwest must also use its supply of thermal resources to meet load. In the future, a larger proportion of Northwest loads will be met with thermal resources. However, hydropower will still be used to meet load and its variability will still drive system operations.

Therefore, not all thermal resources will operate constantly in all years. It is assumed that nuclear plants, once they have been acquired, operate at a constant level throughout the year, except for planned outages for maintenance. However, all other thermal resources (such as coal and combustion turbines) can be displaced if sufficient hydropower exists to meet load. Due to this variability in system operation, the discussion of environmental effects is based on the level of resource operations modeled in ISAAC, and not resource acquisitions.

BPA bases its plans to acquire resources on the assumption that the region will have critically low water levels (critical water), not average water levels. In the EIS, analysis of resource operations (as opposed to resource acquisitions) is based on modeling using randomly selected water conditions to provide a more realistic analysis of potential environmental impacts.

Resources can take up to 10 years to plan and build. Because of this long lead time, large amounts of resources are not acquired in any of the alternatives before the mid-1990s. It is assumed that extra-regional purchases of firm power can be made on a short-term basis to meet near-term loads. Therefore, environmental impacts of adding resources to the existing system are evaluated for the mid-term year 2000 and the long-term year 2010. BPA resource acquisitions and operations in 2000 and 2010 for all alternatives are included in Tables 4-2 through 4-5.

The acquisition and operation of new resources can have adverse effects on many elements of the environment. As discussed in Chapter 5, many of the potential environmental effects are site-specific, or would result from trade-offs between power and nonpower uses of the hydro system, which are now being evaluated in the SOR EIS. BPA recognizes its responsibilities to evaluate these potential impacts and to take action to protect, enhance, and restore the environment. Although these potential environmental impacts are acknowledged in this EIS, they will also be considered in the site-specific environmental documents that will be tiered to this EIS.

With the exception of the No Action Alternative, all of the alternatives are compared to the Base Case Alternative. In comparing alternatives, this chapter focuses on the impacts to air quality, water quality and use, and land use from the operation of the new resources acquired in each alternative, and on impacts from conservation measures. The system costs of the various alternatives are also compared. In addition, the capacity characteristics of each alternative are compared (in terms of the relative ratios of capacity versus energy provided).

The potential for each alternative to affect the operation of the hydro system was also examined. The hydro system operation studies showed that the resource characteristics that most affect hydro system operation are resource shaping throughout the year and the load/resource balance. Resources which are large in size or require long lead times to develop are more likely to result in a firm power surplus. This surplus may be used to displace higher-cost resources or may be sold outside the region. The hydro system may be operated differently, however, in surplus conditions. Shaped resources include those resources with maintenance outages (outages in April and May are typical of many existing thermal plants) and those with energy available during September through April of each year (typical of energy imported from the Pacific Southwest).

In general, then, the greater the amount of shaping and the greater the amount of surplus, the greater the potential for effects on hydro system operations and associated environmental effects. Chapter 5 includes a discussion of the environmental impacts associated with these potential changes in hydro system operations. The magnitude of potential impacts of resource additions on nonpower uses of the hydro system, however, is limited by constraints, including those to protect nonpower uses. These nonpower operating requirements are being examined in the SOR EIS.

4.1.2 Effect of Medium Loads

BPA received comments on the Draft RPEIS regarding the use of the high load forecast to model resource additions to the Northwest electric system. In order to determine maximum environmental impacts from resource acquisitions, resources were added to meet resource needs under the high load forecast. However, the likelihood of loads growing at the high forecast rate is very low.

For comparison, an analysis of resources to meet medium loads was prepared. This analysis is based on the 1991 Joint Load Forecast and 1991 BPA resource supply estimates. The analysis assumes resources are acquired to meet medium loads. The resource acquisitions from BPA's 1990 Resource Program (350 aMW

of conservation, generation, and other resources and 800 aMW of options) are assumed to be acquired, as well as the resource additions from the 1992 Resource Program (660 aMW of conservation through 2003, 400 aMW of generating resource acquisitions, and 250 aMW of options). A loss of 80 aMW of Firm Energy Load Carrying Capability (FELCC) on the Snake River from changes in river operations to aid salmon migration is also assumed.

If medium loads are assumed, resources are acquired to meet a deficit of 1,800 aMW by 2010 (compared with the near-5,000 aMW deficit under the high loads case used in the rest of the analysis in this EIS). The results of this analysis are summarized in Table 4-1. In the year 2000, in the medium loads case, no nuclear or renewables and less cogeneration and combustion turbines would be acquired versus the Base Case (assuming high loads). Conservation (517 aMW) and combustion turbines (598 aMW) would make up more than half of the total resource acquisition.

In 2010, no nuclear would be acquired under the medium loads case, while two nuclear plants would be acquired in the high loads Base Case. There would also be considerably fewer renewables and CTs acquired, and less cogeneration. As in 2000, the majority of resource acquisitions would be made up of conservation (1,099 aMW) and combustion turbines (747 aMW).

It is important to note that the resources acquired in this analysis are not necessarily the resources that will actually be added to the existing system over the next several years. BPA has developed its generating resources strategy to address the competitive acquisition of resources (see Draft II of the 1992 Resource Program). Under the generating resources strategy, BPA will explore many sources for generating resources, including interregional transactions, unsolicited proposals, billing credits, bidding, and other options. Its goal is to assure the acquisition of the most cost-effective resources for the region while meeting the decision factors of the 1992 Resource Program and the goals and objectives of the 1991 Power Plan.

Table 4-1
Resource Acquisitions Under Medium Loads¹

Resource Type	2000 (aMW)	2010 (aMW)
Conservation	517	1,099
Efficiency Improvements	117	122
Renewables	0	22
Cogeneration	149	149
Combustion Turbines ²	598	747
Nuclear	0	0
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0
Total	1,381	2,139
Load/Resource Balance	495	197

¹Assumes medium load forecast.

²Includes combustion turbines and interregional transactions.

Table 4-2
New Resource Acquisitions - 2000

Resource Types (in aMW):	Alternatives											
	Status Quo	Base Case	Conservation	High Conservation	Renewables	Cogeneration	CT's	Nuclear	Coal	Clean Coa	Fuel Switching	Imports
Conservation	477	477	477	815	477	458	477	404	441	452	477	197
Effic Imp	134	134	134	134	134	134	134	114	134	134	134	133
Renewables	60	105	105	60	716	49	105	46	49	60	105	0
Cogen	140	260	260	260	140	1380	260	10	170	140	260	0
CT's	1046	1046	1046	1046	696	349	1046	349	696	696	1046	0
Nuclear	813	813	813	0	0	0	813	1619	0	0	0	0
Coal	0	0	0	0	0	0	0	0	1127	0	0	0
Clean Coal	0	0	0	0	0	0	0	0	0	806	0	0
Fuel Switching	0	0	0	0	0	0	0	0	0	0	241	0
Imports	0	0	0	0	0	0	0	0	0	0	0	2000
Total	2670	2835	2835	2315	2163	2370	2835	2542	2619	2290	2263	2330
Load/Resource Balance	397	562	562	44	-107	99	562	272	345	16	-10	60

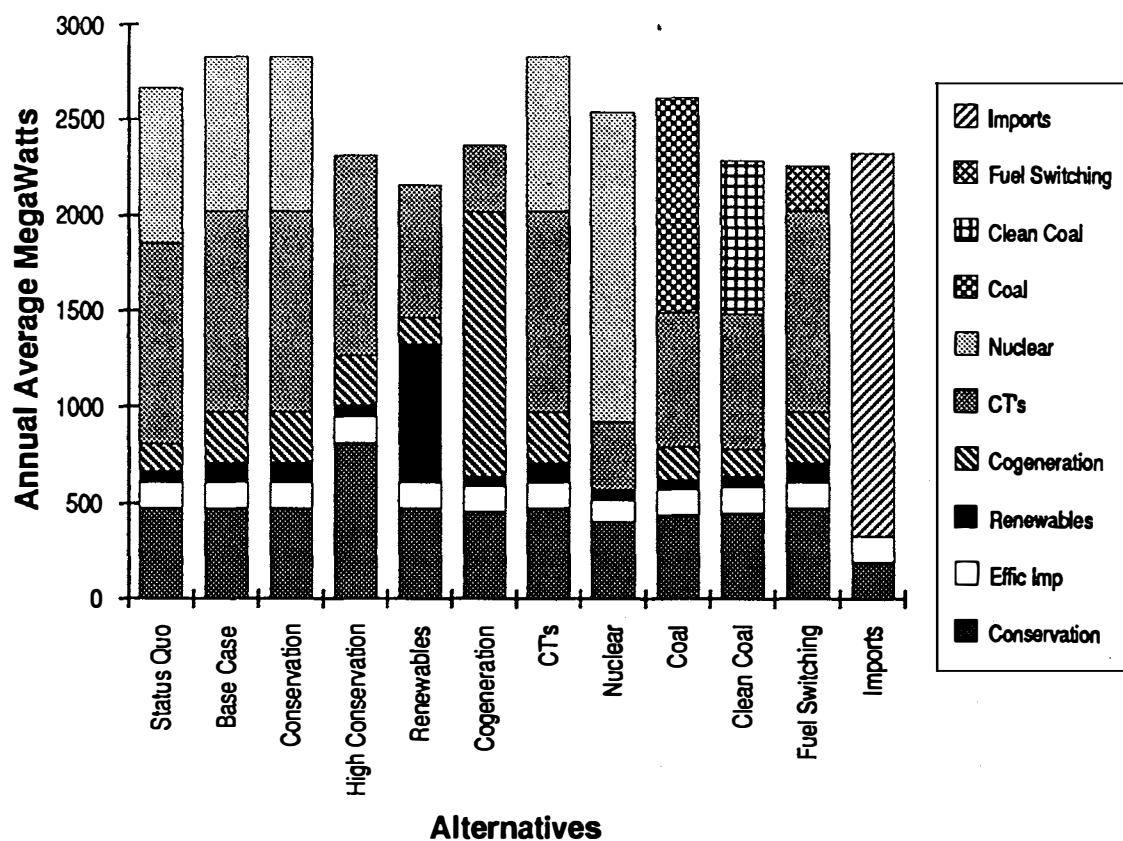


Table 4-3
New Resource Acquisitions - 2010

Resource Types (in aMW):	Alternatives											
	Status Quo	Base Case	Conservation	High Conservation	Renewables	Cogeneration	CT's	Nuclear	Coal	Clean Coal	Fuel Switching	Imports
Conservation	1033	1033	1033	1881	1033	1029	1033	1011	1029	1033	1033	858
Effic Imp	134	134	134	134	134	134	134	134	134	134	134	134
Renewables	367	480	480	349	967	405	480	412	314	213	367	60
Cogen	390	840	840	400	490	1380	840	930	340	280	430	120
CT's	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046	1046
Nuclear	1619	1619	1619	1619	1619	1619	1619	1619	1619	1619	1619	0
Coal	563	0	0	0	0	0	0	0	1127	0	0	0
Clean Coal	0	0	0	0	0	0	0	0	0	1286	0	0
Fuel Switching	0	0	0	0	0	0	0	0	0	0	556	0
Imports	0	0	0	0	0	0	0	0	0	0	0	3000
Total	5152	5152	5152	5429	5289	5613	5152	5152	5609	5611	5185	5218
Load/Resource Balance	55	55	55	333	193	517	55	56	512	514	89	124

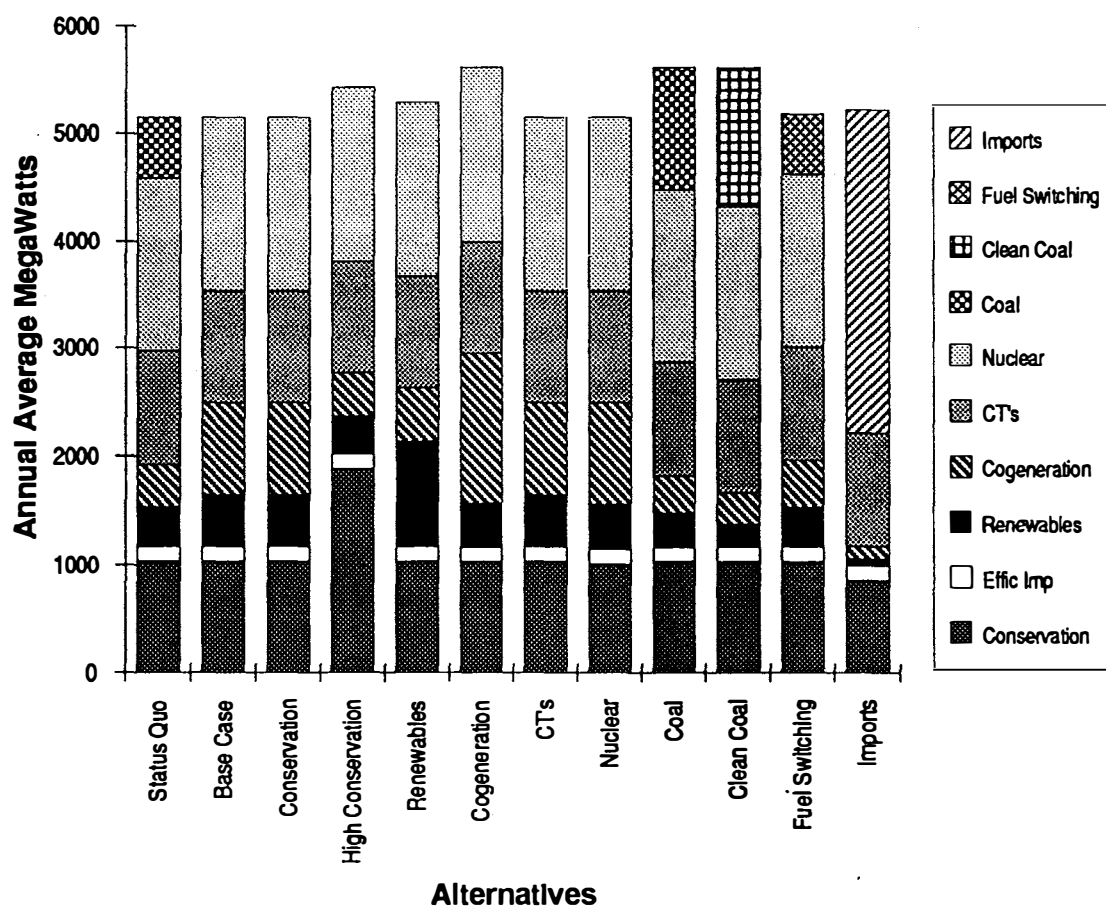


Table 4-4
New Resource Operations - 2000

Resource Types (in aMW):	Alternatives											
	Status Quo	Base Case	Conservation	High Conservation	Renewables	Cogeneration	CT's	Nuclear	Coal	Clean Coal	Fuel Switching	Imports
Conservation	477	477	477	815	477	458	477	404	441	452	477	197
Effic Imp	134	134	134	134	134	134	134	114	134	134	134	134
Renewables	60	105	105	60	716	49	105	46	49	60	105	0
Cogen	140	260	260	260	140	1380	260	10	170	140	260	0
CT's	185	140	140	277	185	70	141	35	109	176	283	0
Nuclear	813	813	813	0	0	0	813	1619	0	0	0	0
Coal	0	0	0	0	0	0	0	0	958	0	0	0
Clean Coal	0	0	0	0	0	0	0	0	0	697	0	0
Fuel Switching	0	0	0	0	0	0	0	0	0	0	241	0
Imports	0	0	0	0	0	0	0	0	0	0	0	681

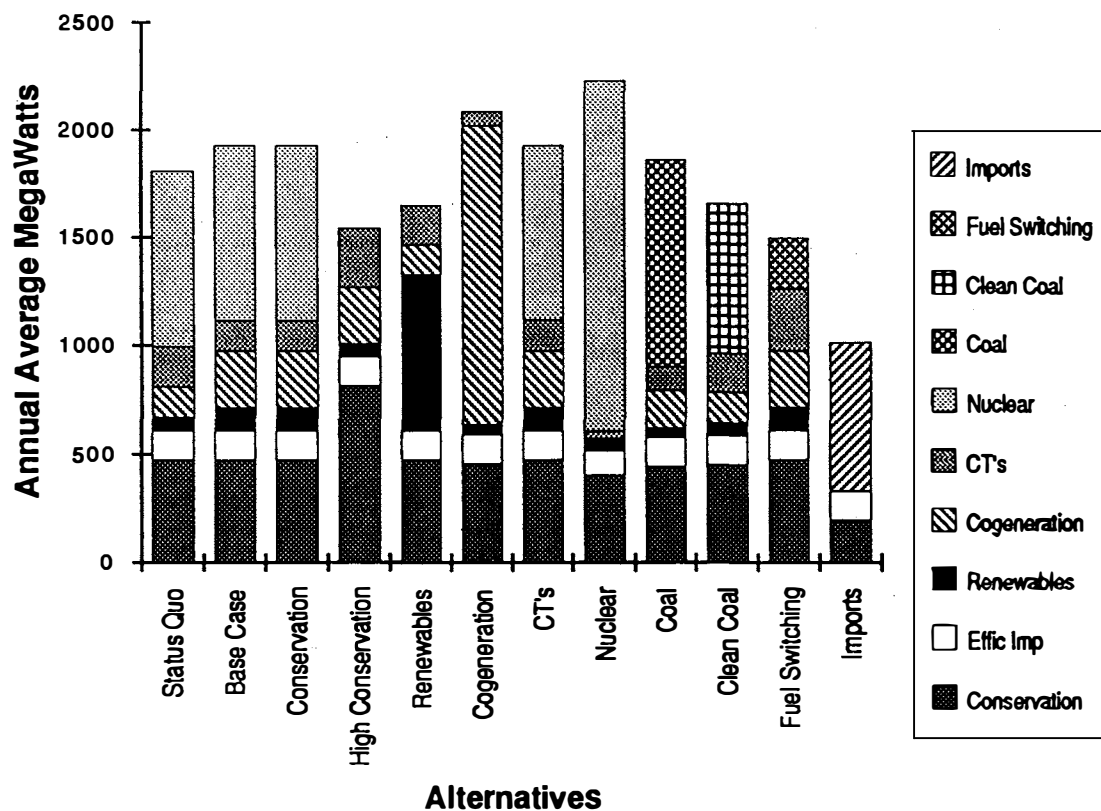
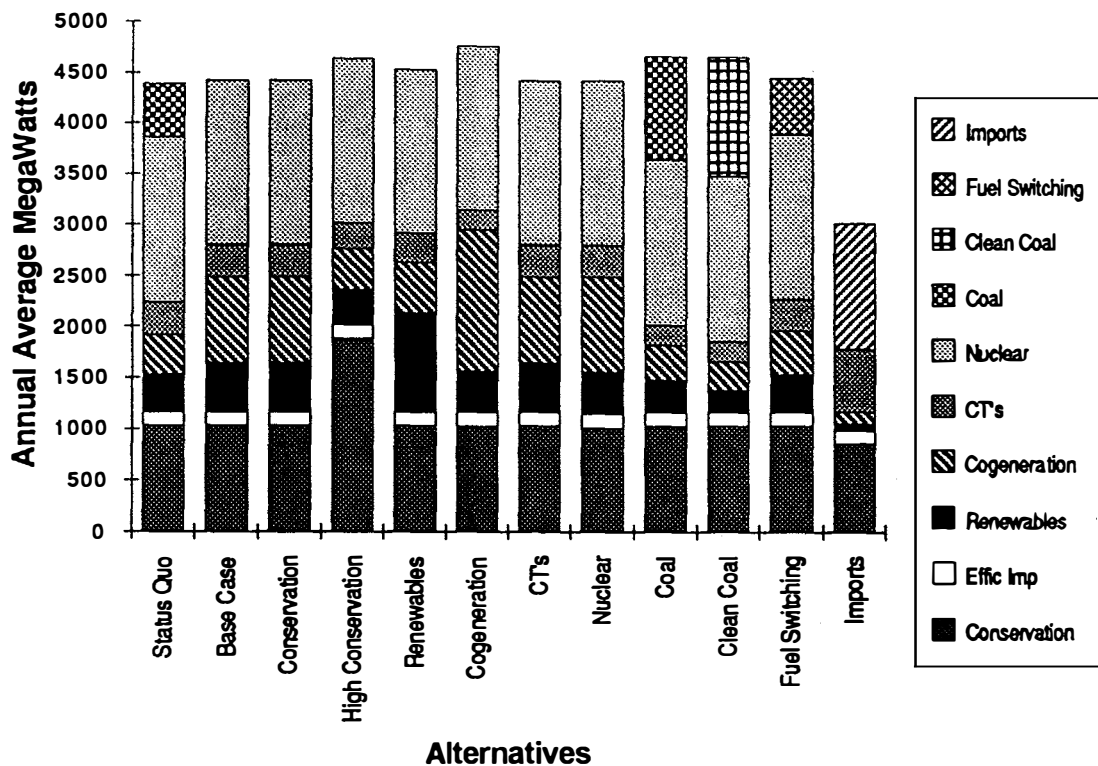


Table 4-5
New Resource Operations - 2010

Resource Types (in aMW):	Alternatives											
	Status Quo	Base Case	Conservation	High Conservation	Renewables	Cogeneration	CT's	Nuclear	Coal	Clean Coal	Fuel Switching	Imports
Conservation	1033	1033	1033	1881	1033	1029	1033	1011	1029	1033	1033	858
Effic Imp	134	134	134	134	134	134	134	134	134	134	134	134
Renewables	367	480	480	349	967	405	480	412	314	213	367	60
Cogen	390	840	840	400	490	1380	840	930	340	280	430	120
CT's	315	316	316	253	290	198	316	315	200	198	305	613
Nuclear	1619	1619	1619	1619	1619	1619	1619	1619	1619	1619	1619	0
Coal	534	0	0	0	0	0	0	0	1032	0	0	0
Clean Coal	0	0	0	0	0	0	0	0	0	1176	0	0
Fuel Switching	0	0	0	0	0	0	0	0	0	0	556	0
Imports	0	0	0	0	0	0	0	0	0	0	0	1235



4.2 Description of the Alternatives

The following sections describe the alternatives and compare their environmental impacts. Figures 4-1 and 4-2 compare the alternatives in terms of several key environmental impacts of resource operations.

Figure 4-1
Selected Environmental Impacts of Operations
of Resource Alternatives Compared to
the Base Case Alternative - 2000

POTENTIAL EFFECT	BASE CASE	ALTERNATIVE									
		Status Quo	Conservation	High Conservation	Renewables	Cogeneration	CTs	Nuclear	Coal	Clean Coal	Fuel Switching
SO ₂	9 tons										
NO _x	1,800 tons										
TSP	9 tons										
CO	300 tons										
CO ₂	1.24 million tons										
Water Consumption	17,000 acre-ft										
Thermal Discharge	52 million mmBtu										
Land Use	1,900 acres										
Direct Cost ^{1]}	Base case										
Environmental Cost ^{1]}	Base case										
Hydro System Operations	800 aMw large thermal with maintenance; no shaped import										



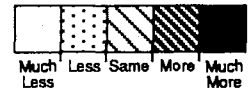
Much Less Less Same More Much More

^{1]} Relative expected present value over entire study period

Figure 4-2
Selected Environmental Impacts of Operations
of Resource Alternatives Compared to
the Base Case Alternative - 2010

POTENTIAL EFFECT	BASE CASE	ALTERNATIVE									
		Status Quo	Conservation	High Conservation	Renewables	Cogeneration	CTs	Nuclear	Coal	Clean Coal	Fuel Switching
SO ₂	26 tons	■	▨	▨	▨	▨	▨	▨	■	▨	▨
NO _x	5,100 tons	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
TSP	26 tons	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
CO	700 tons	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
CO ₂	3.7 million tons	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Water Consumption	48,000 acre-ft	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Thermal Discharge	151 million mmBtu	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Land Use	3,900 acres	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Direct Cost ¹⁾	Base case	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Environmental Cost ¹⁾	Base case	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨
Hydro System Operations	1600 aMw large thermal with maintenance; no shaped import	▨	▨	▨	▨	▨	▨	▨	▨	▨	▨

¹⁾ Relative expected present value over entire study period



4.2.1 No Action Alternative

Under the No Action Alternative, the underlying need for energy to meet the growing loads of BPA customers would not be satisfied. Neither BPA nor the region would acquire new resources to meet these loads. However, including a discussion of the No Action Alternative helps reveal the true difference between meeting and not meeting the underlying need.

If the No Action Alternative were implemented, there would be no new major thermal plants built. Cogeneration would become very attractive to major users of electricity. Renewable resource development would be small scale--probably limited to individual homeowners and businesses, and perhaps municipalities. Existing BPA-funded conservation programs would not be extended and new programs would not be implemented. Consumers would independently pursue conservation as electricity prices rose, and would be inclined to advocate more public emphasis on conservation, including support of more energy-efficient building codes, programs offered by the states, and possibly even surcharges. Voluntary load curtailment, rate structures that encourage interruptibility, and other load management measures are also likely responses. There would be an emphasis on more efficient use of the existing generating resources, including investments for life extension and rehabilitation, and an increased emphasis on and investment in research and development. Transmission and distribution efficiency improvements would further stretch the capabilities of the existing system, as would interregional capacity-energy exchanges. Many consumers would consider fuel switching to natural gas or wood attractive for some end uses, particularly heating applications. A trend toward formation of cooperatives and merger of public and private utilities to take advantage of preference status could mean fewer utilities in the region. An energy allocation scheme would likely be developed to assure some base level of service and rate stability for BPA customers.

Socio-economic impacts could be major and adverse, as one of the institutional foundations for the Northwest economic infrastructure--abundant and relatively cheap electricity--changed dramatically. New industries and residents would be discouraged from relocating to the region and many existing industries and residents would likely emigrate. Population growth would likely become more dispersed, with a small but significant increase in residential or micro-farm acreage and large, planned developments that would require inclusion of power plants to serve future residents. Acquiring sufficient land to develop communities large enough to support power plants would encourage "leapfrog" development to obtain large amounts of land cheaply enough to make eventual residences affordable. There would be an escalation of electricity costs as demand for power increased with no accompanying increase in supply. In some cases, consumers would be able to create unofficial transfers of "rights" to electricity use.

Environmental effects associated with the large-scale development of energy resources would be avoided. Fewer average megawatts of resources would be developed and the development that occurred would be in small increments. Impacts to the physical environment would include degradation of air quality, especially in densely populated areas, primarily from wood burning. There would also be significant and largely adverse impacts on land use, vegetation, and fish and wildlife habitat, and visual impacts from numerous small generating facilities and from increased population dispersion. Water quality impacts from increased

rural development would generally be adverse. Increased consumptive water use for cooling at major thermal plants would not occur.

4.2.2 Status Quo Alternative

In this alternative, resources acquired continue to be on the least-cost planning course set in the 1990 Resource Program. Acquisitions are based on minimizing system costs, without including quantifiable external environmental costs.

Since the Status Quo Alternative was developed by minimizing direct costs, the direct costs of this alternative are lower than those of the Base Case Alternative. However, once environmental costs are taken into account, the Status Quo Alternative has higher total system costs. The primary difference between this alternative and the Base Case Alternative is that by 2010 coal is acquired and operated instead of some geothermal and cogeneration.

In 2000, the 60 aMW of renewables are all hydro. Compared to the Base Case, only about half as many average megawatts of cogeneration and no geothermal resources operate. The slight increase in air quality impacts from increased CT generation compared to the Base Case is offset by the decrease in air quality impacts because of less cogeneration and geothermal. Water consumption and thermal discharge are reduced; land use impacts are about the same.

**Resource Operation - 2000
(aMW)**

Resource Type	Base Case	Status Quo
Conservation	477	477
Efficiency Improvements	134	134
Renewables	105	60
Cogeneration	260	140
CTs	140	185
Nuclear	813	813
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

Resource Operation - 2010 (aMW)

Resource Type	Base Case	Status Quo
Conservation	1,033	1,033
Efficiency Improvements	134	134
Renewables	480	367
Cogeneration	840	390
CTs	316	315
Nuclear	1,619	1,619
Coal	0	534
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

In 2010, the 367 aMW of renewables include 97 aMW of hydro and 270 aMW of geothermal. Compared to the Base Case, considerably more coal resources but fewer cogeneration and renewable resources operate and air quality impacts are much greater, due primarily to the greater amount of coal generation. Land use impacts are also higher. Because there is a smaller surplus than in the Base Case (397 aMW compared to 562 aMW), the potential for impacts to hydro system operations is less. Potential impacts to hydro system operation from shaping are the same. The Status Quo Alternative would bring approximately the same ratio of capacity to energy as the Base Case.

The load/resource balance is the same in 2010 for the Status Quo and Base Case Alternatives. However, since the Status Quo Alternative includes more resources that are shaped, this alternative has a greater potential to impact hydro system operation. The portfolio of resources in the Status Quo alternative in the year 2010 would bring a somewhat higher capacity-to-energy ratio than the Base Case.

The impacts of conservation for the Status Quo Alternative are the same as those in the Base Case Alternative, described below, because both alternatives include the same amount of conservation resources. Air quality impacts would be greater than in the Base Case for 2010, particularly from SO₂, because of the additional coal in this alternative. Water use and thermal discharges would be less, but land use would be greater.

4.2.3 Base Case Alternative

The Base Case Alternative reflects BPA's decision to include quantifiable environmental costs in resource planning, and is the benchmark against which all of the other alternatives are compared. Under this alternative, the ISAAC model acquired resources based on minimizing total system cost, including quantified

external costs. Since the Base Case Alternative was developed specifically to minimize total system costs, it is the least-cost alternative with the exception of the Fuel Switching and High Conservation Alternatives. Both fuel switching and the conservation resources included in the High Conservation Alternative were assumed to be relatively inexpensive and to have fairly low environmental costs. However, neither of these types of resources was included in the Base Case because neither has yet been confirmed as to cost or availability. The Base Case Alternative then is, in essence, the least-cost alternative.

As shown in Appendix B, in the year 2000, the 477 aMW of conservation resources in this alternative would include 193 aMW of commercial sector conservation, 82 aMW of industrial conservation, 9 aMW of irrigation conservation, 67 aMW of appliance conservation (including water heaters), and 126 aMW of other residential conservation (including Model Conservation Standards, manufactured housing, and residential weatherization).

Renewables in the year 2000 would include 60 aMW of hydro and 45 aMW of geothermal. Efficiency improvements would provide 134 aMW. Cogeneration would amount to 260 aMW of operations, and CTs would provide 140 aMW. In this alternative (which assumes high loads), 813 aMW would be provided by either WNP-1 or WNP-3.

The impacts of the conservation resources associated with this alternative would be relatively minor, and/or fully mitigable. Potential environmental impacts of conservation measures are described in Chapter 3 and in more detail in Appendices A-3 and C. Potential environmental effects include impacts to indoor air quality, which can be mitigated by various types of ventilation; the release of CFCs, which are associated with global warming; and the need to properly dispose of hazardous wastes (such as asbestos, and mercury and PCBs from existing light ballasts), which generally would occur even in the absence of the conservation program.

The major environmental impacts of the Base Case Alternative would result from the operations of the generating resources in this alternative. As shown in Figure 4-1, there would be impacts to air quality, primarily from cogeneration and CTs. Land use would be affected by the land requirements of nuclear and renewables, in particular, while cogeneration, CTs, and nuclear would affect water consumption and thermal discharges.

In general, the greater the amount of shaping and the greater the amount of surplus, the greater the potential for effects on hydro system operation. The 562 aMW surplus in 2000 is likely to affect hydro system operation. The Base Case Alternative includes thermal generation that may be down for maintenance during a portion of the year. However, impacts due to shaping are expected to be small.

Resource Operation - 2000
(aMW)

Resource Type	Base Case
Conservation	477
Efficiency Improvements	134
Renewables	105
Cogeneration	260
CTs	140
Nuclear	813
Coal	0
Clean Coal	0
Fuel Switching	0
Imports	0

Resource Operation - 2010
(in aMW)

Resource Type	Base Case
Conservation	1,033
Efficiency Improvements	134
Renewables	480
Cogeneration	840
CTs	316
Nuclear	1,619
Coal	0
Clean Coal	0
Fuel Switching	0
Imports	0

As shown in detail in Appendix B, in 2010, the 1,033 aMW of conservation in the Base Case includes approximately two to two-and-one-half times more conservation in each of the residential, commercial, and industrial programs as in 2000. The 450 aMW of renewables is comprised of 97 aMW of hydro and 383 aMW of geothermal. As in 2000, the impacts of conservation are generally minor and/or mitigable. The more significant impacts are from generating resources, and include air quality impacts from cogeneration and CTs, land use impacts of renewables and nuclear, and water consumption and thermal discharges associated with cogeneration, CTs, and nuclear. In 2010, the surplus is only 55 aMW. Therefore, environmental impacts from changes to hydro system operations due to a surplus load/resource balance are not likely. Because both nuclear plants are operated, there may be some impacts to hydro system operation from shaping.

4.2.4 Emphasize Conservation Alternative

Because of its relatively low cost, all of the available conservation is already at the top of the resource stack in the Base Case Alternative. Therefore, the Emphasize Conservation Alternative and the Base Case Alternative are the same.

4.2.5 Emphasize High Conservation Alternative

In this alternative, additional conservation resource potential was assumed for residential refrigeration, residential freezers, other residential appliances, new commercial buildings, and industrial facilities (excluding aluminum smelters operated by direct-service industrial customers of BPA). This additional achievable potential is based, in large part, on the 1990 analysis of the regional energy conservation resource potential by the Natural Resources Defense Council and the Northwest Conservation Act Coalition. The Emphasize High Conservation Alternative has a lower total system cost than the Base Case Alternative because of lower direct costs and very low environmental costs. There is some concern, however, over the reliability and commercial availability of these additional conservation resources. They do not have the institutional support of supply curves, with their publicly reviewed derivations of cost and availability. However, since more conservation is expected to be available in the future than current supply curves indicate, emphasizing an increased amount of conservation resources was included as an alternative in this EIS.

The 815 aMW of conservation resources in this alternative in 2000 (listed in more detail in Appendix B) include 394 aMW in the commercial sector, 106 aMW in the industrial sector, 9 aMW of irrigation conservation, and 80 aMW of appliance conservation (including water heaters). The acquisition of a larger amount of conservation changes the overall portfolio of resource acquisitions. In addition to the increase in conservation, the main difference between this alternative and the Base Case Alternative in 2000 is that a nuclear plant is not acquired or operated. Almost twice as many CTs are operated and there are no geothermal resources (all the renewables are hydro).

Because of increased NO_x and CO production from additional CT operation, air quality impacts are worse than in the Base Case. However, water consumption and thermal discharge impacts are all much lower—primarily because there is no nuclear and fewer renewables. Impacts from conservation would be similar in type to those described for the Base Case, and in general would be minor and/or fully mitigable. Since the system is essentially in load/resource balance and there are no large thermal plants, this alternative is expected to have much less impact on hydro system operations in 2000 than the Base Case Alternative. The resources in this alternative would probably bring somewhat less capacity than the Base Case (in part because, for purposes of this analysis, overall conservation is assumed to bring capacity in a one-to-one ratio with energy).

In the year 2010, the 1,881 aMW of conservation resources (listed in more detail in Appendix B) include major expansions of residential, commercial, industrial, and appliance conservation compared to the year 2000. Renewable resources in 2010 include 79 aMW of hydro and 270 aMW of geothermal. Environmental impacts of the conservation measures in this alternative would be similar in type to those described for the Base Case, and would generally be minor and/or fully

mitigable. Because fewer geothermal, cogeneration, and combustion turbine resources operate, impacts to air quality (especially NO_x and CO₂) in this

Resource Operation - 2000
(aMW)

Resource Type	Base Case	High Conservation
Conservation	477	815
Efficiency Improvements	134	134
Renewables	105	60
Cogeneration	260	260
CTs	140	277
Nuclear	813	0
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

alternative are less than those of the Base Case Alternative. Water consumption and thermal discharge impacts are also less. Because there is a 333 aMW surplus, effects on hydro system operation are potentially larger than in the Base Case, even though the amount of shaped resources is the same. In 2010 as in 2000, this alternative would probably bring less capacity than the Base Case.

Resource Operation - 2010
(aMW)

Resource Type	Base Case	High Conservation
Conservation	1,033	1,881
Efficiency Improvements	134	134
Renewables	480	349
Cogeneration	840	400
CTs	316	253
Nuclear	1,619	1,619
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

4.2.6 Emphasize Renewables Alternative

Under this alternative, the renewable energy resources (hydropower, geothermal, wind, and solar) available to BPA were moved to the top of the Base Case resource stack and acquired first. Although this alternative has lower environmental costs than the Base Case Alternative, direct costs are much higher. Therefore, the total system costs are higher for this alternative than for any other.

**Resource Operation - 2000
(aMW)**

Resource Type	Base Case	Renewables
Conservation	477	477
Efficiency Improvements	134	134
Renewables	105	716
Cogeneration	260	140
CTs	140	185
Nuclear	813	0
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

The 716 aMW of renewables operating in 2000 include 97 aMW of hydro, 297 aMW of geothermal, 236 aMW of wind, and 86 aMW of solar.

Approximately seven times as many average megawatts of renewable resources operate compared with the Base Case. No nuclear plant is on line and fewer cogeneration resources operate than in the Base Case. However, the same amount of conservation is acquired.

Overall, air quality impacts are approximately the same as in the Base Case, in part because decreased operations of cogeneration are partially offset by increased operations of CTs. Water consumption and thermal discharges are less, but land use impacts are higher than for any other alternative because of the high land use requirements of wind and solar.

**Resource Operation - 2010
(aMW)**

Resource Type	Base Case	Renewables
Conservation	1,033	1,033
Efficiency Improvements	134	134
Renewables	480	967
Cogeneration	840	490
CTs	316	290
Nuclear	1,619	1,619
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

Because the load/resource balance shows a smaller surplus than the Base Case, and there are no large thermal plants with shaping impacts, the potential for affecting operation of the hydro system is less than in the Base Case. This alternative would bring somewhat less capacity than the Base Case in 2000.

In 2010, all available renewable resources (including 97 aMW of renewable hydro, 410 aMW of geothermal, 374 aMW of wind, and 86 aMW of solar) are operating. Conservation acquisitions are the same as in the Base Case. There is an increase of 487 aMW of renewable resource operation and a decrease in operation of 350 aMW of cogeneration and 26 aMW of CTs. Air quality and thermal discharge impacts in this alternative are less than in the Base Case Alternative. However, land use impacts are much higher because of the relatively large amount of acres per megawatt required for wind and solar resources. The Emphasize Renewables Alternative would have approximately the same amount of shaping, but a larger surplus, and therefore would have a somewhat larger potential to affect the operation of the hydrosystem. This alternative would bring approximately the same amount of capacity as the Base Case in 2010.

4.2.7 Emphasize Cogeneration Alternative

For this alternative, cogeneration resources were moved to the top of the Base Case resource stack. A variety of fuel types—including biomass and municipal solid waste—can be used in cogeneration. However, in modeling air quality impacts, cogeneration was assumed to use natural gas because most of the new cogeneration available uses natural gas as fuel.

The Cogeneration Alternative has much higher direct and total costs than the Base Case. Since this EIS was initiated, cogeneration costs appear to have dropped as natural gas prices have declined.

In 2000, the renewable resources are all hydro. Conservation acquisitions are slightly lower than in the Base Case and no nuclear operates. This alternative includes over five times as much cogeneration as the Base Case, so there is a greater impact on NO_x and CO₂ emissions. Despite the increase in cogeneration operations, water consumption and thermal discharges are less because there is no nuclear and fewer renewables, which have substantial impacts in those areas. Land use is much lower, in part because cogeneration projects are often constructed within existing industrial sites and therefore do not require much land. The surplus in 2000 is only 99 aMW and there are no large thermal plants, so this alternative is much less likely to impact hydro system operation than is the Base Case. The portfolio of resources in this alternative would bring considerably less capacity than the Base Case in 2000, in large part because cogeneration is assumed to have a relatively high energy-to-capacity ratio.

**Resource Operation - 2000
(aMW)**

Resource Type	Base Case	Cogeneration
Conservation	477	458
Efficiency Improvements	134	134
Renewables	105	49
Cogeneration	260	1,380
CTs	140	70
Nuclear	813	0
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

In 2010, the amount of cogeneration remains unchanged, as the forecasted supply was exhausted by the year 2000. Renewable resources include 93 aMW of hydro, 279 aMW of geothermal, and 33 aMW of wind. Although the differences between

Resource Operation - 2010 (aMW)

Resource Type	Base Case	Cogeneration
Conservation	1,033	1,029
Efficiency Improvements	134	134
Renewables	480	405
Cogeneration	840	1,380
CTs	316	198
Nuclear	1,619	1,619
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

the Emphasize Cogeneration Alternative and the Base Case are less pronounced in 2010 than in 2000, considerably more cogeneration and fewer geothermal resources and CTs operate in this alternative.

Therefore, the Emphasize Cogeneration Alternative has a greater impact on air quality—especially from production of NO_x and CO₂—than the Base Case, but water consumption is less.

In 2010, there is a much greater surplus than in the Base Case (517 aMW versus 55 aMW). Environmental impacts from changes to hydro system operations due to a surplus are much more likely. Because both alternatives have similar amounts of generation that may be down for maintenance during the year, the potential for impacts to hydro system operation from shaping are expected to be the same. As in 2000, the resources in this alternative would bring less capacity in the Base Case, in large part because of the high amount of cogeneration.

4.2.8 Emphasize Combustion Turbines Alternative

In this alternative, all of the available combustion turbine resource is moved to the top of the Base Case stack. Because CTs are already near the top of BPA's resource stack and because the alternatives are modeled against a deterministic high load, all of the available CTs were acquired in the Base Case by 2000. Therefore, moving the CTs to the top of the stack does not change the average megawatts of resources acquired or operated in 2000 or 2010. Therefore, the potential environmental impacts and effects on hydro system operation from the Emphasize Combustion Turbine Alternative and the Base Case Alternative are expected to be the same. The environmental costs are also the same for both alternatives.

**Resource Operation - 2010
(aMW)**

Resource Type	Base Case	CTs
Conservation	477	477
Efficiency Improvements	134	134
Renewables	105	105
Cogeneration	260	260
CTs	140	141
Nuclear	813	813
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

**Resource Operation - 2010
(aMW)**

Resource Type	Base Case	CTs
Conservation	1,033	1,033
Efficiency Improvements	134	134
Renewables	480	480
Cogeneration	840	840
CTs	316	316
Nuclear	1,619	1,619
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

4.2.9 Emphasize Nuclear Alternative

In this alternative, the partially completed Washington Nuclear Projects (WNP) -1 and -3 were placed at the top of the resource stack. The total costs of the Emphasize Nuclear Alternative are close to those of the Base Case because the slightly higher environmental costs are offset by the somewhat lower direct costs of this alternative. The major difference between this alternative and the Base Case is that both nuclear plants would be acquired and operated by 2000, and almost no cogeneration or CT resources would be operated. Conservation acquisitions are 73 aMW less than in the Base Case.

**Resource Operation - 2000
(aMW)**

Resource Type	Base Case	Nuclear
Conservation	477	404
Efficiency Improvements	134	114
Renewables	105	46
Cogeneration	260	10
CTs	140	35
Nuclear	813	1,619
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

In 2000, all renewables are hydro. Compared to the Base Case, the Emphasize Nuclear Alternative would have fewer impacts on air quality, particularly NO_x, CO, and CO₂--primarily because there would be so few cogeneration and CT resources operating. Even though there is no geothermal and little cogeneration or CTs, both WNP-1 and -3 would be operating. Therefore, water consumption and thermal discharges would be much higher. This alternative creates the greatest land use impacts of any of the alternatives except Emphasize Renewables in 2000 because of the large number of acres required for both nuclear plants. The Emphasize Nuclear Alternative has a potentially greater impact on hydro system operations than the Base Case. Although there is less

**Resource Operation - 2010
(aMW)**

Resource Type	Base Case	Nuclear
Conservation	1,033	1,011
Efficiency Improvements	134	134
Renewables	480	412
Cogeneration	840	930
CTs	316	315
Nuclear	1,619	1,619
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

of a surplus, impacts due to shaping are much greater because this alternative includes a larger amount of generation that may be down for maintenance during a

portion of the year. This alternative would probably bring more capacity to the system than the Base Case because of the relatively low energy-to-capacity ratio assumed for nuclear (65 percent). It should be noted, however, that the capacity assumed to come with nuclear may not always be available to serve the system's capacity needs because the low capacity-to-energy ratio for nuclear results in part from unscheduled downtimes.

In 2010, renewables include 97 aMW of hydro and 315 aMW of geothermal. The differences between this alternative and the Base Case are less pronounced in 2010. More cogeneration and slightly less geothermal operate. Air quality impacts are essentially the same as in the Base Case, except for CO₂, which is higher because more cogeneration resources operate. Water consumption and thermal discharges are lower because less geothermal operates. In 2010, the load/resource surplus is only 56 aMW. As in the Base Case, environmental impacts from changes to hydro system operations due to a surplus load/resource balance are not likely. The potential for impacts to hydro system operation due to shaping are the same. The resources in this alternative in 2010 would bring about the same amount of capacity as the Base Case.

4.2.10 Emphasize Coal Alternative

In this alternative, the conventional coal resources available to BPA are moved to the top of the resource stack. The Emphasize Coal Alternative has higher direct costs than the Base Case Alternative. This difference in direct costs is mainly due to higher generating resource capital costs, since coal replaces less expensive generating resources. Because coal has the highest environmental costs of all the resources in the stack, the total system cost for this alternative is higher than for any of the other alternatives except renewables.

**Resource Operation - 2000
(aMW)**

Resource Type	Base Case	Coal
Conservation	477	441
Efficiency Improvements	134	134
Renewables	105	49
Cogeneration	260	170
CTs	140	109
Nuclear	813	0
Coal	0	958
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

In 2000, the primary difference between this alternative and the Base Case is that coal plants operate instead of a nuclear plant. However, there is also slightly less conservation, renewables (there is no geothermal), cogeneration, and CTs.

Adverse impacts to air quality from all pollutants analyzed are much greater than in the Base Case. NO_x, CO, CO₂, TSP, and SO₂ emissions all increase dramatically. Water consumption and thermal discharge are less, and this alternative has less land use impacts than the Base Case Alternative.

Because the Emphasize Coal Alternative is closer to load/resource balance than the Base Case Alternative, it may have less effect on the hydro system when compared to the existing system. Both this alternative and the Base Case have similar amounts of generation that may be down for maintenance during part of the year. However, since the coal plants have smaller unit sizes and the maintenance schedules can be spread out, the Emphasize Coal Alternative is likely to have fewer impacts due to shaping. This alternative would bring somewhat less capacity than the Base Case in 2000, in part because it is assumed that coal has a higher energy-to-capacity ratio (i.e., less relative capacity) than nuclear, which would not be brought on by 2000 in the Emphasize Coal Alternative.

In 2010, renewables include 89 aMW of hydro and 225 aMW of geothermal. Less than one-half the cogeneration and almost one-third less geothermal and combustion turbine resources operate in this alternative compared to the Base Case. This alternative has a much greater adverse impact on air quality from SO₂, TSP, NO_x, CO, and CO₂ than the Base Case. Water consumption and thermal discharge are also much higher than in the Base Case. In 2010, the Emphasize Coal Alternative has the highest land use requirement of all the alternatives except renewables.

Resource Operation - 2010 (aMW)

Resource Type	Base Case	Coal
Conservation	1,033	1,029
Efficiency Improvements	134	134
Renewables	480	314
Cogeneration	840	340
CTs	316	200
Nuclear	1,619	1,619
Coal	0	1032
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	0

Because there is such a large surplus, this alternative is much more likely than the Base Case to have an impact on hydro system operations due to a surplus load/resource balance. The Emphasize Coal Alternative also has the potential to have a much greater impact due to shaping than the Base Case because of the larger amount of thermal resources with accompanying maintenance schedules. The resources in this alternative would bring somewhat more capacity than the Base Case Alternative.

4.2.11 Emphasize Clean Coal Alternative

In this alternative, the amount of high technology coal, including fluidized bed combustion and coal gasification, available to BPA was moved to the top of the resource stack. Although this clean coal has substantially lower environmental costs than conventional coal, the environmental costs are higher than the Base Case. Since the direct costs are also high (due mainly to higher generating resource capital costs because coal replaces less expensive generating resources), this alternative has total system costs much higher than the Base Case. In fact, this alternative had the third highest total system costs of all the alternatives analyzed (after Renewables and Coal).

In 2000, renewables are all hydro. The major difference between this alternative and the Base Case is that clean coal replaces nuclear. Also, only about one-half of the cogeneration and two-thirds of the CTs operate, there is no geothermal, and there is slightly less conservation. Compared to the Base Case, the Emphasize Clean Coal Alternative has a generally much greater adverse impact on air quality from all types of emissions. (In fact, air emissions impacts are generally second only to the Coal Alternative.) Water consumption and thermal discharge impacts are less, primarily because there is no geothermal or nuclear and less cogeneration. Land requirements are also less in this alternative than in the Base Case.

The potential effect on hydro system operations is much less than for the Base Case. In 2000, the Emphasize Clean Coal Alternative is at load/resource balance. In addition, there are fewer impacts due to shaping because, when compared to WNP-1 or WNP-3, the clean coal plants have smaller unit sizes and scheduled maintenance can be spread throughout the year. The resources in this alternative would bring much less capacity than the Base Case in 2000, in part because clean coal is assumed to have a higher energy-to-capacity ratio (i.e., less relative capacity) than nuclear, which would not be brought on by 2000 in the Emphasize Clean Coal Alternative.

**Resource Operation - 2000
(aMW)**

Resource Type	Base Case	Clean Coal
Conservation	477	452
Efficiency Improvements	134	134
Renewables	105	60
Cogeneration	260	140
CTs	140	176
Nuclear	813	0
Coal	0	0
Clean Coal	0	697
Fuel Switching	0	0
Imports	0	0

**Resource Operation - 2010
(aMW)**

Resource Type	Base Case	Clean Coal
Conservation	1,033	1,033
Efficiency Improvements	134	134
Renewables	480	213
Cogeneration	840	280
CTs	316	198
Nuclear	1,619	1,619
Coal	0	0
Clean Coal	0	1,176
Fuel Switching	0	0

In 2010, renewables include 78 aMW of hydro and 135 aMW of geothermal. There are fewer differences between the Emphasize Clean Coal and Base Case Alternatives in 2010. High technology coal replaces about two-thirds of the geothermal and cogeneration about one-third of the CTs in the Base Case. However, WNP-1 and WNP-3 operate in both alternatives. The Emphasize Clean Coal Alternative has a much greater adverse impact on air quality than the Base Case Alternative,--SO₂, NO_x, CO, and CO₂ emissions all exceed Base Case levels. Water consumption is much more than, and thermal discharge impacts are about the same as the Base Case. Land use impacts are less than in the Base Case because there are fewer renewable energy sources, which have high land use requirements.

The Emphasize Clean Coal Alternative is more likely than the Base Case Alternative to have an impact on hydro system operations when compared to the

existing system. Because this alternative has such a large surplus, it is more likely than the Base Case to have an impact on hydro system operations due to a surplus load/resource balance. This alternative also has the potential to have a much greater impact due to shaping than the Base Case because of the larger amount of thermal generation resources that have maintenance schedules. Again in 2010, this alternative would probably bring less capacity than the Base Case.

4.2.12 Emphasize Fuel Switching Alternative

Fuel switching from electric to natural gas for some applications is a means of reducing load. In the hypothetical program modeled for this alternative, BPA would pay the costs involved in bringing gas lines near residential areas and subsidize conversion from electric to gas. The Fuel Switching Alternative could also be a proxy for other types of load reduction.

In this alternative, the 556 aMW of fuel switching assumed to be available to BPA is placed at the top of the resource stack. Fuel switching is not otherwise included in the Base Case resource stack because its supply and costs have not been confirmed. It is, however, an option now being explored by some Pacific Northwest utilities. Even though the environmental costs estimated for the Emphasize Fuel Switching Alternative are slightly higher than the environmental costs for the Base Case Alternative, the estimated direct costs are lower. Therefore, the total system costs of the Emphasize Fuel Switching Alternative appear to be slightly less than the total system costs of the Base Case.

In 2000, almost half the fuel switching potential has been achieved. Renewables include 60 aMW of hydro and 45 aMW of geothermal. Compared to the Base Case Alternative, this alternative includes twice as much generation from CTs, no nuclear generation, and a reduction in load of 241 aMW. Except for NO_x and CO emissions (which are greater because of the additional CTs operating), air quality impacts are about the same as for the Base Case Alternative. Water consumption and thermal discharge are much less, mainly because there is no nuclear generation. Land use impacts are minimal. Because BPA is essentially in load/resource balance and there are no large thermal plants with shaping impacts, the potential for affecting operation of the hydro system is much less than in the Base Case. This alternative would bring somewhat less capacity than the Base Case in 2000, largely because fuel switching is assumed to have a one-to-one energy-to-capacity ratio.

**Resource Operation - 2000
(aMW)**

Resource Type	Base Case	Fuel Switching
Conservation	477	477
Efficiency Improvements	134	134
Renewables	105	105
Cogeneration	260	260
CTs	140	283
Nuclear	813	0
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	241
Imports	0	0

**Resource Operation - 2010
(aMW)**

Resource Type	Base Case	Fuel Switching
Conservation	1,033	1,033
Efficiency Improvements	134	134
Renewables	480	367
Cogeneration	840	430
CTs	316	305
Nuclear	1,619	1,619
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	556
Imports	0	0

In 2010, renewables include 97 aMW of hydro and 270 aMW of geothermal. All of the fuel switching assumed to be available has been accomplished. The primary difference between this alternative and the Base Case is the inclusion of fuel switching. However, the Emphasize Fuel Switching Alternative also includes about one-third less geothermal and only half as much cogeneration as the Base Case. Air quality impacts are less in the Emphasize Fuel Switching Alternative than in the Base Case. Water consumption, thermal discharge, and land use impacts are about the same.

In 2010, the potential for impacting hydro system operations is essentially the same in the Emphasize Fuel Switching Alternative and the Base Case Alternative. Both the load/resource balances and the amounts of resource shaping are similar. Again in 2010, this alternative would bring somewhat less capacity than the Base Case.

4.2.13 Emphasize Imports Alternative

In this alternative, an estimated supply of imports was moved to the top of the resource stack. These imports were modeled as gas-fired CTs—two-thirds new and one-third existing. It was assumed that half of the imports were from Canada and half were from the Pacific Southwest. In addition, the imports from Canada were assumed to be available all year and the imports from the Pacific Southwest were shaped September through April. The costs of building adequate transmission and related facilities were included in the resource cost estimates. Although the estimated direct costs were slightly lower than the direct costs of the Base Case Alternative, the estimated environmental costs were substantially higher. Therefore, the total system costs for the Emphasize Imports Alternative are greater than for the Base Case.

In this alternative, 280 aMW less conservation would be acquired by 2000 than in the Base Case, and no renewables or new regional thermal resources would operate. In 2000, the Emphasize Imports Alternative had a greater adverse impact on air quality than the Base Case due to higher SO₂, NO_x, CO, and CO₂ emissions. However, water consumption and thermal discharge impacts were much less in the Emphasize Imports Alternative than in the Base Case. Since no large thermal plants were acquired or operated, land use impacts were

**Resource Operation - 2000
(aMW)**

Resource Type	Base Case	Imports
Conservation	477	197
Efficiency Improvements	134	134
Renewables	105	0
Cogeneration	260	0
CTs	140	0
Nuclear	813	0
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	681

**Resource Operation - 2010
(aMW)**

Resource Type	Base Case	Imports
Conservation	1,033	858
Efficiency Improvements	134	134
Renewables	480	60
Cogeneration	840	120
CTs	316	613
Nuclear	1,619	0
Coal	0	0
Clean Coal	0	0
Fuel Switching	0	0
Imports	0	1235

were substantially less than in the Base Case. The potential for impacts to hydro system operation from a surplus load/resource balance were also much less. Even though no large thermal plants were operating in the Emphasize Imports Alternative, one-half of the imports were shaped September through April. The hydro system studies showed that this shaping could result in fairly large changes in hydro system operations under some conditions. Therefore, the impacts due to shaping are anticipated to be greater for this alternative than for the Base Case. This alternative would bring much less capacity than the Base Case, in large part because, overall, imports are assumed here to have a one-to-one capacity-to-energy ratio.

In addition to being the only alternative in which neither WNP-1 or WNP-3 is operating by 2010, the Emphasize Imports Alternative has much less conservation, renewables (only 60 aMW of hydro), and cogeneration than any of the other alternatives. Because of the large amount of gas-fired CTs, however, this alternative has much greater impacts to air quality from NO_x, CO, and CO₂ than the Base Case. Water consumption and thermal discharge impacts are much less than in the Base Case. Potential land use impacts are a fraction of the land use impacts for the Base Case Alternative.

BPA is only slightly more surplus in the Emphasize Imports Alternative, so potential impacts to hydro system operations are expected to be about the same as in the Base Case. Since it includes a substantial amount of generation that is shaped September through April, however, the Emphasize Imports Alternative is expected to have a greater impact than the Base Case on hydro system operations from shaping. Again in 2010, this alternative would bring much less capacity than the Base Case.

4.3 Preferred Alternative(s)

BPA's preferred alternative is the Emphasize Conservation Alternative. Both system and environmental costs are relatively low. Environmental impacts from conservation are minimal. To the extent BPA's customers' needs can be met by using electric energy more efficiently, this alternative is clearly superior to other alternatives considered. With regard to other resources in the stack, conclusions are not so clear. All generating technologies have potentially significant effects, although, with the exception of hydro, the renewables appear to have potentially lower adverse impacts (except for land use). The impacts of thermal generation are greatly affected by the design and operation of the plants, however, and with the exception of CO₂, which is emitted in large quantities by all organic fuels, thermal emissions can be largely controlled. The trade-off is between cost/quality of plant operations and quantity of emissions. These would be addressed in site-specific environmental documentation for any generating resource BPA proposes to acquire or pay for with billing credits.

4.4 Other Considerations

With two exceptions, the alternatives compared in this EIS include resource types that are currently in BPA's resource stack. Although cost and supply have not been confirmed for either high conservation or fuel switching, both resource types were also included in the Base Case stack. More conservation is expected to be available in the future than the supply curves indicate, and fuel switching is an option already being pursued by utilities in the Pacific Northwest.

Emerging Technologies

As other sources of energy, such as the new and emerging technologies described in Chapter 3, become both commercially available and cost-effective, they may replace other resources in the stack. The potential environmental effects of these emerging technologies may be substituted for the environmental effects of the replaced resources when comparing alternatives.

Load Management

In addition to the emerging technologies, some of the load management options discussed in Chapter 3 may be feasible if they gain public acceptability. These options and their environmental effects, if any, could also be substituted for the highest-cost resources in the stack and their corresponding environmental effects. These changes would need to be considered when comparing the environmental impacts of the alternatives.

Resource Supply Expansion Program (RSEP)

In the 1991 Northwest Power Plan, the Council set a goal of "confirming" additional conservation and renewable energy resources in the region. BPA initiated the Resource Supply Expansion Program (RSEP) as a primary vehicle for achieving this goal. RSEP is examining innovative means of working with regional utilities, the Council, other offices within the U.S. Department of Energy, interest groups, and the public to move conservation and renewable technologies to market readiness, and to help utilities pursue the accelerated path called for in the Conservation Implementation Plan.

The primary approach for confirming a resource or technology in RSEP is the demonstration project. By mid-1992, RSEP participants had begun to focus on three specific areas: demand-side management, renewable resource generation (including wind), and disposed generation/system efficiency. It is not yet known precisely what technologies will be demonstrated in RSEP, other than a general focus on conservation and renewable resource technologies. The RPEIS includes a programmatic evaluation of several types of resources that may be developed further in RSEP. As specific actions are identified, they will be subject to project-specific NEPA assessments.

Canadian Entitlement

The Columbia River Treaty provides that Canada receive one-half of the downstream benefits generated in the United States as the Canadian Entitlement. The rights to this energy and capacity were sold to U. S. utilities for a period of 30 years. Initially, it was resold to California, but more recently is being recalled to meet Pacific Northwest loads. This sale begins to expire in 1998 and is fully terminated by 2003.

BPA currently plans for the return of the Canadian Entitlement, considering it a load in BPA's determination of load and resource balance. A preliminary estimate of the expected value of the Entitlement is 550 MW of energy and 1,250 MW of capacity. The Treaty specifies that the capacity be returned as scheduled by Canada and the energy be returned in equal monthly amounts. During the life of the Treaty, at least to 2024, resources would need to be acquired to replace the returned Entitlement power. Returning the Entitlement at or near Oliver, British Columbia, as specified by the Treaty, would require construction of new transmission in both Canada and the U.S. Although the Treaty provides that the Entities can agree to a point of delivery other than Oliver, the alternate sites could also require construction of new transmission.

In assessing the environmental impacts of the return of Canadian Entitlement, the environmental effects of both the replacement resources and the transmission line must be considered. These potential environmental effects have been described generically in Chapter 3. Also, depending upon the shape of the monthly return requested by BC Hydro, the operation of the hydro system could be affected.

In addition to acquiring resources in the U.S. to replace the Canadian Entitlement, BPA could make a system purchase from existing or planned resources in BC. The decisions on these resources would already have been made by Canada and their environmental impacts reviewed.

The BC government has initiated a public process to review options for the return of the Canadian Entitlement. In support of these discussions, the U.S. has begun to identify alternatives for the return of the Canadian Entitlement to find the most cost-effective and environmentally sound way for the U.S. and Canada to satisfy the Canadian Entitlement obligation.

Alternatives being considered and their potential environmental impacts include:

Repurchase the Entire Canadian Entitlement. The Canadian Entitlement (both energy and capacity) could be purchased outright by the U.S. There would be no change in environmental impacts in the U.S. and the impacts associated with the construction of a transmission line to return the Entitlement to Oliver would be avoided. BC could use the money to acquire resources as necessary to replace the

Entitlement return. Decisions on the amount, type, and timing of these acquisitions would be considered in BC's resource planning process. The potential environmental impacts would then be subject to analysis in the Province's environmental review processes.

Acquire Either Capacity or Energy. Acquiring only the capacity portion of the Canadian Entitlement and returning the energy portion to Canada, or pursuing the purchase of the energy separately and leaving the capacity in BC are potential options. If, in the future, operation of the hydroelectric system in the U.S. changes as a result of the System Operation Review, the capacity element of the Canadian Entitlement could become more attractive. Transmission construction requirements are expected to be minimal for returning only the energy portion of the Entitlement. Providing BC with access to the Intertie is also a potential component of any resolution of the Canadian Entitlement return obligation.

Acquire resources in BC. The U.S. could acquire enough resources in BC to satisfy the U.S. obligation for the Canadian Entitlement. Numerous hydro projects in British Columbia, including new hydro and additions at existing hydro projects, have been identified for future development. Independent power producers in Canada have identified gas-fired combined-cycle CTs and cogeneration projects. And, although there are plans to capture one-half of the economic conservation in BC over the next 20 years, the remaining cost-effective conservation could be acquired by the U.S. to discharge the Entitlement return obligation.

4.5 Resource Acquisition

Approaches

An approach that will allow BPA to obtain sufficient cost-effective resources to meet its need while, at the same time, retaining the flexibility to respond to the uncertainties surrounding resource supply and load growth must be a fundamental part of BPA's resource acquisition process. As part of this strategy, BPA will rely on a variety of resource acquisition approaches, including competitive bidding, billing credits, and targeted acquisition. Any of these approaches could be used to implement the alternatives in the RPEIS.

Competitive Bidding

Competitive bidding can be used to acquire both generation and conservation resources. Using a competitive solicitation, BPA could select proposals for new resources and firm power offers based on the amount of firm power needs indicated in the solicitation. In some cases, the identification of desirable resource characteristics may influence the type, size, and location of resources that are offered to, or requested by, BPA. In other cases, to provide a wide range of choices for meeting resource needs, the solicitations may be unrestricted in terms of eligible resource size or technologies.

Billing Credits

Billing credits are a means of paying for resources developed and owned by BPA's customers. They are based on the premise that independent utility action to develop conservation or generation resources reduces BPA's need to acquire resources. Section 6(h) of the Northwest Power Act directs the BPA Administrator to grant billing credits to customers upon request for resources that reduce BPA's obligation to serve loads. BPA may grant billing credits to eligible

customers for conservation, retail rate structures, and renewable, multipurpose, and conventional generating resources.

Targeted Acquisitions

BPA has tested a targeted acquisition program for selected conservation resources. In the targeted acquisitions program, BPA purchases verified savings from comprehensive (installation of all appropriate, cost-effective measures) utility designed and operated energy efficiency programs. Under the current program, utilities provide a description of the resource to BPA. The description must contain sufficient detail for BPA to understand the resource offered and to approve the evaluation plan. BPA may expand the targeted acquisition concept to address additional conservation or generation potential.

Process

Experience throughout the utility industry has shown that solicitations for resource acquisitions usually result in offers totaling many more megawatts than needed to satisfy the request. Therefore, BPA's resource acquisition process must insure that the most cost-effective, reliable, and environmentally sound resources are selected no matter which approach is used. BPA will generally select the lowest-cost set of resources consistent with the acquisition goal. Not all cost considerations can be quantified in monetary terms, however, so variances may occur to account for risk, system diversity, non-quantifiable environmental effects, and other factors.

BPA tested its resource acquisition process as part of the 1990 Resource Program. The general process (which would be the same for all approaches) is multi-stage, with each stage involving a more rigorous evaluation than the previous stage.

- ◆ Identify resource acquisition needs in the biennial Resource Program.
- ◆ Issue a resource solicitation, specifying the technical, economic, and environmental criteria, such as requiring a demonstration that a hydroelectric project is not located in Protected Areas designated by the Council.
- ◆ Evaluate the proposals against the published criteria, requesting additional information if necessary.
- ◆ Identify the most promising resource proposals (the "short list") for a more thorough evaluation, including additional price and non-price analysis.
- ◆ Discuss the proposals on the short list with the sponsors. During the discussion stage, determine the status of environmental review and documentation for each proposal.
- ◆ If discussions are successful, initiate letters of intent to sign a contract, pending completion of environmental review.
- ◆ Complete environmental analysis and documentation for each proposal.
- ◆ Based upon a consideration of the environmental review for each proposal, determine whether or not to sign a contract.

Other Approaches

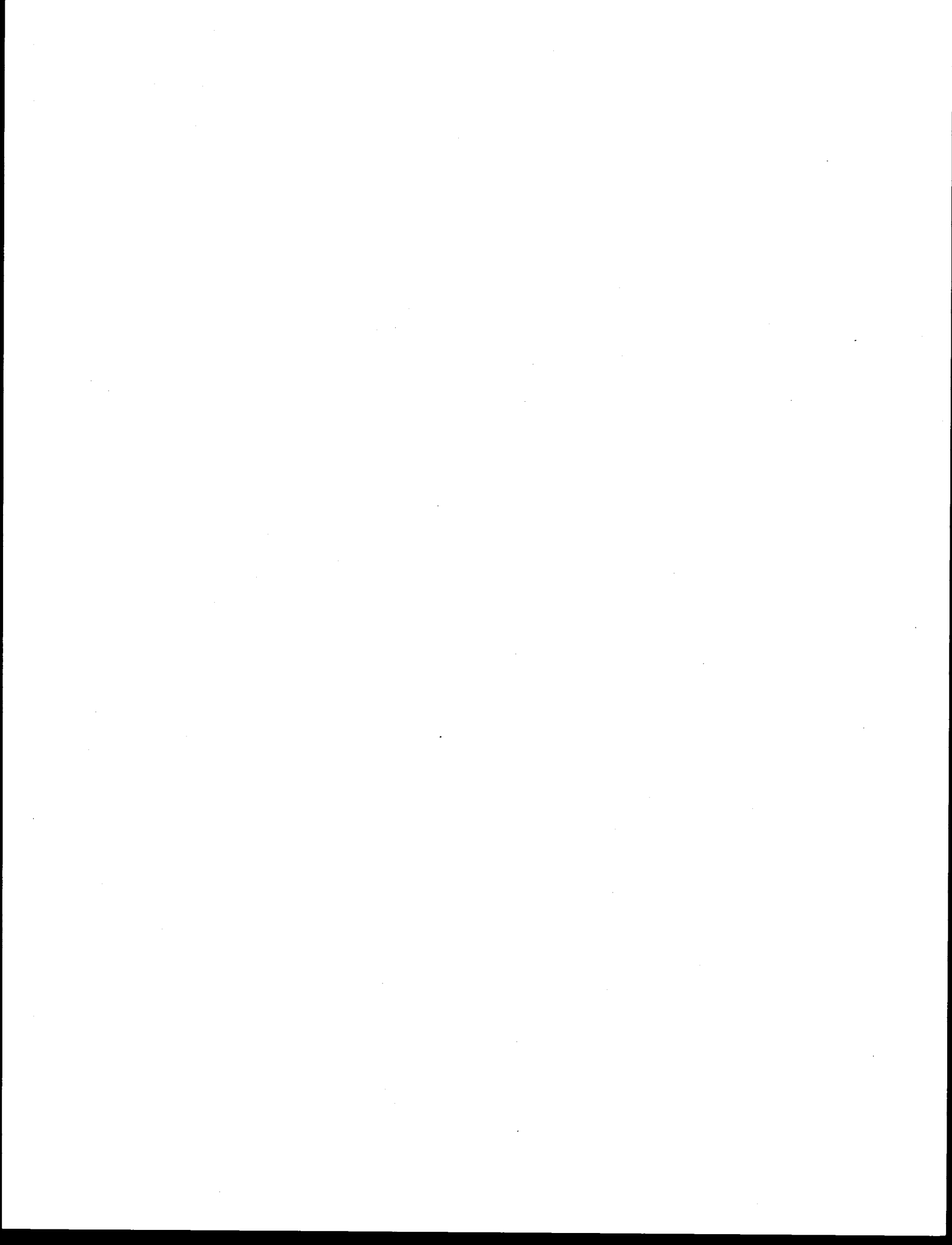
This resource acquisition process does not foreclose the use of other approaches. Unsolicited proposals for resources that are highly attractive, based on cost-effectiveness, and that are reliable and environmentally sound may be acquired by BPA using the same general multi-stage process without issuing a solicitation. Exchanges and other interregional transactions are another potential source of acquisitions. In addition, the RSEP is expected to identify additional conservation and renewable resources that can be considered for acquisition. BPA is also exploring a separate approach for pursuing cogeneration.

4.6 Resource Contingency Plan

The Resource Contingency Plan (RCP) is a key element in BPA's resource planning to reduce the risk of deficits. Although higher than expected loads, sustained critical water conditions, loss of hydro system flexibility, or other large, unforeseen resource losses are unlikely, they all pose a risk. The RCP allows BPA to take actions, at a reasonable cost, to reduce exposure to this risk.

The RCP was conceptualized as a means to obtain options on firm energy that could shorten the lead time normally required to bring cost-effective resources on line. Although options on CTs and displaceable purchases were initially envisioned, the scope of potential options was expanded as BPA learned more about the availability of resources for optioning. All of the resources under consideration for optioning are included in the RPEIS analysis.

The 1990 Resource Program identified an 800 aMW contingency plan. An additional 250 aMW of firm energy options are under consideration in BPA's 1992 Resource Program. The RCP is likely to be a strategy in future Resource Programs, also.



Environmental Consequences of Adding Resources to the System

Chapter 5

Chapter 5

Environmental Consequences of Adding Resources to the Existing System

This chapter assesses the regional environmental impacts of acquisition and operation of new resources and load reduction options. The specific environmental impacts associated with future power resource development cannot be determined because resource mixes (i.e., proportions of new generation to be contributed by each resource type) and locations are not known. Instead, this analysis evaluates maximum potential impacts by assuming that the complete supply of each resource type would be acquired, up to the 5,000 average megawatt limit of BPA's high load growth forecasts. It is, therefore, unlikely that any of the alternatives described in this chapter would actually occur. Future acquisition of resources is likely to be made up of some combination of the resources and options described in this draft EIS.

Because the analysis in this EIS addresses maximum potential impacts, the actual impacts of the mix of resources BPA actually acquires are likely to fall within the parameters of the impacts addressed in this document.

5.1 Modeling and Analysis

Several modeling tools were used to develop and analyze the alternatives.

The Integrated System for Analysis of Acquisitions (ISAAC) was used to model resource acquisitions and operations, and to estimate the economic impacts of the alternatives for this EIS.

External Environmental Costs

An ISAAC postprocessor was developed to calculate the external environmental costs of each alternative. Environmental costs were not included as resource costs in the ISAAC model itself; their inclusion would have affected the dispatch of resources during the model's resource operations phase. The postprocessor applied the appropriate environmental cost estimates to the simulated operations, then added the present value of other system costs to develop a

least cost stack and for comparison of alternatives. The environmental costs estimates are unlikely, in the near-term, to be used in the dispatch and displacement of resources. In addition, BPA's environmental externality estimates are for generic resource types and are not plant- or site-specific. (See section 5.3.3 for explanation of environmental costs.)

Hydro Operations

ISAAC is a "one dam" model with limited capability to simulate hydro system operation. The System Analysis Model (SAM) simulates the operation of the existing Pacific Northwest hydro and thermal system for the various resource acquisition scenarios. SAM's hydro system operation logic allows analysis of reservoir elevations and river flows. SAM does not make decisions regarding acquisition of resources, but uses acquisitions identified by ISAAC and determines potential effects on the Pacific Northwest hydroelectric system.

Air Quality Impacts

Models were used to estimate concentrations of ozone and other air pollutants, acid deposition rates, and visibility attenuation. Because no single, comprehensive dispersion model efficiently addressed all areas, four types of models were used. All of these models were applied to four study sites that represent population and geographic features in the Pacific Northwest. These sites and other assumptions are described in section 5.2.2.4 of this chapter and in Glantz et al. 1992.

Ozone concentrations were modeled with a reactive plume model, which required detailed meteorological and pollutant characterization data for each simulation. A series of model simulations was conducted using site-specific information. The complex nature of reactive plume models, and the episodic nature of incidents of high ozone concentrations required the analysis of ozone impacts to focus on concentrations during sample episodes. Separate simulations were required for each release site and for each type of episodic condition. Resources with similar emission characteristics were modeled together. Model results estimated ozone concentrations at key locations over a mid-term range (the year 2000) and a long-term range (the year 2010). Results of these efforts are presented in section 5.2.2.4.

The Industrial Source Complex Short-Term (ISCST) model was used to study the criteria pollutants: SO_2 , NO_x , carbon monoxide, and TSP. The ISCST model generates air quality estimates and the contour plots and tables used to present concentrations. The ISCST model is a steady-state Gaussian plume model designed to estimate pollutant concentrations from a wide variety of sources associated with industrial complexes. The model is appropriate for flat or rolling terrain, urban or rural environments, and is approved by the EPA for specific regulatory applications. A series of model simulations was conducted. Separate simulations were run for each release site, type of release facility, season of the year (as emission rates vary on a seasonal basis), and pollutant of concern. Air quality impacts were examined on both a regional and local scale. Modeling results include estimates of annual average impacts, the maximum short-term impacts over the meteorological data set, and total impact from all sources at each release site.

The modeling of acid deposition required the use of a relatively sophisticated atmospheric dispersion model. Algorithms within the model simulated atmospheric chemistry processes, atmospheric transport, and pollutant diffusion.

The impacts of pollutant emissions on visibility were assessed using standard EPA visibility models (i.e., VISSCREEN and PLUVUE II). The EPA visibility models provide a relatively simple treatment of atmospheric transport, diffusion, and chemistry. These models focus on short-term incidents of visibility attenuation rather than long-term average reduction in visibility.

Economic Analysis

Regional economic values (costs) are calculated for human health effects, crop losses, and visibility reductions associated with increased air pollution from power generation sources. The economic analysis takes the physical effects data and combines it with price data (for market goods such as crops) or values produced by economic valuation studies (for nonmarket goods) to calculate the total costs associated with the environmental effects of each of the alternatives.

For example, to estimate the cost associated with increased cancer risk due to air emissions, the health risk data are multiplied by the economic (dollar) value of specific health impacts in order to calculate total social costs. An in-depth discussion of the data sources and econometrics techniques used in the economic analysis is in Appendix F.

5.1.1 Integrated System for Analysis of Acquisitions (ISAAC)

General Description

ISAAC is a decision analysis model developed jointly by BPA, the Northwest Power Planning Council (NWPPC), and others in the region to analyze resource acquisition strategies and issues. ISAAC simulates the acquisition of resources and the operation of the power system over a wide range of uncertainties, including load growth, resource supply, water conditions, fuel prices, and aluminum markets.

A typical study consists of 100 or more games, each game being a 40-year (or longer) simulation with random values for load growth, water conditions, and other factors. Results are typically reported as means over all games, with corresponding frequency distributions. ISAAC generally models the Northwest as consisting of three planning parties: BPA, the generating public utilities (GPUBs), and the investor-owned utilities (IOUs). ISAAC is an energy model and runs on a four-season basis defined by flows in the system. The four seasons are September through December, January through April, May (the period for peak runoff and fish migration), and June through August.

ISAAC models the Northwest's electric system in terms of seasonal energy needs only. ISAAC does not deal with capacity. In the past, the Northwest hydro system provided BPA with a large capacity surplus; therefore BPA did not address capacity issues in its planning processes and ISAAC was developed to model energy needs only. Now, however, BPA's capacity surplus is limited. BPA has developed the Power Marketing Decision Analysis Model (PMDAM) to model the entire West Coast electric system. PMDAM does account for capacity and is used by BPA for analysis of capacity issues. In future Resource Programs, BPA analysis will more fully integrate energy and capacity planning using both ISAAC and PMDAM.

The model reports capital costs, system operating costs, and extra-regional revenues, as well as revenue flows between the Northwest parties. ISAAC also

shows how often particular resources are acquired over a multi-game study and how often those resources are dispatched.

Inputs to ISAAC include a distribution of the load forecast covering the BPA low to high forecasts, new resource supply estimates (cost, availability, lead times, etc.), aluminum industry data (price forecasts and plant capabilities), California market conditions, extra- and intra-regional contracts, and cost and performance characteristics of the existing hydro and thermal resources.

5.1.2 System Analysis Model (SAM)

SAM is a simulation model developed jointly by BPA and other Pacific Northwest utilities to evaluate planning and operation of the coordinated hydroelectric system of the Pacific Northwest and British Columbia. SAM analyzes how existing and projected resources can be operated most efficiently to meet load, taking into account a variety of system operations constraints. Additional constraints were added to the model and, in some cases, existing constraints were modified to simulate the effects of resource decisions and resource operations.

SAM simulates the dispatch and operation of Pacific Northwest resources. If additional energy is available, and if a market exists in California to purchase that surplus power at prices economical to both regions, SAM markets the surplus power to California, up to available intertie capacity. Appendix D contains more detailed information on SAM.

5.1.3 Hourly Operations and Scheduling Simulator (HOSS)

The first version of an hourly model--HOSS--that works in coordination with SAM is currently being developed by BPA. HOSS will provide the ability to analyze capacity issues in detail, studying the effects of changes in the configuration of the Pacific Northwest system or changes in its operating policies on hourly streamflows, generation, and the amount of sustained peaking capacity the system can produce.

5.2 Power System Operations

5.2.1 Hydro System Operations

Changes in several hydro system parameters were assessed to determine the potential effects of different resource acquisitions on hydro system operation and the resulting effects on fish and wildlife. These include the probability of system refill, total system energy content, reservoir elevations at four major Federal storage reservoirs (Libby, Hungry Horse, Grand Coulee, and Dworshak), Columbia and Snake River flows, and system overgeneration or "spill" (see section 5.2.1.5).

BPA's decisions on resource acquisitions do not affect the Pacific Northwest Coordination Agreement (PNCA) planning process or the guidelines for system operations established by it. See Appendix E for a summary of hydro system planning and operation.

5.2.1.1 Analytical Methods

Development of Scenarios

It is likely that a variety of new resources will be acquired to meet load growth in the Pacific Northwest. The alternatives modeled in ISAAC for this EIS are comprised of resource combinations. These combinations have resource additions for each year, a monthly shape for each resource, and a resulting system load/resource balance for each year. Therefore, for a given alternative, each year of a 40-year study period may have a different amount, type, and shape of resources, as well as a different load/resource balance. Because so many parameters are changing at one time, it is difficult to determine which characteristics of the new resource additions have the greatest potential to affect existing hydro system operations. In order to explore the relationship between resource additions and hydro system operations, scenarios were constructed to evaluate a variety of resource characteristics.

Resource additions interact with the existing hydro system in two major ways: (1) by changing the shape and amount of firm load the hydro system is used to meet (residual hydro load); and (2) by changing the availability and use of nonfirm energy produced by the hydro system. Resource characteristics that affect the residual hydro load include the magnitude and monthly shape of new resource power. Those that most affect nonfirm use are displaceability and resource operating cost. The scenarios were developed based on the resource and system characteristic of magnitude, shape, operating cost, and overall load/resource balance. These characteristics were incorporated into scenarios to evaluate the effects of resource additions on hydro system operations. The scenarios are presented in Figure 5-1.

Figure 5-1
Scenarios for Hydro System Studies

Summary of Scenarios for Hydro System Studies With 1,000 MW and 5,000 MW of Resource Additions			
BASE CASE = EXISTING SYSTEM			
RESOURCE TYPE:	NON- DISPLACEABLE	MEDIUM-PRICED DISPLACEABLE	HIGH-PRICED DISPLACEABLE
SHAPE: Flat	√	√	√
Maintenance April 16 - May 31	√	√	√
Shaped September through April	√		√
Surplus 500 MW	√	√	√

Magnitude. Both the size of a new resource and the total number of new resources added affect hydro system operation. As greater total amounts of resources are added to the existing system, the potential for effects on the hydro

system is increased. Also, a resource that is large in size or requires a long lead time to develop (a nuclear generating facility, for example) is likely to result in a firm power surplus when it first comes on-line. This surplus may be used to displace higher-cost resources or may be sold outside the region. SAM operates the hydro system differently in surplus conditions; typically, surplus energy from future years is shifted into the present year to increase operating flexibility or to enhance marketing opportunities. This also reduces the surplus that must be accommodated in future years.

For this hydro system analysis, minimum and maximum levels of resource acquisition were considered:

- ♦ 1,000 MW
- ♦ 5,000 MW

and two levels of load/resource balance were considered:

- ♦ load/resource balance
- ♦ 500 MW surplus

Short-term load/resource deficits are addressed by short-term power purchases to keep the hydro system within its established operating limits. These short-term deficits are not evaluated in this analysis.

Monthly Shape. To the extent that the monthly shape of resource additions differs from the monthly load shape of added loads, hydro system residual load shape will change. This residual load shape, in turn, affects hydro system operations.

For the hydro system analysis, three different monthly resource shapes were considered that covered the range of expected potential resource additions:

- ♦ **Flat.** Energy is available in equal monthly amounts (uniform).
- ♦ **Shaped with a maintenance outage in April and May.** This shape is typical of many Pacific Northwest thermal plants.
- ♦ **Shaped with energy available during September through April of each year.** This could be the shape of some imports.

Displaceability/Operating Cost. The extent to which new resources are displaceable and are economic to displace with nonfirm hydro power may affect uses and sales of nonfirm energy. The operating cost of a resource is a major factor in determining how frequently it will actually be displaced.

For this hydro system analysis, three levels of displaceability were considered that cover the range of expected potential resource additions:

- ♦ **Non-Displaceable.** These resources will run regardless of the amount of nonfirm available. Included in this group could be nuclear plants, conservation, and some imports.
- ♦ **Medium-priced Displaceable.** These resources would not normally be displaced because their operating costs are relatively low. In abundant water years, however, they could be shut down.

- ♦ **High-priced Displaceable.** These resources use fairly expensive fuels and are therefore typically run only occasionally or for brief periods. Combustion turbines are an example of this type of resource.

The scenarios evaluated to determine potential effects of additional new resources on the hydro system are presented in a matrix, Figure 5-1.

Study Methodology

For each scenario, a fixed amount of resources and load was added to the existing power system. SAM then simulated the system with the added loads and resources for a 5-year period. Operation was simulated 50 times for each study case, each time with different water conditions. This allowed analysis for each of the 50 historical water years for which detailed records are available. Further details regarding study assumptions are provided in Appendix D.

To better understand the effects of different resource acquisitions over a variety of operating conditions, hydro system data are grouped according to water condition whenever possible. Low water conditions (approximately the lowest 10 percent of the 102-year record) are considered to be those years with a January-July runoff forecast at The Dalles of less than 70 million acre-feet (MAF). In the historical flow information used by SAM, this group includes the 1929, 1930, 1931, 1937, 1941, and 1944 water years. The high water group (approximately the highest 10 percent of the 102-year record) is typical of water years 1948 and 1956, in which the January through July runoff at The Dalles exceeded 125 million acre-feet. All other water years are grouped together and are termed "typical" or "average" water conditions in the following discussion.

5.2.1.2 System Refill

The amount of water stored in the hydro system at the end of each refill season (usually the end of July) is available for power production and non-power uses during the remainder of that year or the following year. Hydro system operation after mid-January is based on the runoff forecast in order to enhance the probability of refill while meeting firm loads. To the extent that resource acquisitions would affect hydro system refill, reservoir uses, such as recreation and resident fisheries, as well as service to BPA's customers, may be affected.

System refill data for five years from the SAM studies were used to assess the potential for changes in system refill. The system is considered to have refilled if, at the end of July, system storage content is 94 percent of total possible system storage. The 94 percent figure is essentially the same for both the SAM studies and for adoption of first-year firm energy load carrying capability (FELCC) in Pacific Northwest Coordination Agreement (PNCA) planning, and is used to determine the next years' rule curves.

For the existing system, probability of coordinated system refill ranges from about 86 to 92 percent, depending on the study year. The average probability of system refill is 87.6 percent for the five years studied. Similar ranges and averages occur for most scenarios studied. Two scenarios--the Non-Displaceable case and the High-Cost Displaceable case--result in a somewhat lower probability of refill, with 5,000 MW of resource additions shaped into the September through April period. In these cases, the hydro system is not expected to refill about 18 to 19 percent of the time (compared to 13 to 15 percent of the time for other scenarios) if large amounts (5,000 MW) of shaped resources are added to the system.

5.2.1.3 System Draft and Reservoir Elevations

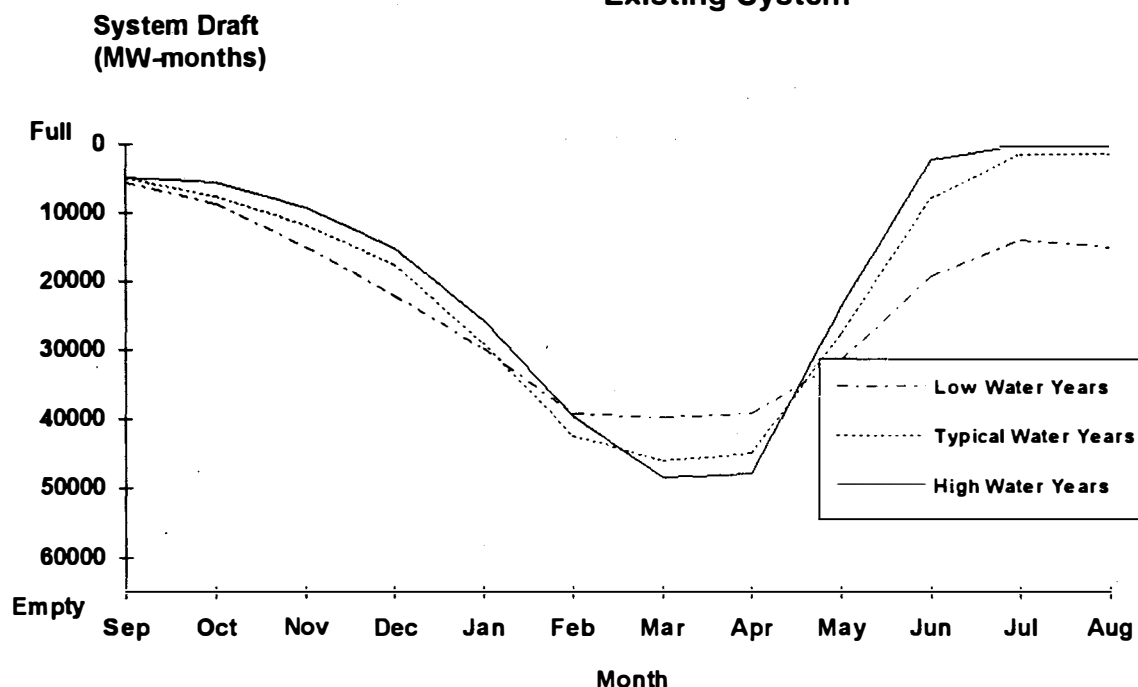
System Draft

System draft is a measure of how far below full (in megawatt-months) the total usable storage content is. Total available Pacific Northwest coordinated system draft is approximately 65,000 megawatt-months. The smaller the system draft, the greater the amount of water remaining in the system. These data represent the total hydro system, whereas reservoir elevation data are project-specific.

Figure 5-2 depicts typical system draft shape for low, typical, and high water years. The greatest system draft occurs during the spring months in high runoff years due to flood control requirements. In low runoff years, spring draft occurs primarily to serve load and provide water for the Water Budget. In this figure, the system in low water conditions does not draft as deeply as in higher water conditions; however, the ability to refill is limited due to the low runoff available for refill.

In most scenarios analyzed, there was little change in annual average system draft over all water conditions. Most scenarios indicated the same or slightly higher reservoir content would occur if 1,000 MW of new resources were added, regardless of type, as long as the system stayed in load/resource balance. The situation is similar for the 5,000 megawatt resource addition scenarios, although the changes are somewhat larger and more variable between years. In all scenarios with 500 MW of surplus (including the existing system with a 500 MW surplus), system draft was greater than in those scenarios in load/resource balance. In some cases, the additional draft reached 2,000 to 4,000 megawatt-months, on an annual average basis, over the 50 water years studied. This added average draft is the result of shifting and shaping of firm energy from future years into the fall period of the current year. This shifting is discretionary; SAM allows this shifting when there is a firm surplus, but not when the system is in load/resource balance. The draft, therefore, may or may not occur, and is not an inevitable result of the resource additions.

Figure 5-2
U.S. Hydro System Draft
Existing System



Reservoir Elevations

Addition of resources may influence reservoir elevations and affect reservoir uses. However, flood control and PNCA planning requirements would not be affected, as these operating constraints take precedence. Changes in reservoir elevations may affect resident fish, wildlife, recreation, irrigation, and cultural resources. These environmental effects are discussed in sections 5.3 and 5.4.

Throughout the year, reservoir elevations tend to be shaped similar to Figure 5-2 for system draft, where zero represents a full reservoir. As resources are added to the existing system, the use of hydro system resources may change, depending on the characteristics of the added resources. For example, importing power during specific time periods may cause the hydro system to be used less during those periods and more during other periods when imported energy is not available.

Some trends emerge when examining the effects of resource additions on reservoir elevations. Those trends relate to water condition, level of resource development, monthly shape of the resource, and the amount of energy shifting and shaping that occurs. How these trends relate to the resource scenarios is described below.

Water Condition

In most cases, the greatest changes in reservoir levels occur in low runoff years, with smaller changes in typical runoff years, and lesser effects in high water years. This is particularly true during the summer months, when reservoirs fill in high water years in all scenarios.

Level of Resource Development

As may be expected, greater changes in reservoir levels occur when 5,000 MW of new resources are added than when 1,000 MW are added. This is due primarily to the larger differences between monthly loads and monthly resource availabilities that occur in the 5,000-MW scenarios.

Resource Shaping

Reservoir elevation results indicate that resources that are heavily shaped, such as the scenarios with the entire resource addition shaped into the September through April period, can result in substantial changes in hydro system operations. The SAM studies did not impose project-specific constraints to limit the amount of hydro system draft to meet regional firm loads. In the SAM analysis, as long as the hydro residual load (the amount of regional load less non-hydro resources) can be met on an annual basis, it assumes the load can be met on a monthly basis as well. In actual operations, however, project owners impose constraints on project operations to power and non-power requirements. These project operating requirements limit the amount of hydro energy that can be produced in each month and are intended to protect non-power uses of reservoirs. The tradeoffs between power production and non-power requirements for reservoirs is being addressed in the System Operation Review (SOR) EIS.

Energy Shifting

Energy shifting is the process of producing as much firm energy in the current year as possible while giving up rights to firm energy in future years if the hydro system fails to refill at the end of the year. Typically, the additional firm energy will be produced in the September through December period. SAM will shift energy from future years into the current year for three reasons: (1) to cover a deficit in the current year; (2) to shift as much surplus as possible from future years into the current year; or (3) to cover a portion of the direct service industries' (DSI) first quartile load.

In the RPEIS studies, SAM shifted more energy in those cases with a firm surplus than in those with a load/resource balance. This results in additional reservoir drafts in those scenarios with a firm surplus. The RPEIS scenarios are very similar to the study of the existing system with 500 MW of firm surplus.

Somewhat lower reservoir levels occur with higher-priced displaceable resources than with either non-displaceable or medium-priced resources, since it is more economic to draft reservoirs for power production than to generate using high cost displaceable resources.

Shifting is currently done each year in the annual planning process under the PNCA. It is expected that this practice will continue regardless of future resource additions. The impact of operating practices and non-power requirements on reservoir uses is being examined in the SOR EIS.

Summary of Potential Effects of Resource Additions on Reservoir Operations

Adding new resources may affect hydro system operations primarily by changing the shape of the load the hydro system is used to meet. The more closely resource additions match increased loads in magnitude and shape, the smaller the hydro system impacts are expected to be. The magnitude of potential impacts of resource additions on non-power uses of the hydro system is limited by non-power operating requirements. These requirements are being examined in the SOR EIS.

5.2.1.4 Columbia and Snake River Flows

The acquisition of new resources may affect operation of the hydro system, and, potentially, the flows of the Columbia and Snake Rivers. The following discussion outlines the general shape and magnitude of potential flow changes that could result from the scenarios analyzed. The scenarios studied result in little or no change in flows on the Snake River. Therefore, the following discussion refers to flow changes on the Columbia River that are the same for the mid-Columbia at Priest Rapids as well as the lower Columbia at The Dalles (below the confluence of the Snake River). The effects of flow changes on anadromous fish survival are discussed in section 5.4.2.

As expected from the SAM results for system draft and reservoir elevations (discussed in section 5.2.1.3), the greatest changes in flow result from scenarios with the greatest shaping of generation. In general, relatively small flow changes occur for those scenarios with flat resource additions. Some changes in flow do occur because the added load is shaped, while the resource addition is flat, resulting in a slightly different load shape for the hydro system to meet. These changes are relatively small, generally less than 5 thousand cubic feet-per-second (kcfs). This change occurs regardless of resource type added. In addition, in typical water years, scenarios with high-variable-costs resources tend to conserve water in the hydro system in January and February in order to avoid having to run a large amount of high-cost resources later in the year. This results in lower flows in the winter (up to about 20 kcfs) and higher flows in the spring and summer (up to about 10 kcfs).

As more shaping of resource availability occurs, there is a greater amount of shaping in the load the hydro system is required to meet. This results in fairly large flow changes in some scenarios. The greatest flow changes due to this type of shaping occur in the scenario with 5,000 MW of new resources (annual average) shaped into the September through April period (Imports Alternative). As would be expected, flows are reduced during September through April and increased during May through August. The largest changes typically occur in low runoff years, with reductions on the order of 15 to 20 kcfs, and increases on the order of 40 to 50 kcfs.

Other scenarios with shaping result in smaller flow changes that may still be important from an environmental point of view. The scenarios with maintenance in April and May result in higher flows those months, with slightly lower flows the remainder of the year. Those scenarios that have surplus firm energy result in shifting energy as discussed in section 5.2.1.3. Flows are then increased September through December and decreased the remainder of the operating year. The results of the firm surplus scenarios are equivalent to the existing system with a firm surplus assumed.

The extent to which the hydro system can be shaped is limited by many constraints, including those to protect non-power uses. Evaluation of the effects of these constraints on hydro system operations is being conducted in the SOR EIS. It is quite likely that the hydro system cannot and will not be able to shape as much as is indicated in these scenarios.

5.2.1.5 Overgeneration

Spring runoff usually provides more energy than can be used in the Pacific Northwest. Much of this energy is stored or sold outside the region, and the remainder must be spilled. The water which is spilled due to lack of available market is called "overgeneration." Overgeneration spill can help anadromous fish bypass turbines and spill can be moved on the system to where it can be most beneficial to fish. Potential effects of the resource acquisition scenarios on anadromous fish are discussed in section 5.4.2.

SAM was used to project monthly amounts of overgeneration in megawatts for the resource acquisition scenarios. Results of 50 simulations were averaged to obtain average monthly overgeneration amounts for each of the five years in the studies. Differences between scenarios were analyzed to determine the effects of resource additions on system spill.

Overgeneration varies greatly between years, but averages about 150 MW annually over a 5-year simulation period. In the existing system, almost 80 percent of the overgeneration occurs in May, June, and July.

Unlike the results for reservoir operations, which depend primarily on the shape of the resource addition rather than the type of resource, changes in overgeneration result from displaceability of the added resource, as well as its size and shape.

In the hydro system analysis, the addition of non-displaceable resources has the least impact on overgeneration spill, although the shape of the resource addition does have some influence on the monthly shape. For example, those scenarios with new resource maintenance in April and May show reductions in overgeneration during those months. The greatest effects occur from adding large amounts of both medium- and high-priced displaceable resources (coal, and potentially CTs and imports). In those scenarios, overgeneration is virtually eliminated in all months except for a small amount remaining in June. This is because water that would otherwise be spilled can be used to produce generation and displace the more expensive resources.

5.2.1.6 Comparison of Resource Acquisition Alternatives and Hydro System Analysis Scenarios

The alternatives each emphasize a different resource from the resource stack. A variety of resources were acquired in all of these alternatives. However, the amounts and kinds of resources acquired vary between alternatives. In contrast, the alternatives examined to evaluate potential effects of new resources on hydro system operation focused on resource characteristics rather than specific resources. The questions, then, are (1) how do the resource stacks examined in the acquisition alternatives relate to the resource characteristics in the hydro system analysis, and (2) what environmental effects may result from changes in hydro system operation to accommodate the new resources.

Resource shaping throughout the year affects operation of the hydro system and the region's load/resource balance. In general, the greater the amount of shaping

and the greater the amount of surplus, the greater the potential for effects on hydro system operations and the environment.

Resource acquisition alternatives were examined for two years, 2000 and 2010, with particular attention to alternatives that may involve a lot of shaping, or which create a regional load/resource balance that is surplus. In the year 2000, the Conservation, Combustion Turbine, and Base Case Alternatives all have the same load/resource balance, and all are surplus. All other alternatives are closer to load/resource balance and may, therefore, have less effect on the hydro system compared to the existing system. Those alternatives with large amounts of generation that may be down for maintenance during a portion of the year (e.g., Coal, Clean Coal, Nuclear) may have impacts due to shaping. The smaller the unit sizes and the shorter the maintenance outages, the fewer the impacts. The Emphasize Imports Alternative could have major effects on the hydro system, depending on the shape of the import. In the hydro system alternatives, 1,000 MW of resources were shaped into the September through April period, which resulted in fairly large changes in Columbia River flows under some conditions.

In the year 2010, most of the Resource Acquisition scenarios were similar. The Coal, Clean Coal, and Cogeneration Alternatives, however, increased surplus approximately 450 MW beyond the surplus achieved under the other scenarios. These simulated operations would not be permitted if they would significantly and adversely impact the use of the river system for other authorized purposes or for fish. Instead, the region would incur costs for avoiding such impacts, most likely by paying for but not running the resources. Resource shaping is also a consideration that may result in impacts in the Coal, Clean Coal, Nuclear, and Import Alternatives.

5.2.2 Thermal System Operations

5.2.2.1 Modeling Thermal System Operations

Information on fossil-fuel thermal plant operation was provided by output from BPA's ISAAC model. Two types of ISAAC files were provided for each resource alternative. One provides the average megawatts produced by existing and acquired coal plants, nuclear plants, and combustion turbines. The second identifies when new plants are acquired and reports the average megawatts available from all types of new energy resources, including conservation, renewables, and cogeneration. These files were combined to determine the total mix of energy resources. This combined picture is used to calculate the environmental impacts discussed in this chapter, including air quality, employment, land use, water consumption, and water effluent.

5.2.2.2 Annual Change in Regional Thermal Generation

The thermal generation analysis focuses on the years 1991, 2000, and 2010. It is based on total regional energy availability, regardless of which utilities or agencies operate the plants or programs. Energy is acquired based on cost, with least-cost plants or programs used first.

The thermal power plants examined include up to two natural gas-fired combined cycle combustion turbines (CCCT); eight natural gas-fired cogeneration facilities; five conventional coal-fired power plants; five atmospheric fluidized-bed coal-fired power plants; five integrated gasification coal-fired power plants; four nuclear power plants; and power generating facilities outside the BPA service region.

Some new power plants, such as the coal plant in eastern Washington, are used in all resource alternatives. Other power plants are used in only one or a few alternatives. The atmospheric fluidized-bed and gasification coal-fired power plants, for example, are only used in the Clean Coal Alternative.

Cogeneration facilities were assumed to always operate at maximum capacity with a cost below that of coal-fired power plants. CT plants are assumed to always be more expensive to operate than coal-fired power plants; it is also assumed that there are no significant cost differences between CT plants operating on the west versus east side of the Cascade Mountain Range. For the Imports Alternative, power from combined cycle combustion turbine plants within BPA's service region is assumed to be cheaper than power from similar plants located outside the region because transmission costs and line losses would be less and because Pacific Northwest plants would all be new, with state-of-the-art efficiency. The cost of power from CCCT plants in California is assumed to be less than the cost of power from Canadian plants; however, power from California plants is only available from September through April. The California plants are assumed to produce "exchange" energy and to have their capital costs embedded in rate base, whereas Canadian plants are assumed to be built for and fully paid for by Pacific Northwest ratepayers. Atmospheric fluidized-bed and integrated coal gasification plants are used only in the Clean Coal Alternative. The costs of each energy type are shown in Chapter 3.

Results of the Alternatives

The combination of thermal power plants that makes up each alternative and the power produced by each type of plant is shown in Tables 5-1, 5-2, and 5-3. Figures 5-3 and 5-4 show existing thermal power plants operations. Figures 5-5 and 5-6 show acquired thermal power plant operations.

As Table 5-1 shows, in 1991, operations of existing thermal plants would be the same in all alternatives.

Table 5-1
Regional Thermal Operations, 1991
(average megawatts)

Energy Resources	Alternatives											
	Status Quo	Base Case	Fuel Switch	Nuclear	Import	Cogen	CTs	Coal	Clean Coal	High Cons	Cons	Renew
EXISTING NUCLEAR												
Western Oregon	726	726	726	726	726	726	726	726	726	726	726	726
Eastern Washington	711	711	711	711	711	711	711	711	711	711	711	711
EXISTING COAL												
Eastern Montana	914	914	914	914	914	914	914	914	914	914	914	914
Nevada	115	115	115	115	115	115	115	115	115	115	115	115
Eastern Oregon	207	207	207	207	207	207	207	207	207	207	207	207
Western Washington	901	901	901	901	901	901	901	901	901	901	901	901
Wyoming	494	494	494	494	494	494	494	494	494	494	494	494

Table 5-2
Regional Thermal Operations, 2000
(average megawatts)

Energy Resources	Alternatives											
	Status Quo	Base Case	Fuel Switch	Nuclear	Import	Cogen	CTs	Coal	Clean Coal	High Cons	Cons	Renew
EXISTING NUCLEAR												
Western Oregon	726	726	726	726	726	726	726	726	726	726	726	726
Eastern Washington	711	711	711	711	711	711	711	711	711	711	711	711
ACQUIRED NUCLEAR												
Western Washington	0	0	0	806	0	0	0	0	0	0	0	0
Eastern Washington	813	813	0	813	0	0	813	0	0	0	813	0
EXISTING COAL												
Eastern Montana	1015	1010	1021	1006	1021	990	1011	1019	1020	1017	1010	1015
Nevada	178	176	178	173	184	170	176	158	159	176	176	175
Eastern Oregon	324	322	327	319	331	309	322	296	315	325	322	320
Western Washington	1036	1032	1040	1025	1067	1007	1033	1050	1051	1037	1032	1035
Wyoming	564	564	570	560	567	554	564	569	569	570	564	569
ACQUIRED COAL												
Eastern Montana	551	551	556	552	554	549	552	924	555	556	551	556
Eastern Washington	525	524	530	513	544	506	524	621	481	526	524	525
Eastern Oregon	0	0	0	0	0	0	0	148	0	0	0	0
Nevada	0	0	0	0	0	0	0	159	0	0	0	0
Western Washington	0	0	0	0	0	0	0	144	0	0	0	0
ACQUIRED AFB COAL												
Eastern Montana	0	0	0	0	0	0	0	0	160	0	0	0
Eastern Washington	0	0	0	0	0	0	0	0	144	0	0	0
Eastern Oregon	0	0	0	0	0	0	0	0	128	0	0	0

Table 5-2, continued:

Energy Resources	Alternatives											
	Status Quo	Base Case	Fuel Switch	Nuclear	Import	Cogen	CTs	Coal	Clean Coal	High Cons	Cons	Renew
ACQUIRED IGCC COAL												
Eastern Montana	0	0	0	0	0	0	0	0	158	0	0	0
Eastern Washington	0	0	0	0	0	0	0	0	150	0	0	0
EXISTING SCT												
Western Washington	0	0	21	2	105	3	0	0	17	12	0	5
ACQUIRED CCCT												
Combined Cycle BPA	195	184	213	0	0	0	184	96	104	213	184	212
Combined Cycle MIX	82	44	172	104	121	157	45	96	171	166	44	161
ACQUIRED COGEN	2060	2180	2180	1930	1920	3300	2180	2090	2060	2000	2180	2060

NOTE: AFB Coal = Atmospheric Fluidized Bed Coal

IGCC Coal = Integrated Gasified Combined Cycle

CCCT = Combined Cycle Combustion Turbine

SCT = Simple Cycle Turbine

Table 5-3
Regional Thermal Operations, 2010
(average megawatts)

Energy Resources	Alternatives											
	Status Quo	Base Case	Fuel Switch	Nuclear	Import	Cogen	CTs	Coal	Clean Coal	High Cons	Cons	Renew
EXISTING NUCLEAR												
Western Oregon	726	726	726	726	726	726	726	726	726	726	726	726
Eastern Washington	711	711	711	711	711	711	711	711	711	711	711	711
ACQUIRED NUCLEAR												
Western Washington	806	806	806	806	0	806	806	806	806	806	806	806
Eastern Washington	813	813	813	813	0	813	813	813	813	813	813	813
EXISTING COAL												
Eastern Montana	1022	1022	1203	1022	1029	1021	1022	1029	1029	1022	1022	1022
Nevada	180	185	185	185	190	184	185	175	172	185	185	185
Eastern Oregon	326	322	325	323	344	322	22	326	327	322	322	323
Western Washington	1071	1072	1074	1073	1086	1071	1072	1071	1074	1072	1072	1073
Wyoming	566	566	567	566	576	564	566	576	576	566	566	566
ACQUIRED COAL												
Eastern Montana	1666	1287	1290	1288	1313	1283	1287	1688	1313	1287	1287	1287
Eastern Washington	715	530	533	532	563	529	530	716	536	530	530	532
Eastern Oregon	535	530	533	532	563	529	530	697	502	530	530	532
Nevada	0	0	0	0	0	0	0	179	0	0	0	0
Eastern Washington	0	0	0	0	0	0	0	163	0	0	0	0
ACQUIRED AFB COAL												
Eastern Montana	0	0	0	0	0	0	0	0	162	0	0	0
Eastern Washington	0	0	0	0	0	0	0	0	155	0	0	0
Eastern Oregon	0	0	0	0	0	0	0	0	151	0	0	0

Table 5-3, continued:

Energy Resources	Alternatives											
	Status Quo	Base Case	Fuel Switch	Nuclear	Import	Cogen	CTs	Coal	Clean Coal	High Cons	Cons	Renew
ACQUIRED IGCC COAL												
Eastern Montana	0	0	0	0	0	0	0	0	160	0	0	0
Eastern Washington	0	0	0	0	0	0	0	0	153	0	0	0
Eastern Oregon	0	0	0	0	0	0	0	0	153	0	0	0
Nevada	0	0	0	0	0	0	0	0	153	0	0	0
Western Washington	0	0	0	0	0	0	0	0	153	0	0	0
EXISTING SCT												
Western Washington	26	24	17	25	155	1	24	0	0	2	24	24
ACQUIRED CCCT												
Combined Cycle BPA	229	230	228	229	404	0	230	210	208	219	230	230
Combined Cycle MIX	192	193	185	193	369	0	193	80	80	132	193	192
ACQUIRED COGEN	4030	4480	4070	4570	3760	5020	4480	3980	3920	4340	4480	4300

NOTE: AFB Coal = Atmospheric Fluidized Bed Coal

IGCC Coal = Integrated Gasified Combined Cycle

CCCT = Combined Cycle Combustion Turbine

SCT = Simple Cycle Turbine

Figure 5-3
Existing Regional Thermal Operations: 2000

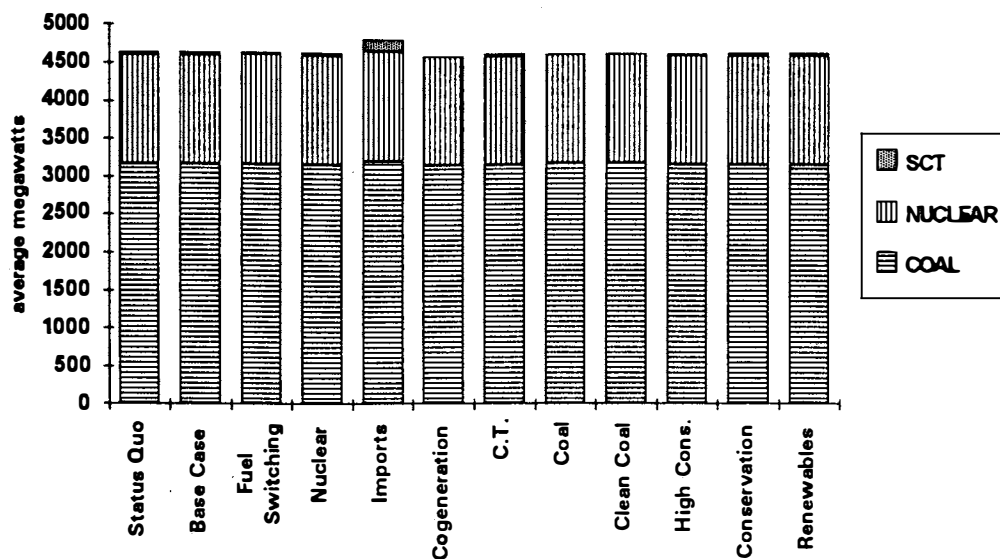
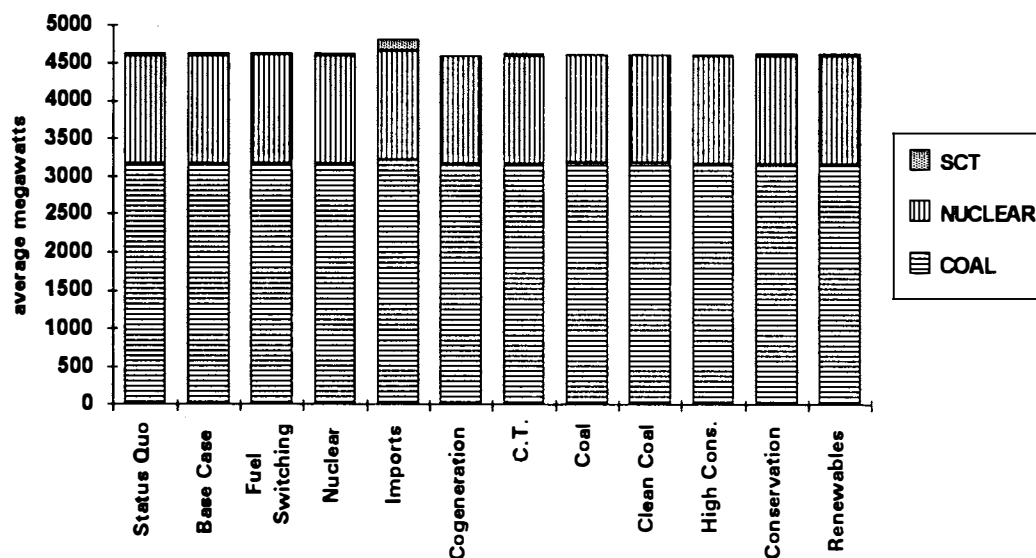


Figure 5-4
Existing Regional Thermal Operations: 2010



NOTE: Because imports were assumed to be relatively expensive and somewhat displaceable, occasionally Pacific Northwest simple cycle turbines (SCTs) are run to displace a portion of the imports.

Figure 5-5
Acquired Regional Thermal Operations: 2000

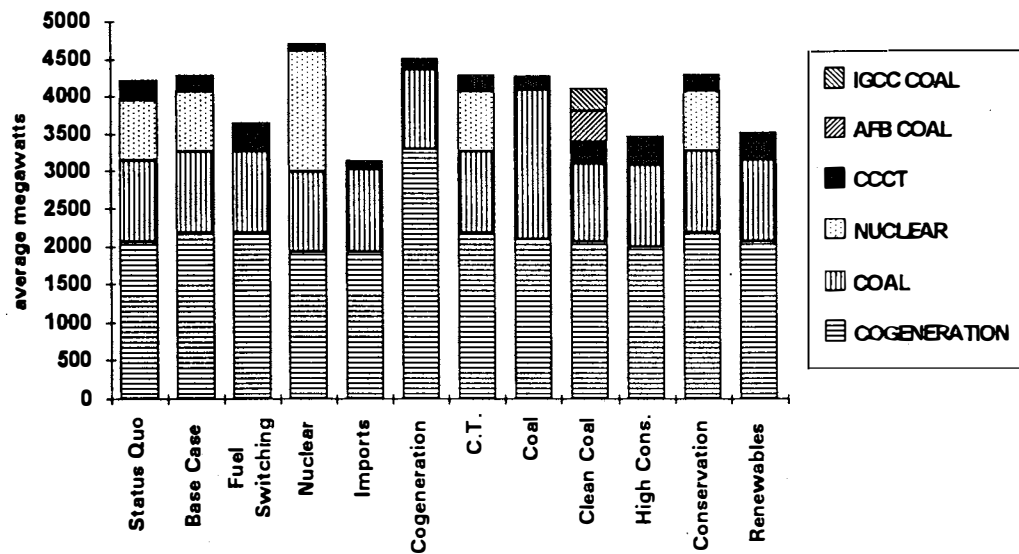
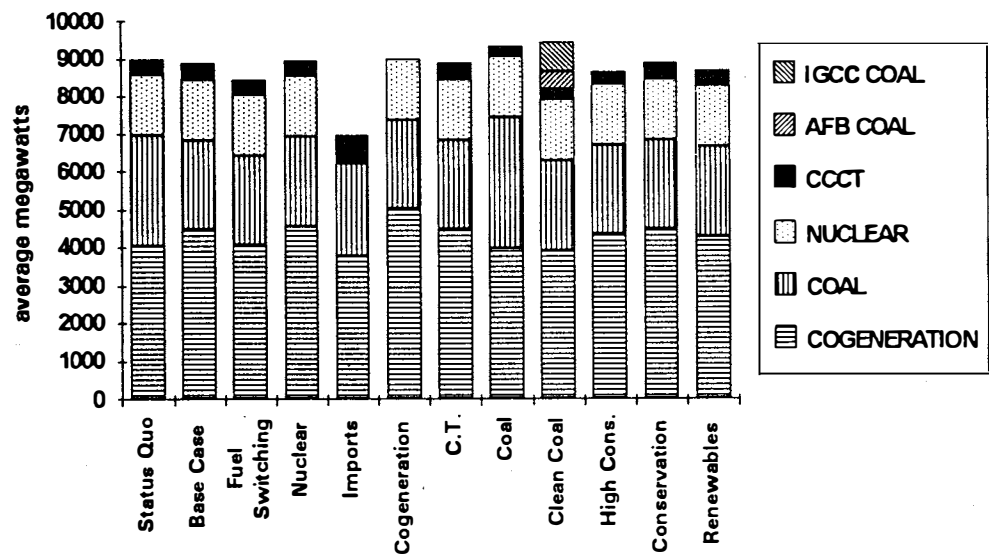


Figure 5-6
Acquired Regional Thermal Operations: 2010



5.2.2.3 Land Use and Nonrenewable Resource Consumption

Electricity generation impacts land use because of the physical location of the plant and because of mining, drilling, and exploration activities needed to supply the plant with fuel. Figure 5-7 shows the acres of land that would be occupied in order to site the power plants identified in each of the alternatives in each of the study years. A description of land use requirements is in Chapter 3. In addition to siting land use requirements, coal resources also cause permanent land use impacts from mining activities. Figure 5-8 shows the total acres of land that would be disrupted by coal mining to supply coal for each of the alternatives in each of the study years.

Figure 5-7
Land Use

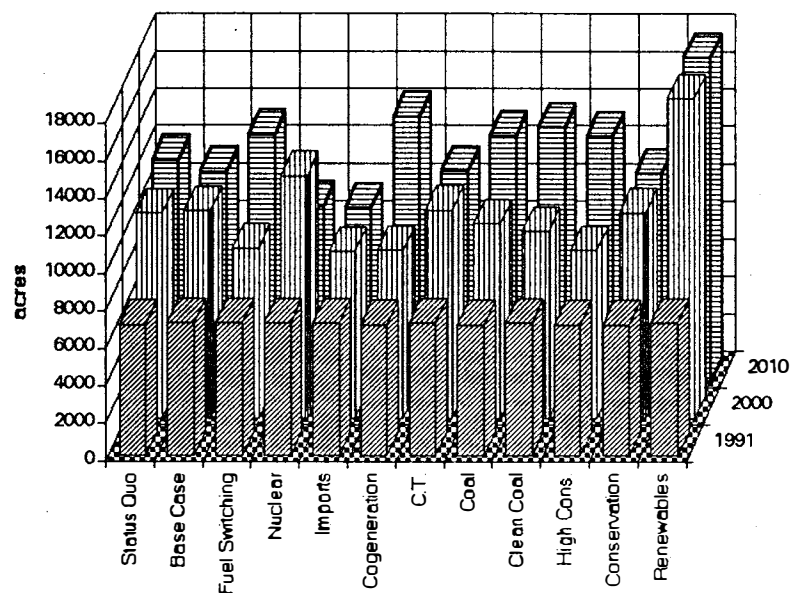
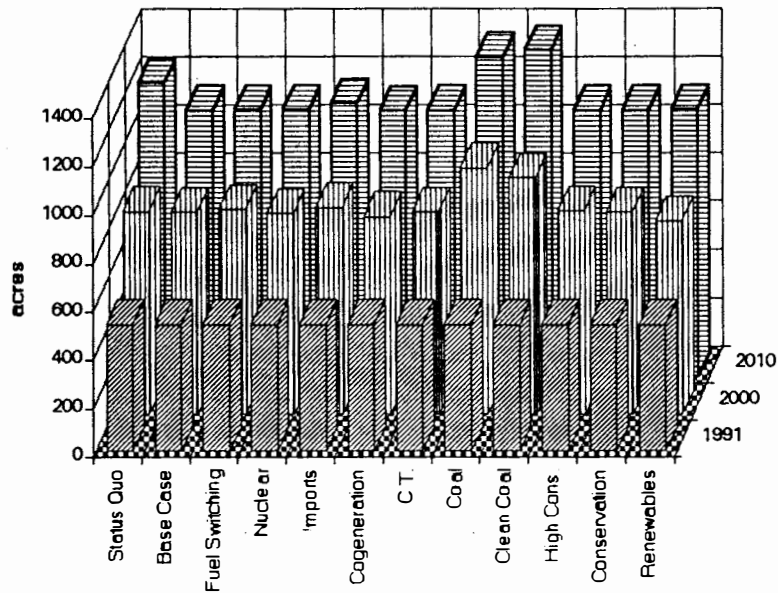


Figure 5-8
Land Use Impacts
Associated With Coal Mining in Each Alternative



5.2.2.4 Air Quality and Global Warming

Air Quality Analysis

Air quality impacts were estimated for all existing and new fossil-fuel combustion power generation facilities. The facilities are assumed to be located at four generic sites located in western Washington, eastern Washington, eastern Oregon, and eastern Montana. The projected locations of new power plants are summarized in Table 5-4.

Table 5-4
Generic Locations of New Power Generation Facilities ^a

Type of Facility	Generic Location ^a			
	Western Washington	Eastern Washington	Eastern Oregon	Eastern Montana
Conventional Coal	√	√	√	√
Fluidized Bed Coal	√	√	√	√
Gasified Coal	√	√	√	√
Combustion Turbine	√	√	⊗	⊗
Cogeneration	√	⊗	√	⊗

^a √ indicates a facility is located at the indicated site; ⊗ indicates a facility is not located there.

All existing coal-fired power plants use conventional pulverized coal technology. Atmospheric fluidized bed and integrated gasification coal plants are included only in the Emphasize Clean Coal Alternative.

For modeling purposes, all existing natural gas-fired combustion turbine plants are assumed to be located in western Washington. New combustion turbine plants are also assumed to be located in western Washington, except for the Emphasize Combustion Turbine Alternative. In this case, the plants are assumed to be split between eastern and western Washington.

There are no existing natural-gas cogeneration facilities providing power. For air quality modeling purposes, new facilities are assumed to be located in western Washington and eastern Oregon.

Data on power plant emissions used to calculate air quality impacts are shown in Table 5-5. Technical assumptions about stack height, air velocity, and other factors are listed in a separate technical report on air quality (Glantz et al., 1992).

Table 5-5
Emission Factors for Use in the Resource Program
Air Quality Analysis

Generating Resource Types	Oxides of Nitrogen (lbs/MMBtu)	Oxides of Sulfur (lbs/MMBtu)	Total Suspended Particulate (lbs/MMBtu)	Carbon Dioxide (lbs/MMBtu)
Northwest Existing Simple Cycle Combustion Turbine	0.174	0.001	0.0133 ^a	117
Northwest Existing Combined Cycle Combustion Turbines	0.174	0.001	0.0133 ^a	117
Northwest New Combined Cycle Combustion Turbine	0.174	0.001	0.001	117
Northwest New Cogeneration	0.175	0.001	0.001	117
Northwest Existing Conventional Coal	0.5833 ^a	0.774 ^a	0.030	205
Northwest New Conventional Coal	0.500	0.200	0.030	205
Northwest New Atmospheric Fluidized Bed Combustion Coal	0.134	0.080	0.015	205
Northwest New Integrated Gasification Combined Cycle Coal	0.105	0.040	0.0066	205
California Existing Combustion Turbines	0.118 ^a	0.0006 ^a	0.001	119
California New Combined Cycle Combustion Turbines	0.0275 ^a	0.0006 ^a	0.001	119
Canadian New Combined Cycle Combustion Turbines	0.174	0.001	0.001	117

^a These values are taken from the California Energy Commission, 1989, *Staff Recommendations For Generic Power Plant Emission Factors*, Sacramento, California.

Assumed fossil fuel-fired thermal power plant heat rates for the air quality analysis are as follows:

- ◆ natural gas-fired combined cycle combustion turbine - 7,620 Btu/kWh
- ◆ natural gas-fired simple cycle combustion turbine - 11,480 Btu/kWh
- ◆ natural gas-fired cogeneration - 5,017 Btu/kWh
- ◆ pulverized coal-fired generation - 10,856 Btu/kWh
- ◆ atmospheric fluidized bed coal-fired generation - 9,885 Btu/kWh
- ◆ integrated gasification combined cycle coal generation - 9,270 Btu/kWh

Combining data on the Power Generation Heat rate (shown above) and emission factors (Table 5-5) with the appropriate unit conversion factors provides the quantity of pollutant emissions (grams) released by each type of power plant per unit of energy generated (megawatt-seconds). These data are presented in Table 5-6.

Table 5-6
Quantity of Pollutant Released Per Unit of Energy Generated
 (Values are presented in units of the grams of pollutant emitted to the atmosphere for each megawatt-second of generated energy.)

Type of Plant	NO _x (g/mWs)	SO ₂ (g/mWs)	TSP (g/mWs)	CO ₂ (g/mWs)
Existing Conventional Coal	0.78	1.02	0.040	280.
Acquired Conventional Coal	0.68	0.27	0.041	280.
Atmospheric Fluidized-Bed Coal	0.17	0.10	0.019	260.
Integrated Gasification Coal	0.12	0.047	0.0077	200.
Single Cycle Combustion Turbine	0.25	0.0015	0.019	170.
Combined Cycle Combustion Turbine	0.17	0.00096	0.00096	110.
Cogeneration (natural gas) ^(a)	0.11	0.00063	0.00063	74.

(a) Emissions from cogeneration facilities only consider the increase in emissions required to generate power, it does not include the emissions required to generate heat for industrial applications.

NO_x, SO₂, and TSP Emissions

Emissions of NO_x, SO₂, and TSP in 1991 at the western Washington study site come from two coal-fired power plants.

At the eastern Oregon study site, 1991 emissions are from three coal-fired power units.

At the eastern Washington study site, there are no emissions in 1991.

At the eastern Montana study site, emissions in 1991 are from eight coal-fired power units that represent the Colstrip (4 units) and Jim Bridger (4 units) power plants.

Figures 5-9, 5-10, and 5-11 indicate that for all of the resource alternatives there will be a significant increase in emissions of NO_x , SO_2 , and TSP between 1991 and 2000. Note that the figures' scales are not consistent. The scales were adjusted to emphasize differences between the alternatives.

In the year 2000, the highest emission rates for all pollutants occur for the Coal Alternative. The next highest emission rates occur for the Imports (including emissions both within and outside of the BPA study region) and Clean Coal Alternatives. The Nuclear and Cogeneration alternatives have the lowest emission rates.

Figures 5-9, 5-10, and 5-11 also indicate that for all of the resource alternatives there will be a significant increase in emissions of NO_x , SO_2 , and TSP between the years 2000 and 2010.

In 2010, the highest emission rates for all pollutants occur for the Coal Alternative. The next highest emission rates occur for the Status Quo Alternative. The High Conservation and Cogeneration alternatives have the lowest emission rates.

Figure 5-9
Total Regional NO_x Emissions

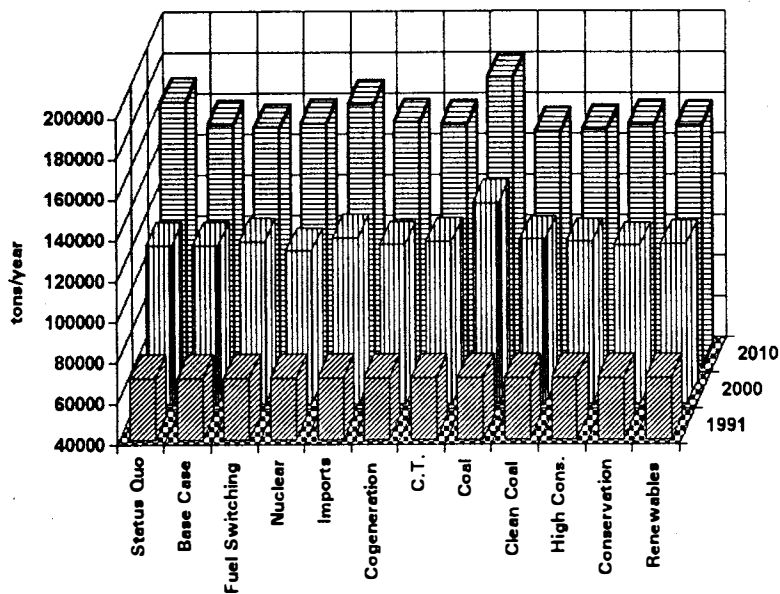


Figure 5-10
Total Regional SO₂ Emissions

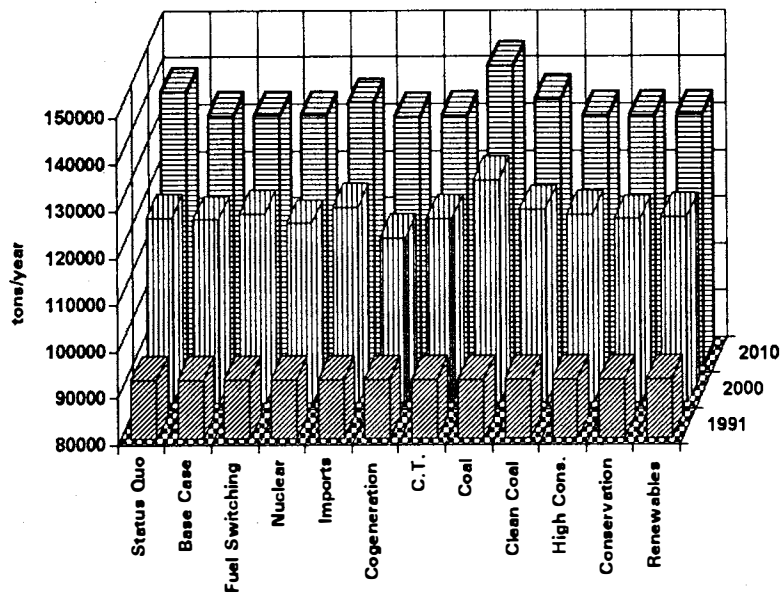
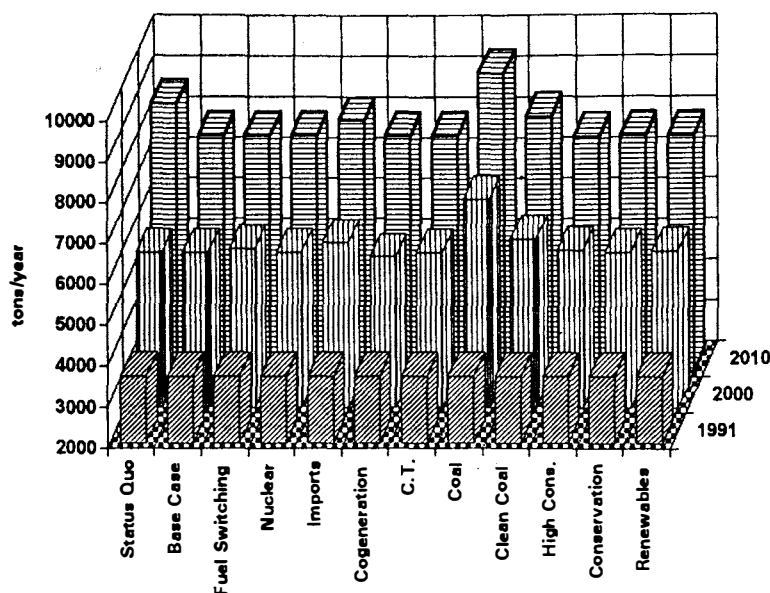


Figure 5-11
Total Regional TSP Emissions



In 2000 and 2010, all resource alternatives involve significant increases in pollutant emission rates over 1991 values. The Coal Alternative has the highest pollutant emission rates in each study year. The Clean Coal and Imports Alternatives have above-median pollutant emission rates in each study year. The Combustion Turbine, Fuel Switching, and High Conservation Alternatives have near-median emissions in 2000 and below-median emissions in 2010.

In evaluating these results, note that the Fuel Switching Alternative underestimates pollutant emissions in the Pacific Northwest by not considering the increased emissions from homes and industry that would result from the switch to fossil fuels to meet heating requirements. Also, the Cogeneration Alternative only considers the increase in pollutant emissions associated with the production of electricity, not the routine emissions associated with generating heat for industrial applications. In all the resource alternatives, emissions from power plants in eastern Montana are based on the amount of power provided to the BPA region and do not include emissions associated with power generated for other areas.

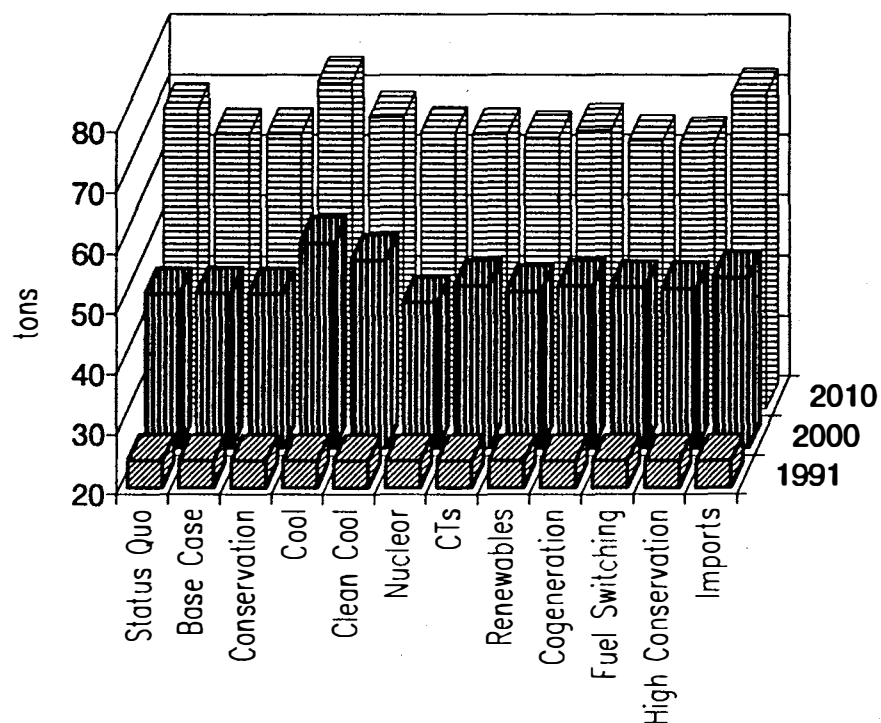
CO₂ Emissions

In 1991, the annual level of CO₂ emissions for electricity generation are estimated to be 19.25×10^6 tons per year. In 2000 and 2010, additional CO₂ emissions will come from the increased operation of the existing coal-fired power plants, the operation of new coal-fired power plants, and the operation of new combustion turbine and cogeneration facilities. Figure 5-12 presents information on the annual level of CO₂ emissions for each resource alternative in 1991, 2000, and 2010.

The Coal and Clean Coal Alternatives produce the highest levels of CO₂ emissions in each study year. On the whole, the Coal, Imports, and Status Quo Alternatives have high CO₂ emission levels compared to other resource alternatives. The Status Quo Alternative has below-median CO₂ emissions in 2000 and above-median

emissions in 2010. The Cogeneration and Combustion Turbine Alternatives have emission levels slightly above or close to median values. The Base Case, Conservation, and Nuclear Alternatives have below-median emission levels in 2000 and near-median values in 2010. The Renewable, Fuel Switching, and High Conservation Alternatives have near-median CO₂ emission levels in 2000 and below-median values in 2010; however, the Fuel Switching Alternative does not consider the increase in CO₂ emissions that would occur from homes and industry as a result of the switch to fossil fuels to meet heating requirements.

Figure 5-12
Total Regional Carbon Dioxide Emissions



NO_x, SO₂, and TSP Concentrations

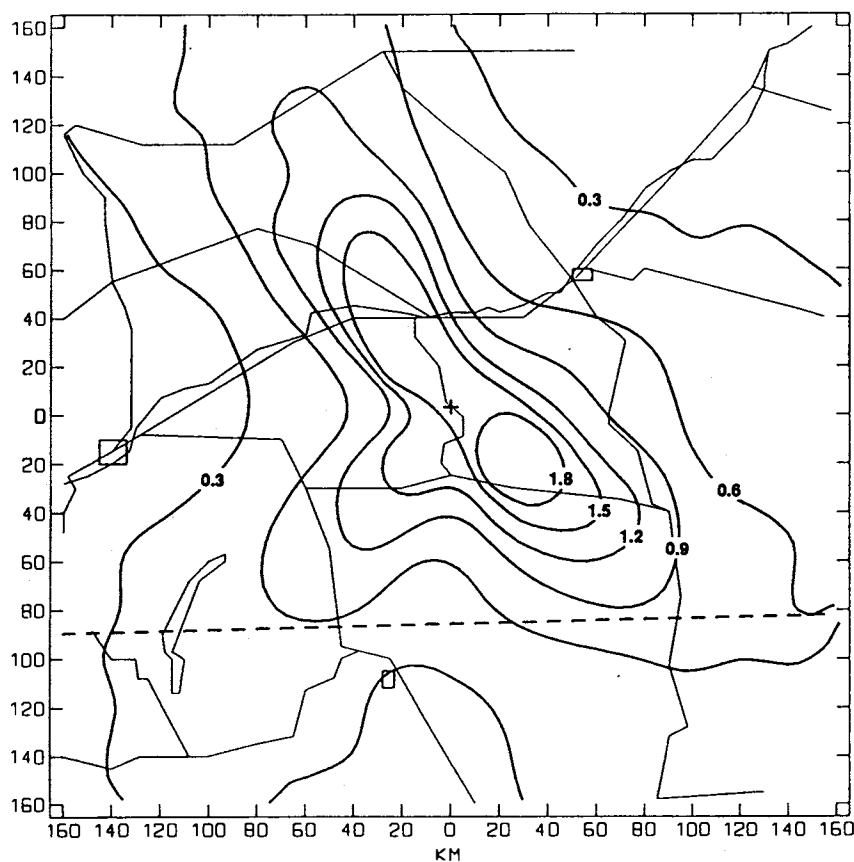
NO_x, SO₂, and TSP concentrations resulting from power plant emissions were estimated to assess ecological, human health, and regulatory impacts. The ISCST model was used to generate air quality estimates and the contour plots and tables used to present concentrations.

To estimate the air quality impacts over a broad region around the assumed pollutant release sites, an expanded Cartesian grid was used. This grid covers a domain of 320 by 320 kilometers. A local grid was used to estimate pollutant concentrations to assess health and ecological impacts. On the extended grid, the annual average air quality impacts for each combination of basic criteria pollutant, release site, study year, and resource alternative are presented using a contour plot. The purpose of this plot is to show the spatial variation in annual average pollutant concentration in the area within a hundred miles of the release site. Examples of such plots are presented in Figures 5-13, 5-14, and 5-15. These examples show the greatest concentrations found of each of the three pollutant types. A full collection of these maps, showing all pollutant concentrations found at all four study sites, is listed in Glantz et al. 1992.

In these figures, labeled contours of annual average pollutant concentration are plotted using thick lines. Contours are drawn over a background map of the study region. Roads, rivers, and urban boundaries are plotted using thin lines. The release site, located at the center of the grid, is indicated by a cross (+). The captions on the bottom of the figure and at the right describe the plotted product in detail. In the lower right corner of the figure, the three highest pollutant concentrations recorded on the modeling grid are reported and the distance from the release site at which these concentrations are computed.

The distribution of pollutant concentrations presented in the figures provides a rough, but generally conservative estimate of annual average pollutant concentrations over the entire modeling domain. The actual direction of mean pollutant transport may be significantly different from what is displayed in the contour plots because the actual spatial and time variation in local winds and winds aloft throughout a year are much more complex than the ISCST model's simple transport algorithm is capable of projecting.

Figure 5-13



CONTOURS REPRESENT THE
POLLUTANT CONCENTRATION
IN UNITS OF:
MICROGRAMS / CUBIC METER

STUDY YEAR: 2010
SITE: COLSTRIP

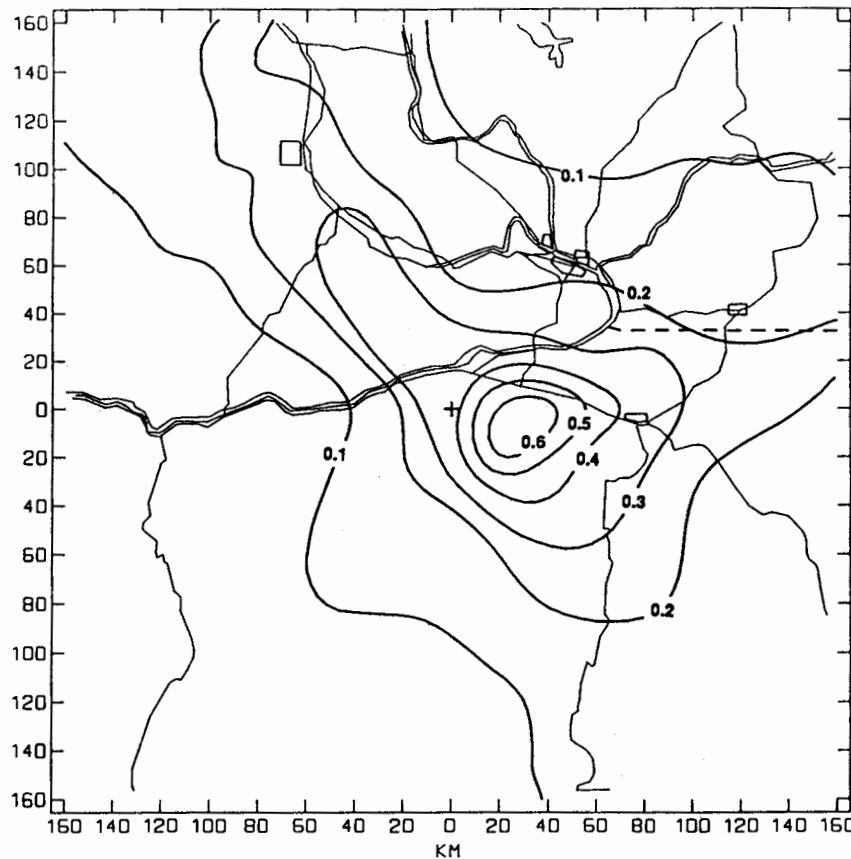
RESOURCE ALTERNATIVES

CONVENTIONAL COAL

THREE HIGHEST CONC.	GRID X(KM)	VALUES Y(KM)
3.24	20.	-20.
2.80	-20.	20.
2.71	-20.	40.

ANNUAL AVERAGE SULFUR DIOXIDE CONCENTRATIONS
FROM ALL POWER PLANT EMISSIONS

Figure 5-14



CONTOURS REPRESENT THE
POLLUTANT CONCENTRATION
IN UNITS OF:
MICROGRAMS / CUBIC METER

STUDY YEAR: 2010
SITE: BOARDMAN

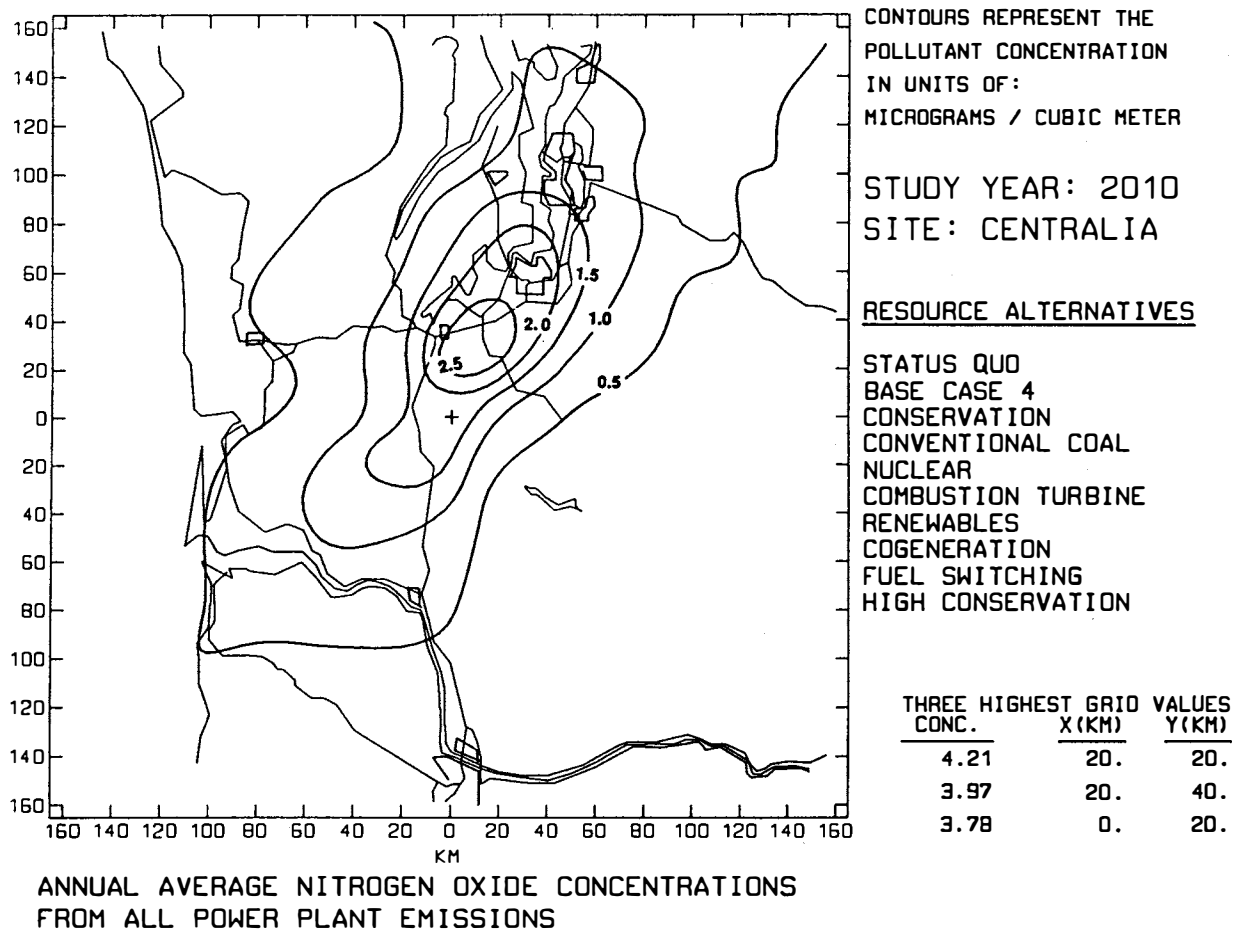
RESOURCE ALTERNATIVES

CONVENTIONAL COAL

THREE HIGHEST CONC.	GRID X(KM)	VALUES Y(KM)
1.47	20.	0.
.79	40.	0.
.74	20.	-20.

ANNUAL AVERAGE SULFUR DIOXIDE CONCENTRATIONS
FROM ALL POWER PLANT EMISSIONS

Figure 5-15



Considering all sites, the alternative that produced the highest overall NO_x, SO₂, and TSP concentrations is the Coal Alternative. The Coal Alternative produced the highest pollutant concentrations in eastern Washington, eastern Oregon, and eastern Montana in both 2000 and 2010. The Imports Alternative produced the highest air quality impacts in western Washington in both 2000 and 2010; however, the Imports Alternative overstates regional air pollution impacts by assuming that emissions in California would occur at the western Washington and eastern Oregon release sites. Thus, the contour map in Figure 5-15 shows the second- highest distribution of NO_x impacts (a distribution that is representative of several resource alternatives).

The greatest SO₂, NO_x and TSP concentrations of all alternatives, calculated over regulatory time periods, are shown in Table 5-7. This table does not consider emissions from power plants in California and Canada because emissions from these sources would have a negligible impact on local air quality near the four release sites in the BPA study region. The pollutant concentrations presented in these tables only represent the impact of emissions from new and existing power plants. None of the alternatives produces a maximum pollutant concentration that approaches National Ambient Air Quality Standards (these standards are presented in Chapter 2, Table 2-2). It is important to note that if the cumulative emissions from automobiles, industrial development, wood stoves, and other sources of pollutants continue to increase within the region, additional power plant emissions could potentially contribute to a violation of Federal, state, or local air quality standards.

Table 5-7
Highest Concentrations of NO_x, SO₂, and TSP of All Alternatives
for Each Location Averaged Over Regulatory Time Periods

	Year: 1991				Year: 2000				Year: 2010			
<u>Pollutants</u>	Annual	24-hour	3-hour	1-hour	Annual	24-hour	3-hour	1-hour	Annual	24-hour	3-hour	1-hour
Western Washington												
NO _x (ppm)	0.0011	0.0145	-	-	0.0040	0.0403	-	-	0.0059	0.0607		
SO ₂ (ppm)	0.0011	0.0138	0.0715	0.1652	0.0013	0.0181	0.0879	0.1768	0.0014	0.0194	0.0943	0.1769
TSP (ug/m3)	0.1110	1.4000	-	-	0.1830	2.0400	-	-	0.1800	2.3900		
Eastern Washington												
NO _x (ppm)	0.0000	0.0000	-	-	0.0008	0.0105	-	-	0.0009	0.0138		
SO ₂ (ppm)	0.0000	0.0000	0.0000	0.0000	0.0002	0.0030	0.0181	0.0300	0.0002	0.0040	0.0181	0.0400
TSP (ug/m3)	0.0000	0.0000	-	-	0.0770	1.1500	-	-	0.0930	1.5600		
Eastern Oregon												
NO _x (ppm)	0.0006	0.0088	-	-	0.0023	0.0218	-	-	0.0044	0.0479		
SO ₂ (ppm)	0.0006	0.0084	0.0392	0.0796	0.0011	0.0134	0.0582	0.1390	0.0016	0.0203	0.0885	0.2113
TSP (ug/m3)	0.0620	0.8500	-	-	0.1630	1.7400	-	-	0.3230	3.9600		
E. Montana												
NO _x (ppm)	0.0013	0.0311	-	-	0.0022	0.0550	-	-	0.0028	0.0698		
SO ₂ (ppm)	0.0012	0.0297	0.1464	0.2910	0.0016	0.0405	0.1928	0.3969	0.0018	0.0451	0.2144	0.4413
TSP (ug/m3)	0.1220	3.0100	-	-	0.2200	5.6100	-	-	0.2900	7.2800		

Concentrations may be compared with National Ambient Air Quality Standards shown in Table 2-2. The concentrations shown in this table are taken from whatever alternative has the greatest levels.

Ozone

Ozone pollution does not result from the direct emission of ozone into the atmosphere but from a complex series of photochemical reactions involving other air pollutants.

Ozone concentrations are a complex function of pollutant emission rate, meteorological conditions, background pollutant concentrations, time of year, time of day, wind direction, and distance from emission location.

High ozone concentrations occur with a limited frequency in the Pacific Northwest. The frequency and severity of ozone incidents in the BPA region is low because of the region's northern latitude, cloudy weather, relatively low pollutant emission levels, typically low background pollutant concentrations, and low to moderate frequency of stagnant air conditions.

In the analysis of ozone concentrations, a limited number of release and meteorological conditions were studied to estimate the worst-case and more typical ozone concentrations that could result from changes in pollutant emission rates at each of the four BPA-specified regional release sites.

A version of the EPA's Reactive Plume Model (RPM-II) was used in the analysis of episodic conditions. This model is designed to estimate short-term concentrations of ozone resulting from point or area source emissions.

The model simulations indicate that the current and projected level of pollutant emissions from power plants would produce worst-case ozone concentrations that would only exceed background levels by a small percentage. The specific results obtained for each study site are shown in Table 5-8.

The results of the model simulations indicate that there is little variation in the highest hourly ozone concentration as a function of the resource alternative at a given site and study year. On the average, the analysis indicates that power plant emissions seem to be of secondary importance in ozone formation when compared with the type and quantity of pollutants in the background air.

Table 5-8
Estimates of the Seasonal Average 7-Hour Ozone Increment
for Various Combinations of Release Site, Study Year, and
Resource Alternative

In the following table, "increment" represents the change in ozone concentrations from background levels. Values are presented in pphm (1 ppm = 100 pphm). The 7-hour period is used to represent the daytime period when ozone concentrations are generally at their maximum.

<u>Scenario/ year/ emission level</u>	The average 7-hour increment in O ₃ concentrations when there are high levels of ambient O ₃			Growing Season 7-h average O ₃ increment (for all background O ₃ levels (pphm))
	4 pphm ambient (pphm)	6 pphm ambient (pphm)	10 pphm ambient (pphm)	
Eastern Montana				
1991	-0.3	-0.4	-0.2	-0.08
2000 high	-0.5	-0.8	-1.0	-0.13
2000 low	-0.45	-0.7	-0.8	-0.12
2010 high	-0.55	-0.9	-1.3	-0.14
2010 low	-0.5	-0.9	-1.2 to 0.13	
Eastern Oregon				
1991	0.7	0.7	0.8	0.16
2000 high	0.2	0.2	0.5	0.04
2000 low	0.4	0.4	0.7	0.09
2010 high	-0.3	-0.6	-0.5	-0.08
2010 low	-0.3	-0.4	-0.2	-0.06
Eastern Washington				
2000 high	0.4	0.5	0.8	0.10
2000 low	0.6	0.7	0.8	0.15
2010 high	0.2	0.2	0.6	0.05
2010 low	0.4	0.5	0.8	0.09
Western Washington				
1991	0.1	0	0.4	0.01
2000 high	-0.3	-0.4	-0.2 to 0.07	
2000 low	-0.2	-0.3	0.1	-0.04
2010	-0.3	-0.6	-0.4	-0.08

* Reflects a typical distribution of background ozone concentrations (typically, background O₃ concentrations are below 4.0 pphm at our study sites).

Acid Deposition

Acidic compounds are formed in the atmosphere as a result of chemical reactions involving the pollutants NO_x and SO₂. As discussed earlier, these pollutants are emitted in significant quantities by fossil fuel-consuming power plants in the Pacific Northwest. Once formed, acidic compounds can be removed from the atmosphere by gravitational settling (dry deposition) and precipitation scavenging.

(wet deposition) processes. The resulting flux of acid material to the surface can have an impact on soils and vegetation.

To study acid deposition, a modified version of the EPA's MESOPUFF II model was used. MESOPUFF is a regional scale, Gaussian puff model designed to calculate concentrations of up to five pollutant species on the model's receptor domain.

Seasonal estimates of the average pH of rainfall, based on the results of the MESOPUFF simulations, are summarized in Tables 5-9 and 5-10. In the analysis, a pH of 5.7 for "unpolluted" rain (i.e., a slightly acidic background) was assumed. The wet deposition of acidic compounds that formed as a result of power plant emissions acts to reduce the average pH of rainfall (increasing acidity). The tables show that pH values vary little by the level of sulfur compounds emitted but vary greatly depending on location and season. It is interesting to note that the lowest average pH of precipitation occurs in the summer, and not in the winter or fall when power plant emissions are at their maximum. Although rain may be more acidic in the summer, the amount of rain falling during this period is much lower than in the fall and winter. As a result, more acidic compounds are deposited on the surface in the fall and winter, although the average pH of the precipitation is higher. The greater acidity in the summer season may be due to a greater intensity of precipitation on those occasions when precipitation tends to occur (e.g., during thunderstorms), and lower average wind speeds, which may act to increase the concentration of acidic compounds in the atmosphere.

The effects of acidic deposition are dominated by local geography more than by alternatives, thus effects are consistent across the alternatives.

Table 5-9
Average pH of Rainfall in the Western and
Eastern Washington Study Areas

Values are presented for the point of maximum impact anywhere on the study grid and greater than 200 kilometers (120 miles) from the release site. Values are presented as a function of release site, study year, season, and level of sulfur compound emission. A pH of 5.7 is assumed for rainfall in the absence of power plant emissions.

Site Name	Year	Season	Resource Alternative Low or High Sulfur Emissions	Average pH of Rainfall at	
				Maximally Impacted Point Anywhere on Study Grid	Maximally Impacted Point > 200 km From Source
Western Washington	1991	Fall	---	5.0	5.6
		Winter	---	5.3	5.5
		Spring	---	5.7	5.7
		Summer	---	5.2	5.5
	2010	Fall	Low	5.0	5.4
		Fall	High	4.9	5.4
		Winter	Low	5.0	5.3
		Winter	High	5.0	5.3
		Spring	Low	5.5	5.5
		Spring	High	5.1	5.2
		Summer	Low	4.4	5.1
		Summer	High	4.4	5.1
Eastern Washington	1991	Fall	---	5.7	5.7
		Winter	---	5.7	5.7
		Spring	---	5.7	5.7
		Summer	---	5.7	5.7
Eastern Montana	2010	Fall	Low	5.3	5.6
		Fall	High	5.2	5.6
		Winter	Low	5.3	5.3
		Winter	High	5.3	5.3
		Spring	Low	5.4	5.5
		Spring	High	5.2	5.4
		Summer	Low	4.7	5.3
		Summer	High	4.5	5.2

Table 5-10
Average pH of Rainfall in the Eastern Oregon and
Eastern Montana Study Areas

Values are presented for the point of maximum impact anywhere on the study grid and greater than 200 kilometers (120 miles) from the release site. Values are presented as a function of release site, study year, season, and level of sulfur compound emission. A pH of 5.7 is assumed for rainfall in the absence of power plant emissions.

Site Name	Year	Season	Resource Alternative Low or High Sulfur Emissions	Average pH of Rainfall at	
				Maximally Impacted Point Anywhere on Study Grid	Maximally Impacted Point > 200 km From Source
Eastern Oregon	1991	Fall	---	5.4	5.6
		Winter	---	5.6	5.7
		Spring	---	5.7	5.7
		Summer	---	4.8	5.4
	2010	Fall	Low	5.1	5.5
		Fall	High	5.0	5.4
		Winter	Low	5.1	5.2
		Winter	High	5.0	5.1
		Spring	Low	5.1	5.4
		Spring	High	4.9	5.2
		Summer	Low	4.5	5.3
		Summer	High	4.3	5.1
Eastern Montana	1991	Fall	---	5.0	5.4
		Winter	---	5.0	5.0
		Spring	---	5.2	5.4
		Summer	---	4.2	4.9
Eastern Montana	2010	Fall	Low	4.8	5.2
		Fall	High	4.7	5.2
		Winter	Low	4.8	4.8
		Winter	High	4.7	4.8
		Spring	Low	4.7	5.0
		Spring	High	4.7	5.0
		Summer	Low	4.0	4.7
		Summer	High	4.1	4.7

Visibility

Visibility attenuation occurs as a result of scattering and absorption by air pollutants. The emission of pollutants (NO_x, SO₂, and particulates) by power plants will impact visibility either directly or by undergoing chemical transformation into pollutants that are involved in visibility attenuation.

In the analysis of visibility attenuation, the EPA's PLUVUE II model was used to compute the reductions in visual range that would occur against a sky background at each of the four release sites for each study year and resource alternative. The PLUVUE II model computes reductions in visual range and other visibility

parameters for a specific set of user-defined release characteristics, meteorological conditions, background pollutant air concentrations, and plume/observer geometries.

In this analysis, PLUVUE II was run for a series of observer locations, plume downwind distances, meteorological conditions, and pollutant emission rates. Tables 5-11 through 5-14 present the results for each combination of release site, resource alternative, and study year, using the meteorological conditions, background conditions, and plume/observer geometry specified above. As would be expected, the reductions in visible range are greatest at the eastern Montana study site, where pollutant emission rates are highest. Western Washington has the next highest reduction in visible range, followed by eastern Oregon and eastern Washington. For a given site and study year, the greatest reductions in visible range typically occur for the Coal Alternative. Most other alternatives have slightly lower reductions in visible range.

Table 5-11
Estimates of Reduction in Visible Range (RVR) Values
in Western Washington for Stable Conditions With the Wind
Blowing From 270° and the Observer 20 km Directly South of
the Pollutant Source

Year: 1991	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
All Alternatives	3.4	2.5	3.1	4.0	4.9	4.5	1.8

Year: 2000	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
Status Quo	4.6	3.2	3.9	5.1	6.3	5.5	2.2
Base Case	4.6	3.2	3.9	5.1	6.3	5.5	2.2
Conservation	4.6	3.2	3.9	5.0	6.3	5.5	2.2
Coal	5.1	3.5	4.2	5.4	6.8	5.8	2.4
Clean Coal	4.6	3.2	3.9	5.1	6.3	5.5	2.2
Nuclear	4.3	3.0	3.7	4.8	6.0	5.3	2.1
Combustion Turbine	4.8	3.3	4.0	5.2	6.5	5.6	2.3
Renewables	4.6	3.2	3.9	5.1	6.3	5.5	2.2
Cogeneration	4.2	3.0	3.7	4.8	6.1	5.3	2.2
Fuel Switching	4.8	3.3	4.0	5.2	6.5	5.6	2.3
High Conservation	4.8	3.3	4.0	5.2	6.5	5.6	2.3
Imports	5.0	3.4	4.1	5.4	6.7	5.7	2.4

Year: 2010	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
Status Quo	4.8	3.3	4.0	5.3	6.7	5.8	2.3
Base Case	5.1	3.5	4.2	5.5	6.9	6.0	2.4
Conservation	5.1	3.5	4.2	5.5	6.9	6.0	2.4
Coal	5.5	3.7	4.4	5.8	7.3	6.1	2.5
Clean Coal	4.8	3.3	4.0	5.2	6.5	5.6	2.3
Nuclear	5.1	3.5	4.2	5.5	6.9	6.0	2.4
Combustion Turbine	5.0	3.4	4.1	5.4	6.8	5.9	2.3
Renewables	5.1	3.5	4.2	5.5	6.9	6.0	2.4
Cogeneration	5.1	3.5	4.2	5.5	6.9	6.0	2.4
Fuel Switching	5.0	3.4	4.1	5.4	6.8	5.9	2.3
High Conservation	4.8	3.3	4.0	5.3	6.7	5.8	2.3
Imports	5.5	3.8	4.5	5.9	7.5	6.2	2.5

Table 5-12
Estimates of Reduction in Visible Range (RVR) Values in
Eastern Oregon for Stable Conditions With the Wind Blowing
From 270° and the Observer 20 km Directly South of
the Pollutant Source

Year: 1991	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
All Alternatives	1.3	1.1	1.4	1.7	2.0	2.1	0.8

Year: 2000	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
Status Quo	2.0	1.7	2.1	2.7	3.3	3.2	1.2
Base Case	2.0	1.7	2.1	2.7	3.3	3.1	1.2
Conservation	2.0	1.7	2.1	2.7	3.3	3.1	1.2
Coal	3.1	2.3	2.9	3.7	4.5	4.2	1.7
Clean Coal	2.0	1.7	2.1	2.7	3.3	3.1	1.2
Nuclear	2.0	1.7	2.1	2.7	3.3	3.1	1.2
Combustion Turbine	2.0	1.7	2.1	2.7	3.3	3.1	1.2
Renewables	2.0	1.7	2.1	2.7	3.3	3.1	1.2
Cogeneration	2.0	1.7	2.2	2.9	3.5	3.4	1.3
Fuel Switching	2.0	1.7	2.1	2.7	3.3	3.2	1.2
High Conservation	2.0	1.7	2.1	2.7	3.3	3.1	1.2
Imports	2.1	1.7	2.2	2.8	3.4	3.3	1.3

Year: 2010	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
Status Quo	4.4	3.1	3.8	4.9	6.2	5.4	2.1
Base Case	4.4	3.1	3.8	4.9	6.2	5.4	2.1
Conservation	4.4	3.1	3.8	4.9	6.2	5.4	2.1
Coal	5.9	3.9	4.6	5.9	7.5	6.2	2.5
Clean Coal	4.5	3.1	3.8	4.9	6.0	5.2	2.1
Nuclear	4.4	3.1	3.8	4.9	6.2	5.4	2.1
Combustion Turbine	4.4	3.1	3.8	4.9	6.2	5.4	2.1
Renewables	4.4	3.1	3.8	4.9	6.2	5.4	2.1
Cogeneration	4.8	3.3	4.0	5.2	6.6	5.6	2.2
Fuel Switching	4.4	3.1	3.8	4.9	6.2	5.4	2.1
High Conservation	4.4	3.1	3.8	4.9	6.2	5.4	2.1
Imports	5.2	3.6	4.3	5.5	7.0	5.9	2.3

Table 5-13

**Estimates of Reduction in Visible Range (RVR) Values in
Eastern Washington for Stable Conditions With the Wind Blowing
From 270° and the Observer 20 km Directly South of
the Pollutant Source**

Year: 1991

**There are no emissions at this site
during this year.**

Year: 2000	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
Status Quo	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Base Case	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Conservation	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Coal	2.3	1.8	2.2	2.7	3.2	3.0	1.2
Clean Coal	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Nuclear	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Combustion Turbine	2.0	1.6	1.9	2.4	2.8	2.8	1.1
Renewables	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Cogeneration	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Fuel Switching	1.9	1.5	1.8	2.2	2.7	2.6	1.0
High Conservation	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Imports	2.0	1.6	1.9	2.4	2.8	2.8	1.1

Year: 2010	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
Status Quo	2.6	2.0	2.4	3.0	3.6	3.4	1.3
Base Case	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Conservation	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Coal	2.6	2.0	2.4	3.0	3.6	3.4	1.3
Clean Coal	2.1	1.7	2.0	2.5	3.0	2.9	1.1
Nuclear	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Combustion Turbine	1.9	1.5	1.9	2.4	2.9	2.8	1.2
Renewables	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Cogeneration	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Fuel Switching	1.9	1.5	1.8	2.2	2.7	2.6	1.0
High Conservation	1.9	1.5	1.8	2.2	2.7	2.6	1.0
Imports	2.1	1.7	2.0	2.5	2.9	2.8	1.1

Table 5-14

**Estimates of Reduction in Visible Range (RVR) Values in
Eastern Montana for Stable Conditions With the Wind Blowing
From 270° and the Observer 20 km Directly South of the
Pollutant Source**

Year: 1991	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
All Alternatives	5.7	3.8	4.4	5.7	7.2	6.0	2.5

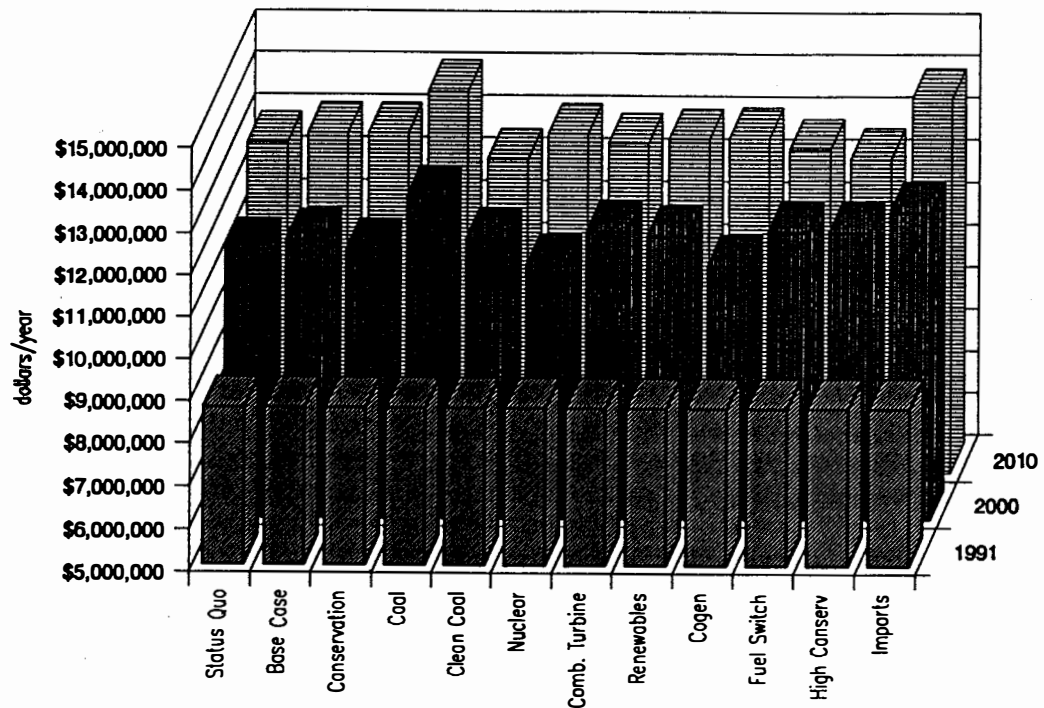
Year: 2000	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
Status Quo	9.3	5.7	6.3	8.0	10.0	7.7	3.2
Base Case	9.3	5.7	6.3	8.0	10.0	7.7	3.2
Conservation	9.3	5.7	6.3	8.0	10.0	7.7	3.2
Coal	11.1	6.7	7.4	9.2	11.4	8.2	3.5
Clean Coal	9.7	5.9	6.6	8.3	10.4	7.8	3.2
Nuclear	9.3	5.7	6.3	8.0	10.0	7.7	3.2
Combustion Turbine	9.3	5.7	6.3	8.0	10.0	7.7	3.2
Renewables	9.4	5.8	6.4	8.1	10.1	7.7	3.2
Cogeneration	9.0	5.6	6.2	7.9	9.8	7.5	3.1
Fuel Switching	9.5	5.8	6.4	8.1	10.1	7.7	3.2
High Conservation	9.4	5.8	6.4	8.1	10.1	7.7	3.2
Imports	9.4	5.8	6.4	8.1	10.1	7.7	3.2

Year: 2010	RVR (%) at the Following Distances (km)						
Resource Alternative	2	10	20	30	40	50	60
Status Quo	15.3	8.8	9.5	11.6	14.2	9.3	4.0
Base Case	12.6	7.5	8.1	10.0	12.4	8.6	3.7
Conservation	12.6	7.5	8.1	10.0	12.4	8.6	3.7
Coal	13.3	7.9	8.5	10.4	12.9	8.8	3.8
Clean Coal	12.6	7.5	8.1	10.0	12.4	8.6	3.7
Nuclear	12.6	7.5	8.1	10.0	12.4	8.6	3.7
Combustion Turbine	12.6	7.5	8.1	10.0	12.4	8.6	3.7
Renewables	12.6	7.5	8.1	10.0	12.4	8.6	3.7
Cogeneration	12.6	7.5	8.1	10.0	12.4	8.6	3.7
Fuel Switching	12.6	7.5	8.1	10.0	12.4	8.6	3.7
High Conservation	12.6	7.5	8.1	10.0	12.4	8.6	3.7
Imports	13.0	7.7	8.3	10.2	12.6	8.7	3.7

Visibility Impacts

The economic analysis calculates the value of visibility attenuation from criteria pollutant emissions for each alternative. The air quality analysis calculated visibility attenuation for different observer locations at each site. For the purposes of the economic analysis, data from two observation points at each study site were calculated. These points were used to calculate an average reduction in visual range for an observer at an arbitrary location affected by the plume at each site. This data was multiplied by the economic value of visibility reduction (\$41 per mile per person on the west side of the Cascade Mountains; \$7 per mile per person on the east side) to determine the total costs of visibility impacts. Figure 5-16 shows the economic values calculated for visibility reduction for each alternative in all study years.

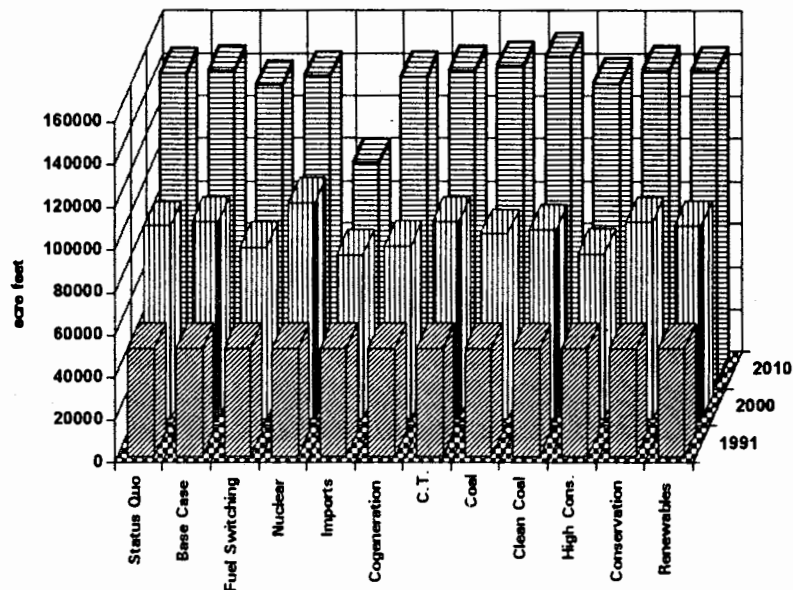
Figure 5-16
Economic Value of Visibility Reduction



5.2.2.5 Water Consumption

Water consumption for each of the alternatives in each of the study years is shown in Figure 5-17. In the year 2000, the Nuclear Alternative would have the greatest impact on water consumption. In 2010, the alternatives generally have the same impact on water consumption, except for the Imports Alternative, which is estimated to use about 50,000 acre-feet less water than the others. Estimates of water consumption for each resource type are provided in Chapter 3 in the Environmental Effects and Mitigation section for each resource.

Figure 5-17
Water Consumption



5.2.3 Transmission

Developing certain additional resources would require construction of major new transmission lines to deliver the power to load centers. Some resources would not require major new transmission construction. Generally, resources located farther from load centers, especially resources east of BPA's transmission system, would require construction of more transmission facilities than would resources closer to load centers.

For resources that would require construction of major transmission facilities, the probable routes of new transmission lines would generally be along existing transmission line corridors and would use recognized corridors across the Cascade Mountains. This evaluation provides only a general understanding of the potential impacts of integrating probable transmission requirements for each resource. (See Appendix E.) Detailed, site-specific analysis of transmission alternatives and impacts will proceed when specific generating resources are proposed for development.

5.3 Social and Economic Effects

5.3.1 River Uses

Recreation

Although many recreational activities are potentially impacted by new energy resource development, most are site-specific and would be addressed vis-a-vis specific resource proposals. Some generic recreation impacts are associated with operation of the hydro system, however, and are acknowledged here.

Changes to reservoir elevations or project discharges resulting from new resource acquisition may influence recreational activities. Generally, elevation changes would affect recreation at the reservoirs, while discharge changes would influence downstream recreation.

Potential effects of additional resources were assessed using data from the SAM studies. Reservoir elevation data were examined to determine if recreational use of reservoirs is likely to be affected. Recreational activities may be affected when large amounts of resources are shaped into the September through April time period. While the reservoirs are higher in the spring, they tend to be lower during the prime recreation season in the summer and fall.

Downstream recreational activities, such as fishing, swimming, rafting, and boating, are influenced by project discharge. Constraints have been developed limiting the rate of change in project discharge to protect downstream users. It is difficult, however, to assess the potential impacts on downstream recreation because effects are related to short-term fluctuations in flow.

Recreational use of the Columbia River system is another of the areas being studied in the System Operation Review. The System Operating Strategy developed in the SOR will help define specific non-power constraints necessary to accommodate recreational uses of the river.

Irrigation

Hydro projects in the Columbia River Basin provide water and power for irrigation. The alternatives assessed in this EIS are not expected to result in large water level fluctuations at the reservoirs. The issue of trade-offs between water use for irrigation and power production will be addressed in the SOR EIS.

5.3.2 Cultural Resources/Historic Preservation

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. Cultural resources that could be affected by BPA's resource acquisition decisions are located throughout the Pacific Northwest--anywhere a conservation or generating resource could be located.

Consistent with Section 106 of the National Historic Preservation Act (16 U.S.C. 470), BPA will consult with the appropriate State Historic Preservation Officers before acquiring specific generating resources to determine if there are effects on any of these properties. A complete discussion of potential impacts will be included in the site-specific environmental document prepared for that resource.

Addition of new resources could cause changes in operation of the existing power system. The effects could include changes in reservoir elevations at storage reservoirs. BPA has recently executed a Programmatic Agreement that would effectively mitigate for impacts to cultural resources at the five Federal storage reservoirs on the Columbia and Snake Rivers. Parties to this agreement include the Advisory Council on Historic Preservation; the Idaho, Montana, and Washington State Historic Preservation Officers; BPA; the Bureau of Reclamation; the Army Corps of Engineers; and others. Under this Agreement, potentially affected cultural resources at these Columbia River Basin reservoirs will be surveyed, evaluated, and protected, thus satisfying BPA's responsibilities under Section 106 of the National Historic Preservation Act for effects from potential changes in reservoir elevations. The Programmatic Agreement will also ensure BPA's consistency with the American Indian Religious Freedom Act (42 USC 1996) and Native American Graves Protection and Repatriation Act by providing for BPA participation in the disposition of Native American burials if such sites are discovered.

In 1983, BPA, the Advisory Council on Historic Preservation, and the State Historic Preservation Officers of California, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming signed Programmatic Memoranda Of Agreement that specified procedures for ensuring that BPA's energy conservation programs were consistent with historic preservation values. These procedures will be followed to protect cultural resource values of historic buildings as additional conservation is acquired, and will fully satisfy National Historic Preservation Act review requirements relevant to energy conservation.

5.3.3 Economic Effects

System Costs

The Pacific Northwest Electric Power Planning and Conservation Act (Act) defines system cost as:

"...an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource."

In this analysis, system cost consists of two components: direct costs, and environmental externality costs. Direct costs are borne by a regional party (BPA, IOUs, GPUBs, or consumers) and include generating resource and conservation capital and administrative costs, and production and purchased power costs. Revenues from secondary sales are credited against direct costs.

Environmental Externality Costs

Environmental externalities are the economic costs and benefits that are not directly borne by the party causing the environmental effect. BPA is required by the Northwest Power Act to include quantifiable environmental externalities in determining a resource's total system cost for BPA's planning and acquisition activities. The Northwest Power Act also directs the Northwest Power Planning Council to develop, as a guide for BPA, a methodology for quantifying environmental externality costs and benefits. The Council did so in its 1986 *Northwest Conservation and Electric Power Plan*.

The methodology developed by the Council outlines a series of steps and thresholds. First, the characteristics of the particular resource or conservation measure are identified and quantified in terms of the appropriate physical units. All effects on the environment that could result in a change in an economic value are identified. The studies performed undergo public review and comment, and are updated as new information is available. Next, a determination is made whether a meaningful economic analysis of the environmental cost or benefit can be done and whether the cost or benefit can be adequately represented in monetary terms. This judgment includes consideration whether sufficient information exists or can be obtained to allow for a meaningful analysis; whether the quantified environmental costs and benefits would likely affect the relative cost-effectiveness of alternative resources; and whether state and local standards significantly eliminate the environmental effect. Then, the Administrator selects a specific economic evaluation method appropriate to the economic effect under question. Each step is documented and undergoes public review. For those effects that cannot be meaningfully monetized, key physical and biological characteristics are described and quantified where possible.

BPA has followed the methodology proposed by the Council in the development of BPA's environmental costs and benefits estimates. Studies have been performed over the past decade that identified the environmental

effects of generating resources and conservation. These studies are the backbone of BPA's current estimates of environmental costs.

BPA's estimates focus on the effects of operating generic resources (in other words, not site-specific resources) on atmospheric visibility, human health risks, forests, crops, materials, and on land and water. Three airborne pollutants are analyzed--sulfur oxides, oxides of nitrogen, and particulate matter. The effects of carbon dioxide (CO₂) emissions were initially monetized and included in the material that was sent to the public for review during the development of the environmental costs for this EIS. It was determined, after reviewing comments submitted, that the uncertain scientific evidence concerning the effects of CO₂ did not enable BPA to place a value on the effects of CO₂ emissions. BPA recognizes, however, that some states and utilities have placed a cost on CO₂ emissions based on existing studies.

Similarly, potential environmental costs associated with radioactive emissions from a catastrophic nuclear event are not estimated by BPA. Environmental costs for nuclear plants consist only of estimates associated with land and water use impacts for all large thermal plants.

Much uncertainty and debate surround environmental cost quantifications. Several organizations have estimated environmental costs and the range of values for each pollutant or other potential cost is quite large in some instances. Two potential environmental effects that have high uncertainty and increasingly present business risk are CO₂ emissions and radioactive materials (whether from waste emissions or from catastrophic events). As more becomes known about global warming, thermal generation, which produces large amounts of CO₂, may be subject to taxes, mitigation requirements, or output restrictions, all of which would increase costs above current estimates. New nuclear power plants, given current public concerns about safety and reliability, may be difficult to site or operate. In addition, the business risks associated with political and regulatory changes that may affect future resource costs are significant considerations in resource planning and acquisition processes.

Currently, five states require monetization of environmental externality cost. Three of these states, Massachusetts, California, and Wisconsin,* allow for an offset in lieu of application of externality values. The remaining two states, Nevada and New York, do not allow offsets. Nine states, including Oregon and Washington, have opened or are considering opening dockets addressing the incorporation of environmental externality costs in utility resource planning. Thirteen states do not have a policy for environmental externality costs and are not taking any action to develop one. Four states, Colorado, Virginia, Michigan, and South Carolina, have explicitly rejected monetization of environmental externality costs, but may take them into account in other ways. The remaining 19 states have considered externality costs in some way, e.g., qualitative requirements, ranking, bonuses for conservation, but have not required monetization. The Federal Energy Regulatory Commission has also issued a report on consideration of externality values.

* Massachusetts and California, in the fall of 1992, put into effect policies that would cause externality values not to be applied to certain incremental emissions from a proposed new plant if the emissions were offset. Wisconsin requires monetization of externality costs only for greenhouse gases.

While the environmental cost assumed by BPA for nuclear is 2 mills/kWh, reflecting only the land and water impacts of a nuclear plant, efforts are underway to revise BPA's environmental cost value for nuclear. BPA will use findings from the U.S. Department of Energy's joint study with the European Community on the environmental externality costs of the total fuel cycle for energy resources, and results from BPA's contingent valuation method survey of the public's willingness to pay to avoid the environmental costs of various energy resources, including nuclear.

A technical work group was formed in November 1990 to review the methodology and information used by BPA for its environmental costs and benefits estimates being developed for this EIS. The work group members were representatives from public and investor-owned utilities, state and Federal agencies, independent power producers, interest groups, and private citizens. The work group met throughout the RPEIS process to review and comment on BPA's efforts in this area.

Table 5-15 shows the range of environmental cost estimates used or being considered by BPA, the states of Massachusetts, Nevada, New York and California, and the Pace University Center for Environmental Legal Studies in its 1990 publication, *The Environmental Costs of Electricity*.

Table 5-15
Environmental Externality Costs
Competitive Acquisition of Firm Energy
(1990 mills/kWh)

Resource Type	BPA ¹	PACE ² 1989 mills/ kWh	MA ³	NV ⁴	NY ⁵	CA ⁶
Coal	5.1	39	46.5	45.4	9.1	83.1
Coal (Fluidized Bed)	3.0	28	28.9	27.8	3.3	29.3
Coal (Coal Gasification)	2.6	25	25.7	24.7	2.6	21.0
Simple Cycle CT	1.5	NA	22.4	21.8	3.4	24.8
Combined Cycle CT	1.4	10	14.9	14.5	2.3	16.5
New Hydro Facility	2.0	NA				
Natural Gas Cogeneration	1.2	NA	9.8	9.5	1.5	10.8
Additions to Existing Hydro	1.0	NA				
Geothermal	1.0	NA				
Wind	0.5	0 to 1				
Solar	1.0	0 to 4				
Conservation	0	NA				
Wood-Fired Cogeneration	3.8	0 to 7	16.5	16.5	6.1	61.4
Municipal Solid Waste-Fired Cogeneration	7.9	NA	26.3	26.3	9.9	124.7
Nuclear	2.0	29				

¹ These adjustments are subject to change based on an on-going review and are in real levelized 1990 mills/kWh. BPA adjustments are for "default" emission rates. Specific plants with emission rates different than the default rates are assigned different adjustments.

² Pace University Center for Environmental Legal Studies, *The Environmental Costs of Electricity*

³ Massachusetts Department of Public Utilities, Regional Economic Research, Inc. *Valuing the Environmental Impacts of Alternative Resources, Phase III Task I Report* (January 1991, pp. II-5-6.)

⁴ State of Nevada Public Services Commission

⁵ New York State Energy Plan

⁶ California Energy Commission

Estimates of the environmental costs and benefits associated with the various resource acquisition options are detailed in Appendix D, Section 7.

Results

Economic results from ISAAC are applicable only in relative terms. That is, economic results from one alternative are meaningful only when compared with results of another. ISAAC is not structured to yield exact, absolute values (levels). Therefore, the economic impacts of the alternatives will be determined based upon a comparison to the Base Case Alternative.

Table 5-16 summarizes the differences in system costs from the Base Case.

In comparing the costs of the various alternatives, it is important to keep in mind the assumptions behind the analysis. All alternatives were run against a high load forecast. The assumption of high loads significantly affects the economics of the analysis. It makes nondisplaceable generating resources much more attractive than would be the case under random loads. Actual resource programs use random load forecasts and therefore have system cost impacts that may differ dramatically from those generated by high load scenarios: the differences are primarily due to greater use of displaceable resources. Under high loads, resources with high variable costs must be run fairly often and have significant operating costs. Therefore, baseload resources (with lower variable costs) are economically attractive under high loads. When economic (load) uncertainty is incorporated (via use of random loads), nondisplaceable resources are not always necessary to meet system load, and therefore are not as cost-effective.

The economic analysis indicates that the Base Case Alternative is the least-cost alternative with the exception of the Fuel Switching and High Conservation Alternatives. This result is intuitive in that the Base Case resource stack was developed specifically to minimize total system costs. The Fuel Switching and High Conservation Alternatives have lower estimated system costs because each incorporates assumptions which are fairly generous in terms of cost-effectiveness. In addition, neither of these resources is included in the Base Case stack because neither has the institutional support of supply curves with publicly reviewed derivations of cost and availability. These resources may be subject to additional analyses in the future, and might be confirmed, at least in part, as viable resources in the near future. For this reason, they were included as alternatives in this EIS. However, their inclusion does not imply any policy conclusions on their treatment as resources.

The direct costs of the Status Quo Alternative are lower than those of the Base Case Alternative. This result is to be expected because the Status Quo resource stack was developed to minimize direct costs. However, once environmental costs are taken into account, Base Case total system costs are lower than those of the Status Quo Alternative.

Table 5-16
RPEIS Alternatives Expected Present Value of Total System Costs
(Million 1988\$)

Changes From Base Case

Alternative	Direct Costs	Environmental	Total System Costs
High Conservation	-1,680	-273	-1,953
Fuel Switching	-119	+102	-18
Base Case	0	0	0
Conservation	0	0	0
Nuclear	-20	+29	+9
Combustion Turbines	+16	0	+16
Status Quo	-247	+337	+90
Imports	-70	+425	+355
Renewables	+1,526	-94	+1,432
Cogeneration	+1,159	-46	+1,113
Clean Coal	+825	+329	+1,154
Coal	+629	+746	+1,375

The Coal and High Tech Coal Alternatives have significantly higher direct and environmental costs compared to the Base Case Alternative. The difference in direct costs is mainly due to higher generating resource capital costs, since coal replaces less expensive generating resources in the two coal alternatives. Because coal has the highest environmental cost of the resources analyzed, total system costs for these two alternatives are also relatively high.

The costs of the Nuclear Alternative are nearest those of the Base Case because the cost estimates for nuclear supply are relatively low. Neither the cost-to-complete nor the operation and maintenance cost estimates have been updated recently, while significant shifts have occurred to reduce relative costs of other thermal generation. In addition, use of a high forecast biases the analysis in favor of large thermal baseload resources. Incorporation of load uncertainty and day-to-day system operational considerations would reduce the apparent economic advantage of non-displaceable base load plants.

The Renewables Alternative has higher direct costs and lower environmental costs than the Base Case. An increase in the acquisition of hydro (37 aMW above the Base Case), geothermal (162 aMW), wind (236 aMW) and solar resources (86 aMW) by 2000 contributes to higher generating capital costs (\$1.5 billion higher than the Base Case). These resources decrease production costs relative to the Base Case, but not enough to overcome the increase in capital costs. The Renewables Alternative also has environmental costs that are \$94 million lower than the Base Case, primarily because hydro, geothermal, solar, and wind resources have relatively low environmental costs.

Similarly, the Cogeneration Alternative has higher direct costs and lower environmental costs than the Base Case. The costs of cogeneration are all modeled as expenses in these analyses, since these were assumed to be energy output resources only (i.e., BPA would not have to provide capital for the plants). Therefore, generating resource capital costs are fairly low (\$0.6 billion less than the Base Case). However, production costs are \$2.2 billion higher. Environmental costs differ from the Base Case by only -\$46 million. Shifts in fuel costs since the alternatives were developed could

change some of the economics of cogeneration and combustion turbine resources.

The Combustion Turbine Alternative also has costs that are close to the Base Case. The resource acquisitions by 2010 under both alternatives are similar, although the timing of these acquisitions is different. Nevertheless, the net present values of direct costs for these alternatives are relatively close and the net present values of environmental costs are equal.

Under the Imports Alternative, direct costs are only \$70 million lower than the Base Case. For BPA acquisitions, the import resources replace the acquisition of about 175 aMW of conservation plus WNP-3 and WNP-1 by 2010.

Because the costs of the import resources are expensed, generating resource capital costs are \$4.5 billion less. Conservation capital costs are \$0.7 billion less than the Base Case, due to reduced conservation acquisition. However, these decreases in capital costs are offset by increases in production costs of \$2.5 billion and declines in extra-regional revenues of \$2.8 million.

Environmental costs are \$289 million higher under the Imports Alternative. A \$598 million decrease in the environmental costs of nuclear (since WNP-3 is not completed) is offset by a \$251 million increase in environmental costs for replacement resources and \$589 million of environmental costs for imports.

Impact on Rates

BPA's rates are set to meet its annual cost or revenue requirement. The ISAAC rates logic is patterned after the Supply Pricing Model (SPM), which simulates the BPA ratesetting process. The rates module takes loads, generating resource data, existing system costs (i.e., hydro, transmission, conservation), costs of new resources acquired, and secondary market information from the ISAAC run to determine resource pool costs and rate pools. ISAAC then allocates costs among rate pools and performs several rate design adjustments based upon a methodology described in the *1991 Final Rate Proposal Wholesale Power Rate Development Study*. The results are estimates of the various BPA rates.

In general, higher-cost resources show a larger rate impact. Two factors affect rates: 1) whether the cost stream of a resource exhibits small expenses continuously over a long period of time or a large cost in one period, and 2) how BPA will pay for the resource (i.e., capitalize or expense).

For purposes of the economic analysis, the BPA Priority Firm (PF) rate has been examined for all alternatives. As with system costs, rates output from ISAAC is meant to be used comparatively; absolute values are not meaningful.

PF rate impacts have been estimated for three periods: near-term, medium-term and long-term. The near-term PF impacts are defined as the difference from the Base Case averaged over the years 1991 through 1996. Medium-term impacts are averaged over the years 1997 through 2002, while long-term PF impacts are for the years 2003 through 2010. PF rate impacts of the RPEIS alternatives are listed in Table 5-17.

Table 5-17
RPEIS Alternatives
Expected Priority Firm Rates
(Mills/kWh 1988\$)
Changes From Base Case

Alternative	Near-Term	Medium-Term PF	Long-Term PF
Status Quo	0.0	-0.1	+0.4
Base Case	0.0	0.0	0.0
Coal	+0.2	+0.5	+1.0
Clean Coal	+0.3	+0.5	+1.4
Nuclear	+0.4	-0.3	-0.1
Renewables	+0.8	+0.7	+0.9
Cogeneration	-0.1	-0.1	+1.3
Combustion Turbines	+0.1	0.0	0.0
Fuel Switching	-0.0	-0.2	-0.1
High Conservation	+0.2	+0.3	+0.8
Imports	-1.1	-2.3	-0.1
Conservation	0.0	0.0	0.0

Most of the alternatives have PF rates consistent with the results of the economic analysis. That is, if direct costs of an alternative are higher than the Base Case, its PF rates are also generally higher. Similarly, alternatives with lower direct costs have lower PF rates. However, there are some exceptions.

Near-term rate differentials vary by less than 1 mill from the Base Case for all alternatives except the Imports Alternative. Rates for the Conventional Coal, Nuclear, Combustion Turbine, Renewables, Clean Coal, and High Conservation Alternatives are higher than the Base Case, but within 1 mill. The Cogeneration Alternative has a lower rate than the Base Case (but, again, within 1 mill). Rates for the Status Quo, Conservation, and Fuel Switching Alternatives are the same as the Base Case. The Imports Alternative has a near-term PF rate that is between 1 and 2 mills lower than the Base Case. This result is primarily due to decreased capital costs in the early years of the study, due to deferral of acquisition of generating resources by BPA. Although production costs are higher and secondary sales revenues are lower than in the Base Case for the near term, the decrease in capital costs offsets those costs, resulting in a lower PF rate.

Medium-term PF rates for the alternatives are again relatively close to that of the Base Case (within 1 mill). Rates under the Coal, Renewables, Clean Coal, and High Conservation Alternatives are less than 1 mill higher than the Base Case. The Nuclear, Status Quo, Cogeneration, and Fuel Switching Alternatives have medium-term PF rates less than 1 mill below the Base Case PF rate. Rates for the Combustion Turbine and Conservation Alternatives are the same as the Base Case. Finally, the medium-term PF rate of the Imports

Alternative is again lower than the Base Case (by approximately 2 mills) because of the previously discussed differences in costs.

Long-term PF rates are within 1 mill higher than the Base Case for all alternatives except the Nuclear, Import, and Fuel Switching Alternatives. The long-term PF rates for the Nuclear, Import, and Fuel Switching Alternatives are less than 1 mill lower than that of the Base Case.

When the rate difference is within 1 mill, a change of this magnitude is not expected to affect the loads, the region, or the stack.

Natural Gas Sensitivity

A sensitivity study of the Combustion Turbine Alternative with low natural gas prices was conducted. Gas prices used in the 1990 Resource Program were high compared to the actual prices and forecasts of late 1990. The magnitude of the changes could have substantial implications for BPA's resource stack, potentially making natural gas the resource of choice after conservation and other efficiencies are exhausted. This marks a major change in the potential resource picture, due both to lower gas costs, and to the magnitude (several thousand average megawatts) of gas supplies in western Canada. Potential supply changes of this magnitude do not appear realizable within the current decade for other resource types.

The model output from the low gas price case compared to the Combustion Turbine Alternative is as follows:

Regional system costs increased by \$2.9 billion under low gas prices. This result seems counterintuitive. However, gas prices were reduced not only in the Pacific Northwest, but in the Pacific Southwest, as well. When gas prices fall, it becomes more cost-effective for Pacific Southwest utilities to operate their gas-fired resources and import less energy from the Northwest. Therefore, although regional production costs fall by \$4.4 billion from lower gas prices, secondary sales revenues fall by over \$7.5 billion.

Impact on Employment

Electricity generation and conservation creates employment through the construction of generating plants, the installation of conservation measures, and the maintenance of generation facilities. We refer to the first of these as construction employment. Construction employment tends to be relatively short term in nature and may contribute to boom town effects in locations where power plants are built. Conservation resources tend to be less geographically concentrated and are built over a longer time frame. Thus, conservation contributes less to boom town effects. Construction employment is reported in employee-years, which includes the total employees needed to build a project or install conservation measures over the entire time needed to finish the project.

Operations employment refers to the employees needed to maintain a facility. These employee requirements are less than those needed for construction, but the employment is longer term. Employee positions may last the lifetime of the power plant. Conservation resources do not require continuing operation and maintenance labor, and so do not contribute these types of positions. Operations employment is reported in employees per year.

Figures 5-18 and 5-19 show the construction and operation employment resulting from each of the alternatives in each of the study years.

Figure 5-18
Construction Employment Impact

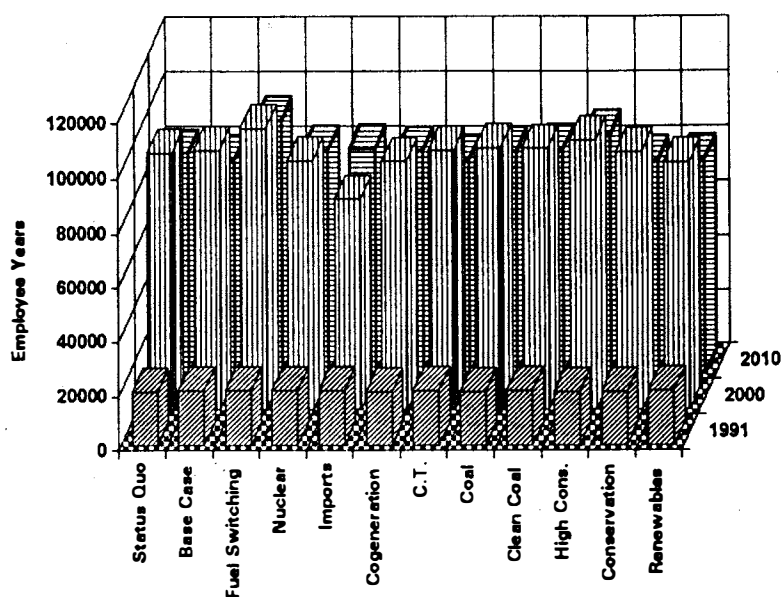
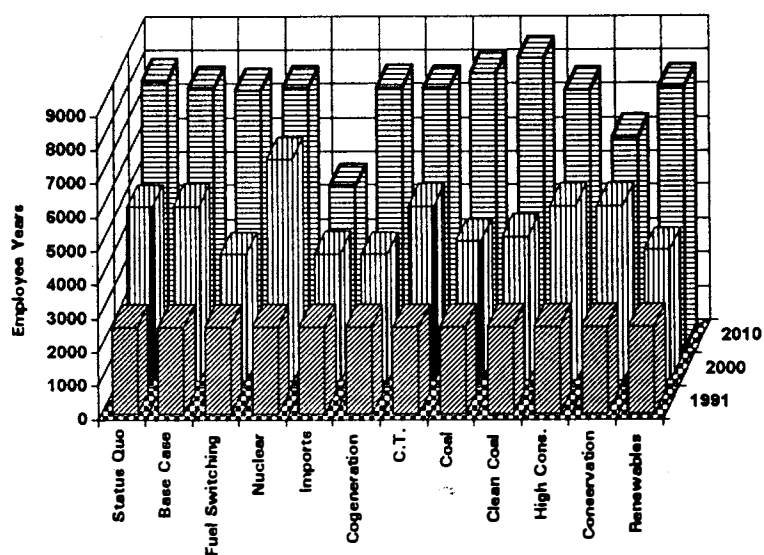


Figure 5-19
Operations Employment Impact



5.3.4 Human Health Effects

5.3.4.1 Energy Conservation

Polychlorinated Biphenyls (PCBs)

The handling and disposal of PCBs in pre-1978 fluorescent light ballasts is the key issue associated with lighting measures implemented for energy conservation programs. PCBs were banned from use in 1978. Prior to 1979, PCBs were widely used as coolants in electrical equipment, such as transformers, capacitors, and switches because the compounds do not easily burn, conduct electricity, or react with other chemicals. Many fluorescent fixtures manufactured in the United States prior to 1978 are still in use, and some foreign manufacturers may still be producing ballasts containing PCBs. Ballasts that do not contain PCBs are clearly marked "No PCBs." If the ballast does not have such a marking, it should be assumed that the capacitor in the ballast contains PCBs.

PCBs do not easily decompose when released into the environment. The compounds are relatively insoluble in water and have a high solubility in lipids such as fats. As a result, PCBs can accumulate in the food chain. Laboratory tests show that PCBs cause cancer in animals. Even though there is no direct proof that PCBs cause cancer in humans, the EPA policy is to consider any animal carcinogen as a potential human carcinogen. Animal studies show adverse reproductive and developmental effects from repeated exposure to PCBs. In addition, it has been shown that PCBs are toxic to fish at very low levels of exposure. The survival rate and the reproductive success of fish can be adversely affected by the presence of PCBs. EPA believes there may be similar cause for concern when humans are exposed to large doses of PCBs. A study of personnel exposed to PCBs released from fluorescent light fixtures in an office complex found the following acute symptoms: headache, eye irritation, sore throat, nasal congestion, nausea, dizziness, and itchy skin. Ingestion can cause liver damage and digestive problems. The National Institute for Occupational Safety and Health (NIOSH) recommends that PCBs be regarded as potential human carcinogens in the workplace.

Several recent studies have focused on airborne contamination from PCB-ballast failure, surface contamination, and contamination from fire (Pacific Northwest Laboratory, 1990, Appendix F). In general, those studies indicated that the average level of airborne PCBs in buildings with transformers containing PCBs was nearly twice the level in buildings without such fixtures. NIOSH found that classrooms which have experienced ballast burnout showed elevated PCB levels, especially immediately after ballast failure. NIOSH did not detect PCBs in classrooms which had not experienced ballast burnout. The studies also show that "normal" indoor air in a number of laboratories, offices, and homes had PCB concentrations an order of magnitude greater than PCB concentrations found outdoors. This suggests that certain electrical appliances or fluorescent lighting can emit PCBs into the indoor air, thus pushing indoor air concentrations above those found outdoors. All of this data indicates that incidents of fluorescent light ballast burnout can release PCBs into indoor air and can result in PCB concentrations above comparable background levels.

Strictly speaking, it would be legally possible to dispose of a PCB light ballast

in any landfill as long as the capacitor is not leaking (and assuming there is not a state regulation in place governing disposal of all material containing PCBs). In practice, most municipal landfills will not knowingly accept them. The EPA has prepared a fact sheet which provides guidelines for building owners to follow when disposing of ballasts containing PCBs (e.g., in a chemical waste landfill or through incineration).

There is a wide range of prices for disposal of ballasts containing PCBs. The cost varies considerably depending upon the disposal method chosen and the prices quoted by haulers who are licensed to dispose of PCB material. An informal survey of licensed haulers in Oregon and Washington was conducted to obtain a price range. The prices quoted generally include pick-up and packing the PCB ballasts in 55-gallon drums, storage at the hauler's storage facility until they have a full truckload of hazardous waste, transportation to the waste disposal facility, and actual disposal.

Prices quoted for disposal in a EPA-approved chemical waste landfill ranged from a low of \$1.28 per ballast to a high of \$3.00 per ballast. Prices quoted for disposal by incineration were considerably higher and had a much larger price range between haulers. The survey indicated a range of prices from a low of \$4.23 per ballast to a high of \$15.00 per ballast for incineration.

It is possible to bring disposal costs down. For example, a school district in Milwaukee, Wisconsin, reported much lower disposal costs for incineration. By removing the capacitor from the ballast, they were able reduce their incineration costs to \$2.00 per ballast. In another case, a lighting vendor in California has a contract in Hawaii to replace 8,000 ballasts. The lighting vendor quoted \$1.86 per ballast for removing the ballast, separating the capacitor, shipping, and incineration.

Indoor Air Quality

Concern over the quality of the air in buildings is increasing. One of the most visible or "popular" problems associated with indoor air quality in buildings is "sick building syndrome." Public awareness of this problem has been increasing, as demonstrated by the periodic appearance of articles in the press about reputed sick buildings, as has been litigation associated with the problem. Considerable effort on the part of building owners and operators as well as the professional, environmental, and scientific community has been expended to deal with indoor air quality. Professional efforts culminated with the establishment of ASHRAE Standard 62-89.

A list of potential ECMs to be used throughout the region is shown in Appendix C. Some of these ECMs may introduce potential pollutants into a building's indoor air, or may change the rate at which pollutants are drawn into or removed from the indoor air.

The quality of the air inside buildings is a complex issue. Indoor air quality is a function of the building itself, its inhabitants, activities and functions of the occupants within the building, sources of pollutants within the building structure, external sources of pollutants that could be drawn into the building, temperatures and humidity conditions, operation and condition of the HVAC system, etc. Sick building syndrome is generally ascribed to the combined effects of pollutants, the nature of the building, and the activities performed in it. Sick building syndrome refers to comfort and health, not just problems

with the temperature or humidity within a building. These problems could culminate in clinically defined illness, disease, or infirmity. Most of the problems are caused by pollutants themselves or the interaction among them, but sick building syndrome may be increased by inadequate building ventilation.

Building ventilation is the process of getting air into and out of a building. It is accommodated by three means: infiltration, natural ventilation, and mechanical ventilation. The overall process of infiltration generally is a combination of these three factors. Infiltration is the flow of air through any unplanned openings in a building. Natural ventilation is the flow of air through windows, doors, skylights, ventilators, stacks, and other planned openings in the building. Natural ventilation is controlled by a building's occupants. Mechanical ventilation is the forced movement of air by fans into or out of a building.

During the operations and maintenance of a commercial building, it is possible that the systems may become contaminated with bacteria and similar organisms if the system is not kept in the proper balance of temperature and humidity. Some researchers have linked complaints of occupants with microbiological contamination from dampness or from chillers or humidifiers, but when studies have been performed, no direct relationship between the two has been found. Some molds may produce direct toxicity. Most contaminants do not cause harmful effects. Many produce effects only in individuals particularly sensitive to the organism, the most common symptom being allergies. It also is possible that chemicals used in cleaning and maintaining the systems may produce the same effects if not properly used. Proper operations and maintenance practices can reduce the potential for harmful effects from biological and chemical contaminants.

Pollutants in residential or commercial buildings may be controlled at their source. Some of the control techniques include removal of pollutant sources, encapsulation of sources, substitution of alternative building materials (generally caulks, paints, adhesives and the like) gauged likely to produce less potentially harmful pollutants in a building, and scheduling applications for times when fewer people are present. In a report on indoor air quality issues related to the acquisition of conservation in commercial buildings (PNL 7504¹), the author includes renovation as a control technique. Renovation may be the most expensive technique for controlling pollutants. However, there are often other reasons for the renovation.

Radon gas, which comes from the soil, is primarily associated with residential energy conservation efforts. The decay products of radon emit alpha radiation and may cause lung cancer. The major health effects seen in studies of underground miners are a consistent relationship between lung cancer incidence and exposure to radon decay products. Studies that simulate exposures akin to the mining environment have shown pulmonary emphysema, pulmonary fibrosis, pneumoconiosis, lung cancer, and shortened life span. Other effects observed in test animals exposed to radon progeny seem to be either spontaneous or related only indirectly to radon exposure. In general,

¹Pacific Northwest Laboratory of Battelle Memorial Institute. 1990. *Indoor Air Quality Issues Related to the Acquisition of Conservation in Commercial Buildings*, pages 43-44.

experimental studies of the uranium mine environment, using rats, show that pulmonary fibrosis, emphysema, and lifespan shortening are not produced to any significant extent until radon-daughter exposures exceed about 5,000 working level months (WLM). Lung cancer is produced in these studies at levels down to 20 WLM, which are typical for human environmental exposures. These numbers do not imply the levels at which regulatory standards should be set; rather they are the results of animal studies and demonstrate that respiratory carcinoma is the most prominent health effect associated with radon exposure.

The EPA has a recommended action level of 4 picocuries (pCi) per liter. For comparison, 1 pCi/l translates to about 0.005 working levels (WL) using typical assumptions. Thus, 1 WL equals about 200 pCi/l. Exposure to 1 WL for 170 hours (1 working month) amounts to 1 WLM of exposure. Most people spend much more than 170 hours in their home over the course of a month; thus residential exposure may be much greater than 1 WLM on a monthly basis. For example, over a month's time, a child spending 75 percent of his or her time at home would receive an exposure of 3.2 WLM at 1 WL exposure (NRC 1991²).

Few data exist to clearly determine the health effects of radon at the low exposure levels that occur in most homes. There is a great deal of uncertainty in extrapolating human health effects from hard working, adult, male miners receiving relatively high doses in mine environments for short periods of time to a more sedentary and diverse group of individuals exposed to low levels of radon for extended periods of time. However, recent studies suggest that data from miners is likely to be the principal basis for estimating the risks of indoor radon for the immediate future (NRC 1991). These studies also demonstrate the uncertainty surrounding risk assessments of radon in homes and conclude that even recent extrapolations of risk estimates from mining to the home environment may overestimate the number of radon-caused lung cancer cases by 20 to 30 percent (NRC 1991).

The presence of radon in the soil varies across the region. Parts of northeast Washington, central and northern Idaho, and Montana may have localities with higher radon levels in the soil than other parts of the region. Radon prone areas are not precisely mapped, nor can radon levels be determined from geologic features. Neither can geologic features be correlated with radon release rates. The influx of radon into a particular structure is not predictable. Concentrations of radon and its decay products have been shown to be elevated in basements, but lower on other floors. Indoor concentrations varied inversely with ventilation rates. Intact slabs without cracks or leaks around pipes have been shown to reduce infiltration of radon into a building by a factor of 10.

EPA is currently trying to determine an appropriate national standard for radon in buildings.

²National Research Council (NRC). 1991. *Comparative Dosimetry of Radon In Mines and Homes*. National Academy Press, Washington D.C.

Health and Safety

Several energy conservation activities may pose health and safety concerns if not properly installed. Failure to maintain water temperatures in hot water heaters above 140° F could increase the potential for Legionella contamination. Certain insulation practices, such as wraps, could increase the hazard from fire. Use of certain types of water heating or dishwashing systems employing chemicals could increase the potential for chemical contamination of domestic water supplies or dishes.

These potential impacts can easily be mitigated by insuring water temperatures are maintained at safe levels to prevent the growth of bacteria, the addition of insulation around storage tanks adheres to all fire codes, plumbing systems adhere to all applicable codes, and chemical dishwashing systems follow all proper use and maintenance practices.

5.3.4.2 Generating Resources

Outside Air Quality

The effects of air pollutants from fossil-fueled generating plants on human health for each of the four generic plant locations were estimated. Modeled estimates of air pollutant dispersion (as discussed in the Air Quality Analysis section of this chapter) were coupled with human population figures for the areas reached by the air pollution plumes. These estimates were then combined with published risk estimates for acute morbidity and mortality. These risk estimates provide the statistical likelihood that a certain pollutant exposure will result in death or illness during or soon after exposure. A complete discussion of the analysis of human health impacts is in Appendix A of this EIS.

Estimates of lifetime cancer risk were developed for metals and radionuclides associated with airborne particulates. Lifetime cancer risks were divided by 70 (years, the length of an assumed average lifetime) to convert them to annual risks.

The calculation of potential deaths and illnesses (for both lifetime cancer and acute effects) is presented in greater detail in Appendix F of this EIS. The uncertainty surrounding these estimates can be as large as the estimate itself. Thus, the actual health effects resulting from the alternatives could range from none to double the estimates provided. However, the purpose of this analysis is not to predict actual health impacts to a fine level. Greater accuracy will be achieved when specific generation plant designs and locations are known and a thorough analysis of pollutant emissions, weather conditions, terrain, and population is conducted. The purpose of this analysis is to provide a consistent means to compare the alternatives and to demonstrate the types of potential impacts that may occur.

In the summary graphs shown in Figures 5-20, and 5-21, total potential deaths and illnesses resulting from exposure to nonreactionary criteria pollutants are shown for the region. The imports alternative includes effects that may result from the generation of power outside the region. As already indicated, death includes both acute and long term cancers. In this analysis, the pollutants contributing to mortality (death) include nitrogen oxides, sulfur oxides, particulates, metals, and radionuclides. The analysis of illnesses (morbidity) is based on impacts to the lower respiratory system. These impacts include

illnesses such as bronchitis, disease, cough, and colds. In the analysis, sulfur oxides contribute to each of these illnesses. Particulates contribute to bronchitis. Other pollutants were not included in the analysis of morbidity because of a lack of risk factors.

Figure 5-22 shows potential deaths resulting from exposure to ozone. Ozone is a criteria pollutant that forms in the atmosphere from a combination of sunlight and other pollutants. Ozone concentrations are found to be equivalent for all alternatives within the uncertainties of the model. Thus, the impacts shown in Figure 5-22 apply equally to all alternatives. The total impacts range from near zero to about 4.5 annual deaths at the four individual study sites. In the years 2000 and 2010, deaths per study site average about 2.5. In 1991, the average for each site is about 1.5.

Figure 5-20
Criteria Pollutant Mortality

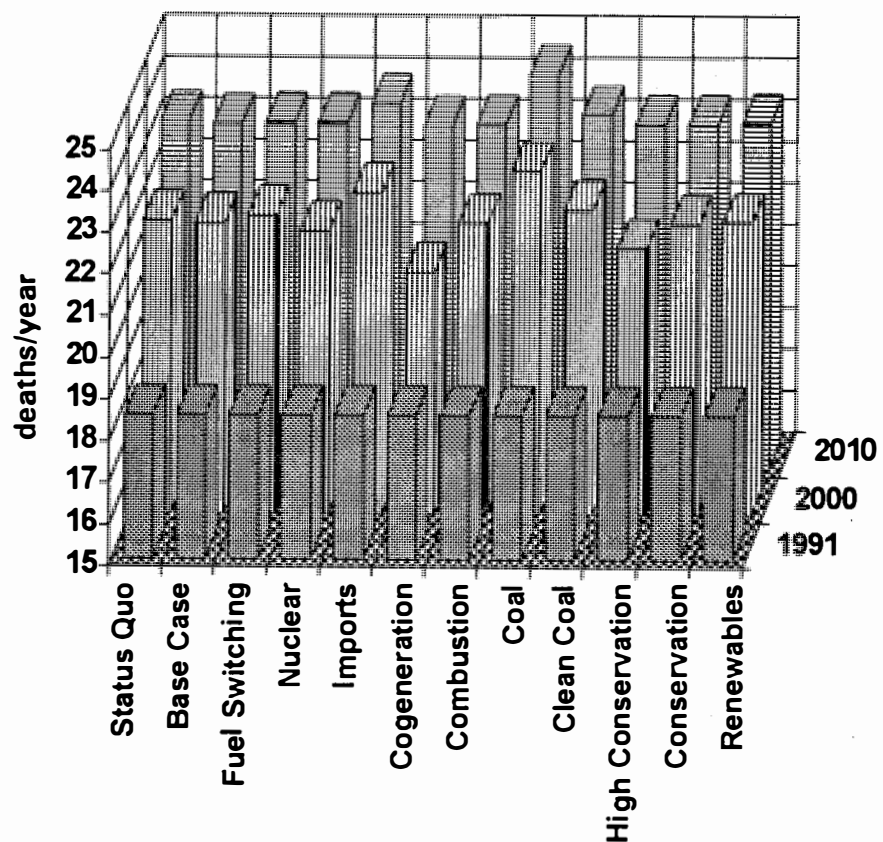


Figure 5-21
Criteria Pollutant Morbidity

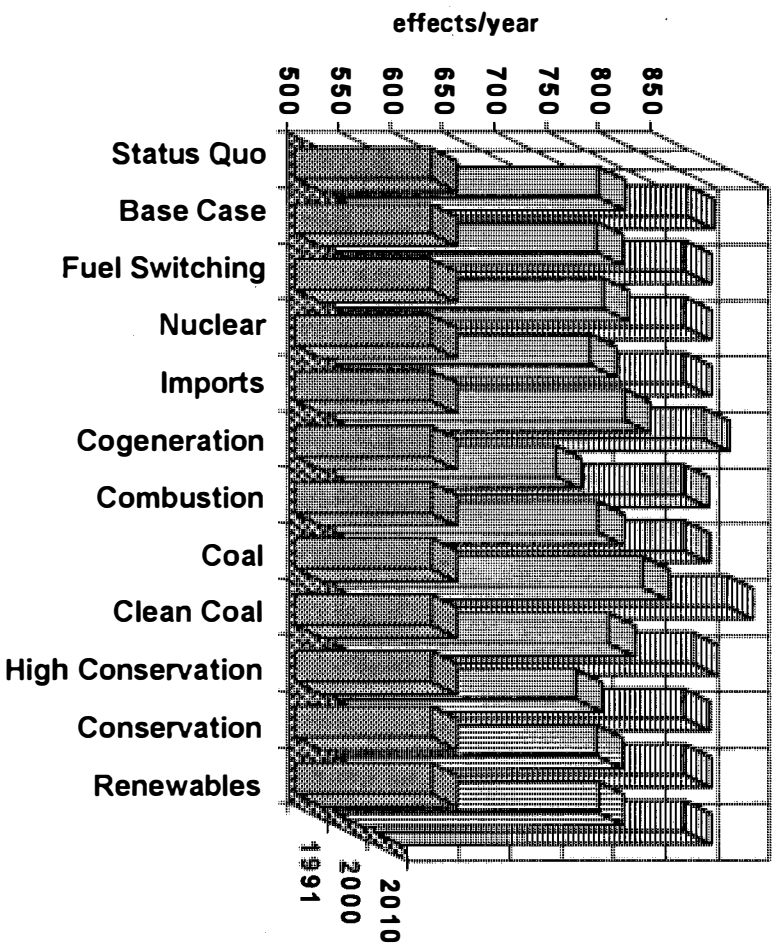
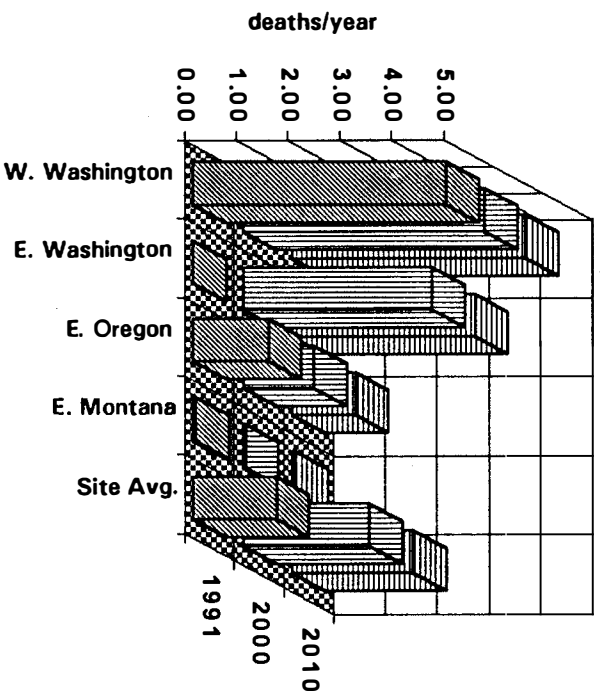


Figure 5-22
Ozone Mortality



Economic Impacts

Costs were calculated for mortality and morbidity (nonfatal) effects caused by criteria pollutant emissions. Mortality effects include cancer fatalities and deaths from acute illness. Morbidity effects include bronchitis, lower respiratory disease, coughs, and colds. For ozone, only mortality effects were estimated because no data were available for morbidity.

To calculate mortality costs, the value of a statistical life (\$4.388 million) was multiplied by the mortality risks for SO₂, NO_x, TSP and ozone. The value of a statistical life is derived by aggregating the value for small risks faced by the entire population. The resulting mortality costs for each alternative are shown in Figure 5-23 for each of the study years.

Coal results in the highest mortality impacts, primarily from non-cancer deaths, in 2000 and 2010. Cogeneration and High Conservation produce early savings--they have the smallest economic values in 2000--but by 2010 have values similar to most of the other alternatives. The value of Imports is higher than all the other alternatives except Coal in 2010.

For ozone, the mortality rates were the same across all alternatives. Thus, there is a single dollar amount for all alternatives in each study year, as shown in Figure 5-24 (\$27.90 million in 1991, \$42.65 million in 2000, and \$40.72 million in 2010). The estimated ambient ozone levels are very similar in 2000 and 2010, as are the economic values of ozone mortality.

The analysis of morbidity (illness) effects is based on impacts to the lower respiratory system. In order to calculate the costs associated with these effects, the economic value of respiratory symptoms (\$9.63 per day) was multiplied by the morbidity risks for each alternative. This value is the amount an individual would be willing to pay to have one less day of these symptoms. The resulting morbidity costs for each alternative are shown in Figure 5-25 for each of the study years.

The economic values for total morbidity effects range between \$68,154 (Cogeneration) and \$76,249 (Coal) in 2000. The values for 2010 are slightly higher than those for 2000 for all effects, with most alternatives valued at a little over \$76,000. Coal, Imports, and Clean Coal have higher values.

Figure 5-23
Economic Value of Human Mortality Due To Criteria Pollutants

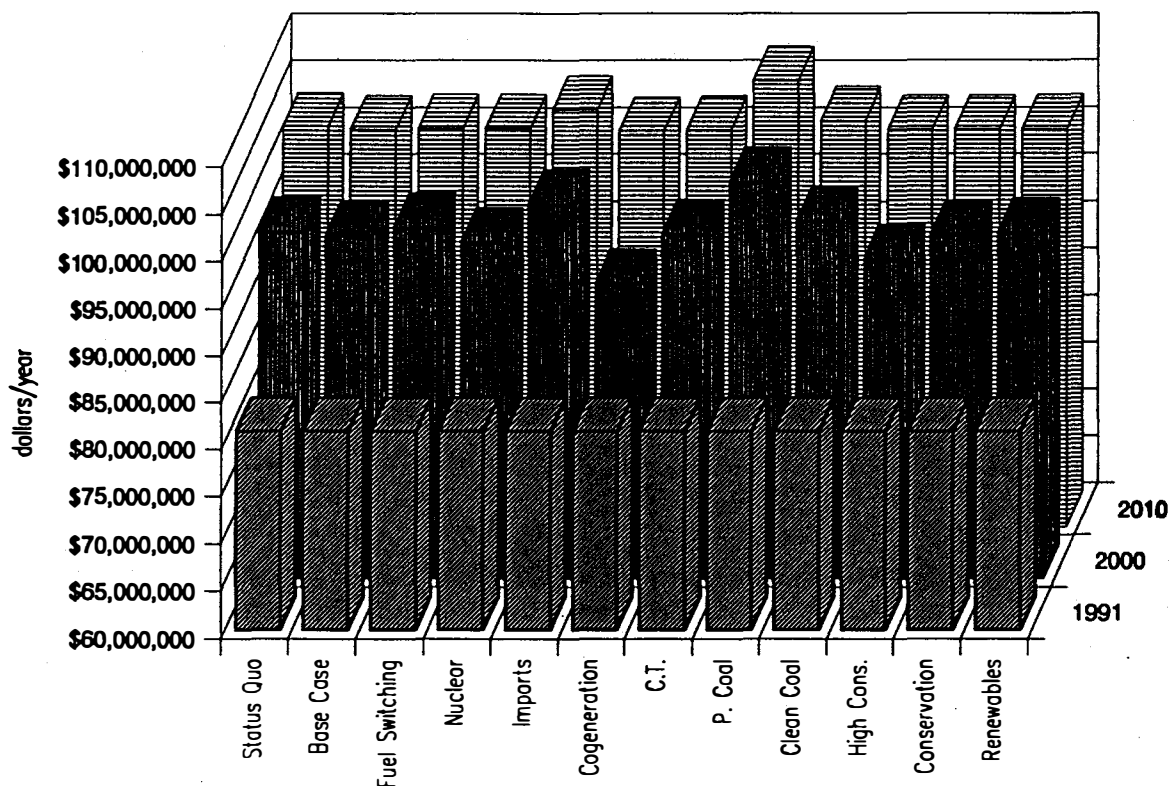


Figure 5-24
Economic Value of Human Mortality Due To Ozone

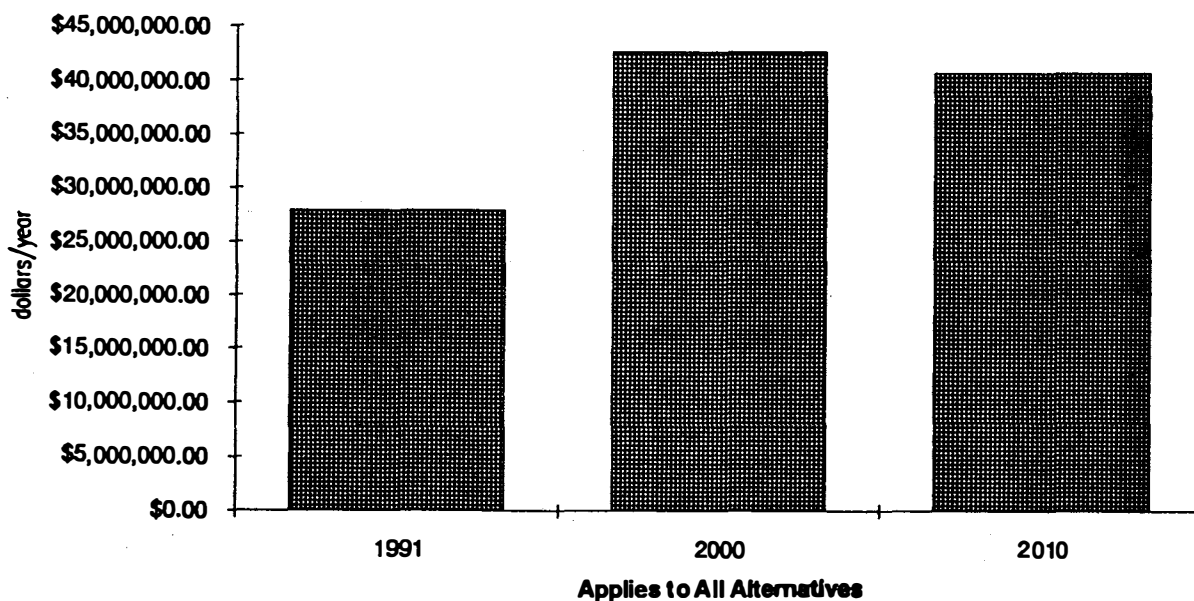
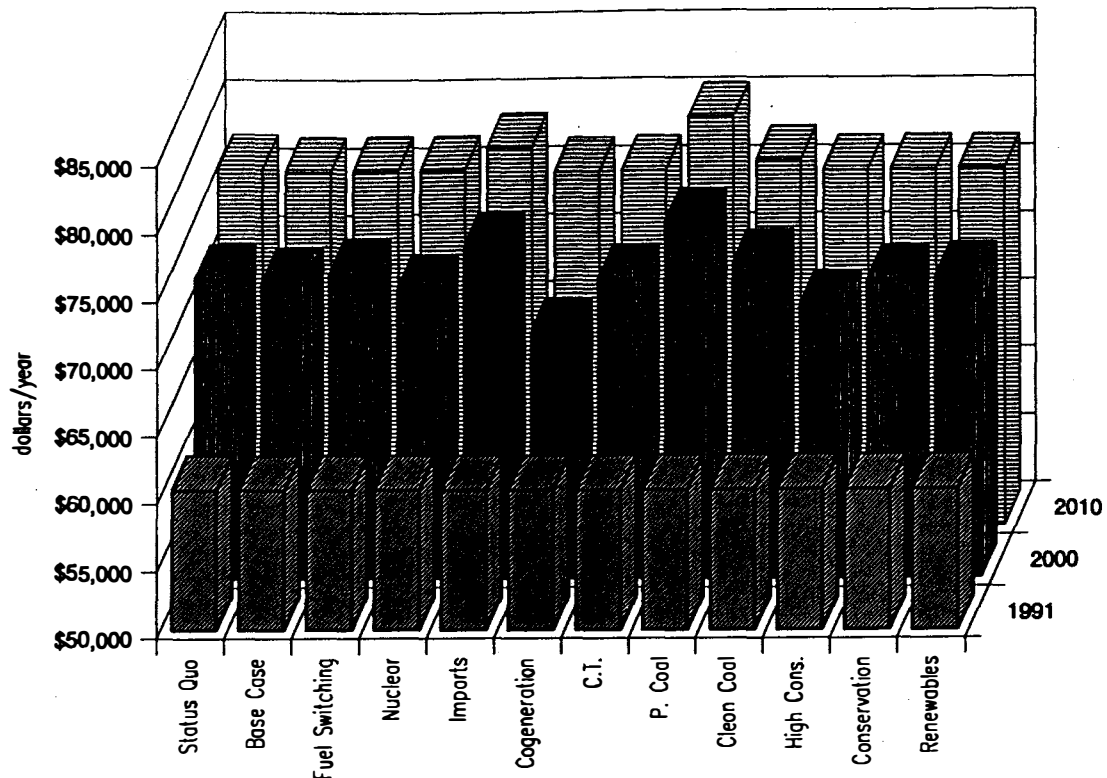


Figure 5-25
Economic Value of Human Morbidity From Criteria Pollutants



5.4 Natural Resources Effects

5.4.1 Resident Fish

Residing in Reservoirs

Drawdown of reservoirs can affect resident game fish populations by altering the physical and biological characteristics within the reservoir. Lowered reservoir elevations reduce the productive shallow areas near the shoreline. This can result in reduced habitat for game fish and their food organisms. Reservoir fluctuations also change water temperature, which can affect fish growth.

In analyzing the SAM data to evaluate effects of various resources acquisitions on resident fish, special attention was paid to the April through November period. This is the primary period of biological activity for most resident fish species in the Columbia River Basin's Federal storage reservoirs. The majority of the species spawn in the spring. The young fish hatch in late spring and early summer and attain the bulk of their growth May through October. Excessive drawdown of reservoirs in these months may impact resident fish productivity and growth.

Reservoir elevations were not particularly sensitive to the type of resources acquired, but rather, the amount and shape in which the resources were added and the amount of remaining surplus. Changes in elevations were greatest in low water conditions and diminished as water conditions improved.

Only small changes in reservoir elevations occurred, regardless of the resource type or shape, when 1,000 megawatts of energy was acquired. Changes in reservoir levels were more pronounced when 5,000 megawatts of a new resource were added. The largest impacts occurred when resource additions were shaped September through April, particularly in low water conditions. Reservoirs began the spring period as much as 10 to 20 feet higher, and by the fall period, could be as much as 20 feet lower.

Reservoir levels were also lower in the summer and fall months, when addition of resources created a large surplus. Reservoirs were drafted harder during this period to shape surplus energy into higher valued markets. While this represents a change from the case in which the system is in load/resource balance, it is not much different than the existing system under surplus conditions.

Alternatives that lend themselves to being shaped into just a portion of the year include Combustion Turbines and Imports. These alternatives have the potential to impact resident fish. It should be noted that the extent to which the hydro system can be shaped is limited by several power and non-power operating requirements. These requirements are being analyzed in the SOR and may change such that this degree of shaping is no longer possible.

Kootenai and Flathead Rivers

While non-migrating fish species reside throughout the region, two stream reaches have been identified in the Northwest Power Planning Council's (Council) Fish and Wildlife Program as requiring special protection for resident fish. These are the Kootenai River downstream of Libby Dam, and the Flathead River below Hungry Horse Dam. Reduced flows below the dams can interfere with spawning, incubation, emergence, rearing, and migration of resident fish and can lower production of aquatic fish food organisms. In addition, lack of high spring flushing flows can create sediment problems. The Council has recommended that flows below Libby not go below 4,000 cfs, except in years of extremely low runoff, when no less than 3,000 cfs should be provided to protect westslope cutthroat, rainbow trout, and Dolly Varden trout. They also recommend that flows on the Flathead River at Columbia Falls not go below 3,500 cfs to protect kokanee. Flows at Columbia Falls should also not exceed 4,500 cfs between October 15 and December 15, when these fish are spawning.

These flow requirements were not violated for any of the alternatives.

The System Operation Review EIS will look closely at the effects of reservoir operations on resident fish in streams and recommends reservoir operations.

5.4.2 Anadromous Fish

The acquisition of new resources can change the operation of the hydro system, which alters the amount and timing of spill and flow available to migrating juvenile salmon and steelhead. The primary period of downstream migration for most stocks is between April 15 and June 15, with summer and fall species continuing to migrate through early November. It is uncertain at this time to what extent these later species are dependent on flow to aid in their migration. Until adequate bypass facilities can be installed, spill remains important in passing young fish over the dams.

Operations on the Snake River did not change substantially as a result of any of the resource additions. Therefore, the results presented in this section pertain to the mid and lower Columbia River.

Flow changes result primarily from the shape in which resources are added, not from the type of resource acquisition. When resources are added uniformly over the year, there is little change in the monthly average flow. Resources which are down for maintenance in the spring months aid juvenile migration by increasing flows during this period. Flow changes become more pronounced as more energy is added to the system. For example, adding 1,000 megawatts of energy with an April 15 through May maintenance period causes flows to increase between 1 and 5 kcfs, while a 5,000 megawatt addition can cause flows to increase between 5 and 30 kcfs. Flows generally decrease slightly during the remainder of the year. Alternatives which would typically include maintenance during the spring period include those that emphasize nuclear and coal.

Resources that are shaped September through April generally cause flows to increase April 15 through August and decrease the remainder of the year. Again, this is beneficial to the spring migrating fish but may cause problems for those species that migrate later in the fall. Flow changes are most pronounced in low water conditions. A 1,000-megawatt addition causes flows to increase an average of 10 kcfs June through August, while a 5,000-megawatt addition can cause flows to increase up to 50 kcfs. Alternatives which lend themselves to heavy shaping include combustion turbines and imports. It should be noted that the extent to which the hydro system can be shaped is limited by several power and non-power operating requirements. These requirements are being reviewed in the SOR and may change such that this degree of shaping is no longer possible.

Spring flows generally decrease when resources are added such that a surplus occurs. This is due to more energy being shifted into the fall from the spring and summer periods. Flows typically decrease between 1 and 10 kcfs.

The addition of new resources to the system also affects the amount of overgeneration spill produced. Displaceable resources, both medium and high cost, decrease the amount of overgeneration spill available for fish in all cases. Overgeneration spill decreased as much as 70 percent in April and May when 1,000 megawatts were added, and was eliminated in all months except June when 5,000 megawatts of displaceable resources were added. Only when the system was surplus did overgeneration spill increase. This decrease in spill does not affect the amounts of planned spill released specifically to aid juvenile fish past the dams.

The problems associated with juvenile fish migration are currently being addressed in several forums. The Council has recently amended their Fish and Wildlife Program to provide greater protection for anadromous fish. The System Operation Review is addressing all uses of the river system and will develop a System Operating Strategy which will guide the operation of the hydro system.

5.4.3 Vegetation

Site-specific impacts on vegetation occur from all generation resources. These impacts would be evaluated in the site-specific environmental documentation of each resource that BPA would consider acquiring. Generic impacts on vegetation resulting from thermal generation and hydro system operation are described in the following section.

Impacts From Thermal Generation

Strip mining impacts may be a factor for some thermal generating resources. Strip mining involves excavation, backfilling, and grading that removes vegetation from large tracts.

Uncontrolled runoff and the resulting soil erosion may contaminate surface and ground waters, altering species composition and soil characteristics. Accidental fires may temporarily affect vegetation.

Exploration and mine development involve the use of drill rigs and test pits, which have localized impacts on soil and vegetation due to grading, clearing, noise, dust, runoff, excavation, and related activities, but on a far smaller scale than actual mining operations. Mines on Federal lands are operating under permits granted by the Office of Surface Mining (OSM). Permits require compliance with the National Environmental Policy Act (NEPA), including a requirement dealing with threatened and endangered species. The U.S. Department of the Interior must approve the permit. Since these permitting requirements and resulting certification are mandated, none of the actions covered by the RPEIS would cause impacts to any threatened or endangered species or other species from the operation of mines serving thermal generation.

Where spills or seepage from waste storage ponds contaminate soil or groundwater, vegetation may accumulate toxins. Leaching from lined sites is negligible. The Resource Conservation and Recovery Act forbids placing waste storage facilities in environmentally sensitive areas (e.g., wetlands), in critical habitat for endangered species, in seismically active areas, or within recharge zones of sole-source aquifers. Waste-handling facilities cannot discharge pollutants into surface waters in violation of the requirements of the National Pollution Discharge Elimination System established through the Clean Water Act. Therefore, only accidental spills or poorly operated facilities are likely to affect vegetation.

Effects from nuclear power plants depend on the plant's location and cooling system used. Nuclear plants produce radioactive waste, radioactive emissions, waste heat, and chemical residuals from the cooling water system. The impact of nuclear power plants on terrestrial vegetation is most likely to occur through the deposition of drifting steam that is released from cooling towers. Trace amounts of heavy metals, including arsenic, cadmium, lead, chromium, and mercury, have also been found in tower drift. This drift can damage nearby vegetation, especially if salt water is used for cooling. Improved engineering design can control the problem through the use of baffles or drift eliminators, which reduce the amount of water droplets in the air stream.

Impacts of diverting water for use in cooling depends on the source of the water. If diverted from surface drainages, there may be some reduction in the amount of riparian vegetation and a shift in composition to less moisture-dependent species. This would be of greatest concern in arid environments.

Impacts to Crops From Changes in Air Quality

Concentrations of SO_x , NO_x , and TSP are not expected to result in significant impacts to crops for any of the alternatives. Impacts from exposure to ozone are equal across the alternatives with impacts resulting in no more than 1 percent crop losses at some locations. The following estimates apply to all alternatives. A complete discussion of the crops impacts analysis is in Appendix F of this EIS.

Relationships between the seasonal 7-hour/day mean ozone concentration and crop yield were developed by Heck et al. (1982). They provide linear relationships between ozone concentration and the percent reduction for corn, soybean, kidney bean, lettuce, spinach, turnip, and wheat.

In eastern Montana, the seasonal 7-hour average incremental increase is negative for all estimates. This provides a positive impact. These positive effects on crop yields should be considered as neutral or no potential change.

In eastern Oregon, the seasonal 7-hour average incremental increase is negative for the 2010 estimates. The increase is positive for 1991 and 2000. Estimates indicate less than a 1 percent reduction in crop yield during 1991.

In eastern Washington, the seasonal 7-hour average incremental increase is positive in 2000 and 2010. No estimate is applied for 1991. Estimates indicate a 1 percent or less reduction in crop yield during 2000.

In western Washington, the seasonal 7-hour average incremental increase is negative except for the year 2000's high values. Estimates indicate a less than 0.1 percent reduction in yield.

Impacts From Hydro Projects

River impoundments and their reservoirs or man-made lakes result in a complex web of impacts that affect biological, physical, and chemical components of the environment. The hydrology, or the way a river flows, is fundamental to the character or description of a stream. Controlling a river's discharge by impoundment redistributes flow over time. Flow is controlled by discharge from the dam rather than annual precipitation and snow melt. The changes in water fluctuation timing and magnitude affect all the inhabitants and users of the stream.

Primary production in rivers is dominated by macrophytes and periphyton. Aquatic macrophytes, as used here, refers to macroscopic forms of vegetation growing in water. Commonly included are mats of green algae, stoneworks, mosses, and ferns. Periphyton refers to the microscopic algae that is attached to underwater substrates of a lake or river. Phytoplankton (the unattached algae in the waters of a lake or river) is usually found only in large, slow-moving rivers. Much of the organic input to a river can come from terrestrial production that falls into the river or blows or washes from the shore. This shoreline vegetation is the riparian habitat and includes all the land bordering the channel of a river. Each of these plant communities contributes to the overall health of the river. Each is affected by water level fluctuations.

Algae can be attached to most any object in a river. Like other plants, algae respond to combinations of temperature, light, substrate, and current. Current velocity is one of the more important variables. Velocities that provide a rapid exchange of nutrient can promote growth. Fast currents, however, can destabilize the substrate and scour attached algae.

Fluctuating water levels can affect algal growth. Established algal growths that are dewatered will dry up and die. The enhancement of low-flows will produce more habitat that remains productive for longer periods. The magnitude of impacts related to algae growth is dependent on the type of algae that is enhanced or adversely affected.

The spatial distribution of vascular plants is related to the interaction of several physical and chemical attributes: discharge, depth, velocity, turbidity, dissolved

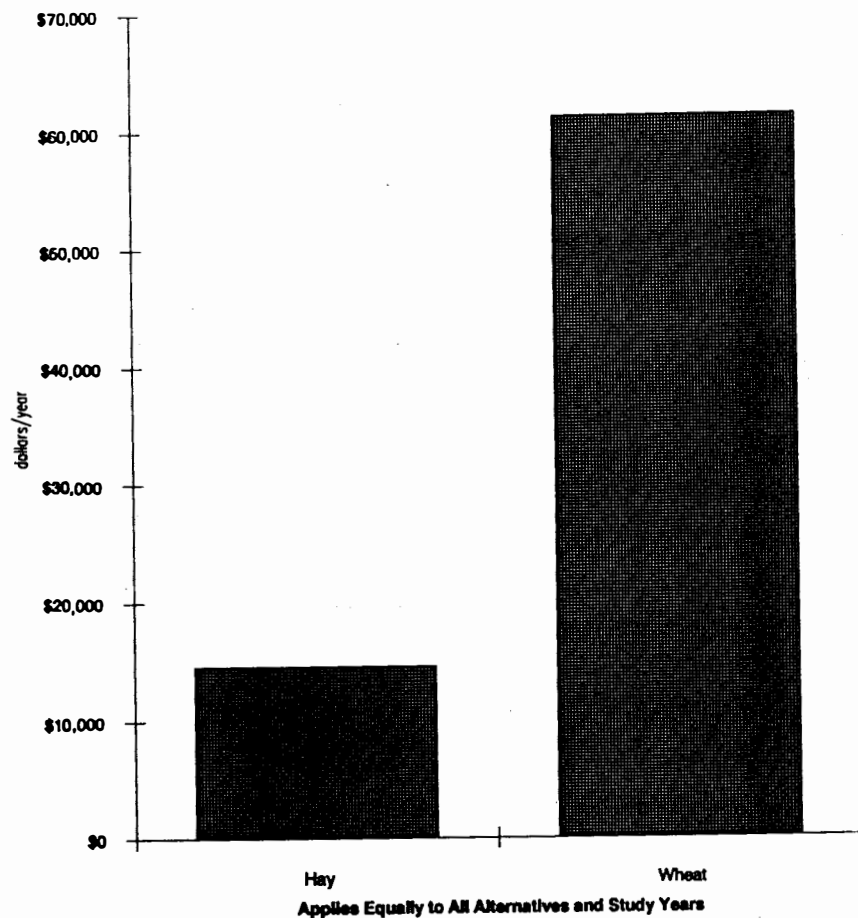
chemicals, and substrate size. It is not likely that reservoir releases that affect temperature or nutrients will affect higher plants. However, the exception is possible if effluent discharges from agricultural or industrial releases comprise a high percentage of the flow, or river discharges are supplied by a nutrient-rich release. In either case, aquatic macrophytes may develop.

Turbidity controls the depth of light penetration. In most cases, turbidity is reduced by upstream impoundment. Thus, an expansion of the macrophyte communities could be expected. Substrate stability is influenced by dam discharge. Substrate stability is increased in areas where flow is slowed. The root systems of macrophytes are more able to become established and the area of substrate available for macrophytes increases. Increased macrophytes can be positive when they provide an increased food supply for mammals and birds. Increased riparian habitat can provide cover to moderate water temperatures, thus increasing rearing habitat for juvenile fish.

Economic Impacts on Crop Yields From Changes in Air Quality

The crops analysis found no significant impact on crop yields associated with criteria pollutant emissions except ozone. Impacts from exposure to ozone were equal across alternatives, with no more than 1 percent crop losses found at some locations. This analysis averaged 1989 market prices in Idaho, Oregon, and Washington for hay and wheat. The average prices were inflated to 1991 dollars, resulting in values of \$89.26 per ton of hay and \$4.45 per bushel of wheat. These values multiplied by the estimated crop losses give the results shown in Figure 5-26. These costs apply to all alternatives in all study years.

Figure 5-26
Economic Value of Crop Losses From Ozone



5.4.4 Wildlife

Site-specific wildlife impacts are likely to occur from generating resources. Major generic impacts associated with thermal generation and development and operation of hydro systems are described below. Potential impacts will also be addressed in the site-specific documents tiered to the RPEIS.

Impacts From Thermal Generation

Strip mining associated with some thermal generation affects wildlife primarily through disturbance and loss of habitat. Displacement of species may cause species to move into adjacent areas, where overcrowding and competition for limited resources may increase mortality, especially in critical habitat areas. Accidental fires may temporarily affect wildlife.

Exploration and mine development involve the use of drill rigs and test pits, which have localized impacts on wildlife due to grading, clearing, noise, dust, runoff, excavation, and related activities, but on a far smaller scale than actual mining operations. Mines operate within standards set by the U.S. Department of the Interior and other government standards. Therefore, none of the actions covered by the RPEIS will affect Federally listed threatened and endangered species. (See Appendix F.)

For existing coal-fired plants, impacts can occur from increased water withdrawals for cooling or increased return-water temperature. (See Water Use section.) Hauling of coal and overburden may result in noise, dust, air emissions, soil compaction, and road-kills.

Impacts resulting from spills or seepage from waste storage ponds are described above (Section 5.4.3, Vegetation).

Disposal ponds may attract waterbirds, especially if there are nearby sources of food. Birds using these ponds for resting and feeding can ingest potentially toxic particles or slag. Surface-feeding waterfowl are most vulnerable to ingesting slag, which may contain beneficial as well as detrimental trace metals. Birds may also collide with transmission towers and lines situated close to the ponds. There would be a slight change in the amount of ash deposited into disposal ponds as a result of the thermal generation in the alternatives addressed in this EIS. (Further discussion of solid waste disposal is contained in Appendix F.)

Effects from nuclear power plants depend on the plant's location and cooling system used. Nuclear plants produce radioactive waste, radioactive emissions, waste heat, and chemical residuals from the cooling water system.

Impacts From Changes in Air Quality

Wildlife impacts from criteria pollutants, trace metals, and acid deposition were estimated for each of the alternatives. Wildlife population density estimates were from local wildlife biologists near each of the four study sites. Mortality estimates for avian species were based on the total adult breeding birds of all species per square mile of habitat type. Waterfowl production estimates were obtained from state wildlife biologists and the U.S. Fish and Wildlife Service. A complete discussion of the wildlife impacts analysis can be found in Appendix F of this EIS.

Criteria Pollutants

Acute mortality risk estimates were developed using those for human populations. Applying these risk factors to animals assumes that wildlife populations have about the same sensitivity to air pollutants as humans, and receive about the same dose. However, many smaller animals, and especially birds, take in more air per unit of body weight than do people. Some larger animals, such as deer and elk, have slower respiratory rates. Thus, the mortality measures should be viewed as relative estimates for purposes of comparing alternatives, rather than as predictions of actual outcomes.

Criteria pollutant impacts were calculated for species within 32 kilometers (20 miles) of the study sites. Mortality estimates were not calculated for nitrogen oxides because of a lack of direct mortality rate information for chronic low level exposure.

Wildlife deaths were estimated for deer, elk, ground squirrel, mink, beaver, avian, and small rodents from SO_x and TSP emissions.

Estimates of wildlife deaths for rodents, deer, and avian species are shown in Figures 5-27 through 5-32. Death rates from SO_x and TSP for other wildlife species are reported in Appendix A, Figures A-3 through A-10.

The number of deaths resulting from exposure to sulfur dioxide and particulates are highest for birds and rodents. For example, in western Washington, mortality

estimates include 300 birds and 12,000 rodents. These figures amount to about 0.02 percent of these local populations.

Figure 5-27
Regional Small Rodent Mortality From SO_x Emissions

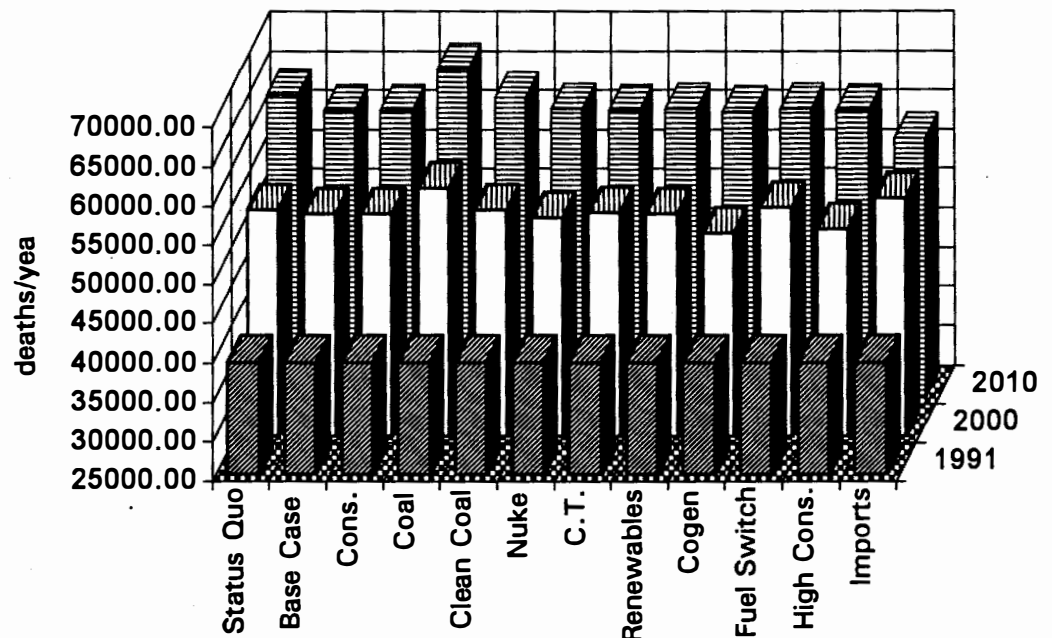


Figure 5-28
Regional Deer (all species) Mortality From SO_x Emissions

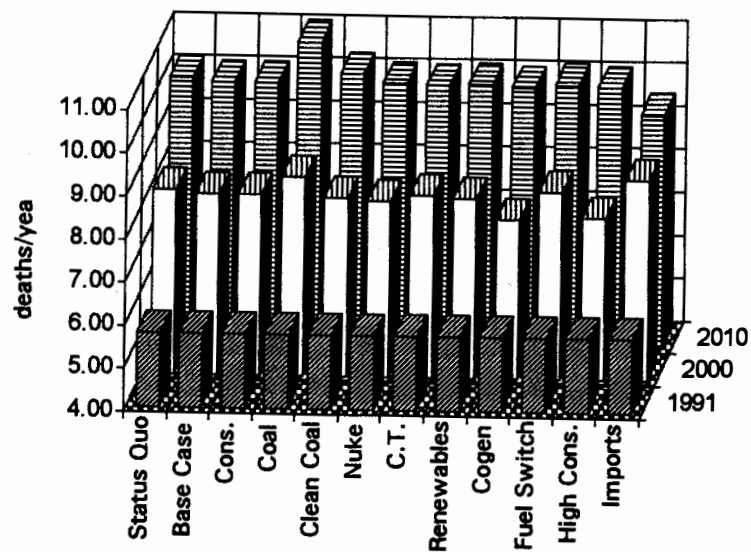


Figure 5-29
Regional Avian (all species) Mortality From SO_x Emissions

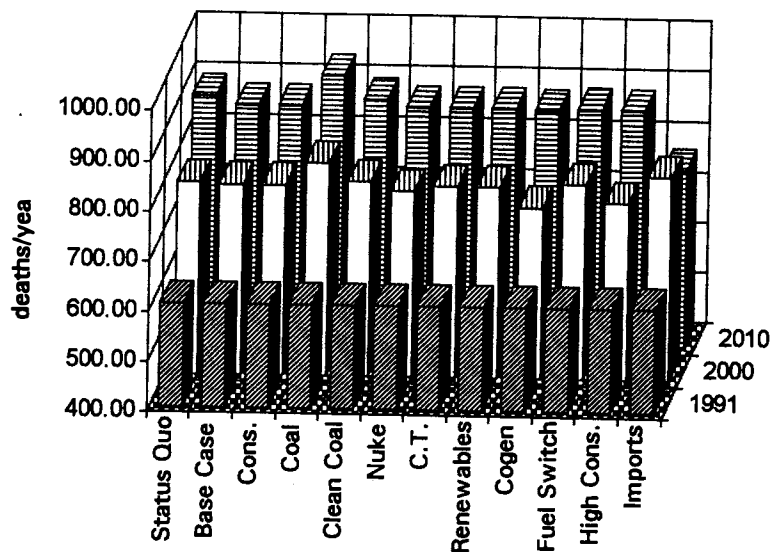


Figure 5-30
Regional Small Rodent Mortality From TSP Emissions

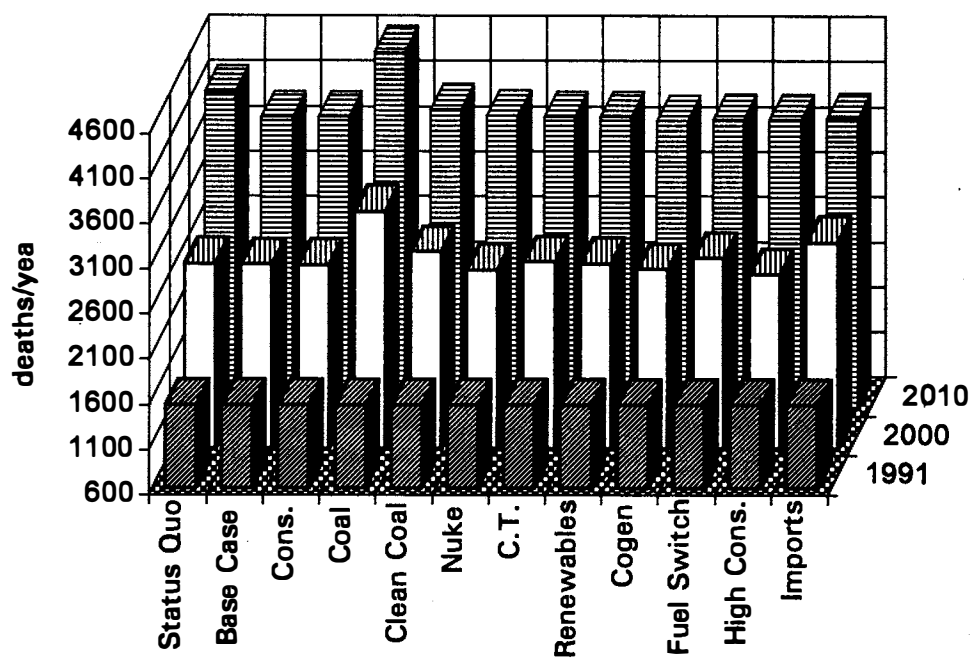


Figure 5-31
Regional Deer Mortality From TSP Emissions

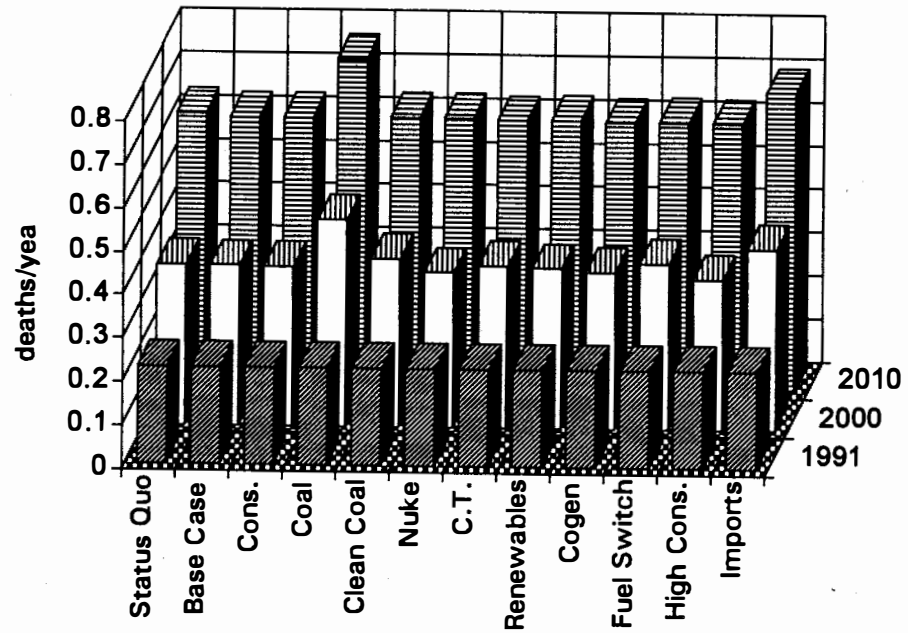
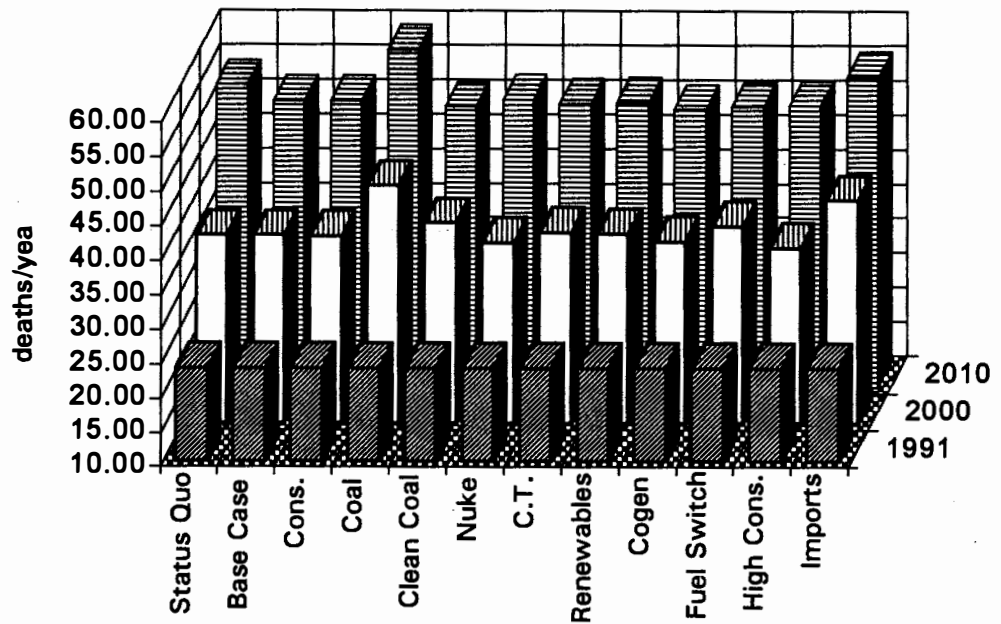


Figure 5-32
Regional Avian (all species) Mortality From TSP Emissions



Acidic Deposition

Acidification of surface waters within a 400-kilometer radius was used to estimate potential impacts to waterfowl production from acidification. Areas within 400 kilometers of the generating plant where the projected pH of rainfall was less than or equal to 5.0 were superimposed on the surface water alkalinities of the area.

Acidification in western Washington may cause a reduction in waterfowl production. About 2,000 additional duckling deaths may occur per year. Some species may continue to live in the area, but ultimately, increased difficulty in foraging will reduce the population of the species.

Metal contamination was calculated using particulate deposition estimates. These estimates were used to calculate potential metal deposition to soil and aquatic environments.

The Coal Alternative results in the greatest emissions of particulate that carries trace metals. Therefore, this alternative was used to test the magnitude of potential impacts.

Plant loss or ecosystem changes from metal deposition are not anticipated for any alternative. Although the impacts could not be quantified, a potential adverse effect on plants was noted for western Washington. Western Washington is susceptible to acid deposition, which can increase the solubility and plant uptake of several metals.

Two metals, arsenic and selenium, pose potential health problems for wildlife that feed on aquatic organisms.

Selenium concentrations will probably not reach levels that may pose a direct threat to wild animals feeding on aquatic organisms for any of the resource alternatives at any of the sites. However, selenium concentrations in the water may greatly alter the food resources of wildlife in western Washington and eastern Montana, where concentrations in the waters exceed 20 ug/L. The Coal Alternative may introduce potentially harmful levels of selenium in eastern Oregon's aquatic environment in the year 2010.

Distances greater than 60 kilometers from the study sites typically had the greatest ozone concentrations. Minimum and maximum ozone concentrations were calculated. The differences found between the alternatives was less than the uncertainty in modeling the ozone concentrations. Thus, we assume that the alternatives will result in approximately equivalent concentrations. The minimum exposure scenario for ozone resulted in additional deaths only for rodents. However, death rates for typical small rodent populations would be increased by less than 0.0001 percent, a very small number. Under maximum exposure conditions, 1 to 4 additional bird deaths may occur per year. These impacts are assumed to occur equally for all alternatives.

The number of additional deaths of birds and mammals appears minimal unless endangered or threatened species are present in the downwind areas. Loss of even a few individuals from a limited population can have a profound impact on the species' survival in that area. The habitat of all four sites supports several state or Federally listed endangered and threatened birds and/or mammals. It should be

noted that the mortality incidence will be reduced in species receiving only seasonal exposure to the plume compared to those of animals receiving a year-round or critical season (i.e., summer for ozone production) exposure.

Impacts From Hydro Projects

Dams change the annual flood regime of a river system. This can cause conflict with the natural conditions between flora and fauna and the riparian habitat. These habitats are important for food, cover, and breeding. Riparian areas are productive inland habitats for waterfowl because of the annual replacement of nutrients by flowing water. Floodplains and deltas function as sanctuary and breeding ground for ducks and geese. Many of these areas are islands that protect breeding and rearing populations from terrestrial predators.

Aquatic mammals also depend upon the annual floods to maintain the riparian habitat in a high state of biological productivity. Large mammals are partly dependent upon the lush growth of semi-annually flooded areas. This can be diminished or lost by the "unnatural" water-level fluctuations necessary for electrical production or flood control. Water-level fluctuations can impact winter movement of mammal populations near a reservoir. After areas of a reservoir have frozen, fluctuations can break up ice sheets and make them impassable. Animals can become isolated from feeding or sanctuary areas during this time.

Potential impacts to fish at hydroelectric projects can be extensive. Eggs may be in nests buried in the bottom substrate, excavated on the substrate water interface, or in standing, aquatic vegetation. Where generating facilities draw water away from nesting areas, eggs may be dewatered. Repeated or lengthy dewatering can reduce survival. Eggs that are in the nests during the winter can be exposed to freezing conditions if nests are dewatered.

Juvenile fish generally rear near the shore, in areas where they can hide from predators and find adequate food supplies. Again, dewatering or water level fluctuations can alter these near-shore environments.

Juvenile fish are also susceptible to entrainment and impingement at water intakes. If the juveniles are entrained by water diverted through generator turbines or by water not returned to rearing environment, they will likely die.

Adults become susceptible to potential impacts of water level fluctuations when shore erosion increases, feeding areas are limited, and spawning areas are flooded or dewatered. Nesting areas can be exposed during spawning, beds of submerged vegetation can be left dewatered, and fish may be forced into waters that are unsuitable. Fluctuating water levels can result in the loss of valuable benthic fish-food organisms and in the increased survival of species that have less recreational value.

Economic Impacts

Although mortality data for different wildlife species are available, for most of the species in question, such as rodents, there has been no research on the consumptive value (e.g., hunting, observation) of an individual animal. Therefore, assessment of the costs of wildlife mortality is not possible. The following is an example of consumptive values that may be applied to game species:

Species	Economic Value
Waterfowl	\$2.40 to \$4.65 per bird
Deer	\$1.80 per animal per square mile

Even knowing the consumptive values, economic values associated with population reductions cannot be calculated without specific information about species, visits (for observers), or success rates (for hunters). For example, an increased mortality risk of 1/100,000 per deer due to air emissions would be worth about $\$1.80 \times 10^{-5}$ per hunter, using the above consumptive value. Assuming that the value is the same for all consumptive and nonconsumptive users, with an average of 100,000 visits per year to hunt or view wildlife in the affected area, the reduction in value due to air pollution would be \$1.80 per year. Other estimates have put values for deer as high as \$6,285 each. However, these studies have been found to be greatly inflated.

However, mortality impacts on game species were found to be very small. For the entire region, less than one statistical elk or deer is lost. Thus, economic values were not calculated for wildlife impacts.

5.4.5 Water Quality

Thermal power plants release pollutants and thermal discharges to bodies of water. The effluents resulting from each alternative for each of the study years are shown in Figure 5-33. The figure shows effluent from coal and natural gas-fired generation. The effluent from nuclear power plants is typically reported in milligrams per liter, rather than tons per year as for fossil-fuel plants, and is therefore not included in the amounts shown in Figure 5-33. For the year 2010, adding nuclear to the analysis of effluents would make little difference to the results shown in Figure 5-33, because the same amount of nuclear operations show up in all alternatives except Emphasize Imports (which has no nuclear).

Figure 5-34 shows thermal discharge from all thermal generation (including nuclear) and from renewables with cooling water requirements (principally solar thermal and geothermal).

Conservation programs and ECMs should have no impacts on floodplains or wetlands, except as noted below. No new water systems should be built as a result of new ECMs or programs.

New programs may include the use of ground and water source heat pumps. Impacts from water source heat pumps or ground-coupled heat pumps may occur either from a small amount of disturbance caused by their construction, or more probably, from leaks or accidental discharges from their use. Some systems use potentially toxic transfer fluids. Water source heat pump systems use plain, untreated water. Ground source heat pump systems use a mixture of water and ethylene glycol, propylene glycol, or calcium chloride; or refrigerant. Water-based systems need to be protected from freezing, which is accomplished by using anti-freeze/water mixtures. Systems using refrigerant and a direct expansion coil in the ground are much less common, because the coils are often custom designed and the coil must be made of copper. While less common, they also may be more efficient than other systems.

Figure 5-33
Effluent From Coal and Natural Gas-Fired Power Plants

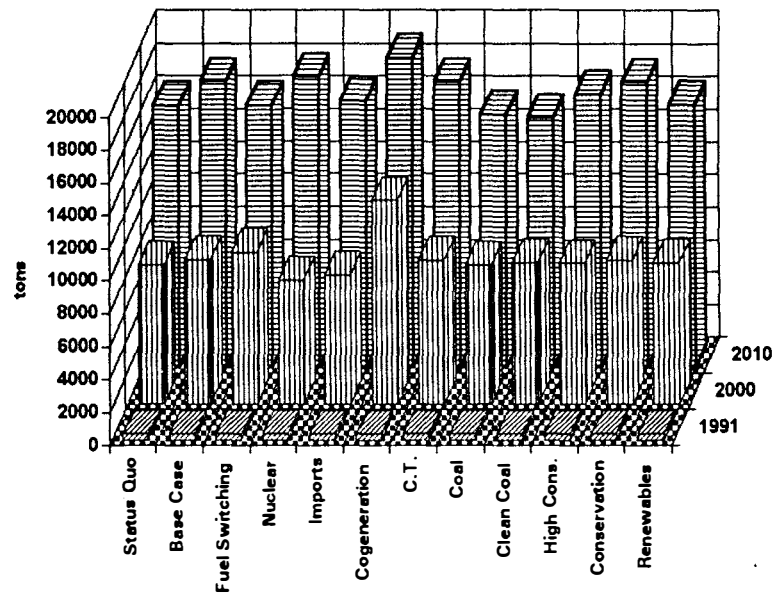
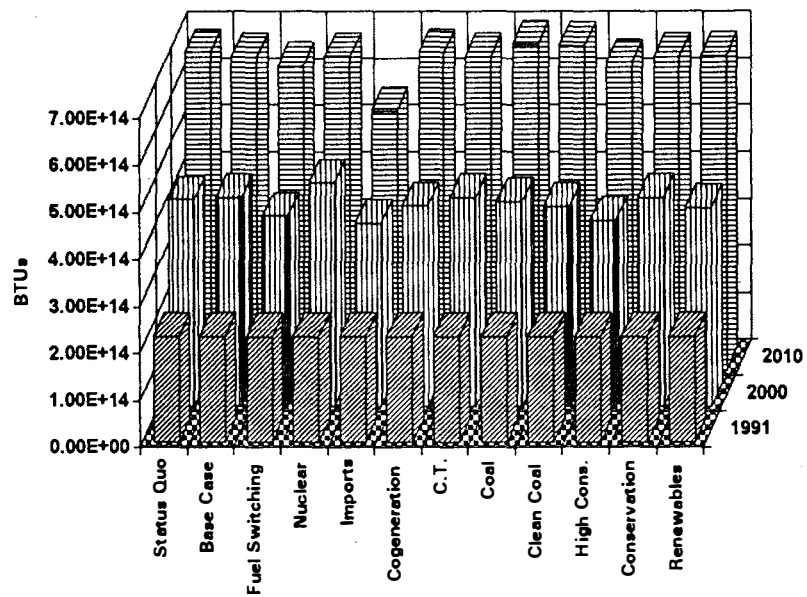


Figure 5-34
Thermal Discharges



5.5 Cumulative Impacts

The alternatives analyzed in this EIS were modeled to address the cumulative impacts of adding different stacks of resources to the existing power system.

Chapter 5 presents the impacts of BPA acquiring and operating resources to meet load in the context of the environmental effects of resource acquisition activities and operations in the rest of the region. Since the comparison of alternatives should provide a clear basis for choice by the decisionmaker, the environmental effects of BPA's actions were derived and presented in Chapter 4.

5.6 Relationship Between Short-Term Uses of the Environment and the Maintenance and Enhancement of Long-Term Productivity

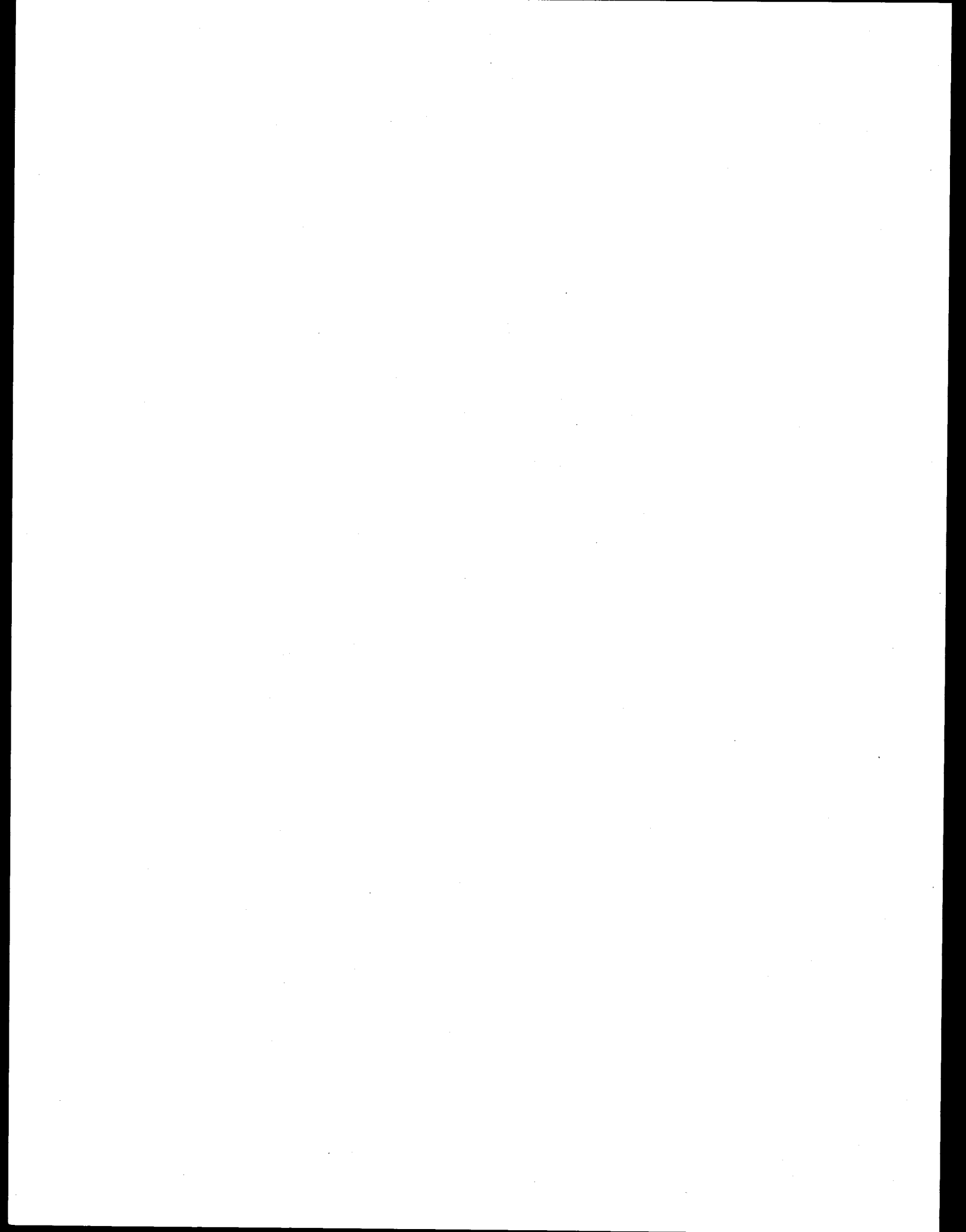
The acquisition and operation of resources to meet BPA's potential electricity deficit may cause both short-term and long-term impacts to the affected environment which are not mitigable. To the extent that each of the alternatives contain conservation, the need for generating resources is deferred. However, the generating resources which are also included in all of the alternatives would require both short-term and long-term uses of the environment.

All of the alternatives will cause short-term impacts from the construction or installation of generating facilities, including noise, soil compaction and erosion, degradation of water quality, destruction of vegetation, displacement of wildlife, disruption of habitat, and alteration of land use. Socioeconomic impacts are also expected in the short-term from the localized increase in work force required during construction. Long-term impacts include impacts associated with mining, processing, and/or transporting fuels; loss of habitat and alteration of land use; changes in water quality; and visual impacts. Other long-term impacts associated with all of the alternatives include potential impacts to human health, nuclear waste disposal, acid deposition, and contributions to global warming. Many of these impacts are site-specific and will be discussed further in the site-specific environmental documentation prepared on individual resource acquisitions.

Both the short-term and long-term uses of man's environment will, however, have a beneficial effect on long-term productivity. The acquisition of resources to provide electricity will allow maintenance and enhancement of lifestyles in the Pacific Northwest. The availability of electric power will also help maintain the region's economic growth. All of the alternatives give priority to conservation and renewables and the more efficient use of existing resources and thermal processes are encouraged. The inclusion of quantifiable environmental costs also helps assure that the underlying need will be met in an environmentally responsible and cost-effective manner.

5.7 Irreversible or Irretrievable Commitments of Resources

The acquisition of new resources is expected to have irreversible and irretrievable impacts. Every alternative analyzed is expected to have these types of impacts because each alternative acquires resources that use fossil fuels or nonrenewable resources. This EIS does include alternatives that acquire the maximum available amount of conservation and renewable resources in the Emphasize Conservation Alternative, the Emphasize High Conservation Alternative, and the Emphasize Renewables Alternative. In these alternatives, scenarios were developed and analyzed that assumed that the region would acquire the maximum amount of those resources, even at higher cost. However, even these alternatives require some generation by thermal and other nonrenewable resources and would therefore require an irreversible and irretrievable commitment of resources.



Consultation, Review, and Permit Requirements

Chapter 6

Chapter 6

Environmental Consultation, Review, and Permit Requirements

6.1 National Environmental Policy

This environmental impact statement (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.

6.2 Endangered and Threatened Species and Critical Habitat

The Endangered Species Act 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 Idaho, Montana, Wyoming, Nevada, Oregon, and Washington, and is presented in Appendix A.

As specific resource acquisitions are proposed, these lists will be updated. Biological Assessments analyzing the effects of those acquisitions on the various species will be prepared. These Biological Assessments will be forwarded to the USFWS for concurrence and included in the site-specific NEPA documents prepared for the acquisitions.

6.3 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 U.S. Fish and Wildlife Service in order to conserve or improve wildlife resources. As specific resource acquisitions are proposed, BPA will consult with the USFWS to conserve, improve, and protect fish and 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.

6.4 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. Consistent with Section 106 of the National Historic Preservation Act (16 U.S.C. 470), BPA will consult with the appropriate State Historic Preservation Officers before acquiring specific generating resources to determine if there are effects on any of these properties.

BPA has recently executed a Programmatic Agreement with the Bureau of Reclamation; Corps of Engineers; 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.

In 1983, BPA, the Advisory Council on Historic Preservation, and the State Historic Preservation Officers of California, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming signed Programmatic Memoranda Of Agreement which specified procedures for ensuring that BPA's energy conservation programs were consistent with Section 106 of the National Historic Preservation Act and implementing regulations. These procedures will be followed for any conservation acquired.

6.5 State, Area-wide, and 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. In addition, specific resource acquisitions will be coordinated with state and local government agencies to ensure maximum consistency practicable with regional, state, and local permitting and planning.

Significant environmental impacts from non-compliance with state, area-wide, or local plans and programs will not occur from BPA's conservation programs. BPA's commercial sector programs recommend (in the case of design assistance, i.e., where no payments are involved) or require (in cases where payments are involved) that ECMs be installed in a manner consistent with applicable Federal, state and local building codes and regulations. To participate in a program, building owners must agree to secure permits and comply with codes and regulations.

ECMs and conservation programs would be conducted in compliance with state and local building codes. Activities would be in compliance with state, area-wide, and local plans.

6.6 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. If specific resource acquisitions could affect the coastal zone, BPA will consult with the appropriate state(s) to ensure consistency with the state programs.

6.7 Floodplains Management

Executive Order 11988 (Floodplain Management) and Department of Energy (DOE) 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. As specific resource acquisitions are proposed, alternatives to development in existing floodplains will be considered.

6.8 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. All resource acquisitions will be evaluated to determine if they include actions in or affecting a wetland or result in a net loss of wetlands. If a wetland will be affected, a finding must be made that there is no practicable alternative to affecting a wetland and that all practicable measures have been taken to minimize harm to wetlands.

6.9 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. Each specific resource acquisition will be evaluated to determine whether it includes an action which would convert farmlands to other uses or cause physical deterioration and/or reduction in productivity of farmlands. A farmlands assessment will be prepared if any prime or unique farmland or farmland of statewide importance is affected.

6.10 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.

6.11 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.

6.12 Permits for Structures in Navigable Waters

If a proposed resource acquisition 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 U.S. Army Corps of Engineers.

6.13 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 U.S. Army Corps of Engineers if a resource acquisition includes the discharge of dredged or fill material into waters of the United States.

6.14 Permits for Rights-of-Way on Public Land

If acquiring a resource 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.

6.15 Energy Conservation at Federal Facilities

Energy conservation at Federal facilities will be addressed if a proposed resource acquisition 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.

6.16 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. Most of the Federal actions related to the alternatives discussed in this EIS do not 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. Site-specific documents will be prepared as necessary and required; specific environmental laws will be cited as appropriate in each 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"

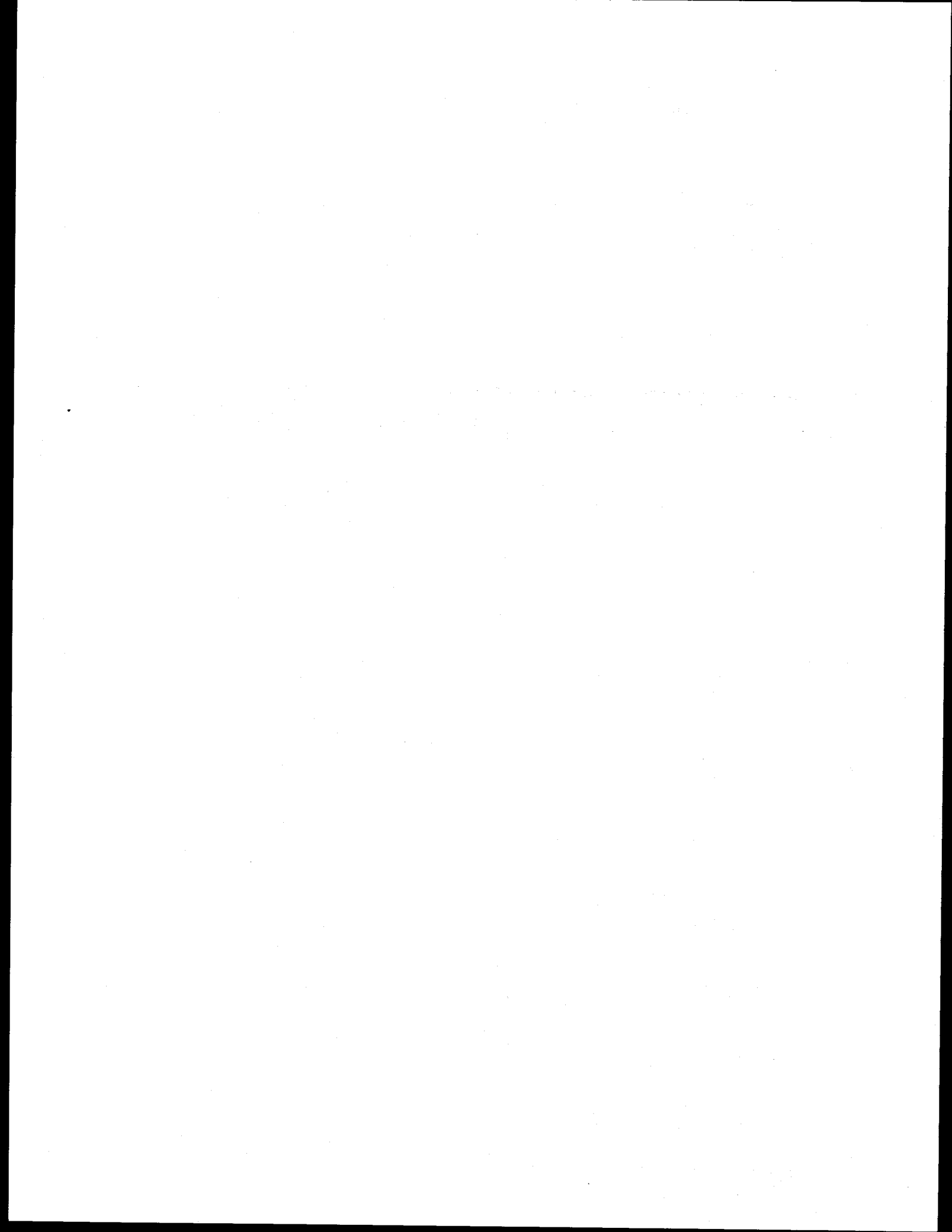
- ♦ Title 40 CFR Part 191, "Environmental Radiation Protection Standards for Management and Disposal of Spent Nuclear Fuel, High-Level, and Transuranic Radioactive Wastes"
- ♦ Title 40 CFR Part 192, "Health and Environmental Protection Standards for Uranium and Thorium Mill Tailings"
- ♦ Title 42 U.S.C. 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

6.17 Other

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

List of Preparers

Chapter 7



Chapter 7

List of Preparers

Name	EIS Responsibility	Qualifications
Charles Alton	Office Environmental Coordinator	B.S., Sociology; M.S., Public Administration. BPA - 5 years, Environmental Specialist for Energy Conservation and Renewable Energy; 4 years, Environmental Coordinator for Office of Energy Resources.
Robert W. Anderson	Fuel Switching Analysis	M.S., Economics. BPA - 3-1/2 years, Puget Sound Area Economist; 3 years, Long-Term Forecasting.
Michael C. Baechler	Project Manager	B.A., Environmental Pacific Northwest Studies; M.P.A., Laboratory Policy Analysis, PNL* - 8 years, Senior Research Scientist, Energy Sciences Department.
Michael Berger	Generating Resources Supply & Costs	B.S., Electrical Engineering; Masters of Business Administration. BPA - 5 years, Project Analysis & Evaluation; 8 years, Resource Assessment.
Orville Blumhardt	Conservation Resource Supply Analysis	B.S., Business Economics; M.S., Agricultural Economics. BPA - 6 years, Division of Rates; 4 years, Division of Resource Planning.

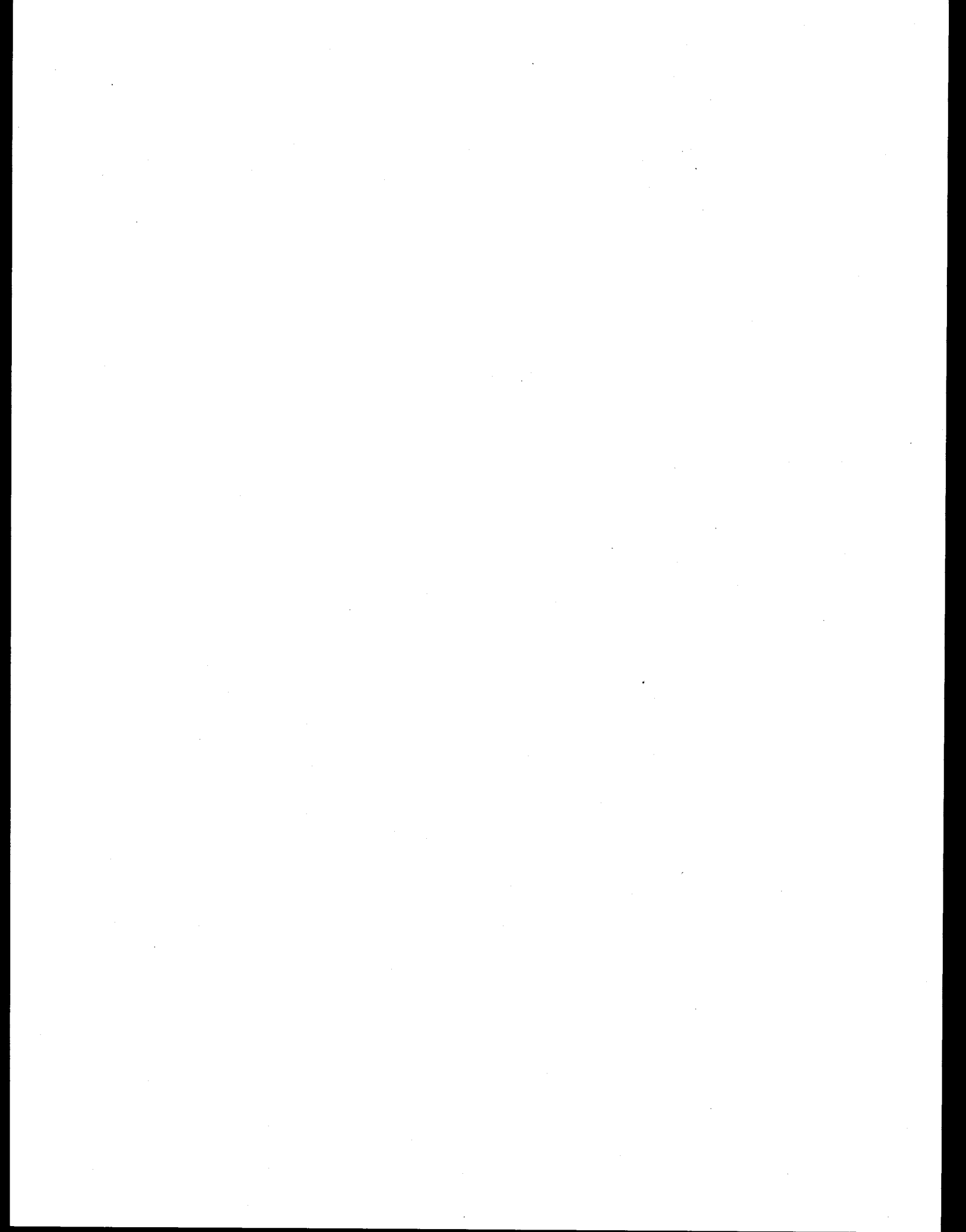
*PNL = Pacific Northwest Laboratories

Elizabeth Bowers	Quantification of Environmental Costs	B.S., Industrial Labor Relations. BPA - 2 years, Economist in Financial Management Planning and Analysis; 2 years, Economist in Resource Planning.
Carol Brodsky	Writer/Editor	B.A., Journalism. BPA - 4 years, contract writer/editor. Loads & Resources Studies; Power Sales Contracts EIS; PNW Long-Term Forecast; other projects.
Shepard Buchanan	Environmental Costs and Benefits Analysis	B.S., Resource Economics; Benefits Analysis; M.S., Agricultural and Resource Economics. BPA - 10 years, Resource Planning.
Kenneth Burk	Computer Programming	PNL - 9 years, Technical Specialist, Earth and Environmental Sciences Center.
M.Terry Dana	Acid Deposition Impacts	B.S., M.S., Physics; PNL - 25 years, Senior Research Scientist, Earth and Environmental Sciences Center.
Crystal J. Driver	Wildlife and Other Ecological Impacts	B.S., Biology; M.S., Applied Biology; Ph.D., Environmental Toxicology; PNL - 12 years, Earth and Environmental Sciences Center.
Jeffrey E. Englin	Economics	B.S., M.S., Ph.D., Economics, PNL - 8 years, Technology Planning and Assessment Center.
Norm Fuller	Generation Technologies	B.S., Chemical Engineering. General Electric Company - 10 years; BPA - 26 years in generation engineering.
Clifford S. Glantz	Air Quality Impact	B.S., Atmospheric Science and Physics; M.S., Atmospheric Science; PNL - 13 years, Research Scientist, Earth and Environmental Sciences Center.
Helen Goodwin	Alternatives, Resource Acquisition Process	B.S., M.S., Master of Administration. BPA - 5 years, Supervisory Public Utilities Specialist; 4 years, Public Utilities Specialist; emphasis on budget/resource planning.

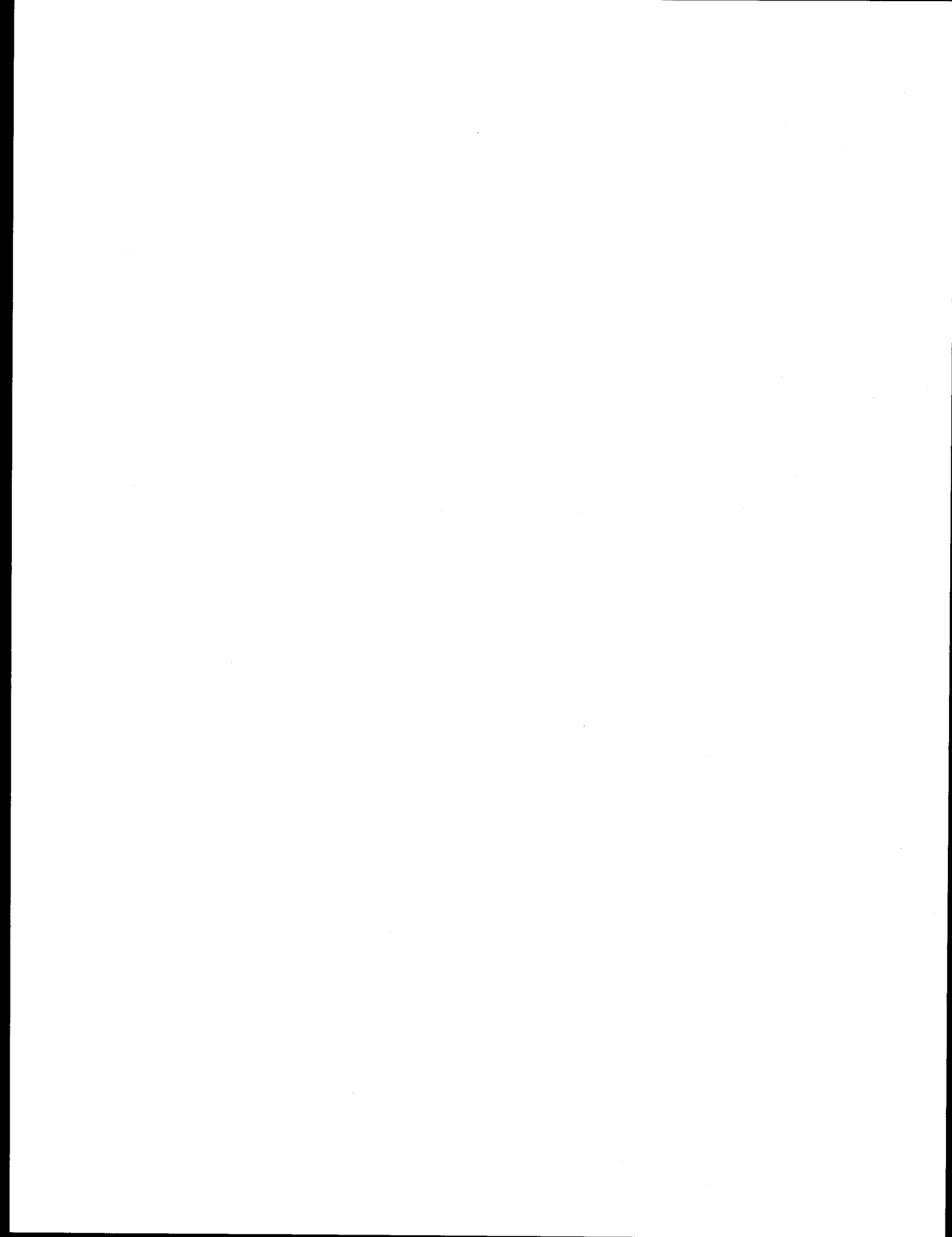
Stephen E. Grover	Socioeconomic Impacts	M.S., Economics; PNL - 7 years. Research Economist, Technology Planning and Analysis Center.
Gary C. Insley	Commercial Conservation	B.S., Forestry. USDA-Forest Service - 2 years, Timber Sale Administrator; 5 years, Environmental Specialist. BPA - 5 years, Alternative Energy RD&D Project Manager; 3 years, Commercial Program Manager.
Pamela Kingsbury	Hydro System Studies	M.S., Chemical Oceanography. Private - 3 years Environmental Consulting. BPA - 4 years, Power Scheduler; 4 years work for Environmental Coordinator; 3 years, Canadian Treaty and Hydro System Analysis.
Gail L. Laws	Visibility Impacts	B.S., Physics. PNL - 9 years, Technical Specialist, Earth and Environmental Sciences Center.
James L. Liljegren	Carbon Dioxide Impacts	B.S., M.S., and Ph.D., Mechanical Engineering, Earth and Environmental Sciences Center.
Andy Linehan	Project Manager, Final EIS	M.A., Public Affairs and Urban and Regional Planning; B.A., International Studies. BPA - 4 years; private environmental consulting, 5 years, CH2M Hill.
Robyn MacKay	Fisheries Analyses	B.S., Mechanical Engineering. BPA - 5 years, Long-Term Hydrosystem Planning; 4 years, Fish & Wildlife.
Don Matheson	Transmission Cost	B.S., Electrical Engineering and Applied Science. BPA - 19 years, Electrical Engineer.
Thomas McKinney	Transmission Impacts	B.A., Geography. BPA - 13 years, Environmental Specialist.

Brad Miller	Industrial Health Effects	B.S., Mechanical Engineering. Nero & Associates - 1 year on Bill 504 EIS Team; BPA - 8 years, Conservation, IAQ, Ventilation Infiltration; 3 years, Industrial Technology.
Sharron Monohon	Hydro Operations Analysis	B.S., Mathematics. Analysis. BPA - 9 years, Power Systems Planning.
Duane A. Neitzel	Fish and Wildlife Impacts	B.S., Zoology; M.A., Biological Sciences; PNL - 18 years as a fisheries scientist, Earth and Environmental Sciences Center.
Tom Pansky	Protected Areas; Environmental Effects and Consequences of Hydro Development	B.A., Philosophy/Physics., Manager, Northwest Environmental Data Base, 9 years.
Kris Parks	ISAAC Modeling	B.S., Economics; BPA - 2 years, Economist.
Kathy Pierce	Assistant Project Manager; NEPA Coordinator	B.S., Forestry and Wildlife Ecology; M.F., Forest Ecology; BPA - 11 years, Environmental Analysis.
Kathleen Rhoads	Human Health Impacts	B.S., Microbiology; M.S., Radiological Sciences; PNL - 17 years, Life Sciences Center.
Kristina Rohe	Project Manager, Draft EIS	B.S., Economics. BPA - 4 years, Power Forecasting and DSI Forecasting; 2 years, Resource Planning.
Tracey Salazar	ISAAC Modeling	B.A., Economics; M.A., Regulatory Economics. BPA - 1 year, Financial Analyst; 2 years, Industry Economist.
Stephen Schloth	Computer Specialist. Program and maintain the ISAAC model and related software	B.S. & M.S., Mathematics. BPA - 10 years.

Randy D. Seiffert	Air quality; water quality and use	B.S., Chemical Engineering. BPA - 16 years, Environmental Analysis.
Steven A. Shankle	Socioeconomic Impacts	M.S., Economics; PNL - 7 years, Research Economist, Technology Planning and Analysis Center.
Ralph N. Stein	Capacity Analysis	B.S., Mathematics. BPA - 20 years, Resource Planning; 5 years, Power System Planning.
Dennis L. Strenge	Human Health Impacts	B.S., M.S., Chemical Engineering; PNL - 24 years, Life Sciences Center.
Judy Woodward	Writer/Editor	B.A., Geography and Arts and Letters. BPA - 15 years, Environmental Analysis and Public Involvement; 8 months - communications consultant.



**List of Agencies,
Organizations, and Persons
to Whom Copies of the EIS
Are Sent
Chapter 8**



Chapter 8

List of Agencies, Organizations, and Persons to Whom Copies of the Statement are Sent

Federal Agencies

District XI Human Resources, Missoula, MT

U.S. Attorney's Office, Portland, OR

U.S. House of Representatives, Office of Congressman Jim McDermott, Seattle, WA

U.S. House of Representatives, Office of Honorable Peter Defazio, Coos Bay, OR

USA Corps of Engineers, Seattle, WA

USA Corps of Engineers, McNary, OR

USA Corps of Engineers, Division Office, Portland, OR

USA Corps of Engineers, North Pacific Division, Portland, OR

USA Corps of Engineers, Seattle District Office, Seattle, WA

USDA Forest Service, Hungry Horse Ranger District, Hungry Horse, MT

USDA Forest Service, Portland, OR

USDA Forest Service, Wenatchee National Forest, Wenatchee, WA

USDOC NOAA National Marine Fisheries Service, Cook WA

USDOC NOAA National Marine Fisheries Service, Hammond, OR

USDOC NOAA Nat'l Marine Fisheries Service, Environment'l & Tech, Portland, OR

USDOE, A5 90, Richland, WA

USDOE, Seattle Support Office, Seattle, WA

USDOE, Western Area Power Admin, Contracts & Conservation, Sacramento, CA
USDOJ, Bureau of Indian Affairs, Branch of Business & Credit, Portland, OR
USDOJ, Bureau of Indian Affairs, Colville Agency, Nespelem, WA
USDOJ, Bureau of Indian Affairs, Yakima Agency, Land Operations, Toppenish, WA
USDOJ, Bureau of Land Management, Boise, ID
USDOJ, Bureau of Land Management, Billings, MT
USDOJ, Bureau of Land Management, Medford District, Medford, OR
USDOJ, Bureau of Land Management, Oregon State Office No. 935, Portland, OR
USDOJ, Bureau of Reclamation, Ephrata, WA
USDOJ, Bureau of Reclamation, Department of Power, Boise, ID
USDOJ, Bureau of Reclamation, Pacific Northwest Region, Boise, ID
USDOJ, Bureau of Reclamation, Power Branch, GP 460, Billings, MT
USDOJ, Fish & Wildlife Service, Portland, OR
USDOJ, Fish & Wildlife Service, Fisheries & Federal Aid, Portland, OR
USHUD, Regional Office, Missoula, MT
USHUD, Regional Office, Seattle, WA

STATE OF CALIFORNIA

Department of Fish & Game, Sacramento
Energy Resource Conservation & Development, Sacramento
Public Utilities Commission, San Francisco

STATE OF IDAHO

Department of Fish & Game, Boise
Department of Fish & Game, Eagle
Department of Natural Resources, Boise
Department of Parks & Recreation, Boise
Department of Water Resources, Boise
Public Utilities Commission, Boise
Division of Planning & Policy, Boise

STATE OF MONTANA

Local Government Energy Office, Missoula
Office of Fisheries Program, Kalispell
Office of Budget & Program Planning, Helena

STATE OF NEVADA

Office of the Governor, Community Services, Carson City
State of Nevada Energy Conservation Program, Carson City

STATE OF OREGON

Department of Energy, Salem
Department of Fish & Wildlife, The Dalles
Department of Fish & Wildlife, Portland
Department of Fish & Wildlife, Central Point
Department of Fish & Wildlife, Portland
Department of Fish & Wildlife, Enterprise
Department of Geology & Mineral Industries, Portland
Department of Intergovernmental Relations, Salem
Department of Water Resources, Salem, OR
Office of the Governor, Salem
Public Utilities Commission, Salem
Research & Development Section, Clackamas

STATE OF WASHINGTON

Department of Ecology, Olympia
Department of Fisheries, Olympia
Department of Fisheries, Kennewick
Department of Fisheries, Battle Ground
Department of Game, Beaver Creek Hatchery, Cathlamet
Department of General Administration, Olympia
Department of Transportation, Electric City
Department of Transportation, Davenport
Department of Wildlife, Elk

Department of Community Development, Division of Housing, Olympia
Energy Facility Site Evaluation Council, Olympia
Energy Office, Olympia
Grange, Olympia
House Energy & Utilities Committee, Olympia
Office of Energy, Olympia
Senate Energy & Utilities Committee, Olympia
Utilities & Transportation Commission, Olympia
Section of Environmental Review, Olympia
Division of Habitat Management, Tumwater
Washington State Patrol, Colville
Weatherization Programs, Olympia

STATE OF WYOMING

Public Service Commission, Cheyenne

STATE OF CALIFORNIA

Local/County Agencies

City of Anaheim, Department of Public Utilities, Anaheim
City of Banning, Department of Public Utilities, Banning
City of Los Angeles, Department of Water & Power, Los Angeles
City of Pasadena, Department of Water & Power, Pasadena
City of Roseville, Electric Department, Roseville

STATE OF IDAHO

Local/County Agencies

City of Burley, Burley
City of Moscow, Moscow
City of Pocatello, Pocatello
Idaho Association of Counties, Boise
Orofino Chamber of Commerce, Orofino

STATE OF MONTANA

Local/County Agencies

County of Lake, Land Services Department of Planning, Polson

STATE OF OREGON

Local/County Agencies

City of Ashland, Ashland

City of Dufur, Dufur

City of Irrigon, Irrigon

City of Klamath Falls, Klamath Falls

City of McMinnville, Department of Water & Light, McMinnville

City of Milton-Freewater, Department of Light & Powr, Milton-Freewater

City of Portland, Portland

County of Jefferson, Madras

County of Klamath, Board of Commissioners, Klamath Falls

Lane County, Council of Governments, Eugene

Regional & Local Clearinghouses

Umpqua Regional Council of Governments, Roseburg

STATE OF WASHINGTON

Local/County Agencies

City of Cheney, Cheney

City of Everett, Everett

City of Issaquah, Issaquah

City of Morton, Morton

City of Pasco, Kennewick

City of Port Angeles, Port Angeles

City of Port Angeles, Department of Light, Port Angeles

City of Renton, Renton

City of Richland, Department of Energy Services, Richland

City of Seattle, Council, Seattle

City of Seattle, Office of Management & Budget, Seattle

City of Yakima

County of Adams, Department of Planning, Othello

County of Asotin

County of Benton, Department of Planning, Prosser

County of Benton & Franklin, Richland

County of Spokane, Department of Buildings

County of Stevens, Board of Commissioners, Colville

County of Stevens, Director of Planning, Colville

Tacoma Public Utilities

Town of Steilacoom

STATE OF WYOMING

County of Lincoln, Board of Commissioners, Kemmerer

INTEREST GROUPS

Adams County Economic Development Council, Othello, WA

American Association of Retired People, Prineville, OR

Big Bend Bass Masters, Moses Lake, WA

Clark County Citizen Rate Advisory Committee, Vancouver, WA

Columbia Basin Apartment Owners Association, Richland, WA

Columbia Basin Fish & Wildlife Authority Fish Passage Center, Portland, OR

Columbia Basin Fly Casters, Richland, WA

Columbia River Estuary Study Taskforce, Astoria, OR

Columbia River Fishermen's Protective Union, Astoria, OR

Common Cause, Eugene, OR

Common Cause Energy Task Force, Olympia, WA

Concrete Products, Moses Lake, WA

Elder Citizens Coalition of Washington, Seattle, WA

Environmental Information Center, Helena, MT

Fair Share of Springfield, Springfield, OR

Friends of the Earth Northwest Office, Seattle, WA

Greenpeace Northwest, Seattle, WA

Greypanthers of Portland Energy Study Committee, Portland, OR

HDR Engineering Inc., Bellevue, WA

Heller, Ehrman, White, & McAuliffe (Direct Service Industries), Portland, OR
Idaho Citizens Network, Pocatello, ID
Idaho Consumer Affairs Inc. Energy Committee, Nampa, ID
Idaho Water Users Association, Boise, ID
International Brotherhood of Electric Workers Local No. 76, Aberdeen, WA
Izaak Walton League of America Inc., Division of Oregon, Corvallis, OR
King County Outdoor Sports Council, Seattle, WA
KJ Booster Club, Tacoma, WA
Klamath Solar Association, Keno, OR
Lake Roosevelt Property Owners Association, Davenport, WA
League of Oregon Cities, Beaverton, OR
League of Women Voters, Port Angeles, WA
League of Women Voters, Spokane, WA
League of Women Voters East Multnomah County, Gresham, OR
League of Women Voters, Woodinville, WA
Libby Chamber of Commerce, Libby, MT
Lower Columbia Basin Audubon Society Conservation Committee, Pasco, WA
Mid Willamette Valley Council of Governments, Salem, OR
Montana Consumer Council, Helena, MT
National Wildlife Federation, Portland, OR
Northwest Conservation Act Coalition, Seattle, WA
Northwest Steelheaders, Vancouver, WA
Oregon State Grange, Portland, OR
Oregon State Grange Energy Committee, Troutdale, OR
Peoples Organization for Washington Energy Resources, Seattle, WA
Professional Activities IEEE Committee for Engineers Richland Sec, Richland, WA
Public Power Council, Portland, OR
Puget Consumer Panel, Olympia, WA
Quincy Grange No. 990, Quincy, WA
Raft River Rate Payers, Malta, ID
Renton Chamber of Commerce, Renton, WA
Research Group, Corvallis, OR
Salem Lions Club, Salem, OR
Sierra Club, Seattle, WA
Sierra Club, Portland, OR

Southwest Washington Anglers, Vancouver, WA
Spokane Area Chamber of Commerce, Spokane, WA
Spokane Neighborhood Centers Administrative Offices, Spokane, WA
Tacoma Audubon Society, Tacoma, WA
Tacoma Pierce County Chamber of Commerce, Tacoma, WA
Trout Unlimited, East Wenatchee, WA
Trout Unlimited NWSSC, Yakima, WA
Union Colation of Energy, East Wenatchee, WA
Vancouver Education Association Teacher River Guide, Vancouver, WA
Washington Association of Cities, Olympia, WA
Washington Energy Extension Service, Seattle, WA
Washington Society Professional Engineers Enengy Committee, Seattle, WA
Washington State Grange, Olympia, WA
Washington State Sportsmen's Council, Olympia, WA
Washington Troll Association, Ilwaco, WA
Washington Water Resources Association, Yakima, WA
Wenatchee Sportsmens Association Inc., Wenatchee, WA

TRIBES

Coeur D'Alene Tribe of Idaho, Plummer, ID
Colville Confederated Tribes, Nespelem, WA
Confederated Tribes of Colville Reservation, Nespelem, WA
Confederated Tribes of Salish & Kootenai, Pablo, MT
Jamestown Clallam Indian Tribe, Sequim, WA
Nez Perce Tribe of Idaho Department of Fisheries, Lapwai, ID
Northwest Indian Fisheries Commission, Olympia, WA
Shoshone Bannock Tribes Department of Fisheries, Fort Hall, ID
Upper Columbia United Tribes Fish Centr EWU Biology Department, Cheney, WA

DEPOSITORY LIBRARIES

Eastern Washington University Department of Library Documents, Cheney, WA
Nevada State Library, Carson City, NV
San Francisco Public Library Department of Government Documents, San Francisco, CA

State of California Regional Depository Library Government Publications
Section, Sacramento, CA
State of Oregon Library, Salem, OR
University of Idaho U.S. Documents Library, Moscow, ID
University of Montana Library Documents Section, Missoula, MT
University of Washington Gallagher Law Library, Seattle, WA
University of Washington Suzzallo Library Government Publications, Seattle, WA
Western Washington University Mabel Zoe Wilson Library Documents Division,
Bellingham, WA

LIBRARIES

Boise Public Library, Boise, ID
County of Pierce Library, Tacoma, WA
Ebasco Services Inc., Bellevue, WA
Kitsap Regional Library, Bremerton, WA
National Center for Appropriate Technology, Butte, MT
Tacoma Public Library, Tacoma, WA

NW POWER PLANNING COUNCIL

Northwest Power Planning Council, Boise, ID
Northwest Power Planning Council, Portland, OR
Northwest Power Planning Council, Olympia, WA

MEDIA-NEWSPAPERS

Business Journal, Portland, OR
Oil & Gas Journal, Portland, OR
Oregonian, Portland, OR
Perkins Cole Environmental News, Seattle, WA
Spokesman Review, Spokane, WA
Tacoma Morning News Tribune, Tacoma, WA

MEDIA-RADIO/TV

KEZI TV, Eugene, OR

KIHR & KCGB FM, Hood River, OR

KMJY Radio, Oldtown, ID

UNIVERSITIES/COLLEGES/SCHOOL DISTRICTS

American Institute of Mining, Boise, ID

Central Washington University, Department of Geography, Ellensburg, WA

Eastern Washington University, Cheney, WA

Evergreen State College, Department of Physics Lab 1, Olympia, WA

Lewis & Clark College, Department of Political Science, Portland, OR

Oregon Institute of Technology, Geo. Heat Center, Klamath Falls, OR

Oregon State University, Department of Agriculture Engineering, Corvallis, OR

Oregon State University, Department of Fish & Wildlife, Corvallis, OR

Oregon State University, Extension Service, Corvallis, OR

Portland State University, Portland, OR

Ravalli County School District No. 1, Corvallis, MT

University of California, Santa Barbara, CA

University of Idaho, College of Law, Moscow, ID

University of Montana, Department of Economics, Missoula, MT

University of Oregon, Physical Plant, Eugene, OR

University of Oregon, School of Architecture & Allied Arts, Eugene, OR

University of Washington, Seattle, WA

University of Washington Canoe Club, Darrington, WA

University of Washington HN 15, Seattle, WA

University of Washington, Institute for Environmental Studies, Seattle, WA

USDOC NOAA National Marine Fisheries Services, Seattle, WA

Washington State University, Pullman, WA

Washington State University, Bellevue, WA

Washington State University, Department of Agriculture Economics, Pullman, WA

Washington State University, Department of Physical Plant, Pullman, WA

Washington State University, Department of Zoology, Pullman, WA

Washington State University, Office of Applied Energy Studies, Pullman, WA

Washington State University, Office of Water Research & Technology, Pullman, WA

Western Washington University, Department of Economics, Bellingham, WA

UTILITIES & UTILITY ASSOCIATIONS

Association of Northwest Gas Utilities, Portland, OR

Ater, Wynne, Hewitt, Dodson & Skerrett Non Generating Public Utility, Portland,
OR

Benton County PUD No. 1, Kennewick, WA

Big Bend Electric Coop Inc., Board of Trustees, Ritzville, WA

Big Bend Electric Coop Inc., Board of Trustees, Pasco, WA

Big Bend Electrical Coop, Board of Directors, Connell, WA

Blachly Lane County Coop, Elmira, OR

California Energy Company Inc., San Francisco, CA

Canby Utility Board, Public Power Council, Canby, OR

Cascade Natural Gas Corporation, Seattle, WA

Central Lincoln PUD, Engineering & Operations, Newport, OR

Chelan County PUD No. 1, Power Operations, Wenatchee, WA

Chelan County PUD No. 1, System Planning & Design, Wenatchee, WA

Clallam County PUD No. 1, Port Angeles, WA

Clark Public Utilities, Vancouver, WA

Clatskanie PUD, Clatskanie, OR

Clearwater Power Company, Board of Directors, Craigmont, ID

Clearwater Power Company, Board of Directors, Asotin, WA

Columbia River PUD, Saint Helens, OR

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Consumers Power Inc., Philomath, OR

Cowlitz County PUD No. 1, Longview, WA

Douglas County PUD No.1, Power Operations Superintendent, East Wenatchee, WA

Elmhurst Mutual Power & Light Company, Tacoma, WA

Emerald PUD, Eugene, OR

Emerald PUD Governing Board, Cottage Grove, OR

Eugene Water & Electric Board, Eugene, OR

Ferry County PUD, Board of Commissioners, Curlew, WA

Ferry County PUD No. 1, Board of Commissioners, Republic, WA

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Flathead Irrigation Project, Joint Board of Control, St. Ignatius, MT

Franklin County PUD No. 1, Pasco, WA

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Glacier Electric Coop Inc., Board of Trustees, Cut Bank, MT
Glacier Energy Company, Maple Falls, WA
Grant County PUD, Ephrata, WA
Grant County PUD, Board of Commissioners, Soap Lake, WA
Grant County PUD No. 2, Moses Lake, WA
Grays Harbor County PUD No. 1, Abedeen, WA
Idaho Power Company, Boise, ID
Inland Power & Light Company, Advisory Committee, Loon Lake, WA
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Intercompany Pool, Spokane, WA
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Lower Valley Power & Light Company, Afton, WY
Lower Valley Power & Light Company, Board of Directors, Etna, WY
Mason County PUD No. 3, Shelton, WA
Mason County PUD No. 3, Board of Commissioners, Belfair, WA
Mid Columbia PUD, Regional Coordination Office, Portland, OR
Midstate Electric Coop Inc., La Pine, OR
Mission Valley Power, Board of Directors, Polson, MT
Missoula Electric Coop Inc., Board of Trustees, Florence, MT
Missoula Electric Coop Inc., Board of Trustees, Ovando, MT
Missoula Electric Coop Inc., Board of Trustees, Missoula, MT
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 Northern Lights Inc., Board of Directors, Bonners Ferry, ID
 Northwest Electric Light & Power Association, Portland, OR
 Northwest Irrigation Utilities, Portland, OR
 Northwest Natural Gas Company, Portland, OR
 Northwest Natural Gas Company, Salem, OR
 Northwest Public Power Association, Vancouver, WA
 Okanogan County PUD No. 1, Okanogan, WA
 Oregon PUD Association, Salem, OR
 Pacific Energy Association, Portland, OR
 Pacific Gas & Electric Company, Department of Transmission Planning, San Francisco, CA
 Pacific Northwest Generating Coop, Portland, OR
 Pacific NW Utilities Conference Committee, Portland, OR
 Pacific NW Utilities Conference Committee, Power Management, Portland, OR
 Pacific Power & Light Company, Walla Walla, WA
 Pacific Power & Light Company, Portland, OR
 Pacific Power & Light Company, Klamath Falls, OR
 Pacific Power & Light Company, Veterans Club, Yakima, WA
 PacifiCorp Electric Operations, Power Planning Regulation, Portland, OR
 PacifiCorp Electric Operations, Group Energy Efficiency Services, Portland, OR
 Portland General Electric Company, Portland, OR
 Portland General Electric Company, Legal Department, Portland, OR
 Portland General Electric Company, Rates & Revenue, Portland, OR
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 Puget Sound Power & Light Company, Renton, WA
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 Roza Irrigation District, Sunnyside, WA
 Sacramento Municipal Utility District, Sacramento, CA
 Sacramento Municipal Utility District, Power Systems, Sacramento, CA
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Skamania County PUD No 1, Carson, WA
Skamania County PUD No 1, Everett, WA
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Utah Power & Light Company, Salt Lake City, UT
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Vigilante Electric Coop Inc., Board of Trustees, Dell, MT
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Wahkiakum County PUD, Board of Commissioners, Cathlamet, WA
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Washington Public Power Supply System, Richland, WA
Washington Public Power Supply System, Seattle, WA
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Washington Water Power Company, Licensing & Environmental Affairs, Spokane, WA
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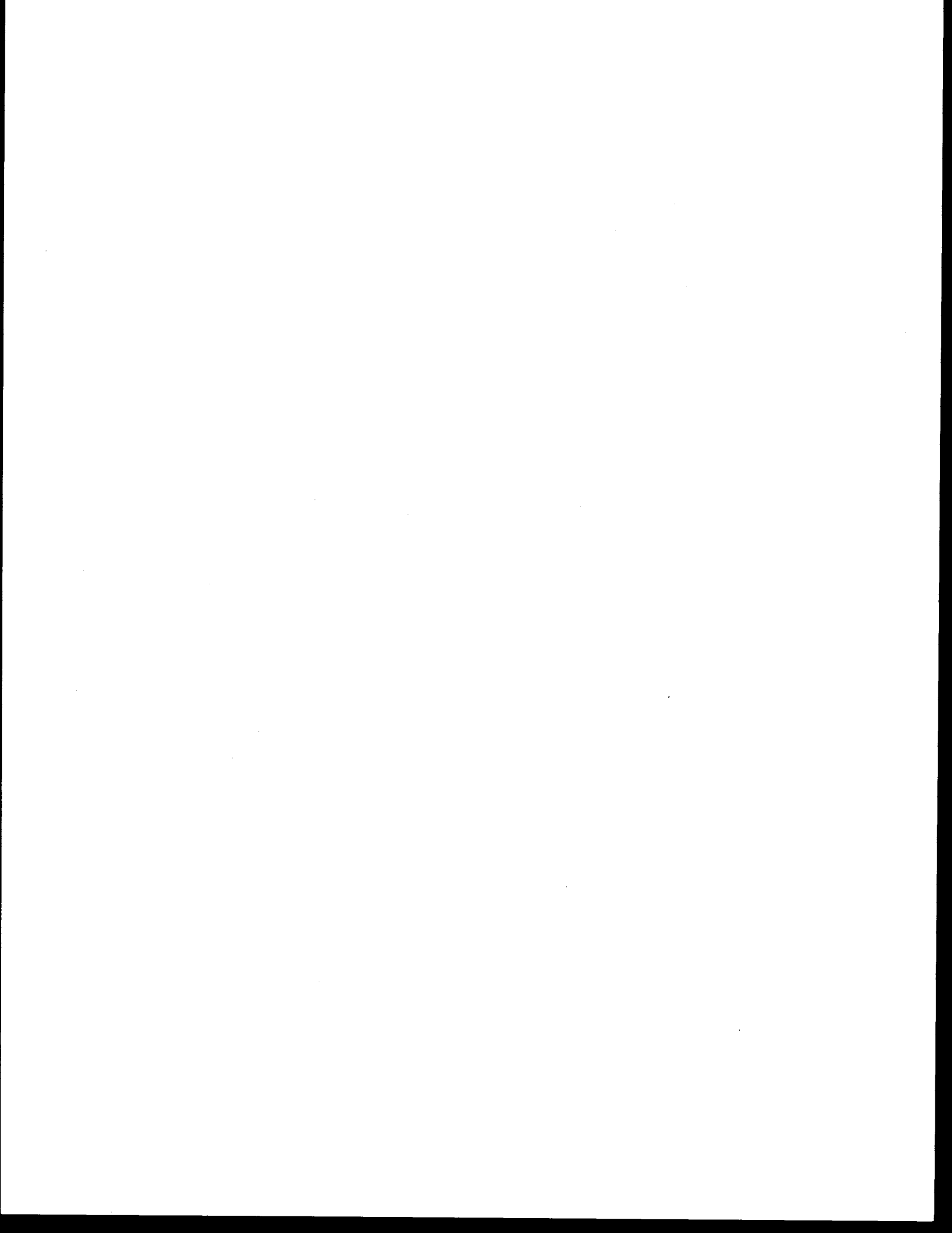
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D. Williams
J. Williams
L. Winnard
Z. Winnicki
J. Witt
S. Wonacott
F. Woodfield
G. Wyss
J. Yeck

W. Youngquist



References

Chapter 9

1. The first part of the report is a general introduction to the subject of the study. It discusses the importance of the study and the objectives of the research.

2. The second part of the report is a detailed description of the methodology used in the study. It includes information about the sample size, the data collection methods, and the statistical analysis techniques.

3. The third part of the report is a discussion of the results of the study. It presents the findings of the research and discusses their implications.

4. The fourth part of the report is a conclusion. It summarizes the main findings of the study and provides recommendations for future research.

5. The fifth part of the report is a list of references. It includes all the sources of information used in the study.

6. The sixth part of the report is an appendix. It contains additional information that is not included in the main body of the report.

7. The seventh part of the report is a glossary. It defines the key terms used in the study.

8. The eighth part of the report is a list of figures. It includes all the charts and graphs used in the study.

9. The ninth part of the report is a list of tables. It includes all the tables used in the study.

10. The tenth part of the report is a list of abbreviations. It includes all the abbreviations used in the study.

Chapter 9

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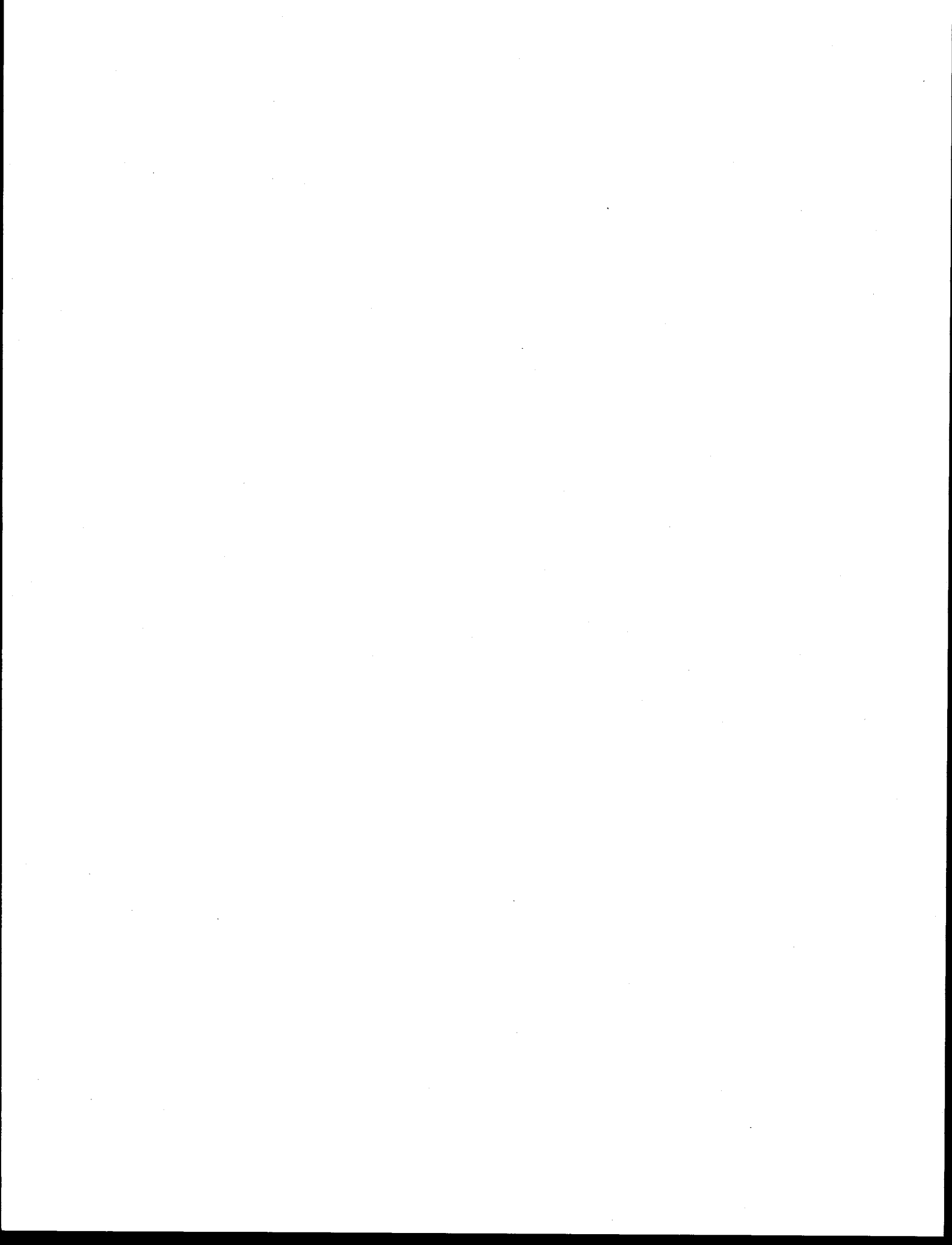
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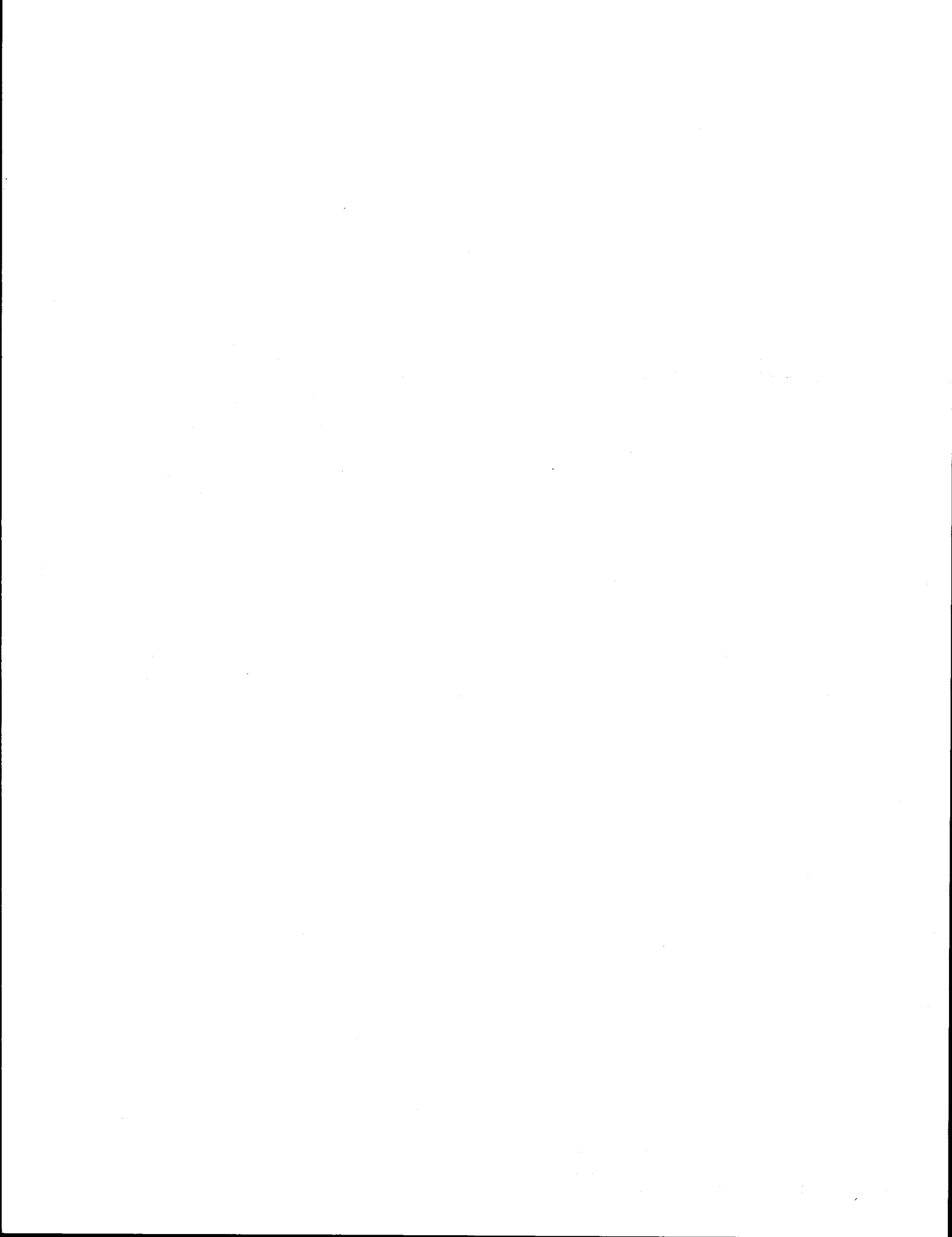
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Glossary

Chapter 10



Chapter 10

Glossary

The words below are defined for the reader as they are used in this EIS.

A list of acronyms and abbreviations begins on page 10-26.

ac - (see Alternating current)

aMW - (see Average megawatts)

Access - (see Intertie access)

Acid deposition - The combination of oxides of nitrogen and sulfur, in the air, with water, forming acid rain or snow, which may adversely affect water resources and plant and animal life.

Acquisition - The gain of a power resource, including demand-side and supply-side categories, in the form of energy or capacity. The term is commonly used by BPA to distinguish acquisition from ownership of a project and its facilities, from which BPA is prohibited by law.

Acre-foot - The volume of water that will cover an area of one-acre to a depth of one foot.

Air basins - Defined areas which generally confine the air-borne pollutants produced within them. Air pollutants tend to circulate and mix together within a basin.

Alluvial fan - A low cone-shaped deposit of sediment laid down by a swift-flowing stream as it enters a plain or an open valley, commonly in dry regions with interior drainage.

Alternating current (ac) - Term applied to an electric current or voltage that reverses its direction of flow at regular intervals and has alternately positive and negative values, the average value of which (over a period of time) is zero.

Ambient air - Ambient air is the air surrounding a particular spot, such as a power plant.

Anadromous fish - Fish species that spawn and initially rear in fresh water, migrate and mature in the ocean and return to fresh water as adults.

Annual average megawatts - A unit of energy output over a year equivalent to the energy produced by the continuous operation of one megawatt of capacity over a period of one year (equivalent to 8,760,000 kilowatthours).

Aquatic biota - The plant and animal life of a water body, considered as a total ecological entity.

Aquifer - Any geological formation containing water, especially one that supplies water to wells, springs, etc..

Artifact - An object of any type made by human hands. Tools, weapons, pottery, and sculptured and engraved objects are representative artifacts.

Availability factor - Ratio of the amount of time a resource is capable of providing service to the amount of time the resource is actually in service over a given period.

Average megawatts (aMW) - The average amount of energy (number of megawatts) supplied or demanded over a specified period of time.

Baseload - In a demand sense, a load that varies only slightly in level over a specified time period. In a supply sense, a plant that operates most efficiently at a relatively constant level of generation.

BC Hydro - The British Columbia Hydro and Power Authority. This Crown corporation was formed in 1962 following the merger of an expropriated private utility and the BC Power Commission.

Benthic insects - Insects living on the bottom of reservoirs or streams.

Billing credits - Under the Northwest Power Act, billing credits give a utility credit on its BPA power bills or equivalent cash payments for resources the utility supplies that reduces its need for power from BPA. Billing credits defer an acquisition by BPA and encourage customers to develop their own resources.

Biomass - Organic matter, derived from living organisms, that can be used as fuel in combustion, anaerobic digestion, or other energy conversion processes. Biomass sources include wood, grain crops, algae and other aquatic plants, and waste and residues from livestock, agriculture, logging and municipal operations.

Biomass fuels - Any liquid, solid, or gaseous fuel produced from biomass resources including wood chips, alcohol, methane, and gasification syngas.

Boreal - Pertaining to the forest areas and tundras of the North Temperate zone and Arctic region.

Bottom-ash - Uncombusted materials which accumulate in the bottom of a boiler and which must be removed and, generally, disposed of as solid waste.

Brackish - Containing some salt. Brackish water often results where fresh waters meet the ocean.

Buffering capability - The ability of a material to resist a change in pH (acidity or basicity) when an acid or base is added.

Buy-back - A conservation program that, in effect, purchases electrical energy in the form of conservation measures installed by a consumer. The consumer is paid a certain amount per kilowatthour on energy saved.

Bypass - Water released from a project which does not go through the turbines or over the spillway. Bypass may include leakage, navigation lock releases, and fish ladders.

cfs - (see Cubic feet per second)

- Canadian Entitlement** - The Canadian Entitlement is Canada's 50-percent share of the downstream power benefits of Canada's three large storage dams, Duncan, Keenleyside, and Mica. These dams were built as part of the Columbia River Treaty. Canada offered the rights to this Entitlement for sale in the United States for an agreed upon period of 30 years, beginning with the operational dates of the storage project dams.
- 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.
- Capacity additions** - Proposals to increase the power carrying capability of the Intertie-- the Third AC/COTP and the DC Terminal Expansion Project.
- Capacity/energy exchange** - A transaction in which one utility provides another with capacity service in exchange for additional amounts of firm energy (exchange energy) usually during offpeak hours or money under specified conditions.
- Capacity/energy diversity exchange** - A transaction in which one utility provides another with capacity service during its peak season, with compensation as the delivery of additional amounts of energy to the first utility during its peak season. This type of exchange benefits utilities that do not peak at the same time, if deliveries and returns can be made at the time of each utility's system peak.
- Capacity factor** - Ratio of the average generation of a resource to its rated capacity over a given period of time.
- Capital costs** - The costs to construct a power plant, including the costs of materials, permits, and interest on borrowing.
- Capital investment in new resources** - (see Capital costs)
- Carcinogen** - An agent capable of inducing a cancer response.
- Carrying capacity** - The amount of energy that a transmission facility can carry under specified conditions.
- Cogeneration** - The generation of power in conjunction with (usually) an industrial process, using waste heat from one process to fuel the other.
- Columbia River Treaty** - A treaty signed by the United States and Canada on September 16, 1964, for joint development of the Columbia River. Under the Treaty, Canada built three large storage dams on the upper reaches of the Columbia River, which originates in Canada: Duncan, Keenleyside, and Mica.
- Competitive acquisition** - An approach used by BPA to acquire power resources for long-term use, involving soliciting and selecting proposed resources by applying systematic quantitative and non-quantitative criteria. The term "competitive acquisition" is commonly used by BPA to refer to resource acquisition from non-Federal sources based on a bidding process. (See "Target Acquisition.")
- Competitive bidding** - An approach used by some utilities to acquire power that is similar to competitive acquisition. The difference between competitive acquisition and competitive bidding is that BPA does acquisitions and utilities do bidding. Bidding programs are typically regulated by local utility commissions and often characterized by fixed-price bidding. (See "Competitive Acquisition.")

- Conservation Acquisition Program** - A program offered by BPA for the purpose of producing cost-effective energy savings to meet a forecasted need by using less energy or using energy more efficiently.
- Conservation and generation resources** - Generating facilities, power importing arrangements, and energy efficiency measures that contribute toward BPA meeting its load obligations. Generation resources produce electricity; conservation results in the efficient use, distribution, or production of energy resources.
- Conservation measure** - An action taken to reduce energy or to use energy more efficiently. Installing insulation, retrofitting energy-efficient lighting, and applying better energy system controls are all examples. (Also see "Energy conservation measure.")
- Conservation transfers** - A conservation transfer is a mechanism through which BPA transfers energy to a utility in need of it from a utility that has surplus capacity due to energy conservation. If a utility develops conservation measures to reduce its power purchases from BPA, BPA sells the saved amount of energy back to the utility. The conserving utility in turn sells the energy bought from BPA to another utility. The revenues from the sale are used to offset conservation costs for the conserving party.
- Contingency power** (See "Resource Contingency Plan.")
- Cost-effective** - An acceptable level of cost for a measure or a resource that meets or reduces electrical power demand by consumers. A resource or measure is cost-effective if its estimated incremental system cost is no greater than that of the least-cost similarly reliable and available alternative or combination of alternatives.
- Critical period** - The portion of the historical stream flow of record for the Columbia River System during which the least amount of electrical energy can be generated by drafting the reservoirs according to seasonal power demands. Critical period is a fundamental planning concept used to determine annual firm energy load carrying capacity for the hydro system.
- Critical period average energy generation** - The average amount of energy projected to be generated during a period (which can vary in length depending on the purpose of the planning) of extremely low streamflow. Used as a basis for resource planning.
- Critical rule curve** - A set of end-of-month reservoir contents which take the reservoir from full to empty during a critical period. Critical rule curves are used to guide reservoir operation during actual operation.
- Cubic feet per second (cfs)** - A unit of measurement pertaining to flow of water. One cfs is equal to 449 gallons per minute.
- Cultural resources** - The nonrenewable evidence of human occupation or activity as seen in any district, site, building, structure, artifact, ruin, object, work of art, architecture, or natural feature that was important in human history at the national, state, or local level.
- DC** - (see Direct current)
- DSI** - (see Direct-service industries)
- Dam passage** - The percentage of fish which get from one side of a dam to the other alive.

- Damage functions** - Mathematical expressions based on scientific and socioeconomic observations which can be used to relate exposure to an environmental condition to an economic or social condition.
- Daylighting** - Use of natural sunlight as a replacement for some or all of the indoor electric lighting in buildings.
- Decremental cost** - The cost that a utility could avoid by not operating a power plant; a utility's decremental cost is considered by some regulators to be a "fair" rate for the utility to pay for purchased power.
- Deficit utility** - A utility that has less resources than it needs to meet its loads.
- Demand** - The level of electric energy, in kilowatts or megawatts, that is needed at any given time.
- 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.
- Deoxygenation** - The depletion of dissolved oxygen in water.
- Dewater** - (a) To remove water from a solution containing wastes in order to concentrate and then dispose of the wastes. (b) To divert or remove water from a stream or river channel in order to construct or rebuild dams and related hydroelectric facilities.
- Direct current (DC)** - Term applied to an electric current or voltage which may have pulsating characteristics, but which does not reverse direction at regular intervals.
- Direct-service industries (DSIs)** - Industrial customers, primarily aluminum smelters, that buy power directly from BPA at relatively high voltages.
- Dispatch** - The monitoring and regulation of an electrical system to provide coordination; or the sequence by which electrical generating resources are called upon to generate power to serve changing amounts of load.
- Displacement** - The substitution of less-expensive energy (usually hydroelectric energy transmitted from the Pacific Northwest or Canada) for more expensive thermal energy produced in California. Such displacement means that the thermal plants may reduce or shut down their production, saving money and often reducing air pollution as well.
- Dissolved gas concentrations** - The amount of chemicals normally occurring as gases, such as nitrogen and oxygen, which are held in solution in water, expressed in units such as milligrams of the gas per liter of liquid.
- Distribution costs** - Costs faced by a utility that sells electricity at retail to consumers, the costs of transporting the power from the transmission substation to the consumer.
- Dose-response relationship** - A relationship between the amount of an agent (either administered, absorbed, or believed to be effective) and changes in certain aspects of the biological system (usually toxic effects), apparently in response to that agent.
- Double-circuit** - The placing of two separate electrical circuits on the same row of towers. For alternating current, each circuit consists of three separate conductors or bundles of conductors.

- Downstream migrant survival** - The survival of an individual juvenile salmon or steelhead from the time it enters the mainstem Snake or Columbia Rivers, until it gets below Bonneville Dam.
- Drawdown** - The distance that the water surface of a reservoir is lowered from a given elevation as water is released from the reservoir (drafted).
- ECM** - (see Energy Conservation Measure)
- Economic dispatch** - Scheduling the operation (or, for the EIS, access to the Intertie) of power plants in the order of increasing monetary costs; that is, the least-expensive first.
- Economy energy** - Nonfirm energy that can be generated on a partially loaded generating unit, or purchases of energy, at a price less than decremental cost. Economy energy is unconditionally interruptible.
- Electrostatic precipitators** - Devices used to remove particulate air pollutants from an air stream by establishing an electric charge on the particles which then are attracted to an oppositely charged collector.
- Emergence** - Migration of hatched salmon fry up through the gravel of a redd preparatory to continuing their life cycle in open water.
- Endangered** - A plant or animal species which is in danger of extinction throughout all or a significant portion of its range because its habitat is threatened with destruction, drastic modification, or severe curtailment, or because of overexploitation, disease, predation, or other factors; Federally endangered species are officially designated by the U.S. Fish and Wildlife Service and published in the Federal Register.
- End-use energy** - A final, discrete use of electrical energy, such as lighting, space heating and cooling, refrigeration, office equipment, or any other discrete load.
- End-use loads** - (See "End-use energy.")
- Energization** - The point at which a completed energy facility is put into operation.
- Energy** - The ability to produce electrical power over a period of time--expressed in kilowatthours.
- Energy conservation** - Any reduction in electric power consumption, from what it would otherwise have been, as a result of increases in the efficiency of energy use, production, or distribution.
- Energy conservation measure (ECM)** - An action taken to reduce energy or to use energy more efficiently. Installing insulation, retrofitting energy-efficient lighting, and applying better energy system controls are all examples.
- Energy content curve (ECC)** - A set of end-of-month reservoir contents which assure a high probability of refilling the reservoirs.
- Energy losses** - The difference between power supplied and power received, due to dissipation by the transmission line or other facility.
- Energy surplus** - A condition in which a utility system can supply more energy than is demanded; the energy may be nonfirm, due to water conditions, or firm, due to excess generating capability.
- Entrainment** - The drawing of fish and other aquatic organisms into tubes or tunnels carrying water for cooling purposes into thermal plants or for generating purposes

into hydroelectric plants. Entrainment increases mortality rates for those organisms.

Environmental dispatch - Scheduling the operation (or, for this EIS, access to the Intertie) of power plants in the order of increasing damage to the environment; that is, the most environmentally benign first.

Equilibrium values - For the projection of BC Hydro's retail power rates for the EIS, the rates that reflect an economic equilibrium of supply and demand, considering the cost to supply the power (less revenues from secondary sales) and the loads.

Estuary - A coastal inlet where salt water meets fresh water, as at a river's mouth.

Eutrophication - The increase of aquatic vegetation (at the expense of animal life) as more plant nutrients are supplied.

Exchange energy - Under a capacity/energy exchange contract, the energy that must be generated or purchased by a utility as compensation for capacity service that was provided by another utility.

Export sales - The sales of electricity from one region to another.

Extraregional - Any entity or place not within the Pacific Northwest.

FCRPS - (see Federal Columbia River Power System)

FEIS - Final Environmental Impact Statement

FGD - (see Flue-gas desulfurization)

Federal Columbia River Power System (FCRPS) - The hydroelectric dams on the Columbia River financed by the U.S. Treasury, which operate as a coordinated generation system, and for which BPA serves as the power marketer.

Fingerlings - Young or small fish, especially very small salmon or trout.

Firm - In the power industry, guaranteed or assured. May refer to a guaranteed supply of power, to guaranteed access to a means to transmit power, or, with reference to loads, to guaranteed service for a defined need. Usually defined for a given period of time.

Firm displacement power - Under the Firm Displacement Power (FD-85) rate, power that BPA would sell to Pacific Northwest utilities to displace their planned resources, which would then be sold out of the region for at least 3 years.

Firm energy load carrying capability - The minimum level of energy that can be produced and shaped to load during the period it would take reservoirs to be drafted from full to empty under critical streamflow conditions.

Fish ladder - A series of ascending pools constructed to enable salmon or other fish to swim upstream around or over a dam.

Fish passage facilities - Features of a hydroelectric or other type of dam to enable fish to move around, through, or over them without harm.

Fish spill plan - A plan to provide a certain percentage of the total flow of a project as spill, for Federal and non-Federal projects.

Flaring - The practice of disposing of a waste combustible gas by burning it in an open flame without recovery of heat and, typically, at the top of a stack.

Flow rate - The volume of a fluid which passes a point in a defined channel per unit of time.

Flow regimes - The pattern of flow as it changes with time over the course of some specific time period.

- Fluctuation zone** - The area between the maximum and minimum water levels in a reservoir.
- Flue-gas desulfurization (FGD)** - The process of removing sulfur dioxide and other oxides of sulfur from gases generated by combustion or some other process before they are discharged to the atmosphere.
- Fly-ash** - Particulate matter remaining after combustion of a material which is entrained into the gas stream, and which may in large part be captured by an air pollution control device and, generally, disposed as a solid waste. Fly-ash not so captured is discharged as particulate matter into the atmosphere.
- Foodweb** - The interlocking pattern of food chains that results from their interconnection with one another; a way of presenting the flow of energy through an ecosystem.
- Forced outage** - The unexpected failure of some part of the power system to perform its function.
- Forebay** - The portion of the reservoir at a hydroelectric plant which is immediately upstream of the generating station.
- Formula allocation** - Conditions established by the NTIAP for allocating access to the Intertie, specified by formula.
- Fossil fuel** - A combustible, carbonaceous material formed from the remains of ancient plants and animals. Common fossil fuels include coal, natural gas, and derivatives of petroleum such as fuel oil and gasoline.
- Functional capacity** - The actual power carrying capability of a transmission line.
- Fuel conversion efficiencies** - The ratio (commonly expressed in percent) of the heating value of the fuel used per unit time to the power output of a generating plant.
- Generic firm contract** - A hypothetical regional firm power sale that converts to a capacity sale and capacity/energy exchange as the region's surplus firm energy disappears.
- Geothermal (energy)** - The heat energy available in the rocks, hot water, and steam beneath the earth's surface.
- Global warming** - The phenomenon of gradually increasing average temperatures in the earth's atmosphere due primarily to accumulation of carbon dioxide. Carbon dioxide comes from the burning of fossil fuels and removal of forests and vegetation that take carbon dioxide out of the air.
- Groundwater** - The supply of fresh water under the earth's surface in an aquifer or soil.
- Guaranteed access** - (see Assured access)
- High/low export conditions** - The range of availability of export power from the Pacific Northwest due to water conditions was analyzed to provide a background against which to see the effects of the various Intertie decisions: the high 10 percent, low 10 percent, and middle 80 percent of export availability conditions were grouped.
- HOSS** - (see Hourly Operations and Scheduling Simulator)
- Hourly allocation (nonfirm) basis** - The method for allocating access to the Intertie for short-term (hourly) transactions of nonfirm energy.
- Hourly Operations and Scheduling Simulator** - A computer model that works in coordination with the System Analysis Model (SAM) to determine the effects of changes in the configuration or operation of the hydro system on hourly streamflows, generation, and amount of sustained peaking capability.

- Hydraulic head** - The vertical distance between the surface of the reservoir and the surface immediately downstream of the turbine and dam.
- Hydraulic residence times** - The average travel time for a particle of water through a reservoir or other body of water.
- Hydro block** - The electrical energy available from the hydro system which is divided into various portions or "blocks," depending on conditions applied to its use.
- Hydrocarbons** - Chemical compounds containing hydrogen and carbon. Some hydrocarbons may become air pollutants. Some hydrocarbon air pollutants are carcinogenic, and some react with other air pollutants to form photochemical smog.
- Hydroelectric** - With reference to a power system, the production of electric power through use of the gravitational force of falling water.
- Hydrology** - The localized conditions relating to the occurrence, circulation, distribution, and properties of ground and surface waters.
- Hydrostatic testing** - The use of pressurized water to test a tank, pipeline, or other equipment for leaks.
- IGCC (Integrated Gasification/Combined Cycle)** - An advanced coal conversion technology that thermally decomposes solid coal into a high quality fuel that is then burned in a combustion turbine with a heat recovery steam generator. In gasification, the coal is partially oxidized producing CO and H₂, which are combustible gases. A subsequent acid process removes the sulfur from the gas stream and converts the reactants to hydrogen sulfide, which is easily removed. Gasification provides a clean, combustible gas that is almost entirely sulfur-free.
- Indoor Air Quality (IAQ)** - Quality of the air inside a structure.
- IOU** - (see Investor-owned utilities)
- ISCST** - (see Industrial Source Complex Short-Term Model)
- ISW** - (see Inland Southwest)
- Impoundment** - The accumulation of water in a reservoir.
- Incubation** - The period between fertilization of an egg and its hatching.
- Independent power producers** - Non-utility producers of 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.
- Industrial Source Complex Short-Term Model (ISCST)** - A computer-based steady-state Gaussian plume model designed to estimate pollutant concentrations from a wide variety of sources associated with industrial complexes. The model is appropriate for flat or rolling terrain, urban or rural environments, and is approved by the Environmental Protection Agency for specific regulatory applications.
- Inland Southwest (ISW)** - For the purposes of this EIS, the States of Nevada, Arizona, Utah, and New Mexico.
- Instantaneous flow rate** - The minimum amount of flow required (usually in terms of fish survival and functioning) at a given moment in time.
- Integrated System for Analysis of Acquisitions (ISAAC)** - A computer model used by BPA and the Pacific Northwest Power Planning Council for analysis of resource acquisitions.

- Interruptibility** - The extent to which the flow of power can be stopped for a given period of time. By agreement, the supply of interruptible power can be shut off to a customer on relatively short (hours or a few days') notice.
- Intertie** - A transmission line or system of lines permitting a flow of energy between major power systems. BPA has several interties, both AC and DC, connecting the Pacific Northwest to the Southwest.
- Intertie access** - The assigned right to send a defined amount of electric power at a certain time over the high-voltage line system called the Pacific Northwest-Pacific Southwest Intertie.
- Inundation** - The flooding or covering up of an area with water. Inundation occurs when a reservoir is first filled.
- Investor-owned utility (IOU)** - A privately owned utility whose programs are financed by private (nongovernment) investors in the utility's stocks and bonds. (In contrast to publicly owned utilities.)
- Juvenile** - The stage in the life cycle of anadromous fish when they migrate downstream to the ocean.
- kcfs** - One thousand cubic feet per second. A measure of speed and volume of water flow. (see Cubic feet per second)
- Kilowatthour (kWh)** - The common unit of electric energy equal to 1 kilowatt of power supplied to or taken from an electric circuit for 1 hour. A kilowatt equals 1,000 watts.
- Larvae** - The newly hatched, earliest stage of anadromous fish.
- Leakage** - An amount of water which leaks around a dam without passing through the turbines, spillway gates, or navigation locks.
- Least cost mix of resources** - The combination of generating (including conservation) resources that would meet a given amount of load at a given time or for a given period most economically.
- Levelized** - Of costs, a method of calculating equal, periodic payments or receipts from unequal cost data for the same time period, considering the time value of money.
- Linear regression analysis** - The derivation of a mathematical relationship between dependent and independent variables based on a random sample of observations.
- Littoral zone** - The shallower waters near the shore of a reservoir or lake.
- Load** - The amount of electric power or energy delivered or required at any specified point or points on a system. Load originates primarily at the energy-consuming equipment of the customers.
- Load growth** - Increase in demand for electricity.
- Load management** - Methods or programs used by utilities or building and facility managers to reduce, reshape, or redistribute electrical loads.
- Load profiles** - Information on the shape of customers' demands for electricity over time.
- Load/resource balance** - The point at which the demand for electricity matches or balances the amount and type of resources available to serve that demand.
- Load shape** - The profile of a building or facility's kilowatt demand over time, usually over the hours of the day, which can be derived from metered data. Typically, utility system load shapes peak during the day and are reduced at night. Different types of businesses, industrial operations, and residential users show markedly different load shapes.

Lockage - An amount of water which passes through the navigation locks and does not pass through the spillway gates or turbines of a dam.

Long-Term Intertie Access Policy (LTIAP) - The policy being developed by BPA to allocate use of the Federal portion of the Intertie for the long-term, an indefinite period that would at least encompass long-term power sales (up to 20 years) and long-term transmission contracts.

Long-term transmission contracts - Contracts between BPA and other entities for the use of the Federal transmission system, including the Intertie, for 20 years.

Lost opportunity resources - Resources that, because of physical or institutional characteristics, may lose their cost-effectiveness unless actions are taken to develop them or hold them for future use. Energy-efficient new buildings, for example, may be lost opportunities because it is so much more effective and less expensive to design energy efficiency into a building before it is built, rather than trying to retrofit energy-efficient measures later on.

Low water years - Years in which less water than usual is received in a river system producing power from water flow. This is usually a consequence of reduced rain/snowfall over the fall and winter months.

MW - (see Megawatts)

Manufactured housing technical specifications - Energy-efficient design specifications that apply to manufactured housing.

Marginal energy costs - For a generating resource, the cost to produce one more kilowatthour of electricity.

Megawatt (MW) - A megawatt is one million watts, an electrical unit of power.

Microclimate - The climate of a small area, as of houses, of plant communities, or of urban communities.

Mill - A tenth of one cent. A thousand mills equals one dollar. The cost of electricity is often expressed in mills per kilowatthour.

Mine-mouth - Used to refer to thermal generating plants located close enough to the fuel source (generally coal) that no long-distance fuel transport is necessary.

Minimum generation constraints - For thermal power plants, the minimum level of operation that must be maintained to keep the plant ready to generate power when needed.

Model - A mathematical function with parameters that can be adjusted so that the function closely describes a set of empirical data. A "mathematical" or "mechanistic" model is usually based on biological or physical mechanisms, and has model parameters that have real-world interpretation. In contrast, "statistical" or "empirical" models are curve-fitting to data where the math function used is selected for its numerical properties. Extrapolation from mechanistic models (e.g., pharmacokinetic equations) usually carries higher confidence than extrapolation using empirical models (e.g., logic).

Model Conservation Standards (MCS) - Energy-efficient building standards (developed by the Northwest Power Planning Council) for new electrically-heated commercial and residential buildings.

Near term - In general, the immediate future--a period of time usually less than 3 years.

Net billing - A financial arrangement that allows BPA to underwrite the costs of electric generating projects. Utilities that own shares in thermal projects, who also pay a share of their costs, assign to BPA all or part of the generating capability of these

resources. BPA, in turn, credits the wholesale power bills of these utilities to cover the costs of the utilities' shares in the thermal resources. BPA then sells the output from the thermal plants averaging the higher costs of the thermal power with lower cost hydro power. Washington Public Power Supply System Nuclear Projects -1, -2, and -3--and part of the Trojan Nuclear Project--are net billed.

Nitrogen supersaturation - A condition of water in which the concentration of dissolved nitrogen exceeds the saturation level of the water. Excess nitrogen can lead to bubbles of nitrogen in the circulatory systems of fish.

Nominal dollars - For economic analysis, dollars in the year specified, not adjusted for the effects of inflation or the time value of money.

Nonfirm energy sales - Sales of electricity that are not guaranteed, but are interruptible under specified conditions.

Nonfirm access - Use of the Intertie to transport sales of nonfirm energy.

Nonfirm allocation procedure - The method to allocate use of the Intertie on an hourly basis for sales other than long-term firm power sales.

Nonfirm energy - Energy produced by the hydropower system that is available when water conditions are better than critical period water flows and after reservoir refill is assured. Non-firm energy is available in varying amounts depending upon season and weather conditions. Non-firm energy is made available or supplied by BPA to a purchaser under an arrangement that does not have the guaranteed continuous availability of firm power. (See "Critical Period.")

Non-Treaty Storage Agreement (NTSA) - Three storage dams were built under the Canadian Treaty--Mica, Duncan, and Arrow (Keenleyside)--these dams together provide more storage than is required under the Columbia River Treaty. This extra storage space was not covered by the Treaty. In 1983, a short-term (10-year) agreement was worked out on this issue; recently (November, 1990) a new agreement was reached on how to share the extra several million acre-feet.

Northwest Environmental Data Base (NED) - BPA established the NED as a means to store and analyze information related to regional energy resources and the environment. The data base is region-wide in scope and focuses on information relating to rivers and hydropower. Information can be accessed by computer and can be mapped using geographic information system technology. The Northwest Power Planning Council and the four Pacific Northwest States are active participants in the development and maintenance of the NED. (Also see Rivers Study Data Base.)

Northwest Power Pool - The Northwest Power Pool is comprised of public and private utilities serving the Northwest and British Columbia. The Pool has a coordinating group whose primary function is administering the Pacific Northwest Coordination Agreement of 1964, a comprehensive plan for optimizing system-wide generation, storage, and transmission resources. Members of the Pool are BPA, the Corps of Engineers, the Bureau of Reclamation, and all public and investor-owned utilities with generating resources.

Nutrient loading - The quantity of elements or compounds essential as raw materials for organism growth and development which are dissolved or suspended in a sample of water.

Offpeak hours - Period of relatively low system demand for electrical energy, as specified by the supplier (such as the middle of the night).

- Operating year** - The 12-month period from September 1 through August 31.
- Outplantings** - Fish hatched and initially reared in a hatchery, which are then planted into natural habitats to continue juvenile rearing.
- Overburden** - The topmost layers of soil. In this EIS, the 30-50' layers of soil stripped off to reveal coal seams in the process of strip mining.
- PCB's** - (see Polychlorinated biphenyls)
- PF rate** - (see Priority Firm rate)
- PNW** - (see Pacific Northwest)
- PSD** - (see Prevention of Significant Deterioration increments)
- PURPA** - (see Public Utilities Regulatory Policy Act)
- Pacific Northwest (PNW)** - According to the 1980 Northwest Power Act, the Pacific Northwest comprises Oregon, Washington, Idaho, and Montana west of the Continental Divide, as well as portions of Nevada, Utah, and Wyoming that are within the Columbia-Snake River Basin. The Pacific Northwest also includes any contiguous areas not more than 75 miles from the region defined above that are part of the service area of rural electric cooperative customers served by BPA on the effective date of the Act whose distribution system serves both within and without the region.
- Pacific Northwest Coordination Agreement (PNCA)** - An agreement between Federal and non-Federal owners of hydropower generation on the Columbia River system. This agreement governs the seasonal release of stored water to obtain the maximum usable energy, subject to other uses.
- Pacific Northwest Electric Power Planning and Conservation Act** - In December, 1980, Congress passed this Act, Public Law 96-501 (referred to as the Northwest Power Act). This Act authorized the four Pacific Northwest States--Idaho, Montana, Oregon, and Washington--to enter into an interstate compact for the purpose of long-range planning and protection of shared resources. As a result of the Act, each of the four States passed enabling legislation to create the Pacific Northwest Electric Power Planning and Conservation Council in April 1981.
- Pacific Northwest Electric Power Planning and Conservation Council (Council)** - A council established by the Pacific Northwest Electric Power Planning and Conservation Act in 1981 made up of two voting representatives from each Northwest State--Washington, Oregon, Idaho, and Montana. The Council is charged with planning for power resources and enhancement of fish and wildlife resources in the region.
- Pacific Northwest Non-Residential Energy Survey (PNNonRES)** - A survey designed to get regional estimates of the energy-using equipment and physical characteristics of buildings in the Pacific Northwest. The 5-year effort gathered information on occupancy patterns, type of heating and cooling systems, and other data that could not be obtained through end-use electrical metering.
- Pacific Northwest Power Act** - (see Pacific Northwest Electric Power Planning and Conservation Act)
- Pacific Northwest Residential Energy Survey (PNWRES83)** - A comprehensive regional survey of energy use in over 4,000 private residences conducted by BPA in 1983.

- Pacific Northwest Utilities Conference Committee (PNUCC)** - A voluntary association of consumer and investor-owned utilities and BPA's direct service industries in the Pacific Northwest. Its primary role is to represent its members and their interests in pending legislation and regulating the formation of power planning policy.
- Passage survival** - The survival rate of migratory fish through, around, or over dams or other obstructions in a stream or river.
- Peak energy** - The amount of energy (in megawatt-hours) used during a peak load period.
- Peak loads** - The maximum electrical demand for power in a stated period of time. It may be the maximum instantaneous load or the maximum average load within a designated interval of the stated period of time.
- Phytoplankton** - The plant portion of the floating or weakly swimming organisms, often microscopic in size, in a body of water.
- Plume** - The discharge of gas and other pollutants into ambient air, or the discharge of polluted or heated water into a body of water from its source to the point where the discharge is no longer identifiable since it has mixed with the ambient air or the water.
- Plunging flows** - Water flow over a very steep surface or off of a precipice into a pool. This situation is one which produces high levels of dissolved gases in the water, such as nitrogen supersaturation.
- PLUVUE II** - An Environmental Protection Agency visibility model that provides a relatively simple treatment of atmospheric transport, diffusion, and chemistry. This computerized model focuses on short-term incidents of visibility attenuation rather than long-term average reduction in visibility.
- Point of delivery (POD)** - The point where power is transferred from one system to another.
- Polychlorinated biphenyls (PCB's)** - A group of non-combustible synthetic insulating/dielectric fluids used in certain electrical equipment; found to be very persistent in the environment and strongly suspected of having carcinogenic effects.
- Pool mortality** - Death that occurs to a juvenile salmon or steelhead as it migrates through the pool or reservoir of a run-of-the river project.
- Power broker** - A central power scheduling utility that matches lowest cost power offers in the Pacific Northwest with the highest offers to buy in the Southwest.
- Power Plan** - A 20-year power plan developed by the Pacific Northwest Electric Power Planning and Conservation Council. In the Plan, the Council proposed a comprehensive set of actions and projects to be undertaken to assure the region of adequate power resources, giving due consideration to conservation and fish and wildlife needs.
- Power pool** - A power pool is two or more electric systems interconnected and coordinated to supply power in the most economical manner for their combined load requirements and maintenance program.
- Predation** - The capturing of prey as a means of maintaining life.
- Pre-emergent fry** - Fish after they have hatched from their eggs but before they have left their incubation environment.
- Preference customers** - One of the regional publicly-owned or cooperative utilities, who sell retail electricity, and Federal agency end-users to whom BPA markets power. Preference status is accorded by prior Congressional act.

Priority Firm (PF) rate - The priority firm (PF) rate schedule is for sale of firm power to be used within the Pacific Northwest by public bodies, cooperatives, Federal agencies, and IOU's participating in the residential and small farm exchange under Section 5(C) of the Pacific Northwest Power Act.

Process evaluation - A process evaluation documents a program's implementation, identifies the causes behind the effects of a program, and examines the opportunities for and the barriers to a program's effective implementation.

Programs in Perspective (PIP) - An annual program conducted by BPA to take the agency's proposed programs and budgets before the public, both to explain the agency's plans and to get constructive feedback.

Project outflow - The volume of water per unit of time downstream from a project.

Public Utilities Regulatory Policy Act (PURPA) - This 1978 Federal legislation requires utilities to purchase electricity from qualified independent power producers at the utility's avoided cost. The Act was designed to encourage the development of small-scale cogeneration and renewable resources from non-utility sources.

Pumped storage - An arrangement whereby electric power may be generated during peak load periods by hydroelectric plants using water previously pumped into a storage reservoir during offpeak periods.

Qualifying facilities (QF's) - Renewable and cogeneration resources developed under the Public Utilities Regulatory Policy Act of 1978.

Real cost escalations - The increase in cost over a period of time due solely to the time value of money; that is, adjusted for price inflation.

Real discount rate - The factor used to compute the present value of a future amount, which adjusts solely for the time value of money and does not include price inflation.

Reclamation - The restoration of land to resemble its original condition or an acceptable substitute as to shape, vegetation, and wildlife; reclamation takes place after an area has been stripmined or after an energy facility has been built.

Record of Decision - The document notifying the public of a decision taken on a power project, together with the reasons for the choices entering into that decision. The Record of Decision is published in the Federal Register.

Regional - Referring to the characteristics of an area, as opposed to those of a surrounding or adjacent area. Generally used in this EIS to distinguish between the Pacific Northwest and Canada or California or the Inland Southwest. (see Extraregional)

Relative - Considered in relation to a base case condition; comparative; not absolute or independent (opposed to absolute).

Relative change in survival - The difference in survival between the two alternatives divided by the base case survival value. The change in survival in relation to the base case survival.

Reliability level - For a power system, a measure of the degree of certainty that the system will continue operation for a specified period of time.

Renewable resource - A resource that uses solar, wind, water (hydro), geothermal, biomass, or similar sources of energy, and is used either for electric power generation or for reducing the electric power requirements of a customer.

Reserve margins - For a power plant or transmission facility, extra capacity above the amount projected to be needed, to allow for unanticipated demand for power, equipment failure, or other unforeseen events.

- Reservoir draft rate** - The rate at which water, released from storage behind a dam, reduces the pool elevation of the reservoir.
- Reservoir elevations** - The various levels reached by water stored behind a dam.
- Resident fish** - Fish species which reside in fresh water during their entire life cycle.
- Residential Exchange Program** - An exchange of power prescribed by section 5(c) of the Pacific Northwest Power Act. Pacific Northwest utilities sell BPA an amount of power equal to their residential and small farm load, in exchange for less-expensive Federal electricity. The cost benefits are directly passed on by the utilities to their residential and small farm consumers, in the form of lower retail rates to those customers.
- Residual fuel oil** - Fuel oil that remains after separation of valuable distillates (such as gasoline) from petroleum through distillation.
- Resource Contingency Plan** - A BPA plan to obtain options to bring cost-effective firm energy resources on-line in the event that BPA has to meet higher than anticipated firm load obligations.
- Resource dispatch** - For this EIS, the order of access or the monitoring of power resources for access to the Intertie.
- Resource mix** - The different types of resources used to generate power (e.g., hydroelectric, thermal, etc.) within a given area or for a given utility.
- Resource schedule** - The planned schedule of when and what resources will be available in the future to serve load in a given area or of a given utility.
- Resource supply curves** - A traditional economic tool used to depict or forecast the amount of a product available across a range of prices.
- Retrofit** - To install an energy conservation measure in an existing home, piece of equipment or system, regardless of the type of incentive used.
- Return energy** - The energy that is returned to the Pacific Northwest, equalling the amount of energy previously sent south, under the terms of the capacity sales and capacity energy contracts.
- Riprap** - Broken rock, cobbles, or boulders placed on the bank of a stream or river for protection against the erosive action of water.
- Risk** - The probability of injury, disease, or death under specific circumstances. In quantitative terms, risk is expressed in values ranging from zero (representing the certainty that harm will not occur) to 1 (representing the certainty that harm will occur). The following are examples showing the manner in which risk is expressed: E-4 = a risk of 1/10,000; E-5 = a risk of 1/100,000; E-6 = a risk of 1/1,000,000. Similarly, $1.3E-3$ = a risk of $1.3/1,000 = 1/770$; $8E-3$ = a risk of $1/125$; and $1.2E-5$ = a risk of $1/83,000$.
- Risk assessment** - The determination of the kind and degree of hazard posed by an agent, the extent to which a particular group of people has been or may be exposed to the agent, and the present or potential health risk that exists due to the agent.
- Rivers Study Data Base** - Classification of the Pacific Northwest river resources. Stream resource categories evaluated include anadromous fish, resident fish, wildlife, natural features, recreation, cultural features (Indian, historic and archaeological resources, etc.), and institutional constraints. Now maintained as part of the Northwest Environmental Data Base (NED).
- Run-of-the-river plant** - A hydroelectric plant where limited storage capacity behind the hydro plant dam confines its operation to daily or weekly shaping.

- Run-of-the-river dams** - Hydroelectric generating plants that operate based only on available streamflow and some short-term storage (hourly, daily, or weekly).
- Running costs** - Also called variable costs--the costs that are incurred or are increased when a power plant operates.
- Salmonids** - Fish belonging to the family of salmonidae, including salmon, trout char, whitefish, and allied freshwater and anadromous fish.
- SAM** - (See System Analysis Model)
- Scheduling utilities** - Pacific Northwest scheduling utilities include Bonneville Power Administration, Seattle City Light, Tacoma City Light, Grant County PUD, Douglas County PUD, Chelan County PUD, Pend Oreille PUD, Eugene Water and Electric Board, Cowlitz County PUD, Snohomish County PUD, Montana Power Company, Idaho Power Company, Pacific Power & Light Company, Portland General Electric Company, Puget Sound Power & Light and Washington Water Power Company. Utilities that either operate a generation control area or are within BPA's control area that schedule with BPA.
- Scoping** - The definition of the range of issues requiring examination in studying the environmental effects of a proposed action. Scoping generally takes place through public consultation with interested individuals and groups, as well as with agencies with jurisdictions over parts of the project area or resources in that area. Scoping is mandated by the Council on Environmental Quality regulations.
- Secondary power** - The excess above firm power to be furnished to a customer when, as, and if available.
- Secondary revenues** - Revenues received from sales of secondary energy, which is the energy produced in excess of firm power due to favorable water conditions.
- Secondary sales** - Surplus power, both firm and nonfirm, in the Pacific Northwest that is available for sale to the Pacific Southwest.
- Sector** - A large group of energy users with similar types of conservation or generation opportunities. Sectors include residential, commercial, industrial, and agricultural.
- Sedimentation** - The settling of material (such as dust or other particles) into water and eventual deposition on the bottoms of streams, rivers, and so on.
- Settling ponds** - A pond into which water containing suspended solid material is discharged to allow the solid material to separate from the water by gravity.
- Shaping** - The scheduling and operation of generating resources to meet load of changing levels. Load shaping on a hydro system usually involves the adjustment of storage releases so that generation and load are continuously in balance.
- Short-run marginal cost** - The cost per unit of buying (or the amount saved by not buying) or producing a specified amount of a product in the near future.
- Short-term sales** - Sales made for a relatively short period of time.
- Sick building syndrome** - A condition in some buildings where occupants suffer, to varying degrees, from such symptoms as headaches, allergies, nausea, and sinus problems due to inadequate ventilation.
- Simulation** - The representation of an actual system by analogous characteristics of some device easier to construct, modify, or understand, or by mathematical equations.
- Slag** - In the context of this EIS, molten or solidified ash formed from noncombustible material in a fuel by chemical action and fusion at boiler operating temperatures.

- Sludge** - The wet, solid, or semisolid material formed when particulate air pollutants and/or sulfur dioxide is removed by a wet scrubber air pollution control device.
- Slurry pipeline** - A means of coal transport in which the coal is finely ground; mixed with water, and run through a pipeline to its destination, where it is dewatered and combusted.
- Smolt** - A juvenile salmon or steelhead that is migrating to the ocean and is in a physiological state to transition from fresh to salt water.
- Snowmelt freshet** - Increased streamflow from the melting of accumulated snowfall.
- Spawning** - The act of fish releasing and fertilizing eggs.
- Spill (forced)** - Water for which there is not storage capability in the system reservoirs and which could not be used for power production because the resulting flows would exceed turbine capacity.
- Spill (inadvertent/overgeneration)** - An amount of water which could have been used to generate electricity but was not because of lack of available market and inability to store for later use.
- Spill (programmed or planned)** - Water intentionally passed through a hydroelectric project without producing electricity. This is usually done for fisheries mitigation purposes.
- Spoil piles** - Heaps of soil and other material removed during surface mining, and later used to reclaim the site.
- Sport fish** - Fish which are sought by recreational fishermen.
- Spot market** - A market for electricity characterized by negotiation, almost solely on the basis of price, for relatively short-term sales.
- Storage reservoirs** - Reservoirs maintained behind dams for the purpose of retaining excess water readily available during springtime flows as snow melts. Retained water is then released, as necessary, during periods of lower flow in order to maintain necessary levels of power production. (Water may also be released for other purposes, such as navigation, irrigation, and maintenance of life support for fish.)
- Storage rights** - Rights provided to BPA for use of storage in Canadian reservoirs.
- Subalpine** - A terrestrial zone of high upland slopes, immediately below the timberline, characterized by conifer forest consisting of spruce and fir.
- Subyearling** - A juvenile salmonid, normally a fall or summer chinook salmon, that hatches and migrates to the ocean in the same year.
- Surplus capacity** - Amount of electrical capacity above the amount needed to meet the current load requirements of BPA customers.
- Surplus energy** - Generally energy generated that is beyond the immediate needs of the producing system. Specifically for BPA, firm or nonfirm electric energy generated at Federal hydroelectric projects which would otherwise be wasted if there was not a market for the energy.
- Surplus firm energy** - Energy that can be generated and guaranteed to be provided, but is excess to demand.
- Surplus firm power** - Power that can be provided on a guaranteed basis, that is excess to system demand, and that can be provided in an agreed upon shape.
- Surplus nonfirm energy** - An excess of interruptible energy that is available due to water conditions better than critical.

- Surplus peaking capacity** - Electric peaking capacity for which there is no demand in the Pacific Northwest at the rate established for the disposition of such capacity.
- System Analysis Model (SAM)** - A computer model that simulates the full operation of the existing Pacific Northwest hydro system under various specified conditions.
- System Operation Review (SOR)** - A public involvement process conducted by three Federal agencies--BPA, the Bureau of Reclamation, and the Corps of Engineers--who are concerned with the operation and use of the Federal Columbia River Power System (FCRPS). Key events affecting the outcome of the SOR are the pending expiration in 2003 of the Coordination Agreement among U.S. parties who operate the U.S. dams in the FCRPS, and the end of sale period of the Canadian Entitlement, which is part of the Columbia River Treaty that allocated Canada's firm power benefits from the Treaty to the U.S.
- System refill** - The coordinated hydro system is considered full, for the purposes of the IDU EIS modeling, when the amount of water stored in reservoirs is equal to 94 percent of the total available space.
- System stock survival** - The survival of migrating juvenile salmon or steelhead of a particular fish stock from the point of entry into the hydroelectric system to a point below Bonneville Dam.
- TSP** - (see Total suspended particulates)
- Tailwater** - The water surface immediately downstream from a dam or hydroelectric powerplant.
- Targeted acquisition (conservation)** - BPA works with a limited number of customers to develop a focused approach to acquiring conservation in the customer's service area. Customers can identify specific, unique opportunities for programs tailored to their needs. Targeted acquisitions, along with competitive acquisitions, allow innovation and flexibility in acquiring new resources. They are alternative approaches to acquisitions, moving beyond the 1980s model of centrally planned and administered programs by BPA. A similar process could be applied to the acquisition of generating resources.
- Thermal resources** - Generating plants which convert heat energy into electric energy. Coal, oil, and gas-fired power plants and nuclear power plants are common thermal resources.
- Thermal structure** - Reservoirs stratify into three layers in summer months: light warmer water on surface, a thermocline of cooler water, and a layer of cold oxygen deficient water on bottom. Rapid drawdowns cause this stratification to breakdown, reducing production of food organisms, and cooling water temperatures.
- Total suspended particulates (TSP)** - An air pollution term referring to all matter contained in a sample of air which is in solid or liquid form regardless of its particle size or chemical composition.
- Trace elements** - Pollutants, often metals in ionic or chemically combined form, which appear in very small concentrations in water, or in reference to air pollution, which constitute a very small part of the total amount of particulate pollution by weight.
- Transmission grid** - An interconnected system of electrical transmission lines and associated equipment for the transfer of electric energy in bulk between points of supply and points of demand.
- Transmission losses** - Power lost in transmission between one point and another.

- Turbidity** - A measure of the optical clarity of water, which depends on the light scattering and absorption characteristics of both suspended and dissolved material in the water.
- Turbine capacity** - The maximum amount of water that can be passed through the turbines of the dam at any instant.
- Upgrades** - Increases to the physical capacity of the existing Pacific Northwest-Pacific Southwest Intertie to 7900 MW.
- Utility retail rates** - The prices for electricity that a utility charges its classes of consumers.
- Variable ECC** - The January through July portion of the ECC (see Energy Content Curve). It is based on expected amount of spring runoff with available forecasts. The variable can be no higher than the Base ECC.
- Venting** - The release of limited amounts of gases or vapors to maintain pressures within tanks, pipes, and other equipment involved in oil and natural gas processing and transportation within design limits.
- VISSCREEN** - An Environmental Protection Agency visibility model that provides a relatively simple treatment of atmospheric transport, diffusion, and chemistry. This computer model focuses on short-term incidents of visibility attenuation rather than long-term average reduction in visibility.
- Washington Public Power Supply System (WPPSS or Supply System)** - A municipal corporation and joint operating agency in Washington made up of representatives of public utility districts and municipal utilities. Based on power purchase contracts of its members or other utilities, WPPSS has the power to acquire, construct, and operate plants and facilities for the generation or transmission of electric power.
- Water budget** - A means of increasing survival of downstream migrating juvenile fish by increasing water flow during the spring migration period. The water budget was proposed by the Power Council and is overseen by it in conjunction with the U.S. Army Corps of Engineers, the fishery agencies and Indian tribes, BPA, and the Bureau of Reclamation.
- Water conditions** - The overall supply of water to operate the Pacific Northwest hydroelectric generating system at any given time, taking into account reservoir levels, snowpack, needs to provide water or retain water to meet various operating constraints (such as the Water Budget, flood control, flow constraints, etc.), weather conditions, and other factors.
- Wheeling** - The use of the transmission and distribution facilities of one system to transmit power of and for another system.
- Wholesale rates** - The prices for electricity that a utility charges for power that will be resold. In BPA's case, BPA also charges wholesale rates to its DSI customers because they buy at relatively high voltage.
- Yearlings** - Juvenile salmon and steelhead that migrate to the ocean, often spending a full year rearing in fresh water.
- Zooplankton** - Aquatic animals which cannot actively swim against the current and which cannot make their own food by photosynthesis.

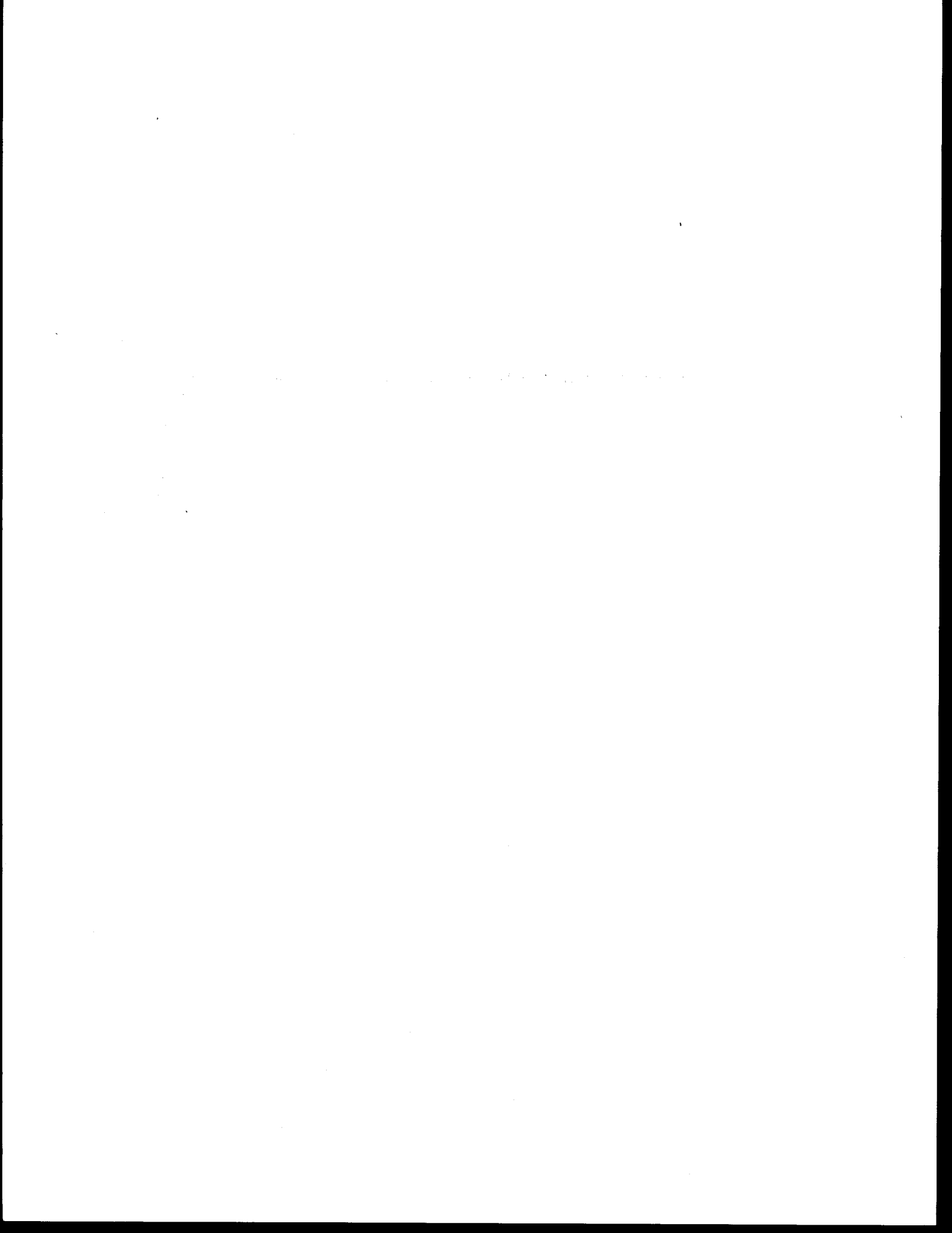
ACRONYMS and ABBREVIATIONS

AFBC	Atmospheric fluidized-bed combustion
aMW	Average megawatts
ASHRAE	American Society of Heating, Refrigerating, and Air Conditioning Engineers
BC Hydro	British Columbia Hydro and Power Authority
BPA	Bonneville Power Administration
BWR	Boiling water reactor
C	Celsius
CCCT	Combined cycle combustion turbine
CEC	California Energy Commission
CFC	Chlorofluorocarbons
Council	Pacific Northwest Power Planning Council
CRFM	Cogeneration Regional Forecasting Model
CSEIs	Customer system efficiency improvements
CT	Combustion turbine
CVR	Conservation voltage reduction
DOE	Department of Energy
DSI	Direct-service industries
ECM	Energy Conservation Measure
EPA	Environmental Protection Agency
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
FIFRA	Federal Insecticide, Fungicide, and Rodenticide Act
FY	Fiscal year
GPUBs	Generating public utilities
HPS	High-pressure sodium
HVAC	Heating, ventilation, and air-conditioning
IAQ	Indoor Air Quality
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utilities
IRAA	Indoor Radon Abatement Act
ISAAC	Integrated System for Analysis of Acquisitions
ISCST	Industrial Source Complex Short-Term Model
ISW	Inland Southwest
kcfs	Thousand cubic feet-per-second
LPS	Low-pressure sodium
LTIAF	Long-Term Intertie Access Policy
MAF	Million acre feet

MDFWP	Montana Department of Fish, Wildlife, and Parks
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NWPPC	Pacific Northwest Power Planning Council
O&M	Operating and maintenance
ODEQ	Oregon Department of Environmental Quality
OSM	Office of Surface Mining
OY	Operating year
PCBs	Polychlorinated biphenyls
PF	Priority firm
PFBC	Pressurized fluidized-bed combustion
PG&E	Pacific Gas and Electric
PNCA	Pacific Northwest Coordination Agreement
pphm	Parts per hundred million
Project Act	Bonneville Project Act of 1937
PURPA	Public Utilities Regulatory Policy Act
PV	Photovoltaic cells
PWR	Pressurized water reactor
RCDP	Residential Construction Demonstration Project
RCP	Resource Contingency Plan
RD&D	Research, development, and demonstration
RPEIS	Resource Programs Environmental Impact Statement
RSP	Respirable suspended particulates
SAM	System Analysis Model
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SIC	Standard Industrial Classification
SOR	System Operation Review
SOS	System Operating Strategy
TSCA	Toxic Substances Control Act
TSP	Total suspended particulates
UFFI	Urea formaldehyde foam insulation
USFWS	United States Fish and Wildlife Service
UV	Ultraviolet
WNP	Washington Nuclear Project

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Chapter 11



Chapter 11

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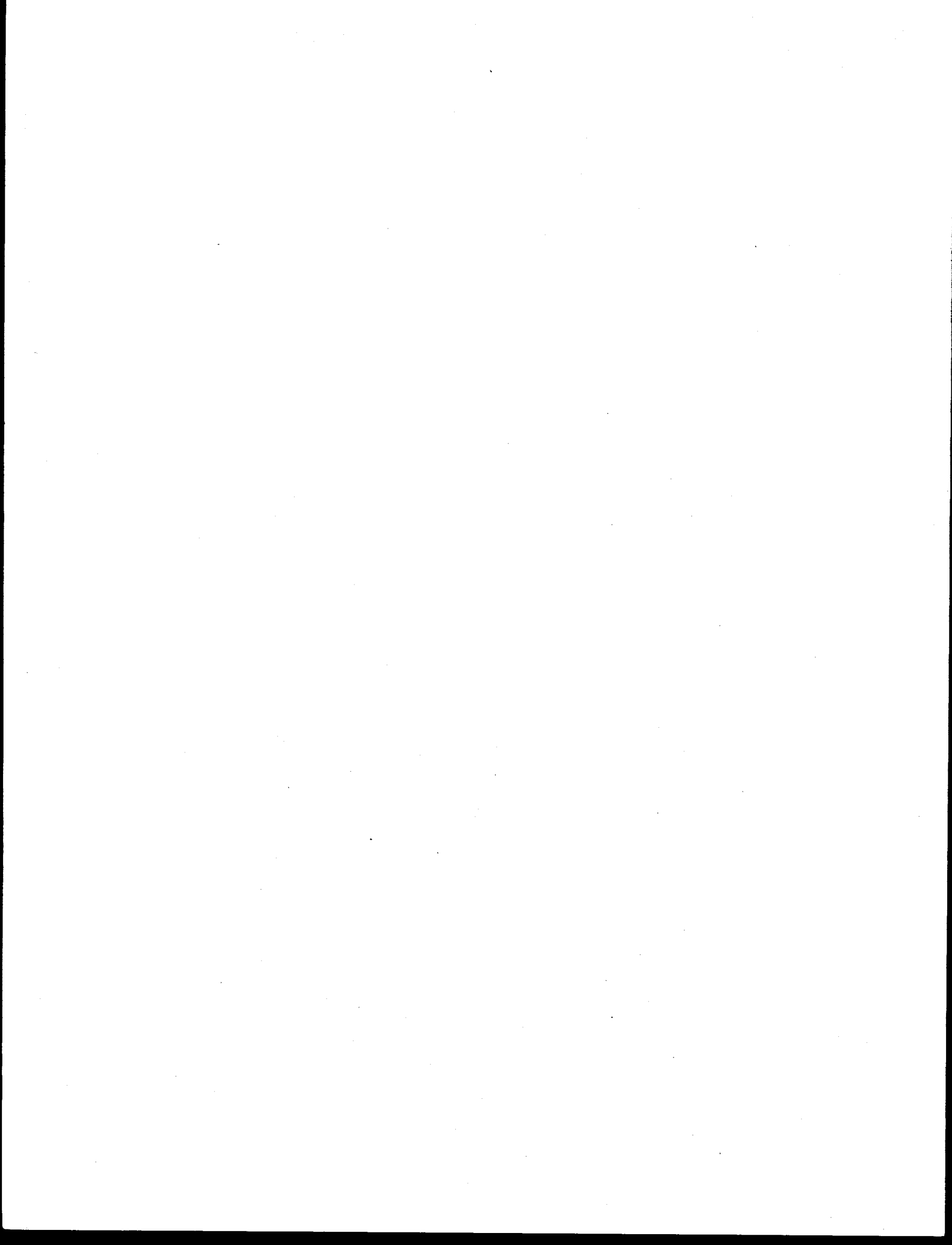
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