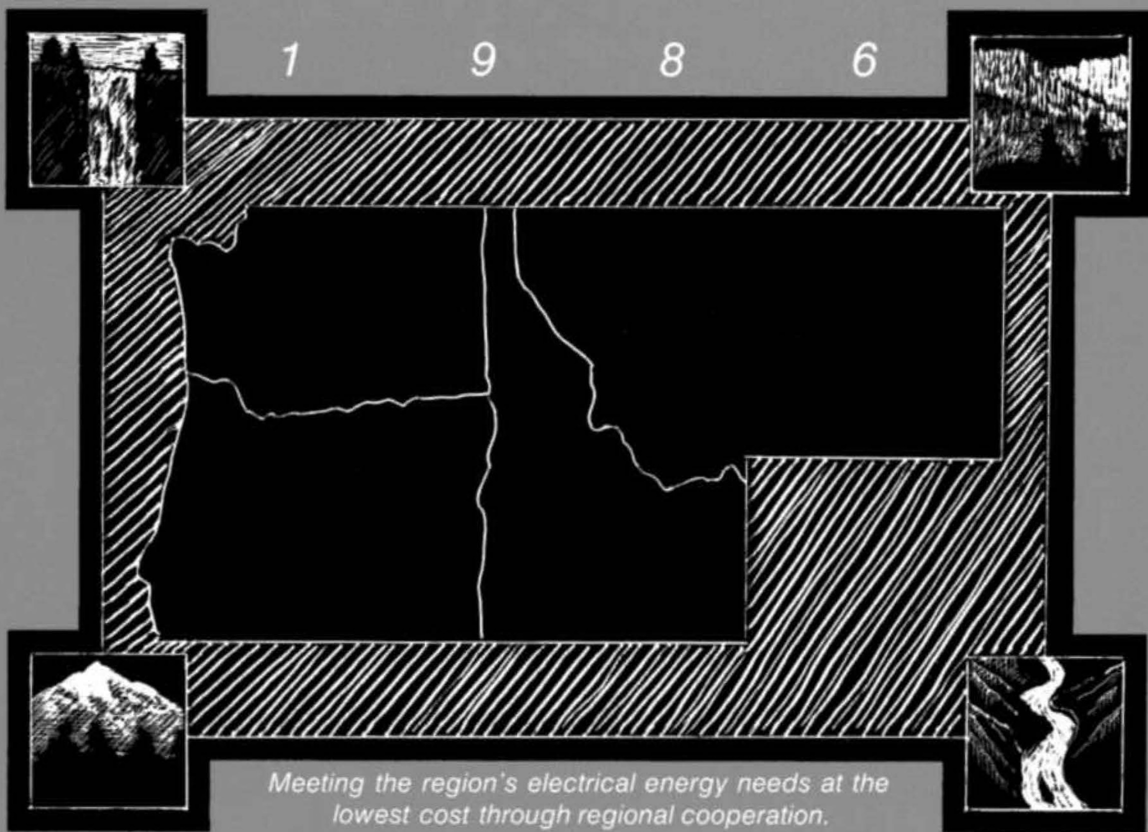


NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN

VOLUME TWO

NORTHWEST POWER PLANNING COUNCIL

Contents

Contents

Chapter	Page

Contents

Chapter	Page

Contents

Chapter	Page

Contents

List of Illustrations

List of Illustrations

List of Tables

List of Tables

Chapter I
Introduction

The overall conclusions of this 1986 Power Plan are described in Volume I. It includes summaries of the basic planning strategies, the important regional power issues, the lowest cost mix and schedules for new resource acquisitions, and the priorities of the Action Plan the region needs to follow to ensure an adequate and reliable supply of power at the lowest cost.

This volume (II) contains supporting documentation for the conclusions and positions in Volume I. It describes the analytical work and technical details leading to the policy decisions.

Chapter 2, "Economic, Demographic and Fuel Price Assumptions," describes the methods and results of an analysis on which the regional load forecasts were based. Population and employment trends, and developments in each of the economic sectors, will determine to a large extent the future need for electricity.

Chapter 3, "Forecast of Demand for Electricity," explains how the load forecasts were derived, what they say and what role they play in the planning process.

Chapter 4, "Financial Assumptions and Resource Cost Effectiveness," examines the financial variables used to estimate quantities and costs of resources, to project future demand for electricity, and to simulate operation of the regional power system with alternative sets of resources. These values, used in the overall analysis, directly influence results and permit consistent comparison of components.

Chapter 5, "Conservation Resources," presents the methods and results of studies that determined how much conservation could be secured in the region and at what cost. This chapter looks at conservation savings and techniques in the residential, commercial, industrial and irrigation sectors. Based on the work outlined in this chapter, the Council identified specific amounts of conservation savings available for the 20-year portfolio of resources that will meet the region's electrical energy needs.

Chapter 6, "Generating Resources," discusses a variety of technologies that could potentially meet future electricity requirements in the Pacific Northwest. This chapter describes the current status of development, estimated cost and availability of these possible sources of electric energy. The most cost-effective and available resources were considered in the development of the Council's resource portfolio. Resources considered promising but not yet fully reliable or cost effective are recommended in the Action Plan for further research, development or demonstration to better establish their role in future power plans. Tables in the chapter appendices describe resource costs and characteristics in detail.

Chapter 7, "Better Use of the Hydropower System," explains the methods and benefits of meeting more firm load in the region with hydropower that is presently nonfirm.

Chapter 8, "Resource Portfolio," describes in detail the Council's resource portfolio. Section A, "Resource Portfolio Analysis," describes the analysis that led to the Council's choice of the portfolio, and gives a brief overview of the decision rules employed. Section B, "Portfolio Uncertainty," presents the results of sensitivity studies that examine the cost and scheduling impacts of assumptions other than those the Council used in developing the resource portfolio. Section C gives details of the Council's analysis of the cost effectiveness of the two Washington Public Power Supply System's nuclear plants 1 and 3 under a variety of future circumstances. Section D presents a more detailed description of the Decision Model. Finally, Section E discusses generating resource lost opportunities. An appendix to Chapter 8 presents the expected increments of resources required over the next 20 years by the region as a whole and by the public utility and direct service industry customers of Bonneville only.

Chapter 9, "Consideration of Environmental Quality and Fish and Wildlife," reviews the environmental effects of all resources considered for use in this plan and summarizes their known likely impacts on fish and wildlife. In addition, this chapter examines the costs and effectiveness of ways to mitigate such impacts. (Appendices II-A and II-B deal further with methods for determining environmental costs and benefits, and with conditions hydropower projects must meet to gain financial assistance from the Bonneville Power Administration.)

Chapter 10, "Public Involvement," describes the public information and public involvement activities the Council has conducted, and will conduct, as part of its responsibility to ensure widespread participation in policy making and power planning by the region's ratepayers, customer groups, state and local governments, and users of the Columbia River system. Council publications and meetings are listed.

Chapter 2
Economic, Demographic and Fuel Price Assumptions

Introduction

Under the Pacific Northwest Electric Power Planning and Conservation Act, Congress charged the Council with forecasting electric power requirements as the basis for a plan for meeting regional electricity needs.

The economic and demographic assumptions are the dominant factors influencing the forecasts of demand for electricity. A good rule of thumb is that demand for electricity will parallel economic activity in the absence of other changes. This relationship is modified by shifts in relative energy prices, including the price of electricity and other fuels; by changes in the composition of economic activity; and by the gradual depreciation and replacement of the buildings and other capital stock of the region. Future sales of electricity will also be affected by conservation activities, although the Council treats conservation as a resource.

Recognizing that the future is highly uncertain, the Council has adopted a planning strategy that incorporates flexibility and risk management. The economic and demographic assumptions are both extremely important determinants of future electricity needs and, at the same time, highly uncertain. The objective of the range of planning assumptions discussed in this chapter is to help define the extent of uncertainty. The plan must address a range of future electricity needs that reflects, among other factors, this underlying economic uncertainty.

In developing the range of forecasts for the plan, the Council adopts forecasts that bracket the highest and lowest plausible economic scenarios for the next 20 years. The purpose of this approach is to develop a flexible resource strategy that provides an adequate supply of electricity at the lowest possible cost. The risks are twofold: the risk of not having an adequate supply of electricity and the risk of being saddled with expensive investments in unnecessary resources.

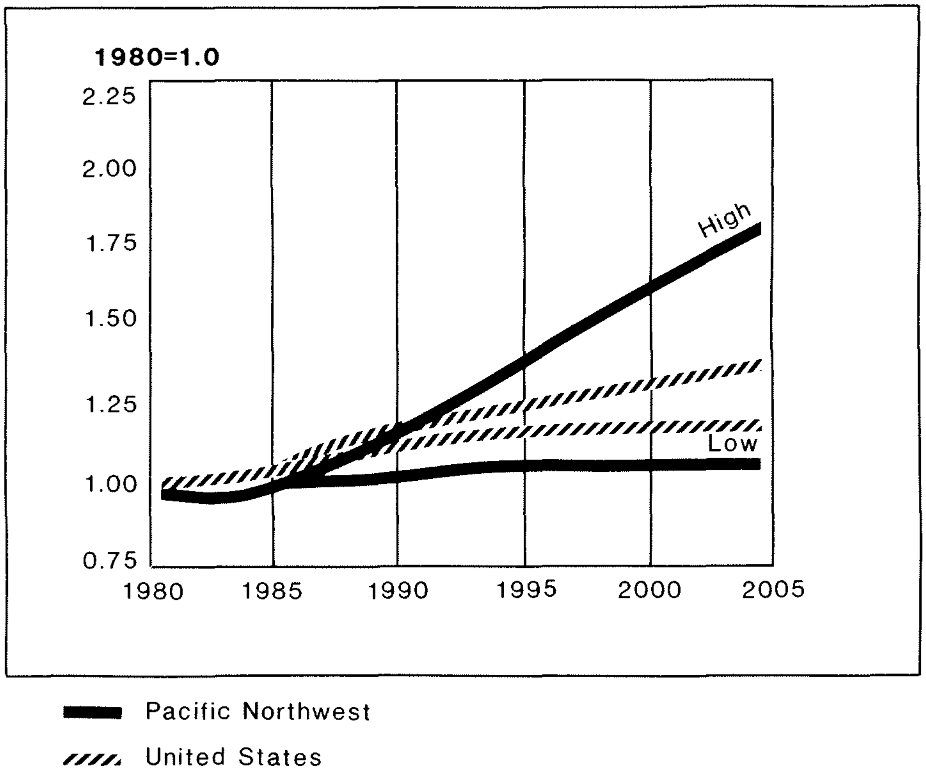


Figure 2-1
Total Employment—Pacific Northwest Region and U.S. Assumptions

The high and low forecasts are designed to describe scenarios that have a low probability of occurrence. While actual levels for any single variable or industry may fall outside the high and low ranges, it is assumed that the probability of the scenarios as a whole is very low.

Equally important to the planning process are the medium-high and medium-low scenarios. These scenarios are assumed to bound an area of most likely load growth. The higher probability of load growth falling within this range will have an impact on the analysis of resource decisions.

The total employment forecasts presented in this report are similar in many respects to the forecasts for the 1983 Power Plan. The forecasts encompass a range of employment growth between 1985 and 2005 comparable to the range in the 1983 plan between 1980 and 2000. The high forecast assures that the Council's plan will accommodate record regional economic growth should it occur. In the high forecast, total regional employment grows 130 percent faster than a high national forecast of employment. The high forecast represents a case where the region grows faster relative to the nation than in any historical five-year period. The low forecast assumes that the Pacific Northwest grows at a rate 40 percent lower than a low growth national forecast. The low case implies a relative performance well below that which has characterized the region in the long term. Figure 2-1 illustrates the forecast range relative to a national forecast range from Wharton Econometric Forecasting Associates.

In spite of the general similarity of the forecast range to that in the 1983 Power Plan, there are several important changes in the details of the economic and demographic forecasts and in the fuel price assumptions. In general, the forecasts show lower levels of employment and population growth in all scenarios.

For example, in the high case, employment was forecast to increase at a rate of 3.7 percent per year from 1980 to 2000 in the 1983 Power Plan forecasts. In the forecasts presented in this chapter, employment is projected to increase at a rate of 3.2 percent per year from 1985 to 2005 for the high case. As a result of the combination of a lower growth rate and a different base year, total employment in the 1986 Power Plan high case is approximately 20 percent lower in the year 2000 than in the 1983 Power Plan high case. This pattern is similar across the range of forecasts. Other significant changes include:

- Lower fuel price assumptions.
- Lower aluminum smelter operating rates in most forecasts.
- Lower heavy manufacturing employment forecasts.
- Increased relative importance of the nonmanufacturing sector.

The forecasts for oil and natural gas prices are generally lower than those in the 1983 Power Plan, reflecting recent history and an improved understanding of the world oil market. The ability of oil producers to achieve ever higher prices for their oil is severely limited by market responses, both on the demand side and on the supply side.

Recent changes in the structure of the world aluminum market and rapid increases in regional electricity rates have raised questions about the long-term viability of some of the aluminum plants in the region. To encompass this potential uncertainty, lower aluminum smelter operating rates were assumed in all forecasts, except the high case. The high case assumes that plants are operating at 100 percent in the long run.

Forecasts of employment growth in a number of heavy manufacturing industries are lower in these forecasts than in the 1983 Power Plan forecasts. The industries include forest products, transportation equipment, food and kindred products, machinery, and primary and fabricated metals. The impact of increased foreign competition, rising relative costs of production (such as electricity and transportation), and the length and severity of the recent recession have taken a toll on the region's manufacturing industries.

In the lumber and wood products industry, higher productivity growth in the last few years has decreased the need for labor relative to a given level of production. For example, employment was estimated to be approximately 20 percent lower in 1984 than in 1979, while production was estimated to be similar to 1979 levels. Other industries have achieved productivity gains, although they may not have been as dramatic.

The nonmanufacturing industries accounted for 82 percent of total employment in the region in 1980. Nonmanufacturing industries are projected to increase employment faster than manufacturing industries in all scenarios. These and other aspects of the forecasts are discussed in more detail in this chapter.

Forecast Overview

Overview of the Regional Economy

The Pacific Northwest is blessed with rich natural resources in its minerals, agricultural lands, fisheries and extensive forests. The abundance of natural resources has provided the region's inhabitants with sources of jobs and income, as well as providing a desirable environment for recreation and maintaining a high quality of life.

The development of the vast Columbia/Snake River system for navigation, electricity production, irrigation and recreation has contributed to economic growth in the region. Low electricity rates, relative to those found elsewhere in the nation, have attracted electricity-intensive industries, such as the aluminum industry, to the Pacific Northwest.

More recently, industries such as electronics have grown in the region, attracted primarily by the quality of the labor force and quality of life. The development of port facilities and growing trade with Alaska and the Pacific Rim countries have provided a source of new jobs for the region. Growth in the nonmanufacturing sectors, in general, has occurred at a rapid rate. These developments have lent diversity to a region dependent on resource-based industries.

During the 1960s and 1970s, total employment grew faster in the region than in the nation. Table 2-1 shows a comparison of growth patterns between the region and the nation for the last two decades. Since 1979, the region has experienced slower growth than the nation. From 1979 to 1984, it is estimated that total employment increased 5.9 percent nationally, while total employment in the region decreased 0.2 percent. This can be explained, in part, by the composition of the region's industrial sector.

In 1979, manufacturing employment accounted for 19 percent of total employment. Within manufacturing, lumber and wood products was the largest employer, accounting for 27 percent of regional manufacturing employment. The lumber industry has suffered from depressed U.S. housing markets induced by high interest rates, competition from other producing areas and new product lines. It is estimated that, in 1984, employment in lumber and wood products in the Northwest was more than 20 percent lower than in 1979.

The lumber and wood products category includes logging activities, some of which are related to pulp and paper production. In addition, many companies have production facilities producing both wood and paper products. Including pulp and paper products, the forest products industry accounted for 31 percent of manufacturing employment.

The second largest regional manufacturing industry is transportation equipment, which is composed primarily of aerospace. It accounted for 17.5 percent of manufacturing employment in 1979. The aerospace industry began to turn around during 1984. Even so, from 1979 to 1984, it is estimated that employment in transportation equipment declined 15 percent.

Primary metals is the largest industrial consumer of electricity in the region, accounting for nearly half of all industrial electricity consumption. Most of the electricity consumption is concentrated in the primary aluminum industry, which operates ten plants in the Northwest. This industry has suffered from dramatic swings in prices of aluminum, increasing electricity prices, and increasing competition from lower-cost producing areas.

Pulp and paper is the second largest industrial consumer of electricity, followed by chemicals and lumber and wood products. In 1977, the top four industrial consumers of electricity accounted for almost 90 percent of the electricity used by industrial customers in the region.

Major Trends

There are a number of basic trends common to the range of forecasts. While the extent of change resulting from these trends varies somewhat in each forecast, it nevertheless forms a context for the future. Many of the trends relate to demographic patterns in the existing population.

One of the primary demographic changes that will occur is the aging of the population. From 1985 to 2005, the national population aged 45-54 is projected to increase almost 60 percent, while the population aged 20-29 is projected to decline by 10 percent. The population over the age of 55 is projected to increase by 35 percent during this period. Figure 2-2 shows the percentage change in population by age group for the nation from 1985 to 2005. Although the age composition of the population in the region will vary among scenarios because of migration, the general patterns of demographic change will persist.

Table 2-1
Comparison of U.S. and Pacific Northwest Employment Trends
Average Annual Rate of Growth (%)

	1960-1979		1979-1984	
	PNW	U.S.	PNW	U.S.
Total Employment	3.0	2.2	0.0	1.1
Manufacturing Employment	2.2	1.2	-2.0	-1.4
SIC[a] 20—Food & Kindred Products	1.3	-0.2	-1.6	-1.1
SIC 24—Lumber & Wood Products	1.0	0.8	-4.5	-1.6
SIC 26—Pulp & Paper Products	0.3	0.9	0.1	-0.7
SIC 28—Chemicals & Allied Products[b]	-0.1	1.6	3.6	-0.9
SIC 33—Primary Metals	2.9	0.3	-5.9	-7.0
SIC 35—Non-Electric Machinery	6.3	2.8	0.1	-2.4
SIC 36,38—Electrical Equipment and Instruments	9.0	2.2	3.9	1.0
SIC 37—Transportation Equipment	2.3	1.1	-3.1	-1.1
Other Manufacturing	3.4	1.0	-1.6	-1.5
Nonmanufacturing Employment	3.2	2.5	0.4	1.9

[a] Standard Industrial Classification (SIC) code.

[b] Change in classification of a facility in the region to chemicals has artificially raised the rate of growth from 1979-1984. Excluding this facility in the 1984 data would yield a growth rate of 2.0 percent.

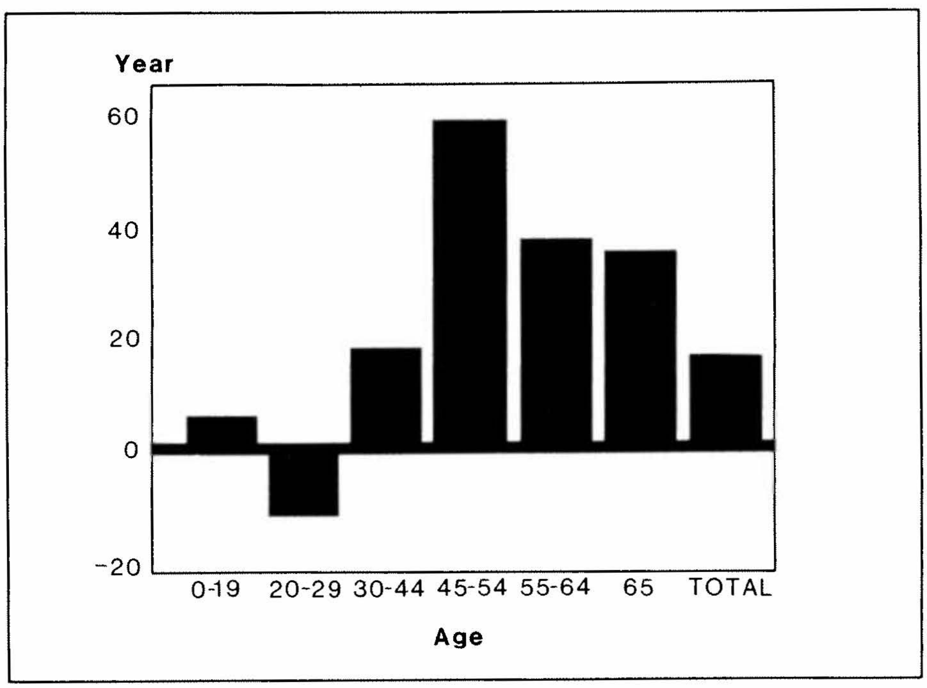


Figure 2-2
Percentage Change by Age Group—1985-2005

This aging of the population is expected to affect consumption patterns, the labor force and labor productivity. Productivity growth should be enhanced by the dramatic slowdown in the growth of the labor force during the forecast period. Slower growth in the labor force will result in upward pressure on wages. Producers will seek to substitute capital for labor, which tends to increase productivity and stimulate technological change. Consumption patterns are expected to emphasize personal services, clothing, travel, and health services.

A second major trend is the increase in the proportion of women in the labor force. From 1960 to 1980, the female labor force participation rate increased from 37 percent to 52 percent. This trend is expected to continue to varying extents in all forecasts.

Growth in the importance of nonmanufacturing industries is projected in each of the forecasts. Traditionally, studies of regional economic growth have focused on the manufacturing industries. Recently, the nonmanufacturing industries have attracted more attention because of their size and rapid growth. In 1980, nonmanufacturing industries accounted for 81 percent of total employment in the region. Nonmanufacturing employment increased at a rate nearly 70 percent higher than manufacturing employment from 1960 to 1979.

The outlook is strong for industries, such as communications and machinery, that will play a key role in growing technological changes and productivity-enhancing investments. The foreign trade sector is expected to continue to increase in importance. The Pacific Northwest is well positioned to participate in trade to the Pacific Rim countries, and that possibility is assumed to be an important component of the higher growth forecasts.

The continued stagnation of the region's large resource-based industries characterizes all of the forecast range. Lumber, aluminum, and basic chemicals are not expected to be important sources of economic growth for the region even in the high forecasts.

Table 2-2
Summary and Comparison of Forecasts
Pacific Northwest and U.S.
Comparison of 1980 and 2005

	AVERAGE ANNUAL RATE OF GROWTH (%) 1960-1980		1985-2005				
	U.S.	PNW	U.S.*	High	Medium-High	Medium-Low	Low
Total Employment	2.1	3.1	1.2	3.2	2.4	1.5	0.5
Manufacturing	1.0	2.0	-0.5	1.6	1.1	0.5	-0.4
Nonmanufacturing	2.4	3.4	1.5	3.4	2.7	1.7	0.7
Population	1.1	1.9	0.8	2.0	1.5	0.9	0.2
Households	2.1	2.8	1.4	2.8	2.0	1.3	0.3

	1980	2005 High	2005 Medium-High	2005 Medium-Low	2005 Low
Persons per Household	2.7	2.2	2.4	2.4	2.6
Employment/Population Ratio	0.41	0.50	0.47	0.44	0.42
Percent of Total Employment	100.0	100.0	100.0	100.0	100.0
Manufacturing	18.2	12.5	13.0	13.7	14.0
Nonmanufacturing	81.8	87.5	87.0	86.3	86.0
Percent of Manufacturing	100.0	100.0	100.0	100.0	100.0
Lumber & Wood Products	23.7	13.8	14.2	14.1	16.9
Transportation Equipment	18.5	17.5	17.0	17.3	15.6
Food & Kindred Products	12.6	11.2	10.8	11.1	11.8
Electronics (SIC 35,36,38)	14.6	26.4	26.0	24.0	20.7
Other	30.6	31.1	32.0	33.5	35.0

*The U.S. forecast is Wharton's medium case projection.

Description of the Scenarios

The economic assumptions presented in this chapter rely on basic policy assumptions, many of which operate at the national level. Each of the four regional economic forecasts was made within the context of a corresponding view of the national economy. However, the linkages between the national forecast and the regional forecast are indirect.

Certain results of the national forecasts are included directly in the regional forecasts. These include inflation rates, interest rates, industry specific productivity growth, and basic demographic patterns. Other assumptions create a greater variation in the regional forecasts than in the national forecasts, however. These include wider fuel price ranges, regional shares of national employment growth by industry, and specific assumptions about the viability of the regional aluminum industry. Forecasts developed by Wharton Econometric Forecasting Associates (Wharton)[1] were the primary source for forecasts of national economic variables used in developing regional projections.

In developing the range, the primary objective was internal consistency for each forecast. That is, incompatible assumptions were not combined in any one forecast just to achieve a wide forecast range. In some cases, there are three forecasts for each industry projection or other assumption. These were combined into four scenarios. For example, there are three forecasts for production and employment in the lumber and wood products industry. These were combined with other industries into four scenarios. In the case of lumber and wood products, the high case forecast was included in the high economic growth scenario, the medium case forecast was included in the medium-high economic growth scenario and the low case forecast was included in the low and medium-low scenarios. This combination of assumptions is intended to reflect the downside risk assumed for the lumber and wood products industry.

In developing the scenarios, it is important to recognize the wide range of possible outcomes for the regional economy. A short-term view of the future was rejected in favor of developing scenarios that would encompass a wide range of uncertainty about the region's economy in the long run. The high case presents quite a different view of the regional economy in the year 2005 than the low case. For example, there are 40 percent more people living in the region in the high case than in the low case by the year 2005.

In addition to an underlying high growth scenario on the national level, the regional outlook for the high growth case implies that the region's economy fares better, relative to the nation, than it has in the past. The large resource-based industries, such as forest products, aluminum, agriculture and basic chemicals, maintain a vital presence in the region's economy, but are not expected to contribute to new jobs. In the high case, employment in lumber and wood products is projected to decline 20 percent from 1984 to 2005. Other resource-based industries show no increase in jobs. On the other hand, industries such as electronics, trade and services expand rapidly, more than doubling their employment in 20 years. As shown in Table 2-2, total employment is projected to increase at a rate of 3.2 percent per year, which is slightly higher than the rate of growth sustained by the region from 1960-1980. Population is projected to grow at 2.0 percent per year, while households grow at 2.8 percent per year. It is assumed in these projections that the region will continue to be a favorable location for growth, because of the richness and diversity of its natural resources, the quality of the environment and labor force, the quality of the educational system, relatively lower electricity prices, and proximity to expanding markets in Japan and other Pacific Rim nations.

In the medium-high scenario, rapid growth in high technology and commercial industries is coupled with moderate levels of activity in forest products, agriculture, and basic chemicals. Employment in lumber and wood products is projected to decline 25 percent from 1984 to 2005. This is accompanied by slight declines in other resource-based industries. The operating level of the region's aluminum plants is assumed to average 85 percent. Employment in electronics and nonmanufacturing increases by nearly 80 percent. These changes result in employment growth of 2.4 percent per year, and population and household growth of 1.5 and 2.0 percent per year, respectively. Although the overall level of employment growth in the medium-high scenario is slower than the region experienced in the 1960s and 1970s, it still represents a case where employment growth is 100 percent faster than national growth in the medium case.

In the medium-low growth forecast, traditional industries experience low levels of economic activity while other manufacturing and commercial industries experience moderate growth levels. Employment in lumber and wood products is projected to decrease by more than a third of its 1984 level. The operating level of the region's aluminum plants is assumed to average 70 percent. The region continues to increase its share of employment in electronics and nonmanufacturing industries, however. Total employment is projected to increase at a rate of 1.5 percent per year, with population and households increasing at rates of 0.9 and 1.3 percent per year, as shown in Table 2-2. In the medium-low scenario, employment growth is 25 percent faster than national growth in the medium case, which is lower than the relative rate of growth experienced by the region from 1960 to 1980.

The regional outlook for the low case shows total employment increasing at a rate of 0.5 percent per year, indicating a rate of growth 40 percent lower than the national rate of employment growth in the low case. The disproportionate impact of the recent recession on major regional industries leads to more severe long-term problems than in the other scenarios. Growth in nonmanufacturing is offset by declines in many of the larger traditional industries. In the low case, the operating level of the region's aluminum plants is assumed to average only 50 percent. In addition, employment in aerospace is projected to decline by more than a third. Total population and households are projected to increase at rates of 0.2 and 0.3 percent per year, respectively. This slow level of growth implies net out-migration of population throughout the forecast period.

Employment and Production

The Forest Products Industries

The long-term outlook for the region's forest products industry is clouded by the roller coaster housing markets of the last few years. New housing accounts for 40 percent of the market for lumber and wood products. Figure 2-3 is a graph showing U.S. housing starts, Pacific Northwest lumber production and plywood production for 1960 to 1983. The graph shows that regional lumber and plywood production follows a cyclical pattern similar to U.S. housing starts.

In 1979, the regional wood products industry accounted for 38 percent of U.S. lumber production and 55 percent of U.S. softwood plywood production. The bulk of production in the region—almost half of lumber production and over 70 percent of the softwood plywood production—occurred in Oregon. Furthermore, a large proportion of production in both Oregon and Washington is west of the Cascades.

In recent years, the regional lumber industry has been threatened by a poor housing industry, a loss of market share to other competing regions and Canada, and competition to plywood from lower-cost substitutes such as waferboard and oriented strandboard.

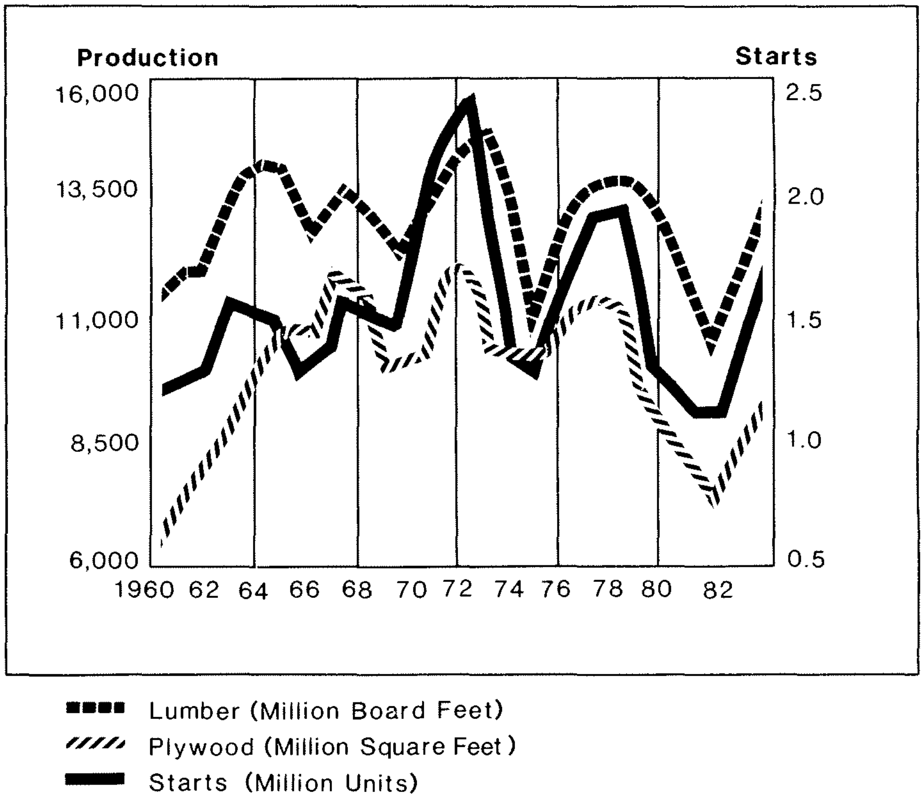


Figure 2-3
Comparison of Pacific Northwest Lumber and Plywood Production with U.S. Housing Starts—1960-1983

The housing industry in the U.S. has undergone a number of fundamental changes through the last recession. Real mortgage rates are projected to remain higher in the future than during the 1970s. The housing boom that led to speculation and high-return investment opportunities for households has fizzled as housing values failed to keep up with the general rate of inflation. The deregulation of the financial industry has opened additional avenues for investment by households. These factors raise the cost and lower the demand for housing.

One important characteristic of the housing market with consequences for lumber and plywood demand is the percentage of total housing units that are single family units. A single family unit uses approximately three times as much lumber and wood products as a multifamily unit. From 1970 to 1974, the average share of single family units to total units was 58 percent. This share increased to 73 percent for the years 1975 to 1979. Wharton projects that the share of single family units will average between 64 and 69 percent over the next 20 years. The share of single family units is affected by the cost of housing and demographic factors.

Another important factor is the average size of new housing units. The average size of new single family units increased from 1,355 square feet in 1962 to 1,760 square feet in 1979. During this period, the average number of persons per household declined from 3.3 to 2.7. Since 1979, the average size of new single family housing units has decreased by approximately 10 percent. The Real Estate Research Corporation projects that average unit size will decrease to 1,200 square feet by the end of the 1980s. This is in contrast to recent U.S. Forest Service (USFS) forecasts, which assume that the average size of new single family housing units will increase gradually, reaching 1,850 square feet by 1990 and 1,950 square feet by 2000. This would have an important impact on the demand for lumber.

Another important area of concern is the forecast of housing starts. The USFS and Wharton forecasts of U.S. housing starts are shown in Table 2-3. The numbers shown are housing starts, excluding manufactured homes. As shown in Table 2-3, the forecasts differ considerably in the 1985-1990 period, but are similar during the 1990s.

The region's lumber industry has experienced increasing competition from lumber-producing areas in the Southeastern United States. Higher transportation, labor and stumpage costs have made it difficult for the Northwest to retain its historical market shares. For example, wage rates are as much as 40 percent lower in the Southeast.

In the Southeast region, timber resources are owned primarily by the lumber industry and other private parties. The timber harvest can respond to fluctuations in demand, relieving pressure on stumpage prices. In the Northwest, the federal government owns more than half of the commercial timberlands. Timber resources under the management of the U.S. Forest Service are governed by laws limiting the level of cuttings to an even flow, nondeclining yield. Stumpage prices have been bid competitively, raising costs dramatically for some mills that rely extensively on timber from National Forest lands. In addition, the tree growth cycle is faster in the Southeast, approximately 35 years compared to 50 years in the Northwest.

One area of uncertainty is in the estimates of future timber resources. Recent studies show that more privately-held timberlands in the Southeast are being lost to other uses, such as agriculture or urban development, than previously thought. In addition, the intensity of management science applied by nonindustry private timber owners is subject to uncertainty. Other factors that add to the uncertainty of future timber resources include natural disasters, improvement of timber management techniques, and changes in wilderness or recreational designations, to name a few.

Canadian producers have increased their share of the U.S. market to one-third, from 28 percent in 1979. Further competitive inroads into U.S. markets may continue. This is a subject of controversy in U.S./Canada trade relations currently. Some U.S. producers claim that the Canadian government is using unfair trade practices by selling public timber at subsidized prices.

Competition to the region's plywood industry is provided by the introduction of low-cost substitute products. The substitutes include products such as waferboard and oriented strandboard. These products are fabricated from faster-growing trees and waste chips. Their main cost advantage is the use of lower cost materials. Estimates of the impact of these new products range from capturing 25 percent of the plywood market by 1985 to 20 percent by 1989.

The potential exists for expanding markets for lumber and wood products in other countries, but represents an area of uncertain magnitude. One factor interfering with the growth of exports has been trade restrictions in other countries, particularly in Japan, against finished wood products. In some potential export markets, wood housing is viewed as inferior or lower quality. Industry and state organizations have carried out marketing programs to increase export markets, but little information is available to assess the impacts on the Northwest lumber industry.

The production forecasts presented in this plan are based on earlier studies adopted by the Council, comparisons with recent Forest Service forecasts, and comments received in the review of the proposed draft assumptions.[2]

The high case combines the assumptions of high levels of housing activity, intensive management of forest industry lands, and increased export of finished wood products from the region.

Table 2-3
Average Annual U.S. Housing Starts
(Million Units)

YEAR	WHARTON High	WHARTON Base	WHARTON Low	USFS
1985-1990	1.78	1.65	1.50	2.07
1992-1995	2.04	1.85	1.65	1.89
1996-2000	2.09	1.82	1.54	1.82
2002-2005	1.82	1.57	1.33	1.71

The medium case assumes there are no major changes in management of timber resources. Housing demand is high in the 1980s, then declines because of demographic shifts in the population. Exports of finished wood products increase slowly through the forecast period. The region's share of national consumption decreases because of competition from the Southeast and Canada.

The low case combines the assumptions of low demand from housing and further loss of market share to other producing regions. Plywood production declines dramatically because of competition from alternative products.

The projections presented in this plan differ from the Council's 1983 studies in that the forecast for production in the plywood industry has been reduced substantially in all scenarios. The lower plywood forecast is in response to the increased competition from substitute products such as oriented strandboard and waferboard. The proposed draft lumber forecasts were reduced for the state of Idaho based on comments from Idaho state agencies and utilities. These changes were consistent with the comparison of recent Forest Service forecasts, which showed a lower forecast for lumber in Idaho. In general, the Forest Service forecasts are slightly lower than the Council's high range for the remainder of the 1980s, and fall halfway between the high and medium range from 1990 to 2005. The forecasts for the lumber and wood products industry are shown in Table 2-4. The high case for lumber and plywood was used in the high scenario. The medium case was used in the medium-high scenario, and the low case was used in the medium-low and low scenarios.

The pulp and paper industry is the second largest industrial consumer of electricity in the region. In 1977, firms in pulp and paper products accounted for 19 percent of the electricity consumed by industry. The industry employed 30,100 people in 1980.

The region's pulp and paper industry supplied an average of 14 percent of national pulp production and an average of 10 percent of national paper and paperboard production in the 1970s. The region's share of pulp production was down from an average of 17 percent during the 1960s.

Most of the raw material used in the pulpmaking process is wood chips, byproducts from lumber and plywood plants. Availability and cost of wood chips in the future will operate as a constraint on capacity expansion in this region. Competition for portions of the timber resource has increased because of improvements in yield from each log by sawmills and plywood plants, and timber management practices that produce more uniform logs. Another factor has been the growth of the export market for chips during the 1970s.

The long-term outlook for the Pacific Northwest industry is favorable with regard to proximity to markets in the West. Other factors, however, including fiber availability and comparative production costs (the costs of labor and environmental regulation, for example) compare less favorably to the Southeastern producing areas. The region's advantage in electricity costs has decreased as a result of large increases in electricity rates since 1979. Not only are electricity costs a major portion of operating costs, but the costs of chemicals used in the bleaching process are important as well. Chlorine and caustic soda are produced through an electrolytic process, which is highly electricity intensive.

Table 2-4
Forecasts of Production and Employment
Lumber and Wood Products
Pacific Northwest
1980-2005

	PRODUCTION 1980	1985	2005	AVERAGE ANNUAL RATE OF GROWTH (%) 1985-2005
Lumber (SIC 2421) (Billion board feet)				
High			12.3	-0.5
Medium	11.2	13.5	11.2	-0.9
Low			8.9	-2.1
Plywood (SIC 2436) (Billion square feet)				
High			9.4	0.0
Medium	8.6	9.3	7.0	-1.4
Low			5.8	-2.3

	EMPLOYMENT (In thousands) 1980	1985	2005	AVERAGE ANNUAL RATE OF GROWTH (%) 1985-2005
High				
Lumber (SIC 2421)			31.6	-2.0
Plywood (SIC 2436)			16.3	-1.4
Other SIC 24			58.5	0.3
Total SIC 24			106.4	-0.8
Medium				
Lumber (SIC 2421)	52.0	47.3	29.3	-2.4
Plywood (SIC 2436)	26.7	22.3	12.5	-2.9
Other SIC 24	61.2	54.6	56.7	0.2
Total SIC 24	139.9	124.2	98.5	-1.2
Low				
Lumber (SIC 2421)			23.7	-3.4
Plywood (SIC 2436)			10.6	-3.7
Other SIC 24			52.0	-0.2
Total SIC 24			86.3	-1.8

Nationally the demand for paper products is expected to be strong, with paper holding its own against petroleum-based plastic products. In addition, the Northwest has the largest inventory of preferred long-fiber softwoods, and access to ports to serve world markets.

The production forecasts for pulp (SIC 2611), paper (SIC 2621) and paperboard (SIC 2631) were based on work performed by Ekono, Inc., for the Brookhaven National Laboratories contract with the Bonneville Power Administration. Ekono, Inc., supplied Brookhaven with a range of projections by industry for the region, based on surveys collected from most of the region's companies and their own analysis of fiber availability and cost.[3]

The Northwest Pulp and Paper Association conducted a survey of regional pulp and paper producers in early 1982,[4] requesting information on raw material use in 1980, pulp and paper production and capacity in 1980, and projections of production increases for the next 20 years. Ekono, Inc., estimated that participating companies represented approximately 75 percent of the installed capacity of pulp, paper and paperboard products in the region. The survey was compiled through Arthur Andersen Company to ensure the privacy of individual companies.

In developing the projections, Ekono, Inc., relied on the survey results, as well as estimates of capacity and production for 1980 and 1981 by product, and trends in fiber availability, production costs, and regional market share in domestic and foreign markets. These projections were updated to reflect data on capacity and production provided by a 1985 Northwest Pulp and Paper Association survey for the years 1982 through 1984. In addition, changes to the relative rates of growth by end-product for Oregon, Idaho and Western Montana were incorporated to reflect differences in historical growth rates by state.

Forecasts for regional production and employment in the pulp and paper industry are shown in Table 2-5. The changes result in a slightly higher regional rate of growth in paperboard production and a slightly lower regional rate of growth in paper production.

The residual category consists of miscellaneous converted paper products (SIC 264), paperboard containers and boxes (SIC 265), and building paper and board mills (SIC 266). These categories include the manufacture of bags, boxes and containers, writing paper, tissue paper and building board at sites where primary products are not produced. Industries within these categories locate close to population centers, and the forecast of production is dependent on regional population growth.

Table 2-5
Forecasts of Production and Employment
Pulp and Paper Products (SIC 26)
Pacific Northwest
1985-2005

INDUSTRY	PRODUCTION Average Annual Rate of Growth (%) 1985-2005 High	Medium	Low
Pulp (SIC 2611)	1.9	1.6	1.4
Paper (SIC 2621)	2.6	2.2	1.8
Paperboard (SIC 2631)	2.0	1.3	0.5
Other Paper	3.9	3.3	1.1

	EMPLOYMENT (in thousands) 1985	2005 High	Medium	Low
Pulp (SIC 2611)	2.1	1.5	1.5	1.7
Paper (SIC 2621)	12.5	10.7	10.5	11.1
Paperboard (SIC 2631)	4.8	3.6	3.3	3.3
Other Paper	8.0	8.6	8.2	6.2
Total SIC 26	27.4	24.4	23.5	22.3

Aluminum Industry

The Pacific Northwest is an important world center for aluminum production. Almost 9 percent of the world's aluminum production capacity is located in this region. The historically low electricity rates and large supplies of hydropower originally attracted aluminum production to the region.

The aluminum industry is far more significant as a consumer of electricity than as an employer. At full operation, the Northwest aluminum plants can consume up to 3,000 megawatts of electricity. This represents about 20 percent of 1982 regional electricity sales. In contrast, the aluminum companies employ about 9,500 persons, or about 0.3 percent of the region's employment.

The aluminum industry is an important economic presence in the region. It supplies intermediate products to a number of industries, including fabricated metals, machinery, transportation equipment, and electronics. Proximity to primary aluminum reduction is an important locational advantage to these industries. Thus, additional numbers of jobs may be indirectly related to the presence of aluminum smelters in the region.

All of the primary aluminum plants are direct service industrial (DSI) customers of the Bonneville Power Administration (Bonneville). As such, they are entitled to contractually-specified maximum amounts of power, of which 25 percent is interruptible under certain conditions. Because of the existence of these long-term contracts, there is an upper limit to the demand for electricity by the aluminum industry. The question that seems to be more current is, what is the lower limit on aluminum industry demand for electricity, and under what conditions is lower demand likely to occur?

Since 1978, the low price of electricity that the region's aluminum companies had enjoyed has increased dramatically. The DSI rates that aluminum companies pay for electricity increased from about .3 cents per kilowatt hour in 1978 to 2.7 cents per kilowatt hour in 1984. These increased costs have made it more difficult for the Northwest's smelters to operate profitably in the recent cyclical depressions of the aluminum market. Bonneville has offered some rate relief to aluminum companies in order to help keep them operating at higher levels, but the long-term viability of the region's smelters is being questioned.

Because of the present condition of the region's aluminum plants, and the doubts being raised about their long-term viability, the size of aluminum industry demands for electricity has become a major uncertainty facing the region's electricity planners. Not only is the long-term viability of the aluminum industry uncertain, but the increased cyclical sensitivity of the industry has important implications for the electricity system. These are planning questions that fall outside the scope of this chapter, however.

The assumptions proposed here should be viewed as assumptions about the possibilities facing the region's aluminum plants in the absence of other policy decisions that may affect their rates for electricity or change the conditions of electric service they receive.

The basic assumption is that reasonably strong aluminum markets will make the Northwest aluminum smelters competitive in the world aluminum market. It is further assumed that strong economic growth is compatible with growing aluminum demand and prices. Therefore, the highest operating rates for Northwest aluminum plants are assumed to occur in the high forecast. The specific assumptions for operating rates of the region's smelters are shown below. The direct service industry loads are treated differently, however, in the analysis of electrical loads faced by the region for resource planning purposes. Further explanation of this treatment is in Chapter 3, Volume II.

Assumed Aluminum Operating Rates

High Forecast: 100 percent

Medium-high Forecast: 85 percent

Medium-low Forecast: 70 percent

Low Forecast: 50 percent

The high forecast assumes strong growth in the world economy and strong growth in aluminum demand. Higher world oil prices keep plastics less competitive with aluminum than in the lower cases. As new capacity is added throughout the world, the average cost of producing aluminum increases, making the Northwest plants relatively more profitable on average. Higher electric rates in the high case may cause some of these plants to close during cyclical weaknesses in the aluminum market. It is assumed that DSI power contracts are transferable to purchasers of Northwest aluminum plants and that the contracts are renewed in 2001. In the high forecast, any efficiency improvements are accomplished along with capacity increases so that electricity demand is unchanged.

The medium cases would be consistent with reasonably good world aluminum markets, but reflect the considerable risk that some of the region's aluminum plants may not survive through the current recession. Such outcomes could result from corporate strategic decisions or pessimistic views of the future aluminum market. These declines in operating rates could also reflect efficiency improvements made in the absence of capacity increases. It is also expected that the real price of electricity for the DSI plants will be stable in the medium cases.

The low case reflects a world in which aluminum markets remain highly cyclical and on average weak. There is only very slow capacity growth in the world, and areas with extremely low or subsidized electric rates are able to attract smelting capacity more suitable to operating through price cycles. In this situation, a larger number of the Northwest plants find it advantageous to close. However, this would take place over a longer period because of the large share of the world capacity that resides in the Northwest, and because there are many less profitable plants in the world that are likely to close before the Northwest plants.

Chemicals

The manufacture of chemicals consumes approximately 12 percent of electricity purchased by the industrial sector in the region. Elemental phosphorus production accounts for approximately half of the electricity consumed by the chemicals industry, followed by chlorine and caustic soda, which accounts for approximately 20 percent. In the Council's forecasting models, the consumption of electricity by these industries is modeled on a plant-by-plant basis. Two of the chlorine and caustic soda plants are direct services industries (DSIs) of Bonneville.

The remainder of the chemicals industry in the region is dominated by nuclear fuels processing and agricultural chemicals (such as fertilizers). The nuclear fuels processing component has exhibited large swings in employment, as policies of the federal government have changed over the last 20 years. The agricultural chemicals component has increased at a steady rate in the last decade, but it is not likely to increase rapidly in the future.

The manufacture of chlorine and caustic soda involves the electrolytic separation of salt into two co-products: chlorine and sodium as sodium hydroxide (caustic soda). Approximately 1.12 pounds of caustic soda are produced per pound of chlorine.

The market outlook for the two products differs substantially. In the past, chlorine has held the stronger market and higher price. Expansion plans were based on growth in chlorine demand. As little as ten years ago, caustic soda was considered an undesirable "byproduct," and for years producers sought to develop a commercial process to produce chlorine without producing caustic soda. In the last few years, the price of caustic soda has risen and supplies have tightened, while chlorine demand has dropped and prices have remained stable.

Industry experts have predicted growth rates for national chlorine demand in the 1980s to range from an average of 1 to 3 percent per year, whereas demand for caustic soda could increase at rates ranging from 2.5 to 5 percent. This is slower than the rate of growth in production from 1960 to 1980, which averaged 4.1 percent per year. From 1970 to 1980, however, production increased at an annual rate of only 1.6 percent. The outlook for chlorine has been affected by environmental regulations on effluent standards. Pulp and paper producers may substitute other chemicals in pulp bleaching to reduce emissions. The outlook for caustic soda is much more favorable because it has a broader base of end-uses. One of the fastest growing end-uses is in the neutralization of waste acids. Tougher environmental standards would enhance the outlook for caustic soda. Soda ash can be substituted for caustic soda, and although the initial investments required to handle soda ash are high, projections of relative price increases for caustic soda and soda ash favor some conversion to soda ash. Production of chlorine and caustic soda is likely to be constrained by the price of chlorine, since chlorine is more difficult to store.

Chlorine and caustic soda are produced in five plants in the region, with four located in Washington and one in Oregon. Nationally, over half of the chlorine produced is used within the chemicals industry in the manufacture of a variety of organic and inorganic chemicals. An additional 13 percent is used by the pulp and paper industry as a bleaching agent in the production of paper. In the Pacific Northwest, a much larger portion of production goes to the pulp and paper industry. In fact, two of the five plants in the region are owned by pulp and paper companies.

The proportion of product going to the pulp and paper industry in the Northwest varies from 32 percent to 80 percent, depending on the plant and temporary shifts in market conditions. This is a much larger proportion than nationally, although the pattern is similar in the Southeastern U.S. Although not all of the chlorine produced in the region is sold to pulp and paper producers, growth in the production of paper (SIC 2621) was chosen as a reasonable indicator of growth in the production of chlorine and caustic soda. The projections presented here are within the range of projections for national production cited in the preceding paragraphs. Comparison of the production growth rates for chlorine and caustic soda and paper (SIC 2621) shows that the projection for chlorine and caustic soda is 0.4 percent per year higher in the high case to allow for higher rates of growth in other end-uses. The medium case growth rate is similar to the medium rate of growth in paper, and the low case is 0.5 percent per year lower than the low case paper projection to reflect lower rates of growth in other end-uses or market penetration by British Columbia producers. Table 2-6 shows projections of production for SIC 2812, chlorine and caustic soda.

Table 2-6
Forecasts of Chemicals Industry Production
Pacific Northwest
1985-2005
Average Annual Rate of Growth (%)

SIC	HIGH	MEDIUM-HIGH	MEDIUM-LOW	LOW
Chlorine/Caustic Soda (SIC 2812)	3.0	2.2	1.3	1.3
Elemental Phosphorus (SIC 2819)	1.6	0.7	0.0	0.0
Other Chemicals (SIC 28XX)	4.4	3.6	2.5	1.4

Elemental phosphorus production is located in only four states (Idaho, Florida, Montana and Tennessee), near deposits of phosphate rock. Elemental phosphorus is extracted from phosphate rock in electric furnaces, and frequently converted nearby to phosphoric acid and other compounds.

Elemental phosphorus plants are classified under industrial inorganic chemicals, not elsewhere classified (SIC 2819). In the Northwest, firms producing elemental phosphorus, nuclear fuel, corn starch, chemical catalysts and a variety of other products are classified under SIC 2819. About half of total U.S. elemental phosphorus production capacity is located in the Northwest. Of this, 85 percent of capacity is located in Idaho, with the remainder in Montana.

The major end-use markets for elemental phosphorus are cleansers and detergents (45 percent), food and beverages (15 percent), metal treating (10 percent) and other chemicals and cleansers (30 percent). The outlook for elemental phosphorus production in the Northwest depends, in part, on the demand for these products.

The detergent market has been projected to remain stable or increase slightly over the forecast period, with growth rates ranging from 0 percent to 1 percent per year. Nondetergent uses, such as food and beverage products and other uses, have been forecast to increase at rates of 1.4 percent to 2.4 percent per year.

The problems facing elemental phosphorus producers in the region include the cost and availability of electricity and mature markets for their products. The costs of additional electricity beyond current contracted amounts may lead to no expansion in capacity over the forecast period. This was assumed to be the case for the low scenario. The high case projection is a weighted average of the higher ranges of forecasts for detergent and nondetergent uses of elemental phosphorus. Projections of production are shown in Table 2-6.

The residual category for chemicals (SIC 28XX) includes a wide variety of products manufactured in the region. The larger groups in employment and energy use are the nuclear engineering, fuels and waste processing segments, and agricultural chemicals (primarily fertilizers and pesticides). There are also many other types of chemical products manufactured in the region.

The forecasts for the other chemicals category are shown in Table 2-6. The forecast range for the region was based on selecting ranges around national forecasts for chemicals, with the exception of the forecasts for Idaho. Comments were received that indicated that the industry in Idaho is dominated by agricultural chemicals. The demand for agricultural chemicals is expected to increase at a slower rate of growth than the demand for other chemicals products. In the high case, production increases at a 30 percent higher rate than Wharton's high case forecast for the nation, while the low case increases at a 30 percent slower rate than Wharton's low case forecast for the nation.

Agriculture and Food Processing

Over the past decade, agriculture has found itself increasingly at the mercy of circumstances beyond its control. These circumstances run the gamut from changing foreign markets for farm products to federal farm policy and state decisions on groundwater pumping. Northwest agriculture markets were primarily regional and national. However, increasing production and sales of farm products from the Midwest and Northeast for large eastern markets has put increasing pressure on Northwest producers to sell overseas. The Orient has been an important destination for many of these sales. A recent comprehensive study of Northwest agriculture concluded that if Northwest agriculture is to maintain its share of national production and make reasonable growth, it must continue to develop foreign markets. Regional agriculture has been fairly successful in doing so. However, farm production and marketing efforts are often offset by a lack of clear agricultural policy from the U.S. government. There are mixed policy signals on the level and structure of price supports, overseas marketing assistance, environmental enforcement, taxes and water policy, just to name a few.

Table 2-7
Forecasts of Employment
Agriculture and Food Processing
Pacific Northwest
1985-2005

	EMPLOYMENT (in thousands) 1985	2005	AVERAGE ANNUAL RATE OF GROWTH (%) 1985-2005
Agriculture			
High		157.9	0.0
Medium-high	157.4	150.9	-0.2
Medium-low		144.9	-0.4
Low		129.5	-1.0
Food Processing			
High		86.0	0.9
Medium-high	72.5	74.8	0.2
Medium-low		68.0	-0.3
Low		60.3	-0.9

The region's agriculture has found itself in increasingly difficult times during the past few years. Crop prices have been low, production costs have continued to increase, and export markets have been shrinking. Furthermore, there are several issues on the horizon which further cloud development of new irrigated land. An unsettled lawsuit in Idaho over priority of use of Snake River water—irrigation or hydrogeneration—has halted most irrigated land development there. In Oregon, groundwater pumping has been restricted in some irrigated areas. The restriction may be expanded to additional areas. In Washington, half the Columbia Basin irrigation project is not yet developed. Federal funding for development is restricted, and there is not yet a decision on partial state funding nor even on the advisability of developing the remaining land.

During the past few years, there are indications that irrigated land development may have leveled off. During this same period, irrigation pumping loads have become more erratic and appear to be leveling off. Many irrigators are installing water and electricity conservation equipment and measures.

Agriculture employed 157,100 persons directly in the region in 1980, accounting for almost 5 percent of total employment. Direct employment in agriculture decreased at a rate of 1.5 percent per year from 1960 to 1980, even though agricultural production increased throughout this period. This resulted because of large increases in mechanization. Agricultural employment is projected to decrease at a slower rate than in the past to reflect increasing costs of capital and fuels. The projections for agricultural employment are shown in Table 2-7.

Agricultural production supports a large food processing industry. In 1980, 74,200 persons were employed in food and kindred products (SIC 20), which represented 13 percent of manufacturing jobs. Activity in this industry is concentrated in preserved fruits and vegetables (SIC 203), which accounted for nearly half of the employment in food and kindred products and over half of the electricity consumption. Processed potatoes are the major products in this category, accounting for over half of the value added in the regional food processing industry. Another portion of the industry important to coastal areas is the seafood canning and freezing industry. Poor commercial fishing conditions have forced closure of a number of these plants.

The outlook for plants in preserved fruits and vegetables relies on future demand for processed foods domestically and in Pacific Rim countries, a recently expanding market. Changes in lifestyle and consumer preferences have had an impact on the market for food products. Comments received during the planning process indicated that high transportation costs and rising electricity rates were leading to more plants locating in the midwestern U.S., closer to markets. In addition, it was pointed out that Wharton's forecast of national employment growth in this sector led to employment decreasing at a rate of 1.4 percent per year from 1985-2005. The projections of employment in food processing for the region are shown in Table 2-7.

The High Technology Industries

A great deal of attention has been focused of late on the so-called high technology industries. State and local governments in the U.S. and national governments around the world have initiated studies and programs designed to understand and attract economic development through the encouragement of growth in high technology industries. In the region, the recent growth of electronics and software firms has been heralded by some as a panacea for stagnation in some of the region's resource-based industries.

The first step in a discussion of high technology industries is to define the group of industries to be discussed. Several methods of defining high technology have been proposed, but general agreement does not exist on which definition is the most appropriate. To a certain extent, the nature of technology intensive activity makes definition difficult, because the industries are changing so rapidly. New industries are created and others become obsolete, thus causing any definition of high technology industries to be tied to a particular point in time.

Most definitions have looked at one or a combination of three factors: research and development expenditures as a proportion of value added, the percentage of scientific and technical personnel in industry employment, and product sophistication. The definition described in this chapter was adopted from a Battelle study[5] for the state of Washington and reflects a combination of all three factors. The Battelle study included a number of chemical industries in its definition of high technology industries. These industries were excluded from the definition of high technology industries used in this chapter, for reasons described below.

Even at the level of industry detail shown in Table 2-8, it is difficult to categorize industries as high technology industries. At more detailed levels of categorization, however, data are not available to analyze the industries because of disclosure laws that protect companies' rights to proprietary information. Comments were received during the planning process that it may be inappropriate to apply definitions developed to describe high technology industries in the state of Washington to the same industries in other states. In particular, concerns were raised about the inclusion of some chemical industries, particularly industrial inorganic chemicals (SIC 281) and agricultural chemicals (SIC 287) in the high technology group. The chemical industry forecasts have been discussed in a previous section. The list of industries included in the high technology group and their SIC codes are shown in Table 2-8.

In the U.S., the industries listed in Table 2-8 comprised approximately 5.3 percent of total wage and salary employment in 1982, compared to 6.0 percent for the region. The high technology share of total employment was 7.9 percent in Washington, 5.0 percent in Oregon, 3.6 percent in Idaho, and 0.4 percent in the state of Montana.

In 1982, high technology industries employed 145,700 persons in the region, with almost half of the employment concentrated in the aerospace category. The second largest category was professional instruments, with 16.2 percent, followed by electrical equipment, with 16.0 percent of high technology employment. Table 2-9 shows employment in 1982 by state for the major high technology groupings.

Table 2-8

High Technology Industries

SIC CODE	INDUSTRY NAME
	Machinery
351	Engine and Turbines
357	Office, Computing and Accounting Machines
	Electrical Equipment
361	Electric Transmission and Distribution Equipment
362	Electrical Industrial Apparatus
365	Radio and Television Receiving Equipment
366	Communication Equipment
367	Electronic Components and Accessories
369	Miscellaneous Electrical Machinery
	Transportation Equipment
372	Aircraft and Parts
376	Guided Missiles and Space Vehicles and Parts
	Professional Instruments
381	Scientific Instruments
382	Measuring and Controlling Instruments
383	Optical Instruments
384	Medical and Dental Instruments
386	Photographic Equipment and Supplies
	Business Services
737	Computer and Data Processing Services
7391	Research and Development Laboratories

Table 2-9
Employment in High Technology Industries, 1982

	UNITED STATES	PACIFIC NORTHWEST	WASHINGTON	OREGON	IDAHO	MONTANA
Machinery (SIC 351, 357)	521,380	13,110	4,580	6,510	2,000	20
percent of high tech	13.2%	9.0%	4.7%	16.9%	23.9%	2.4%
Electrical Equipment (SIC 361, 362, 365, 366, 367, 369)	1,678,140	23,300	11,160	10,225	1,575	340
percent of high tech	42.6%	16.0%	11.4%	26.5%	18.8%	41.0%
Transportation Equipment (SIC 372, 376)	705,820	69,265	67,800	1,450	15	0
percent of high tech	17.9%	47.5%	69.2%	3.8%	0.2%	0.0%
Professional Instruments (SIC 381, 382, 383, 384, 386)	581,740	23,570	6,230	17,000	200	140
percent of high tech	14.8%	16.2%	6.4%	44.1%	2.4%	16.9%
Business Services (SIC 737, 7391)	456,160	16,500	8,210	3,380	4,580	330
percent of high tech	11.6%	11.3%	8.4%	8.8%	54.7%	39.8%
Total High Tech	3,943,240	145,745	97,980	38,565	8,370	830
Percent of Total Employment	5.3%	6.0%	7.9%	5.0%	3.6%	0.4%
TOTAL EMPLOYMENT	74,297,300	2,434,545	1,239,700	763,975	232,400	198,470

SOURCES: U.S. Census Bureau *County Business Patterns*, 1982. The employment figures shown in this table are based on a survey of employment during the pay period including March 12. As such, they are not comparable to annual average data used in other segments of this report. They are used for illustration purposes here because they are available at the level of industry detail needed.

The aerospace industry in the region is dominated by the Boeing Company, which has a number of production facilities in the state of Washington. Employment in aerospace in the state of Washington has been extremely cyclical, dropping from 104,000 in 1968 to 40,000 by 1971. In 1980, it reached a level of 79,600, only to drop to 64,400 by 1983.

From 1970 to 1982, the high technology industries increased employment at an average annual rate of 4.2 percent. This compares to a national growth rate of 2.2 percent over the same period. Removing aerospace from the calculation shows that non-aerospace high technology employment increased at an average annual rate of 11.8 percent in the region, compared to a national rate of 2.8 percent.

The factors often cited as favorable for the region's growth in high technology include the quality of the region's labor force, available land, good educational facilities and an environment suitable for maintaining a high quality of life. A survey of high technology companies regarding location factors was completed by the Congressional Joint Economic Committee. The results are shown in Table 2-10. The existing concentration of firms in the region also testifies to the importance of spin-off activity from Pacific Northwest firms and California firms.

The factors often cited as unfavorable for the region's growth in high technology industries include high labor costs, unfavorable tax policies, and complex regulatory practices that make it difficult to expand or locate facilities. There is also some question as to the region's commitment to improving or maintaining the quality of the educational systems in light of tax revolts and state and local budget crises. Many states and cities in the U.S. are competing aggressively to attract high technology industries. Some areas of the country, such as New England and North Carolina's Research Triangle Park, enjoy advantages in their traditions of high quality academic institutions. While the region will most assuredly continue to see growth in its high technology industries, the question is whether or not the region will be able to increase or maintain its share of national growth.

National forecasts of employment prepared by the U.S. Bureau of Labor Statistics show employment in high technology industries increasing at an annual rate of 2.4 to 2.5 percent between 1982 and 1995. Although this rate of growth is a third to a fifth faster than that projected for total employment, high technology would nevertheless account for only 8 to 9 percent of new jobs. The impact could be greater in particular states and regions.

Forecasts of employment for high technology industries are shown in Table 2-11. The table shows forecasts for industries at the two-digit SIC level, which includes some businesses that are not classified as high technology industries. Electrical equipment and professional instruments are the only categories where nearly all of the employment is in the high technology category. In machinery and business services, only 34 and 20 percent, respectively, of the employment are in the high technology industries. Approximately 73 percent of the employment in transportation equipment is in the high technology category.

A rapidly growing sector of the machinery industry in the region has been the computer machinery category. Much of the remainder of the machinery industry, however, is farm, construction, logging and other heavy machinery. These categories are not forecast to grow rapidly.

Aerospace employment, which is dominated by the Boeing Corporation, accounts for nearly 85 percent of employment in the transportation equipment industry in the region. Commercial aircraft production represents the largest portion of production in the region. During the recent recession, annual average employment in aerospace declined almost 20 percent. Commercial aircraft orders had dropped substantially because of low profits in the airline industry and declines in passenger miles. Since then, Boeing has started to increase employment as orders increased, in response to improvements in economic conditions and the financial condition of airlines. Boeing is well positioned for the next few years because of its fuel-efficient 757 and 767 model aircraft. Its primary competition is Airbus, a European aircraft consortium. The market for commercial aircraft is projected to improve, although it will probably continue to be highly cyclical. Because employment in this category is dominated so much by one company, the forecasts encompass a wide range of uncertainty.

Table 2-10
Factors That Influence Regional Location
of High Technology Companies

FACTOR	PERCENTAGE OF FIRMS CITING FACTORS AS SIGNIFICANT OR VERY SIGNIFICANT
Labor Skills and Availability	89.3
Labor Costs	72.2
Tax Climate	67.2
Academic Institutions	58.7
Cost of Living	58.5
Transportation	58.4
Access to Markets	58.1
Regulatory Practices	49.0
Energy Costs and Availability	41.4
Cultural Amenities	36.8
Climate	35.8
Access to Raw Materials	27.6

NOTE: Firms were asked to rate each factor as very significant, significant, somewhat significant, or not significant.

SOURCE: U.S., Congress, Joint Economic Committee. *Location of High Technology Firms and Regional Economic Development,* 1 June 1982, p. 23.; and from Battelle Seattle Research Center, *High Technology Employment, Education and Training in Washington State,* June 1984.

Table 2-11
Forecasts of Employment
High Technology Industries
Pacific Northwest
Average Annual Rate of Growth (%)
1985-2005

	HIGH	MEDIUM-HIGH	MEDIUM-LOW	LOW
Machinery (SIC 35)	3.8	3.3	2.5	1.4
Electrical Equipment (SIC 36)	4.3	3.5	2.5	0.4
Transportation Equipment (SIC 37)	1.6	1.0	0.4	-1.0
Aerospace (SIC 372)*	1.4	0.6	-0.2	-2.1
Professional Instruments (SIC 38)	4.1	3.5	2.0	0.0
Business Services (SIC 73)	4.7	3.8	2.8	1.7

*Washington only.

Table 2-12
Total Employment Shares
U.S. and the Pacific Northwest
Percent of Total (%)

	PACIFIC NORTHWEST 1970	1980	U.S. 1970	1980
Total Employment	100.0	100.0	100.0	100.0
Manufacturing	20.7	18.2	25.1	21.6
Nonmanufacturing	79.3	81.8	74.9	78.4
Mining	0.5	0.4	0.8	1.1
Agriculture	7.5	4.9	4.3	3.6
Construction	4.4	4.9	5.1	4.6
Transportation & Public Utilities	6.3	5.5	5.8	5.5
Wholesale and Retail Trade	20.9	23.0	20.7	21.7
Finance, Insurance & Real Estate	4.7	5.7	5.0	5.5
Services	14.6	17.9	16.0	19.1
Government	20.5	19.4	17.1	17.3

Growth in Nonmanufacturing Industries

Employment in nonmanufacturing has grown faster in the last two decades than employment in manufacturing. Table 2-12 shows the shares of total employment by industry for the region and the U.S. Nonmanufacturing employment accounted for 81.7 percent of total employment in the region in 1980. The largest category of nonmanufacturing employment in the region is wholesale and retail trade, followed by government. The third largest nonmanufacturing industry is services, which includes such industries as health care, business services, and personal services.

The growth in the nonmanufacturing sectors has occurred on a national level, as well as at the regional level. A larger proportion of manufactured goods are produced in other countries, which has had a negative impact on the proportion of employment in manufacturing. Productivity gains in the past have occurred to a greater extent in manufacturing industries, and this has lowered employment relative to output. Computerization of some activities could lead to higher productivity gains in nonmanufacturing, however.

A closer look at specific industries may add some insight into the growth in the nonmanufacturing sectors. The services industry was the fastest growing industry in the region from 1970-1981, increasing employment at a rate of 6.1 percent per year. In 1981, health services accounted for 33 percent of the region's employment in services. Employment in health services increased at an annual rate of 6.2 percent from 1970-1981. Growth in this sector resulted from the expansion of health care benefits for workers and elderly people and growing public interest in personal health.

The second largest service category, business services, accounted for 16 percent of the region's employment in services. This category was among the fastest growing sectors in services, increasing employment at an annual rate of 8.6 percent. This category includes a diverse group of industries, such as computer and data processing services, advertising agencies, building services companies, and personnel agencies.

Although it only accounted for 3 percent of services employment in 1981, the legal services industry was the fastest growing among services industries. Employment increased at an annual rate of 10.1 percent from 1970-1981.

Employment in construction increased at a rate of 5.0 percent per year from 1970-1981. Since 1979, however, construction employment has decreased, as a result of slower population growth and the cancellation or delay of construction on nuclear power plants.

The finance, insurance and real estate sector increased employment at an average annual rate of 4.8 percent between 1970 and 1981. The most rapidly growing sectors in this industry were credit agencies (other than banks) and investment offices. Deregulation of the financial industry has led to the creation of a wide range of services by a diverse group of businesses. The combination of deregulation, high interest rates, and loan defaults has put a great deal of strain on financial institutions. This may result in an industry shakeout in the next few years, accompanied by slower employment growth.

Wholesale and retail trade accounted for the largest share of total employment in 1981, as shown in Table 2-12. Wholesale trade accounted for approximately one-fourth of employment in trade and increased at an annual rate of 3.7 percent from 1970-1981. Employment in retail trade increased at a rate of 4.4 percent per year during the same time period.

Eating and drinking establishments accounted for 35 percent of employment in retail trade. This was also the fastest growing category of employment in retail trade, increasing at an annual rate of 7.9 percent from 1970-1981. The increase in household consumption of food away from home reflects the increase in household income and the increase in the participation of women in the labor force. A larger proportion of household budgets for persons aged 25-44 is spent on food away from home than for other groups. As the "baby boom" generation continues to move into this age category, growth in the restaurant industry is expected to continue.

Other fast growing retail trade categories included apparel and accessory stores and miscellaneous retail stores, which includes sporting goods stores and mail order houses. Employment in both categories increased at an average annual rate of 4.9 percent.

The public sector was the second largest employment category in the region in 1980, as shown in Table 2-12. State and local government accounted for over 80 percent of employment in government. Between 1970 and 1981, employment in the federal government increased 1.4 percent per year, while state and local government increased employment at a rate of 3.2 percent per year. Education accounts for the largest proportion of state and local government employment. Since 1981, cutbacks in federal, state, and local budgets have led to decreases in public sector employment. The outlook for future employment changes in this sector is dependent on the level of population growth and policy decisions.

Employment in transportation, communications and public utilities increased at an annual rate of 2.8 percent from 1970 to 1981. The fastest growing category was transportation services, which includes travel agencies, freight forwarding services, and shipping agents and brokers. Employment in transportation services increased at an average annual rate of 9.5 percent from 1970 to 1981. The two largest categories of transportation and public utilities employment in 1981 were motor freight transportation and warehousing with 29 percent, and communication services with 32 percent. Motor freight transportation and warehousing employment increased at an average annual rate of 3.6 percent. Employment in communications increased at an average annual rate of 3.5 percent.

The discussion of nonmanufacturing industries presented thus far has centered on industries as defined by the Standard Industrial Classification (SIC) system. Industries such as the travel industry and port activity are not separated from other economic data to allow historical analysis of their importance to the regional economy.

The travel industry, which includes tourism and business travel, has impacts on retail trade sectors, such as eating and drinking places, retail stores, and service stations. It has an impact on transportation industries, such as transportation services, and air or rail transportation. It has an impact on the services industry, which includes hotels and lodging places, personal services, and amusement and recreation services. It also

Table 2-13
Nonmanufacturing Employment Projections
Pacific Northwest
Average Annual Rate of Growth (%)

	1970-1981	1985-2005 High	1985-2005 Low
Construction	5.0	3.6	0.7
Transportation, Communications and Public Utilities	2.8	2.7	-0.2
Trade	4.2	3.8	0.9
Wholesale Trade	3.7	3.9	1.0
Retail Trade	4.4	3.8	0.9
Food Stores	4.2	3.0	0.2
Eating & Drinking Places	7.9	5.0	2.0
Finance, Insurance & Real Estate	4.8	3.6	0.7
Services[a]	6.1	4.2	1.3
Hotels and Lodging Places	3.9	3.6	0.7
Business Services	8.9	4.7	1.7
Amusement & Recreational Services	4.8	3.7	0.8
Health Services	6.2	4.5	1.6
Government	2.8	2.9	0.3
Federal Government	1.4	1.6	0.3
State & Local Government[b]	3.2	3.2	0.3

[a] Excludes Educational Services, SIC 82.

[b] Includes Educational Services, SIC 82.

Table 2-14
Nonmanufacturing Shares of Total Employment
in 2005

	SHARE OF EMPLOYMENT (%)
Pacific Northwest	
High	87.5
Medium-high	87.0
Medium-low	86.3
Low	85.9
U.S. (Wharton)	
High	85.1
Medium	85.2
Low	84.5

Table 2-15
Real Output per Employee, U.S.
Average Annual Rate of Growth (%)

YEARS	ALL INDUSTRIES	MANUFACTURING
1953-1963	1.9	2.6
1963-1973	1.8	3.1
1973-1983	0.3	1.8

FORECAST	ALL INDUSTRIES High	ALL INDUSTRIES Base	ALL INDUSTRIES Low	MANUFACTURING High	MANUFACTURING Base	MANUFACTURING Low
1983-1993	1.4	1.2	1.1	3.2	2.8	2.4
1993-2003	1.6	1.3	0.9	3.3	3.0	2.1

Table 2-16
Total Population and Households

	TOTAL POPULATION (Thousands) 1960	1970	1980	AVERAGE ANNUAL RATE OF GROWTH (%) 1960-70	1970-80
Washington	2,853.2	3,409.2	4,132.2	1.80	1.94
Oregon	1,768.7	2,091.4	2,633.1	1.69	2.33
Idaho	667.2	712.6	944.0	0.67	2.85
W. Montana	231.7	253.5	294.5	0.90	1.51
PNW	5,520.8	6,466.7	8,003.8	1.59	2.16
U.S.	180,671.0	204.878.0	227.020.0	1.27	1.03

	HOUSEHOLDS TOTAL POPULATION (Thousands) 1960	1970	1980	AVERAGE ANNUAL RATE OF GROWTH (%) 1960-70	1970-80
Washington	894	1,106	1,540.5	2.15	3.37
Oregon	558	692	991.6	2.18	3.66
Idaho	194	219	324.1	1.22	4.00
W. Montana	70	79	106.4	1.25	3.47
PNW	1,716	2,096	2,962.6	2.02	3.52
U.S.	53,021	63,450	80,377	1.81	2.39

	PERSONS PER HOUSEHOLD (Total Population/Total Households) 1960	1970	1980
PNW	3.22	3.09	2.70
U.S.	3.41	3.23	2.82

has an impact on the government sector, through parks and recreation, national parks, national and state forests, and the highway system. Because all of these services are consumed by the local population as well as out-of-state travelers, it is difficult to measure the impact of the travel industry on the economy.

Nevertheless, the travel industry is an important activity in the region. The beauty and diversity of the region's natural environment provide opportunities for a variety of recreational activities. Factors that will aid the growth of the travel industry in the future include increases in real income and changes in the age composition of the population. State and local governments in the region have developed programs to promote tourism and conventions, which will add to its growth.

Another economic activity that appears to have increased in importance is port activity related to trade with Alaska and other countries. The expansion of the economies of the Pacific Rim countries and the region's proximity to these countries point to increased trade and transportation activity. The employment impacts are difficult to measure because they are spread across a number of SIC categories. Port activity has an impact on the transportation, wholesale trade, services, and financial industries. It has an impact on manufacturing industries as well, by providing markets for goods produced in the region. A study by the Port of Seattle[6] showed a direct impact of 55,800 jobs resulting from the harbor and airport facilities. This estimate was for 1982, which was a year of worldwide economic slowdown. In addition, the estimate included jobs in King County only, which would underestimate the impact of the port on the state of Washington and the region.

In recent years, more attention has focussed on the nonmanufacturing industries as an increasing source of jobs to the economy. The traditional approach to understanding regional economic development emphasized manufacturing, agriculture, and extractive industries as the providers of the basis for economic growth. Other industries were treated as secondary, providing support services to these industries and to the local population. A recent study of the services sector in the central Puget Sound region[7] disputes this approach. The study interviewed firms from selected industries in the services sector and estimated that approximately one third of the employment in these industries is linked to export markets. The study points out many areas where the dynamics of location and growth of nonmanufacturing industries have remained largely unexplored.

In developing its range of forecasts of employment growth in the nonmanufacturing industries, the Council has relied on national forecasts developed by Wharton and the Bureau of Labor Statistics, and comparison to historical regional growth rates by industry. Table 2-13 shows a comparison of the Council's forecasts of nonmanufacturing employment by industry with historical growth rates. Table 2-14 shows the Council's forecasts of the share of nonmanufacturing employment to total employment for the year 2005. The shares for the nation forecast by Wharton are shown as well.

Changes in Productivity Growth

The early phases of an economic recovery period often show large gains in productivity. The conditions may exist at this time, however, for a more sustained growth in labor productivity in the U.S. that could last well beyond the cyclical impacts of recession and recovery. Some of the factors encouraging higher productivity growth were brought about by the recession. Intense foreign competition and a high value of the U.S. dollar against foreign currencies has put downward pressure on prices. Efforts to increase profitability have focused on improving productivity.

Recent changes in federal government policies have led to increased financial incentives for investment. These include decreased capital gains tax rates, generous tax credits for research and development expenditures, and the Accelerated Cost Recovery program, which allows faster depreciation of capital investments.

Over the long-term, demographic factors will have an impact on productivity growth. With the maturation of the baby boom generation, there will be fewer young, inexperienced workers in the labor force.

The impact of developments in high technology are just beginning to be observed in office automation, robotics, electronic technology, and telecommunications. Spurred by foreign competition and tempted by numerous success stories, U.S. companies are turning to new technology to remain competitive in world markets.

Two factors that may have dampened productivity growth in the 1970s may contribute to productivity growth in the 1980s by their absence. These are energy price shocks and new federal regulations. The costs of adjustment to higher prices and higher environmental standards diverted funds from investments that contribute more directly to measures of productivity. These factors are not likely to be as prominent in the near future.

Table 2-15 shows rates of growth in real output per employee for all industries and for manufacturing. As shown, productivity growth in the 1970s was slow compared to previous decades. Wharton's forecasts for the next twenty years show a continuation of the rapid trends established in the 1950s and 1960s. Table 2-A-4 of Appendix 2-A shows productivity forecasts by industry for manufacturing industries.

Population, Households and Housing Stock

Total population in the region was 8.0 million in 1980. Regional population increased at an average annual rate of 2.2 percent from 1970 to 1980, more than twice the rate of U.S. population growth (1.0 percent) in the same period. Population growth in the region was more than one-third faster in the 1970s than during the 1950s and 1960s. Idaho was the fastest growing state in the region during the 1970s, although it was the slowest growing in the 1960s. Table 2-16 summarizes historical data on population and households.

The number of households in the region and the nation grew at a higher rate than population. Although population growth was slower nationally in the 1970s than in the 1960s, because of lower birth rates, growth in the number of households was considerably higher in the later decade. During the 1970s, the 'baby-boom' generation reached the 20-29 year age group, where household formation rates are high. Decreasing fertility rates also lowered the average household size.

Householder rates, or the proportion of the population in an age group designated to represent a household, increased rapidly with the rise in divorce rates and single person households. In the 1970s, householder rates have increased dramatically for females over the age of 65, as more women in this group have maintained their own household, rather than move in with family or to group quarters. In addition, women in the 20-29 age group have maintained households at a higher rate. The combination of shifts in age composition and of changes in householder rates has lowered average household size in the region from 3.1 in 1970 to 2.7 in 1980.

There were 2.963 million occupied housing units in the region in 1980. Results from the 1980 U.S. Census indicated that approximately 78 percent of the occupied housing stock were single family units (1-4 units per building). An additional 14 percent were multifamily units and 7 percent were manufactured homes.

Table 2-17
Forecast of Population and Households
Pacific Northwest
1980-2005

SCENARIO	1980	2005	AVERAGE ANNUAL RATE OF GROWTH (%)
Total Population (in thousands)			
High		12,449.4	1.8
Medium-high	8,005.1	11,383.6	1.4
Medium-low		10,007.4	0.9
Low		8,785.7	0.4
Total Households (in thousands)			
High		5,605.6	2.6
Medium-high	2,963.7	4,761.1	1.9
Medium-low		4,184.8	1.4
Low		3,381.3	0.5

Table 2-18
Housing Stock Projections
Pacific Northwest
1980-2005
Share of Occupied Housing Units (%)

		2005			
	1980	High	Medium-High	Medium-Low	Low
Single Family (2-4 units)	78.3	77.4	72.0	68.4	72.4
Multifamily (5 and more)	14.2	14.3	17.1	19.9	17.9
Manufactured Homes	7.5	8.3	10.9	11.7	9.7

The forecast for population is derived from the forecast of total employment through an average employment-population ratio. Changes in the employment-population ratio reflect changes in labor force participation, unemployment rates, and age composition of the population. The proportion of women in the labor force increased rapidly in the 1960s and 1970s. From 1960 to 1980, the percentage of women in the labor force increased from 37 percent to 52 percent. The employment-population ratios in this forecast incorporate the impacts of continued increase in female labor force participation, although at slower rates than in the past. The range of projections was based on national trends as forecast by Wharton and the U.S. Bureau of Labor Statistics. Changes in employment-population ratios implied in the national forecasts were tracked in the state-level forecasts, maintaining historical differences between the state and national ratios. Table 2-A-1 in Appendix 2-A shows employment-population ratios for each state.

The forecast for total households is obtained from the forecast of population after dividing by average household size. Changes in average household size reflect changes in the age composition and householder rates. The projections are based on national trends as forecast by the U.S. Bureau of the Census. The high and medium cases assume that householder rates will continue to increase, but at much slower rates than in the 1970s. This results in part because of increases in the relative cost of housing and in a slowing of increases in the divorce rate. The low case assumes that householder rates do not increase, but average household size decreases slightly because of changes in age composition. Average household size projections by state are shown in Table 2-A-2 of Appendix 2-A.

Table 2-17 shows the forecasts of population and households which result from the assumptions described. Change in the housing stock is the result of change in total households plus replacement of existing units. The proportion of new housing units by type is projected for each state. Table 2-A-3 in Appendix 2-A shows the proportion of housing additions by type for each state and scenario. In all scenarios, it is assumed that the affordability of new single family housing will lead to a smaller proportion of single family units than in the current stock of housing in the region.

As noted in Table 2-A-3 in Appendix 2-A, the same proportions of housing additions by type were used in the low and medium-low scenarios. In the low growth scenario, the existing stock is a much larger proportion of total stock in 2005 because there are fewer additions than in the other scenarios. Changes in the stock of housing shown in Table 2-18 for each scenario are the result, therefore, of assumptions regarding the relative proportion of each housing type in additions, and the rate at which additions are added to the stock.

Real per Capita Income

Real per capita income is an important input to many econometric models of energy demand. It plays a far less critical role in the more structural end-use models used by the Council. The only sector it affects directly is the residential sector, where it influences the penetration rate of certain types of appliances, and the long-run expected use of appliances. In 1980, the personal income per capita of the Pacific Northwest was $9,600, only 1.1 percent above the U.S. average of $9,494. The size of the Northwest states' per capita incomes relative to the U.S. average in 1980 is shown in Table 2-19 along with extreme values for other states in the U.S.

Table 2-19
Ratio of State per Capita Income to National per Capita Income, 1980

Oregon	0.98
Idaho	0.85
Montana	0.88
Highest State	1.37
Lowest State	0.69

Table 2-20
Growth Rates of Real Income per Capita
Average Annual Percent

	PACIFIC NORTHWEST	UNITED STATES
Historical		
1960-70	2.9	3.2
1970-80	2.7	2.2
Forecast 1980-2005		
High	2.7	2.5
Medium	1.7	2.0
Low	0.9	1.6

Alternative Fuel Prices

This section describes assumptions about world oil prices and the retail prices of natural gas, oil, and coal. These fuel price assumptions are important for two reasons. First, since these fuels are alternatives to electricity in end-use energy consumption, their prices will affect the forecasts of demand for electricity. This is particularly true for the residential and commercial sectors, where electricity, natural gas, and oil compete for space heating, water heating, air conditioning, and cooking. Sensitivity tests on the demand models show that a doubling of natural gas prices would increase residential demand for electricity by about 4 percent by the year 2000. For the commercial sector the comparable increase in demand for electricity would be about 20 percent. Industrial demand for electricity is not very sensitive to fuel prices, so that roughly weighing the three sectors' responses would indicate that a doubling of gas prices could increase electricity use by about 5 percent.

The second reason that fuel prices are important is that they are highly uncertain. Reasonable assumptions could support a variety of forecasts, ranging from a collapse of fuel prices over the next ten years to another doubling of prices within 20 years. Thus, even though the impacts of a small change in fuel prices on demand for electricity may not be large, the possibility of large variations is great, making fuel prices an important element of uncertainty about future demand for electricity.

During development of the 1983 Power Plan, there was considerable controversy over forecasts of fuel prices. Therefore, the Council contracted with Energy Analysis and Planning, Inc., to develop a method of relating world oil market conditions to the retail prices of fuels in the Pacific Northwest. In addition, Energy Analysis and Planning, Inc., provided an evaluation of conditions in the world oil market and developed three illustrative world oil market scenarios.[8]

The insights into the world oil market, and into the regional fuel markets, provided by the Energy Analysis and Planning, Inc., report appear to be very good. Although the Council did not directly adopt the world oil price forecasts in the report, its ranges were informed by the contractor's report. The Council adopted the simple model developed by Energy Analysis and Planning, Inc., to determine regional retail oil and natural gas prices from world oil price forecasts, and continued to use this model in developing the retail price projections for the 1986 Power Plan.

The process for developing world oil price assumptions included four phases. The first was to read recent studies of the world oil market and evaluated current world oil prices. Second, an informal survey of world oil price forecasts by various groups was made. Third, the Council sent, with its working paper on economic and demographic issues, a questionnaire that contained, among others, a question about world oil prices. These steps did not, of course, eliminate uncertainty about oil prices, but they did help clarify the extent of uncertainty and what would be reasonable forecast ranges. The fourth step was to revise the forecast in response to comments on the draft plan. The final forecasts of fuel price reflect a change in the pattern of the lower cases, but not the 2005 levels, to reflect an increased liklihood of short-term price reductions.

Figure 2-4 shows the range of world oil price forecasts. Figure 2-4 also shows, for comparison, the assumptions used for the 1983 Power Plan and actual world oil prices for 1980-83. The forecasts are all in 1985 dollars. The forecasts are generally lower than those in the 1983 Power Plan, reflecting recent history and a changing understanding of the world oil market. The ability of oil producers to achieve ever growing prices for their oil is severely limited by market responses, both on the demand side and on the supply side. The questionnaire responses indicated that somewhat lower forecasts would be appropriate, although the support for lower forecasts was far from unanimous.

Table 2-20 shows historical and forecast growth of real personal income per capita in the Pacific Northwest and for the U.S. During the 1960s, income per capita increased at a slightly slower rate in the region than in the U.S. In fact, the region's real income per capita dipped below the U.S. in 1970. Income per capita increased faster in the region than in the U.S. during the 1970s. Over the entire 20-year period from 1960 to 1980, the region's per capita income increased at almost the identical rate as the U.S. average. From 1980 to 1983, real income per capita declined to $9,455 (in 1980 dollars) in the region, while it increased to $9,764 in the U.S. The forecasts for 1980 to 2005 are shown in Table 2-20 as well.

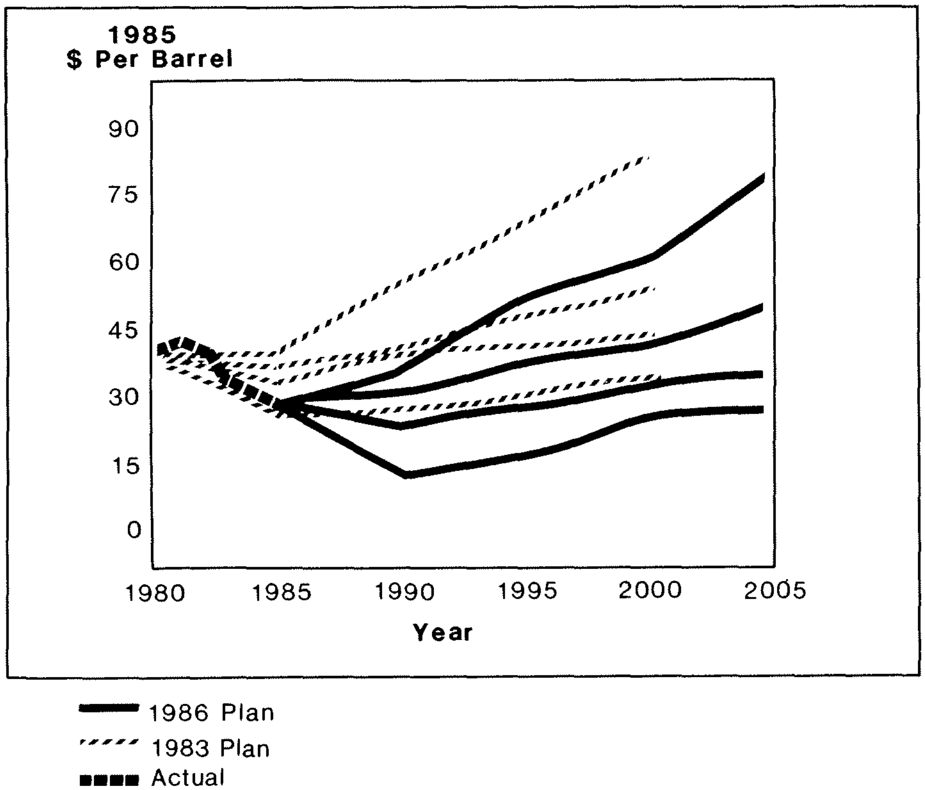


Figure 2-4
Forecasts of World Oil Prices
Comparison of 1986 and 1983 Plan Assumptions

Table 2-21 shows the world oil price assumptions for selected years and selected growth rates. All of the forecasts assume continued weakness in the world oil market through 1986. The cases reflect varying degrees of price increase after 1986.

In the lower part of the Table 2-21 are some forecasts by other organizations for comparison. Of particular interest is the forecast range from the Canadian National Energy Board (CNEB). This range was derived from a survey of independent forecasts of 30 different organizations, predominantly energy companies. With the exception of the U.S. Department of Energy forecasts, all of the forecasts fall well within the Council's proposed range of assumptions. The Department of Energy forecasts seem to lie outside most views of the world oil market, and it is difficult to imagine sustaining such large price increases over a 20-year period.

The world oil price assumptions described above were used to forecast the retail prices of fuel oil and natural gas. The relationship between world oil prices and retail prices is embodied in the Energy Analysis and Planning model. The model is very simple. Wholesale prices of residual oil and distillate oil are related to world oil price through a simple model of refinery economics. Retail price markups, based on historical data, are added to obtain retail oil prices for the residential, commercial, and industrial sectors.

Natural gas prices are determined in competition with residual oil in the industrial boiler market. It is assumed that interruptible natural gas prices will equate to residual oil prices in this market. Markups are added to the industrial interruptible gas price to obtain retail prices for the other sectors. The assumption that natural gas prices will be determined by competition with residual oil in the industrial market was essentially implemented in the new Canadian natural gas export policy.

The retail fuel price forecasts are shown in Tables 2-22 through 2-24. Table 2-24 includes forecasts for industrial coal prices. These forecasts reflect the fact that weaker oil prices tend to cause weak coal demands and prices. There was no formal model involved in forecasting the coal prices. It was assumed that in the absence of oil price increases, coal prices would maintain their current real levels. As oil prices rise in the various forecasts, it was assumed that coal prices would follow with a delay of several years. The larger the oil price increase, the larger the proportion of the oil price increase received by coal. The proportional increases ranged from 20 percent to 75 percent as the amount and duration of the oil price growth increased.

Forecasts for Utility Service Areas

The economic and demographic assumptions are divided into public and investor-owned utility service areas to provide inputs to the demand forecasting system, which forecasts electricity consumption by utility type. Industrial production at the detailed industry level, employment in the commercial sector, and housing units are divided into public and investor-owned utility areas for each state. The splits between public and investor-owned utility areas are provided by Bonneville. In the case of major manufacturing industries, the shares of production allocated to public or investor-owned utilities were developed by detailed industry analysis of plant location or county employment patterns. The shares of commercial employment and housing stock were allocated on the basis of customer counts in the residential sector at the utility and county level. The split into investor-owned and public utility service areas is based on historical data. It is assumed that the shares for each individual component do not change over time. These allocations were updated from the 1983 plan assumptions to reflect more recent Bonneville analysis. Although there were a number of small changes to specific industry shares, the overall impact was negligible.

Table 2-21
World Oil Prices

	HIGH	MEDIUM-HIGH	MEDIUM-LOW	LOW
Prices (1985 $ per barrel)				
1980	40	40	40	40
1981	41	41	41	41
1982	40	40	40	40
1983	33	33	33	33
1984	30	30	30	30
1985	29	28	28	27
1990	34	30	24	13
1995	50	38	28	17
2000	60	42	33	24
2005	80	49	36	28
Growth Rates (% per year)				
1980-1985	-6.2	-6.9	-6.9	-7.6
1983-2005	4.1	1.8	0.4	-0.7
1985-2005	5.4	2.8	1.3	0.0
2005 Forecasts (1985 $ per barrel)				
CNEB*	54	42		30
Bonneville	66	49		36
Wharton		40		
Oregon DOE		45		
U.S. DOE	118	82		53

*Canadian National Energy Board, *Canadian Energy: Supply and Demand 1983-2005*, Sept. 1984, Table A2-1, page A-30. The range of CNEB forecasts came from a survey of 30 independent forecasts of various energy companies and other organizations.

Table 2-22
Residential Sector Fuel Prices

	HIGH	MEDIUM-HIGH	MEDIUM-LOW	LOW
Natural Gas (1985 $ per thousand cubic feet)				
Prices				
1980	6.77	6.77	6.77	6.77
1985	7.39	7.28	7.07	6.65
1990	6.97	6.37	5.38	3.79
2000	10.75	8.16	6.77	5.38
2005	13.73	9.15	7.17	5.97
Growth Rates (% per year)				
1980-1985	1.8	1.5	0.9	-0.4
1985-2005	3.1	1.1	0.0	-2.1
Oil (1985 $ per Gallon)				
Prices				
1980	1.31	1.31	1.31	1.31
1985	1.05	1.04	1.01	.95
1990	1.11	1.01	.86	.60
2000	1.71	1.30	1.08	.86
2005	2.18	1.46	1.14	.95
Growth Rates (% per year)				
1980-1985	-4.3	-4.5	-5.1	-6.2
1985-2005	3.7	1.7	0.6	0.0

Table 2-23
Commercial Sector Fuel Prices

	HIGH	MEDIUM-HIGH	MEDIUM-LOW	LOW
Natural Gas (1985 $ per thousand cubic feet)				
Prices				
1980	6.27	6.27	6.27	6.27
1985	6.71	6.61	6.39	5.95
1990	6.29	5.69	4.69	3.10
2000	10.07	7.48	6.09	4.69
2005	13.05	8.48	6.49	5.29
Growth Rates (% per year)				
1980-1985	1.4	1.1	0.4	-1.0
1985-2005	3.4	1.3	0.1	-0.6
Oil (1985 $ per Gallon)				
Prices				
1980	1.13	1.13	1.13	1.13
1985	.97	.96	.93	.87
1990	1.04	.94	.78	.52
2000	1.65	1.23	1.00	.78
2005	2.13	1.39	1.07	.88
Growth Rates (% per year)				
1980-1985	-3.0	-3.2	-3.8	-5.1
1985-2005	4.0	1.9	0.7	0.1

Table 2-24
Industrial Sector Fuel Prices

	HIGH	MEDIUM-HIGH	MEDIUM-LOW	LOW
Natural Gas (1985 $ per thousand cubic feet)				
Prices				
1980	5.48	5.48	5.48	5.48
1985	5.65	5.54	5.34	4.91
1990	5.64	5.04	4.05	2.46
2000	9.42	6.83	5.44	4.05
2005	12.40	7.83	5.84	4.64
Growth Rates (% per year)				
1980-1985	0.6	0.2	-0.5	-2.1
1985-2005	4.0	1.7	0.4	-0.3
Oil (1985 $ per Barrel)				
Prices				
1980	38.84	38.84	38.84	38.84
1985	35.31	34.70	33.55	31.14
1990	37.89	34.16	27.93	17.87
2000	61.41	45.33	36.65	27.98
2005	79.92	51.51	39.13	31.73
Growth Rates (% per year)				
1980-1985	-1.9	-2.2	-2.9	-4.3
1985-2005	4.2	2.0	0.8	-0.1
Coal (1985 $ per ton)				
Prices				
1980	50.58	50.58	50.58	50.58
1985	50.58	50.58	50.58	50.58
1990	50.58	50.58	50.58	50.58
2000	55.85	53.16	51.86	48.10
2005	63.19	55.88	54.51	49.32
Growth Rates (% per year)				
1980-1985	0.0	0.0	0.0	0.0
1985-2005	1.1	0.5	0.4	-0.1

1./ Wharton Econometric Forecasting Associates, *Long-term Alternative Scenarios and 20-year Extension,* July 1984, Volume 2, Number 4.

2./ Northwest Power Planning Council, "Economic, Demographic and Fuel Price Assumptions," various drafts, December 6, 1984; March 26, 1985; and July 15, 1985.

3./ Aho, William O., letter to Ms. Barbara Pierce, Brookhaven National Laboratory, March 17, 1982.

4./ Northwest Pulp and Paper Association, Results of NWPPA/Ekono Survey, Heidi Schultz, April 2, 1982.

5./ Battelle Seattle Research Center, *High Technology Employment, Education and Training in Washington State,* June 1984.

6./ Port of Seattle, 1982 Economic Impact Study, October 1984.

7./ Beyers, William B., Alvine, Michael J., and Johnsen, Erik G., *The Service Economy: Export of Services in the Central Puget Sound Region,* Central Puget Sound Economic Development District, April 1985.

8./ Energy Analysis and Planning, Inc., "Fuel Prices in the Northwest," August 1982.

APPENDIX 2-A
DETAIL ON ECONOMIC INPUT ASSUMPTIONS

Table 2-A-1
Employment-Population Ratios

	1985	1990	1995	2000	2005
WASHINGTON					
High	.397	.433	.465	.481	.498
Medium-high	.397	.416	.440	.460	.470
Medium-low	.397	.413	.430	.445	.445
Low	.397	.410	.415	.416	.416
OREGON					
High	.392	.434	.468	.484	.496
Medium-high	.392	.416	.440	.460	.475
Medium-low	.392	.413	.428	.450	.455
Low	.392	.410	.416	.418	.418
IDAHO					
High	.366	.410	.442	.467	.500
Medium-high	.366	.395	.422	.445	.460
Medium-low	.366	.384	.408	.425	.435
Low	.366	.381	.400	.410	.420
WESTERN MONTANA					
High	.341	.365	.390	.410	.425
Medium-high	.341	.360	.375	.390	.400
Medium-low	.341	.355	.365	.370	.375
Low	.341	.350	.355	.360	.360
PACIFIC NORTHWEST					
High	.391	.429	.462	.479	.496
Medium-high	.391	.411	.436	.456	.469
Medium-low	.391	.408	.425	.443	.445
Low	.391	.405	.412	.415	.416

Table 2-A-2
Persons per Household

	1980	1985	1990	1995	2000	2005
WASHINGTON						
High		2.60	2.50	2.40	2.30	2.20
Medium*	2.68	2.60	2.52	2.44	2.36	2.36
Low		2.60	2.60	2.58	2.58	2.58
OREGON						
High		2.59	2.50	2.40	2.30	2.20
Medium	2.66	2.59	2.52	2.45	2.38	2.38
Low		2.59	2.58	2.57	2.56	2.56
IDAHO						
High		2.83	2.66	2.52	2.45	2.40
Medium	2.91	2.83	2.75	2.67	2.59	2.59
Low		2.83	2.82	2.81	2.80	2.80
WESTERN MONTANA						
High		2.67	2.48	2.34	2.24	2.24
Medium	2.75	2.67	2.58	2.48	2.39	2.39
Low		2.67	2.66	2.64	2.62	2.62
PACIFIC NORTHWEST						
High		2.62	2.52	2.41	2.31	2.22
Medium	2.70	2.62	2.55	2.47	2.39	2.39
Low		2.62	2.60	2.60	2.60	2.60

* The medium case shown here is used in the medium-high and medium-low.

Table 2-A-3
Housing Additions by Type

STATE	HIGH	MEDIUM*	LOW*
WASHINGTON			
Single Family (1-4 units)	75	62	49
Multifamily (5 and more)	16	22	31
Manufactured Homes	9	16	20
OREGON			
Single Family (1-4 units)	76	65	54
Multifamily (5 and more)	13	19	27
Manufactured Homes	11	16	19
IDAHO			
Single Family (1-4 units)	81	71	60
Multifamily (5 and more)	8	13	18
Manufactured Homes	11	16	22
WESTERN MONTANA			
Single Family (1-4 units)	84	70	60
Multifamily (5 and more)	02	10	15
Manufactured Homes	14	20	25

* The medium case shown here was used in the medium-high scenario. The low case was used in the medium-low and low scenarios.

Table 2-A-4
*Production per Employee by Industry**
Average Annual Rates of Change (%)
1985-2005

SIC	HIGH	MEDIUM	LOW
20	3.1	2.9	2.2
22	3.1	2.7	2.0
23	3.3	3.0	2.3
25	2.3	1.9	1.1
27	2.9	2.5	1.8
29	2.5	2.2	1.4
30	3.2	2.8	2.1
32	2.7	2.4	1.5
33XX	3.2	2.9	2.1
34	2.5	2.2	1.4
35	3.7	3.4	2.6
36	3.7	3.4	2.6
37	2.8	2.4	1.7
38	3.2	2.9	2.2
39	2.9	2.6	1.8
2421	1.6	1.5	1.4
2436	1.6	1.5	1.4
24XX	1.6	1.5	1.4
2611	3.5	3.2	2.4
2621	3.5	3.2	2.4
2631	3.5	3.2	2.4
26XX	3.5	3.2	2.4
2812	3.4	3.0	2.2
2819	2.0	1.0	1.0
28XX	3.4	3.0	2.2
3334	2.5	2.5	2.5

* Please refer to Table 2-B-1 in Appendix 2-B for a listing of SIC Codes.

APPENDIX 2-B
SIC CODE LISTINGS

Table 2-B-1
Code Listings

SIC CODE	INDUSTRY	SIC CODE	INDUSTRY
20	Food and kindred products	3334	Primary aluminum
22	Textiles	40-49	Transportation & public utilities
23	Apparel	50-51	Wholesale trade
25	Furniture	52-53 55-57, 59	Retail trade except food stores (54) and eating places (58)
27	Printing and publishing	54	Food stores
29	Petroleum refining	58	Eating and drinking places
30	Rubber and plastics	60-67	Finance, insurance & real estate
31	Leather and leather products	70	Hotels and lodging
32	Stone, clay, glass & concrete	72	Personal services
33XX	Primary metals except aluminum	73	Business services
34	Fabricated metals	75	Automotive repair & garages
35	Machinery except electrical	76	Miscellaneous repair services
36	Electrical machinery	78	Motion pictures
37	Transportation equipment	79	Amusement and recreation services
38	Professional instruments	80	Health services
39	Miscellaneous manufacturing	81	Legal services
2421	Sawmills & planing mills	82, 941	Educational services
2436	Softwood veneer & plywood	83	Social services
24XX	Other lumber & wood products	84	Museums, art galleries
2611	Pulp mills	86	Membership organizations
2621	Paper mills	89	Miscellaneous services
2631	Paperboard mills	90-99	Government except education (941)
26XX	Other paper products		
2812	Alkalies and chlorine		
2819	Elemental phosphorus		
28XX	Other chemicals		

Chapter 3
Forecast of Demand for Electricity

Introduction

Forecasts of the demand for electricity in the Pacific Northwest region are required by the Northwest Power Planning and Conservation Act. Demand forecasts play three important roles in the Council's power planning process. The first is the traditional role; they are the basis for deciding how much electricity is needed to support a healthy and growing economy. The second role is to explore and define the uncertainty surrounding future electrical resource needs. Finally, the demand forecasts are an essential component of conservation assessment. Conservation, identified as the priority resource in the Act, is directly related to the demand for electricity. Demand forecasts are needed to estimate conservation potential, but, in addition, the forecasting models help determine the effects of conservation actions taken as part of the Council's power plan.

The Council has developed the best available forecasting tools in its demand forecasting system. This system helps the Council determine how assumptions about the growth of the region's economy and energy prices affect the demand for electricity. Figure 3-1 illustrates the general structure of the forecasting system. The growth of the regional economy and changes in its composition are the key factors affecting growth in demand for electricity. Assumptions about the prices of fossil fuels and electricity, however, modify the effects of economic conditions. The Council's forecasting system captures these relationships in considerable detail.

The Council developed three preliminary forecasts of demand for electricity, which underwent public review and revision before draft forecasts were adopted by the Council. The first preliminary forecast was described in a staff issue paper dated February 13, 1985, and was presented to the Council in Boise on February 21, 1985. The second preliminary forecast was presented to the Council in Missoula on April 4, 1985, and was described in a staff report dated March 7, 1985. On April 24, 1985, in Seattle, the Council adopted the third preliminary forecast for purposes of resource portfolio analysis.

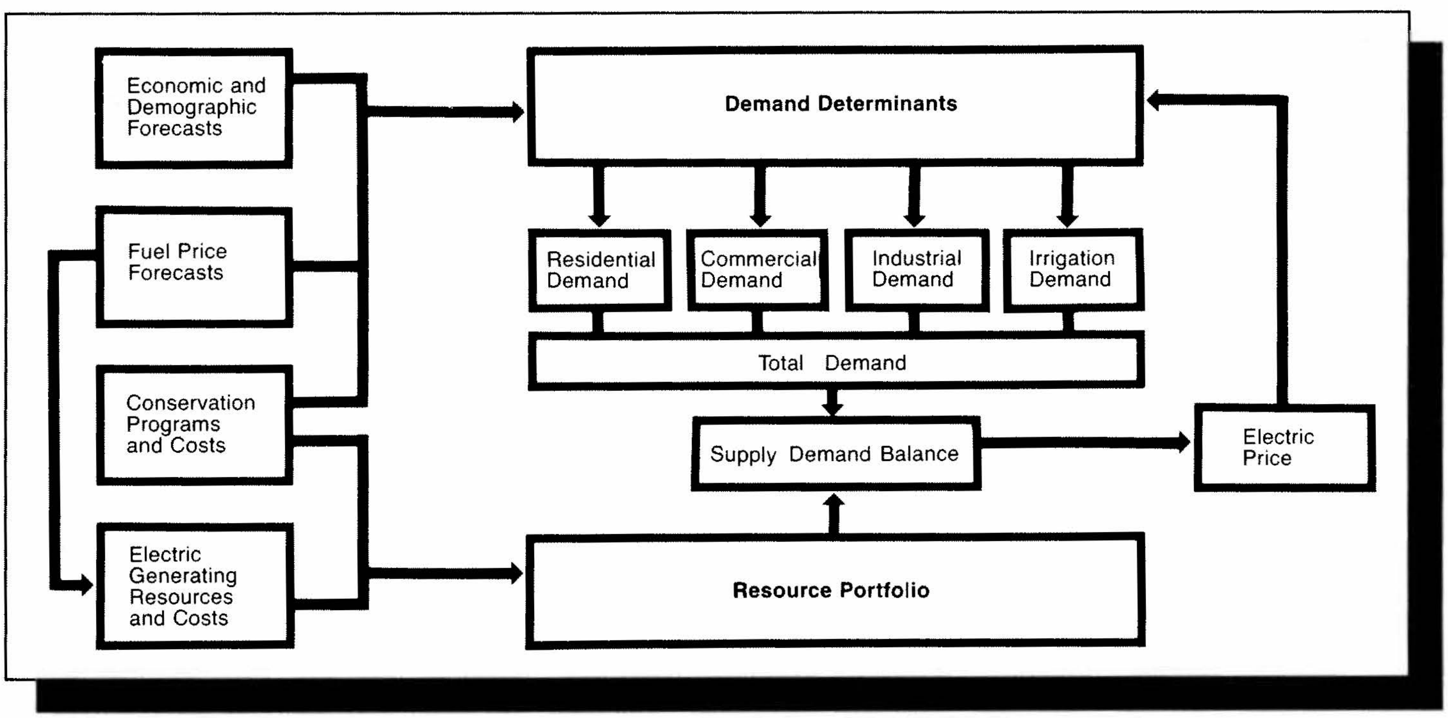


Figure 3-1
Northwest Power Planning Council Demand Forecast System

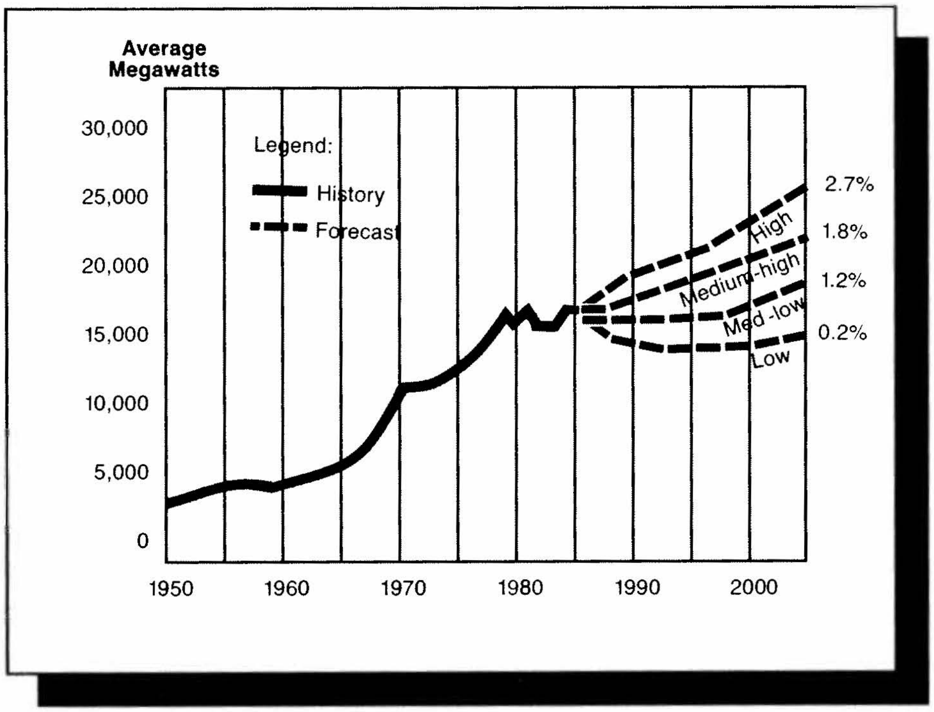


Figure 3-2
Sales of Electricity—Historical and Forecast

These demand forecasts were revised slightly to reflect the effects of the proposed resource portfolio on electricity prices, and were presented in the draft plan adopted August 7, 1985.

The forecasts described here reflect comments received on the draft plan, the adoption of new building codes by the states of Washington and Oregon, and correction of minor errors discovered in the draft plan forecasts.

This chapter expands the discussion of demand forecasts that is included in Volume I, Chapter 4, of the 1986 Power Plan. Some of the material in that chapter is repeated here so this chapter can be read without referring back to Volume I. Following a summary of the forecast results and methods, each consuming sector is discussed. Each of these sections describes the forecasting methods and results in detail. Following the sections on the consuming sectors is a discussion of forecasts of retail electric rates. The last section describes the role of the forecasts in resource planning. Additional detail about the forecasting methods and results is available from the Council.

Overview

The Council's forecast of demand for electricity consists of a range of four forecasts; a low, medium-low, medium-high, and high forecast. The Council's high demand forecast is designed to ensure that power supplies never constrain the regional economy's growth potential. The high forecast reflects the effects of record high regional economic growth relative to the nation combined with less competitive prices for alternative fuels. The likelihood that such a rapid regional growth would occur is considered to be very small. The Council's forecast range is bounded on the low side by a forecast whose pessimism about the regional economy is roughly proportional to the optimism of the high case.

Inside the bounds of the low and high forecasts is a smaller, most probable range of demands bounded by the medium-low and medium-high forecasts. These two medium forecasts will carry a greater weight in the planning of resources than will the high and low extremes. Nevertheless, the possibilities posed by the high growth forecasts must be addressed by appropriate resource options. Similarly, conditions that are implied by the low demand forecast will be considered within a flexible planning strategy designed to minimize regional electricity costs and risks.

The demand forecast ranges are constructed by combining economic assumptions, fuel price assumptions, and some modeling assumptions. The combination of assumptions is designed to explore a wide range of possible demands without combining assumptions unrealistically. That is, mutually inconsistent assumptions are not combined just to obtain extreme forecasts. In the high forecast, for example, the high economic assumptions are combined with high fuel price assumptions. In addition, it was assumed in the industrial sector and irrigation sectors that consumers have relatively low price response, and in the residential sector it was assumed that consumers were less likely to invest in energy efficiency improvements. Electricity prices, which have a significant effect on demand, are not assumed but are determined by the electricity pricing model based on the amount and cost of resources needed to meet demand. Generally, electric prices will be higher for higher demand growth unless different policy assumptions are used in the forecast scenarios. This was only done in the low forecast, where it was assumed that costs associated with Washington Public Power Supply System's Nuclear Projects 4 and 5 (WNP-4 and WNP-5) would have to be paid by electric consumers. In the other cases, it was assumed that those costs would not be reflected in electric rates.

In 1983, firm sales of electricity to the final consumer in the Pacific Northwest totaled 14,593 average megawatts, or 127.8 billion kilowatt-hours. The high forecast shows this demand could grow to 26,101 average megawatts by 2005, an increase in electricity requirements equivalent to the power from 15 nuclear plants the size of WNP-2 at Hanford, Washington. Under the set of assumptions leading to the low forecast, demand only increases to 15,121 average megawatts, an amount little changed from current requirements. Figure 3-2 illustrates the forecast range in the context of historical sales of electricity. This large uncertainty about future needs for electricity resources represents an important challenge for energy planning. The region needs to deal with this uncertainty in a manner that will neither prevent the region from attaining rapid growth, nor impose large and unnecessary costs should slower growth occur.

Table 3-1 summarizes the demand forecasts. Before these forecasts are addressed further, however, their nature should be clarified. The basic concept presented in the Council's demand forecast is a "price effects" forecast. The forecast indicates what demand would be if consumers responded to prices but if no new conservation programs were implemented. Two alternative concepts will be discussed in the final section of this chapter.

Table 3-1 shows that the rate of growth of demand could be as high as 2.7 percent per year, if the high case materialized, or as low as 0.2 percent. A more likely outcome, however, is between the medium-low growth rate of 1.2 percent and the medium-high rate of 1.8 percent.

Table 3-1
Firm Sales of Electricity
(Average Megawatts)

	ACTUAL 1983	FORECASTS 1990	FORECASTS 2000	FORECASTS 2005	GROWTH RATE (% per year) 1983-2005
High	14,593	8,044	23,026	26,101	2.7
Medium-high		16,701	20,022	21,687	1.8
Medium-low		15,351	17,538	18,950	1.2
Low		13,697	14,370	15,121	0.2

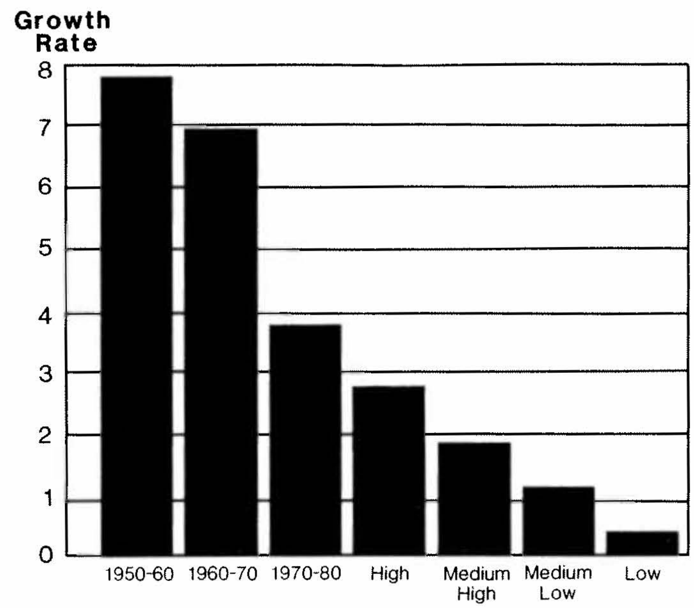


Figure 3-3
Historical and Forecast Growth

Figure 3-3 compares the projected growth rates of demand to growth rates experienced in the region since 1950. Between 1950 and 1970, demand for electricity grew by an average of 7.4 percent each year. During the 1970s, demand grew much more slowly, at about 3.7 percent per year. The forecasts show a continued decline in the rate of growth, even in the high forecast, over the next 20 years.

Decreasing growth rates of demand for electricity, historically and in the forecasts, are a result of many factors. These factors include the rate of growth of the economy, changing standards of living, the price of energy relative to other goods and services, and the changing mix of economic activity, both in the nation and in the region. However, the use of electricity is much different in the Pacific Northwest than in the rest of the nation. This difference is illustrated with use of electricity per person in Table 3-2.

Although the historical patterns of growth in use of electricity are similar in the region and the nation, there is a striking difference in the amount of electricity used. The Pacific Northwest uses nearly twice as much electricity per person as the nation as a whole. This pattern is due primarily to large supplies of low-cost hydroelectric power in this region. Recent large increases in the Northwest price of electricity, however, have changed the outlook for electricity demand. The forecasts show that, while per capita use will

Table 3-2
Per Capita Use of Electricity
(Kilowatt-Hours per Person)

	PACIFIC NORTHWEST	UNITED STATES
History		
1960	8,930	3,810
1970	14,790	6,800
1980	17,230	9,230
1982	16,330	9,000
Forecast, 2005		
High	18,366	12,310
Medium-high	16,689	12,310
Medium-low	16,588	12,310
Low	15,077	12,310

Table 3-3
Firm Sales Forecast for Public and Investor-owned Utilities
(Average Megawatts)

	TOTAL SALES	INVESTOR-OWNED SALES	PUBLIC AND BONNEVILLE SALES Non-DSI	DSI	Total
Actual 1983	14,593	6,854	5,843	1,896	7,739
Forecast 2005					
High	26,101	13,300	10,324	2,477	12,801
Medium-high	21,687	10,896	8,645	2,146	10,791
Medium-low	18,950	9,516	7,692	1,742	9,434
Low	15,121	7,574	6,323	1,224	7,547
Growth rates, 1983-2005					
High	2.7	3.1	2.6	1.2	2.3
Medium-high	1.8	2.1	1.8	0.6	1.5
Medium-low	1.2	1.5	1.3	-0.4	0.9
Low	0.2	0.5	0.4	-2.0	-0.1

remain well above national levels, growth in use per person will be slower than historically and could actually decline in a low forecast. Figure 3-4 illustrates historical and forecast patterns of electricity use per person.

The summary of forecast results that is usually presented in Council issue papers and reports hides the fact that the forecasts are done in great detail. This chapter presents more of that detail than has been presented in Council issue papers or in the 1983 Power Plan. A major dimension of the demand analysis system is the separate forecasting of residential, commercial, industrial, and irrigation uses of electricity. A second major dimension is the separate treatment of demand by customers of public utilities and customers of investor-owned utilities. Each component of demand, e.g., residential use of electricity in investor-owned utility service areas, is analyzed in many more dimensions within the sector forecasting models. Those additional levels of detail are discussed in the sections of this chapter dealing with each sector. The sectoral and utility ownership dimensions are characterized briefly below.

In 1983, total regional firm sales of electricity were 14,593 average megawatts. Investor-owned utilities marketed 6,854 average megawatts or 47 percent of the total. Public utilities and the Bonneville Power Administration marketed 53 percent of the firm sales. Table 3-3 shows the 1983 composition of firm sales and the four forecasts for 2005. In all of the forecasts, the investor-owned utility share of firm sales increases slightly.

Separate forecasts are done for investor-owned and public utility service areas by running the demand forecasting models independently for those groups of consumers. The economic assumptions driving the forecasts are also done separately, as described in Chapter 2 of this volume. These economic assumptions, combined with differences in electric rates and existing conditions, lead to differences in the forecasts for the two customer groups.

Table 3-3 shows the public utility and Bonneville Power Administration sales separately for direct service industries (mostly aluminum companies) and all other customer components. Direct service industries accounted for a third of Bonneville/public sales in 1983, but are forecast to increase only moderately in the high cases, and decrease in the low forecasts. Thus, the direct service industry forecast is an important reason for lower growth in the Bonneville/public sales than in private sales. However, the other Bonneville/public sales are also shown growing somewhat more slowly than investor-owned utility sales.

Figure 3-5 shows the composition by sector of the 1983 electricity sales in the region. The industrial, residential, and commercial sectors account for most of the region's electricity demand. Each of the demand sectors is discussed in some detail in the sections that follow.

Residential Demand

The residential sector accounted for 36 percent of regional firm sales of electricity in 1983. Residential sector demand is influenced by many social and economic factors, including fuel prices, per capita income, and the choices in efficiency of energy-consuming equipment available to consumers (available technology). The most important factor, however, is the number of households. The structure of the residential sector demand model reflects this importance by using the individual household as the basic unit. The model simulates future demand for electricity by projecting future growth in households; their choice of housing type; the amount of electricity-using equipment the average household owns; choices of fuel for space heating, water heating, and cooking; the level of energy efficiency chosen; and the energy-using behavior of the household. These choices are influenced in the model by energy prices, equipment costs, per capita incomes, and available technology. The use of electricity is simulated for each of eight use classifications. Figure 3-6 shows estimated historical shares of these uses in total residential use of electricity for 1983.

The projections of residential demand for electricity cover a wide range. This range results partly from variation in projections of the number of households, per capita income and fuel prices from the economic and demographic growth scenarios. Projected demand also varies because of different assumptions regarding consumer's efficiency choice behavior (implicit discount rates; see Table 4-7 in this volume).

In the absence of new conservation programs, projected residential demand increases from 5,216 average megawatts in 1983 to a range which spans from 9,920 average megawatts in the high growth forecast to 5,825 average megawatts in the low growth forecast in 2005. As shown in Table 3-4, the average demand growth rate ranges from a low of 0.5 percent per year to a high of 3.0 percent.

The Council's residential model of energy demand is the descendant of the computer model originally developed at Oak Ridge National Laboratory in 1978. Since that time, the model has been used in a wide variety of applications for the U.S. Department of Energy, state agencies and utilities. It has also incorporated improvements in logic and data to the extent that the current model is several generations removed from the original.

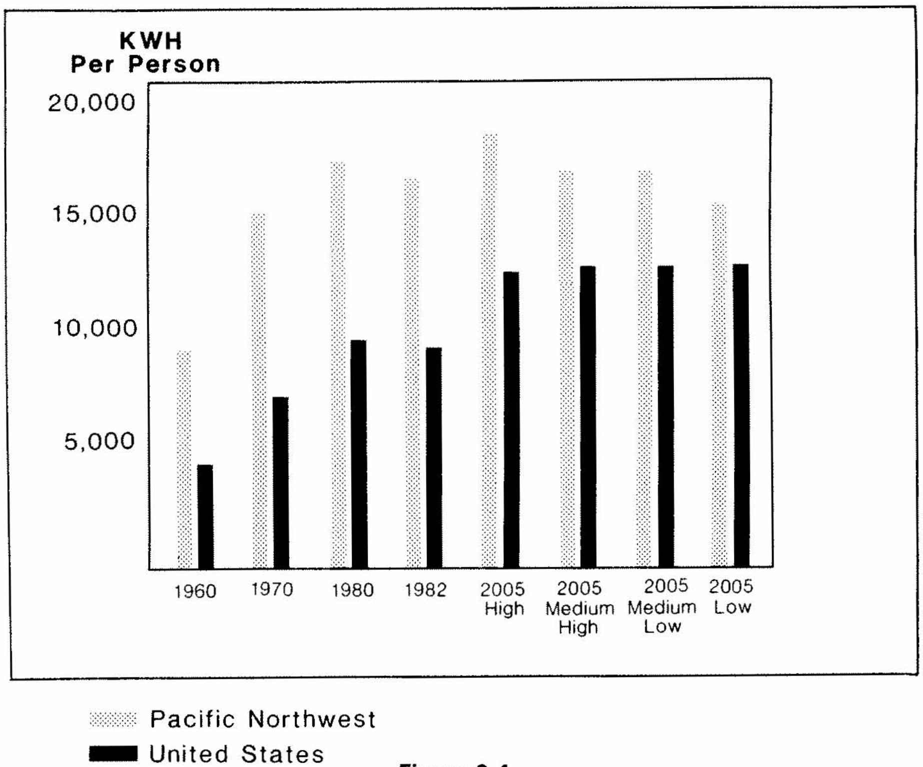


Figure 3-4
Electricity Use per Capita

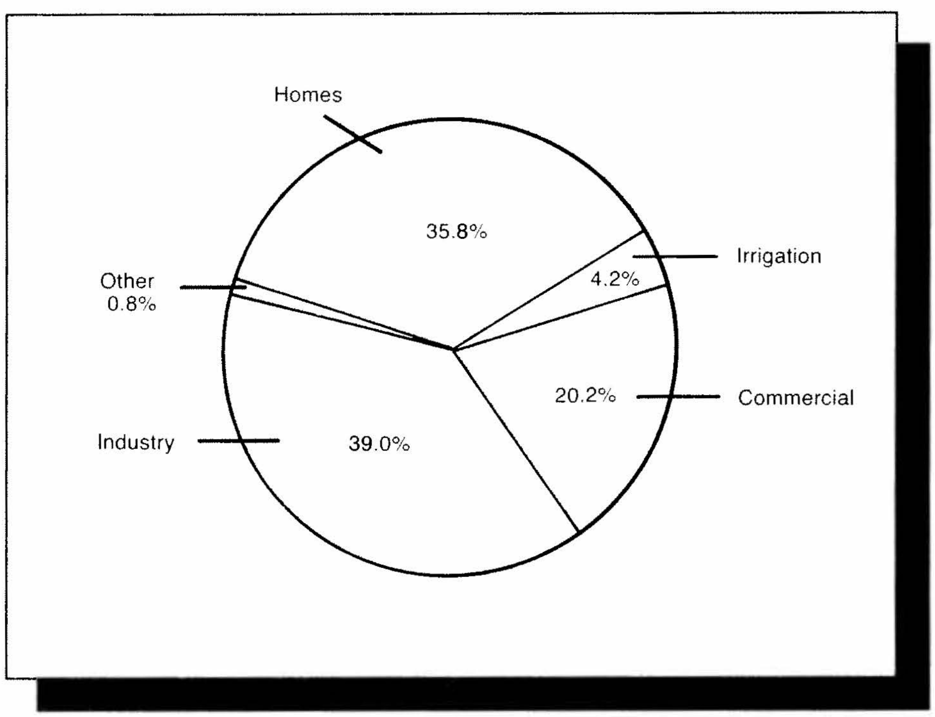


Figure 3-5
1983 Firm Sales Shares

Table 3-4
Residential Sector Electricity Demand
(Average Megawatts)

	ACTUAL 1983	FORECASTS 1990	2000	2005	GROWTH RATE (% per year) 1983-2005
High	5,216	6,628	8,613	9,920	3.0
Medium-high		6,273	7,549	8,128	2.0
Medium-low		5,769	6,726	7,720	1.5
Low		5,206	5,535	5,825	0.5

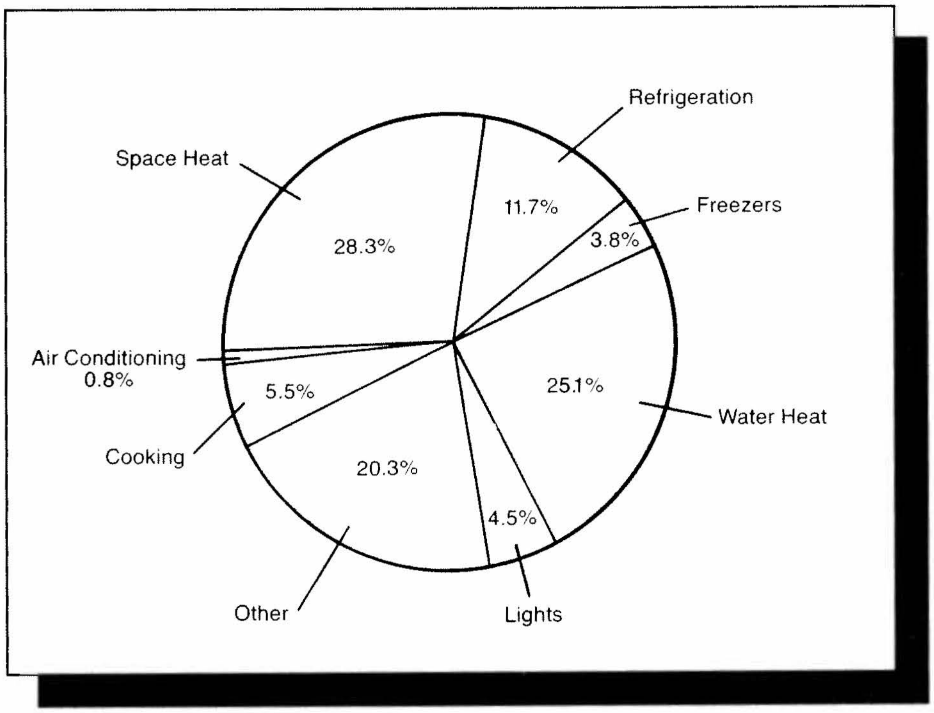


Figure 3-6
1983 Residential Use by Application

The model is best described as a hybrid of engineering and econometric approaches. It is based on the fundamental idea that residential energy is used by equipment such as furnaces, refrigerators and water heaters to provide amenities to the occupants of residences. Residential energy use, as simulated by the model, is a function of:

1. **The total number of residences.** The projections for future years are taken from the economic and demographics projections.

2. **The number of energy-using appliances in the average residence.** Each year's appliance penetrations, or purchases of appliances per household, are simulated based on econometric analysis of historic sales patterns. Penetrations are influenced by equipment and energy costs and by per capita incomes.

3. **The efficiencies of these appliances.** Efficiency choice by consumers is simulated based on engineering analysis of costs of appliances of varying efficiencies and on econometric analysis of observed efficiency choices in the past. Efficiency choices are influenced by energy prices, the cost of more efficient appliances and the inclination of consumers to invest in conservation (represented by their implicit discount rates, described in Chapter 4 of this volume). Efficiency choices can also be constrained (e.g., thermal integrity choices will be no worse than some specified level), which provides the means of representing conservation programs, such as the model conservation standards, whose objectives are to modify consumers' choices of efficiency.

4. **The fuels used by these appliances.** While some appliances such as air conditioners use electricity exclusively, others such as water heaters can use any of several fuels. Fuel choice is simulated based on the model's simulated efficiency choices and econometric analysis of fuel choice behavior that has been observed in the past. Fuel choices are influenced by relative fuel prices, equipment prices, and relative efficiencies of the appliances using the various fuels.

5. **The intensity of use of these appliances.** Intensity of use is varied by such means as thermostat settings, reduced use of hot water for washing clothes, and the like. Variation in intensity of use is based on econometric analysis of observed short run response to fuel prices. Intensity of use is determined in the model by fuel costs, appliance efficiencies, and per capita incomes.

Since the adoption of the Council's 1983 plan, Council staff have worked on several projects to improve the performance and credibility of the residential demand model. These projects fall into three categories: 1) comparison of the model's performance with that of other models that might be used for the Council's forecasting work; 2) development of the logic and structure of the model to eliminate recognized shortcomings; and 3) incorporation of improved data.

Table 3-5
Residential Sector Summary Indicators

		1980	2005 HIGH	2005 MEDIUM-HIGH	2005 MEDIUM-LOW	2005 LOW
Households (millions)		2.964	5.606	4.761	4.185	3.381
Electricity Prices (1985 cents/kWh)	Public	2.0	4.3	3.6	3.1	2.7
	IOU	3.7	4.9	4.3	3.6	3.3
Efficiency Measures:						
Thermal Integrity (New electrically heated single family, efficiency relative to regional 1979 stock)	Public	1.17	1.64	1.60	1.58	1.61
	IOU	1.26	1.63	1.59	1.57	1.60
Refrigerators (New, efficiency relative to 1979 stock)	Public	1.00	1.20	1.50	1.26	1.16
	IOU	1.17	1.26	1.61	1.33	1.19
Saturations:						
Electric Space Heat (% of homes with electric heat)	Public	59	57	55	54	49
	IOU	37	46	41	38	33
Electric Hot Water (% of homes with electric hot water)	Public	90	80	80	79	76
	IOU	81	83	78	77	75
Utilization Intensity (Relative to 1979) (Electrically space heated homes)	Public	.98	.85	.87	.93	.93
	IOU	.98	1.00	1.02	1.08	1.09
kWh per Household (All homes)		16,181	15,501	14,953	15,281	15,090
Space Heat kWh per Household (Electrically heated homes)		10,283	8,316	8,912	9,258	9,506
Non-space-heat kWh per Household (All homes)		11,441	11,287	10,773	11,094	11,356
Space Heat Sales (MW)		1,604	2,697	2,272	1,970	1,441
Total Sales (MW)		5,475	9,920	8,127	7,270	5,824

In the first category, the Council's model was compared to two alternatives. The first of these was the Residential End-use Energy Planning System (REEPS), developed by Cambridge Systematics, Inc. with financial support by the Electric Power Research Institute (EPRI). The objective in comparing the projections of the two models was not only to see by how many average megawatts they differed in some future year, but also to become more familiar with REEPS, its strengths and weaknesses, its ease of use, and its suitability for analysis of policy questions important to the Council.

The comparison required the adaptation of REEPS base-year data to Bonneville's service area, which Cambridge Systematics accomplished under contract from the Council. It also required the translation of economic and demographic projections used in the 1983 plan into the appropriate form for use by REEPS, which was done by Council staff with assistance from Cambridge Systematics.

The projections of REEPS and the Council's model were compared over a substantial range of assumptions. High and medium-low economic and demographic assumptions from the 1983 plan were used, and for each of these economic scenarios, energy use, with and without the model conservation standards, was projected. As a result of these comparisons,[1] some logical flaws in REEPS' structure were discovered. Some of these flaws were remedied quickly, but one in particular, the inability of REEPS to simulate the effect of model conservation standards on space heating fuel choice, was added to the longer run development agenda. The modeling of model conservation standards is very important to the Council; REEPS' problem in this area, in the absence of compelling advantages in other areas, left the Council's existing model preferred for the 1986 Power Plan.

The Council's model was also compared to a version of the Oak Ridge National Laboratory model used by Bonneville (the Residential Reference House Energy Demand Model, or RRHED) in their long run forecasting work. The RRHED model was developed from the same ancestor as the Council's model and differs most importantly in the area of fuel choice. The RRHED model simulates fuel choice based on data gathered in the Pacific Northwest specifically for this purpose. These data were analyzed by researchers at the Massachusetts Institute of Technology and at Oak Ridge National Laboratory under contract from Bonneville. The resulting fuel

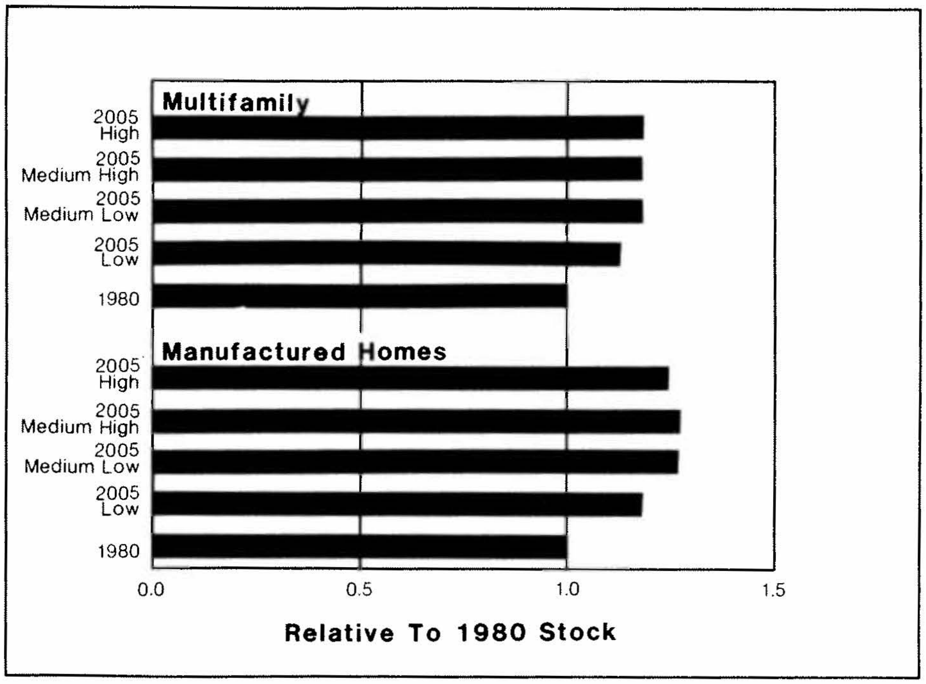


Figure 3-7
Average Size of Electrically Heated Housing Units

Table 3-6
Share of Housing Stock by Building Type
1980-2005 (%)

	1980	2005 HIGH	2005 MEDIUM-HIGH	2005 MEDIUM-LOW	2005 LOW
Single Family	78.3	77.4	72.0	68.4	72.4
Multifamily	14.2	14.3	17.1	19.9	17.9
Manufactured Homes	7.5	8.3	10.9	11.7	9.7

Table 3-7
Commercial Sector Electricity Demand
(Average Megawatts)

	ACTUAL 1983	FORECASTS 1990	FORECASTS 2000	FORECASTS 2005	GROWTH RATE (% per year) 1983-2005
High	2,936	3,654	5,108	5,946	3.3
Medium-high		3,267	4,192	4,651	2.1
Medium-low		2,958	3,483	3,848	1.2
Low		2,727	2,579	2,773	-0.3

choice submodel should be the most credible available for the Pacific Northwest. The adoption of the RRHED model for use by the Council would also have the advantage of making it easier to understand differences which might appear between Bonneville and Council forecasts.

The comparison between the Council's model and Bonneville's followed the general procedure described above for the REEPS comparison. Input data from the Council's 1983 plan high and medium-low forecasts were translated into equivalent inputs for the RRHED model. Projections were compared for both these economic scenarios, with model conservation standards and without them. The process and results are described in detail in a Council staff working paper[2]

Interestingly, the fuel choices simulated by the two models were very close. The differences observed in other components of the models did not indicate any clear superiority of the RRHED model. It became clear that the adoption of the RRHED model would have some disadvantages, however. For example, the RRHED model required about five times as much computer time to run, which would not be a prohibitive disadvantage but which would roughly double the run time of the entire forecasting system. Also, the adoption of the RRHED model would require that it be modified to include a number of important features already in the Council's model. Since the Council's model mimicked the most desirable component of the RRHED model quite closely, there seemed to be no compelling reason to accept the costs of changing models.

In addition to comparisons between the Council residential energy demand model and others, considerable effort has been spent since 1983 on further development of the model. Perhaps the most significant example of this work is the modification of the model to include the interaction of appliance efficiencies and space conditioning requirements.

Since much of the energy used by appliances such as refrigerators and stoves is converted to heat in the living space, that energy decreases space heating requirements and increases air conditioning requirements. Current space heating and air conditioning energy use implicitly reflects this fact. It follows, in the absence of other changes, that future space heating and air conditioning use will change if appliance efficiencies improve, since less appliance energy use will result in less heat in the living space. The Council's model did not take this interaction into account in 1983 (nor do REEPS or the RRHED model currently). As a result, the model's projections of total demand for energy and the estimated effects of model conservation standards were both biased downward, and the estimated effects of programs to improve appliance efficiency were biased upward.

Based on work by Palmiter and Kennedy,[3] Council staff enhanced the Council's model to include future appliance efficiencies in the simulation of future space conditioning demands. This change had modest effects on total demand for electricity,[4] but estimates of effects of conservation programs were affected more significantly. Generally, the modified model makes appliance efficiency programs appear less attractive and space heating conservation programs look more attractive.

The final category of testing and development of the residential model was the development of better input data for the model. These data include updated cost and performance data for thermal integrity, updated cost and performance data on efficient refrigerators and freezers, more recent data on the incidence of wood heating, data on retirement rates for appliances, and others. The effects of these individual data changes on projections of demand are varied; the net effect of all of them together is modest.

Table 3-5 provides a summary of historical and projected values of some of the components that determine total demand for electricity in both public and investor-owned utility (IOU) areas. Although total residential use of electricity varies widely across the four growth forecasts, use per household shows much less variation. The table shows use per household for 2005 for the four growth forecasts, as well as historical use in 1980. Use per household decreases in all forecasts. The fairly narrow range of per household use projections for 2005 means that the variation in total residential demand projections is primarily due to variation in the projections of numbers of households.

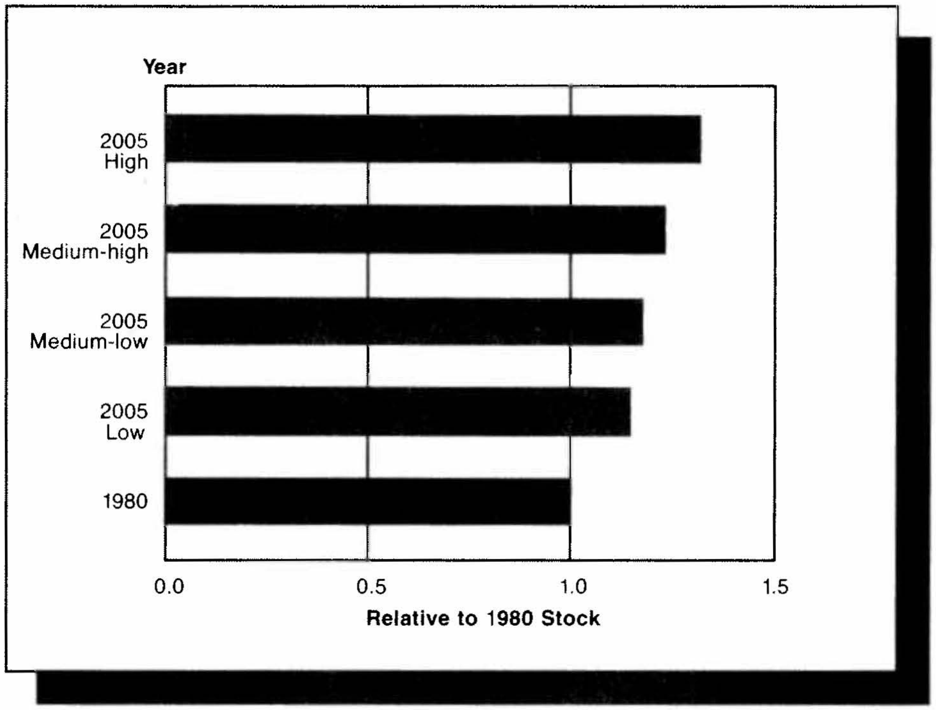


Figure 3-8
Thermal Efficiency of Electrically Heated Single Family Houses

Use per household is the net result of changes in variables such as efficiency, housing type, housing size, and fuel choice. The changes in some of these individual components are substantial, but there is a tendency for them to offset one another in their effects on use per household. For example, efficiencies generally improve, tending to reduce use per household, while the sizes of multifamily units and mobile homes are projected to increase, increasing the per household energy requirements for space conditioning. These patterns are illustrated in Figures 3-7 and 3-8. Figure 3-7 shows the projected increases in the average size of manufactured homes and multifamily housing units, ranging from 11 to 21 percent. Figure 3-8 shows that the average thermal efficiency of electrically heated single family houses improves by between 15 and 30 percent in the various growth forecasts.

The thermal integrity of new houses (shown in Table 3-5) improves significantly from 1980 practices. This is mainly due to more stringent building codes adopted in Washington and Oregon in 1985 taking effect in 1986. The greater thermal integrity of houses built after 1985 raises the average thermal integrity in 2005; the higher growth scenarios have more new houses, and higher average thermal integrity, as shown in Figure 3-8.

Housing type and fuel choice also influence per household energy use. The general trend in housing type projections is a reduction in the total share of homes which are single family houses and an increase in the shares of multifamily units and manufactured homes. Table 3-6 shows the 1980 historical shares of the three building types, along with the projected 2005 shares for each of the forecasts. The effect of this trend is to decrease average use per household, since multifamily units and manufactured homes are smaller and require less energy to heat and cool.

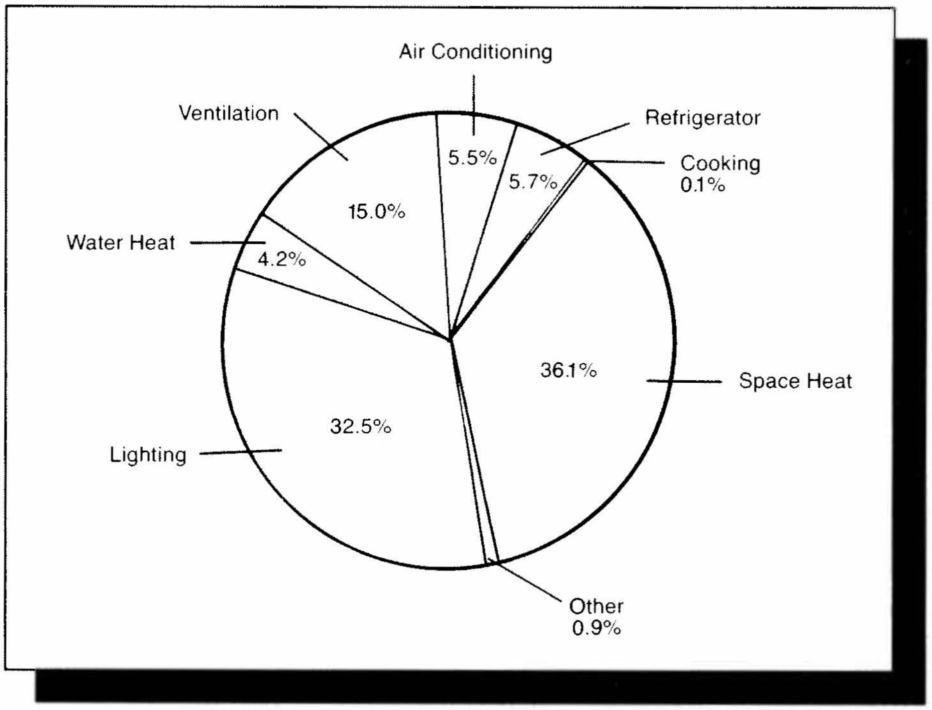


Figure 3-9
1983 Commercial Sector Use by Application

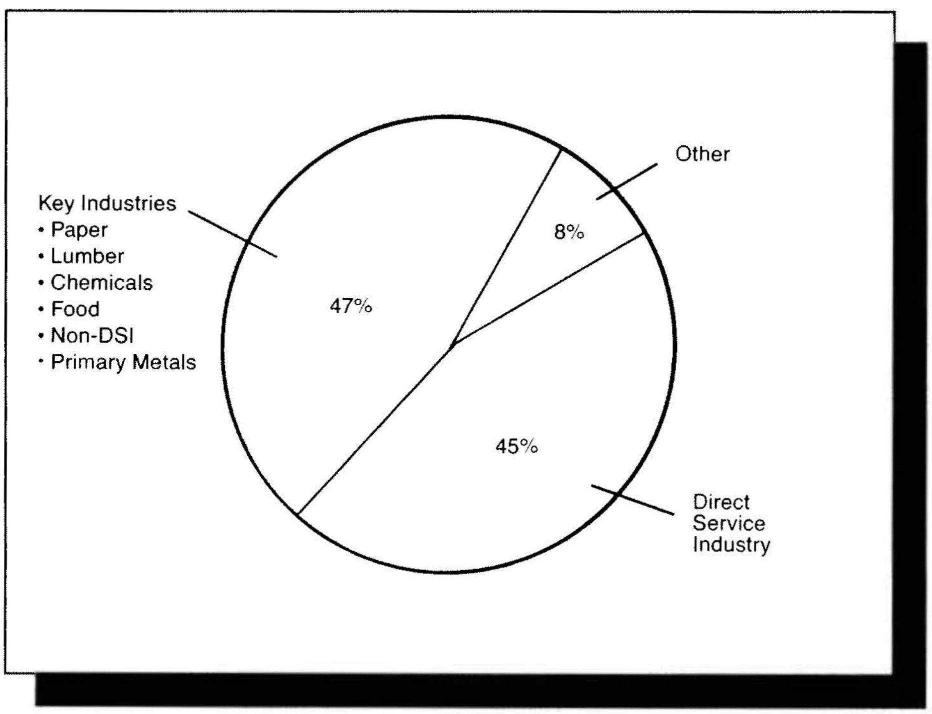


Figure 3-10
Industry Demands

Fuel choice projections have mixed effects on per household energy use. As shown in Table 3-5, the share of households with electric water heating is expected to decrease in all forecasts, but the share with electric space heating shows no clear trend. Space and water heating saturations are influenced by electricity prices, per capita incomes and the share of recently constructed houses in the stock. In addition, they are influenced heavily by the relationship of electricity prices to those of competing fuels such as natural gas and oil. As will be described in the section of electric prices, the higher growth scenarios have higher electricity prices, but *relatively* lower prices of electricity compared to competing fuels. This pattern helps to explain the higher saturation of electrical space and water heating in the higher growth scenarios.

When all the conflicting influences just described are combined, the net effect is the observed pattern of relatively small changes in per household use.

This projection of electrical equipment use is based on demand for electricity before taking into account the Council's proposed conservation programs. The effects of these programs cause sales of electricity to grow at slower rates. In addition, the use of electricity per household would decline because of the increased thermal efficiency of buildings and improved appliance efficiencies. The effects of these efficiency increases would be somewhat diminished, however, by the greater use of energy services due to cost savings from improved efficiency in space and water heating.

Commercial Demand

Commercial demand for electricity accounted for 20 percent of firm sales of electricity in 1983. Commercial sector electricity demand, like that of the residential sector, is influenced by many factors, such as fuel prices and available technology. In particular, one fundamentally important factor used as a basis for energy use projections is the total floorspace of the buildings in the commercial sector. The commercial sector demand model projects the amount of commercial floorspace and then predicts fuel choice, efficiency choice, and the use of the energy-consuming equipment necessary to service this floorspace. These choices are based on investment factors, fuel prices, and

Table 3-8
Commercial Sector Summary Indicators

		1980	2005 HIGH	2005 MEDIUM-HIGH	2005 MEDIUM-LOW	2005 LOW
Floorspace (million sq ft.)		1,283	3,032	2,322	1,903	1,544
Electricity Prices (1985 cents/kWh)	Public	2.0	4.1	3.4	2.9	2.5
	IOU	3.9	6.6	5.8	4.7	4.6
Efficiency Measures						
Electric Space Heat (Average office building, efficiency relative to 1979)	Public	1.03	1.67	1.59	1.47	1.32
	IOU	1.04	2.22	1.89	1.67	1.49
Lighting (Average office building, efficiency relative to 1979)	Public	1.00	1.09	1.08	1.05	1.06
	IOU	1.01	1.11	1.11	1.10	1.11
Saturation of Electric Space Heat (%)	Public	46	94	89	80	60
	IOU	42	75	64	50	23
Utilization Intensity						
Electric Space Heat (Average office building, relative to 1979)	Public	0.97	0.94	0.96	0.98	0.98
	IOU	0.97	1.00	1.00	1.02	1.00
Lighting (Average office building, relative to 1979)	Public	0.96	0.87	0.90	0.93	0.95
	IOU	0.96	0.90	0.92	0.96	0.96
Sales—per Square Foot Floorspace (of those heated by electricity)						
Space Heat (kWh/year)		14.7	8.5	9.5	10.7	12.2
Lighting (kWh/year)		6.3	5.3	5.5	5.7	5.8
Total (kWh/year)		18.9	17.2	17.5	17.7	15.7
Space Heat Sales (MW)		947	2,439	1,873	1,454	819
Lighting Sales (MW)		923	1,841	1,451	1,249	1,021
Total Sales (MW)		2,768	5,946	4,651	3,848	2,773

available technology. Energy use projections are made separately for different building types, applications, and fuel types. Shares of historical commercial sector demand for electricity for various applications are shown in Figure 3-9.

Since 1983, development of the Council's commercial sector energy demand model has been extensive. During that period, the commercial model used by Bonneville for their long range forecasting was modified by Synergic Resources, Inc. (SRC). Because the Bonneville model shares many components with the Council's model, the Council hired Jerry Jackson and Associates (JJA) to assist the Council staff in evaluating the desirability of adopting all or part of the SRC modifications for the Council model. JJA also incorporated new information on fuel and efficiency choice into the Council's model.

The results of this work are described in detail in JJA's contractor's report[5] To summarize, the basic structure of the Council model was retained, but much of the data developed by SRC from Pacific Northwest sources on commercial floorspace and energy use was adopted. In addition, information on space heating fuel choices in recent construction was used to recalibrate the fuel choice component of the model; this change significantly increased the amount of electric space heating projected by the model. Finally, the model's characterization of consumer choices for lighting was completely restructured to reflect new lighting technologies available and an improved simulation of consumer decision making.

Projections of commercial demand for electricity vary widely. In the low growth forecast, commercial demand for electricity decreases from 2,936 megawatts in 1983 to 2,773 megawatts by 2005. In the high growth forecast, it reaches 5,946 megawatts. As shown in Table 3-7, the average rate of growth of demand ranges from −0.3 to 3.3 percent per year.

Table 3-8 shows some of the components underlying these totals. Floorspace increases in all forecasts, as a result of increased employment in the commercial sector, and is the major driver of growth in demand for electricity. Use of electricity per square foot of floorspace decreases in all growth forecasts. The decrease in use per square foot from 1980 to 2005 is modest for all forecasts, ranging from 6 percent in the medium-low growth forecast to 17 percent in the low growth forecast.

Table 3-9
Industrial Sector
(Average Megawatts)

	ACTUAL 1983	FORECASTS 1990	2000	2005	GROWTH RATE (% per year) 1983-2005
High	5,659	6,907	8,348	9,219	2.2
Medium-high		6,342	7,392	7,992	1.6
Medium-low		5,828	6,470	6,956	0.9
Low		5,006	5,417	5,655	0.0

The relatively small projected changes in energy use per square foot are the net result of changes in various components of the forecast that are significant but that tend to offset one another. For example, the fraction of commercial floorspace heated by electricity is projected to increase in nearly all forecasts, with greater increases occurring in the higher-growth forecasts. This would tend to increase the use of electricity per square foot except for the offsetting changes in building and equipment efficiency.

The changes in equipment efficiency are also demonstrated by Table 3-8. Compared to 1980, the 2005 efficiency of space heating in offices improves by percentages that range from 28 percent in public utility service areas for the low forecast, to 113 percent in investor-owned utility service areas in the high forecast. These efficiency improvements are equivalent to reductions in use of 22 percent and 53 percent, respectively. These improvements are substantial but not unreasonable; estimates of space heating use in offices designed according to standard 90-80E of the American Society of Heating, Refrigerating, and Air-conditioning Engineers (ASHRAE) are 59 percent lower than average 1980 levels. Smaller improvements in lighting efficiency are projected.

These projections do not take into account the conservation programs included in this plan, but are based on existing building codes and market response to increased energy prices. The Council's programs will reduce overall demand for electricity, reduce demand per square foot, and improve equipment efficiency. Conservation savings estimated in the Council's conservation analysis will be reduced by increases in the intensity of electricity use, because the programs will decrease operating costs, making the use of electricity more attractive.

Industrial Demand

The industrial sector is the largest of the four consuming sectors. In 1983 the industrial sector consumed 5,659 average megawatts of firm power, accounting for 39 percent of total firm demand in the region. In addition, the direct service industrial (DSI) customers of Bonneville consume varying amounts of nonfirm electrical energy, depending on economic and hydroelectric conditions.

Unlike the residential and commercial sectors, where the general uses of electricity are similar in different houses or buildings, the industrial uses of electricity are extremely diverse. It is very difficult to generalize about the end-uses of energy or the amounts of energy used in a "typical" industrial plant. For example, the primary metals industry uses about 80 times as much electricity per dollar of output as the apparel industry.

The industrial use of electricity in the Northwest is highly concentrated in a few industrial sectors. Figure 3-10 illustrates the composition of total industrial demand for electricity. The data for Figure 3-10 are based on 1977, the most recent year for which a comprehensive accounting of industrial energy use by detailed industry sector in the Northwest was attempted. Direct service industry customers accounted for 45 percent of total industrial demand for electricity, or about one-fifth of total regional sales to all sectors. The direct service industry sales are dominated by ten aluminum plants that consume about 90 percent of the direct service industry electricity. One-fourth of the direct service industry demand is considered nonfirm demand, or interruptible demand. Only the firm portion of direct service industry demands are included in the the Council's forecasts of energy requirements. However, the interruptible portion of direct service industry demand is considered in system operation and electricity pricing analyses.

A more current look at the composition of industrial demand would likely indicate some significant changes. The aluminum companies are currently operating at about 70 percent of capacity. In addition, the trends away from energy intensive industries, which will be discussed in the forecast, have already had some effect since 1977. For example, the medium-high forecast for 1985 shows the direct service industry share of total sales at 33 percent, key industries at 50 percent, and the minor industries' share up to 17 percent.

Five industries account for about 85 percent of the non-DSI industrial demand for electricity. These industries are lumber and wood products, pulp and paper, chemicals, food processing, and primary metals. These five industries combined with the direct service industries account for over 90 percent of the region's industrial demand for electricity.

Forecasts of industrial demand for electricity reflect production forecasts for the various industrial sectors, the amount of energy used per unit of output, and the effects of prices on their use of energy. Table 3-9 shows total industrial firm demand forecasts for selected years for all four forecasts. In the high forecast, consumption of electricity by the industrial sector grows to 9,219 average megawatts by 2005—an average annual growth rate of 2.2 percent per year. In the low forecast there is no growth in industrial demand. The more likely range of industrial demand growth is from 0.9 to 1.6 percent per year.

Table 3-10
Industrial Forecasting Methods

SIC CODE		TITLE	1977 ELECTRICITY SHARE		FORECASTING METHOD	MODEL VERSION
20		Food and Kindred Products	3.7		Econometric Model	ODOE
	203	Canned Fruits and Vegetables		1.9	Not Forecast	
22		Textiles	.1		Econometric Model	AEA
23		Apparel	.1		Simple	
24		Lumber and Wood Products	8.4		Summed	
	2421	Sawmills and Planing Mills		3.7	Key Industry Model	
	2436	Softwood Veneer and Plywood		2.6	Key Industry Model	
	24XX	Rest of SIC 24		2.1	Simple	
25		Furniture	.1		Simple	
26		Pulp and Paper	18.8		Summed	
	2611	Pulp Mills		2.4	Key Industry Model	
	2621	Paper Mills		9.8	Key Industry Model	
	2621	Paper Mills — DSI		.3	Assumption	
	2631	Paperboard Mills		5.3	Key Industry Model	
	26XX	Rest of SIC 26		1.0	Simple	
27		Printing and Publishing	.4		Econometric Model	ODOE
28		Chemicals	11.3		Summed	
	2812	Chlorine and Alkalies		2.3	Key Industry Model	
	2812	Chlorine and Alkalies — DSI		1.4	Assumption	
	2819	Elemental Phosphorous		5.6	Key Industry Model	
	2819	Elemental Phosphorous — DSI		.1	Assumption	
	28XX	Rest of SIC 28		1.9	Econometric Model	ODOE
29		Petroleum Refining	1.6		Simple	
30		Rubber and Plastics	.4		Econometric Model	AEA
31		Leather and Leather Goods	0.0		Not Forecast	
32		Stone, Clay, Glass and Concrete	1.2		Summed	
	3291	Abrasive Products — DSI	.3		Assumption	
	32XX	Rest of SIC 32		.9	Econometric Model	ODOE
33		Primary Metals	49.8		Summed	
	3334	Aluminum — DSI		41.6	Assumption	
	3313	Electrometallurgical — DSI		1.7	Assumption	
	3339	Non-ferrous N.E.C. — DSI		.1	Assumption	
	33XX	Rest of SIC 33		6.5	Simple	
34		Fabricated Metals	.8		Econometric Model	AEA
35		Machinery Except Electrical	.7		Simple	
36		Electrical Machinery	.2		Econometric Model	ODOE
37		Transportation Equipment	1.6		Simple	
38		Professional Instruments	.1		Simple	
39		Miscellaneous Manufacturing	.1		Simple	
XX		Residual Categories	.8		Simple	

Methods of forecasting the industrial demand for electricity vary substantially among different components of the industrial sector. In general, the forecasting methods are most detailed for the activities that consume the greatest amounts of electricity. It is necessary to forecast industrial activity and demand for electricity individually for up to 40 industry components in order to obtain reliable forecasts of total industry demands.

The composition of the industrial forecasting system is shown in Table 3-10. The components of the industrial sector are defined using the Standard Industrial Classification (SIC) code. Table 3-10 shows the share of total industrial consumption of electricity estimated to have been consumed by each subsector in 1977. The concentration of demands for electricity that was described in Figure 3-10 is apparent in Table 3-10.

There are four different forecasting methods used for the industrial sector. The methods are referred to as 1) key industry model, 2) econometric model, 3) simple relationships, and 4) assumptions. The method applied to each industry component is abbreviated in Table 3-10. All of the forecasting methods, except assumptions, are primarily driven by forecasts of industrial production for each industry component. In addition, each of those methods modifies the relationship between production and electricity use to reflect the effects of changing energy prices.

Direct service industrial customers of Bonneville are treated separately from other industrial components. All of their demands are forecast by assumption rather than being explicitly related to causative influences. This approach is used because direct service industry demands are limited on the high side by Bonneville contracts. There is substantial uncertainty, however, whether direct service industry demands will be as large as their contracts allow.

The three largest non-direct service industries are forecast using the Key Industry Models. The Key Industry Models are very detailed approaches to forecasting demand for electricity. The three so-called key industries are lumber and wood products, pulp and paper, and chemicals. First, the industry is further divided into the most energy intensive activities. For those activities, the uses of electricity are divided into several types of uses, such as motors for specific processes, electrolysis, or lighting. The fraction of electricity use attributable to each of these end-uses is estimated for an average plant. In the case of the chemical production of phosphorous and chlorine, the model is specified separately for each of the relatively few plants in the region.

The forecast requires a specification of how the types of end-uses may change their shares over time. In addition, the degree must be specified to which electricity for each type of end-use could be conserved in response to price changes. The degree of price response was varied across forecast scenarios, being largest in the low forecast and smallest in the high forecast. Given these specifications, the demand for electricity per unit of production will change from its base year value as production and electricity prices change.

The Key Industry Models require a great deal of data and judgment. This information goes beyond readily available sources of data. For this reason, specification of the Key Industry Models relied heavily on the participation and advice of industry representatives and trade organizations.

The Council's industrial forecasting system includes a variety of econometric equations for non-direct service industry demand for electricity for all but the key industries. Econometric models consist of equations estimated from historical data. The equations attempt to measure the effect of industry production and energy prices on the demands for different types of energy, including electricity. Because historical data are generally of poor quality at the industrial subsector level, it is often difficult to obtain plausible relationships for econometric equations. Where econometric results appeared implausible, simple relationships between output and electricity use were used to obtain forecasts.

Alternative econometric estimates are available in the demand forecasting system for most industry components. In Table 3-10, the alternative equation used is specified under model version. The Oregon Department of Energy equations are noted as ODOE. Equations used by Bonneville are labeled AEA for the consulting firm that estimated the equations, Applied Economic Associates[6] The Oregon Department of Energy equations were updated since the 1983 plan forecasts. The new estimates were provided to the Council by ODOE.

The sectors whose forecasting methods are listed as "simple" are those for which econometric results were unsatisfactory. The econometric models that were used in the 1983 plan analysis for these industries were abandoned in response to public comment criticizing the behavior of those equations. In these simple forecasts, demand for electricity is assumed to grow at the same rate as production, but is modified by an assumed trend in electricity use per unit of production. There is substantial agreement in econometric models and other research on industrial energy demand, that in the absence of other influences, energy demand will grow with production. There is much less agreement about the degree of influence price changes will have on demand. To reflect this uncertainty, assumptions about changes in demand per unit of production were varied across forecast scenarios. Electricity use per unit of production was assumed constant in the high forecast for industry components that were forecast using the simple method. In the medium-high forecast, the electric intensity was assumed to decrease by 0.3 percent per year; in the medium-low forecast, by 0.7 percent per year; and in the low forecast by 1.0 percent per year. These assumptions are representative of the range of results from econometric equations that are more acceptable theoretically and behaviorally.

The forecast growth rates for industrial demand for electricity are considerably smaller than the projected rates of growth in total industrial production. Production by Northwest manufacturing industries is expected to grow by 4.7 percent per year in the high forecast, 3.9 and 3.3 percent per year in the medium-high and medium-low forecasts, respectively, and by 1.8 percent per year in the low forecast. The relative growth rates of electricity demand and output imply an overall reduction in the electricity intensity of the Northwest industrial sector. The ratios of electricity use to production decline over the forecast period in all four forecasts. The rates of decline vary from 2.4 percent per year in the high case to 1.8 percent per year in the low case. Although these rates of decrease are significant, they are lower than recent regional history. Between 1977 and 1983, regional industrial electricity intensity is estimated to have declined by about 2.8 percent per year. Such decreases in energy intensity are not unprecedented. At the national level, for example, total energy use per unit of production in the industrial sector has been estimated to have decreased by 3.3 percent per year between 1970 and 1982.

There are several factors operating to reduce industrial rates of electricity growth relative to production growth. The most important is a change in the mix of industry. Many of the large users of electricity are not expected to grow as fast as industry does on average. This is most notable in the case of the direct service industries, a very large portion of the industrial demand that is not expected to increase and may decline.

The assumptions regarding direct service industry demand for electricity are shown in this chapter as a range of demand levels associated with specific forecast scenarios. The direct service industry loads are treated differently, however, for resource planning purposes. In the resource portfolio analysis, direct service industry load uncertainty is modeled by including 50 percent of aluminum direct service industry load in all load cases and randomly adding portions of the remaining 50 percent of aluminum direct service industry loads. This is based on the conclusion that half of the aluminum production capacity in the region appears to be economically viable in the long run, while more uncertainty exists about the remaining capacity.

The direct service industry assumptions described in this chapter are incorporated in the four forecast scenarios for purposes of defining the full range of electrical resource needs. Figure 3-11 shows the percent of current aluminum plant demand that is assumed to remain in the region by the end of the forecast period for each of the four forecasts.

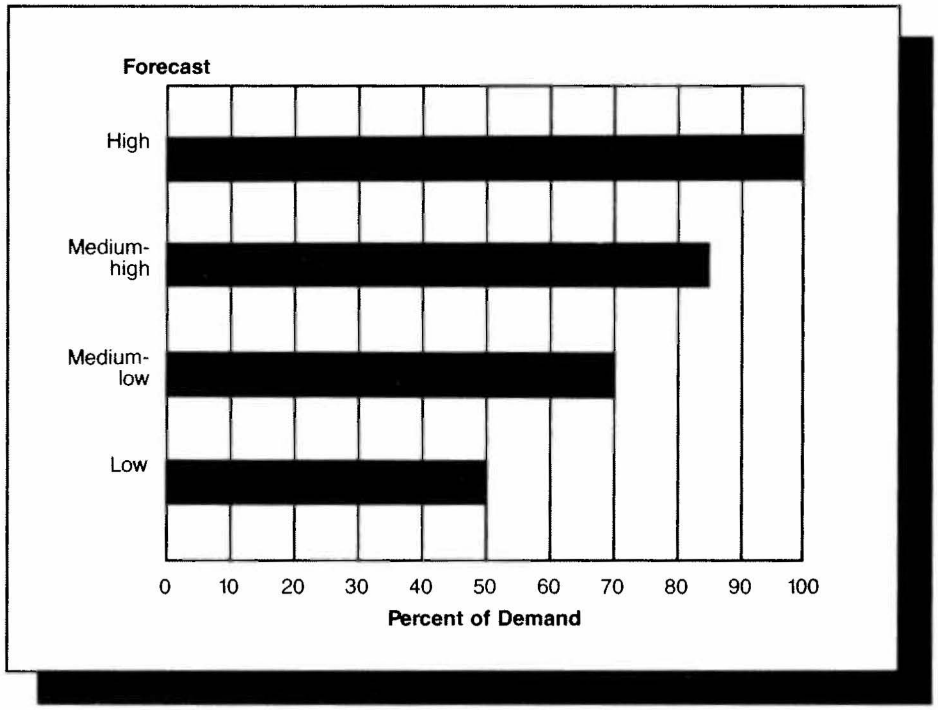


Figure 3-11
Assumed Aluminum Operating Rates

Table 3-11
Composition of Industry Growth, 1983-2005: Medium-High Forecast

	HISTORICAL SHARE OF CONSUMPTION (%)	PRODUCTION GROWTH RATE (% per year)	DEMAND GROWTH RATE (% per year)
DSIs	45	N.A.	0.6
Key industries	47	2.1	1.6
Minor industries	8	5.1	4.8
TOTAL	100	3.9	1.8

Since Bonneville currently has contractual obligations to serve all direct service industry capacity, 100 percent of DSI demands are included in the high forecast. It is assumed that 15 percent of DSI capacity will cease to operate in the medium-high forecast. The reductions in DSI demand in the medium-low and low forecast are 30 and 50 percent, respectively.

The forecast of industrial electricity use is further dampened by the fact that some of the large non-direct service industrial users such as lumber and wood products, food processing, and pulp and paper are not growing as fast as less energy intensive industries. As shown in Table 3-11, output growth for the key non-direct service industries combined is expected to be 2.1 percent per year in the medium-high forecast, compared to 3.9 percent per year for all industrial production. Thus, the two components of the industrial sector that accounted for over 90 percent of the sector's electricity demand historically will show relatively weak growth over the next 20 years.

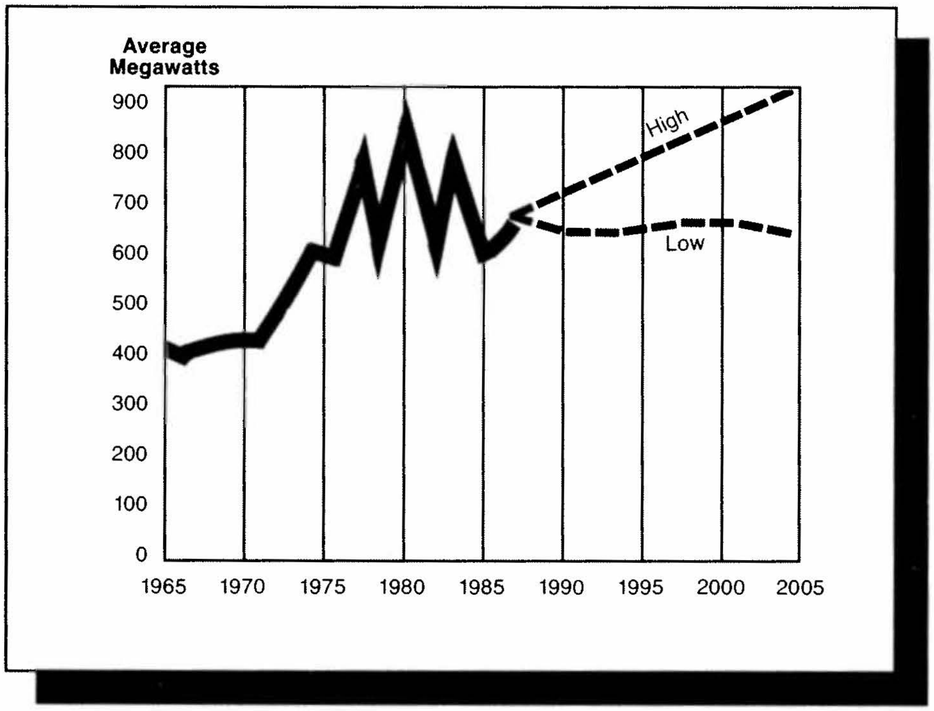


Figure 3-12
Irrigation Demand

Table 3-12
Irrigation Sector
(Average Megawatts)

	ACTUAL 1983	1990	FORECASTS 2000	2005	GROWTH RATE (% per year) 1983-2005
High	615	735	838	896	1.7
Medium-high		699	768	796	1.2
Medium-low		676	739	756	0.9
Low		638	718	748	0.9

The second major reason for lower electricity growth relative to production is the effects of the large changes in the relative price of electricity in the region over the last several years. The effects of price on industrial demand can not be separated into components as they can for the residential and commercial sectors, but conceptually they include efficiency improvements, fuel switching, and product mix changes within individual industrial sectors.

Irrigation Demand

Irrigation use of electricity is less than 5 percent of total regional firm electricity sales. In 1983, 615 average megawatts of electricity were used for irrigation. Until 1977, use of electricity for irrigation was increasing. As shown in Figure 3-12, irrigation sales since 1977 have become erratic and have not grown.

In 1981, there were 8.6 million acres of irrigated land in the region. Most electricity use in irrigation is associated with sprinkler irrigation. Currently, about half of the irrigated land in the region is irrigated with sprinkler systems.

Table 3-12 shows the forecasts of use of electricity for irrigation. The forecasts show some growth in electricity used for irrigation from its 1983 levels, but the growth is small relative to historical growth, which averaged nearly 4 percent a year from 1967 to 1983.

Current use of electricity for irrigation, under normal weather conditions, was assumed to be 700 average megawatts, the average annual use from 1976 to 1983. The forecasts of demand for electricity by the irrigation sector began with assumptions about growth in irrigated acres. The assumptions about growth in irrigated acres were judgmentally made, based on various studies in the region.[7] There is sufficient growth to allow for the possible completion of the proposed Columbia Basin East High Project in the higher forecasts. The development of new irrigation, such as the East High Project, would be accompanied be reduced electricity generating capability of the region's hydroelectric system and could impose additional costs on Bonneville Power Administration. These effects have not been included in the Council's analysis of the higher cases.

The growth in demand for electricity implied by the range of assumptions about increases in irrigated acres is modified by assumptions about the level of price response by irrigators. A range of price responsiveness was assumed based on more detailed models of irrigation sector behavior. The lower forecasts were assumed to have more price response. Long-term price elasticity for the low forecast was assumed to be -0.6; for both medium forecasts it was assumed to be -0.4; and for the high forecast, -0.2. Since real electric rates decline the most in the lowest forecasts, the price response tended to raise those forecasts the most. This results in a more narrow range of forecasts.

Retail Electric Prices

The Council's forecasts of electrical rates in the Pacific Northwest show relatively stable prices over the next several years. The exact price outlook varies substantially in the different forecasts, however, due to differences in the amount of new resources to be acquired. Because nearly all new resources are more costly than the existing resource base, adding new resources will raise electrical rates.

Retail prices are forecast using an electricity pricing model that is part of the demand forecasting system. The pricing model develops forecasts of retail prices for each sector for investor-owned utilities and publicly-owned utilities. These rates are forecast through a detailed consideration of power system costs, secondary power sales, and the provisions of the Act.

The model contains capacity and cost information on both generating and conservation resources. Cost and capacity of the federal base hydroelectric resources are included as a total. However, most other resources are treated on an individual basis. Capacity of each resource is specified for critical water conditions and for peak capacity. Capital cost and operating costs are specified for each generation resource. For conservation resources, only those costs that are to be paid through electric rates are included. The capacity of conservation resources are generally predicted directly in the various demand models, although in some cases the savings are included within the pricing model and subtracted from demand there.

The costs of generation and conservation are added up and allocated to the various owners (Bonneville, investor-owned utilities, and public utilities). The costs of resources used to provide power to customers of Bonneville, public utilities, and investor-owned utilities are combined to reflect contractual agreements among utilities and the exchange and other provisions of the Act. The model develops forecasts of wholesale power costs for three Bonneville rate pools—priority firm, direct service industries, and new resources. Similarly, wholesale rates are developed for investor-owned and public utilities. Retail markups are added to these

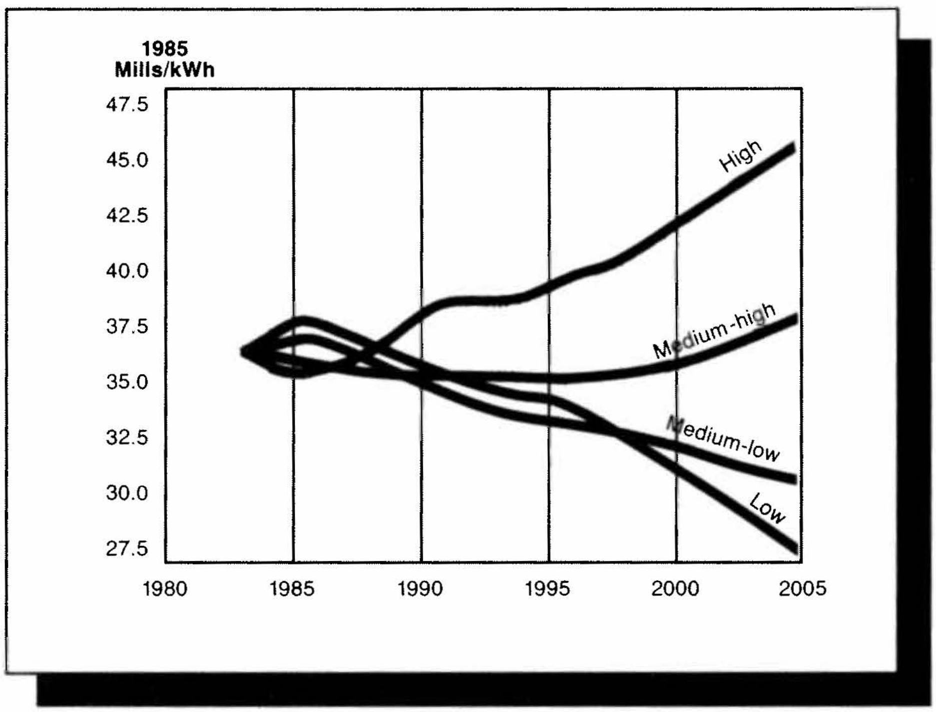


Figure 3-13
Average Retail Electric Rates

wholesale costs to obtain retail rates for each consuming sector of each type of utility.

As demands grow, resources are added to meet demand and the new resource costs are melded with existing resource costs. The pricing model balances resources and demand based on critical water capacities. However, electricity is priced based on expected water conditions.

The effects of different water conditions on secondary energy and electric rates is simulated by the pricing model. The operation of the hydroelectric system on a monthly basis for over 40 historical water years is the basis of this simulation. When there is surplus hydroelectric power in any month for a specific water year, the model allocates that secondary power to various uses according to a set of priorities specified in the model assumptions. These uses, in the assumed order of priority, are 1) serve the top quartile of direct service industry demand, 2) shut down combustion turbines, 3) sell outside the region, and 4) shut down other thermal generation.

For purposes of the pricing model, firm surpluses are added to secondary power and allocated using the same priorities. If the region is in a deficit situation, instead of surplus, the model will import power at a prespecified price until additional resources are added to meet demand.

The revenues from sales of secondary power and firm surplus power, or the costs of importing to cover deficits, are averaged over months and water years to obtain estimates of expected prices of power given uncertain water conditions.

Figure 3-13 shows real average retail rates in 1985 dollars for the four forecasts. As can be seen from Figure 3-13, real retail rates are projected to begin to decline in real terms after 1985. The exception to this is the low case, where it was assumed that the region would lose half of the aluminum companies by 1987. This loss of electrical sales during the surplus increases the rates that other consumers would have to pay and delays the downturn in real prices. In addition to the direct service industry assumption, the low

Table 3-13
Electric Price Forecasts
(1985 Cents per Kilowatt-Hour)

	BPA PREFERENCE WHOLESALE	AVERAGE RETAIL ALL CONSUMERS	AVERAGE RETAIL PUBLIC UTILITIES	AVERAGE RETAIL PRIVATE UTILITIES
Estimated 1984 (1985 cents per kWh)	2.3	3.6	2.8	4.2
Forecast 2005 (1985 cents per kWh)				
High	3.0	4.5	4.0	5.3
Medium-high	2.4	3.8	3.3	4.6
Medium-low	1.7	3.1	2.7	3.7
Low	1.3	2.8	2.4	3.4
Growth rates (% per year) (1984-2005)				
High	1.3	1.1	1.7	1.1
Medium-high	0.2	0.3	0.8	0.4
Medium-low	-1.4	-0.7	-0.2	-0.6
Low	-2.7	-1.2	-0.7	-1.0

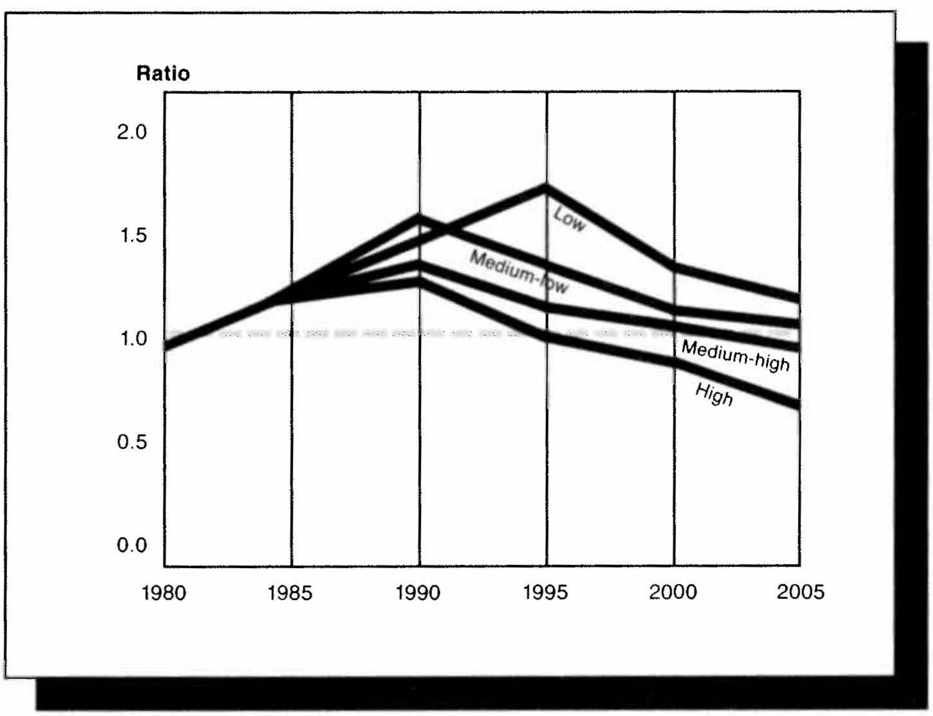


Figure 3-14
Relative Residential Energy Prices
(Ratio of Electricity to Natural Gas)

case also assumes that the debts from the Washington Public Power Supply System Nuclear Projects 4 and 5 (WNP-4 and WNP-5) fall on the region's ratepayers somehow. This is to reflect the fact that there still remains some doubt about the final settlement of the WNP-4 and 5 debts. If those debts did fall on ratepayers, it would contribute to a low case demand. That WNP-4 and 5 assumption accounts for most of the difference in the beginning price level for the low forecast.

Table 3-13 shows 1984 estimated average electric rates, forecasts for 2005, and average annual rates of change for four different kinds of rates. The rates shown include Bonneville wholesale rates for preference customers, average retail rates paid by all consumers combined, average retail rates paid by customers of public utilities, and average retail rates paid by customers of investor-owned utilities.

Bonneville preference customer rates increase faster than inflation in the high and medium-high forecast. In the other forecasts real rates decline. Similar results are shown for retail rates of both public and investor-owned utilities.

These results depend on the assumptions used in the pricing model. One important assumption is that the Council's resource portfolio is implemented, including the proposal that the region option to 90 percent of the load forecast range and build to the expected loads. Another important assumption is that no dramatically revised repayment requirement will be imposed for the federal debt on the region's hydroelectric system. Some of the more extreme versions of the revised repayment costs would have a significant effect on electric rates.

For most of the demand sectors, the relative price of electricity compared to oil or natural gas is important. It is the relative price that is most relevant for consumers' choice of fuel type. Figure 3-14 shows forecast prices of electricity relative to natural gas for residential customers. Natural gas prices have been divided by 0.7 to adjust for differences in the end-use efficiency of gas and electricity. Thus, the relative prices shown in Figure 3-14 are more appropriate comparisons of the cost of heating than of the cost of buying fuel.

Although electric rates are highest in the high forecast, it is in the high forecast that relative electric rates are lowest. This stimulates the demand for electricity in the high forecast.

When the ratio in Figure 3-14 is above 1.0, it means electricity is relatively more expensive than natural gas. During most of the 1970s, electricity in the Pacific Northwest was inexpensive relative to natural gas, its main competitor. However, recent large increases in electric rates combined with decreases in natural gas prices have increased the competitiveness of natural gas. This result is only a general tendency, because the relative prices of electricity vary significantly for different utility areas. Further, the attractiveness of electricity or natural gas also can depend on consumer tastes and the relative cost of equipment used to convert energy to a useful service, such as heat. The general conclusion to be drawn from Figure 3-14 is that natural gas and electricity prices could remain competitive within a fairly broad range.

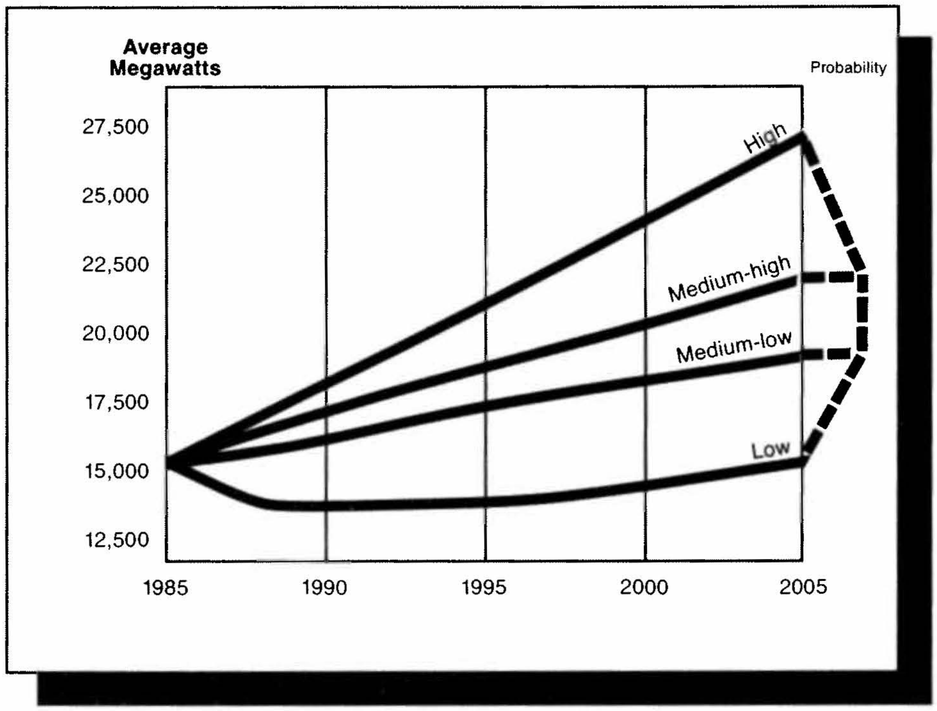


Figure 3-15
Demand Uncertainty

The Role of Demand Forecasts in Planning

Introduction

The role of demand forecasts in the Council's resource planning is significantly different from the traditional role of demand forecasts. The traditional role of demand forecasts could be characterized as deterministic. That is, a best-guess demand forecast determined the amount of new electricity generation capacity needed. Before the early 1970s, it was generally assumed that demand for electricity would grow at close to its historical growth rates. That growth had been rapid and relatively steady. It was assumed that economies of scale in power generation could be relied on to keep prices for electricity from increasing as new capacity was added, so planners saw little reason for demand growth to slow down. In fact, it was widely assumed that there would be little or no response to price changes if they did occur.

The dramatic reduction in demand growth that occurred in response to increases in electricity prices in the early 1970s caught most planners by surprise. The initial reaction of planners seems to have been to develop much more sophisticated forecasting tools. The forecasting models adopted by the Council are representative of the results of those efforts. However, the Council has recognized that, even with the best available forecasting tools, the forecasts of future demands remain highly uncertain. This recognition is moving forecasts away from their deterministic role in planning, to what may be described as an integral role.

The integral planning role of demand forecasts has three major components. First, forecasts of demand define the extent and nature of uncertainty that planners must face. Second, the level of demand is not independent of resource choices, but will respond to the costs of resource choices to meet future demands. Finally, sophisticated demand models are needed to assess the potential impacts of choosing conservation programs as alternatives to building new generating resources.

Defining Range of Uncertainty

The Council defines the uncertainty in future demands for electricity by developing a range of forecasts. The range of demands are based primarily on variations in the key assumptions that determine the demand forecasts. The forecast range has been described above in terms of four forecasts. A subjective probability distribution of future demands is developed based on the four forecasts. The probability distribution describes the liklihood that any given level of electricity demand within the range will occur. Figure 3-15 illustrates probability distributions around the demand forecasts. The Council has adopted the trapezoidal distribution. The implications of the trapezoidal distribution are: (1) that demands outside the high and low forecasts are judged to be of sufficiently low probability that they are not formally considered in resource planning, and (2) that demands between the medium-high and medium-low forecasts are most likely and considered equally probable.

Resource portfolio analysis is based on the entire probability distribution of future loads. This is a major change from the 1983 plan and is made possible by the new Decision Model. The Decision Model analysis utilizes hundreds of possible load paths that are distributed according to the trapezoidal probability distribution defined by the original four demand forecasts, as illustrated in Figure 3-15.

Effects of Resource Choices on Price

As was shown in Figure 3-1 and discussed in the previous section, there is an electricity pricing model in the demand forecasting system. This model translates resource decisions made by the Council into retail prices that various consumers will face in the forecast period. The price model ensures that the implications of future resource decisions, including conservation programs, are reflected in future prices and demands.

Conservation Analysis

In addition to defining uncertainty, the demand forecasting models play an important role in defining and evaluating conservation opportunities. This is particularly true for the residential and commercial sectors, where the demand models are most detailed and conservation opportunities are best defined.

There are two key roles for the demand models in conservation analysis. The first is in helping define the size of the potential conservation. The second is to predict the effectiveness of programs designed to achieve some portion of the potential conservation available.

The stock of energy-using buildings and equipment, including its fuel type and efficiency characteristics, essentially determines how much additional efficiency can be achieved to offset the need for new electricity generation. The building energy demand models provide the necessary stock forecasts for analyzing conservation potential. Obviously, the demand models will show different amounts of conservation potential for different forecasts.

The effects of conservation programs can be quite complicated and the demand models are designed to help assess those effects. For example, the effects of an energy efficient building code can affect all three components of building owner choice: efficiency, fuel type, and use. Of course, the direct impact is on efficiency choice, since a building code constrains that choice directly. However, there are also likely to be unintended effects on fuel choice and intensity of use.

A more stringent code for residential electrical efficiency will tend to increase the construction cost of electrical homes. This relative increase in the initial cost of electrical homes, if borne by homebuyers, may cause some increase in the number of homes heated by natural gas or oil, even though the cost of operating the more efficient electrically heated homes would be reduced. For cost-effective conservation actions, the cost of providing an end-use service, such as space heating, will decrease. With the decrease in cost, the consumer's intensity of use may increase. Another important complication is that appliances give off waste heat affecting the heating and cooling requirements in buildings. More efficient appliances give off less waste heat and, therefore, more heating and less cooling will be needed than with less efficient appliances. These secondary effects can be assessed in the detailed building models to give a more accurate assessment of the actual effects of conservation programs on demand for electricity.

Forecast Concepts

For any given forecast case (i.e., high, medium-high, medium-low, or low), there are three different demand forecast concepts used in the Council's planning activities. Most Council presentations and publications, including the preceding sections of this chapter, describe "price effects" forecasts. Price effects forecasts show what the demand for electricity would be if customers were allowed to respond to price, but no new conservation programs were implemented. Price effects forecasts also include no adoption of the proposed model conservation standards, but do include the more stringent building codes adopted in Washington and Oregon in 1985. An important factor affecting price effects forecasts is the resource mix that is assumed in the electricity price provided to the demand models.

A "sales" forecast is a forecast of the demand for electricity after the effects of the model conservation standards and other conservation programs have been taken into account. This is the amount of electricity that would actually be sold by utilities and flow through power lines to consumers.

The third demand concept, the "frozen efficiency" forecast, is somewhat more complicated to explain. Its purpose is to help avoid double counting of conservation—once as part of the response to price increases, and once as programmatic conservation potential. Essentially, the frozen efficiency forecast attempts to eliminate from the demand forecast the effects of actions that are taken in response to price, but could also be achieved through the Council's proposed conservation programs. The method of developing frozen efficiency forecasts varies by sector.

The first step in developing the three forecasting concepts is to do a sales forecast. In the sales forecast, preliminary resource portfolios are assumed, including conservation resources. The effects of conservation programs for the residential and commercial sector are estimated directly in the demand models. Industrial and irrigation programs are treated as resources that offset those sectors' demands. The sales forecast results in a forecast of electricity prices that is based on the costs of the resources used to meet the demand forecasts. The price effects and frozen efficiency forecasts are done using these electricity prices.

Using the electricity prices from the sales forecast, the price effects forecast answers the following question: What would demand for electricity be if consumers faced forecast prices but there were no new conservation programs? Clearly, electricity prices would be somewhat different than the prices from the sales forecasts if no conservation programs were implemented. This is because the portion of demand served by conservation program effects (beyond what would happen as price response) would have to be met by alternative generating resources whose costs and rate impacts might differ from those of conservation programs.

Frozen efficiency forecasts are also done assuming sales forecast electricity prices. The term "frozen efficiency" comes from the residential and commercial sector demand models, which simulate three components of consumer decision making. The three components are energy efficiency levels, type of fuel, and intensity of use. It is the efficiency choice component of consumer behavior that could potentially duplicate the estimated effects of conservation programs. Therefore, the frozen efficiency forecasts add back the efficiency choice component of price response to the price effects forecast, but leave the other components of price response in the forecast.

The frozen efficiency forecast is accomplished by "freezing" the level of efficiency choice at the levels being simulated by the models for choices made in the years when conservation programs are assumed to go into effect. Thus, for example, thermal integrity choice for new buildings is kept at 1983 choice levels. Residential efficiency of refrigerators, freezers, and water heaters are frozen at 1992 levels, the year currently assumed for appliance code adoption.

The industrial and irrigation models are not sufficiently detailed to use a similar approach to the frozen efficiency forecast. In the 1983 Power Plan analysis, the frozen efficiency forecasts for the irrigation sector assumed there was no price elasticity at all. The industrial frozen efficiency forecast assumed no elasticity with respect to electricity price in the pulp and paper industry, the industry where all of the identified conservation was to occur. The approach of assuming no price elasticity was weak in two respects. First, assuming no price elasticity eliminated all price effects, including those that resulted from price increases in the late 1970s and early 1980s. Second, the industrial and irrigation models do not separate out the components of price response—so not only was efficiency choice being held constant, but fuel choice and use responses were also being limited.

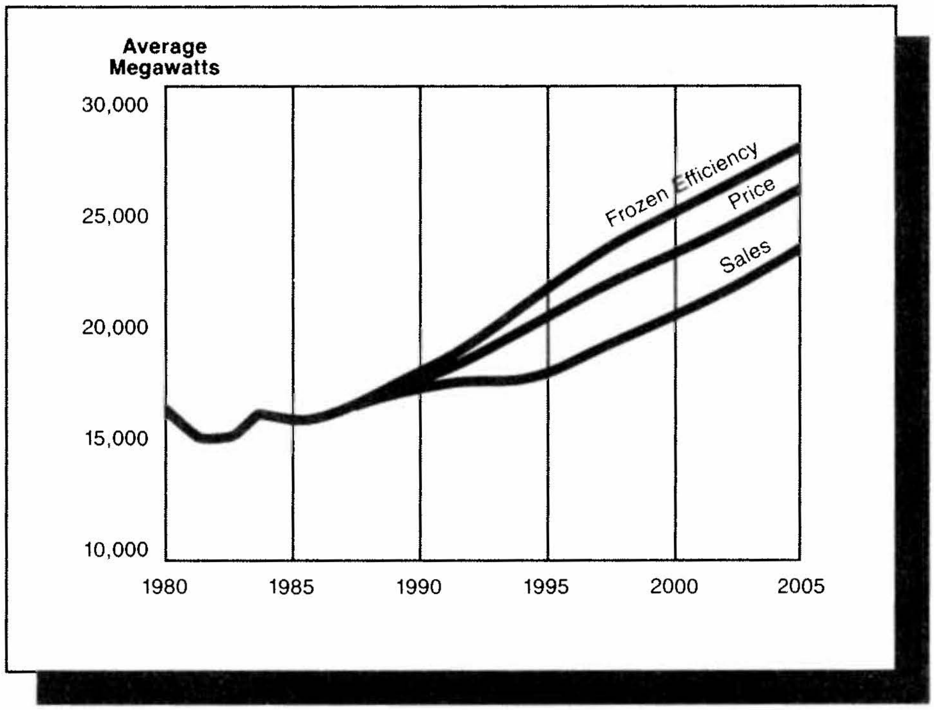


Figure 3-16
Comparison of High Forecasts

The frozen efficiency forecasts for the industrial and irrigation sectors in the 1986 Power Plan have assumed that double counting would not occur. That is, the frozen efficiency and price effects forecasts are the same. The maximum double counting that might occur can be examined by running the models with electricity prices held constant at their 1985 levels and comparing the results to the price effects forecasts. In all but the high case, there is no double counting because electricity prices do not increase during the 1985 to 2005 period. In the high forecast, prices reduce the industrial and irrigation demands by 206 megawatts. Comparison of the price effects on an industry-by-industry basis and for irrigation showed that the maximum double counting in the high case for 2005 could be 170 megawatts (140 megawatts in industry and 30 megawatts in irrigation). This double counting would occur if the conservation actions identified in the Council's industry survey of conservation potential were the same actions that would be taken in response to high case price increases from 1985 to 2005.

Differences between the three forecast concepts have particular meanings. This section discusses those meanings and summarizes the differences. The three forecasts for the high scenario are shown in Figure 3-16 to help visualize the following discussion.

Table 3-14 shows the growth rates for the three forecast concepts for each of the forecast scenarios. The price effects growth rates are the same as those shown in Table 3-1 and Figures 3-2 and 3-3. The frozen efficiency growth rates are slightly higher because part of the demand decreases due to price response have been eliminated. The differences between price effects and frozen efficiency forecasts are relatively small because prices are not forecast to increase much in most forecast scenarios. Demand growth rates for the sales forecasts are significantly lower than the price effects and frozen efficiency forecasts, reflecting potential conservation savings from the Council's programs. Only in the low forecast are the differences among the three forecast concepts small, reflecting the fact that only new building standards savings are acquired.

Table 3-14
Demand Growth by Forecast Concept, 1983-2005
Average Annual Rate of Change (%)

	HIGH	MEDIUM-HIGH	MEDIUM-LOW	LOW
Price Effects	2.7	1.8	1.2	0.2
Frozen Efficiency	2.9	1.9	1.3	0.2
Sales	2.2	1.3	0.7	0.0

The difference between the highest forecast (the frozen efficiency forecast) and the lowest (the sales forecast) is the total effect on electricity demand of conservation resources and cogeneration. The price effects forecast divides that total effect into two parts, that which would result from price response and the incremental effect of conservation programs. The difference between the frozen efficiency and price effects forecasts represents the price response portion. The difference between the price effects and the sales forecasts represents the incremental program impacts.

Electric Loads for Resource Planning

Demand forecasts serve as the basis for the Council's resource portfolio analysis. The actual loads for resource planning are based on the various demand forecast concepts, but must be modified to the appropriate definition for resource planning analysis. This section describes the forecast concepts used and their modifications.

In the 1983 plan, resource loads were based on frozen efficiency forecasts of demand. The 1986 Power Plan loads are also based on frozen efficiency forecasts. However, several adjustments are made to these forecasts before they are used for resource planning.

The assumptions regarding direct service industry demand for electricity are shown in this chapter as a range of operating levels associated with specific forecast scenarios. The direct service industry loads are treated differently, however, in the analysis of electrical loads faced by the region for resource planning purposes. In the resource portfolio analysis, direct service industry load uncertainty is modeled by including 50 percent of aluminum direct service industry load in all load cases and randomly adding portions of the remaining 50 percent of aluminum industry loads. Thus, for resource analysis, the risk associated with the upper half of the aluminum loads has been disassociated with any particular load scenario. This facilitates a better assessment of the uncertainty, because it is not clear that the health of the aluminum industry in this region will be related directly to the general economy; the positive influences of a healthy economy may be offset for aluminum producers by the higher electric rates that would come with a faster growing region.

Several adjustments are made to the demand forecasts to create the load forecasts for resource planning. First, demand forecasts are converted to load forecasts by adding transmission and distribution losses. The demand forecasts are for consumption of electricity at the point of use, while loads are the amount of electricity that needs to be generated. More electricity has to be generated than is actually consumed by utility customers, because some electricity is used or lost in the transmission and distribution of power. The demand forecasts are converted to loads by adding 2.4 percent to direct service industry demand, and 7.5 percent to other demand.

Most resource analysis is done on an operating year basis. Since the demand forecasts are done on a calendar year basis, the demands must be converted from a year that begins in January, to a year that begins the previous September. This is done by calculating a weighted average of the previous and current calendar years. The previous year receives a one-third weight, and the current year a two-thirds weight. In addition, for resource planning, the 1985 and 1986 calendar year forecasts are set to be the same across forecast scenarios. This was done by averaging the four forecasts. The resulting 1986 forecast (a proxy for actual loads) is then interpolated to each scenario's respective 1990 level.

Finally, it is important to restate that the resource portfolio analysis is based on the entire probability distribution of future loads. This major change from the 1983 plan is made possible by the new Decision Model. The Decision Model and resource portfolio analysis are described in Volume II, Chapter 8.

1./ The results of these comparisons are presented in detail in Kenton R. Corum, "REEPS in the Pacific Northwest: Preliminary Results," presented at the EPRI Annual Review of Demand and Conservation Research, Seattle WA, July 10-12, 1984.

2./ "Evaluation of the BPA RRHED Model," Northwest Power Planning Council, Portland OR 97205, November 1984.

3./ Larry Palmiter and Mike Kennedy, *Annual Thermal Utility of Internal Gains*, 8th National Passive Solar Conference, American Solar Energy Society, Santa Fe NM, September 1983.

4./ For a detailed description of methodology and results, see Kenton R. Corum, "Interaction of Appliance Efficiency and Space Conditioning Loads: Application to Residential Energy Demand Projections," proceedings of the American Council for an Energy Efficient Economy Summer Study on Energy Efficiency in Buildings, Santa Cruz CA, August 1984; or "Linking Efficiency and Space Conditioning Loads in Residential Energy Demand Projections," forthcoming in *Energy — The International Journal*.

5./ Jerry Jackson, "Northwest Power Planning Council Commercial Model Update," contractor's report, September 1985.

6./ Applied Economic Associates, Inc., *Update and Re-estimation of the Northwest Energy Policy Project Energy Demand Forecasting Model*, report to Bonneville Power Administration, December 1981.

7./ *Water Today and Tomorrow,* Vol. II, The Region, Pacific Northwest River Basins Commission, June 1979; *Northwest Agricultural Development Project: Final Report,* June 1981; *Demand Response to Increasing Electricity Prices by Pacific Northwest Irrigated Agriculture,* College of Agricultural Research Center, Washington State University, 1981; and unpublished studies and computer runs from Bonneville Power Administration.

Chapter 4
Financial Assumptions and Resource Cost Effectiveness

The Council's planning process involves a number of analytical steps, including estimation of quantities and costs of resources, projection of future demand for electricity under a variety of assumptions, and simulation of the operation of the regional power system to meet demands with alternative sets of resources. All of these analytical steps require that values for a number of financial variables be assumed. Consideration of these assumptions is important for two reasons: first, the values used directly influence the outcome of the analysis; second, the values used in the various components of analysis must be consistent.

A number of financial variables influence the Council's planning process. Like many components of the Council's analysis, the values of these variables cannot be known with absolute certainty. This chapter of Volume II describes the major issues and the reasoning behind the values adopted by the Council. It also provides an explanation of terms used throughout this chapter: nominal dollars, real dollars, present value, levelized cost, and discount rate. Following this explanation, three categories of variables are examined: 1) escalation rates, including those of fuel prices, construction costs, and the general level of prices; 2) cost of capital, including home mortgage rates and the cost of capital for regional resource acquisition; and 3) discount rates, including the rate used for converting streams of regional costs to present values and rates used in projecting consumers' efficiency and fuel choices in the future.

The costs of conservation resources available to the region vary widely. Choosing which of these resources is to be used requires the specification of a cost-effectiveness limit, based on the cost of alternatives available to the region. This specification, given uncertainty about future demand for electricity, is not entirely straightforward. The rationale for the cost-effectiveness limit, for conservation used in this 1986 plan, is described in the last section of this chapter.

Explanation of Terms

Nominal Dollars and Real Dollars. Inflation distorts the apparent costs of any energy resource, making it appear to cost more if it is purchased at a later time. To control for this distortion, three concepts are used. **Nominal dollars** are the actual expenditure of dollars over time and include the effects of inflation. Nominal dollars are therefore dollars that, at the time they are spent, have no adjustments made for the amount of inflation that has affected their value over time. **Real dollars** adjust nominal expenditures to account for the effects of inflation. By correcting for the impact of inflation on a dollar's purchasing power, a real dollar represents constant purchasing power or "real" value. That is, a real dollar has the same value in 1985 that it has in 1995. To convert nominal dollar costs to real dollar costs, a **base year** is chosen, and all costs are converted to that year's dollars; i.e., the inflation that occurs between years is accounted for. Real dollars can be compared across the board, regardless of the year, because they represent equal purchasing power. The Council used a 1985 base year and a forecast inflation rate of 5 percent per year.

Present Value and Levelized Cost. Even after costs are converted to real 1985 dollars, it is difficult to compare the costs of different resources because costs occur in different years. For instance, a hydropower project involves a large outlay at the beginning for construction, but the fuel (water) is essentially free after completion. An oil or gas-fired combustion turbine has a low construction cost, but the fuel cost is high and may even escalate in real terms (that is, it may get more expensive to run even after removing the effect of inflation). Because of the various resources available in the region and the different capital and operating cost structures associated with each, two methods may be used to place them on even footing for cost comparison. **Present value** and **levelized cost** are the methods used. Present value implies that money has a time value. That is, *when* money is spent is as important as the *amount* of money spent. A dollar is worth more today than it is a year from now because it could be invested during the year to earn a financial return. A dollar a year from now is converted back to its present value by calculating, over the year, the interest or return foregone. Present value then allows the equal comparison of costs of energy resources by using a standard discount rate to convert all costs back to the start of the plan. The uniform series of costs that has the same present value is called a resource's levelized costs. For instance, the amount borrowed from a bank is the present value cost of buying a house; the mortgage payment is the levelized cost.

Discount Rate. The value of money over time to the Northwest ratepayer is used in calculating present values and levelized costs and is called the **discount rate.** The discount rate used for the Council's analyses was an inflation-free real rate of 3 percent. Interest rates consist of a real rate and an inflation premium. To convert nominal costs to present values, a nominal discount rate of 8.15 percent that combines the real discount rate of 3 percent with a 5 percent rate of inflation is used.

The application of all the concepts to a generic coal plant is illustrated in Figures 4-1, 4-2, and 4-3. This is only a numerical example, and the actual costs for this hypothetical coal plant do not necessarily agree with the coal plants used in the resource portfolio. The plant produces 452 average megawatts and comes on line in 2001. The concepts are the same for all resources; only the actual costs would differ. Figure 4-1 shows the **nominal** (actual) expenditures for the plant through construction and during its operation. The line labeled "construction" represents the cumulative construction costs from the start of the project in 1995 to the time it comes on-line in 2001. The total capital cost is $2.3 billion, which includes labor and materials of $1.5 billion and interest of $0.8 billion. For the purposes of this example, the assumption has been made that those costs are repaid to lenders at a uniform rate of $395 million a year beginning in 2001. Those annual payments are represented by the "debt service line." The line labeled "O&M" (operations and maintenance) rises faster than the rate of inflation due to increased costs of fuel. O&M starts at $235 million a year and rises to $1.3 billion per year by the end of the plant's 30-year life. Again, all costs in this chart include the effects of inflation over time.

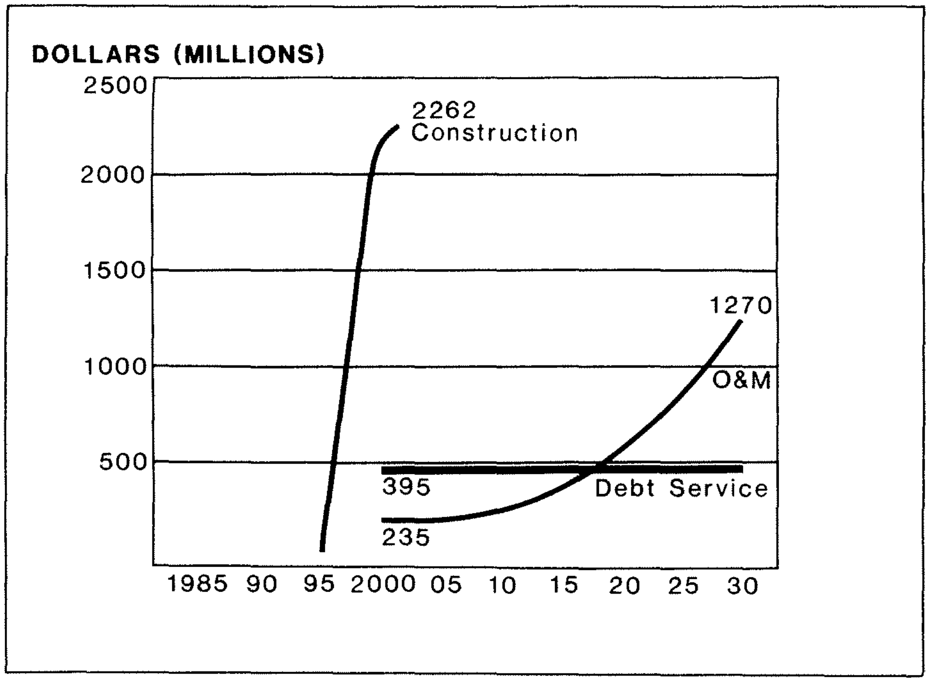


Figure 4-1
Actual Nominal Dollar Expenditures

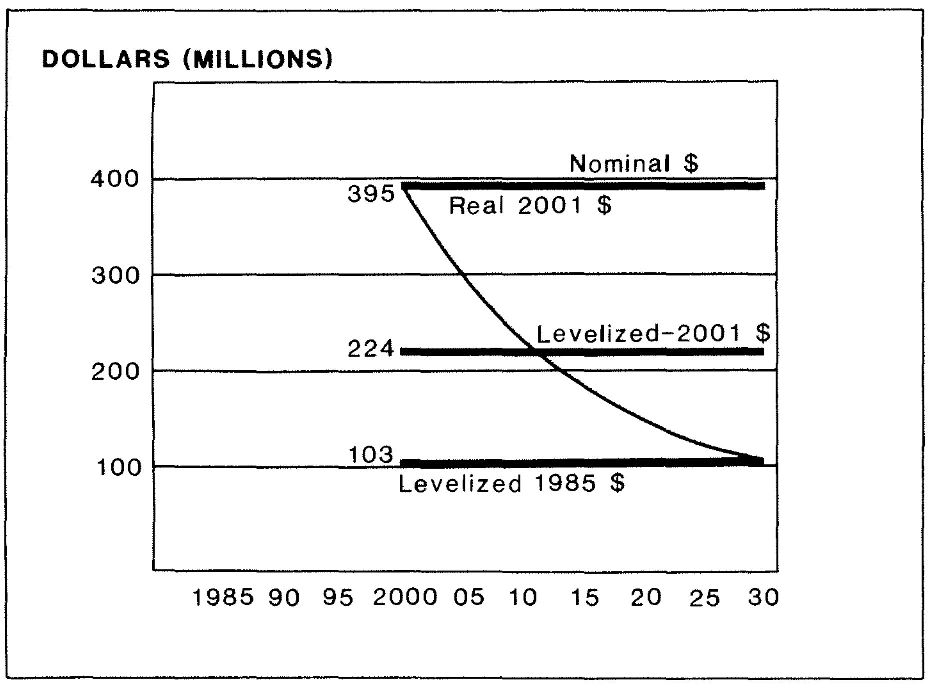


Figure 4-2
Capital Costs

Figure 4-2 takes the debt service line from Figure 4-1 and demonstrates the conversion of nominal dollars to real dollars applying the present value and levelized cost concepts. The line labeled "nominal" represents the repayment of the construction costs from 2001 forward. Those costs include inflation. By converting to real costs, hence adjusting for inflation (line labeled "real 2001$"), the effect of inflation upon the nominal repayment costs is illustrated. Starting in 2001, debt service commences at a fixed payment of $395 million per year. Over the years, repayment is subject to general inflation, but cannot rise to reflect it. Therefore, by the end of the repayment period, the nominal repayment amount of $395 million is worth $91 million in actual 2001 dollars. Inflation has decreased the value of a fixed payment because other wages and costs have risen with inflation. The declining real costs are then annualized to levelized real costs (line labeled "levelized 2001$"). This line represents the constant debt service payments restated to control for inflation. Finally, using the line labeled "levelized 1985$," the debt service payments are restated to the base year 1985 dollars by removing inflation from 1985 to 2001. This process allows the comparison of capital costs of different resource projects by controlling for timing, inflation, and interest rates.

Figure 4-3 goes through the same process, but uses the O&M line from Figure 4-1 to analyze operating costs. Operating costs start at $235 million a year in 2001, and rise in nominal terms (line labeled "nominal") to $1.3 billion by the end of the plant's life. The assumption is made that these costs rise faster than general inflation due to the costs of fuel. Those nominal costs are controlled for inflation, and are represented by the line labeled "real 2001$," which reflects the slightly higher (than inflation) cost increases of fuel over time. Levelizing those costs yields the "levelized 2001$" line. This restates the stream of real dollar costs as an annualized amount. "Levelized 1985$," then, takes the levelized 2001 costs back to 1985 levelized costs by controlling for inflation for those years and using present value.

The various numbers that can describe the same plant are summarized in Table 4-1. The capital cost in nominal dollars is $2.3 billion. The first-year cost, as it would actually affect rates in 2001, the first year of operation, is 16.0 cents per kilowatt-hour. Levelized in 2001 dollars for comparison with other resources that come on-line in 2001, the cost is 12.4 cents per kilowatt-hour. Finally, converted to the base year used in the Council analysis, the levelized cost is 5.7 cents per kilowatt-hour. Table 4-2 gives a sample calculation of the levelized costs of a conservation measure.

It is important to remember that the process described above is used to put resource cost estimates on a consistent basis. It is not a prediction of the impact of any given resource on consumer rates in a given year. In fact, the two example resources mentioned (the hydropower plant and the combustion turbine) could have quite different effects on rates in any given year. The hydropower plant is the most expensive in the first year. Because the capital cost is fixed, its real cost declines through time as other costs and wages rise with inflation. Grand Coulee Dam, for example, was a very expensive project when it was finished in the early 1940s. It is only the succeeding 40 years of inflation that have made the cost of about 0.2 cent per kilowatt-hour relatively cheap compared to the cost of new power plants.

A combustion turbine, on the other hand, has a large percentage of its total cost in its fuel cost. If operated at reasonable levels of annual output, its total cost (capital plus fuel) could be lower in the first years of its operation than the hydropower plant. However, its fuel cost will continue to rise with inflation, if not faster, and its relative rate impact will be much higher 20 years from now than would that of a hydropower plant built now. A resource such as the hydropower plant could have the lowest present value and levelized cost even though it has the highest first-year cost. The Council's resource choice was not based on the rate impacts in any given year but was based on the present-value cost, taking into account the costs and their timing over the life of the resources.

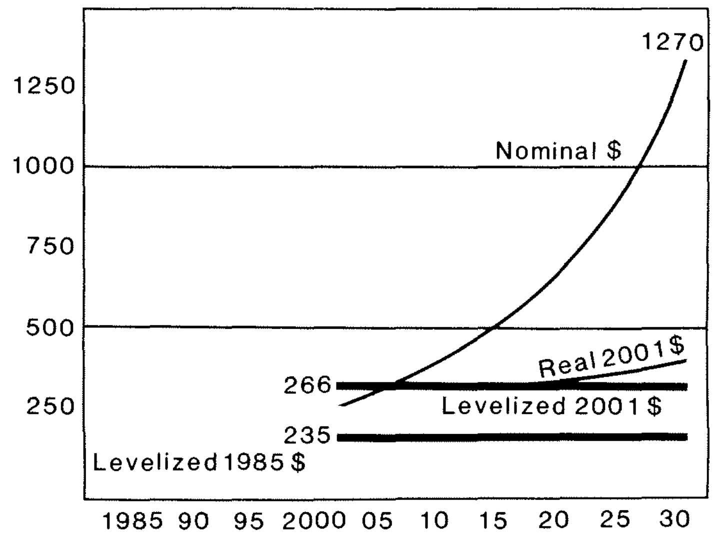


Figure 4-3
Operating Costs

Table 4-1
Cost Analysis Summary

Total Capital Cost	$2.3 billion
Direct Construction	$1.5 billion
First Year Cost	16.0 cents per kilowatt hour
Levelized 2001 dollars (first year of operation)	12.4 cents per kilowatt hour
Levelized 1985 dollars	5.7 cents per kilowatt hour

Table 4-2
Sample Calculation of Levelized Cost of Conservation Measure

$$\text{Levelized Unit Cost} = \frac{\text{Measure Cost 1980 dollars x Annual Capital Recovery Factor}}{\text{Annual Savings in kWh}}$$

MEASURE LIFE (Years)	ANNUAL CAPITAL RECOVERY FACTOR (3% Real Discount Rate)
5	0.218
10	0.117
15	0.084
20	0.067
25	0.056
30	0.051

Formula for Annual Capital Recovery Factor

$$\frac{i(1+i)^N}{(1+i)^N-1}$$

Where N = Measure Life
i = Real Discount Rate

Measure Cost = $ 32

Annual Savings = 435 kWh

Annual Capital Recovery Factor = .117 (10 years)

$$\text{Levelized Unit Cost} = \frac{\$32 \times 0.117}{435 \text{ kWh}}$$

$0.0086/kWh or 8.6 mills/kWh

Levelized cost numbers are appropriate for rough comparison of resources. For the final analysis, the resources' operating characteristics were simulated in the System Analysis Model, and the costs from that simulation converted to present values. This is a very important distinction, because levelized costs do not take into account the changes in system operations that will result when resources with different operating characteristics are added. The system models that the Council uses for evaluating the present value system cost of each resource added to the Northwest's existing system provide the best test of the cost effectiveness of each resource.

Escalation Rates

The regional economic and demographic projections reported in the Council staff report, "Economic, Demographic, and Fuel Price Assumptions" (July 15, 1985), were constructed to be consistent with Wharton Economic Forecasting Associates' national economic forecasts. The Council subscribes to the Wharton national forecasting service and uses Wharton forecasts as the basis for the regional economic scenarios. The specific Wharton forecast used for this 1986 plan is cited in Volume II, Chapter 2. In order to maintain maximum internal consistency among the economic and demographic projections and the financial assumptions developed in this 1986 plan, Wharton projections for the various escalation rates are used wherever feasible.

Fuel Prices. Fuel price escalation rates are used to cost resource alternatives, to project demand for electricity, and to simulate the operation of the regional electrical power system. The 1983 Power Plan used variation in fuel price projections to help generate the range in projections of demand for electricity. Each of the four economic growth scenarios included a unique projection of fuel prices. In contrast, the fuel prices used in costing resource alternatives and in simulating the operation of the power system did not vary with economic growth assumptions. The rationale for this apparent inconsistency was that fuel prices were used to reflect uncertainty about future demand for electricity. The method did not assume that a given demand for electricity could only result from a given set of fuel prices, but that a plausible set of conditions, including fuel prices, could lead to each of the Council's four demand scenarios. There was no implication that these were the *only* conditions that could lead to the demand scenario (e.g., that a medium-low demand scenario could come about only if the medium-low natural gas price assumptions were realized). As a result, fuel cost assumptions for the analysis of resource costs and system operation were not required to be identical to those of each demand scenario.

The region faces considerable uncertainty regarding future prices of fuels, as well as other determinants of costs and performance of generating resources. However, cost-effectiveness analysis would be impossibly complex if the whole spectrum of costs and performance of alternative resources was treated explicitly. The Council's approach was to select the "most likely" values for testing cost effectiveness. Sensitivity studies were done where resource alternatives cost approximately the same.

In the 1986 plan, the Council decided to treat fuel prices as it did in the 1983 plan, using four sets of fuel price assumptions for demand forecasting and a single "best-estimate" set of assumptions for the resource costs and system operation work. Fuel price assumptions for each of the demand scenarios were developed by Council staff as part of the economic-demographic projections. The "best-estimate" set of price escalation assumptions for the resource cost and system operation analysis was obtained for oil and gas by averaging the escalations in the medium-high and medium-low scenarios. Coal price escalations are based on Wharton projections of mine-mouth coal costs and Wharton projections of components of coal transportation costs. Price escalation assumptions used in resource evaluation and system analysis, along with the assumptions used in the 1983 Power Plan, are shown in Table 4-3. All assumptions were presented for extensive public review prior to their adoption.

Table 4-3
Fuel Price Escalation Assumptions
Average Annual Real Rate of Growth (%)

	1983 PLAN (1980-2002)	1986 PLAN (1985-2005)
Natural Gas	2.4	1.8
Oil	1.8	1.6
Coal	1.5	1.0

Construction Costs. Escalation rates for construction costs are needed to estimate future resource costs, which influence both system operation cost and demand projections (the latter through the effect of construction costs on electricity prices). Escalation rates for construction costs of different resources influence the choice of new resources. The overall level of construction costs for all resources influences the number of new resources needed. Based on Wharton projections and Portland General Electric comments, the Council used a 0.4 percent real escalation rate for all resource construction. This compares with the 0.8 percent real escalation rate for construction costs of coal plants and zero percent real escalation in residential conservation costs, used in the 1983 plan.

Inflation. The rate of inflation affects all components of the Council's analytical process. It is impossible to project the effect of changes in costs without considering the changes from both the real and nominal perspective. For example, prices of electricity are determined in part by historical (nominal) construction costs, but projection of demand is usually based on the inflation-corrected (real) path of electricity prices. The necessary translation between real and nominal values requires a set of assumptions regarding the rate of inflation. Economic forecasters generally have lowered their forecasts of long-term inflation, compared to forecasts in 1983. This 1986 plan uses the average inflation rate of 5 percent from the Wharton forecast (in comparison to 6 percent in the 1983 plan).

Cost of Capital

Home Mortgages. One of the most intensively analyzed resources for future electricity conservation is improved thermal efficiency of new homes. The cost of this improved efficiency, both to the individual homeowner and to the region, is influenced by the extra construction cost due to energy efficient measures. These increased costs are mortgaged, and therefore the present value cost is a function of the interest rate charged on the mortgage. Mortgage rates, as projected by Wharton, change over time as the overall state of the national economy changes. Because these rates influence the costs of thermal efficiency, the use of varying mortgage rates would result in varying levels of optimal thermal efficiency. From a practical perspective, this would complicate the planning process prohibitively, so the choice of a single mortgage rate assumption that is a reasonable long-run average seems more appropriate. The Council used a 6.2 percent real after tax rate or 11.5 percent nominal before tax for the mortgage rate assumption, which is the approximate 1994 rate projected by Wharton. This rate compares with the 6 percent real assumption used in the 1983 plan.

Resource Acquisitions by Bonneville. The cost of capital for resources acquired by Bonneville for the region should reflect the actual regional cost of capital for the companies or organizations expected to develop the resources. The region's cost of capital is reduced by any federal tax benefits accruing to the owner of the resource, but includes any risk premium which the financial markets can be expected to attach to the investment. The assumptions for the real cost of capital in the 1983 plan, based on suggestions by the region's utilities, were 4 percent for debt financed by investor-owned utilities, 7.5 percent for equity of investor-owned utilities, 3 percent for debt financed by publicly-owned utilities, and 3 percent for Bonneville borrowing. Based on Wharton projections of the cost of capital and comments from Portland General Electric, the Pacific Northwest Utilities Conference Committee, and Bonneville, these assumptions now appear low. Therefore, the Council adopted higher values of 7 percent, 8.5 percent, 4 percent, and 5 percent, respectively, for these real costs of capital. Details of the comments and analysis leading to these assumed values are available from the Council's staff and the Council's issue paper of January 4, 1985, "Assumptions for Financial Variables."

Ownership and Capital Structure. The net financial cost of resources is a function both of who owns them and what capital structure is used. The generic coal plants and combustion turbines used in this plan were assumed to be owned 100 percent by the investor-owned utilities. The Council assumed that, with Bonneville acquisition available under the Act, generating projects would be financed using a capital structure of 80 percent debt and 20 percent equity.

Conservation, including the model conservation standards, was evaluated using utility financing. This assumption may be a conservatism in the case of the standards, which the Council ultimately expects to be embodied in building codes and financed directly by the consumer at lower rates. The capital structure for conservation assumed regional cooperation. Forty percent of the conservation was assumed to occur in public utility service territories and to be financed by Bonneville. The remaining 60 percent, in the investor-owned utility service territories, was assumed to be financed 75 percent by Bonneville, under its cost-sharing principles, and 25 percent by the investor-owned utilities at their normal ratio of 50 percent debt and 50 percent equity.

The small renewables, small hydropower and cogeneration were assumed to be PURPA resource purchases at 4.0 cents per kilowatt-hour. There was no explicit finance cost attached to these resources.

Table 4-4
Discount Rates Used for Present Value by Source

ORGANIZATION	DISCOUNT RATE	TYPE OF PROJECT
Northwest Power Planning Council (1983 20-year Plan)	3% real	Power system analysis
Bonneville Power Admin.	3% real	Power system analysis
U.S. Office of Management and Budget	10% real	Federal government projects (water projects use lower discount rate)
Pacific Northwest Utilities Conference Committee (PNUCC)	3% real	Power system analysis
Intercompany Pool	7.1% real	Transmission system investment (investor-owned utility perspective)
Natural Resources Defense Council (NRDC)	1% real	Zero-risk social discount rate
	2% real	Costing of conservation
	3.5% real	Evaluation of investments of risk comparable to average common stock
Robert C. Lind, et. al., Discounting for Time and Risk in Energy Policy	1% real	Evaluation of investments of risk comparable to U.S. Treasury bills
	2% real	Evaluation of investments of risk comparable to long-term U.S. government bonds
	4.6% real	Evaluation of investments of risk comparable to "market portfolio"

Discount Rates

The Social Discount Rate. A central feature of the Council's consideration of alternative strategies for providing adequate electricity to the region is the comparison of the strategies' costs. Each strategy's stream of costs must be translated into a present value that can be compared to the present value of each of the other strategies. To accomplish this translation, it is necessary to use a discount rate that represents society's willingness to exchange consumption now for consumption in the future. For example, if the region puts the same value on $1.00 of consumption now as $1.08 a year from now, the region's rate of time preference, or its "nominal social discount rate," is 8 percent. This would then be the appropriate nominal discount rate to use in converting regional power system costs to present values.

While the concept of the social discount rate is fairly straightforward, its application is more complicated. The principal difficulty is that it is not possible to observe the social discount rate directly; it must be imputed from rates of return on investments that are observable. In a perfectly competitive economy, the social discount rate would be equal to the market rate of interest, but in the real world things are less simple. For example:

1. Both corporations and individuals pay income taxes. Income taxes mean that when a consumer postpones current consumption to invest, the future consumption that investment makes possible is less than that implied by the (pre-tax) return to that investment. As a result, individuals investing in a project with a 10 percent rate of return are not demonstrating a rate of time preference of 10 percent, but rather a somewhat lower rate.

2. All investments are risky, and this riskiness varies from one investment to another. This is reflected in varying costs of capital from one investment to another. Ordinarily, the rate of time preference is understood to be the willingness to trade (certain) consumption now for (certain) consumption in the future. For regional planning, however, the Council would like to use a rate that reflects the uncertainty the region confronts as it evaluates resource costs decades from now. The Council is faced, then, with the task of determining how much of observed rates of return are risk premiums, and how much risk premium should be included in the regional social discount rate.

3. Inflation complicates the interpretation of observed costs of capital in terms of the social discount rate. Investors can be expected to insist on a rate of return that, in addition to covering their rate of time preference, tax obligation and risk premium, will also cover the expected rate of inflation. Thus, observable (nominal) costs of capital, even after income taxes and risk premiums are taken into account, will be greater than investors' rates of time preference by the amount of inflation they expect. Attempts to estimate the magnitude of inflation's effect on the cost of capital are complicated by the fact that although the inflation rate that the economy actually experiences can be measured, the inflation rate that investors expect cannot.

For reasons such as these, the estimation of an appropriate social discount rate is fairly complicated. A typical estimate might begin with some measure of cost of capital for low-risk investments, translated to an after-tax return based on some assumed tax rate for the representative investor. This rate of return would be translated to real terms by some estimate of expected inflation, and the risk premium judged appropriate for regional power resource investments added. Each step in this process requires judgments (e.g., which investments are low-risk, should any year's data be excluded, what is a representative investor, how is expected inflation related to historical inflation, etc.) that affect the results of the process. Table 4-4 includes a sample of discount rates suggested or used by various organizations.

While it demonstrates a lack of perfect agreement among the sources represented, Table 4-4 also indicates a rough range of uncertainty for the social discount rate. Two of the sources, the Natural Resources Defense Council and the book *Discounting for Time* and Risk in Energy Policy, describe an estimation process much like the one outlined above. Both analyze data on long-run (1920s to 1970s) average returns to investments of various levels of risk and both estimate real after-tax returns for the lowest-risk class of investment. They both conclude that these yields have varied from −2 percent to +2 percent, depending on the historical period. Further, they conclude that 1 percent real is a reasonable estimate for a long-run average return to low- or no-risk investments.

Given these estimates, the discount rate of 3 percent, which has been used by the Council, Bonneville, and PNUCC for power system analysis in the past, implies that the riskiness of power system investments justifies a 2 percent risk premium. Values used for the Intercompany Pool and for the U.S. Office of Management and Budget reflect the perspectives of the Pacific Northwest's investor-owned utilities and the federal government. These are different from the perspective of the region's consumers. Therefore, it is reasonable for discount rates for these organizations to differ from those used for the Council's power system analysis.

The 3 percent assumption for the social discount rate appears to be reasonable for the 1986 plan. Table 4-5 provides a comparison of the adopted real values for cost of capital and discount rate, their nominal equivalents and several reference values.

Consumers' Implicit Discount Rates; Demand Forecasting. The concept of consumers' implicit discount rates appeared when analysts looked at consumers' fuel and efficiency choices from the perspective of investment behavior. Viewed as an investment, for example, an extra layer of insulation in a homeowner's attic has a cost incurred either as a lump sum (if paid for out of current income) or a stream of payments (if money is borrowed to pay for it). The insulation produces a stream of benefits in the form of energy savings. If the rate of return of the least attractive conservation measure adopted by consumers were known, given the energy costs they face, that rate of return could be used to predict the conservation measures consumers will adopt if their energy costs change.

Table 4-5

Comparative Values of Financial Variables

VARIABLE	CURRENT[a] NOMINAL VALUE	CURRENT REAL VALUE	ADOPTED REAL VALUE	ADOPTED NOMINAL VALUE
Mortgage	12.9%	7.5%	6.2%[c]	11.5%
IOU Debt	13.5[d]	8.1	7.0	12.4
Public Debt	10.1[e]	4.9	4.0	9.2
Treasury	11.3	6.0	5.0	10.3
IOU Equity	15[f]	9.5	8.5	13.9
Consumer Discount Rate	—	—	10.0[g]	19.4
Social Discount Rate	—	—	3.0[g]	10.2[h]

FURTHER COMPARISONS
Wharton Forecasts

VARIABLE	DECEMBER 1984 FORECAST 1994 NOMINAL	1994 REAL[i]	AUGUST 1984 FORECAST 1995 NOMINAL	1995 REAL[j]
Mortgage	11.7	6.6	10.6	5.1
IOU Debt	13.4	8.2	12.4[k]	6.8
Public Debt	8.8[l]	3.6	8.0[l]	2.6
Treasury	10.5	5.5	9.5	4.3

[a] Current values from Wall Street Journal, week of February 4, 1985, unless noted.

[b] Real/nominal conversions made using inflation rate of 5 percent.

[c] This is a before tax real rate. Assuming a 20 percent marginal tax bracket, the 11.5 percent nominal rate is equivalent to 9.2 percent after tax. Correcting for 5 percent inflation, the after tax real rate would be 4.0 percent.

[d] Current value for A-rated utility debt 12.8 percent; Northwest investor- owned utilities are lower rated, PNUCC suggested current values at 12-14 percent, Portland General Electric (PGE) suggested current value of 14.5 percent.

[e] Merrill Lynch retail electric 20-year revenue bond index in The Wall Street Journal; PNUCC suggests current values of 10-12 percent.

[f] PNUCC suggested current values of 15-15.5 percent, PGE suggested current value of 14.5 percent.

[g] After-tax rates (all others pre-tax)

[h] Nominal discount rate calculated from real after-tax rate using a 20 percent marginal tax rate.

[i] Real value calculated with 1994 forecast inflation of 4.74 percent.

[j] Real value calculated with 1995 forecast inflation of 5.23 percent.

[k] Baa utility yield in 1995 calculated using Aaa yield + 2.0 percent, which is approximate difference in 1994 forecast (Baa series not in 1995 data).

[l] Retail electric municipal yield calculated using average general obligation municipal yield + 0.5 percent, which is the approximate current difference between general obligation municipals and retail electrics.

Table 4-6

Estimates of Average Implicit Discount Rates by Source

SOURCE	IMPLICIT RATE	DECISIONS ANALYZED
Berkovic, Hausman and Rust	25%	Fuel choice (heating system, PNW)[a]
	33%	Fuel choice (water heat, PNW)
Cole and Fuller	26%	Thermal integrity (national)
	12%	Thermal integrity (PNW)
	61-108%	Efficiency of refrigerators
Corum and O'Neal	10-21%	Thermal integrity (national, 3 fuels)
	7-20%	Thermal integrity (Seattle, 3 fuels)
Goett		Fuel choice & heating system,
	4%	national (w/central AC)[b]
	21%	national (w/o central AC)
	3%	PNW (w/ central AC)
	27%	PNW (w/o central AC)
	7%	Fuel choice for water heat, national
	3%	Choice of central AC, national
Hausman	24-26%	Efficiency of room air conditioners
Johnson	4%	Influence of total utility bills on resale price of existing house
Arthur D. Little, Inc.	10%	Windows and doors
	32%	Other thermal integrity
Meier and Whittier	34%	Efficiency of refrigerators (Pacific region of U.S.)

[a] PNW = Pacific Northwest.

[b] AC = Air conditioning.

Table 4-7

Input Data for Consumers' Implicit Discount Rates

	INITIAL LEVEL	LOWER BOUND
Thermal Integrity		
High scenario	50% real	7% real
Medium-high scenario	40% real	7% real
Medium-low scenario	30% real	7% real
Low scenario	20% real	7% real
Appliance Efficiency		
High scenario	85% real	85% real
Medium-high scenario	65% real	20% real
Medium-low scenario	65% real	7% real
Low scenario	55% real	7% real

A number of estimates have been made of this rate of return, or of what is commonly called the consumer's "implicit discount rate." As Table 4-6 demonstrates, the estimates vary widely (from as low as 3 percent real to over 100 percent real). Most estimates of the implicit discount rate, however, are significantly higher than the usual range of estimates of the social discount rate, which commonly falls between zero percent real and 10 percent real. In a perfectly competitive economy consumers might undertake all conservation investments with rates of return greater than the social discount rate. However, this evidence indicates that in the real world consumers pass up many conservation investments that have expected rates of return higher than any estimate of the social discount rate. The gap between estimated implicit discount rates and the estimates of the social discount rate has been attributed to various forms of market imperfections (e.g., lack of information about the performance of efficient equipment, uncertainty about resale value of more efficient houses, and limited access to loans for conservation investments).

The demand projections in the Council's 1983 plan used a single set of implicit discount rate assumptions to simulate consumers' efficiency choices. In the residential sector, the initial value of this discount rate for thermal integrity, space conditioning efficiency, and water heating efficiency decisions was 30 percent real. For efficiency decisions for appliances such as refrigerators and freezers, the initial value of this discount rate was set at 65 percent real. All implicit discount rates were simulated to drop significantly (by one-half or more) as fuel prices increased, and consumers became more concerned and informed about their efficiency choices. These assumptions were based on research results and judgment and were the most reasonable single set of assumptions the Council could make at the time. In view of the range of estimates demonstrated in Table 4-6, the Council, in this 1986 plan, used implicit discount rate assumptions that varied by forecast scenario.

For each scenario, two pairs of inputs are required, one pair for thermal integrity decisions and another pair for appliance efficiency decisions. The first value in each pair is the initial level of the implicit discount rate. The discount rate is adjusted during operation of the model as fuel prices change through time and the second value is a lower bound on the range of possible adjustments. Given the projected fuel prices in this plan, implicit discount rates generally stay closer to their initial levels than to the lower bounds. The assumptions are listed in Table 4-7.

Consumers' Discount Rates; Evaluation of Model Conservation Standards. Another important part of the Council's analysis is to examine the effects of the model conservation standards from the consumer's point of view. In the 1983 plan, this analysis used a discount rate of 10 percent real. This value is in the lower part of the range of estimates shown in Table 4-6, and it is lower than the values used in the projections of demand for electricity. It should be pointed out, however, that the appropriate discount rate for evaluation of the standards from the consumer's perspective is only roughly comparable to the discount rates estimated in Table 4-6 and to those used in the demand projections.

First, most of the discount rates in Table 4-6 were estimated using simplifying assumptions which ignored the effects of mortgage financing. This is inconsistent with the detailed examination of cash flow—an important part of the Council analysis of the standards. Perhaps more importantly, the standards may themselves change the appropriate discount rate to use in evaluating effects on consumers. The relatively high implicit discount rates demonstrated in Table 4-6 are commonly attributed in part to consumers' perceived risk. This perceived risk is due to the consumers' lack of reliable information regarding the performance of more efficient equipment and structures. In the case of the standards, there is evidence that the region has learned a great deal and is in the process of learning even more about the costs and performance of thermal integrity measures in Pacific Northwest climates.

Table 4-8
Summary—Financial Assumptions, 1983 Plan and 1986 Plan

VARIABLE	1983 PLAN	1986 PLAN
Escalation Rates		
Natural gas	2.4% real	1.8% real
Oil	1.8% real	1.6% real
Coal	1.5% real	1.0% real
Construction		
Residential conservation	0.0% real	0.4% real
Other resources	0.8% real	0.4% real
Inflation	6%	5%
Cost of Capital		
Home mortgages	6% real	6.2% real
Resource acquisition		
Debt (investor-owned utilities)	4% real	7% real
Equity (investor-owned utilities)	7.5% real	8.5% real
Debt (public utilities)	3% real	4% real
Debt (Bonneville borrowing)	3% real	5% real
Discount Rates		
Social discount rate	3% real	3% real
Consumers' implicit rates		
Thermal integrity	Declining from 30% real	Varying by economic scenario
Appliance efficiency	Declining from 65% real	Varying by economic scenario
Evaluation of model conservation standards from consumers' perspective	10% real	10% real

This new knowledge could be expected to increase consumers' confidence in the performance they expect from the measures incorporated into their homes. To the degree this is so, the implicit discount rate for homebuyers would be lower than the level of two or three years ago. This is another reason not to rely on the values in Table 4-6, which reflect historical situations in which consumers had significantly less information regarding energy conservation investments.

There are good reasons to consider a discount rate lower than 10 percent for the evaluation of the standards from the perspective of the consumer. If the appropriate social discount rate for investments of risk comparable to common stock is in the 4-5 percent real range, as Table 4-4 suggests, there is the question of whether consumers view houses meeting the standards as so much riskier than common stock as to justify a 10 percent real discount rate. Even though 10 percent was appropriate for the 1983 plan, the substantial improvement in information about thermal integrity investments of the last two years would suggest a reduced discount rate now. The other side of the risk from the consumers' perspective, of course, is that owners of houses meeting the standards are largely insulated from unexpected increases in energy costs. In the climate of legal and political uncertainty affecting the region's expected electricity prices, this reduction in risk will be valued by many consumers.

With these arguments in mind, the Council will continue for the present to use the 10 percent rate. As shown in Table 4-5, a discount rate of 10 percent real is the after-tax equivalent of a rate of return to the consumer of 19.4 percent in nominal terms before tax. This is a higher rate of return than is available to most consumers. The use of the 10 percent real rate thus requires that homebuyers receive a rate of return on their investment in the improved efficiency of homes built to the Council's standards, which is quite attractive compared to other investment opportunities available to them.

The financial variable assumptions described in this chapter are summarized in Table 4-8. These assumptions have been influenced in many cases by public comment during the development of the 1986 plan.

Resource Cost Effectiveness

All resources included in the Council's resource portfolio are selected based on their relative cost effectiveness. Cost effectiveness is a measure of the relative cost of the contribution of a resource to the region's electrical power system, and is most frequently measured in cents per kilowatt-hour. The Council has chosen, as the appropriate measure of cost effectiveness, the net present value of each resource in the resource portfolio. The Council uses the levelized life cycle cost of each resource only as a preliminary screening tool to select resources for detailed study in the resource portfolio analysis.

In selecting the amount of resources to be included in the Council's plan, the Council uses cost-effectiveness criteria. These cost-effectiveness criteria have three primary roles in the development of the Council's resource portfolio. The first role is in determining which measures to include in the model conservation standards. The Northwest Power Act directed the Council to develop model conservation standards that include *all* cost-effective conservation measures. In evaluating individual conservation measures for their potential inclusion in the MCS, the Council uses a cost-effectiveness criterion that selects those measures that are lower cost than the expected cost of other resources that would be included in the Council's Plan, if the conservation measures are not included in the MCS. Because this criterion applies to actions taken today and over the next few years, the evaluation was done using the Council's Decision Model, which accounts for the present value of actions in the near-term given the uncertainties in the resource portfolio. MCS measures are lost opportunity resources and, with their seasonal and load-tracking characteristics, were evaluated in the Decision Model to determine the expected present value of incremental MCS savings. The results were adjusted by the transmission system losses and other costs, described below.

The second role of cost-effectiveness criteria is in sizing the amount of resource that may be available from discretionary conservation and generating resources in the future. Discretionary conservation and generating resources are resources that can be acquired when the region's power system has a need for additional energy capability. This criterion is not used to determine actions to be taken today, but rather is used only to size the total cost-effective non-coal resource. Here the evaluation was made using the System Analysis Model to calculate the cost of a coal plant (the Council's marginal resource) put in place in the year 2000. For this purpose, the marginal coal cost was discounted only to the in-service date of the plant, rather than to the present.

The third role of cost-effectiveness criteria is in selecting among near-term acquisitions those opportunities that are cost effective for the region to secure now. These near-term acquisitions are difficult to predict in advance; however, a specific cost-effectiveness criterion will allow the region to select only those that contribute value to the region's power system. This criterion, like the first, is used to evaluate actions to be taken today or in the near future. In calculating the value of near-term acquisition, the Decision Model was used by assuming resources of different lives are acquired in either 1985 or 1990. These resources, of course, did not have the seasonal or load-tracking characteristics or the administrative and other cost adjustments mandated in the Act that apply to marginal MCS measures. The present value of these resources was calculated assuming acquisition in the 1985-1990 time period.

In the following sections, each of these roles of cost effectiveness will be discussed: 1) the cost-effectiveness criteria used in evaluating the model conservation standards; 2) the cost-effectiveness criteria used by the Council in sizing the amount of discretionary resources that will be available in the Council's resource portfolio; and 3) the role of cost-effectiveness criteria in selecting among near-term resource acquisition opportunities.

Cost Effectiveness of the Model Conservation Standards

Figure 4-4 illustrates how the Council systematically approaches the evaluation of the cost effectiveness of the model conservation standards. This figure shows three basic analytical efforts that the Council conducts in evaluating the MCS. The first of these is an evaluation of the cost and energy savings expected from each measure that might be included in the MCS. The second analytical effort involves the evaluation of the value of lost opportunity resources in the Council's resource portfolio. The third analytical effort evaluates the value of marginal MCS investments in the region's resource portfolio.

Each measure that potentially may be included in the MCS is evaluated for its expected cost. Considerable uncertainty exists with respect to financial assumptions, the accuracy and validity of cost data, the amount of administrative and overhead costs needed to secure the measure, and the definition of exactly what a measure includes. Given each of these aspects, the Council must choose the most likely assumption on which to base further analysis. The financial assumptions involved in evaluating the MCS and other resources were discussed earlier in this chapter. The financial characteristics are different for each individual consumer; however, the Council must evaluate the MCS based on assumed typical characteristics for an average regional consumer.

In evaluating the cost of each individual measure, the Council has accumulated a variety of cost information. In reviewing this cost data, it is clear that significant uncertainty exists with respect to the range of cost that is likely to be experienced on each measure. In spite of this significant uncertainty, the Council has selected the median Residential Standards Demonstration Program (RSDP) cost for most measures that are potential candidates for inclusion in the MCS. For the measures dealing with infiltration control and management of indoor air quality, the Council used the lower quartile of RSDP costs, except in climate zone III where median costs were used to reflect the higher cost of installing heat recovery ventilators that can operate in the severe climate. This was done to account more accurately for the substantial cost reductions that have been seen in communities that have adopted the MCS. These are being achieved as builders learn to install the measures more cost effectively and the market infrastructure for heat recovery ventilators is developed.

In reviewing administrative and overhead costs for conservation programs, the Council has decided these costs do not change as the marginal measure changes, but are instead more a function of the administrative characteristics of offering a conservation program. Because the administrative and overhead costs contribute to the average cost of each conservation program, and not incrementally to the marginal measure, the Council includes administrative and overhead costs in the average cost of the MCS program.

In defining measures to be included in the MCS, the Council has tried to select incremental actions that builders might take to improve the efficiency of new buildings. This process is difficult in that measures are not homogenous actions that are simply evaluated individually. Previously, the Council has evaluated as a single measure the combination of two individual actions: the inclusion of a vapor barrier and a heat recovery ventilator (HRV) to compensate for indoor air quality problems. Although it is likely that these two actions are independent and should be evaluated separately, they are evaluated as a single measure in this plan. Because this issue was not fully discussed during the development of this plan, the Council will review, through a public process, the appropriateness of separating these measures in the future.

The expected energy savings must be evaluated for each measure that potentially will be included in the MCS. In evaluating residential measures, a heat loss model is used to estimate the energy savings of each measure. Considerable uncertainty exists over the actual savings that each measure might include when installed in a building. Here again, the Council must deal with a typical structure operated in a typical way and located at a typical site within each climate zone. The actual performance that is likely from each measure in an actual building could be substantially different than the amount forecast by these models.

The Council has validated these models on a sample of actual buildings, and the average savings estimates appear to be accurate. However, the specific performance in each building could differ substantially from the Council's predictions due to a number of factors: differences in building type; location; how the owner chooses to operate the building; the application of other heating sources, such as wood heat; different appliance efficiencies; and possible room closures. Each of these changes from the typical conditions assumed by the Council will result in a different set of expected energy savings from the measures that might be included in the MCS.

While there are a number of factors in this analysis that cannot be known with certainty, the challenge of power planning is to make informed decisions in the face of substantial uncertainty. For this reason, the Council selects a set of typical assumptions using the best cost information available and the best heat loss models available to estimate the levelized life cycle cost of each measure that could be included in the MCS. In addition, when a package of measures has been

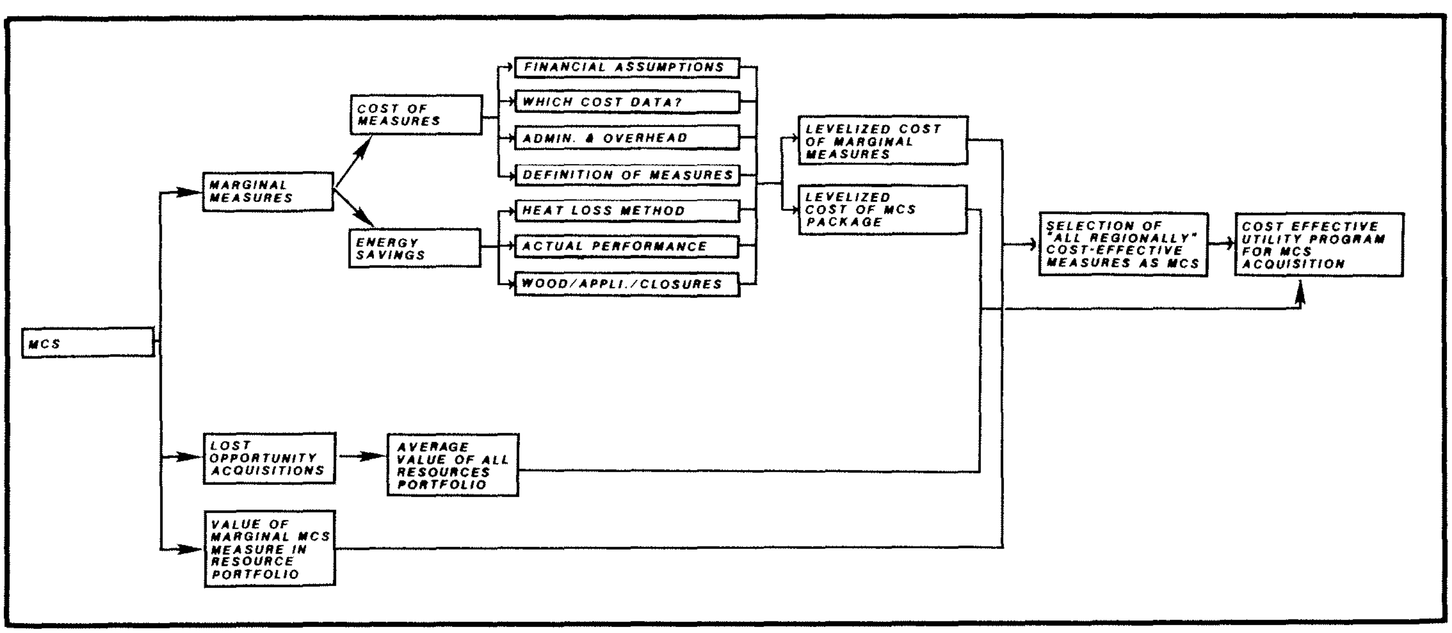


Figure 4-4
Cost-Effectiveness Method for Evaluating the MCS

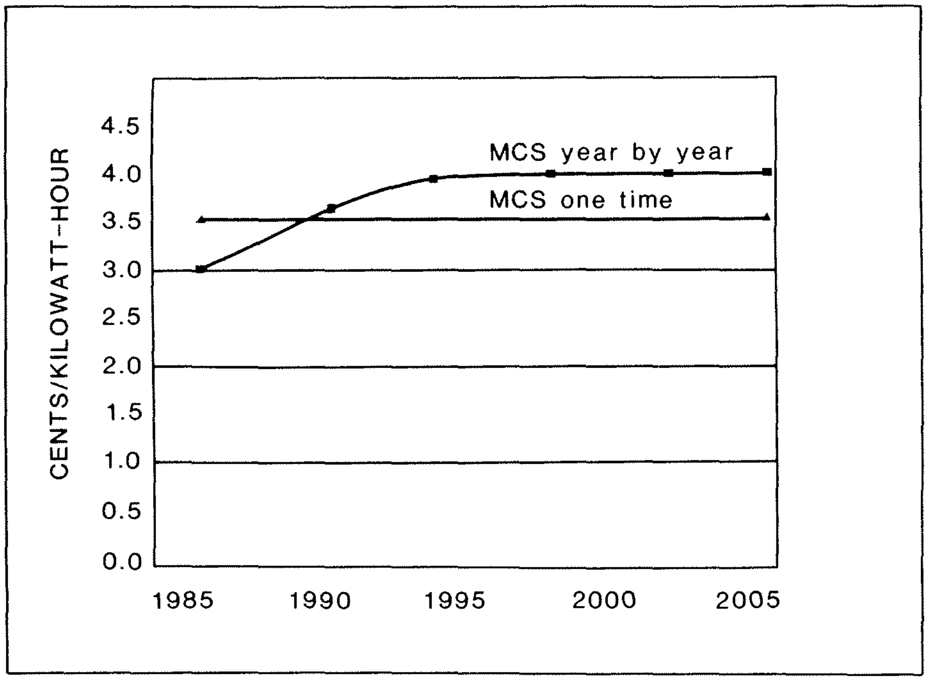


Figure 4-5
Estimates of the MCS Program Marginal Value

selected to be included in the MCS, the Council evaluates the levelized life cycle average cost of the MCS, including administrative and overhead costs.

In evaluating the cost effectiveness of the MCS, the Council first evaluates the marginal value to the Council's resource portfolio of an incremental investment in MCS savings. Figure 4-5 illustrates the results of studies of the marginal value of MCS savings using the Decision Model. A curve and a straight line are shown in this figure. The curve shows the expected value of a marginal MCS investment in each year over the 20-year planning horizon. This figure shows that the marginal value of the MCS in 1986 is approximately 3.0 cents per kilowatt-hour, and that value increases to nearly 4.0 cents per kilowatt-hour in 1995. The value of marginal MCS investments beyond 1995 is approximately flat at 4.0 cents per kilowatt-hour. In other words, if the MCS could be changed year-by-year, the region should begin with an MCS defined to secure all measures costing less than 3.0 cents per kilowatt-hour in 1986. As shown by this curve, the region would expect to change the MCS each year until 1995 when the MCS would be defined to secure all measures costing less than 4 cents per kilowatt-hour.

The horizontal line in Figure 4-5 is an estimate of the marginal value of increased MCS savings. This estimate is based on the discounted present value of all future resources in the plan that are displaced by greater MCS investments. The horizontal line illustrates that the expected present value of a marginal MCS measure is approximately 3.5 cents per kilowatt-hour. This is the Council's best estimate of the marginal value of MCS measures that must be selected today and cannot easily be changed year-by-year. Therefore, if the Council and the region must select a definition of the MCS that is not easily changed year-by-year, but must achieve all cost-effective energy savings in the Council's resource portfolio over the next 20 years, the MCS, based on this analysis, should be set at securing all measures costing less than 3.5 cents per kilowatt-hour.

Because these values do not include the 10 percent cost advantage for conservation in the Act, and the appropriate adjustments for transmission and distribution system cost and losses, the appropriate criteria for evaluating the cost effectiveness of the marginal MCS measures is 3.5 cents increased by the 10 percent advantage in the Act, 7.5 percent for transmission and distribution system losses, and 2.5 percent for transmission and distribution system costs. With these adjustments, the appropriate cut-off for the marginal MCS measure is 4.2 cents per kilowatt-hour in levelized life cycle cost.

Because of the substantial range of uncertainty surrounding each of the individual calculations involved in measuring the cost effectiveness of the MCS, the appropriate range for careful inspection of measures selected to be part of the MCS is established by the Council to be between 4.0 and 4.5 cents per kilowatt-hour. The Council carefully reviews measures in this range of cost and exercises judgment on which of these measures to include. Marginal MCS investments that cost more than 4.5 cents should not be considered further until the costs or performance improve. Measures less than 4.0 cents per kilowatt-hour are clearly cost effective and should be included in the MCS. As a practical matter, only the HRV and infiltration control package in climate zone 1 was a close call. This package in a typical 1,850 square foot house was estimated to cost 4.1 cents per kilowatt-hour. The Council decided to include these measures for health and safety reasons and to monitor their cost effectiveness closely.

Once the Council has selected all of the measures to be included in the MCS, the Council also evaluates the average cost effectiveness of any MCS program designed to secure MCS-level construction over the next several years. This is particularly important at this time because, with this plan, the Council is initiating a new MCS proposal that focuses on a Bonneville/Utility MCS Program. This MCS program is designed to market MCS-level construction and to provide financial assistance to builders. The goal is to secure the MCS as a lost opportunity resource over the next several years, and also to assist the region's building industry in making the transition to more efficient construction.

In evaluating the Bonneville/Utility MCS Program, the Council evaluated the cost effectiveness of acquiring MCS savings during the period from 1986 until 1990, again using the Decision Model. Figure 4-5 showed that the expected value to the Council's resource portfolio of MCS-level savings during 1986 was approximately 3.0 cents per kilowatt-hour. Adjusting this for the 10 percent advantage in the Act, transmission and distribution system costs and losses would mean that an

MCS utility program operated during 1986 should secure MCS-level savings at no greater than 3.6 cents per kilowatt-hour. This same calculation would escalate to a level of 4.4 cents per kilowatt-hour in 1990. For the MCS utility program, the Council estimates show that MCS-level construction can be achieved at an average cost of about 3.0 cents per kilowatt-hour. This is much less than the expected value of MCS savings over the next five years.

The Council therefore uses two independent tests of the cost effectiveness of the MCS. The first is the cost effectiveness of the marginal measure in the MCS. In making this evaluation, the Council uses the expected value in the Council's resource portfolio of the marginal measure in the MCS. The second test is to evaluate the cost effectiveness of any utility program used over the next several years to secure MCS-level construction. These programs will be evaluated to ensure that the level of financial assistance offered to secure MCS-level construction does not exceed the average value of MCS savings during the next several years. The Council has found that the MCS, as they are currently formulated, successfully meet both cost-effectiveness evaluations.

Cost Effectiveness of Discretionary Resources

The process for determining the cost effectiveness of discretionary conservation and generating resources is shown in Figure 4-6. This analysis basically falls into two categories. The first is the resources the region is currently acquiring (at this time only the residential weatherization program) and all other discretionary resources included in the Council's plan. The primary function of this analysis in the Council's planning is to size the amount of each resource that the Council expects to have available in the future in order to meet regional load growth. The cost-effectiveness criteria for discretionary resources are used to cut off the resource supply functions for resources included in the Council's portfolio. Because most of these resource acquisitions will be made when the region is assumed to need resources, it is important that the amount of discretionary resources that are estimated to be available is consistent with other resources that will be acquired at the same time. Since many of the discretionary conservation programs and generating resource programs are begun during the time when the Council's resource portfolio also calls for securing options on new coal plants, the Council sizes the amount of conservation and generating resources included in the plan based on the estimated costs of a new generic coal plant in the region's power system.

The residential weatherization program is a discretionary resource that is currently being acquired. The Council believes that the capability to secure this resource should be maintained by continuing to operate the program at a minimum viable budget. While the program is operating primarily to maintain capability, it should continue to secure all measures that would be required when the program is needed. For this reason, the Council believes that even under minimum viable operations, the residential weatherization program should be securing all measures up to the cost of a new coal plant.

Current estimates of the cost of a new generic coal plant in the region's power system, using the System Analysis Model, are between 4.0 and 4.5 cents per kilowatt-hour discounted to the in-service date of the coal plant. The Council therefore truncates supply functions for all discretionary generating resources at 4.5 cents per kilowatt-hour. This figure needs to be increased for new conservation programs in order to take into account the 10 percent advantage in the Act and

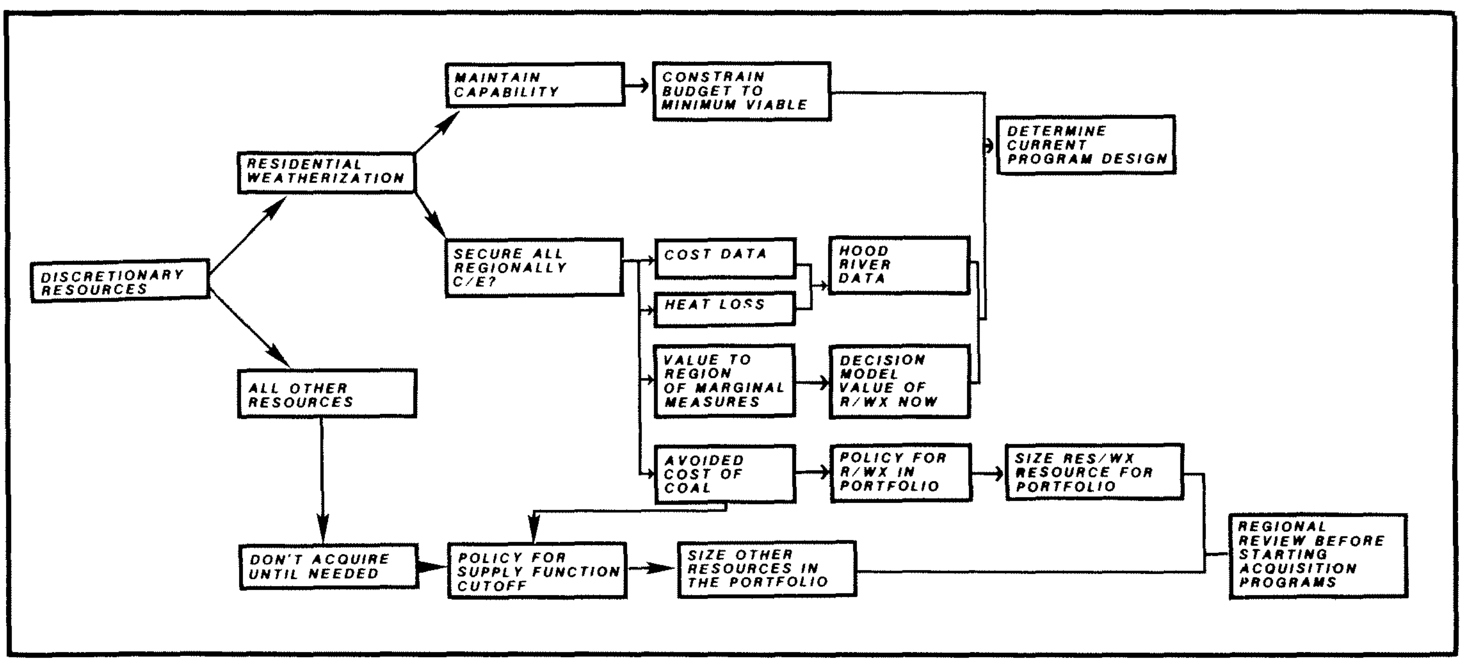


Figure 4-6
Cost-Effectiveness Method for Evaluating Discretionary Resources

transmission and distribution system losses and costs. Increasing the 4.0 to 4.5 cents per kilowatt-hour for a coal plant by 20 percent results in a range for new conservation supply curves of 4.8 to 5.4 cents per kilowatt-hour. The Council has truncated all discretionary conservation supply functions included in the resource portfolio at 5.0 cents per kilowatt-hour. There are very few conservation opportunities between 5.0 and 5.5 cents per kilowatt-hour.

Cost Effectiveness of Near-Term Acquisitions

The process of analyzing the cost effectiveness of near-term acquisitions over the next five years is shown in Figure 4-7. The evaluation begins with an analysis, using the Decision Model, of the value of lost opportunity resources that must be acquired over the next several years if they are not to be lost. For purposes of this plan, the Council has looked at resources that may need to be acquired over the next five years. Figure 4-8 illustrates the value of resources with lifetimes from zero to 70 years if they are acquired in 1986 or alternatively in 1990. These resources are assumed to have a flat seasonal shape over the year and do not adjust their output based on load growth. For these reasons, they are less valuable than the MCS, which have their peak savings in the winter and save considerably more in high load paths than in low loads.

The curves in Figure 4-8 show that a resource with an expected lifetime of 30 years acquired in 1986 has an expected value to the region's power system of approximately 2.5 cents per kilowatt-hour. If this same resource is not acquired until 1990, its expected value will increase to approximately 3.0 cents per kilowatt-hour. The Council will use these avoided cost estimates to determine the value of potential lost opportunity resources that may be acquired during the next five years. If the lost opportunity resources are conservation resources whose cost and savings are measured at the load, these estimates would need to be increased by 20 percent and adjusted for seasonal shape and load following ability. Significant lost opportunities will be evaluated on a case-by-case basis.

Non-lost opportunity resources (a resource that could be acquired any time in the future, such as adding additional generating capability to an existing dam) must be evaluated separately. Because the region currently has a surplus, the value of such a resource would be substantially less than the value of the resource if it were acquired when needed. The relative value of each resource depends on the cost effectiveness and priority of that resource in the Council's resource portfolio. For this reason, it is not possible to develop a uniform policy for all non-lost opportunity resources. An evaluation of each resource acquired before it is needed in the resource portfolio is necessary on a case-by-case basis to determine the resource's value to the region when acquired early.

Conclusions

A comparison of the cost-effectiveness criteria used by the Council is shown in Figure 4-9. This figure illustrates the Council's current estimates of the cost of a new coal-fired plant to be between 4.0 and 4.5 cents per kilowatt-hour. This estimate is used by the Council to truncate supply functions for both conservation and generating resources. Based on these estimates of the cost of coal, the Council has selected a supply function cut-off for new generating resources of 4.5 cents per kilowatt-hour and a supply function cut-off for discretionary conservation programs of 5.0 cents per kilowatt-hour to account for the advantages in the Act and transmission system costs and losses. These two values were used in developing this plan to estimate the amount of each resource expected to be available to the region in the future.

The Council has sized the conservation resources that are included in the Council's resource portfolio based on a selection of all measures that have an expected cost less than 5 cents per kilowatt-hour. Figure 4-9 shows this as the estimated cost-effectiveness criterion for discretionary conservation

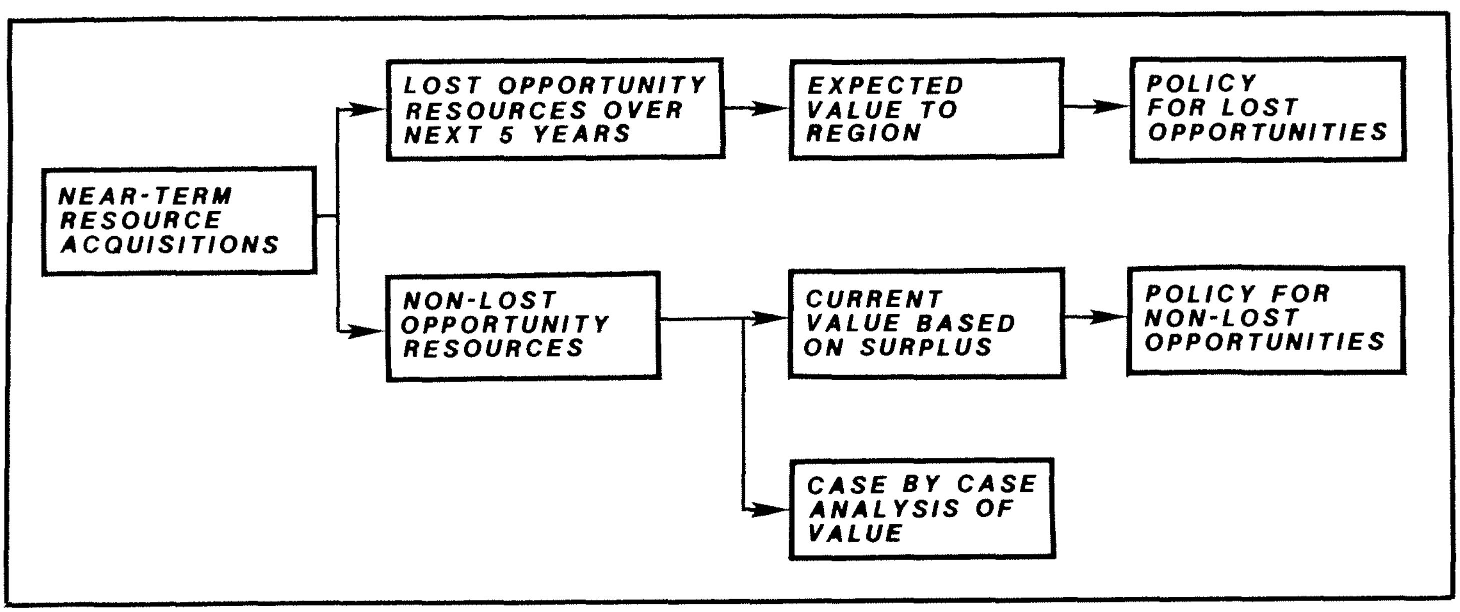


Figure 4-7
Cost-Effectiveness Method for Evaluating Near-Term Acquisitions

programs. The purpose of this estimate in the Council's Plan is to select all conservation measures that would be cost effective in the future as the region needs to acquire new resources.

Because of conservation's greater cost effectiveness and higher priority, discretionary conservation programs are initiated in the Council's resource portfolio as the region begins to experience electrical power deficits. Simultaneously, in most load paths, the region is beginning to secure options on new generating resources, particularly new coal-fired power plants. For this reason, the Council has decided to size the conservation resource potential based on the expected cost to the region of a new generic coal plant. Although there is substantial uncertainty concerning the cost of this new coal plant, the Council estimates that the cost of a new coal plant will be between 4.0 and 4.5 cents per kilowatt-hour. When these costs are adjusted to take account of the advantages in the Act and transmission system costs and losses, the appropriate range of cost-effectiveness criteria for discretionary conservation programs is between 4.8 and 5.4 cents per kilowatt-hour. There is very little conservation capability in the range of 5.0 to 5.5 cents per kilowatt-hour, and therefore the Council has selected 5.0 cents per kilowatt-hour as the appropriate cost-effectiveness criterion to size discretionary conservation programs.

The Council has also estimated the value to the region of a lost opportunity resource with an expected lifetime of 30 years (as well as other lifetimes). If this resource is acquired in 1986, it has an expected value of 2.5 cents and, alternatively, if it is acquired in 1990, it has an expected value of 3.0 cents per kilowatt-hour. These values will either increase of decrease, depending on how actual loads develop in the future. For the purposes of acquiring lost opportunity and generating resources over the next several years, the Council recommends that these resources should not be acquired if they cost more than 2.5 to 3.0 cents per kilowatt-hour.

In evaluating the MCS, the Council has used two cost-effectiveness measures. The first is the value of marginal MCS investments to the region. The Council has estimated that currently the value of marginal MCS investments is between 4.0 and 4.5 cents per kilowatt-hour. For purposes of defining the MCS at

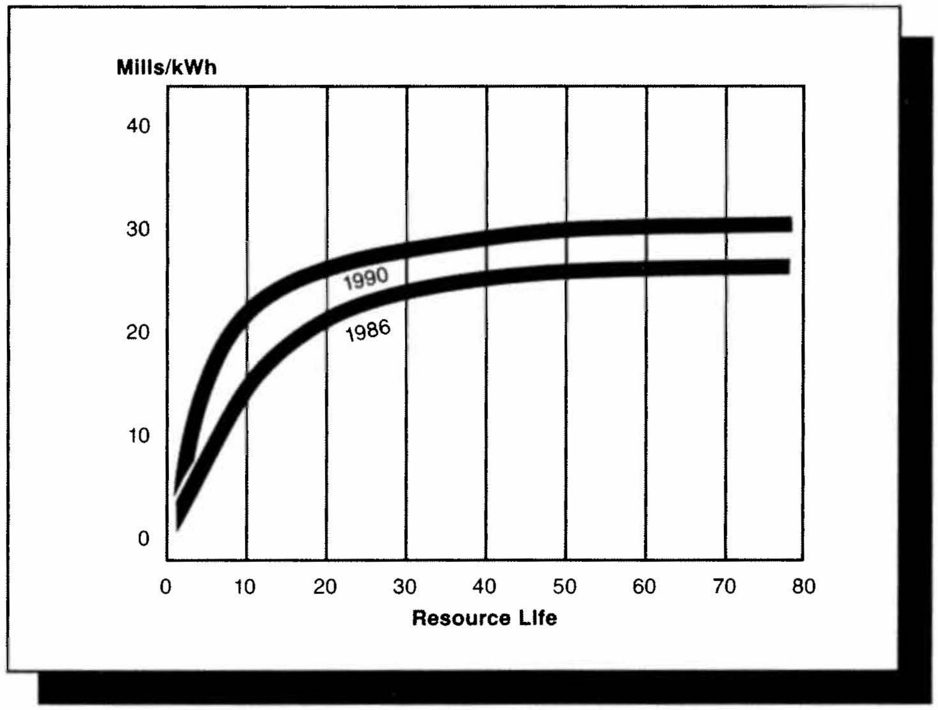


Figure 4-8
Value of Lost Opportunities in the Resource Portfolio

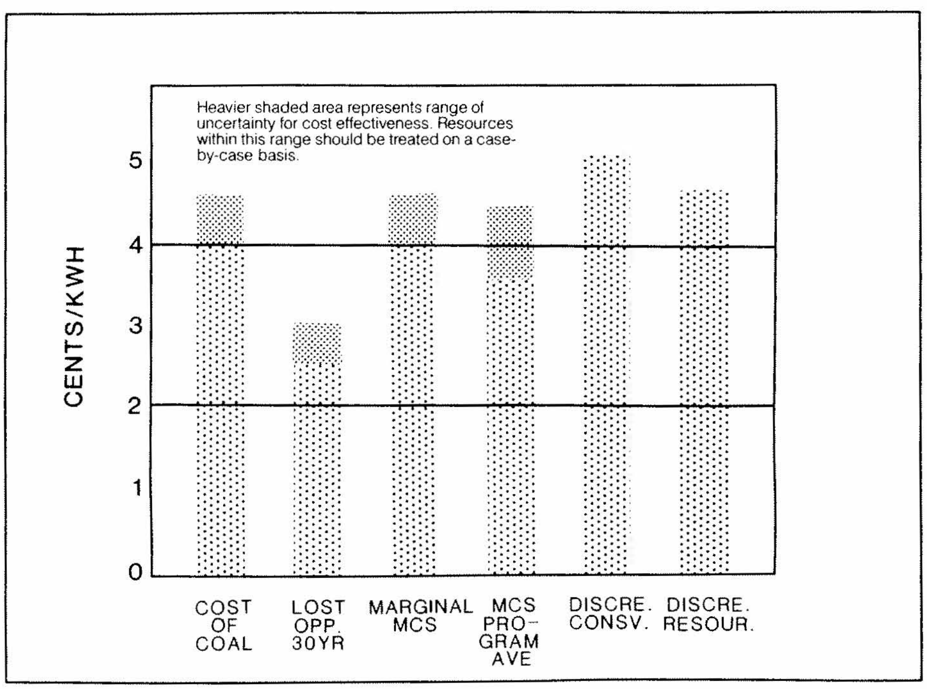


Figure 4-9
Comparison of Cost-Effectiveness Criteria

this time, the Council has evaluated the individual measures that are in the range of 4.0 to 4.5 cents per kilowatt-hour and, based on judgment, selected those measures that the Council believes are cost effective and should be included in the MCS. The second test of the cost effectiveness of the MCS was the cost effectiveness of the average energy savings that are acquired in each individual building through a utility MCS program over the next several years. In evaluating the cost effectiveness of average MCS savings in 1986, the Council found that the region could afford to pay, on average, 3.6 cents per kilowatt-hour for MCS savings. By 1990, this figure will increase to 4.4 cents per kilowatt-hour if expected load growth is experienced. For this reason, in evaluating the average cost of the utility MCS program, the Council used a value of 3.6 cents per kilowatt-hour during 1986, and expects this to escalate to approximately 4.4 cents per kilowatt-hour by 1990.

Finally, in evaluating the cost effectiveness of each individual resource, there are significant non-quantified attributes that must be included in the Council's judgment concerning the cost effectiveness and appropriateness of each resource included in the plan. In deciding on the cost effectiveness of individual actions, the Council included environmental concerns such as indoor air quality, acid rain, mining impacts, transportation, employment, fish and wildlife, etc. Some of the resources included in the Council's plan will help reduce future load growth uncertainty. Also, some resources are particularly flexible and assist the region in adapting to the wide range of uncertainty it is facing. Finally, due to the significant uncertainty that exists with respect to the cost and availability of each resource included in the Council's portfolio, the Council must decide whether sufficient, valid cost and performance information is available on which to make an informed judgment.

Chapter 5
Conservation Resources

Conservation is a key ingredient in the Council's resource portfolio for meeting future electrical energy needs. Each megawatt of electricity conserved is one less megawatt that needs to be generated. The Council has identified close to 3,700[1] average megawatts of conservation in the high demand forecast available at an average cost of 2.4 cents per kilowatt-hour. This is enough energy to replace more than eight coal plants, at about half the cost. Conservation remains an extraordinarily cost-effective resource for the region to acquire. This chapter provides an overview of the procedures and major assumptions used to derive the Council's estimates of regional conservation resources.

In the Council's plan, conservation is the more efficient use of electricity. This means that less electricity is used to produce an amenity level comparable to the one existing before the implementation of the conservation measure. Conservation resources are measures[2] that ensure new and existing residential buildings, household appliances, new and existing commercial buildings, and industrial and irrigation processes use energy efficiently. For example, buildings that cut down heat loss through insulation and tightening require less electricity for heating. These "savings" of electricity mean that fewer power plants must be built to meet growing demand. Conservation also includes measures to reduce electrical losses in the region's generation, transmission and distribution system. These latter conservation resources are discussed in Volume II, Chapter 6.

Estimating the Conservation Resource

The evaluation of conservation resources involves three major steps. The first step is to develop conservation supply curves. This step entails evaluating the levelized life cycle cost[3] of all conservation measures and rank ordering them with the least-cost measure first.

The second step is to group into programs all measures with levelized costs less than a given avoided cost. The avoided cost is the cost of the resource that would be used in the electrical system should conservation not be developed. Avoided cost varies somewhat, depending on the specific characteristics of the conservation program, such as whether the savings from the program can be developed as need occurs or whether it is developed today, during the current surplus. In general, the avoided cost in this plan is the cost of a new coal plant.

The third step involves using the cost and savings characteristics of each program to evaluate the conservation resource's cost effectiveness and compatibility with the existing power system. Cost effectiveness of each conservation program is determined by comparing the program against other resources to develop a least-cost resource portfolio.

The bulk of this chapter deals with steps one and two, which are preliminary cost-effectiveness screens to size the conservation resource that is used in the resource portfolio. Step three is described primarily in the resource portfolio, Volume II, Chapter 8.

Supply Curves

Conservation supply curves are used to evaluate the amount of conservation available at given costs. A supply curve is an economic tool used to depict the amount of a product available across a range of prices. In the case of conservation, this translates into the number of average megawatts that can be conserved (and made available for others to use) at various costs. For example, an industrial customer may be able to recover waste-heat from a process load and conserve 3 average megawatts at a cost of 2 cents per kilowatt-hour. This same customer may conserve 5, 7 and 8 average megawatts of electricity for the respective costs of 3, 4 and 5 cents per kilowatt-hour. These figures represent the conservation supply curve for this particular customer. Individual conservation estimates for end-uses in each sector are merged to arrive at the regional supply curve for that sector.

The supply curves used in this plan do not distinguish between conservation resulting from specific programs and conservation motivated by rising prices of electricity. This is a regional perspective; whether the consumer or the utility invests in a conservation measure, the region is purchasing those savings at a particular price.

Conservation supply curves are primarily a function of the conservation measure's savings and cost. Each measure's savings and cost are used to derive a levelized cost, in terms of cents per kilowatt-hour, for that measure. The absolute value (in terms of kilowatt-hours per year) of the savings produced by adding a conservation measure is a function of the existing level of insulation. The less efficient the existing structure or equipment, the greater the savings obtained from installing the measure. Consequently, the amount of conservation available is directly related to the amount of energy currently used. In order to minimize the costs of efficiency improvements, conservation measures are applied with the least costly measure first[4] until all measures are evaluated.

The levelized costs used to generate the supply curves are based on the capital, operation and maintenance expenditures incurred over the lifetime of the conservation measure. To ensure consistency between the conservation supply curves and the system models,[5] capital recovery factors used in the levelized cost calculation (see Volume II, Chapter 4, for calculation procedure) are the same ones used in the system models. This means that the tax benefits, treatments, rate requirements and other financial considerations specific to the developer of the resource are accounted for in the levelized cost of the conservation resource.

Conservation was assumed to be financed for 20 years by Bonneville and for the average lifetime of the program by the investor-owned utilities. It was assumed that Bonneville would sponsor 40 percent of the conservation acquisition costs and the investor-owned utilities would sponsor 60 percent based on their share of total loads. Twenty-five percent of the investor-owned utilities' share is financed equally between debt and equity, while 75 percent of the investor-owned utilities' share is financed by Bonneville.

Conservation Programs for Portfolio Analysis

After the supply curves are generated for each end-use or sector, the amount of conservation to be used in the portfolio analysis is first sized by cutting off the supply curve at the point where the levelized cost of the last measure included is equal to or just slightly less than the avoided cost. This is called the "technical" conservation potential. The technical potential is then reduced to reflect the portion of the conservation resource that is considered achievable. Achievable conservation is the net savings the Council anticipates after taking into account factors such as changes in consumer behavior, consumer resistance, quality control, and unforeseen technical problems. The Council believes that the wide assortment of incentives and regulatory measures the Act makes available can persuade the region's electric consumers to install a large percentage of the technically available conservation. As a consequence, the proportion of technical potential considered achievable in this plan varies from 50 percent to 90 percent depending on the sector and the conservation measures.

As described in Volume II, Chapter 4, the avoided cost is 5.0 cents per kilowatt-hour for conservation resources that can be scheduled to meet load. These are called "discretionary resources" because they don't need to be developed during the current surplus. Conservation resources that fit into this category are based on existing end-uses—for example, commercial retrofit programs and residential weatherization. Residential weatherization is a special case within the discretionary resource category, because this resource is being secured today, even though a surplus exists. The avoided cost for residential weatherization measures purchased in 1986 is approximately 3.5 cents per kilowatt-hour and increases over time up to 5.0 cents per kilowatt-hour as the surplus nears an end. The residential weatherization program is expected to be reduced to a minimum viable level in the near term, and the majority of savings should not be developed until near the end of the surplus. In addition, any weatherization that does occur should be aimed at developing the capability to deliver the full amount of savings when the program is required to ramp-up. Over the next few years, the weatherization program should be aimed primarily at the low income and rental sub-sectors, because capability needs to be developed here. As a consequence of these factors, the Council used the 5.0 cents per kilowatt-hour cutoff to size the weatherization resource in the portfolio. Even so, the vast majority of measures included in the residential weatherization program cost less than 3.5 cents per kilowatt-hour.

The 5.0 cents per kilowatt-hour avoided cost also applies to conservation resources that grow automatically with economic development, but are not expected to be developed until the later years of the forecast, when the region is no longer in a surplus condition. Savings from refrigerators and freezers, not anticipated to be developed until 1992, fall into this category. Resources that fall into this category have lifetimes that are shorter than expected building lifetimes.

The avoided cost for conservation resources that grow with loads, have lifetimes longer than the duration of the surplus, and must be acquired today or their savings are lost forever is between 4.0 and 4.5 cents per kilowatt-hour. However, the avoided costs for these resources will increase over time. Savings from the model conservation standards in new residential and commercial buildings epitomize this type of conservation resource.

Each conservation program is comprised of the package of measures that cost less than the avoided cost. The present value costs of the achievable savings for each program are adjusted in the following manner before they are used in the system models to determine compatibility with the existing power system and to derive a least-cost resource portfolio.

First, since the system models use conservation programs instead of measures in the resource portfolio, capital replacement costs have to be added to those measures with lifetimes shorter than the lifetime of the major measure in the program. For example, caulking and weatherstripping have shorter lifetimes than insulation; therefore, replacement costs are incurred over the expected lifetime of the insulation to maintain the benefits of caulking and weatherstripping. Consistent with generating resources, these capital replacement costs were escalated at 0.4 percent per year for the first 20 years after netting out the effects of inflation.

Second, in addition to the direct capital and replacement costs of the conservation measures, administrative costs to run the program must be included in the overall cost. The Council believes that the administrative cost of a given program is generally independent from the level of measures that the program installs. For example, the administrative expense of requiring an insulation contractor to install full levels of cost-effective ceiling insulation is no more than if the contractor were only required to install half the cost-effective amount. Processing of contracts, quality checks, and other administrative actions still need to be taken. The Council reviewed current utility conservation programs and those operated by other agencies. This review indicated that conservation program administrative costs range from 10 to 30 percent of the direct cost of measures. As a consequence, the Council has assumed a 20 percent administrative cost in its calculations of cost-effectiveness evaluations for conservation. This means that the average cost of the conservation programs are increased 20 percent before the conservation is compared to other generating resources to determine which is cheaper. As more data becomes available on fully operational conservation programs, the Council will move toward an estimate based on dollars per application instead of percent.

A third factor that must be accounted for when comparing conservation programs with other generating resources is the 10 percent credit given to conservation in the Northwest Power Act. This credit means that conservation can cost 10 percent more than the next lowest cost resource and still be considered cost effective under the Act. This 10 percent benefit is assessed to all conservation measures.

Finally, to ensure that conservation and generating resources are being compared fairly, the costs and savings of both types of resources must be evaluated at the same point of distribution in the electrical grid. Conservation savings and costs are evaluated at the point of use—in the house, for example. In contrast, the costs and generation from a power plant are evaluated at the generator (busbar) itself. Thus, to make conservation and the traditional forms of generation comparable, the costs of the generation plant must be adjusted to include transmission system losses (7.5 percent) and transmission costs (2.5 percent).

The net effect of all these adjustments is different for the marginal conservation measure than for the average program, because administrative costs are assessed to the average program and not the marginal measure. The cost threshold for investment in the marginal conservation measure is the busbar cost of coal plants, the resource that generally establishes the avoided cost, plus 20 percent—10 percent for the Act's credit, 7.5 percent for transmission system losses and 2.5 percent for transmission costs.

The effect on the average cost of conservation programs that are compared to generating resources is to increase the average cost of the conservation programs by 7.5 percent—20 percent added for administrative costs minus 10 percent for the Act's conservation credit and 2.5 percent saved in transmission and distribution costs—and to increase the average savings from the program by 7.5 percent to account for line loss credits.

The adjustments to the average costs and savings from conservation programs were made for purposes of comparing conservation resources with generating resources, as is done in the models used by the Council to simulate system responses. However, in this chapter, the 10 percent benefit from the Act is not included in the average cost calculations, in order to portray the true cost of conservation programs. As a consequence, the levelized program costs in this chapter are 10 percent higher than those used in the system models. In addition, this chapter is based on conservation savings at the end-use, so the savings presented are 7.5 percent lower than those used in the resource portfolio.

Table 5-1

Conservation Program Assumptions in the Decision Model

	MINIMUM VIABLE	MAXIMUM ACCELERATION	MAXIMUM DECELERATION	MAXIMUM RATE
Transmission + Distribution	0	6%	15%	15%
Efficiency Existing Residential	2%	5%	5%	11%
Existing Commercial	2%	6%	6%	15%
Existing Industrial	0	9%	22%	22%
Agricultural	0	5%	10%	10%

Compatibility with the Power System

After these adjustments are made, each conservation program is evaluated in terms of its compatibility with the existing power system and is compared to the cost and savings characteristics of other electricity resources. To assess compatibility, and ultimately the cost effectiveness of the conservation programs, the Council used two complex computer programs, called the Decision Model and the System Analysis Model. These served as a final screen to judge whether a conservation program was regionally cost effective. Both the Decision Model and the System Analysis Model are described fully in Volume II, Chapter 8.

The Decision Model determines how much conservation is needed in each of the Council's forecasts. The conservation that the model secures in any one year to meet energy needs depends on how fast a program can become operational, and on the ultimate amount of cost-effective conservation available. If the region is surplus for a long time, but a conservation program is already operating, the speed at which the program can slow down and the minimum viable level of that program are also important. The minimum viable level of the program, if above zero, determines the amount of savings that would accrue even though the region would prefer to delay purchase of the resource during the surplus period.

Table 5-1 displays the current conservation assumptions used by the Council in the Decision Model. Maximum acceleration and deceleration represent how fast a program can start up or slow down, while the maximum rate indicates how fast the program can run once it is up to top speed. Sensitivity analysis, described in Volume II, Chapter 8, considered the impact on the resource portfolio if these assumptions were altered. In general, the base case assumptions lead to the conclusion that it takes about ten years to secure the total average megawatts available from any given program. Residential weatherization is the conservation program with which the region has the most experience. The values used in the Decision Model for this program reflect levels of weatherization that have been attained in programs operating in the Northwest. If full payment for conservation were offered, instead of incentives, it is likely that these values would be exceeded. Programs aimed at the model conservation standards, refrigerators and freezers, water heaters and manufactured homes are not included in the table, because their savings are driven by demographic assumptions instead of program operation. For example, once incorporated into building codes, the level of savings achieved from the standard would be driven primarily by the number of electrically heated building starts.

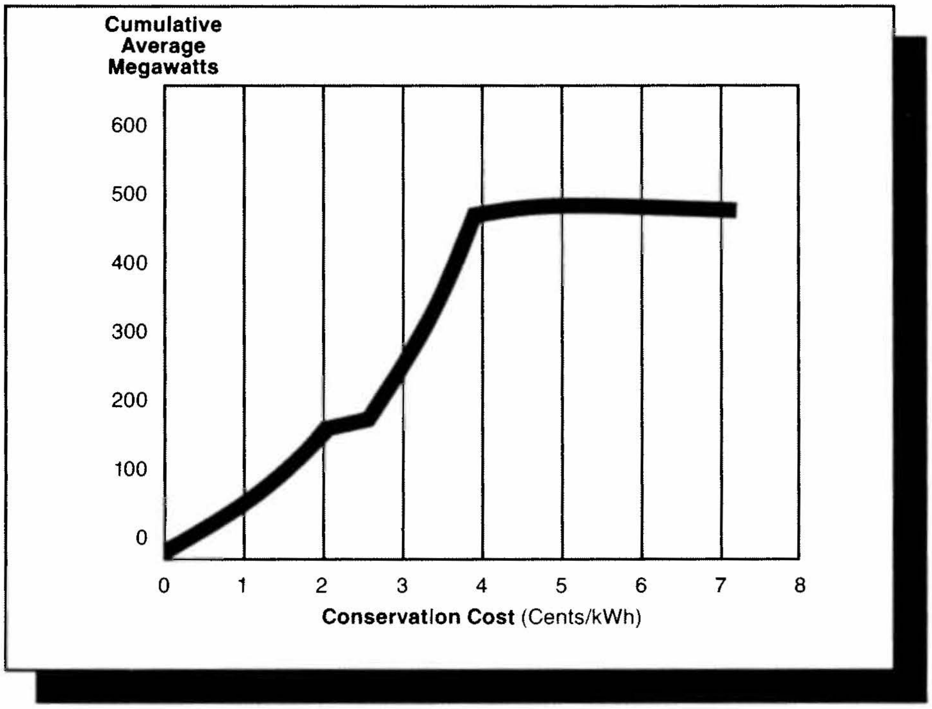


Figure 5-1
Technical Conservation Potential from Space Heating Measures in Existing Residences

The technical discussion that follows describes the evaluation of conservation resources conducted by the Council. The narrative is illustrated with calculations from the high demand forecast, but similar calculations were conducted for all of the Council's forecasts. All costs are in 1985 dollars. This discussion, and the technical exhibits listed at the end of each sector, provide the capital cost data, energy savings, and measure life used by the Council. Bonneville is expected to use comparable assumptions and procedures in any calculation of cost effectiveness.

Residential Sector

In 1983, the region's residential sector consumed 5,216 average megawatts of electricity, which is about 36 percent of the region's total electrical consumption. Space heating is the largest single category of consumption in the residential sector; water heating is second.

Space Heating Conservation in Existing Residential Buildings

Figure 5-1 shows the estimated space heating savings available from existing residences at various electricity prices. The technical conservation available with no single measure exceeding 5.0 cents per kilowatt-hour is 500 average megawatts. The Council's plan calls for developing up to 85 percent of the technical potential, or about 425 average megawatts. This represents a 37 percent savings in heating loads by 2005. The estimated average cost of insulating and weatherizing existing residences is about 2.9 cents per kilowatt-hour.

The Council's assessment of the conservation potential for existing space heating involved four steps. These steps were to:

1. Estimate the cost and potential savings available from improving the thermal efficiency of existing electrically heated dwellings.

2. Develop conservation supply functions that are consistent with the Council's forecasting model.

3. Compare projected cost and savings estimates with historically observed cost and savings data.

4. Estimate realizable conservation potential.

Step 1. **Estimate the costs and savings from conservation measures.** The costs and savings of conservation measures are the primary determinants of the amount of conservation that is available from the supply curves. The Council's estimates of single family weatherization costs are based on information gathered for the 1983 Power Plan and on information provided by Bonneville and utilities on the costs of weatherizing residences. These costs are shown in Table 5-2. Costs from the Hood River Project are preliminary, and were only used for triple glazed windows. Costs for caulking and weatherstripping were taken from Bonneville's weatherization program and increased to $100 per house.

The costs of weatherizing multifamily units are based on the information gathered in the 1983 plan. Cost-effective savings from space heating heat pumps in manufactured homes, estimated to be a total of about 35 average megawatts in the 1983 plan, were not included in the current supply curve in order to reflect some unanswered engineering questions about retrofitting the heat pumps to existing ductwork.

The Council used the source in Table 5-2 with the largest sample size to estimate conservation measure costs for single family houses. The information provided by Bonneville and Puget Power reflects the cost of installing a conservation measure where that measure is the only insulation installed in that particular building component. This cost consequently carries a fixed cost portion with it. For example, Puget's cost of $0.48 per square foot if ceiling insulation is increased from R-19 to R-38 is for precisely that measure added to the ceiling. Had the contractor started with R-11, part of the fixed cost embodied in the $0.48 per square foot would be spread over the costs from R-11 to R-38 instead of just from R-19 to R-38. The fixed cost per R-value added is less, the more insulation is installed. In this discussion, costs that include the fixed portion will be called the "set-up" costs of the weatherization measures. In Table 5-2, prices that incorporate the "set-up" costs appear in columns marked with a "2".

Information from the 1983 Power Plan reflects both the "set-up" costs of insulation measures, and the cost of installing an incremental measure of insulation, assuming the contractor is already laying the base insulation in that building component. In this discussion these will be called "add-on" costs. In Table 5-2, "add-on" costs appear in columns marked with a "1."

It is useful to distinguish between these two types of costs to answer two different questions. "Set-up" costs are included when determining whether any insulation should be added to a building component, given that a certain level already exists. For example, if a ceiling is already insulated to R-38, it turns out that it is not cost effective to the region to pay for a contractor to come to the house and increase the ceiling insulation level to R-49. "Add-on" costs determine how far a building component should be insulated, assuming the contractor is already set up and has installed some base insulation. It turns out, for example, that it is cost effective to set up a contractor to increase ceiling insulation to R-30 from a base of R-19, and it is also cost effective to continue adding insulation to R-49, if the contractor is already there. Thus the regional cost-effectiveness limit is R-49 if R-19 is the base insulation.

Based on the current analysis as described below, the following measures cost less than 5.0 cents per kilowatt-hour: R-49 ceiling insulation if the house has less than R-30; R-11 wall insulation if no insulation currently exists; R-30 underfloor insulation if less than R-19 currently exists; and triple pane windows if single panes are present, but not if the windows are already double paned. The current analysis indicates that if the house is already at R-30 in the ceiling, has some wall insulation, has R-19 or more in the floor and double pane windows, it is not cost effective to weatherize further.

These results have important implications for the design of weatherization programs. For example, if a utility runs a weatherization program that takes the ceiling insulation to R-30 only, the savings from going beyond R-30 are lost to the region, even though it would have been cost effective to go further at the time the house was weatherized. Additionally, these results lead to a weatherization program design that could be modeled after the oil dipstick in a car. If an audit shows that the house already has R-30 in the ceiling, it is only half a quart low and no oil—that is, insulation—should be added. On the other hand, if the audit shows that the ceiling is only at R-19, it is a full quart low, and insulation should be added to the full cost-effectiveness level of R-49, or as close as structural barriers permit.

Table 5-2

Costs of Weatherizing Single Family Houses
(In Dollars Per Square Foot of Component Area—Sample Size = N)

	BPA SET UP[b]	1983 PLAN SET UP[b]	1983 PLAN ADD ON[a]	PUGET POWER SET UP[b]	1985 PLAN SET UP[b]	1985 PLAN ADD ON[a]
Ceiling Insulation						
R0-R19	—	$0.39(N = 23)	—	—	$0.39	—
R19-R38	—	$0.39(N = 23)	$0.22(N = 23)	$0.48(N = 205)	$0.48	$0.22
R30-R38	—	$0.26(N = 23)	$0.09(N = 23)	$0.50(N = 6)	$0.26	$0.09
R38-R49	—	$0.30(N = 23)	$0.13(N = 23)	—	$0.30	$0.13
R0-R38	$0.82(N = 30)	—	—	$0.79(N = 58)	—	—
Floor Insulation						
R0-R19	$0.78(N = 36)	$0.58(N = 23)	—	$0.72(N = 1792)	$0.72	—
R19-R30	—	$0.44(N = 23)	$0.24(N = 23)	—	$0.44	$0.24
Wall Insulation						
R0-R11	$0.60(N = 2)	$0.63(N = 23)	—	$0.51(N = 270)	$0.51	—
Doors	—	$14.05	—	—	$14.05	—
Caulking and Weatherstripping						
	$78/house (N = 893)	—	—	—	$100/ house	—
Glass		**HOOD RIVER PROJECT**				
Add double panes to single			$11.59(N = 157)	—	$11.59	—
Add single pane to single			—	$8.04(N = 1522)	$8.04	

[a] Incremental cost of adding insulation, assuming the contractor is already installing insulation for that building component.

[b] Cost of adding insulation, assuming the contractor is not installing any other insulation in that building component.

Three "typical" building designs were used to estimate the retrofit potential for single family houses in the region. The first is an 850 square foot single-story house built over an unheated basement. The second is a 1,350 square foot house over a vented crawl space, and is similar to the design used in the 1983 plan. The third is a 2,100 square foot two-story house with a heated basement. The multifamily design is a three-story apartment house with four 840 square foot units on each floor.

Savings from weatherization measures installed in all four house designs were estimated using the SUNDAY computer model, which simulates a building's daily space heating energy needs.[6] Savings were evaluated using regional average indoor temperature settings, and internal gains consistent with efficient appliances included in the Council's resource portfolio. Savings from insulation measures were evaluated assuming that consumers who now operate their unweatherized houses at reduced temperatures would raise thermostat settings following weatherization. (This practice is termed "take-back," and it reduces savings.)

The Council assumed that the worst case for the electrical power system would be if consumers who currently heat their unweatherized houses partially with wood, and partially with electricity, chose not to

Table 5-3
Costs and Savings of Single Family Weatherization Measures in Zone 3 — Missoula

MEASURE	UA[a]	CAPITAL COST Total	CAPITAL COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	LEVELIZED COST (85$) mills/kWh
HOUSE SIZE — 850 SQ FT						
Base Case	674	$ 0	$0.00	29,297	34.5	0
Ceiling 0 to R19	483	$ 332	$0.39	19,068	22.4	1.40
Walls 0 to R11	397	$ 813	$0.96	14,621	17.2	4.67
Crawlspace 0 to R19	327	$1,425	$1.68	10,939	12.9	7.17
ACH[b] .6 to .4	302	$1,525	$1.79	9,724	11.4	10.34
Ceiling R19 to 30	288	$1,712	$2.01	9,007	10.6	11.25
Ceiling R30 to 38	285	$1,789	$2.11	8,838	10.4	19.78
Single to Triple Glass	229	$2,879	$3.39	6,171	7.3	23.14
Crawlspace R19 to 30	221	$3,083	$3.63	5,813	6.8	24.58
Wood to Metal Door	209	$3,645	$4.29	5,253	6.2	126.04
HOUSE SIZE — 1,350 SQ FT						
Base Case	1,043	$ 0	$0.00	48,217	35.7	0
Ceiling 0 to R19	740	$ 527	$0.39	31,851	23.6	1.39
Walls 0 to R11	607	$1,139	$0.84	24,769	18.3	3.73
ACH .6 to .4	568	$1,239	$0.92	22,705	16.8	6.09
Crawlspace 0 to R19	456	$2,211	$1.64	16,809	12.5	7.11
Ceiling R19 to 30	433	$2,508	$1.86	15,632	11.6	10.88
Ceiling R30 to 38	428	$2,630	$1.95	15,356	11.4	19.22
Single to Triple Glass	340	$4,357	$3.23	10,891	8.1	21.91
Crawlspace R19 to 30	328	$4,681	$3.47	10,287	7.6	23.17
Wood to Metal Door	316	$5,243	$3.88	9,697	7.2	119.60
HOUSE SIZE — 2,100 SQ FT						
Base Case	1,208	$ 0	$0.00	51,176	24.4	0
Ceiling 0 to R19	1,051	$ 273	$0.13	42,791	20.4	1.40
ACH .6 to .4	985	$ 373	$0.18	39,322	18.7	3.62
Walls 0 to R11	787	$1,327	$0.63	28,964	13.8	3.97
Ceiling RA19 to 30	775	$1,481	$0.71	28,366	13.5	11.12
Ceiling R30 to 38	772	$1,544	$0.74	28,226	13.4	19.55
Single to Triple Glass	586	$5,195	$2.47	18,922	9.0	22.23
Wood to Metal Door	574	$5,757	$2.74	18,346	8.7	122.48

[a] Heat loss rate (U-value x area)
[b] Air changes per hour

Table 5-4
Costs and Savings of Single Family Weatherization Measures in Zone 2 — Spokane

MEASURE	UA	CAPITAL COST Total	CAPITAL COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	LEVELIZED COST (85$) mills/kWh
HOUSE SIZE — 850 SQ FT						
Base Case	674	$ 0	$0.00	25,246	29.7	0
Ceiling 0 to R19	483	$ 332	$0.39	16,332	19.2	1.60
Walls 0 to R11	397	$ 813	$0.96	12,472	14.7	5.38
Crawlspace 0 to R19	327	$1,425	$1.68	9,300	10.9	8.32
ACH .6 to .4	302	$1,525	$1.79	8,233	9.7	11.78
Ceiling R19 to 30	288	$1,712	$2.01	7,604	8.9	12.82
Ceiling R30 to 38	285	$1,789	$2.11	7,456	8.8	22.54
Single to Triple Glass	229	$2,879	$3.39	5,119	6.0	26.40
Crawlspace R19 to 30	221	$3,083	$3.63	4,806	5.7	28.17
Wood to Metal Doors	209	$3,845	$4.29	4,319	5.1	144.91
HOUSE SIZE — 1,350 SQ FT						
Base Case	1,043	$ 0	$0.00	41,598	30.8	0
Ceiling 0 to R19	740	$ 527	$0.39	27,294	20.2	1.59
Walls 0 to R11 607	607	1,139	$0.84	21,145	15.7	4.29
ACH .6 to .4	568	$1,239	$0.92	19,367	14.3	7.07
Crawlspace 0 to R19	456	$2,211	$1.64	14,300	10.6	8.28
Ceiling R19 to 30	433	$2,508	$1.86	13,282	9.8	12.59
Ceiling R30 to 38	428	$2,630	$1.95	13,043	9.7	22.20
Single to Triple Glass	340	$4,357	$3.23	9,171	6.8	25.26
Crawlspace R19 to 30	328	$4,681	$3.47	8,651	6.4	26.86
Wood to Metal Doors	316	$5,243	$3.88	8,143	6.0	139.00
HOUSE SIZE — 2,100 SQ FT						
Base Case	1,208	$ 0	$0.00	43,904	20.9	0
Ceiling 0 to R19	1,051	$ 273	$0.13	36,620	17.4	1.62
ACH .6 to .4	985	$373	$0.18	33,619	16.0	4.19
Walls 0 to R11	787	$1,327	$0.63	24,668	11.7	4.60
Ceiling R19 to 30	775	$1,481	$0.71	24,148	11.5	12.78
Ceiling R30 to 38	772	$1,544	$0.74	24,026	11.4	22.46
Single to Triple Glass	586	$5,195	$2.47	15,929	7.6	25.54
Wood to Metal Doors	574	$5,757	$2.74	15,425	7.3	140.13

use their wood stoves after weatherizing. If the regional cost-effectiveness level were optimized assuming the wood heating use, the house would not be optimally weatherized if wood heating were slowed or discontinued. In order to plan for loads that the electrical system could potentially bear, cost effectiveness for each measure is evaluated assuming no wood heat.

It is also important to note, however, that the Council used the forecasting model to derive space heating use in unweatherized houses, as described below. This forecasting value is used as the base from which savings are calculated. Since the forecasting figures reflect wood heating use and room closures, as well as other responses and behaviors, the total megawatts of weatherization conservation available to the region have been reduced to account for average consumer behavior. Consequently, the average megawatts available from weatherization consider the effects of wood heat use.

Tables 5-3 through 5-6 show the costs, levelized in mills (tenths of a cent) per kilowatt-hour, and the savings from weatherizing the typical design houses in three representative climate zones in the region. Each measure has its own average, or expected, lifetime. Insulation lasts the lifetime of the residence, which for existing stock is on average about 60 or more years. This was reduced to 50 years to reflect a potential loss of savings from sagging or settling. Storm windows are assumed to last on average about 30 years. Storm doors are assumed to last an average of ten years.

Table 5-5
Costs and Savings of Single Family Weatherization Measures in Zone 1 — Seattle

MEASURE	UA	CAPITAL COST Total	CAPITAL COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	LEVELIZED COST (85$) mills/kWh
HOUSE SIZE — 850 SQ FT						
Base Case	674	$ 0	$0.00	18,495	21.8	0
Ceiling 0 to R19	483	$ 332	$0.39	11,465	13.5	2.03
Walls 0 to R11	397	$ 813	$0.96	8,488	10.0	6.98
Crawlspace 0 to R19	327	$1,425	$1.68	6,074	7.1	10.94
ACH .6 to .4	302	$1,525	$1.79	5,280	6.2	15.82
Ceiling R19 to 30	288	$1,712	$2.01	4,812	5.7	17.22
Ceiling R30 to 38	285	$1,789	$2.11	4,702	5.5	30.38
Single to Triple Glass	229	$2,879	$3.39	2,986	3.5	35.96
Crawlspace R19 to 30	221	$3,083	$3.63	2,756	3.2	38.36
Wood to Metal Doors	209	$3,645	$4.29	2,407	2.8	202.01
HOUSE SIZE — 1,350 SQ FT						
Base Case	1,043	$ 0	$0.00	31,469	23.3	0
Ceiling 0 to R19	740	$ 527	$0.39	20,124	14.9	2.00
Walls 0 to R11	607	$1,139	$0.84	15,262	11.3	5.43
ACH .6 to .4	568	$1,239	$0.92	13,857	10.3	8.95
Crawlspace 0 to R19	456	$2,211	$1.64	9,880	7.3	10.55
Ceiling R19 to 30	433	$2,508	$1.86	9,099	6.7	16.42
Ceiling R30 to 38	428	$2,630	$1.95	8,917	6.6	29.09
Single to Triple Glass	340	$4,357	$3.23	5,974	4.4	33.24
Crawlspace R19 to 30	328	$4,681	$3.47	5,582	4.1	35.65
Wood to Metal Doors	316	$5,243	$3.88	5,204	3.9	186.80
HOUSE SIZE — 2,100 SQ FT						
Base Case	1,208	$ 0	$0.00	32,440	15.4	0
Ceiling 0 to R19	1,051	$ 273	$0.13	26,701	12.7	2.05
ACH .6 to .4	985	$ 373	$0.18	24,348	11.6	5.34
Walls 0 to R11	787	$1,327	$0.63	17,430	8.3	5.95
Ceiling R19 to 30	775	$1,481	$0.71	17,034	8.1	16.81
Ceiling R30 to 38	772	$1,544	$0.74	16,941	8.1	29.55
Single to Triple Glass	586	$5,195	$2.47	10,839	5.2	33.88
Wood to Metal Doors	574	$5,757	$2.74	10,633	5.1	342.59

Table 5-6
Costs and Savings of Multifamily Weatherization Measures

MEASURE	USE kWh/yr	USE kWh/sq ft	MEASURE COST	CUMULATIVE COST	COST OF SAVINGS mills/kWh	CUMULATIVE COST/SQ FT
ZONE 1 — PORTLAND						
Base Case	9,865	11.74	$ 0	$ 0	0	$ 0
Walls 0 to R11	7,570	9.01	$342	$ 342	6.43	$0.41
Ceiling 0 to R38	5,033	5.99	$625	$ 967	10.63	$1.15
Floor 0 to R38	3,449	4.11	$625	$1,592	17.03	$1.90
ACH .6 to .4	2,797	3.33	$100	$1,692	19.27	$2.01
Single to Double Glass	1,602	1.91	$959	$2,651	45.45	$3.16
Double to Triple Glass	1,243	1.48	$922	$3,573	145	$4.25
Insulated Door	1,121	1.33	$147	$3,720	151	$4.43
ZONE 2 — SPOKANE						
Base Case	14,985	17.84	$ 0	$ 0	0	$ 0
Walls 0 to R11	11,631	13.85	$342	$ 342	4.40	$0.41
Ceiling 0 to R38	7,916	9.42	$625	$ 967	7.26	$1.15
Floor 0 to R38	5,546	6.60	$625	$1,592	11.38	$1.90
ACH .6 to .4	4,544	5.41	$100	$1,692	12.54	$2.01
Single to Double Glass	2,703	3.22	$959	$2,651	29.50	$3.16
Double to Triple Glass	2,134	2.54	$922	$3,573	91.78	$4.25
Insulated Door	1,943	2.31	$147	$3,720	96.70	$4.43
ZONE 3 — MISSOULA						
Base Case	16,784	19.98	$ 0	$ 0	0	$ 0
Walls 0 to R11	12,911	15.37	$342	$ 342	3.81	$0.41
Ceiling 0 to R38	8,577	10.21	$625	$ 967	6.22	$1.15
Floor 0 to R38	5,837	6.95	$625	$1,592	9.84	$1.90
ACH .6 to .4	4,680	5.57	$100	$1,692	10.86	$2.42
Single to Double Glass	2,545	3.03	$959	$2,651	25.44	$3.57
Double to Triple Glass	1,880	2.24	$922	$3,573	78.53	$4.25
Insulated Door	1,658	1.97	$147	$3,720	83.20	$4.43

The levelized costs displayed in tables 5-3 through 5-6 are used to order the conservation measures in terms of the least-cost measure first. For this screening exercise, which is used to rank order the measures, no replacement costs or savings were assumed for the measures with short lifetimes. When average costs of the entire program were evaluated to be used for comparison with other resources in the resource portfolio, all measures' costs and savings were taken to the same lifetime as the life for the major measure in the program (in this case, insulation). For example, caulking and weatherstripping were assumed to last ten years, while insulation would last the lifetime of the house or about 50 years. For average program costs, caulking and weatherstripping would incur an initial cost and replacement costs every ten years until 50 years is reached.

The levelized cost calculation allows the application of measures with the least-cost measure first; savings for residual measures are reassessed after each measure is added.

Since each measure saves a different amount of energy in each house design and location, an aggregate supply curve must be developed to represent the weighted average savings for all measures in the dwelling types. Accordingly, the savings from each climate zone were combined according to the percentages listed in Table 5-7. For each typical house design the regional average savings and cost appear in Tables 5-8 and 5-9.

Table 5-7
Weights Used to Reflect Regional Weather for Existing Space Heating

	CLIMATE ZONE 1	CLIMATE ZONE 2	CLIMATE ZONE 3
Single Family	84%	11%	5%
Multifamily	73.1%	22.1%	4.8%

Table 5-8
Regionally Weighted Costs and Savings of Single Family Weatherization Measures

MEASURE	COST OF SAVINGS mills/kWh	COST OF SAVINGS $/sq ft	USE kWh/sq ft
850 SQUARE FOOT HOUSE			
Base Case	0	$0.00	23.3
Ceiling 0 to R19	2.0	$0.39	14.6
Walls 0 to R11	6.7	$0.96	10.9
Crawlspace 0 to R19	10.5	$1.68	7.8
ACH .6 to .4	15.1	$1.79	6.9
Ceiling R19 to 30	16.4	$2.01	6.3
Ceiling R30 to 38	29.0	$2.11	6.1
Single to Triple Glass	34.3	$3.39	4.0
Crawlspace R19 to 30	36.5	$3.63	3.7
Wood to Metal Door	191.9	$4.29	3.2
1,350 SQUARE FOOT HOUSE			
Base Case	0	$0.00	24.8
Ceiling 0 to R19	1.9	$0.39	15.9
Wall 0 to R11	5.2	$0.84	12.1
ACH .6 to .4	8.6	$0.92	11.0
Crawlspace 0 to R19	10.1	$1.64	7.9
Ceiling R19 to 30	15.7	$1.86	7.3
Ceiling R30 to 38	27.8	$1.95	7.2
Single to Triple Glass	31.8	$3.23	4.9
Crawlspace R19 to 30	34.1	$3.47	4.6
Wood to Metal Door	178.2	$3.88	4.3
2,100 SQUARE FOOT HOUSE			
Base Case	0	$0.00	16.5
Ceiling 0 to R19	2.0	$0.13	13.6
ACH .6 to .4	5.1	$0.18	12.4
Wall 0 to R11	5.7	$0.63	9.0
Ceiling R19 to 30	16.1	$0.71	8.8
Ceiling R30 to 38	28.3	$0.74	8.7
Single to Triple Glass	32.4	$2.47	5.6
Wood to Metal Door	309.3	$2.74	5.5

The costs of upgrading single pane windows to double and double to triple panes were also evaluated, but do not appear in the tables for single family houses in order not to overcount savings. Single to double upgrading was cost effective for single family houses, but not double to triple, unless the action was part of a one-step upgrade from single. Consequently, only the one step, from single to triple, appears in the tables in order not to count savings from both single to double and single to triple glazing. In addition, although insulating the ceiling to R-49 was cost effective for single family houses, it was not included in the analysis in order to represent some of the savings lost due to structural barriers. Consequently it also does not appear in these tables, and was not counted as part of the total regional weatherization potential.

Step 2. **Develop conservation supply functions that are consistent with the Council's forecast.** The Council's supply function for conservation in existing residential buildings was developed for the year 2005. This was done for three reasons. First, the supply of energy available through conservation in existing buildings is constrained by the rates at which measures can be implemented. Second, these rates are constrained by the need for additional energy supplies. Third, some existing houses will be torn down by the turn of the century. As a result, the conservation savings from existing buildings diminishes with time. By developing its retrofit supply function for the year 2005, the Council was able to account for demolitions and set deployment schedules based on the need for additional supplies.

The forecast model was used to determine the number of electrically heated houses built before 1979 that would survive to 2005 and that could be retrofitted. The number of houses known to be retrofitted by utility-sponsored programs throughout the region, as well as an estimate of the number of households that installed retrofit measures on their own, was subtracted from the number surviving. This calculation resulted in 678,200 single family electrically heated houses and 281,700 multifamily units that could still be weatherized. Houses built to current practice between 1979 and 1985 are not included as weatherization potential. Current practice houses represent a lost conservation opportunity because they are insulated well enough that weatherization is not cost effective, yet they are not insulated to the level cost effective for new homes.

The cost and savings for each of the three single family houses were merged to estimate regional conservation potential by cents per kilowatt-hour. Based on the Pacific Northwest survey, the 2,100 square foot, 1,350 square foot, and 850 square foot houses represented approximately 22, 46, and 32 percent respectively of the regional stock. These weights result in an average house size of 1,355 square feet. Table 5-10 and 5-11 show the curve of regionally weighted costs and savings for single family and multifamily houses. Savings from this curve would be multiplied by the number of eligible units to derive a supply curve that represents regional potential if all houses in the region were uninsulated. However, the vast majority of houses in the region, even those that are not retrofitted, already have some insulation. Therefore, the supply curve for remaining savings cannot be taken from the uninsulated case, but must be estimated based on the average energy consumption or average existing insulation levels in the eligible stock.

The ideal solution to this problem would be to know the actual measures already existing in unretrofitted houses so that conservation potential could be directly determined. However, there is currently no reliable data base of such information. The Council relied on its demand forecast to estimate the space heating use of pre-1979 stock that had not been retrofitted by 2005. The number of existing 1979 stock houses that have not yet been retrofitted was estimated. Then the model was run until 2005, allowing removals from this stock to occur and allowing all variables to change except the efficiency level of the shell. Unweatherized single family houses surviving in 2005 are forecast to use about 11,047 kilowatt-hours per year and multifamily units about 5,421 kilowatt-hours per year. These forecasting figures reflect insulation levels, wood heating use and room closures, as well as other consumer responses. By using the forecasting figures as the base case from which average megawatt savings are derived, the Council's weatherization potential automatically accounts for reduced conservation potential from current use of wood heat and room closures. Since forecasting figures are for the year 2005, they incorporate the level of internal gains that results from the appearance of efficient appliances between 1985 and 2005. Consequently, no adjustment was necessary for consistency of assumptions about internal gains between the forecast and the individual measure cost-effectiveness evaluations.

Table 5-9
Regionally Weighted Costs and Savings of Multifamily Weatherization Measures

MEASURE	USE kWh/yr	USE sq ft/yr	COST OF SAVINGS mills/kWh	COST OF SAVINGS Cumulative $/sq ft
Base Case	11,329	13.49	0	$ 0
Walls 0 to R11	8,724	10.39	5.67	$0.41
Ceiling 0 to R38	5,840	6.95	9.35	$1.15
Floor 0 to R38	4,027	4.79	14.87	$1.90
ACH .6 to .4	3,273	3.90	16.67	$2.01
Single to Double Glass	1,891	2.25	39.28	$3.16
Double to Triple Glass	1,471	1.75	124	$4.25
Insulated Doors	1,329	1.58	130	$4.43

Table 5-10
Regionally Weighted Single Family Weatherization Savings by Cost Category

MILLS /KWH	COST/ SQ FT	ANNUAL USE kWh/sq ft	ANNUAL USE kWh/yr	CUMULATIVE COST
0	$0.00	22.5	30,436	$ 0
5	$0.65	12.3	16,727	$ 886
10	$1.38	8.3	11,312	$1,870
15	$1.57	7.5	10,212	$2,125
20	$1.68	7.3	9,839	$2,275
25	$1.71	7.2	9,773	$2,318
30	$2.29	6.2	8,374	$3,107
35	$3.25	4.6	6,199	$4,403
40	$3.31	4.5	6,103	$4,491
45	$3.33	4.5	6,090	$4,510
50	$3.34	4.5	6,077	$4,530
55	$3.36	4.5	6,063	$4,550
60	$3.37	4.5	6,050	$4,569
65	$3.39	4.5	6,037	$4,589
70	$3.40	4.4	6,024	$4,609

The weatherization conservation potential available to the region is the difference between the forecast use and the use after all cost-effective measures have been installed. Tables 5-10 and 5-11 show that houses retrofitted to the regional cost-effectiveness limit of 5.0 cents per kilowatt-hour use about 6,077 kilowatt-hours per year (kWh/yr) for single family (SF) and 1,838 kilowatt-hours per year for multifamily (MF). The total technical potential can be calculated:

Table 5-11
Regionally Weighted Multifamily Weatherization Savings by Cost Category

MILLS /KWH	COST/ SQ FT	ANNUAL USE kWh/sq ft	kWh/yr	CUMULATIVE COST
0	$0.00	13.49	11,329	$ 0
5	$0.36	10.75	9,030	$ 302
10	$1.24	6.70	5,628	$1,040
15	$1.90	4.73	3,974	$1,599
20	$2.18	3.65	3,070	$1,833
25	$2.43	3.29	2,764	$2,045
30	$2.69	2.93	2,458	$2,257
35	$2.94	2.56	2,152	$2,469
40	$3.17	2.25	1,887	$2,659
45	$3.23	2.22	1,862	$2,713
50	$3.29	2.19	1,838	$2,767
55	$3.36	2.16	1,813	$2,821
60	$3.42	2.13	1,788	$2,876
65	$3.49	2.10	1,764	$2,930
70	$3.55	2.07	1,739	$2,984
75	$3.62	2.04	1,714	$3,038
80	$3.68	2.01	1,689	$3,093

Table 5-12
Technical Conservation from Existing Space Heating

LEVELIZED COST (cents/kWh)	CUMULATIVE TECHNICAL POTENTIAL (AVERAGE MEGAWATTS) Single Family	Multifamily
1	40	10
2	93	75
3	207	95
4	383	113
5	385	115
6	387	117
7	389	118

$$\frac{678{,}200 \text{ SF households} \times (11{,}047 - 6{,}077 \text{ kWh/yr})}{8{,}766{,}000 \text{ (kilowatt-hours per average megawatt)}} = 385 \text{ average megawatts}$$

PLUS

$$\frac{281{,}700 \text{ MF households} \times (5{,}421 - 1{,}838 \text{ kWh/yr})}{8{,}766{,}000 \text{ (kilowatt-hours per average megawatt)}} = 115 \text{ average megawatts}$$

Some eligible houses do not have any insulation while others have significant amounts. Thus the supply curve generated from a completely uninsulated house needs to be reduced from the uninsulated base case to a total potential of 500 average megawatts to reflect current levels of insulation in eligible houses. The supply curve was reduced by eliminating the cheapest measures, which are assumed to be installed already in existing houses. This was done by excluding the savings and costs between the uninsulated house and the level of consumption predicted by the demand forecast. The adjusted conservation supply function for residential space heating in existing buildings is shown in Table 5-12.

Step 3. **Compare cost and savings estimates with observed cost and savings.** The Council compared its estimates of projected energy savings and costs with those observed in current utility weatherization programs. Figure 5-2 shows the relative space heating energy use of electrically heated homes before and after they were retrofitted. It also shows the expenditures to achieve those savings. The curve of this graph represents the Council's estimates of costs and associated savings from weatherizing single family households, based on the models and inputs described above. The plotted points depict utility program experience. The Council's cost and savings estimates generally agree with existing utility program experience, in terms of relative performance and cost.

The principal assumption made in plotting the observed bill changes is that pre-weatherization space heating electricity use represents the actual thermal efficiency of the house, and is not due to factors such as room closures and wood heat use. The alternative assumption would have been to assume that differences in the observed use pre- and post-weatherization were due to occupant behavior such as lowering thermostat temperature, closing off rooms and using wood heat before the house was weatherized. Survey data reveal significant use of wood heat and room closures in unweatherized houses. However, this assumption was not adopted. A lower estimate of the available technical potential for conservation is produced by the assumption that observed use represents the actual thermal efficiency of buildings. It implies that some conservation measures have already been installed that, indeed, may not be in place. Rather than include this technical potential in its assessment of retrofit savings, the Council conservatively assumed that consumers who now operate their unweatherized houses at reduced temperatures would raise thermostat settings following weatherization. (This is termed "take-back;" it reduces conservation savings.) Subsequently, the actual bill changes (i.e., savings) expected by the Council assume that consumers will discontinue their use of wood, reopen closed-off rooms and increase thermostat settings.

Step 4. **Estimate realizable conservation potential.** The final step in the Council's assessment of retrofit potential was to develop an estimate of the share of the 500 average megawatt potential that could realistically be achieved over the next 20 years. Given the tools to secure conservation under the Northwest Power Act, the Council estimated that 85 percent of the technical potential is achievable. For example, the Hood River Project, which paid fully for all weatherization measures offered to every house in the community of Hood River, Oregon, and prior weatherization programs operated in the community secured weatherization saturations that are similar to this figure. The 15 percent reduction accounts for less than complete market penetration, unanticipated building barriers beyond those already credited in the estimate, and quality control. The energy savings available in the Council's plan under its high growth forecast are 425 average megawatts (500 x 0.85).

Space Heating Conservation in New Residential Buildings

Figure 5-3 shows the technical space heating savings available from new residences at various costs. New single family homes represent approximately 770 average megawatts of technical potential. Multifamily and manufactured homes each represent approximately 90 average megawatts of technical potential. The Council's plan call for developing 610, 70 and 45 average megawatts of the technical potential as achievable for single family, multifamily and manufactured homes respectively. The total achievable conservation potential saves 48 percent of new space heating loads in 2005. The average cost of improving the thermal efficiency of new buildings is about 3 cents per kilowatt-hour.

Making new houses more efficient is a high priority for securing a least-cost energy future for the region. It is important to insulate houses fully at the time they are built, or cost-effective savings can be lost. In addition, while the number of houses eligible for retrofitting will diminish over time, the number of applications that conservation can reach in new houses continues to grow as every new house is built.

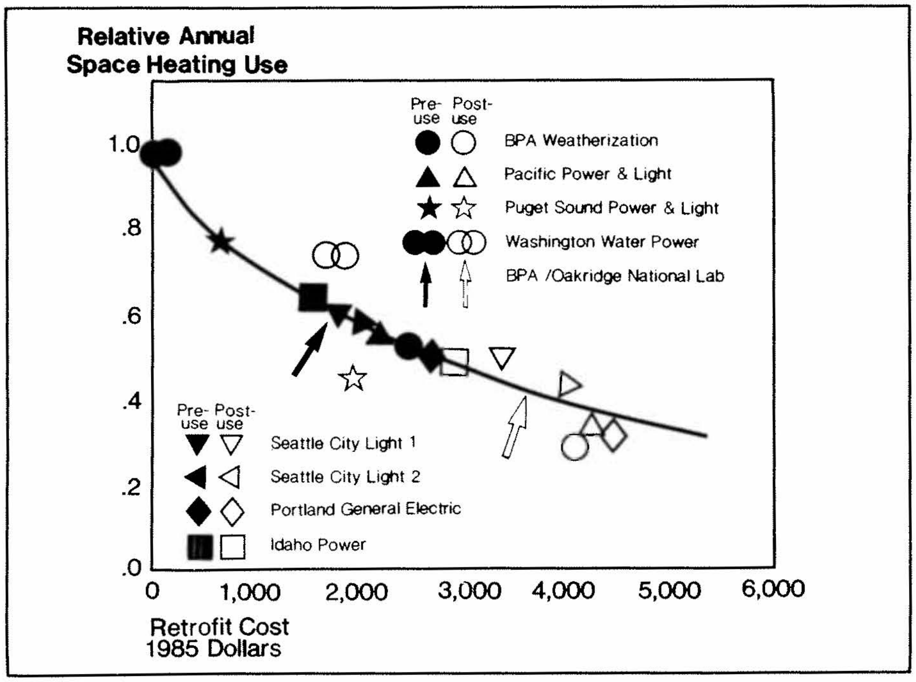


Figure 5-2
Comparison of Regional Thermal Integrity Curve
Estimated Cost and Savings Compared to Observed Bill Changes
in Existing Utility Weatherization Programs

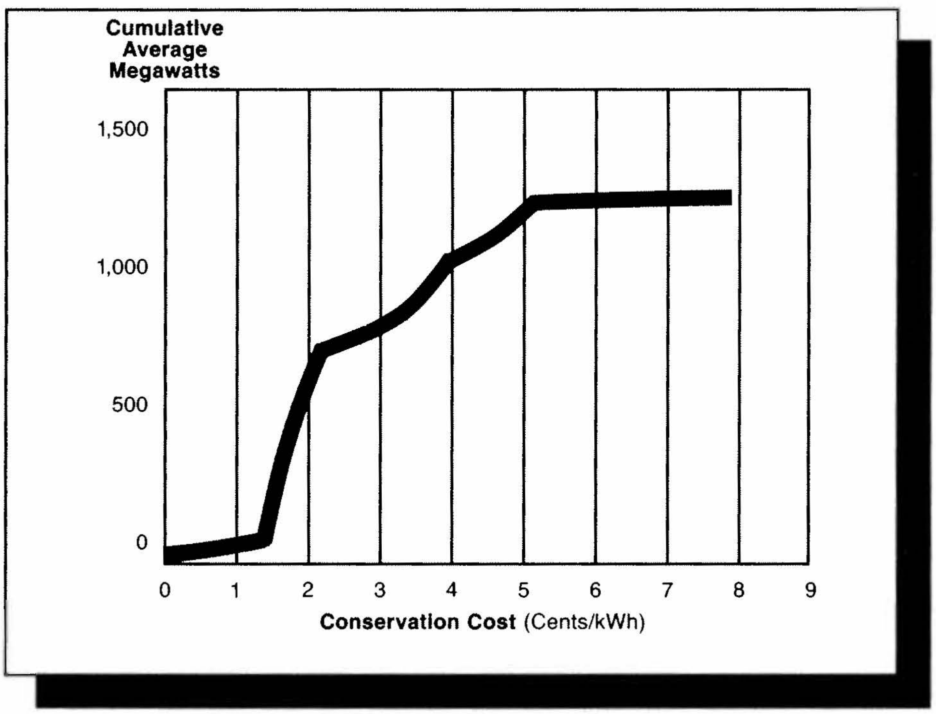


Figure 5-3
Technical Conservation from Space Heating Measures
in New Residences

The conservation potential available through improvements in the energy efficiency of new residential buildings was developed in five steps. These steps were to:

1. Establish the characteristics of current new residential construction.

2. Develop construction cost estimates for space heating conservation measures in new dwellings.

3. Assess the cost effectiveness of space heating energy savings produced by efficiency improvements in new residential buildings.

4. Estimate the technical potential available from space heating energy conservation in new dwellings.

5. Estimate the achievable conservation potential available from space heating energy conservation in new dwellings.

Separate estimates were prepared for single family dwellings (up to four units and less than four stories), multifamily dwellings (fiveplex and larger) and manufactured housing (e.g., mobile homes—please see glossary). A description of each of these steps, the data and major assumptions used and their sources follows.

Step 1. **Establish the characteristics of new residential construction.** To determine the potential for improving the energy efficiency of new residential structures it was first necessary to establish their current level of efficiency. In addition to identifying the level of insulation and type of windows commonly installed in new housing, other new home characteristics had to be ascertained, such as average floor area heated, number of stories, window area, "tightness" of the dwelling and foundation type. These characteristics significantly affect the amount of energy needed for space heating.

Table 5-13 shows by climate zone and building type the "base case" insulation levels assumed by the Council in its assessment of space heating conservation potential in new dwellings. The information on new single family and multifamily housing characteristics shown in this table is derived from three sources. The first was a regional residential energy survey conducted for Bonneville in 1983 (Pacific Northwest Residential Energy Survey 1983, "PNRES '83"). This survey was used to estimate the average size of new dwellings. The second data source was the 1977 through 1983 annual survey of new home characteristics prepared by Housing Industry Dynamics (HID) for Bonneville. The HID survey data was used to determine the typical glass area and foundation types found in new dwellings. For those areas in the region which enforce an energy code, the requirements of such codes served to establish the minimum thermal efficiency levels found in typical new single family and multifamily dwellings. For areas where no energy codes are enforced or where the HID survey data indicated that prevailing practice exceeded current code, the Council assumed the level of construction indicated by the survey.

The base case characteristics for new manufactured housing, shown in Table 5-13, were derived from information submitted to the Council by the Manufactured Housing Institute. The insulation levels assumed reflect the requirements of the U.S. Department of Housing and Urban Development's rules concerning the eligibility of manufactured homes for mortgage insurance under Title II of the National Housing Act.

Once the general characteristics of new dwellings had been identified, "typical" building designs were developed for detailed analysis of space heating conservation potential. Three typical single family detached dwelling designs were developed to represent the mixture of house sizes and foundation types being constructed in the region. A single multifamily building design was chosen to represent new multifamily construction larger than four-plexes. Two manufactured home designs were selected to represent those typically being sold in the region. Table 5-14 summarizes the basic characteristics of the new dwellings used in the Council's assessment. These designs were selected as representative based on features related to their space heating requirements, such as foundation type, and not on the basis of their architectural styles.

Step 2. **Develop construction cost estimates for space heating conservation measures in new dwellings.** In the development of the 1983 plan, the Council conducted an extensive survey of conservation costs in new residential buildings. Pursuant to the Council's plan, Bonneville, in cooperation with the four Northwest states, initiated a regionwide demonstration program on energy efficient new home construction called the Residential Standards Demonstration Program (RSDP). The Council has analyzed approximately 75 percent of the cost reports submitted by builders in this program. Except for one measure, infiltration control with mechanical ventilation, the median costs reported by participating builders agreed with those used by the Council in the 1983 plan. Consequently, for all measures except infiltration control with mechanical ventilation, the Council used RSDP median cost in its cost-effectiveness analysis.

It appears that the principal reasons for the difference between the Council's estimated cost for infiltration control with mechanical ventilation and the cost reported by builders stem from the limited experience the builders have with the measure and the lack of a competitive market. In Tacoma, where infiltration control measures coupled with mechanical ventilation are installed more frequently, builder costs appear to be \$300 to \$400 below the median value reported in the demonstration program. Moreover, builders who used an approach to reducing uncontrolled air leakage that employs common dry wall as a continuous air barrier are reporting significantly lower (75 percent less) costs than builders who used the more conventional plastic film.

The Council believes the cost reported by Tacoma builders for heat recovery ventilation devices and by those builders who employed the "air-tight" dry wall approach is more representative of the long-term cost for these measures. Consequently, in updating the estimated cost for infiltration control and heat recovery ventilators, the Council used the lower quartile cost reported by the demonstration program builders. However, median costs for heat recovery ventilators reported by the builders in the demonstration program were used to reflect the cost of these units in climate zone 3, where freeze protection fea-

Table 5-13
New Residential Construction Base Case Efficiency Levels and Annual Space Heating Use Assumptions

	CLIMATE ZONE 1		CLIMATE ZONE 2		CLIMATE ZONE 3		
BUILDING TYPE	**INSULATION LEVEL**	**ANNUAL USE (kWh/sq ft)**	**INSULATION LEVEL**	**ANNUAL USE (kWh/sq ft)**	**INSULATION LEVEL**	**ANNUAL USE (kWh/sq ft)**	**WEIGHTED AVERAGE USE (kWh/sq ft)**
Single Family		7.9		10.7		9.9	8.4
Ceiling/Roof	R-30		R-30		R-38		
Walls	R-11		R-11		R-19		
Underfloor	R-11/19		R-19		R-19		
Windows	Double glazed		Double glazed		Double glazed		
	(U-.90)		(U-.90)		(U-.65)		
Multifamily		5.0		7.5		9.0	5.5
Ceiling/Roof	R-30		R-30		R-30		
Walls	R-11		R-11		R-11		
Underfloor	R-11/19		R-19		R-19		
Windows	Double glazed		Double glazed		Double glazed		
	(U-.90)		(U-.90)		(U-.65)		
Manufactured Homes		9.7		13.8		16.3	10.5
Ceiling/Roof	R-11		R-11		R-11		
Walls	R-11		R-11		R-11		
Underfloor	R-11		R-11		R-11		
Windows	Double glazed		Double glazed		Double glazed		
	(U-.90)		(U-.90)		(U-.90)		

Table 5-14
Typical New Dwelling Characteristics

CHARACTERISTIC	SINGLE FAMILY DETACHED			MULTIFAMILY	MANUFACTURED HOME	
Prototype Label	A	B	C	12-Units@	A	B
Size—Gross Floor Area (sq. ft.)	1,344	1,848	2,352	840 sq ft/unit	924	1,344
Foundation Type	Crawlspace	Crawlspace	Basement		Skirted	Crawlspace
Number of Stories	1	2-Split Level	1 w/full basement	3-4/w garage	1	1
Window Area (sq. ft.)	175	240	258	1,140	144	144
Glass Area as a % of Floor Area	13%	13%	11%	11.9%	15.6%	10.8%
Gross Wall Area						
Above Grade	1,376	2,048	1,596	6,422	1,200	1,200
Below Grade	—	—	736	—	—	—
Total Exterior Envelope Area (sq. ft.)	4,064	4,624	5,244	14,070	3,048	3,888

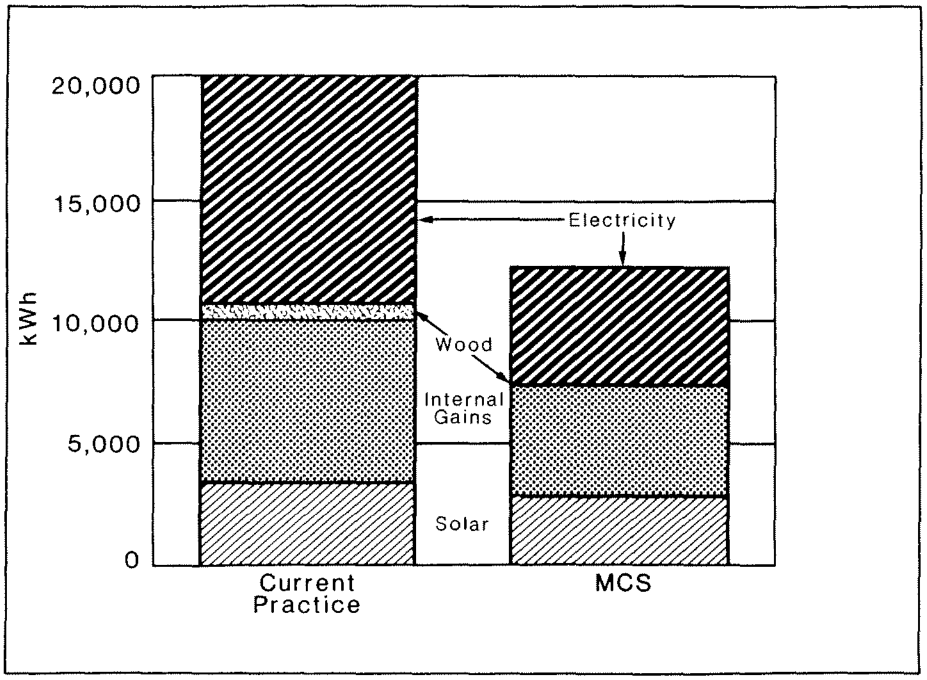


Figure 5-4
Sources of Residential Heating

tures must be added. The Council believes that for infiltration control with heat recovery ventilation, this approach reflects both Tacoma's experience and the use of the "air-tight" dry wall infiltration control strategy.

As noted earlier, not all space heating conservation measures have similar useful lives. Insulation and infiltration control measures (i.e., air/vapor barriers) installed in new single family and multifamily dwellings are anticipated to last at least 70 years (i.e., the life of the structure). These same measures installed in new manufactured houses are also expected to last the life of the building (i.e., 45 years). However, the Council has assumed that two measures, heat recovery ventilators and energy efficient windows, must be repaired or replaced before the end of the life of the structure. The Council included the cost of repairing and/or replacing these two space heating conservation measures when calculating their levelized cost. For the heat recovery ventilator cost, the Council assumed that the ventilation fans would last 15 years, similar to furnace fans, and that the ventilator itself would be replaced every 30 years. Fan replacement was assumed to cost $100. The replacement of heat recovery ventilators was assumed to cost $700 in climate zones 1 and 2, and $900 in climate zone 3. The difference in replacement cost for zone 3 is due to the need to provide for freeze protection features on the heat recovery ventilator. Operational costs (i.e., for energy) were accounted for in the assumed heat recovery efficiency of 60 percent. All the windows in new residential structures were assumed to be replaced at 30-year intervals at a cost equivalent to their initial capital cost.

The costs of improvements in the space heating efficiency of new manufactured housing were taken from a study prepared for the Manufactured Housing Institute (MHI) and submitted to the Council by MHI. The costs reported in that study and the Bonneville energy efficient new home demonstration program were adjusted to 1985 dollars from 1984 dollars using the Gross National Product deflator from mid-1984 to January 1985. Tables 5-15 through 5-21 show the retail cost assumed by the Council for potential cost-effective space heating conservation measures for new single and multifamily dwellings and manufactured housing.

Abbreviations: (Tables 5-15 through 5-21)

UA— measure of resistance to heat loss
Btu/F—British thermal units per degree of Fahrenheit
DG to TGTB—double glazed to triple glazed with thermal break
Std—standard truss, which compresses insulating bats at ends
Adv—advanced truss, which allows more effective use of R-values by not compressing bats at the ends
ACH— air changes per hour

Step 3. **Estimate the cost effectiveness of space heating energy savings produced by efficiency improvements in new residential buildings.** Once typical new dwelling designs were selected, the Council used a computer simulation model to estimate potential space heating energy savings that could be produced by each conservation measure. This model, SUNDAY, is also used to estimate savings from weatherization measures (see discussion above).

The absolute value (in kilowatt-hours per year) of the space heating energy savings produced by adding an individual conservation measure is a function of the existing thermal efficiency level of the building. The less efficient the existing building, the larger the savings that will be obtained from installing the same measure.

To assess the savings that could be produced by installing each space heating conservation measure, it is necessary to take into account their interaction. This was done by determining each measure's benefit (i.e., change in heat loss rate) and cost (i.e., dollars per square foot). The savings produced by each potentially cost-effective measure were then analyzed under the assumption that all measures with higher benefit-to-cost ratios had already been installed in the house.

Figure 5-4 illustrates how the heating requirements of an average current practice house and a model conservation standards house might be met. Heating requirements are met by solar heat, internal gains (the amount of heat released indoors by people and appliances), and the furnace, which can be supplemented by heat from wood burning stoves or other sources. The current practice house reflects average conditions for a house that is primarily heated with electricity. If the house were primarily heated with wood, the contribution from wood would be much larger, but electrical savings would still be significant as long as electricity were the marginal fuel.

Table 5-15
Costs and Savings from Conservation Measures in New Single Family Houses
Zone 1 — Seattle

CONSERVATION MEASURE	UA Btu/F	COST Incremental	COST Cumulative	COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	ANNUAL SAVINGS kWh/yr	LEVELIZED COST mills/kWh	AVERAGE ACTUAL R-VALUE
HOUSE SIZE 1,344									
Base Case	487	$ 0	$ 0	$0.00	10,577	7.9	0	0.0	8.35
Floors R11 to R19	470	202	202	0.15	10,006	7.4	571	13.9	8.65
Walls R11 to R19	443	418	620	0.46	9,089	6.8	917	17.9	9.17
Windows DG to TGTB	374	784	1,404	1.04	6,799	5.1	2,290	20.6	10.86
Insulated Door	363	191	1,595	1.19	6,449	4.8	350	21.5	11.18
Ceilings R30 to R38 Std	355	188	1,783	1.33	6,187	4.6	261	28.4	11.44
Floors 19 to R30	341	376	2,160	1.61	5,715	4.3	472	31.4	11.93
Walls R19 to R25	324	581	2,740	2.04	5,210	3.9	505	45.3	12.53
Ceilings R38 to R49 Adv	311	524	2,264	2.43	4,795	3.6	415	49.7	13.07
Infiltration .6 to .3 ACH	253	1,735	4,999	3.72	3,084	2.3	1,711	51.9	16.08
HOUSE SIZE 1,848									
Base Case	632	$ 0	$ 0	$0.00	14,560	7.9	0	0.0	7.31
Floor R11 to R19	614	193	193	0.10	13,933	7.5	627	12.1	7.53
Walls R11 to R19	573	636	829	0.45	12,511	6.8	1,422	17.6	8.07
Windows DG to TGTB	480	1,075	1,904	1.03	9,372	5.1	3,139	20.6	9.64
Insulated Door	469	191	2,095	1.13	9,015	4.9	356	21.1	9.86
Ceilings R30 to R38 Std	461	180	2,276	1.23	8,760	4.7	255	27.8	10.02
Floors R19 to R30	447	361	2,636	1.43	8,301	4.5	459	31.0	10.34
Infiltration .6 to .3 ACH	367	2,075	4,711	2.55	5,778	3.1	2,523	40.5	12.59
Walls R19 to R25	343	884	5,595	3.03	5,039	2.7	739	47.1	13.50
Ceilings R38 to R49 Adv	330	502	6,098	3.30	4,661	2.5	378	52.3	14.02
HOUSE SIZE 2,352									
Base Case	699	$ 0	$ 0	$0.00	15,620	6.6	0	0.0	7.50
Floors R11 to R19	692	84	84	0.04	15,376	6.5	244	13.6	7.58
Walls R11 to R19	663	460	544	0.23	14,394	6.1	982	18.4	7.91
Windows DG to TGTB	562	1,156	1,700	0.72	11,036	4.7	3,358	20.7	9.33
Insulated Door	546	287	1,987	0.84	10,514	4.5	522	21.6	9.61
Ceilings R30 to R38 Std	537	204	2,191	0.93	10,235	4.4	279	28.8	9.77
Floors R19 to R30	531	157	2,347	1.00	10,056	4.3	179	34.5	9.87
Infiltration .6 to .3 ACH	430	2,430	4,777	2.03	6,869	2.9	3,187	36.5	12.20
Walls R19 to R25	412	639	5,416	2.30	6,331	2.7	538	46.7	12.73
Ceilings R38 to R49 Adv	397	568	5,984	2.54	5,899	2.5	432	51.7	13.20

Table 5-16
Costs and Savings from Conservation Measures in New Single Family Homes
Zone 2 — Spokane

CONSERVATION MEASURE	UA Btu/F	COST Incremental	COST Cumulative	COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	ANNUAL SAVINGS kWh/yr	LEVELIZED COST mills/kWh	AVERAGE ACTUAL R-VALUE
HOUSE SIZE 1,344									
Base Case	469	$ 0	$ 0	$0.00	14,459	10.8	0	0.0	8.66
Walls R11 to R19	442	418	418	0.31	13,260	9.9	1,198	13.7	9.19
Windows DG to TGTB	374	784	1,202	0.89	10,292	7.7	2,969	15.9	10.86
Insulated Door	363	191	1,393	1.04	9,826	7.3	465	16.2	11.18
Ceilings R30 to R38 Std	355	188	1,581	1.18	9,479	7.1	347	21.3	11.44
Floors R19 to R30	341	376	1,958	1.46	8,848	6.6	631	23.5	11.93
Walls R19 to R25	324	581	2,538	1.89	8,171	6.1	677	33.8	12.53
Ceilings R38 to R49 Adv	311	524	3,062	2.28	7,615	5.7	555	37.2	13.07
Infiltration .6 to .3 ACH	253	1,735	4,797	3.57	5,258	3.9	2,357	37.7	16.08
HOUSE SIZE 1,848									
Base Case	614	$ 0	$ 0	$0.00	19,693	10.7	0	0.0	7.53
Walls R11 to R19	573	636	636	0.34	17,863	9.7	1,830	13.7	8.07
Windows DG to TGTB	480	1,075	1,711	0.93	13,768	7.5	4,095	15.8	9.64
Insulated Door	469	191	1,902	1.03	13,299	7.2	470	16.0	9.86
Ceilings R30 to R38 Std	461	180	2,083	1.13	12,962	7.0	336	21.1	10.02
Floors R19 to R30	447	361	2,443	1.32	12,357	6.7	605	23.5	10.34
Infiltration .6 to .3 ACH	367	2,075	4,518	2.44	8,988	4.9	3,369	30.3	12.59
Walls R19 to R25	343	884	5,402	2.92	7,985	4.3	1,003	34.7	13.50
Ceilings R38 to R49 Adv	330	502	5,904	3.20	7,470	4.0	515	38.4	14.02
HOUSE SIZE 2,352									
Base Case	692	$ 0	$ 0	$0.00	21,805	9.3	0	0.0	7.58
Walls R11 to R19	663	460	460	0.20	20,523	8.7	1,282	14.1	7.91
Windows DG to TGTB	562	1,156	1,616	0.69	16,135	6.9	4,388	15.2	9.33
Insulated Door	546	287	1,903	0.81	15,396	6.5	739	15.8	9.61
Ceilings R30 to R38 Std	537	204	2,107	0.90	15,023	6.4	373	21.5	9.77
Floors R19 to R30	531	157	2,263	0.96	14,784	6.3	239	25.9	9.87
Infiltration .6 to .3 ACH	430	2,430	4,693	2.00	10,527	4.5	4,257	27.3	12.20
Walls R19 to R25	412	639	5,332	2.27	9,793	4.2	734	34.3	12.73
Ceilings R38 to R49 Adv	397	568	5,900	2.51	9,196	3.9	597	37.4	13.20

Table 5-17
Costs and Savings from Conservation Measures in New Single Family Houses
Zone 3 — Missoula

CONSERVATION MEASURE	UA Btu/F	COST Incremental	COST Cumulative	COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	ANNUAL SAVINGS kWh/yr	LEVELIZED COST mills/kWh	AVERAGE ACTUAL R-VALUE
HOUSE SIZE 1,344									
Base Case	396	$ 0	$ 0	$0.00	13,280	9.9	0	0.0	10.27
Windows DGTB to TGTB	355	$ 599	$ 599	$0.45	11,271	8.4	2,010	17.9	11.44
Floors R19 to R30	341	$ 376	$ 975	$0.73	10,540	7.8	731	20.2	11.93
Walls R19 to R31	315	$ 813	$1,788	$1.33	9,302	6.9	1,238	25.8	12.90
Ceiling R38 to R49 Adv	302	$ 564	$2,352	$1.75	8,653	6.4	649	34.2	13.48
Infiltration .6 to .3 ACH	243	$1,935	$4,287	$3.19	5,913	4.4	2,740	36.8	16.69
HOUSE SIZE 1,848									
Base Case	517	$ 0	$ 0	$0.00	18,149	9.8	0	0.0	8.95
Windows DGTB to TGTB	461	$ 821	$ 821	$0.44	15,371	8.3	2,778	17.8	10.02
Floors R19 to R30	447	$ 361	$1,181	$0.64	14,669	7.9	702	20.2	10.34
Walls R19 to R31	407	$1,238	$2,419	$1.31	12,665	6.9	2,003	24.3	11.37
Infiltration .6 to .3 ACH	327	$2,275	$4,694	$2.54	8,812	4.8	3,853	29.7	14.15
Ceilings R38 to R49 Adv	314	$ 541	$5,235	$2.83	8,214	4.4	598	35.6	14.73
HOUSE SIZE 2,352									
Base Case	596	$ 0	$ 0	$0.00	20,731	8.8	0	0.0	8.79
Windows DGTB to TGTB	537	$ 882	$ 882	$0.38	17,794	7.6	2,937	18.0	9.77
Floors R19 to R30	531	$ 157	$1,039	$0.44	17,519	7.4	275	22.5	9.87
Walls R19 to R31	502	$ 895	$1,934	$0.82	16,114	6.9	1,405	25.1	10.45
Infiltration .6 to .3 ACH	400	$2,603	$4,537	$1.93	11,278	4.8	4,836	26.5	13.10
Ceilings R38 to R49 Adv	386	$ 612	$5,149	$2.19	10,601	4.5	677	35.6	13.59

Table 5-18
Costs and Savings from Conservation Measures in New Multifamily Residences
Dwelling Unit Size 840 square feet

CONSERVATION MEASURE	UA Btu/F	COST Incremental	COST Cumulative	COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	ANNUAL SAVINGS kWh/yr	LEVELIZED COST mills/kWh	AVERAGE ACTUAL R-VALUE
ZONE 1 — SEATTLE									
Base Case	2,764	$ 0	$ 0	$ 0	4,168	5.0	0	0.0	5.09
Floors R11 to R19	2,691	$ 48	$ 48	$0.06	3,967	4.7	201	9.5	5.23
Ceilings R30 to R38 Std	2,645	$ 45	$ 93	$0.11	3,844	4.6	123	14.3	5.32
Walls R11 to R19	2,526	$ 155	$ 248	$0.29	3,525	4.2	319	19.1	5.57
Windows DG to TGTB	2,081	$ 426	$ 674	$0.80	2,380	2.8	1,145	22.4	6.76
Insulated Door	2,047	$ 50	$ 724	$0.86	2,296	2.7	84	23.4	6.87
Floors R19 to R30	,002	$ 89	$ 813	$0.97	2,186	2.6	110	31.8	7.03
Walls R11 to R25	1,929	$ 215	$1,028	$1.22	2,017	2.4	170	49.8	7.29
Infiltration .6 to .3 ACH	1,434	$1,135	$2,163	$2.58	899	1.1	1,118	53.8	9.81
Ceilings R38 to R49 Adv	1,403	$ 124	$2,287	$2.72	838	1.0	61	80.0	10.03
ZONE 2 — SPOKANE									
Base Case	2,764	$ 0	$ 0	$ 0	6,337	7.5	0	0.0	5.09
Floors R11 to R19	2,691	$ 48	$ 48	$0.06	6,069	7.2	268	7.1	5.23
Ceilings R30 to R38 Std	2,645	$ 45	$ 93	$0.11	5,904	7.0	165	10.7	5.32
Walls R11 to R19	2,526	$ 155	$ 248	$0.29	5,477	6.5	427	14.3	5.57
Windows DG to TGTB	2,081	$ 426	$ 674	$0.80	3,921	4.7	1,556	16.4	6.76
Insulated Door	2,047	$ 50	$ 724	$0.86	3,806	4.5	115	17.1	6.87
Floors R19 to R30	2,002	$ 89	$ 813	$0.97	3,654	4.3	152	22.6	7.03
Walls R11 to R25	1,929	$ 215	$1,028	$1.22	3,418	4.1	236	35.9	7.29
Infiltration .6 to .3 ACH	1,434	$1,135	$2,163	$2.58	1,849	2.2	1,569	38.3	9.81
Ceilings R38 to R49 Adv	1,403	$ 124	$2,287	$2.72	1,757	2.1	92	53.0	10.03
ZONE 3 — MISSOULA									
Base Case	2,764	$ 0	$ 0	$ 0	7,517	8.9	0	0.0	5.09
Floors R11 to R19	2,691	$ 48	$ 48	$0.06	7,208	8.6	308	6.2	5.23
Ceilings R30 to R38 Std	2,645	$ 45	$ 93	$0.11	7,019	8.4	189	9.3	5.32
Walls R11 to R19	2,526	$ 155	$ 248	$0.29	6,524	7.8	494	12.4	5.57
Windows DG to TGTB	2,081	$ 426	$ 674	$0.80	4,720	5.6	1,804	14.2	6.76
Insulated Door	2,047	$ 50	$ 724	$0.86	4,586	5.5	134	14.7	6.87
Floors R19 to R30	2,002	$ 89	$ 813	$0.97	4,409	5.2	177	19.8	7.03
Walls R19 to R25	1,929	$ 215	$1,028	$1.22	4,131	4.9	277	30.5	7.29
Infiltration .6 to .3 ACH	1,434	$1,335	$2,363	$2.81	2,283	2.7	1,848	39.0	9.81
Ceilings R38 to R49 Adv	1,403	$ 124	$2,487	$2.96	2,174	2.6	109	44.8	10.03

Table 5-19
Costs and Savings from Conservation Measures in New Manufactured Homes
Zone 1 — Seattle
Dwelling Unit Size 840 square feet

CONSERVATION MEASURE	UA Btu/F	COST Incremental	COST Cumulative	COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	SAVINGS kWh/yr	LEVELIZED COST mills/kWh	AVERAGE ACTUAL R-VALUE
HOUSE SIZE 924									
Base Case	440	$ 0	$ 0	$0.00	9,391	10.2	0	0.0	6.92
Ceilings R11 to R19	424	62	62	0.07	8,829	9.6	561	5.2	7.20
Floors R11 to R19	405	162	224	0.24	8,187	8.9	642	11.8	7.52
Ceilings R19 to R27	394	166	390	0.42	7,809	8.5	378	20.5	7.74
Walls R11 to R19	361	568	958	1.04	6,733	7.3	1,076	24.7	8.43
Insulated Door	352	175	1,133	1.23	6,410	6.9	323	25.3	8.66
Floors R19 to R30	334	480	1,613	1.75	5,809	6.3	601	37.3	9.14
Windows DG to TGTB	302	756	2,369	2.56	4,807	5.2	1,003	44.8	10.11
Ceilings R27 to R38	296	228	2,597	2.81	4,631	5.0	175	60.9	10.30
Infiltration .6 to .3 ACH	259	1,450	4,047	4.38	3,498	3.8	1,133	72.3	11.79
HOUSE SIZE 1,344									
Base Case	537	$ 0	$ 0	$0.00	12,493	9.3	0	0.0	7.24
Ceilings R11 to R19	513	90	90	0.07	11,625	8.6	868	4.9	7.58
Floors R11 to R19	486	235	325	0.24	10,674	7.9	951	11.6	8.00
Ceilings R19 to R27	470	242	567	0.42	10,138	7.5	536	21.1	8.27
Walls R11 to R19	437	568	1,135	0.84	9,243	6.9	895	29.7	8.90
Insulated Door	428	175	1,310	0.97	8,968	6.7	275	29.7	9.09
Floors R19 to R30	401	699	2,009	1.49	8,045	6.0	923	35.4	9.70
Windows DG to TGTB	369	756	2,765	2.06	6,985	5.2	1,060	42.4	10.53
Infiltration .6 to .3 ACH	315	1,450	4,215	3.14	5,215	3.9	1,770	46.3	12.36
Ceilings R27 to R38	307	332	4,547	3.38	4,961	3.7	253	61.3	12.68

Table 5-20
Costs and Savings from Conservation Measures in New Manufactured Homes
Zone 2 — Spokane
Dwelling Unit Size 840 square feet

CONSERVATION MEASURE	UA Btu/F	COST Incremental	COST Cumulative	COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	SAVINGS kWh/yr	LEVELIZED COST mills/kWh	AVERAGE ACTUAL R-VALUE
HOUSE SIZE 924									
Base Case	440	$ 0	$ 0	$0.00	13,667	14.8	0	0.0	6.92
Ceilings R11 to R19	424	62	62	0.07	12,937	14.0	730	4.0	7.20
Floors R11 to R19	405	162	224	0.24	12,100	13.1	837	9.1	7.52
Ceilings R19 to R27	394	166	390	0.42	11,604	12.6	496	15.6	7.74
Walls R11 to R19	361	568	958	1.04	10,182	11.0	1,422	18.7	8.43
Insulated Door	352	175	1,133	1.23	9,753	10.6	429	19.1	8.66
Floors R19 to R30	334	480	1,613	1.75	8,951	9.7	801	28.0	9.14
Windows DG to TGTB	302	756	2,369	2.56	7,606	8.2	1,345	33.4	10.11
Ceilings R27 to R38	296	228	2,597	2.81	7,369	8.0	237	45.0	10.30
Infiltration .6 to .3 ACH	259	1,450	4,047	4.38	5,809	6.3	1,560	52.5	11.79
HOUSE SIZE 1,344									
Base Case	537	$ 0	$ 0	$0.00	17,609	13.1	0	0.0	7.24
Ceilings R11 to R19	513	90	90	0.07	16,503	12.3	1,106	3.8	7.58
Floors R11 to R19	486	235	325	0.24	15,350	11.4	1,153	9.5	8.00
Ceilings R19 to R27	470	242	567	0.42	14,679	10.9	671	16.9	8.27
Walls R11 to R19	437	568	1,135	0.84	13,167	9.8	1,512	17.6	8.90
Insulated Door	428	175	1,310	0.97	12,776	9.5	390	21.0	9.09
Floors R19 to R30	401	699	2,009	1.49	11,586	8.6	1,190	27.5	9.70
Windows DG to TGTB	369	756	2,765	2.06	10,200	7.6	1,386	32.4	10.53
Infiltration .6 to .3 ACH	315	1,450	4,215	3.14	7,919	5.9	2,281	35.9	12.36
Ceilings R27 to R38	307	332	4,547	3.38	7,648	5.7	271	57.3	12.68

Table 5-21
Costs and Savings from Conservation Measures in New Manufactured Homes
Zones 3 — Missoula
Dwelling Unit Size 840 square feet

CONSERVATION MEASURE	UA Btu/F	COST Incremental	COST Cumulative	COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	SAVINGS kWh/yr	LEVELIZED COST mills/kWh	AVERAGE ACTUAL R-VALUE
				HOUSE SIZE 924					
Base Case	440	$ 0	$ 0	$0.00	16,069	17.4	0	0.0	6.92
Ceilings R11 to R19	424	62	62	0.07	15,224	16.5	846	3.4	7.20
Floors R11 to R19	405	162	224	0.24	14,254	15.4	969	7.8	7.52
Ceilings R19 to R27	394	166	390	0.42	13,681	14.8	573	13.5	7.74
Walls R11 to R19	361	568	958	1.04	12,045	13.0	1,637	16.2	8.43
Insulated Door	352	175	1,133	1.23	11,552	12.5	493	16.5	8.66
Floors R19 to R30	334	480	1,613	1.75	10,629	11.5	923	24.3	9.14
Windows DG to TGTB	302	756	2,369	2.56	9,066	9.8	1,563	28.8	10.11
Ceilings R27 to R38	296	228	2,597	2.81	8,791	9.5	275	38.8	10.30
Infiltration .6 to .3 ACH	259	1,450	4.047	4.38	6,981	7.6	1,810	45.3	11.79
				HOUSE SIZE 1,344					
Base Case	537	$ 0	$ 0	$0.00	20,875	15.5	0	0.0	7.24
Ceilings R11 to R19	513	90	90	0.07	19,588	14.6	1,287	3.3	7.58
Floors R11 to R19	486	235	325	0.24	18,247	13.6	1,341	8.2	8.00
Ceilings R19 to R27	470	242	567	0.42	17,448	13.0	799	14.2	8.27
Walls R11 to R19	437	568	1,135	0.84	15,627	11.6	1,822	14.6	8.90
Insulated Door	428	175	1,310	0.97	15,144	11.3	482	17.0	9.09
Floors R19 to R30	401	699	2,009	1.49	13,754	10.2	1,390	23.5	9.70
Windows DG to TGTB	369	756	2,765	2.06	12,179	9.1	1,575	28.5	10.53
Infiltration .6 to .3 ACH	315	1,450	4,215	3.14	9,508	7.1	2,671	30.7	12.36
Ceilings R27 to R38	307	332	4,547	3.38	9,192	6.8	316	49.1	12.68

Table 5-22
Weighting Factors Used to Aggregate Individual Building & Location Savings to Region

BUILDING TYPE	WEIGHT	MEAN SIZE
Single Family (less than five-plex)		
1,344 sq. ft. — Single Story	90%	
1,848 sq. ft. — Two Story	9%	
2,352 sq. ft. — One Story w/Basement	1%	1,400 sq. ft.
Multifamily (five-plex and larger)		
12-Unit	100%	840 sq. ft./unit
Manufactured Homes		
924 Single Wide	42%	
1,344 Double Wide	58%	1,170 sq. ft.
ZONE	**HDD***	**WEIGHT**
Zone 1 — Seattle	5,444	80%
Zone 2 — Spokane	6,818	16%
Zone 3 — Missoula	7,773	4%
Region	5,757	

*HDD — Heating Degree Days at 65°F based on Typical Meterological Year (TMY) weather tape used to estimate savings. TMY weather tapes vary slightly from published long-term averages.

Table 5-23
Regionally Weighted Savings and Costs in New Single Family Dwellings

LEVELIZED COST mills/kWh	CAPITAL COST Total	CAPITAL COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	RELATIVE USE % of base	ANNUAL SAVINGS kWh/yr	AVERAGE R-VALUE
0	$ 0	$0.00	11,742	8.4	100	0	8.37
5	$ 91	$0.07	11,479	8.2	98	263	8.50
10	$ 181	$0.13	11,216	8.0	96	527	8.63
15	$ 435	0.31	10,485	7.5	90	1,257	9.01
20	$1,309	$0.94	8,112	5.8	69	3,630	10.56
25	$1,800	$1.29	7,117	5.1	60	4,625	11.35
30	$2,114	$1.51	6,708	4.8	57	5,034	11.73
35	$2,534	$1.81	6,225	4.5	53	5,518	12.22
40	$3,101	$2.21	5,553	4.0	48	6,189	13.01
45	$3,332	$2.37	5,332	3.8	46	6,410	13.25
50	$4,048	$2.89	4,708	3.4	40	7,034	14.18
55	$5,047	$3.63	3,731	2.7	31	8,012	15.89
60	$5,047	$3.63	3,731	2.7	31	8,012	15.89
65	$5,047	$3.63	3,731	2.7	31	8,012	15.89
70	$5,047	$6.63	3,731	2.7	31	8,012	15.89
75	$5,047	$3.63	3,731	2.7	31	8,012	15.89
80	$5,047	$3.63	3,731	2.7	31	8,012	15.89
85	$5,047	$3.63	3,731	2.7	31	8,012	15.89
90	$5,047	$3.63	3,731	2.7	31	8,012	15.89
95	$5,047	$3.63	3,731	2.7	31	8,012	15.89
100	$5,047	$3.63	3,731	2.7	31	8,012	15.89

Table 5-24
Regionally Weighted Savings and Costs in New Multifamily Dwellings

LEVELIZED COST mills/kWh	CAPITAL COST Total	CAPITAL COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	RELATIVE USE % of base	ANNUAL SAVINGS kWh/yr	AVERAGE R-VALUE
0	$ 0	$0.00	4,649	5.5	100	0	5.09
5	$ 27	$0.03	4,524	5.4	97	125	5.17
10	$ 61	$0.07	4,389	5.2	95	260	5.25
15	$ 184	$0.22	4,014	4.8	88	635	5.51
20	$ 447	$0.53	3,343	4.0	73	1,306	6.11
25	$ 766	$0.91	2,569	3.1	55	2,080	6.94
30	$ 825	$0.98	2,497	3.0	54	2,152	7.04
35	$ 913	$1.09	2,400	2.9	52	2,248	7.17
40	$1,173	$1.40	2,072	2.5	46	2,577	7.69
45	$1,231	$1.47	2,026	2.4	45	2,623	7.77
50	$1,329	$1.58	1,940	2.3	43	2,709	7.93
55	$2,200	$2.62	1,085	1.3	23	3,564	9.86
60	$2,219	$2.64	1,076	1.3	23	3,573	9.90
65	$2,238	$2.66	1,067	1.3	22	3,582	9.93
70	$2,257	$2.69	1,057	1.3	22	3,591	9.96
75	$2,276	$2.71	1,048	1.2	22	3,601	10.00
80	$2,295	$2.73	1,039	1.2	22	3,610	10.03
85	$2,295	$2.73	1,039	1.2	22	3,610	10.03
90	$2,295	$2.73	1,039	1.2	22	3,610	10.03
95	$2,295	$2.73	1,039	1.2	22	3,610	10.03
100	$2,295	$2.73	1,039	1.2	22	3,610	10.03

Table 5-25
Regionally Weighted Savings and Costs in New Manufactured Dwellings

LEVELIZED COST mills/kWh	CAPITAL COST Total	CAPITAL COST $/sq ft	ANNUAL USE kWh/yr	ANNUAL USE kWh/sq ft	RELATIVE USE % of base	ANNUAL SAVINGS kWh/yr	AVERAGE R-VALUE
0	$ 0	$0.00	12,279	10.6	100	0	7.11
5	$ 88	$0.07	11,442	9.9	93	836	7.44
10	$ 248	$0.21	10,768	9.3	88	1,511	7.73
15	$ 398	$0.34	10,322	8.9	84	1,956	7.94
20	$ 635	$0.55	9,749	8.4	80	2,530	8.21
25	$1,014	$0.88	9,086	7.8	75	3,193	8.63
30	$1,577	$1.37	8,165	7.0	67	4,113	9.25
35	$2,015	$1.74	7,539	6.5	62	4,740	9.69
40	$2,522	$2.18	6,837	5.9	56	5,442	10.27
45	$2,995	$2.59	6,232	5.4	51	6,047	10.82
50	$3,463	$2.96	5,688	4.9	47	6,591	11.38
55	$3,826	$3.28	5,317	4.6	44	6,961	11.79
60	$4,064	$3.52	5,132	4.4	42	7,147	12.03
65	$4,300	$3.76	4,949	4.3	40	7,330	12.27
70	$4,340	$3.80	4,918	4.2	40	7,361	12.31
75	$4,340	$3.80	4,918	4.2	40	7,361	12.31
80	$4,340	$3.80	4,918	4.2	40	7,361	12.31
85	$4,340	$3.80	4,918	4.2	40	7,361	12.31
90	$4,340	$3.80	4,918	4.2	40	7,361	12.31
95	$4,340	$3.80	4,918	4.2	40	7,361	12.31
100	$4,340	$3.80	4,918	4.2	40	7,361	12.31

When determining the electrical savings of measures applied to a current practice house, at least the following three policy considerations must be evaluated: the treatment of wood heating, internal temperature settings for the whole house, and internal gains.[7] The Council assumed no wood heating when evaluating measure savings in new residential buildings. The Council used a constant thermostat setting of 65° for the whole house to represent a combination of higher temperatures when the house was occupied and the occupants active, and a lower nighttime setback. Finally, the Council assumed a cadre of efficient appliances, reflecting appliances that would be in place for the majority of the life of the house, and are present in the region throughout most of the Council's plan. Appliances currently in place in houses are not very efficient, contribute more usable heat to the house, and thus cut space heating loads. This is reflected in Figure 5-4, where internal gains are larger in the current practice house.

The Council re-assessed the planning assumptions described above before issuing the current plan and feels that these assumptions should be maintained based on the following reasons. First, there is no assurance that occupants of houses built to the standards will continue to use wood heat. Changing wood prices, income levels, wood availability and environmental regulations all could reduce the use of wood heating, leaving the electrical system vulnerable to mass "fuel switching" to electricity, an action that would be difficult if not impossible to plan resources for. Second, the Act defines conservation as an efficiency improvement, not a change in lifestyle. Current behavior of consumers to close off rooms or lower thermostats may represent curtailment rather than conservation as defined in the Northwest Power Act. Such behavior is not expected to continue after cost-effective efficiency improvements are made. Third, more efficient appliances are clearly cost-effective resources and will be the norm, especially in new houses, in the next decade. Appliance manufacturers have testified that, even without appliance standards such as those adopted recently in California and called for in this plan, new appliances will be much more efficient. Therefore, the Council's estimates reflect less heat escaping from these appliances to heat the house. Finally, the adoption of planning assumptions different than these would subject the region to greater planning uncertainties than the present set of assumptions. If the energy efficiency requirements of the standards are made less stringent because it is assumed consumers will continue to close off rooms and heat with wood, the degree of uncertainty the region must plan for increases.

Tables 5-15 through 5-21 show the levelized cost, annual energy use, and energy savings produced by the addition of each measure for each dwelling type, building design and for three representative climate types found in the region (Zone 1-Seattle, Zone 2-Spokane and Zone 3-Missoula). The levelized cost shown for single family and multifamily buildings is based on a 70-year physical life and a financing cost of approximately 4 percent real.[8] Levelization was done using a 3 percent real discount rate. The levelized cost shown for manufactured housing is based on a 45-year economic life and levelization at a 3 percent real discount rate. For planning purposes, it has been assumed that the efficiency improvements in single family and multifamily houses and manufactured housing will be obtained via a marketing and incentive program financed through Bonneville, public utilities and the region's investor-owned utilities.

The Council has established model conservation standards for new single family and multifamily houses heated with electricity. The standards are required to achieve all regionally cost-effective conservation savings. As discussed in Volume II, Chapter 4, the Council has found that power savings that can be achieved at a cost in the range of 4.0 to 4.5 cents per kilowatt-hour represent regionally cost-effective resources. Appendix I-B (Volume I) sets forth an illustrative prescriptive path for each climate zone that if installed in a typical new house would satisfy the standards. The measures shown in Appendix I-B are all regionally cost effective for the average 1,850 sq. ft. single family house (one and two family dwelling) currently being constructed in the region. In selecting the measures shown in Appendix I-B, the Council chose a typical structure in a typical location in each climate zone, and assumed the building was operated in a typical way. Actual buildings will vary from these typical assumptions. It is not administratively feasible to implement a standard that varies as the actual building conditions vary. Therefore, the specific measures included in the MCS will not perform the same in all houses. For example, the heat recovery ventilator has a higher levelized life cycle cost in the smallest (1,344 sq. ft.) home analyzed by the Council. The Council's model conservation standards retain this measure for three reasons.

First, the measure is regionally cost effective for the average new single family house built in the region, since such houses have 1,850 square feet of floor area. Second, as discussed elsewhere, the Council anticipates that the cost of this measure will decline significantly as more builders develop experience with the heat recovery ventilators and the market for such products matures. Third, the Council believes that some form of mechanical ventilation should be provided in new residences to ensure adequate indoor air quality. Consequently, the Council considers the use of heat recovery ventilation systems necessary to maintain satisfactory ventilation while minimizing the energy lost.

As shown in Tables 5-16 and 5-17, the installation of R-49 ceiling insulation rather than R-38 ceiling insulation in climate zones 2 and 3 appears to be regionally cost effective. However, the Council has not included this measure in its standards for these climate zones, due to the limited size of the data base on which these costs are based. At the time the Council conducted its analysis, only nine demonstration programs builders had reported costs for this measure.

Step 4. **Estimate the regional conservation potential available from space heating conservation in new dwellings.** The next step in the Council's development of a regional supply curve for space heating conservation potential requires combining the engineering estimates of individual house savings by climate zone to establish a regional total. Because each measure saves a different amount of energy in each house design and in each location, an aggregate supply curve must be developed that represents the weighted average savings for all measures in comparable dwelling types.

Table 5-26
Forecast Model vs. Engineering Estimate for Space Heating in New Dwellings, Regional Average Use

BUILDING TYPE	FORECASTING MODEL kWh/yr	FORECASTING MODEL kWh/sq ft/yr	ENGINEERING ESTIMATE kWh/yr	ENGINEERING ESTIMATE kWh/sq ft/yr
Single family	9,990	7.1	11,742	8.4
Multifamily	3,590	4.3	4,650	5.5
Manufactured Home	8,160	8.9	12,280	10.5

Table 5-27
Forecasting Model Dwelling Size vs. Average New Dwellings (square feet)

BUILDING TYPE	MODEL EXISTING STOCK	NEW STOCK	RATIO OF NEW STOCK TO MODEL
Single Family	1,400	1,400	1.00
Multifamily	840	1,030	1.23
Manufactured Home	920	1,170	1.27

Each of the three single family dwelling designs was assigned a weight based on its foundation type, size and window area. The specific weight assigned to each design approximately reflects that design's share of the new housing stock additions expected over the forecast period. This was also done for the two manufactured housing designs. Building type weighting was unnecessary for multifamily space heating, because only one multifamily design was used. It should be noted that the Council's forecasting model defines all units up to and including four-plexes as "single family dwellings." Consequently, the weights selected are designed to achieve a much smaller average size for new single family houses (i.e., 1,400 square feet of floor area) than had they been selected on the basis of the more conventional definition of a single family home (one and two family dwellings) used to establish the standards. The average size of typical new one and two family dwellings recently constructed in the region is between 1,600 and 1,800 square feet of floor area.

Once each building design's weight had been established, the average savings by climate type was calculated for all designs. These savings were then aggregated to the regional level based on the share of new electrically heated dwellings expected to be constructed in each climate over the forecast period. Table 5-22 shows the weight assigned each building design and climate type. Tables 5-23 through 5-25 show the weighted average use, cost and savings available from new single family, multifamily and manufactured houses at levelized costs less than 10 cents per kilowatt-hour (equivalent to 100 mills per kilowatt-hour).

Step 5. **Estimate the realizable conservation potential from new residential space heating efficiency improvements.** In order to establish the proportion of technically available space heating conservation that can realistically be achieved, two adjustments must be made to the engineering savings estimates. First, to ensure consistency with the Council's load forecast, the conservation resource based on engineering estimates of current space heating energy use must be adjusted or scaled to account for the forecasting model's estimate of current space heating use. Table 5-26 compares the average space heating energy use by dwelling type, as estimated by the Council's forecasting model for 1985 in the high forecast, and the engineering estimate of space heating use for houses built to current practice. The primary reasons for the differences between each estimate are variations in dwelling unit size, the waste heat released by appliances located in the house, and the use of wood as a substitute for electric heating.

The Council's forecasting model does not explicitly assume a specific average dwelling unit size. However, the space heating energy use for each dwelling type in the model implicitly assumes the average dwelling size for existing dwellings in the model's base year (1979). The forecasting model's present implicit assumptions regarding average size for existing dwellings are shown in Table 5-27. Based on survey data, it appears that average new multifamily dwellings (five-plex and larger) and manufactured houses being built today are typically larger than the model assumes for all existing multifamily dwellings and manufactured houses. However, new single family housing (less than five-plexes) appears to be the same size as the existing single family stock. Therefore, engineering estimates of cost and energy savings from conservation actions in new multifamily dwellings and manufactured homes were scaled to match the forecast model's implicit assumptions regarding unit size. This was done by multiplying the engineering estimates of use, cost and savings by the ratio of average unit size implicitly assumed in the forecast model to the average floor area of new dwelling units. No size adjustment was made for new single family dwellings, because their size appears to be consistent with the existing stock.

Once the adjustment for unit size is made, the forecasting model's estimate of multifamily space heating use is 4,415 kilowatt-hours per year compared to the engineering estimate of 5,720 kilowatt-hours per year for a similar sized unit. Similarly, the forecasting model estimates that space heating use in new manufactured homes is 10,365 kilowatt-hours per year compared to the engineering model's estimate for a comparably sized unit of 12,280 kilowatt-hours per year.

In addition to differences due to variations in dwelling unit size, the Council's engineering estimates of space heating energy use in new dwellings departs from the forecasting model due to underlying assumptions regarding appliance efficiency and family size. In order to match current (1985) consumption, the forecasting model must use current (1985) appliance efficiencies. However, because the Council anticipates substantial efficiency improvements in appliance energy use within the next seven to 15 years, the Council's engineering estimate of space

Table 5-28
Internal Gain Changes from More Efficient Appliances

APPLIANCE/SOURCE	ENERGY USE PER UNIT (kWh/yr) Saturation (units/household)	At Current Efficiencies	At Forecast Efficiencies	Percent Indoors	INTERNAL GAINS PROVIDED At Current Efficiencies (kWh/yr)	At Forecast Efficiencies (kWh/yr)
Lighting[a]	1.00	690	650	90	620	585
Refrigerator[b]	1.083	1,450	675	100	1,570	730
Range/Cooking	1.00	980	880	100	980	880
Freezer	.53	1,170	520	50	310	140
Water Heater[c]	1.00	1,200	675	50	600	340
Television	2,000 set-hr/yr	200	200	100	200	200
Clothesdryer	.7	950	900	10	70	60
Dishwashers, Clotheswashers, & Misc. Appliances	—	1,750	1,500	50	875	750
People[d]	2.63/2.22	1,920	1,810	100	1,930	1,720
TOTAL					7,135	5,355

[a]Assumes 1,400 square foot home. For other floor areas, lighting loads should be scaled by floor area.

[b]Assumes one refrigerator is located inside the house and 50 percent of .165 refrigerators are located outside the house.

[c]Assumes water tank has R-10 for current efficiencies, and R-20, with R-10 bottom board, and temperature setting of 130°F on 50 percent of tanks. Waste heat from water use is included with contribution from people.

[d]Contribution from people includes 290 kilowatt-hours per year per occupant as sensible heat and 230 kilowatt-hours per year per occupant as latent heat. Also included is 565 kilowatt-hours per year of latent heat provided to the house from the use of warm water for cooking and bathing.

heating use assumes the presence of more efficient appliances.

Table 5-28 shows the difference in waste heat (i.e., internal gains) released inside typical single family dwellings from people and appliances assumed by the forecasting model in 1985 and in 2005. At current efficiencies and persons per household, approximately 7,100 kilowatt-hours of heat are released each year inside the house by people, lights and appliances. However, with anticipated improvements in appliance efficiency and a reduction in the average number of people per household, this will drop to approximately 5,350 kilowatt-hours per year by 2005.

Because this waste heat offsets the need for space heating, more efficient appliances mean larger space heating energy requirements. Had the Council assumed less efficient appliances in its engineering estimates, the regional average space heating energy used in new single family houses built in 1985 would fall about 1.2 kilowatt-hour per square foot. This reduction amounts to about 1,600 kilowatt-hours per year in the average new single family house. However, failure to recognize the installation of efficient appliances in this same house by the year 2005 would result in an underestimate of space heating energy needs by 0.9 kilowatt-hours per square foot per year. Therefore, the Council used the lower value, which reflects the appliance efficiency present in new homes over the majority of their useful life. The use of the lower quantity of waste heat in the Council's engineering estimate produces savings for space heating energy that are larger in the near term (when the region is surplus); however, this value results in better estimates of long-term requirements (when the region faces new resource decisions).

Nearly 90 percent of the 1,735 kilowatt-hour per year difference between the engineering estimate of space heating use in single family houses and that shown by the forecasting model can be attributed to alternative assumptions regarding appliance efficiency. The Council increased the space heating energy use shown by the forecasting model for single family houses by approximately 1,600 kilowatt-hours per year to account for the interaction of space heating and appliance efficiency. Multifamily space heating use was increased by just over 1,100 kilowatt-hours per year, and manufactured home space heating use was increased by just under 1,700 kilowatt-hours per year. Although it appears likely that the remaining difference (approximately 500 kilowatt-hours per year) between the forecast model and engineering model's estimates of space heating use can be accounted for by supplemental heating with wood, the Council has assumed as a conservatism that the difference represents energy efficiency improvements already implemented in new single family dwellings. However, this adjustment and the size adjustment result in a base use for space heating of approximately 11,400 kilowatt-hours per year for new single family houses, 5,570 kilowatt-hours per year for new multifamily dwellings and 12,525 kilowatt-hours per year for new manufactured housing.

Table 5-29
Technical Savings per Unit and Megawatts for New Single Family Houses

Number of New Units: Public	IOU	Total	Savings kWh per unit: Public	IOU	Levelized Cost mills/kWh	Average Annual Savings in MW: Public	IOU	Total
482,690	658,980	1,141,670	263	0	5	15	0	15
			527	0	10	29	0	29
			1,257	359	15	69	27	96
			3,630	2,732	20	200	206	406
			4,625	3,727	25	255	280	535
			5,034	4,136	30	277	311	589
			5,518	4,619	35	304	347	652
			6,189	5,291	40	341	398	739
			6,410	5,512	45	353	415	768
			7,034	6,136	50	388	462	849
			8,012	7,113	55	441	535	977
			8,012	7,113	60	441	535	977
			8,012	7,113	65	441	535	977
			8,012	7,113	70	441	535	977
			8,012	7,113	75	441	535	977
			8,012	7,113	80	441	535	977
			8,012	7,113	85	441	535	977
			8,012	7,113	90	441	535	977
			8,012	7,113	95	441	535	977
			8,012	7,113	100	441	535	977

Table 5-30
Technical Savings per Unit and Megawatts for New Multifamily Units

Number of New Units: Public	IOU	Total	Savings kWh per unit: Public	IOU	Levelized Cost mills/kWh	Regional Potential in Megawatts: Public	IOU	Total
129,883	138,016	267,899	154	0	5	2	0	2
			319	0	10	5	0	5
			780	127	15	12	2	14
			1,607	954	20	24	15	39
			2,558	1,905	25	38	30	68
			2,646	1,993	30	39	31	71
			2,765	2,112	35	41	33	74
			3,170	2,516	40	47	40	87
			3,226	2,573	45	48	41	88
			3,332	2,679	50	49	42	92
			4,383	3,730	55	65	59	124
			4,395	3,742	60	65	59	124
			4,406	3,753	65	65	59	124
			4,417	3,764	70	65	59	125
			4,429	3,776	75	66	59	125
			4,440	3,787	80	66	60	126
			4,440	3,787	85	66	60	126
			4,440	3,787	90	66	60	126
			4,440	3,787	95	66	60	126
			4,440	3,787	100	66	60	126

Table 5-31
Technical Savings per Unit and Megawatts for New Manufactured Homes

Number of New Units: Public	IOU	Total	Savings kWh per unit: Public	IOU	Levelized Cost mills/kWh	Regional Potential in Megawatts: Public	IOU	Total
60,493	102,655	163,148	0	0	5	0	0	0
			836	88	10	6	1	7
			1,511	533	15	10	6	17
			1,956	1,107	20	14	13	26
			2,530	1,770	25	17	21	38
			3,193	2,690	30	22	32	54
			4,113	3,317	35	28	39	67
			4,740	4,019	40	33	47	80
			5,442	4,624	45	38	54	92
			6,047	5,168	50	42	61	102
			6,591	5,539	55	46	65	110
			6,961	5,724	60	48	67	115
			7,147	5,907	65	49	69	119
			7,330	5,938	70	51	70	120
			7,361	5,938	75	51	70	120
			7,361	5,938	80	51	70	120
			7,361	5,938	85	51	70	120
			7,361	5,938	90	51	70	120
			7,361	5,938	95	51	70	120
			7,361	5,938	100	51	70	120

The Council anticipates current research activities in the region will measure actual space heating consumption in new dwellings. When this information becomes available it can be used to adjust both the engineering estimate and the forecast model estimate of space heating use in new dwellings.

Tables 5-29 through 5-31 show the technical savings per unit and the average megawatts of technical conservation potential from improvements in space heating efficiency in new single and multifamily dwellings and manufactured houses. The achievable conservation potential for new single family and multifamily dwellings assume a gradually increasing share of new electrically heated residences that install all regionally cost-effective space heating conservation measures between 1986 and 1990. This share is 35 percent in 1986, 45 percent in 1987, 60 percent in 1988 and 75 percent in 1989. After 1989, 85 percent of all new electrically heated single family and multifamily units are assumed to install all regionally cost-effective measures. Similarly, gradual increases in the share of new manufactured houses (10 percent in 1986, increasing at an additional 10 percent per year) are assumed to include all regionally cost-effective measures between 1986 and 1989. After 1989, 50 percent of all new electrically heated manufactured houses are assumed to install all regionally cost-effective measures.

The combined total of achievable space heating conservation potential in new residences included in the Council's high load forecast is 725 average megawatts.

Electric Water Heating Conservation

The energy used to heat water represents the second largest end-use of electricity in the residential sector. Figure 5-5 shows the technical potential for improving the efficiency of residential water heating at various costs of electricity. These savings represent better insulated water heaters, pipe wraps, and more efficient appliances that use hot water (e.g., clotheswashers and dishwashers).

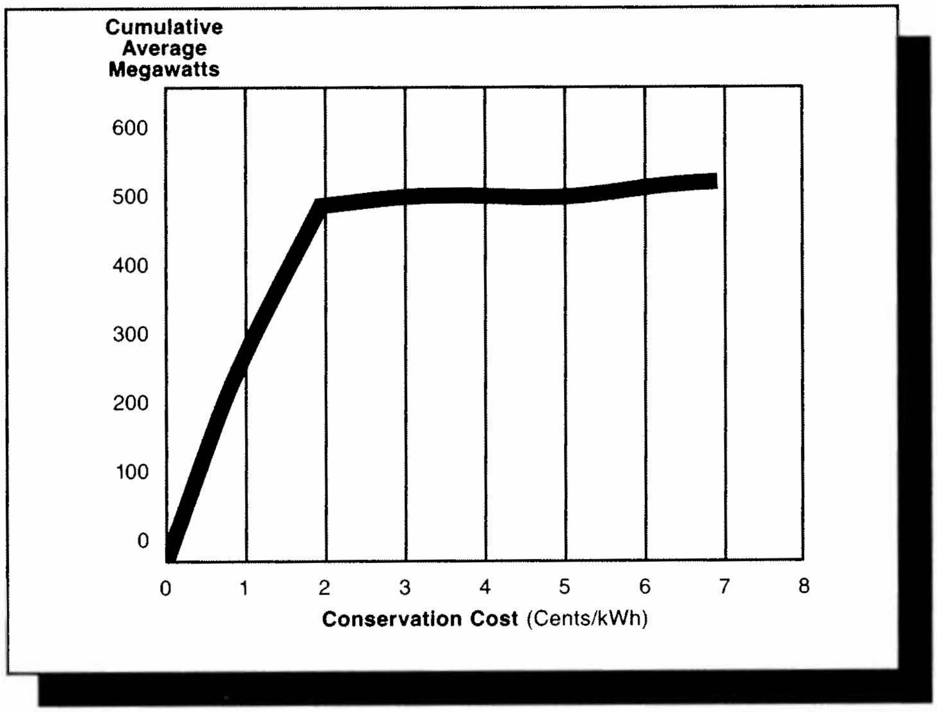


Figure 5-5
Technical Conservation Potential from Residential Water Heating Measures

The cost-effective technical potential identified by the Council for electric water heaters is about 514 average megawatts. The achievable portion of this, about 377 average megawatts, represents about 18 percent of water heating loads in 2005. The average cost of improving the efficiency of electric water heaters is 1.8 cents per kilowatt-hour.

The Council's assessment of the conservation potential available from improved residential water heating efficiency involved three steps. These were to:

1. Estimate the cost and savings potential available from improved water heating efficiency.

2. Develop conservation supply functions for technical and achievable potential.

3. Calibrate savings to the Council's forecast.

Step 1. **Estimate the cost and savings potential available from improved water heating efficiency.** The amount of energy consumed for water heating depends on two factors: standby losses and variable use. Standby losses refer to the energy that is used during storage to keep the water hot; they are determined by the temperature of the water and insulation levels of the hot water storage tank and supply piping. Variable use is the amount of hot water actually used in the household. Variable use differs substantially among households, depending upon such factors as the habits and number of occupants, and the stock of appliances that use hot water (such as clotheswashers and dishwashers), as well as the temperature of the hot water and the cold water that enters the tank.

The base use of water heaters from which conservation potential could be estimated was derived by reviewing current research on the question. Table 5-32 summarizes available data on standby losses from conventional (typically R-5) tanks. Water heat was directly submetered in all field studies. Laboratory tests on individual units had lower standby losses than those found in field tests. The average value of the full sample is 1,610 kilowatt-hours per year, identical to the Seattle City Light number of 1,610 kilowatt-hours per year, which was used in the 1983 plan. This is the value used for conventional tank standby losses.

Table 5-32
Data on Standby Losses from Conventional Water Heater Tanks

SOURCE	STANDBY (kWh/yr)	N	NOTES
Seattle City Light	1,610	26	All unwrapped, submetered
Biemer/Auburg '84	1,375	1	Laboratory tests
Goldstein/Clear	1,468		Calculated for 1960-1980 vintage tanks
Ek '82 (#36	1,483	1	Laboratory Test
Ecotope '82	1,995	91	Some wrapped, many different locations.
Ecotope Heat Pump Study	1,731	39	Median standby losses in three cities are weighted by climate zone's contribution to regional population.
Average	1,610		

Table 5-33
Variable Demand Use for Hot Water

SOURCE	GALLONS/YEAR PER PERSON	N	NOTES
Lawrence Berkely Laboratories	5,582		
Natural Resources Defense Council	5,411		Calculated
Seattle City Light	6,019	26	Calculated
Ecotope Heat Pump Study	7,680	38	Submetered participants selected on basis of family size and high water use.
Bavir	7,094		Regression results from submetered sample.
Long Island Light Co.	6,788	257	Submetered
Average	6,429 gallons/person/year		

At 90° temperature differential this translates to: 1,399 kWh/person/year

Table 5-34
Savings from Water Heating Measures
(kWh/yr at 80° Temperature Differential)

	SEATTLE CITY LIGHT		BIEMER/AUBURG '84	
Standby losses for R-5 tank	1,610		1,375	
	Savings	**% of use**	**Savings**	**% of use**
R-20 tank	700	43.5	550	40.0
R-11 wrap	100	11.0	192	23.3
Bottom board	40	4.9	19	3.0
Thermal trap	180	23.4	74	12.1
Total percent savings		63.3		60.7

Variable use for the pre-conservation situation was estimated from studies that reported the gallons of hot water used per person or per household. Table 5-33 summarizes the empirical data. Hot water demand was actually measured in some cases, while in others it was calculated. If the figures are converted to kilowatt-hours per person,[9] the average kilowatt-hour use per occupant is approximately 1,400 kilowatt-hours per year. Given the tremendous variation inherent in hot water variable use, this number is reasonably close to the value used in the 1983 plan, which is 1,310 kilowatt-hour per occupant for an 80° temperature differential. The Council continued using the 1,310 kilowatt-hours per occupant for base year use, since available data did not dictate a change.

The two primary sources for estimating the savings available from various standby conservation measures were a Seattle City Light (SCL) study, which served as the basis for the 1983 plan figures, and a new laboratory study conducted by Bonneville in 1984 (Biemer and Auburg). Both studies tested R-5 tanks. These studies started with different standby losses (1,610 kilowatt-hour per year for SCL compared to 1,375 kilowatt-hour per year for the Bonneville study) and found different absolute savings estimates. However, the two studies produced comparable results in terms of the relative savings attained for all measures combined, and for two of the four individual measures. The results for each study are shown in Table 5-34. Water heater wraps and thermal traps are the individual measures with the greatest difference. The Council used an average of the percent savings reported in both studies, and applied these to the base year standby use.

The cost of efficient tanks is from a survey done by the Pacific Northwest Utilities Conference Committee. This cost is the incremental cost of purchasing an efficient rather than a conventional tank. Costs for water heater wraps are from Bonneville. Costs for thermal traps, bottom boards, and energy-saving showerheads were adapted from work done at Seattle City Light.

Conservation measures for variable use include clotheswashers and dishwashers that use hot water more efficiently, and energy-saving showerheads.[10] The costs and savings available from efficient clotheswashers and dishwashers and costs for showerheads were taken from work done at Lawrence Berkeley Laboratories (LBL). LBL estimated more efficient clotheswashers would save about 355 kilowatt-hours per year and more efficient dishwashers would save 245 kilowatt-hours per year. Estimates of savings made by the Natural Resources Defense Council for dishwashers are somewhat lower. Energy-saving showerheads are assumed to save 35 percent of the hot water used for showers.

The lifetimes of the measures discussed above are 12 years, except for showerheads at 20 years, and clotheswashers and dishwashers assumed to be ten years.

It should be noted that the savings for standby loss conservation measures have been reduced to reflect the interaction between internal gains from water heaters and space heating electricity consumption. This is described in a section that follows the analysis of refrigerator and freezer conservation potential.

Base case heat pump water heater costs were taken from work done by the Pacific Northwest Utilities Conference Committee. For a sensitivity analysis described later in this section, costs from an Electric Power Research Institute paper were used. Heat pump water heater savings are from a recent research study conducted for Bonneville. This report indicated that heat pump water heaters saved an average 40 percent of total hot water use. Savings are calculated by assuming that all of the less expensive conservation measures have been installed first. The lifetime of heat pump water heaters is assumed to be 12 years.

The costs of solar water heaters were taken from work done by the Oregon Department of Energy, where the system costs of the solar water heaters were derived from state tax forms. The cost for a system installed by a small contractor was about $4,000. Costs ranged from $3,000 if owner-installed to $5,000 if a large marketing company did the work. Where solar systems were installed as part of a contract to install numerous systems in one geographic area, the costs could get as low as $2,400. Base case costs used in this analysis are $4,000 per installation plus $10 per year maintenance costs. For a sensitivity analysis, $2,400 per installation plus maintenance costs were used. Savings are from the interim results of Bonneville's program of monitoring solar water heaters and are about 40 percent of total water heating use. Lifetime is estimated to be 20 years.

The above assumptions led to the cost-effectiveness calculation for each measure shown in Table 5-35. This table assumes an average household with 2.4 occupants. It shows the marginal cost of each water heating conservation measure, starting with an estimated average tank[11] and water heater use. Except for heat pumps, solar water heaters and bottom boards, none of the measures exceed 5.0 cents per kilowatt-hour even after taking into account the interactive effect with space heating. Bottom boards are on the margin of being cost effective and would certainly be so if other measures could not be installed. The analysis suggests that energy efficient tanks, wrapped with insulating blankets and fitted with thermal traps, and all variable reduction measures, are cost effective.

Table 5-35

Measure Costs and Savings for Water Heaters

MEASURE	MEASURE COST	SAVINGS	SAVINGS WITH INTERACTION[b]	CENTS/KWH	LIFE CYCLE COST[c]
Base Use = 4,454 kWh/Year					
Base Case	$ 0	0	0	0	1,177
Efficient Showerhead	$ 34.20	450	450	0.55	1,104
Efficient Clotheswasher	$ 22.00	355	355	0.78	1,056
Efficient Dishwasher	$ 22.00	245	245	1.13	1,032
Efficient Tank	$ 45.00	344	286	1.41	1,005
Thermal Trap	$ 22.80	173	144	1.42	992
R-11 Wrap	$ 42.40	136	113	3.36	1,006
Bottom Board	$ 12.54	26	22	5.19	1,013
Heat Pump	$1,488.00	1,090	1,090	14.70	2,274
Solar Water Heater[a]	$4,175.00	1,090	1,090	27.40	3,291

[a]Without heat pump installed.

[b]This reflects the reduced savings from standby loss measures due to the interaction with electric space heating.

[c]Parameters for the life cycle cost calculation are: 10 percent consumer discount rate, zero electricity price escalation and an average residential rate of 3.7 cents per kilowatt-hour. All measures' costs and savings are calculated proportionally based on 12 years.

Also shown in Table 5-35 is the cost of purchasing and operating the water heater over a 12-year period (called the "life cycle cost"). Life cycle costs have been used by the Council to determine the attractiveness of conservation measures to the consumer. All measures that are cost effective to the region—less than 5.0 cents per kilowatt hour—also result in a lower life cycle cost to the consumer than the base case.

As with most water heating conservation measures, the cost effectiveness of heat pump and solar water heaters depends on the amount of hot water consumed in the household, which can vary significantly even among households of the same size. As shown in Table 5-35, for an average family size with a water heater where all cheaper conservation measures are installed first, the heat pump and solar water heaters are not cost effective. Table 5-36 shows the calculated levelized cost for heat pumps and solar water heaters under various assumptions of family size, pre-installed conservation measures, and capital cost.

Table 5-36

Sensitivity Analysis on the Cost Effectiveness of Heat Pump and Solar Water Heaters

Base Case: Base costs of heat pump and solar water heaters, all cheaper conservation measures installed first.

	HEAT PUMP WATER HEATER			SOLAR WATER HEATERS		
FAMILY SIZE (persons/household)	COST	SAVINGS (kWh/yr)	LEVELIZED COST (cents/kWh)	COST	SAVINGS (kWh/yr)	LEVELIZED COST (cents/kWh)
2.4	$1,488	1,090	14.7	$4,150	1,090	27.4
3	$1,488	1,299	12.3	$4,150	1,299	23.0
4	$1,488	1,648	9.7	$4,150	1,648	18.1
5	$1,488	1,997	8.0	$4,150	1,997	15.0
6	$1,488	2,346	6.8	$4,150	2,346	12.7
Sensitivity 1: No variable usage conservation measures installed.						
2.4	$1,488	1,510	10.6	$4,150	1,510	19.8
3	$1,488	1,824	8.8	$4,150	1,824	16.4
4	$1,488	2,348	6.8	$4,150	2,348	12.7
5	$1,488	2,872	5.6	$4,150	2,872	10.4
6	$1,488	3,396	4.7	$4,150	3,396	8.8
Sensitivity 2: Less expensive installation costs for heat pump and solar water heaters.						
2.4	$ 765	1,090	7.6	$2,550	1,090	16.9
3	$ 765	1,299	6.3	$2,550	1,299	14.1
4	$ 765	1,648	5.0	$2,550	1,648	11.1
5	$ 765	1,997	4.1	$2,550	1,997	9.2
6	$ 765	2,346	3.5	$2,550	2,346	7.8

Step 2. **Develop conservation supply functions for technical and achievable potential.** The savings for each measure were multiplied by the number of units that appear in the forecast between 1992 and 2005 to which that measure applied. The savings from showerheads is limited by the number of new houses likely to be built between 1992 and 2005 with electric water heaters. The number of clotheswashers and dishwashers is assumed to track the number of new electric water heaters with saturations of 78 percent and 50 percent respectively. The number of units was then multiplied by the achievable saturation, also measure-specific, that the Council felt could be secured between 1992 and 2005. The number of units and the achievable saturation for the high demand forecast appear in Table 5-37. The described calculation derives the number of average megawatts that can be secured.

Table 5-36 shows that the cost of solar water heaters only approaches the 5.0 cents per kilowatt-hour threshold in high water use households or if low capital costs emerge. Heat pump water heaters are cost effective for a six-person household if no variable conservation measures costing less than the heat pump, such as energy-saving showerheads, are installed first. In addition, if the installation and maintenance costs of heat pump water heaters is significantly reduced over the next few years, they might become cost effective for household sizes of four and greater. This estimate however, does not take into account the negative impact on space heating that a heat pump water heater would have if installed in the heated space. Heat pump and solar water heaters are not considered cost effective in the current analysis. However, heat pump water heaters and to some extent solar water heaters appear to be promising resources. The Council will reevaluate costs and savings for future analyses of cost-effective conservation resources.

Step 3. **Calibrate the supply curve to the Council's forecast.** The engineering and field measurements described above predict a base use of about 4,450 kilowatt-hours per year for an average household. As mentioned above, this figure represents a mix of unwrapped conventional tanks, wrapped tanks, and some efficient tanks. Standby losses in 1992 are anticipated to differ from the standby losses included in the above described number due to a different mix of conventional and efficient tanks. In order to capture this change, and to be consistent with the Council's forecast of electricity consumption, the base case needs to vary with the forecast's prediction of water heating electricity use in 1992. In the demand forecast, base case use in 1992 varied between 4,602 kilowatt-hours per year and 4,223 kilowatt-hours per year, depending on the forecast scenario. For purposes of the supply curve, the difference between the forecast base case use and the calculated base case use was assumed to be due to level of water heater insulation. This difference altered the supply curve somewhat to account for the different base case uses. For the high demand forecast, this adjustment reduced the technical supply curve by 50 average megawatts at about the 2 cent per kilowatt-hour level.

The amount of conservation available in the high demand forecast at various costs is presented in Table 5-38.

Conservation in Other Residential Appliances

Approximately one-quarter of the electricity currently consumed in the residential sector is used to operate refrigerators, freezers, stoves and lights. This section describes the conservation assessment for refrigerator/freezers and freezers. For electric ranges, the most significant conservation potential would stem from the substitution of bi-radiant ovens for electric ovens. This is a technology that should be watched for future assessments of conservation potential. The technical conservation potential from replacing traditional incandescent bulbs with fluorescent bulbs in residential applications represents roughly 50 average megawatts. When the region approaches the end of the current surplus period, the savings from fluorescent bulbs should probably be pursued. No program should be pursued in the meantime, however, because the bulbs are short-lived. As a conservatism in the conservation assessment for the resource portfolio, the Council did not include an estimate of fluorescent bulb savings in residential applications.

The Council has included only 368 average megawatts in its estimates of achievable potential for refrigerators and freezers, which is much less than the amount that could technically be accomplished for a marginal measure cutoff of 5.0 cents per kilowatt-hour as described below. Even so, achievable conservation through the use of more efficient refrigerators and freezers represents a 12 percent savings by 2005. At an average cost of 0.8 cents per kilowatt-hour, these savings are the most cost-effective conservation resource available to the region.

The savings identified by the Council are based on the level of efficiency improvements resulting from revised appliance standards recently adopted in California that become effective in 1992. The new California standard is phased in starting in 1987, with a more stringent standard becoming effective in 1992.[12] The Council's savings reflect the impact of the 1992 standard only, although both the level of the 1987 and 1992 standards are cost effective for this region. The Council found that refrigerators and freezers that go significantly beyond the California 1992 standard are not yet commercially available, although engineering estimates indicate that technologies to beat the 1992 standards are attainable.[13] An alternative design refrigerator that beats the energy requirement of the 1992 standard by about two-thirds is available today, but is quite costly because each unit is handmade. This refrigerator further corroborates the engineering estimates that refrigerators can be made to beat the 1992 California standards. Savings from going beyond the standard are substantial and represent a promising resource for future evaluations of conservation potential if such units become commercially available.

The Council used four steps to evaluate the savings available from refrigerator and freezer efficiency improvements. These were to:

Table 5-37

Number of Eligible Units by 2005 and Achievable Conservation Percent for Water Heating Measures

High Demand Forecast

MEASURE	NUMBER	ACHIEVABLE PERCENT
Efficient Showerheads	1,630,000	90%
Efficient Clotheswashers	3,568,500	50%
Efficient Dishwashers	2,287,500	50%
Efficient Tanks	4,575,000	90%
Thermal Trap	4,575,000	85%
R-11 Wrap	4,575,000	85%
Bottom Board	4,575,000	85%

Table 5-38

Conservation Available from Water Heaters

LEVELIZED COST (cents/kWh)	CUMULATIVE TECHNICAL POTENTIAL (average megawatts)
1	269
2	473
3	504
4	518
5	525
6	526
7	526

1. Estimate the cost and savings potential available from improved refrigerator and freezer efficiency.

2. Develop technical and achievable conservation potential.

3. Calibrate the achievable conservation potential to the Council's forecast.

Step 1. **Estimate the costs and savings potential available from improved refrigerator and freezer efficiency.** The potential for energy savings from improved refrigerator and freezer operating efficiencies is well documented. The U.S. Department of Energy (DOE) and the California Energy Commission (CEC) have recently reviewed the option of appliance efficiency standards. The DOE proceeding limited its investigation of efficiency improvement design options to those based on "available" technology. Available technology was defined by DOE as those technologies implemented in units available and sold in 1980. In addition, the DOE analysis only included options that had a payback period of less than five years. The payback period for an energy-saving design option is the length of time it takes an average consumer (in this case, a national consumer) to recover the higher purchase price through the lower cost of energy used to operate the appliance. Both these limits significantly reduced the efficiency options evaluated by DOE.[14]

The CEC hearings looked at technologies that went beyond the measures analyzed in the DOE hearings. This resulted in a much larger and broader set of designs to reduce refrigerator energy consumption. The CEC proceedings resulted in adoption of revised refrigerator and freezer standards that will lower the current California standards first in 1987 and again in 1992.[15] The level of efficiency chosen for the most stringent standard—effective in 1992—was set at about the strongest level investigated by DOE. As a consequence, this standard did not include the additional measures that emerged during the CEC hearings.

Table 5-39
Measure Cost and Savings for Prototype Refrigerators

	USE kWh/yr	MEASURE COST	CUMULATIVE COST	COST OF SAVINGS (cents/kWh)[a]	DISCOUNTED LIFE CYCLE COST[b]
Base Case in DOE analysis	1,354	$ 0	$ 0	0	$1,000
Foam insulation substituted in door	1,208	$ 7.38	$ 7.38	0.44	$ 969
Compressor EER[c] 3.65	1,072	$ 7.44	$ 14.82	0.47	$ 942
Anti-sweat switch	978	$ 8.17	$ 22.99	0.75	$ 926
Increase door thickness to 2″	940	$ 3.72	$ 26.71	0.84	$ 919
2.4″ cabinet insulation, 2½″ freezer insulation	768	$14.82	$ 41.53	0.74	$ 890
High efficiency fan	688	$10.98	$ 52.51	1.18	$ 880
2.4″ cabinet insulation, 3″ freezer insulation	613	$13.18	$65.69	1.52	$ 874
EER 4.5	518	$27.45	$ 93.14	2.48	$ 877
Evacuated panel	228	$88.40	$181.54	2.63	$ 890
EER 4.8	217	$ 5.49	$187.03	4.10	$ 893
Double freezer gasket	204	$20.60	$207.63	13.8	$ 910
Double gasket-door	186	$34.04	$241.67	16.0	$ 940

[a]Adjusted for space heat interaction.

[b]Parameters used for the life cycle cost analysis included: 10 percent consumer discount rate, 22 year lifetime, zero electricity price escalation, and an average residential rate of 3.7 cents per kilowatt-hour.

[c]EER stands for Energy Efficiency Ratio.

California's 1992 standard is illustrated by taking a frost-free 17 cubic foot refrigerator as an example. In 1992 this unit will be required to use less than 672 kilowatt-hours per year. The current energy use of this appliance will be almost halved, compared to 1,156 kilowatt-hours per year, the average energy use of the same unit sold in 1983 according to the Association of Home Appliance Manufacturers (AHAM).

The Council used the information that emerged from the DOE and CEC hearings to evaluate the cost effectiveness of efficiency improvements in refrigerators and freezers in the Northwest region. In some cases this meant adjusting savings for the interaction with space heating needs (described in the following section) or re-ordering measures so they were applied with the most cost effective first. In this analysis, the Council used a 17 cubic foot automatic defrost prototype to represent refrigerators, and a 15 cubic foot chest freezer to represent freezers. Automatic defrost units represent approximately 78 percent of the refrigerators sold today.

Cost effectiveness was analyzed from both the perspective of the region and the individual consumer. Table 5-39 presents this cost and savings information for the prototype 17 cubic foot refrigerator. Savings and levelized costs include the interaction of appliance efficiency improvements with space heating requirements, described more fully in the next section.

The costs of measures and their savings were evaluated starting with the base case from the DOE proceedings. However, refrigerators on the market today incorporate some of the measures evaluated in Table 5-39, and consequently a number of models are more efficient than the base case in the DOE analysis. The costs and savings curve, however, can still be used to represent the relative efficiency improvement available for a given cost. The base case is just moved further down the curve to represent currently sold units that have incorporated some of the measures listed in the table. For example, many units sold today have more insulation than the 1.6 inch thick fiberglass insulation assumed in the base case. However, other measures in the table are still viable options for reducing consumption in the average refrigerator. Since a measure's levelized cost is independent of where the base case originates on the curve, the fact that current units exceed the DOE 1980 base case does not mean that the measures in the table are any less cost-effective.

Improving the efficiency of the prototype refrigerator to the level where the last measure installed has a marginal cost of 5.0 cents per kilowatt-hour, a new prototypical 17 cubic foot refrigerator would save 939 kilowatt-hours per year beyond 1983 current average use of 1,156 kilowatt-hours per year. This results in a total consumption of about 217 kilowatt-hours per year. The purchase and operation costs of the refrigerator over its lifetime (life cycle cost) at 10 percent discount rate is less at the cost-effectiveness limit (a consumption of 217 kilowatt-hours per year) than at the base case. However, the 5.0 cents per kilowatt-hour cost-effectiveness limit results in a much lower energy use than the 1992 California standard. The 1992 California standard results in refrigeration use of about 672 kilowatt-hours per year for the prototype, which represents a marginal cost of about 1.2 cents per kilowatt-hour, and a net reduction in life cycle cost. For the average stock of refrigerators instead of the prototype, the level of the 1992 standard is about 675 kilowatt-hours per year. The level of the 1992 standard for average refrigerators was used for the Council's conservation assessment.

The costs and savings for measures that can be applied to the prototype chest freezer appear in Table 5-40. Less extensive analysis was done on freezer conservation potential than on refrigerator potential in both the Department of Energy and the California hearings. The last measure analyzed has a marginal cost of only 1.7 cents per kilowatt-hour—even after the cost of the last measure was increased significantly to account for the fact that it represents advanced technology. Consumption is reduced from 720 kilowatt-hours per year, which is average 1983 consumption for this type of freezer according to AHAM, to 342 kilowatt-hours per year, a savings of 378 kilowatt-hours per year if all measures are used. All measures investigated resulted in lower purchase and operation costs than the base case over the life of the freezer. The 1992 California standard for average freezers is about 519 kilowatt-hours per year. The level of the 1992 standard for average freezers was used to establish the Council's limit of available and reliable conservation for this appliance.

Table 5-40
Measure Cost and Savings for Prototype Freezers

	USE kWh/yr	MEASURE COST	CUMULATIVE COST	COST OF SAVINGS (cents/kWh)[a]	DISCOUNTED LIFE CYCLE COST[b]
Base Case in DOE analysis	851	$ 0	$ 0	0	$739
Compressor EER 3.5	788	$ 4.58	$ 4.58	0.58	$726
Foam Insulation substituted in door	704	$ 8.25	$12.83	0.78	$710
Increase door thickness to 2″	678	$ 3.12	$15.95	0.95	$706
Increase cabinet thickness to 2.5″	571	$19.34	$35.29	1.43	$696
Advanced technology	342	$50.00	$85.29	1.73	$681

[a]Includes interaction with space heater.

[b]Parameters used for the life cycle cost analysis are: 10 percent consumer discount rate, 22 year lifetime, zero electricity price escalation, and an average residential rate of 3.7 cents per kilowatt-hour.

Step 2. **Develop conservation supply functions for technical and achievable potential.** The savings resulting from the level of the 1992 California refrigerator and freezer standards were multiplied by the number of refrigerators and freezers purchased between 1992 and 2005. Since the energy load that has to be met by thermal plants after conservation actions are taken is determined by the forecast, the savings from conservation measures in refrigerators and freezers has to be evaluated consistently with the values carried in the forecasting model.

There is reason to suspect that the forecasting model's projections of electricity use by these appliances are too high. The model projects refrigerator use of about 1,400 kilowatt-hours per year in 1984, which is significantly above the average use of 1,140 kilowatt-hours per year estimated by AHAM based on actual 1984 sales. This discrepancy in 1984 suggests that the model's projections in 1992 could be too high. This would have two effects: First, estimates of savings due to the California standards would be too high, and second, projected demands would be too high by an equivalent amount.

This evidence raises several questions. Is the DOE test procedure, on which the AHAM estimates are based, an accurate simulation of actual use, which the forecast tries to capture? Are the technology curves used in the forecasting model accurate representations of available technology? Would it be reasonable to adjust the consumers' implicit discount rates in the forecasting model to make the model match AHAM-estimated appliance efficiencies in 1984?

A thorough analysis of this issue will take a significant amount of work. This analysis has not been given first priority in the preparation of this plan, because the policy impact of the possible error is negligible. The amount of generating resources required to serve these appliances after the effect of the standard would be unaffected by such an error. Likewise, the marginal cost effectiveness of measures included in the standard is unchanged. Consequently, the Council's forecasting model was used to estimate the base case use of refrigerators and freezers in 1992. In the high demand forecast in 1992, new refrigerators used 1,402 kilowatt-hours per year and freezers used 1,147 kilowatt-hours per year.

For refrigerators, a base use of 1,402 kilowatt-hours per year and a standard in 1992 of 675 kilowatt-hours (kWh) per year resulted in a total technical potential:

$$\frac{[4{,}483{,}000 \text{ refrigerators purchased 1992-2005} \times (1{,}402 - 675 \text{ kWh/year}) \times (1 - .2 \text{ space heat interaction})]}{8{,}766{,}000 \text{ kWh per average megawatt(MWa)}} = 297 \text{ MWa}$$

For freezers, a base case use in 1992 of 1,147 kilowatt-hours per year and a standard of 519 kilowatt-hours per year resulted in a total technical potential:

$$\frac{[1{,}796{,}000 \text{ freezers purchased 1992-2005} \times (1{,}147 - 519 \text{ kWh/year}) \times (1 - .13 \text{ space heat interaction})]}{8{,}766{,}000 \text{ kWh per average megawatt (MWa)}} = 112 \text{ MWa}$$

These technically achievable savings were reduced by 10 percent to account for noncompliance.

Should current shipment-weighted usage for refrigerators and for freezers be used as base year usage instead of the forecasting values, total savings would be about 190 average megawatts for refrigerators and 50 average megawatts for freezers. The cost effectiveness, or desirability, of savings from refrigerator and freezer efficiency improvements is not reduced by using either the base case from the forecasting model or the case from shipment-weighted average efficiencies.

The Interaction between Internal Gains and Electric Space Heat

A house is warmed by a combination of internal and external heat sources. Internal heat comes from incidental or waste heat given off by appliances and people (usually called "internal gains") and from the space heater. The external source of heat is primarily radiant energy from the sun (usually called "solar gain"). These heating sources are in balance, and if the heat produced by any one of them decreases, more heat must be added from the other components to keep the house at the same temperature. This section deals with the interaction between the waste heat given off by appliances and the heat supplied by the space heater.[16]

If the efficiency of an appliance located inside the heated space, such as a refrigerator, is improved, the unit both uses less energy and gives off less waste heat. This in turn causes the space heater to use more energy in order to keep the house at the same temperature it was before the refrigerator's efficiency was improved.

The balance between how much energy is saved by the refrigerator and how much extra heating is done by the space heater depends on many factors. A prominent factor is the insulation level of the house. The better insulated a dwelling is, the less useful the waste heat from the appliance. For example, the space heater must produce about an additional 5 kilowatt-hours per year for every 10 kilowatt-hours per year saved by the appliance efficiency improvement, assuming all of the following: the appliance is located in the heated space, electricity is the space heating fuel, no air conditioning is installed, and the house is fairly uninsulated. In other words, only 50 percent of the savings from improving appliance efficiency would be realized.

This estimate accounts for periods of the year, such as summer, when additional space heat is not necessary. This estimate must be tempered by other intervening variables to calculate the average expected impact on the Northwest electrical system from improved appliance efficiencies. First, the appliance must be one that produces internal gains. Many do not; for example, about half the electric freezers in the region are located outside heated areas. Waste heat generated from freezers (and other appliances) that are outside the heated shell of the house does not contribute to internal gains. Consequently, any efficiency improvements in appliances located outside the house would be fully realized as 100 percent energy savings and would not require that additional heat be provided by the furnace.

Second, a number of electrical appliances that do produce internal gains, such as refrigerators, are located in houses that do not use electricity for their space heating. In this case, the full amount of electricity saved by improving the appliance's efficiency is realized by the region's electrical system.

Finally, the reduction of internal gains is a benefit to the house if air conditioning equipment is installed. In this case, less cooling needs to be provided in the summer to offset the internal gains from inefficient appliances.

For water heaters, only the standby use of holding hot water in the tank (for units located in the house) is an internal gain. Variable hot water demand does not contribute significantly to internal gains, even though it uses electricity.[17] Consequently, only efficiency improvements in standby use for tanks located in the house increase the heat needed from the space heater.

When all of these factors are considered, electricity used for space heating must make up, on average in the region, about 17 percent, 20 percent and 13 percent of the savings from standby losses on water heaters, refrigerators, and freezers, respectively. These figures were used to devalue the savings obtainable from these appliances in the preceding cost-effectiveness evaluations.

Primary Sources for the Residential Sector

Space Heating:
Bonneville Power Administration, *Pacific Northwest Residential Energy Survey,* 1983.

Letter from Reidun Crowley, Puget Power, May 1, 1985, on costs of residential conservation retrofits.

Gates, Howard, Manufactured Housing Institute, *Optimum Thermal Insulation for Manufactured Homes,* September 1984, revised October 1984.

Goldman, C.A., *Technical Performance and Cost-Effectiveness of Conservation Retrofits in Existing U.S. Residential Buildings: Analysis of the BECA-B Data Base,* LBL-17088, October 1983.

Hirst, Eric, Richard Goeltz, Dennis White, Benson Bronfman, David Lerman, Kenneth Keating, *Evaluation of the BPA Residential Weatherization Program,* ORNL/CON-180, June 1985.

Housing Industry Dynamics, *Special Report,* December 1984, prepared for the Bonneville Power Administration.

Palmiter, Larry and David Baylon, *Assessment of Electric Power Conservation in the Pacific Northwest, Volume 1, Residential Building Conservation,* June 1982 (Draft), Submitted to Battelle Pacific Northwest Laboratories by Ecotope Group.

Palmiter, Larry and Mike Kennedy, *Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest, Volume 1, Supplement A — Heat Pumps in Residential Buildings,* January 1983 (Draft), Submitted to Battelle Pacific Northwest Laboratories by Ecotope Group.

Palmiter, Larry and Mike Kennedy, *Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest, Volume 1, Supplement B — Passive Solar, Internal Gains and Monthly Loads of Residential Buildings,* February 1983 (Draft) Submitted to Battelle Pacific Northwest Laboratories by Ecotope Group.

Water Heating and Appliances:
Letter from David Robison, Oregon Department of Energy, March 13, 1985, on the costs of solar water heaters.

Letter from Fred Avril, Long Island Lighting Company, April 2, 1984, on annual hot water usage from solar demonstration program.

Memorandum to File from Alan Cooke, Pacific Northwest Utilities Conference Committee, April 18, 1984, "Conservative Assumptions: The Plan Assumes No Use of Most Efficient Water Heater Heat Pumps."

Memorandum to Residential Supply Curve Work Group from Alan Cooke, Pacific Northwest Utilities Conference Committee, January 8, 1985, "Water Heater Cost Comparison."

Hanford, Jim, Mike Kennedy, Mary Jane DeLaHunt, Larry Palmiter, Ecotope Group, *Heat Pump Water Heater Field Test, DRAFT Final Report,* April 3, 1985, Contract with Bonneville.

Biemer, Jon, C. Douglas Auburg, Calvin Ek, Bonneville Power Administration, "Domestic Water Heating — Summary Research Findings for Conventional Systems" in *Conservation in Buildings: Northwest Perspective,* May 19-22, 1985, in Butte, Montana.

Harris, Jeff and Chris Dent, "Measured Results of 75 Solar Water Heating Systems in the Northwest; Interim Results" in *Conservation in Buildings: Northwest Perspective,* May 19-22, 1985, in Butte, Montana.

U.S. Department of Energy, *Consumer Products Efficiency Standards Engineering and Economic Analysis Document and Supplement,* March 1982.

Natural Resources Defense Council, *Appliance Survey,* 1981.

Natural Resources Defense Council, *A Model Electric Power and Conservation Plan for the Pacific Northwest,* November 1982, Prepared for the Northwest Conservation Act Coalition.

Messenger, Michael, and R. Michael Martin, California Energy Commission, *Technical Analysis of the Energy Conservation Potential for Refrigerators, Refrigerator-Freezers and Freezers: Part I-Recommended Efficiency Levels, and Part II-Final Staff Recommendations for Revised Standards/Fleet Average Goals,* Docket 84-AES-1, Item Code P400-84-013, Revised August 1984.

Association of Home Appliance Manufacturers, *1983 Energy Consumption and Efficiency Data for Refrigerators, Refrigerator-Freezers and Freezers,* June 1, 1984, Revised July 1, 1984.

Geller, Howard S., *Analysis of Minimum Efficiency Standards for Domestic Refrigerators and Freezers in the Pacific Northwest,* Draft, February 1985, Prepared for Bonneville Power Administration.

Sherman, Max, Mark Modera, Dariush Hekmat, *Energy Impacts of Efficient Refrigerators in the Pacific Northwest,* February 20, 1985, Prepared for Bonneville Power Administration.

Reese, S.P., and H.A. Wall, *Residential Electric Water Heater Conservation Potential,* 1981, Seattle City Light.

Dobyns, J.E., and M.H. Blatt, Science Applications, Inc., *Heat Pump Water Heaters,* EM-3582 Research Project 2033-5, May 1984, Prepared for Electric Power Research Institute.

Bavir, et. al., "Hour Use Profiles for Solar Domestic Hot Water Heaters in the National Solar Network," *Solar Engineering,* 1981.

Ek, Calvin, *The Effects of External Insulation on Electric Water Heater: A Laboratory Report (Revised Edition),* 1982, Bonneville Power Administration.

Seattle City Light, *Conservation Planning Process: A Status Report,* 1982.

Ek, C.W., and R.J. Miller, *The Effectiveness of Anti-Convection Devices in Reducing Standby Losses from Domestic Water Heaters,* 1982, Bonneville Power Administration, Division of Laboratories.

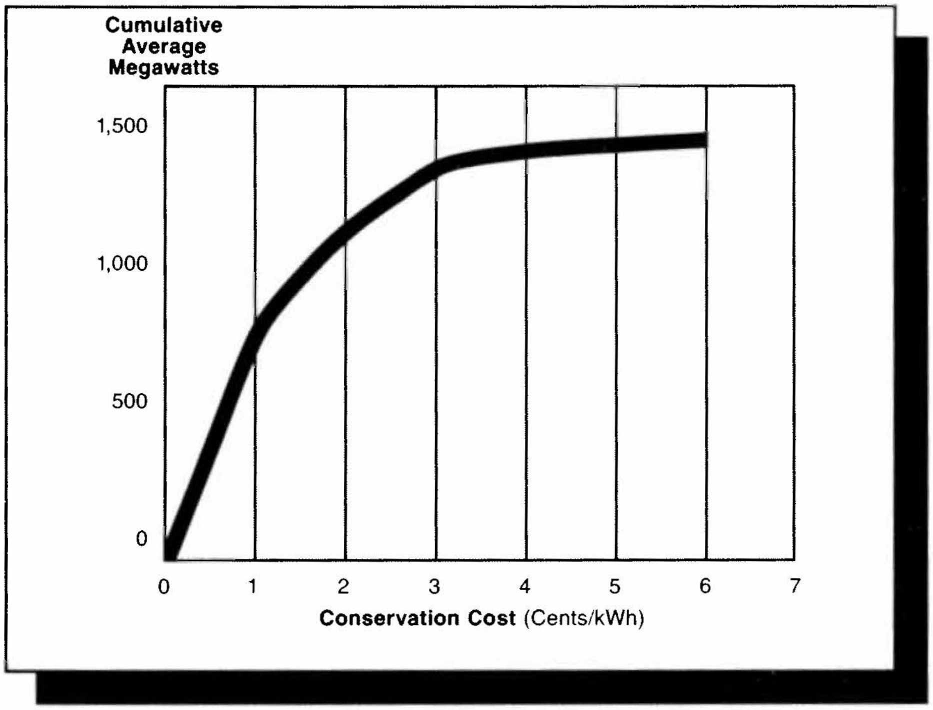


Figure 5-6
Technical Conservation Potential from the Commercial Sector

Commercial Sector

The commercial sector consumed approximately 20 percent of the region's total energy sales in 1983, or about 2,936 average megawatts. This sector's energy consumption is dominated by space heating, cooling, and lighting.

The commercial sector consists of many diverse buildings that use electricity in myriad ways. Because of the complexity of electricity use, much less precision is possible for estimating the conservation potential in this sector compared to the residential sector. However, projects are currently underway in the region that will enable analysts to better understand the end-uses of electricity and better evaluate the conservation potential in this sector.

This section evaluates the conservation potential from the array of traditional commercial buildings, such as offices and schools, as well as from less well known sources, such as pumping in municipal waste water treatment plants. Because of their unique nature, waste water treatment plants are discussed in a separate section at the end of the text on commercial buildings. This section includes savings from both privately and publicly-owned buildings.

The Council's current conservation assessments for existing commercial buildings are based on experience from current regional programs and on engineering estimates. The conservation estimate for new commercial buildings is based on engineering estimates of how much electricity will be saved by the commercial model conservation standards within each building type. Figure 5-6 shows the amount of commercial sector conservation available at various costs in existing and new buildings and waste water treatment facilities. In the high demand forecast, the Council estimates 780 average megawatts of technical conservation potential in existing commercial buildings, 514 average megawatts from new commercial buildings, and 15 average megawatts from waste water treatment plants. The potential from new commercial buildings includes only those savings resulting from the commercial model conservation standards.

For existing commercial buildings, 732 average megawatts of the technical potential is achievable in the high forecast. For new commercial buildings, about 430 average megawatts of the technical potential is achievable in the high forecast. Achievable savings from existing commercial buildings represent about 25 percent of electrical load from these buildings in 2005, and are available at an average cost of 2.3 cents per kilowatt-hour. Achievable savings from new commercial buildings represent a savings of about 12 percent of load in the year 2005 and are available at an average cost of about 2.0 cents per kilowatt-hour. Similar to new residences, new commercial buildings will last longer than the current electrical surplus. It is important to build these structures efficiently in order to avoid losing a cost-effective conservation resource.

The Council's estimate of conservation savings from the commercial sector involved the following three steps:

1. Identify the current regional average consumption for typical existing commercial building categories and typical new commercial buildings.

2. Evaluate conservation potential in existing and new commercial buildings.

3. Develop estimates of realizable potential for conservation at various costs in new and existing commercial buildings.

Step 1. **Identify the current regional average consumption for typical existing commercial building categories and typical new commercial buildings.** The Council's commercial sector forecasting model contains representations of ten building categories. Table 5-41 shows the annual energy use for all-electric commercial buildings existing in 1985, as estimated by the Council's forecast. This table also presents estimates from several recent analyses of existing commercial building consumption, which can be compared to the forecast values. To convey the relative importance of each building type in the analysis, the percent of total electricity in 1985 consumed by each building type is also shown.

In comparing the data shown in Table 5-41 and the forecast model assumptions, three factors should be kept in mind. First, the buildings shown in Table 5-41 were not selected to be statistically representative of the average. Second, the annual use figures in Table 5-41 from research on buildings in this region represent each building's total energy use regardless of the fuel source; total energy use is then converted to kilowatt-hours per square foot. Since many of these buildings use natural gas or fuel oil for some end-uses, the conversion efficiencies of these fuels are included in the figures. In contrast, the forecasting figures assume that all the energy requirements of the building are supplied by electricity. Third, the year of operation for the buildings in the sample is not 1985, while the forecast figures use 1985 as the operating year.

Even given these caveats, the sample data available to the Council on actual energy use per square foot in existing commercial buildings are reasonably close to the Council's forecasting estimates. The building category with the most variance is restaurants. Restaurants are particularly sensitive to the problem of fuel conversion efficiencies, because some energy intensive end-uses in this building type are non-electric. Additionally, energy use in restaurants, especially fast food establishments, is related more to the number of customers served than to the square footage of the building. Restaurants, however, are a relatively small portion of commercial electricity use. The table also shows that office buildings, retail establishments and the miscellaneous category are by far the dominant users of electricity in the commercial sector. These three categories make up about 60 percent of the total commercial sector electrical use.

Much less data are available on the actual energy use of newly built commercial buildings in the region. Table 5-42 shows some of the data for new commercial buildings. The Council's forecast assumptions on new commercial buildings built to current practice appear first in Table 5-42. These buildings are assumed to meet the level of ASHRAE 90-80.[18] The next column shows the level of efficiency assumed by the forecast resulting from the commercial model conservation standards, which are essentially ASHRAE

Table 5-41

Summary of Annual Energy Use for Existing Commercial Buildings Located in the Region

BUILDING TYPE (Sample Size = N)	ANNUAL ENERGY USE (kWh/sq ft/yr)			COUNCIL'S FORECAST (kWh/sq ft/yr)	BUILDING TYPE'S PERCENT OF TOTAL CONSUMPTION
	High	Low	Mean		
Office (N = 157)	108	6	27	27	27%
Retail (N = 581)	281	5	22	30	21%
Grocery (N = 336)	86	50	61	51	7%
Restaurant (N = 220)	375	49	116	45	7%
Hotel (N = 6)	32	16	23	19	3%
Hospital (N = 30)	—	—	29	30	4%
School (N = 146)	49	2	20	23	8%
College	Included in "Schools"			28	3%
Warehouse (N = 77)	107	2	20	11	7%
Other (N = 41)	45	7	22	26	13%

Table 5-42

Summary of Annual Energy Use for New Commercial Buildings Located in the Region (Kilowatt-Hours per Square Foot)

	CURRENT PRACTICE FROM FORECAST	MODELED MCS FROM FORECAST	SAMPLE OF CURRENT PRACTICE BUILDINGS (Sample Size = N)
Office	21	17	19 (N = 14)
Restaurant	39	39	—
Retail	22	20	22 (N = 8)
Grocery	46	46	44 (N = 1)
Warehouse	8	7	18 (N = 1)
School	19	17	16 (N = 3)
College	23	22	22 (N = 1)
Health	26	26	—
Hotel/Motel	15	14	—
Miscellaneous	22	22	28 (N = 2)

Table 5-43
*Retrofit Savings from Existing Commercial Buildings: Puget Power's Program**

BUILDING TYPE (Sample Size = N)	PERCENT SAVINGS FROM AVERAGE USE	AVERAGE USE OF PROGRAM BUILDINGS (PRE-RETROFIT) (kWh/sq ft/yr)	COUNCIL FORECAST (kWh/sq ft/yr)
Office (N = 62)	30%	26	27
Retail (N = 11)	16%	25	30
Grocery (N = 36)	23%	62	51
Restaurant (N = 10)	22%	89	45
Hotel (N = 2)	16%	24	19
Hospital (N = 30)	28%	29	30
School (N = 28)	17%	24	23
Warehouse (N = 4)	26%	16	11
Other (N = 8)	21%	22	26

Average savings = 22%
Average savings weighted by building type = 22%

*Program offers measures such as heating, ventilating and air conditioning modifications, glazing and insulation, lighting measures and some process modifications.

Table 5-44
Technical Conservation from Commercial Buildings

LEVELIZED COST (cents/kWh)	CUMULATIVE MEGAWATTS New	Existing
1.0	293	421
2.0	457	684
3.0	509	769
4.0	514	773
5.0	514	780
6.0	519	788

90-80 with lighting improvements in some building types (modeled from ASHRAE 90-80E). The third column shows available data from work done by a Bonneville contractor and from work at the Oregon Department of Energy that documents actual energy use in a few recently built (post-1980) commercial buildings.

These figures need to be qualified. First, the forecast figures for both current practice and the model conservation standards assume an all-electric building; consequently, fuel conversion efficiencies are not required. In contrast, the average use figures for current practice buildings are for total energy and include fuel conversion efficiencies. Secondly, the sample size of current practice buildings is very small and buildings were not selected to represent the region. Even given these caveats, there is general agreement among the sources.

Step 2. **Evaluate the conservation potential in existing and new commercial buildings.** For existing buildings, the Council used engineering estimates of conservation potential conducted for the 1983 plan and estimates of conservation from Puget Sound Power & Light's commercial retrofit program. The modeling done for the 1983 plan was on a limited number of building types, but resulted in about 30 percent savings beyond current demand forecast usages for a cost less than about 5 cents per kilowatt-hour.

Puget's program corroborates this engineering estimate. Table 5-43 displays the current savings information available from Puget Power and shows the base year use figures from both Puget and the Council's forecasting model. Percent savings are from the engineering estimates done at the time of the audit. Preliminary results of post-retrofit billing data suggest that, on average, the engineering estimates are reasonably accurate, although estimates for particular buildings may vary significantly. Puget's program is aimed at measures that cost less than 3 cents per kilowatt-hour,[19] and more conservation would be expected if marginal measures cost up to 5.0 cents per kilowatt-hour. On average, all the savings from Puget's program would produce electricity at a cost significantly less than 3 cents per kilowatt-hour.

The savings that appear in Table 5-43 reflect heating, ventilating, air conditioning, lighting, and insulation measures, and, in some cases, process improvements for the combination of measures that were installed. Any given building may have installed only one, or all, of the measures. Total percent savings are about 22 percent whether a simple average of the savings is calculated or the savings are weighted based on 1985 electricity consumption by building type. If lighting improvements, which include some outdoor lighting, and process improvements, which aren't related to square footage, are removed from the estimates of savings, the total savings is reduced to about 20 percent.

Puget's base consumption figures are close to those used by the Council's forecast. In addition, Puget's overall savings figure of 22 percent for a marginal measure cost of 3 cents per kilowatt-hour compares favorably with the Council's estimate of 30 percent savings in existing buildings for a marginal measure cost of about 5 cents per kilowatt-hour. Thirty percent savings was used as the technical potential for conservation in existing commercial buildings.

For new commercial buildings, the Council modeled the improvement over current practice (ASHRAE 90-80) that would result from the model conservation standards. These efficiency changes, primarily lighting efficiency improvements, were modeled based on ASHRAE 90-80E. The main impact of the standards is to change the connected lighting load, which particularly affects offices and retail stores. The measures evaluated are available for less than 5.0 cents per kilowatt-hour. Table 5-42 shows the Council's forecast estimate of the energy consumption of current practice new buildings and the estimate of use from commercial buildings meeting the standards. Savings for all commercial buildings from the standards range between 0 and 19 percent of current use.

Savings beyond current practice to the standards level are small compared to savings evaluated on prototype buildings for the Council in the 1983 plan. Data from the prototype buildings indicate that, with the last measure installed costing about 5.0 cents per kilowatt-hour, savings of 38 percent in offices, 19 percent in retail stores, 68 percent in schools, and 31 percent in motel/hotels are possible beyond current practice for new construction. These prototype savings indicate that the resource available from making commercial buildings more efficient than the standards is quite promising and should be investigated further.

This is further supported by additional information provided by Bonneville. The 1983 Power Plan asked Bonneville to develop energy use and cost data on energy efficient commercial buildings in climates similar to those found in the region. Figure 5-7 shows the results of this work. The contractor selected by Bonneville collected energy use data on buildings in the region that were reputed to be energy efficient. Slightly less than half the buildings found were more energy efficient than the commercial model conservation standards. A few bettered the standards by 30 percent. The contractor noted, however, that it was difficult to quantify why one building met the standard and another did not.

While the Council is not currently counting as a reliable and available resource any savings from constructing buildings more efficiently than the commercial standards, such savings do reflect a very promising resource. In the Action Plan, the Council identifies ways Bonneville can help make these additional savings more reliable and achievable. The actual measures that beat the standards and that can be generically recommended for average buildings need to be identified, as well as their cost. Mechanisms to secure this

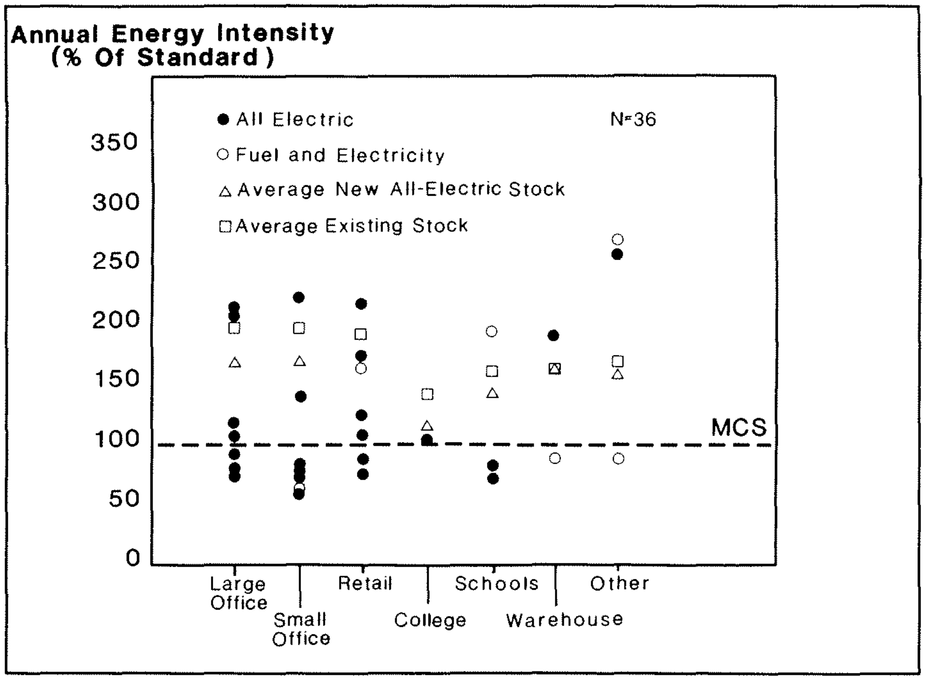


Figure 5-7
Annual Energy Use of New Commercial Buildings in the Northwest as a Percentage of the Model Conservation Standards

resource need to be developed aggressively to bring the resource into the portfolio.

Step 3. **Develop estimates of realizable potential for conservation in new and existing commercial buildings.** As described above, the Council's estimates of the technical potential for conservation were based on a 30 percent savings in existing commercial buildings and on a range between 4 and 19 percent savings, depending on the building type, for new commercial buildings. The total regional savings available from this average level of improvement were estimated using the Council's commercial sector forecasting models as described below.

First, this sector's demand was forecast assuming no further improvements in efficiency. Demand was forecast separately for new and existing buildings. Then the percent of improvement over current efficiencies represented by the commercial standards was imposed on the model, and the demand was re-estimated. The difference between projected demand at current efficiencies and demand with the improvements from the commercial model conservation standards represented the total technical conservation. Achievable potential was then estimated by re-running the model with percent efficiency improvements that reflected achievable saturations. The achievable level of saturation in both existing and new commercial buildings was 85 percent.

In the Council's high forecast, 732 average megawatts are achievable in existing buildings, and 430 average megawatts in new commercial buildings. Table 5-44 shows the achievable conservation that is available at a given cost in the high demand forecast. This curve was estimated using the breakdowns by cost given in the 1983 plan.

It should be noted that the current estimate does not separate the conservation potential in governmental buildings from the rest of the commercial sector. Bonneville sponsored a project that attempted a census of institutional buildings and extrapolated the results from respondents to non-respondents. Some results from this census produced anomalies when compared to the forecast assumptions. For example, the floorspace reported in schools exceeded the floorspace allocated to this building type in the Council's commercial sector forecast by 24 percent. When additional information becomes available to enable a reasonable calibration, the Council will separate the conservation potential in government buildings from the general commercial sector.

Waste Water Treatment

Recent information is available for estimating the conservation potential from waste water treatment facilities. A report on waste water facilities produced by a Bonneville contractor provides some of the information used to estimate conservation potential in this sector. In addition to this work, the Council conducted a telephone survey of municipal water systems in the region's major population centers to determine the approximate size of preconservation loads.

The Council's assessment of conservation relies on data collected in the telephone survey and on a review of Environmental Protection Agency data on the 550 waste water treatment plants in the Pacific Northwest. In addition, energy use and energy conservation audit information from plants outside the region were used to assess the costs and potential energy savings from 15 cost-effective conservation measures.

Table 5-45
Technical Conservation from Waste Water Treatment Facilities

LEVELIZED COST (cents/kWh)	CUMULATIVE MEGAWATTS
1.0	8
2.0	8
3.0	10
4.0	14
5.0	15
6.0	15

In waste water treatment plants the treatment processes themselves account for the largest use of energy. Energy required for lighting and heating, ventilating and air conditioning equipment is less significant than the energy required for pumping, aeration and sludge treatment. Of these in-plant processes, the electrical energy used to operate pumps and motors accounts for the largest energy demand. The conservation potential estimated here does not include potential generation of electricity from methane cogeneration potential.

Of the 15 energy conservation measures analyzed, only one, the installation of high efficiency motors, was found to exceed 5.0 cents per kilowatt-hour and was therefore not considered in the analysis. Table 5-45 shows the total estimated technical savings at about 15 average megawatts based on an estimated load of 68 average megawatts. Achievable savings were estimated to be about 85 percent of the technical potential, or about 13 average megawatts.

Primary Sources for the Commercial Sector

Battelle Pacific Northwest Laboratory, *Recommendations for Energy Conservation Standards and Guidelines for New Commercial Buildings Volume III: Description of the Testing Process,* October 1983, Prepared for the U.S. Department of Energy.

Letters from Reidun Crowley, Puget Sound Power & Light, February 12 and 15, 1985, on commercial retrofit costs and savings.

Energuard Corporation, *Summary of End Use Data in Commercial Buildings,* December 1984.

Charlie Grist, Oregon Department of Energy Commercial Building Survey and personal communication.

JRB Associates, *Assessment of the Potential for Conservation in Waste Water Treatment Plants,* JRB No. 2-815-02-796, February 1985, Prepared for the Bonneville Power Administration.

Lerman, David, John Weigant, Benson Bronfman of Evaluation Research Corporation, *DRAFT Institutional Buildings Program Census Extrapolation and Analysis,* ERC/PO-7, February 1985, Prepared for the Bonneville Power Administration.

Mazzuchi, Richard P., *Assessment of Electric Power Conservation and Supply Resources in the Pacific Northwest, Volume II — Commercial Building Conservation,* June 1982 (Draft), Battelle Pacific Northwest Laboratories.

Piette, Mary Ann, Denise Flora and Scott Crowder, *Energy Efficient New Commercial Buildings in the Northwest Region: A Compilation of Measured Data,* March 1985, Prepared for the Bonneville Power Administration.

Portland Energy Conservation Incorporated, personal communication, January 1983, on energy use of monitored commercial buildings.

City of Tacoma, Jake Fey, personal communication, January 1983, on energy use of commercial buildings.

Al Wilson, Seattle City Light, personal communication, July 1, 1985.

Industrial Sector

In 1983, firm sales to the industrial sector were 5,659 average megawatts, which is about 39 percent of firm loads. About 34 percent of firm industrial electricity use was consumed by firm load requirements of the direct service industries, which are mainly the aluminum industry and some chemical and other primary metal producers. The largest consumers among the non-direct service industries, representing about 85 percent of non-direct service industry demand, are lumber and wood products, pulp and paper, chemicals, food processing and primary metals.

The Council used 500 average megawatts as the technical and achievable conservation potential from the direct service and non-direct service industries. This conservation saves about 5 percent of projected industrial use in the year 2005. Industrial sector savings cost an average of about 3.1 cents per kilowatt-hour. Figure 5-8 depicts this conservation at various costs.

Assessing the technical and economic potential for industrial conservation presents a more difficult problem than in any other sector. Not only are industrial uses of electricity more diverse than the commercial sector, but the conservation potential is also more site-specific. Moreover, because energy use frequently plays a major role in industrial processes, many industries consider energy-use data proprietary. For new industrial plants, estimating conservation potential is not yet possible, because incoming plants are quite specific in their energy use, and a "base-case" plant from which to estimate savings has not been established. All these factors make it difficult to estimate conservation savings.

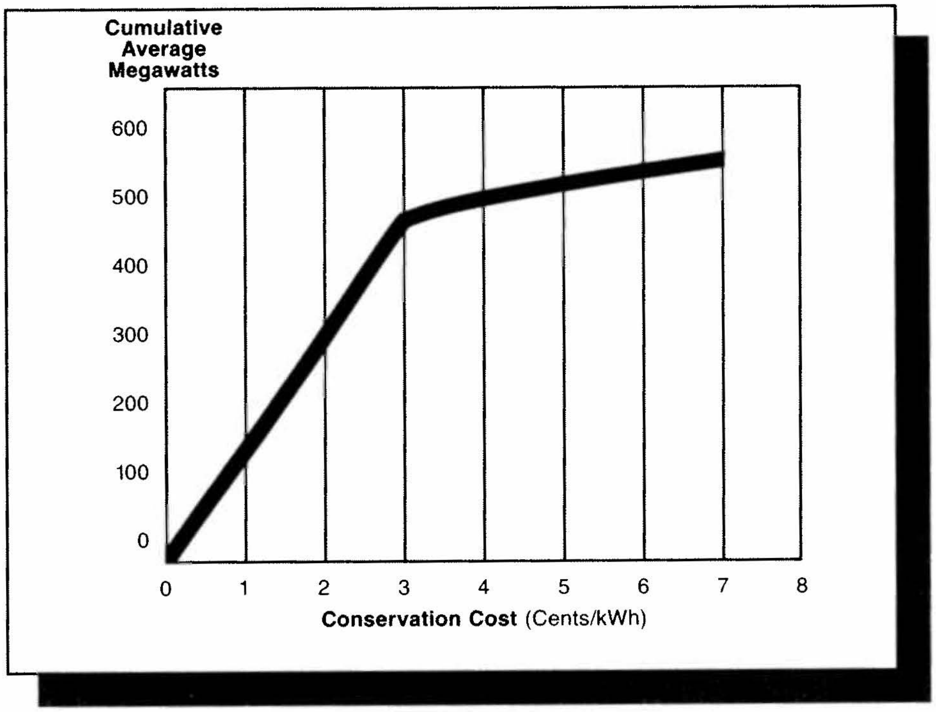


Figure 5-8
Technical Conservation Potential from the Industrial Sector

In the past, industrial representatives have been skeptical of studies that estimate the potential of industrial conservation based on a "typical plant" within an industry. Such studies extrapolate results from a typical plant to estimate the potential for the whole industry. Industry spokespeople argued that typical plants do not exist for most industries. Among other reasons, differences in product lines and the age of plants do not allow comparison of individual plants within the same industry. Industrial representatives were concerned that even though their plant was not like the typical plant used in the analyses, policies and programs affecting them would be developed based on those analyses.

For these reasons, in the 1983 Power Plan the Council did not attempt to draw upon or redo studies based on the typical plant approach. Instead, the Council relied on estimates supplied by industry in response to a Council survey. The Council also conducted an analysis of its own which attempted to estimate industrial conservation potential by specific end-uses, such as motors, lights, etc. This approach had some of the same problems of the typical plant analysis—lack of information about how electricity was used in the various plants.

In preparation for the 1986 Power Plan, the Council considered ways to estimate conservation potential in the region's industries that would have the support of industrial representatives. The approach that received such support was a survey asking individual plant managers to estimate conservation potentials in their specific plant. The surveys were coordinated by industry trade associations such as Northwest Pulp and Paper Association and the Industrial Customers of Northwest Utilities. Data from specific firms were masked to protect proprietary data. Each firm was asked how much conservation would be available at specified prices in each of four areas: 1) motors, 2) motor controls, 3) lighting, and 4) other, a category that depended on the nature of the firm. The firm was also asked to estimate the lifetime of equipment in each of the four categories. Finally, since the Council and industrial representatives did not want to follow this survey with yet another, firms were asked to estimate how much cogeneration would be available to the region at specified prices per kilowatt-hour.

The survey was sent to over 200 industrial firms in the Northwest. Forty-seven of the surveys were returned, representing 70 percent of industrial electricity use in the region. Non-direct service industries which returned surveys represent 52 percent of the non-direct service industry regional load. All of the direct service industries responded through Direct Service Industries, Inc. The results of survey respondents were extrapolated to nonrespondents in order to capture regional conservation potential in the industrial sector.

The results of this survey are presented in Table 5-46. The Council's plan includes developing 500 average megawatts of the currently identified conservation potential in the industrial sector at an average cost of 3.1 cents per kilowatt-hour. This conservation is both technical and achievable, since the survey identified what could and would be done for given prices. In forecasts lower than the high case, conservation from the direct service industries was reduced to reflect the demand forecast assumptions concerning reduced load from these industries.

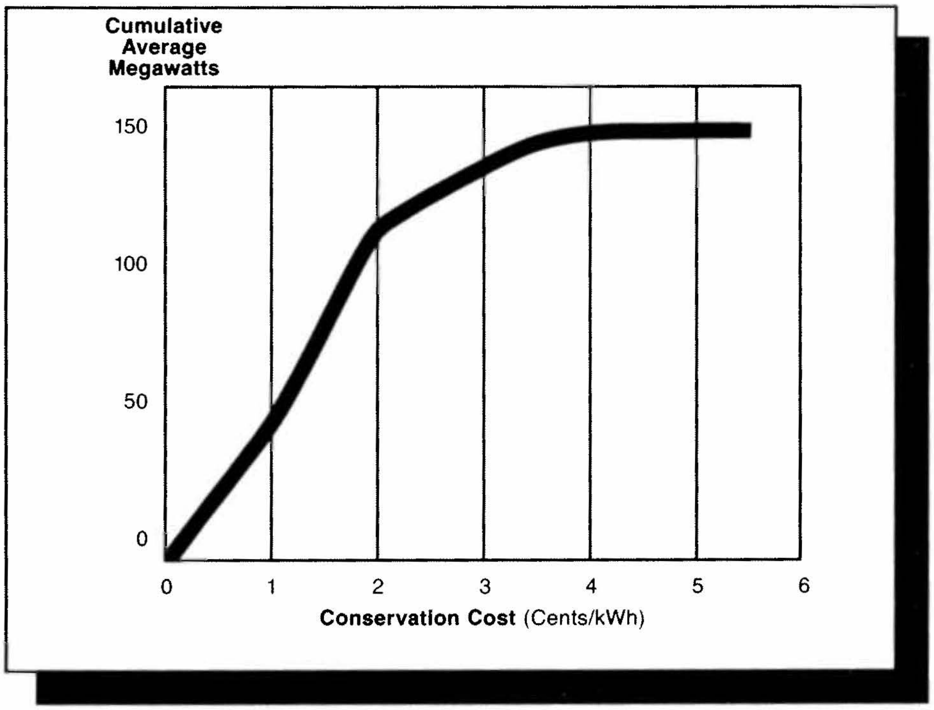


Figure 5-9
Technical Conservation Potential from Irrigated Agriculture

Table 5-46
Industrial Sector Technical Conservation Potential

LEVELIZED COST (cents/kWh)	CUMULATIVE POTENTIAL (Megawatts)
1.0	130
3.0	466
5.0	500
7.0	529

Primary Sources for the Industrial Sector

Andrews, Laurel, Neil Leary and Craig McDonald, Synergic Resources Corporation, *Survey of Industrial Conservation and Cogeneration Potential in the Pacific Northwest,* SCR Report No. 7193-R3, 1984, Prepared for the Northwest Power Planning Council.

Letter from Laurel Andrews, Synergic Resources Corporation, April 23, 1985.

Irrigation Sector

In 1983, the region's irrigated agriculture consumed 615 average megawatts of electricity, less than 5 percent of the region's total consumption. Figure 5-9 shows the estimated irrigation savings available from existing and new irrigation systems at various electricity prices. The technical potential, evaluated with a marginal measure not exceeding a cost of 5.0 cents per kilowatt-hour, is 146 average megawatts. The Council's plan calls for developing up to 85 percent of this potential, or 124 average megawatts. This represents about 14 percent of electricity use for irrigation in 2005 and is available at an average cost of about 1.8 cents per kilowatt-hour.

The Council's assessment of conservation potential for this sector involved the following two steps:

1. Evaluate the end-use conservation measures to be included in the supply curve analysis.

2. Estimate realizable conservation potential by using the cost and potential savings data available from the Irrigation Sector Energy Planning Model, and compare the relationship of the cost and savings data derived from the base load forecast used by Bonneville with the Council's load forecasts.

Step 1. **Evaluate the end-use conservation measures to be included in the analysis.** In the 1983 Power Plan, the Council relied on estimates of conservation potential in irrigated agriculture provided by a Council contractor. At the time, the research represented the most complete picture of energy conservation opportunities in the region's irrigation sector. Since that time, Bonneville has hired various contractors to continue analytical studies in order to better characterize the irrigation sector. These efforts have produced improved baseline data and analytical tools, which the Council used to prepare its assessment of the conservation potentials in this sector.

The conservation opportunities considered in the irrigation supply curve estimates include:

- low pressure irrigation on center-pivot, side-roll, and handmove systems;
- fittings redesign;
- mainline modifications;
- improved scheduling.

Low pressure irrigation involves using sprinkler or spray application devices designed to operate at lower pressures than conventional sprinkler devices. These low pressure devices can be divided into three major types: low pressure spray heads, low pressure impact sprinklers and drop tubes.

The fittings of an irrigation system include valves, elbow joints and other components used to connect the irrigation pump to the pipes of the system and to connect the pipes within the system to each other. Fittings redesign involves using larger tapered fittings to replace valves and elbows that are too small or that change abruptly in size and direction.

Mainline modification involves increasing the size of the system's mainline, resulting in decreased energy losses due to friction. This redesign generally can be accomplished most economically by installing a second mainline pipe parallel to the existing one.

Improved scheduling involves the improvements in both timing and amount of water applications. This reduces water use without reducing crop yields, and energy use is reduced due to a decrease in pumping requirements. Scheduling is the cornerstone of a basic comprehensive management approach to efficient water and energy management, with all other conservation measures being necessary components.

The supply curve analysis does not address two major options which were included in the 1983 plan: very low pressure systems[20] and pump improvements.

Very low pressure water application systems are not unlike existing low pressure center-pivot systems equipped with drop tubes. It appears, however, that the application of this very low pressure system on slope conditions typical in the Northwest works best as part of an agriculture practice known as reservoir or basin tillage. This practice creates small circular furrows which hold the applied water, reducing the problem of runoff. Field tests, planned over the next two years, will assess the hydraulic characteristics of very low pressure (5-15 pounds per square inch) system components, evaluate reservoir tillage and associated soil/irrigation management practices, and determine energy savings. Until results are analyzed, there appears to be no reliable estimate of potential conservation savings from this technology.

There is broad recognition of the need to operate pumps at efficiencies that match the original operating specifications. Worn pump components, improper sizing, dirty water conditions, scale build-up in the mainline, improper fittings, pumps taking in air, and multiple versus single pump usage, can all affect pump efficiency. In addition, bringing pump efficiencies to original specifications may increase horsepower and result in increased energy use. Pump testing programs have been conducted in the region for several years. However, Bonneville abandoned the testing program after acknowledging the need for a more comprehensive approach to irrigation efficiency.

There is also information to suggest that some of the pump testing conducted not only on irrigation systems, but also on municipal water systems, has been incomplete. Pumps operate optimally when the clearance between the impeller and pump housing is properly adjusted. According to some professionals in the field, this adjustment is not done enough, especially prior to testing. It is analogous to attempting to determine the fuel efficiency of a car without first tuning the engine. Consequently, there are currently no reliable estimates of conservation potential for pump efficiency improvements. However, both very low pressure systems and pump efficiency improvements are promising resources and deserve further research and analysis.

Step 2. **Estimate realizable conservation potential.** Conservation supply estimates for the irrigation sector were developed using the Irrigation Sector Energy Planning Model (ISEP). The model combines both engineering and economic principles to derive energy savings and levelized costs per kilowatt-hour for conservation investments.

The model uses a number of baseline data inputs, including estimates of crop-specific acreages in 11 subbasins in the region; type of irrigation systems used; pumping lift; pumping plant efficiencies; estimates of water application volumes to specific crops by irrigation system type; and system operating pressures. The model also uses rough estimates of conservation measures believed to have been applied on existing acreages and subtracts these estimated savings prior to calculating the remaining conservation potential.

In a test of the model to estimate the baseline energy use for regional irrigation loads, the ISEP model estimates were within 7 percent of the load estimated from billing records. This indicates a high degree of confidence for this part of the model.

The irrigation savings information provided to the Council by Bonneville is based on a 1984 final Bonneville base case load forecast and Bonneville acreage forecasts. The average megawatt estimates used in this plan are adjusted from the estimates provided by Bonneville with a ratio proportionate to the difference between the Council's 1985 high case irrigation load forecast and the 1984 Bonneville base irrigation load forecast. The Council's 1985 agricultural forecasts were adjusted downward to reflect the subtraction of loads from U.S. Bureau of Reclamation projects in the region. This is necessary in order to adjust irrigation savings from the ISEP, which are based on Bonneville loads, because the Bonneville forecast does not include Bureau loads. The Council assumes a total of 116 average megawatts of Bureau load in the region, of which 55 average megawatts are directly related to pumping facilities at Grand Coulee Dam. The rest of the load is scattered in the region.

Table 5-47
Technical Conservation Potential from the Irrigation Sector

LEVELIZED COST (cents/kWh)	MEGAWATTS Existing	New
1	18	25
2	81	29
3.2	106	29
4.2	116	30
4.7	116	30

Table 5-47 summarizes the estimates of conservation potentials on existing and new acreages that result from the above-described models and adjustments. The conservation estimate for existing acreages is 116 average megawatts of technical potential. The conservation estimate for new acreage is 30 average megawatts, which is only included in the high demand forecast.

Primary Sources for the Irrigation Sector

Gordon, Fred, *Irrigation Technical Supply Curve Project Research Summary,* Bonneville Power Administration, December 1984.

Harrer, B.J., Lezberg, A.J., Wilfert, G. L., *An Integrated Assessment of Conservation Opportunities in the Irrigated Agriculture Sector of the Pacific Northwest,* Battelle Pacific Northwest Laboratory, February 1985.

Harrer, B.J., *Draft: A Sensitivity Analysis of Conservation Opportunities in the Irrigated Agriculture Sector of the Pacific Northwest,* Battelle Pacific Northwest Laboratory, February 1985.

Pharayra, Barbara, *Summary of 1984 Pacific Northwest Irrigation Conservation Potential: 1984 BPA Final Load Forecast—Base Case,* Bonneville Power Administration, May 1985.

1./ These savings must be increased by line losses of 7.5 percent to be consistent with evaluations in the resource portfolio, as described later in this chapter.

2./ A "measure" means, as appropriate, either an individual measure or action or a combination of actions.

3./ Levelized life cycle cost is the present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments; unit levelized life cycle costs (cents per kilowatt-hour) are obtained by dividing this payment by the annual kilowatt-hours saved or produced. Unlike installed cost, levelized costs that have been corrected for inflation permit comparisons of resources with different lifetimes and generating capabilities. The term "levelized cost" as generally used in this chapter refers to unit levelized life cycle cost

4./ Least costly is defined in terms of a measure's levelized life cycle cost, stated in terms of mills or cents per kilowatt-hour.

5./ The system models are the Decision Model and the System Analysis Model. These are briefly described later in this chapter and fully described in Volume II, Chapter 8.

6./ The SUNDAY model simulates space heating needs based on heat loss rate, daily access to solar energy, daily inside and outside temperatures, thermal mass, and the amount of "waste heat" given off by lights, people and appliances.

7./ These items are discussed here in terms of the calculated savings per measure. Under Step 5, these items are discussed in terms of differences between the demand forecast estimates of space heating loads and estimates from the engineering model.

8./ As noted in the introduction, finance costs are taken from the system models and reflect a sponsorship mixed among Bonneville and investor-owned utilities.

9./ This assumes a 90°F temperature differential between the incoming water and the tank setting.

10./ In the 1983 plan, these efficiency improvements were credited to the miscellaneous appliance sector. Since they pertain to the amount of hot water used by these appliances, they are more accurately included as water heating savings.

11./ This assumes about 50 percent of current tanks are wrapped, about 5 percent are efficient tanks and there is some saturation of other standby loss measures.

12./ The California standard represents a minimum efficiency level for various product classes (for example, a refrigerator with top-mounted freezer and automatic defrost capability) within the grouping of refrigerators, refrigerator/freezers and freezers. This standard also varies by the size of the refrigerated space and the freezer space.

13./ For example, those technologies included in the supply curves presented in this section.

14./ As a consequence of litigation over the DOE standards that resulted from the described evaluation, DOE has been required to return to the evaluation and investigate all technologically feasible measures.

15./ Appliance manufacturers have sued the CEC over the revised standard.

16./ Solar gains are considered constant in this discussion.

17./ A recent American Society of Heating, Refrigerating and Air-Conditioning Engineers' publication suggests that the minor internal gain from variable use should be ignored. The gain from the hot water in the pipes is offset by heat used to heat cold water brought inside the heated shell through other pipes.

18./ ASHRAE stands for the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. This organization sets various standards for building practices based on consensus.

19./ The program allows measures costing more than 3 cents per kilowatt-hour to be installed if financed independently from the program.

20./ This technology was called "low energy precision application" or "LEPA" in the 1983 Power Plan.

Chapter 6
Generating Resources

This chapter describes the selection of generating resources for development of the resource portfolio. Resources selected were further assessed to develop the detailed information required by the system planning models. The chapter concludes with a discussion of how existing resources are allocated between public agencies and investor-owned utilities for the purpose of determining the Administrator's obligations.

This chapter considers alternatives using coal, geothermal, hydropower, municipal solid waste, natural gas, nuclear power, solar insolation, wind, wood residue and waste heat as sources of energy for electrical power generation. Both stand-alone and cogeneration opportunities are considered. The chapter also examines opportunities for increasing the capability of existing regional generation projects and for reducing losses in the regional power transmission and distribution system. The chapter includes a description of existing contracts for the import and export of power, and a discussion of potential future imports.

The focus is on central station generation of electricity; however, consumers might use certain resources considered in this chapter to generate electricity at the point of end use, or to offset the need for electrical power through direct resource applications. An example of the former might be the use of solar photovoltaics for local electricity production. The latter would include the use of low temperature geothermal energy for space heating. End-use applications are considered in the Council's planning as conservation resources.

Selection of Available Resources

The Northwest Power Act requires that the Council's plan give priority to resources that the Council determines to be cost effective. For resources of equal cost effectiveness, priority is given first to conservation, second to renewable resources, third to generating resources using waste heat or generating resources of high fuel conversion efficiency, and finally to all other resources.

The Northwest Power Act defines "cost effective" to mean that a measure or resource must be forecast to be reliable and available within the time it is needed and to meet or reduce electrical power demand of consumers at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative or combination of alternatives. System cost, in turn, is defined as an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, distribution and transmission costs, waste disposal costs, end-of-cycle costs, fuel costs and quantifiable environmental costs. The Council is also required to take into account projected realization factors and plant factors, including appropriate historical experience with similar measures or resources. Finally, the Northwest Power Act provides a 10 percent advantage in calculation of system costs for conservation resources.

Resources were classified as "cost effective," or "promising," using screening criteria based on the resource requirements of the Northwest Power Act described above. Cost-effective resources were incorporated into the system planning models as part of developing the resource portfolio. Promising resources are candidates for future resource portfolios. Research, development or demonstration activities and other actions will better establish the role of promising resources in future power plans.

Criteria used to judge the availability, reliability and cost effectiveness of resources are as follows:

1. Commercially Available Technology: The technology for producing electrical power or for increasing the efficiency of the existing power system must be commercially available.

2. Predictable Cost and Performance: It must be sufficiently demonstrated that the technology's cost and performance characteristics are predictable.

3. Competitive Cost: The resource must be cost-competitive using currently available technology. Because of the complexity of the regional power system, it is not possible to forecast cost-competitiveness accurately without using the system planning models. However, a preliminary estimate of cost-competitiveness can be made using levelized life cycle costs.[1] A levelized life cycle energy cost of 4.5 cents per kilowatt-hour (January 1985 dollars) is used as a criterion for generating resources. A levelized life cycle energy cost of 5.0 cents per kilowatt-hour is used for conservation resources. These levels were chosen on the basis of the estimated cost of energy from new conventional coal projects, as described in Chapter 3 of Volume I.

4. Demonstrated Resource Base: The estimates of the amount of capacity and energy available from a given resource require a confirmed primary energy source (e.g., coal, falling water, wind).

5. Institutionally Feasible: Development of the resource must not be currently constrained by legal, financial, regulatory or other institutional barriers.

6. Environmentally Acceptable: The resource must be environmentally acceptable and capable of complying with current environmental policies, laws and regulations of the federal, state and local governments, and the Council's Columbia River Basin Fish and Wildlife Program. Further discussion of the environmental effects of resources is provided in Chapter 9 of this volume.

The conclusions described below represent the best judgment of the Council given the information presently available.

Development of Detailed Planning Information

Resources judged to be available using the criteria described above were further assessed to fully develop the cost, technical performance and other information required for planning. This information was obtained by assessing actual projects, either proposed or under construction, or by assessing generic projects representative of actual projects that might be developed in the region. Detailed planning information is provided in Appendices 6-B through 6-J to this chapter.

Transmission and Distribution System Efficiency Improvements

For the 1984-85 operating year, it is estimated that Bonneville losses will be 135 megawatts (exclusive of losses attributable to serving nonfirm load). Losses for the balance of the regional system are estimated to be about 1,200 megawatts.

Measures available to reduce transmission and distribution losses include conductor and transformer replacement, voltage upgrade, addition of parallel transmission lines or distribution feeders, power factor correction, capacitor replacement and system reconfiguration. These measures are commercially available and well demonstrated. Promising measures include advanced design transformers, improved voltage regulation and optimization of generating patterns. Because these measures reduce the consumption of electrical energy, they are considered to be conservation resources under the Regional Act.

Measures that improve the efficiency of transmission and distribution have several attractive characteristics. Because losses vary with the square of the load, loss reduction measures are effective in reducing peak loads. Older transformers and capacitors often contain PCB fluids which can be disposed of if the equipment is replaced to improve system efficiency. Because system efficiency improvements do not affect sales, they do not reduce revenue to the implementing utility.

Cost and Availability

Because much of the regional transmission and distribution system was designed when the cost of losses was much lower than at present, there are many cost- effective opportunities to upgrade the system. Often, where efficiency improvement measures cannot be justified solely on the basis of loss reduction, cost effectiveness can be achieved when upgrades are required to increase capacity or to improve reliability. Although the cost and performance of individual loss-saving components are typically well understood, the complexity of the transmission and distribution system is such that analyses of specific applications are required to assess accurately the cost-effective loss reduction potential of these improvements.

Bonneville System Efficiency Improvements

Bonneville has established a Loss Savings Task Force to assess potential loss savings projects on the Bonneville system. This task force has identified 38 possible loss reduction projects, providing in excess of 41 megawatts total energy savings at estimated costs of 10 cents per kilowatt-hour or less. Thirty-six of these projects, totaling 34 megawatts, are estimated to be available at costs of less than 5.0 cents per kilowatt-hour.

The Loss Savings Task Force identified additional measures with the potential for cost-effective reduction of Bonneville system losses. These include reconductoring with compacted conductors, addition of subconductors, insulating groundwires, transpositions, and modification of system operating practice. The feasibility and cost effectiveness of these measures require further study.

Utility System Efficiency Improvements

Bonneville has established the Customer System Efficiency Improvement (CSEI) project in response to Action Item 11.2 of the 1983 Power Plan. The purpose of this project is to perform an assessment of the potential for loss reduction on non-Bonneville regional transmission and distribution systems, including those of Bonneville's federal and direct service industrial customers. The study is assessing the technical potential, economic potential and likely achievable level of system efficiency improvements.

A summary progress report of the CSEI project, issued in January 1985, estimates technically available loss reduction to be 350 to 585 megawatts (approximately 30 to 50 percent of current system losses). Preliminary estimates of the availability and cost effectiveness were prepared for two specific loss reduction measures—reconductoring subtransmission and primary distribution lines and transformer replacement. These estimates indicate that approximately 115 megawatts of energy could be obtained from high efficiency distribution transformers at costs of 5.0 cents per kilowatt-hour or less. An additional 30 to 35 megawatts of energy could be obtained at similar cost by reconductoring subtransmission lines and distribution feeders.

Conclusion

The 36 Bonneville loss reduction projects, totaling 34 megawatts at 5.0 cents per kilowatt-hour or less, are considered available for the resource portfolio. The Council encourages continued assessment of the cost and availability of loss reduction potential on the Bonneville system. The cost and availability of these projects are shown in Table 6-1.

Table 6-1
Cost and Availability of Transmission and Distribution System Efficiency Improvements

LEVELIZED COST (cents/kWh)	TRANSMISSION & DISTRIBUTION (average megawatts)
0-1.0	7
1.0-2.0	1
2.0-3.0	22
3.0-4.0	4
4.0-5.0	0
TOTAL	34

Because of the preliminary nature of the estimates of loss reduction potential on non-Bonneville systems, the Council does not consider these savings to be available for the resource portfolio. Because of the potential magnitude and cost effectiveness of this resource, the Council seeks additional information regarding availability, cost effectiveness and methods of acquisition of this resource.

The Council also encourages confirmation of the cost and performance of advanced transmission and distribution loss reduction measures.

Hydropower Efficiency Improvements

Hydropower efficiency improvement measures offer the potential for cost-effective increases in capacity and energy from existing regional hydropower projects. This potential is due to advanced designs, materials and equipment that have become available since many of the region's hydroelectric projects were built. Additionally, electrical energy costs, and therefore the cost of electrical losses, are much higher now than when much of the regional hydropower system was designed. Because the cost of losses used for the original designs was lower than if these projects were being designed today, designs and equipment were often chosen that are of lower efficiency than those that would be selected today.

Preliminary estimates of at least 270 average megawatts of potential savings through improvements to hydropower generation prompted the Council to include Action Item 11.2 in the 1983 Power Plan. It called for the Bonneville Power Administration to conduct studies of potential improvements that could be made in the efficiency of power generation, transmission and distribution. Substantial progress in assessing these resources has occurred since. A December 1984 report, prepared by the U.S. Army Corps of Engineers, assessed ongoing and potential improvements in the efficiency of the Corps hydropower projects. A January 1985 report, prepared by Raymond Kaiser Engineers for Bonneville, is the first attempt at a regionwide assessment of hydropower efficiency improvement potential. This study estimates the costs and energy savings attributable to a variety of efficiency improvement measures applied to a generic 100 megawatt hydropower unit. The generic estimates are augmented by a case study of the 774 megawatt Wells hydropower project. Regionwide estimates are developed by extrapolating generic plant estimates. During preparation of the plan, Bonneville, the Pacific Northwest Utilities Conference Committee and regional hydropower operators worked to refine the estimates of hydropower efficiency improvements appearing in the Raymond Kaiser study. The results of this refinement are used in this plan.

Efficiency Improvement Measures

The principal measures available to improve hydropower project efficiency are the following:

Turbine Improvements. Turbine runners (blade and hub assembly) of improved design and materials, air injection, contour reshaping and seal improvement may improve turbine reliability and efficiency beyond original design specifications, especially for older units. In addition, improvements in the efficiency of turbine operation and design will often reduce the mortality of fish passing through the units.

Turbine Governor Improvements. Many of the region's hydropower projects use turbines of the Kaplan type. The blade angle of a Kaplan turbine is adjustable to improve efficiency as load and water head vary. On early units, the blade angle was controlled by a two-dimensional mechanical cam. As reservoir level fluctuated, cams were to be changed to maintain optimum efficiency. Because of the effort required, these cams have typically been changed only when it is anticipated that the reservoir will be maintained at a constant level for some time. As a result, these turbines are often operated at less than optimum efficiency.

In the early 1970s, a three-dimensional mechanical cam was developed. The three-dimensional cams incorporate the contours of the set of two-dimensional cams in a single cam, eliminating the need to change cams manually to follow operating head. Three-dimensional mechanical cams have been retrofitted to The Dalles units 15 - 22, Bonneville units 1 - 10, and three units each at Little Goose, Lower Monumental and Lower Granite.

More recently, a microprocessor-based blade control system has been developed in which the relationships between blade angle, gate opening and operating head are electronically programmed. The second Bonneville powerhouse employs this system. Unit 7 at Wells and all John Day and McNary units have been retrofitted with this system.

To maintain optimum performance, a Kaplan turbine should have an "index" test performed that determines the optimal relationship among blade angle, gate opening and operating head. This relationship is unit-specific and varies over the unit life. An advanced microprocessor-based blade control system has been proposed, that would provide automatic index testing and update of the electronic cam program. The expected increase in efficiency has been estimated to be from 0.5 percent to 3 percent. Development and demonstration of governors incorporating automatic index testing is required before the potential of these devices can be assessed.

Generator Windage Loss Reduction. Improvements in the design of generator cooling systems have reduced "windage" losses due to air friction. Retrofit of older generators with improved cooling systems has been demonstrated; however, not all older machines lend themselves to retrofitting. The general feasibility of cooling system retrofits has also been questioned because of interference with access to generator internals. Additional assessment of this measure is required before the cost and availability of potential energy savings can be determined.

Generator Rewinding. Modern conductor insulation is thinner than that available in the past, allowing a greater amount of conducting material to be placed in each stator slot in a generator rewind. This reduces resistance losses and may increase the rated capacity of the machine to fully use the increased generator capacity; however, turbine improvements may also be required. Addi-

Table 6-2
Generic Hydropower Efficiency Improvement Measures[a]

MEASURE	NEW KAPLAN RUNNERS	NEW FRANCES RUNNERS	ELECTRONIC 3-D CAM
Capacity (Net MW)	100	100	100
Capacity Factor (%)	64	64	64
Efficiency Gain (%) (Typical)	1.50	1.50	1.0
Annual Energy (MWa) (Typical)	0.96	0.96	0.6
Option Lead Time (mos)[b]	12	12	12
Construction Lead Time (mos)	12	12	12
Option Cost (million $)	0.14	0.08	<0.01
Construction Cost (million $)	1.27	0.68	0.04
Fixed O&M[c] Cost (million $/yr)	0.00	0.00	0.00
Variable O&M Cost (cents/kWh)	0.0	0.0	0.0
Capital Replacement (million $/yr)	0.00	0.00	0.00
Net Decommissioning Cost (million $)	0.00	0.00	0.00
Amortization Life (yrs)	30	30	30
Operating Life (yrs)	30	30	30
Energy Cost (cents/kWh)[d]	1.1	0.6	0.1

MEASURE	WINDAGE LOSS REDUCTION	GENERATOR REWIND	SOLID STATE EXCITERS
Capacity (Net MW)	100	100	100
Capacity Factor (%)	64	64	64
Efficiency Gain (%)	0.20	0.05	0.06
Annual Energy (MWa)	0.13	0.03	0.04
Option Lead Time (mos)[b]	12	12	12
Construction Lead Time (mos)	12	12	12
Option Cost (million $)	<0.01	0.15	0.02
Construction Cost (million $)	0.05	1.35	0.21
Fixed O&M[c] Cost (million $/yr)	0.00	0.00	<-0.01
Variable O&M Cost (cents/kWh)	0.0	0.0	0.0
Capital Replacement (million $/yr)	0.00	0.00	0.00
Net Decommissioning Cost (million $)	0.00	0.00	0.00
Amortization Life (yrs)	30	30	30
Operating Life (yrs)	30	30	30
Energy Cost (cents/kWh)[d]	0.3	39.8	4.3

(table continued on next page)

tional assessment of this measure is required before the cost and availability of potential energy savings can be determined.

Solid State Exciters. Solid state exciters are now available that feature lower losses and reduced maintenance costs compared to earlier designs. Additional assessment of this measure is required before the cost and availability of potential energy savings can be determined.

High Efficiency Transformers. Transformers are inherently high efficiency devices. Losses are affected by the number of core laminations, the number of windings and other design (and cost) factors. Older units were selected upon the basis of energy costs much lower than those experienced at present, and therefore may be less efficient than designs that would be selected based upon current and forecast energy costs. The cost and availability of energy savings through replacement of main power transformers should be assessed as part of the Customer System Efficiency Improvement study (see preceding section). This is a conservation measure under Regional Act criteria.

Improved Water Use. Water bypassing turbines at existing hydropower projects may include water used for fishway attraction, navigation lock operation, fish ladders and juvenile fish bypass systems. Small quantities of bypass water are necessary to operate fish ladders, navigational locks and juvenile fish bypass systems, and cannot be reduced beyond certain practical limits. However, bypass losses can be reduced at certain projects through improved spillway gate seals, spillway gate position indicators, bypass water energy recovery facilities and other measures.

Increased Operating Head. Increasing the operating head of hydraulic turbines can increase the turbine power output. Turbine modifications and generator rewind may be required to fully use the additional power. Methods available for increasing operating head include raising reservoir levels and reducing head losses due to hydraulic friction. The feasibility of raising reservoir levels is highly site-specific and requires consideration of the social and environmental effects of the increased pool level, possible impacts on the output of upstream projects due to increase in tailwater levels and the cost of modifying turbine generator units to exploit the increased operating head. The Chief Joseph pool level was raised successfully; conversely, the proposed High Ross project was terminated, largely on environmental grounds. Head losses result from friction in water intakes, canals, penstocks and other water conveyance structures. These losses can be reduced by several means, including enlarging the existing water conveyance structures and constructing parallel structures. The Council does not consider any energy from these measures to be available at this time, because of the site-specific feasibility of potential increases in reservoir levels and reductions in operating head, and the lack of regionwide assessments of the availability, cost and potential environmental and social impacts of these measures.

Reduction in Station Service Loads. Hydropower station loads may be reduced through typical industrial conservation measures. These include efficient motors, high efficiency lighting and controls, load balancing, power factor correction, high efficiency station service transformers, removal of unnecessary voltage regulators, heating, ventilating and air conditioning (HVAC) improvements, and weatherization. No energy from this source is considered to be available at this time. This is a conservation resource under Regional Act criteria.

Resource Cost

The Council has assessed the cost of hydropower system efficiency improvements, using as its principal source the study prepared for Bonneville by Kaiser Engineers. The Kaiser study develops estimates of the cost and performance characteristics of each of the hydropower efficiency improvements described above, with the exception of bypass water energy recovery facilities. These are too site-specific to be estimated generically. Typical cost and performance estimates, based on a generic 100 megawatt capacity hydropower unit operating at 64 percent capacity, are shown in Table 6-2.

Table 6-2 (Continued)

MEASURE	IMPROVED GATE POSITION INDICATORS	HIGH-EFFICIENCY MOTORS	IMPROVED LIGHTING
Capacity (Net MW)	100	100	100
Capacity Factor (%)	—	—	—
Efficiency Gain (%)	—	0.002	0.015
Annual Energy (MWa)	0.08	0.002	0.015
Option Lead Time (mos)[b]	12	12	12
Construction Lead Time (mos)	12	12	12
Option Cost (million $)	<0.01	<0.01	<0.01
Construction Cost (million $)	0.07	<0.01	0.01
Fixed O&M[c] Cost (million $/yr)	0.00	0.00	<0.01
Variable O&M Cost (cents/kWh)	0.0	0.0	0.0
Capital Replacement (million $/yr)	0.00	0.00	0.00
Net Decommissioning Cost (million $)	0.00	0.00	0.00
Amortization Life (yrs)	30	30	30
Operating Life (yrs)	30	30	30
Energy Cost (cents/kWh)[d]	0.1	1.7	1.0

MEASURE	IMPROVED POWERHOUSE HVAC	HIGH-EFFICIENCY MAIN TRANSFORMERS
Capacity (Net MW)	100	100
Capacity Factor (%)	—	64
Efficiency Gain (%)	—	0.12
Annual Energy (MWa)	0.038	0.08
Option Lead Time (mos)[b]	12	12
Construction Lead Time (mos)	12	12
Option Cost (million $)	0.01	0.14
Construction Cost (million $)	0.07	1.22
Fixed O&M[c] Cost (million $/yr)	<0.01	0.00
Variable O&M Cost (mills/kWh)	0.0	0.0
Capital Replacement (million $/yr)	0.00	0.00
Net Decommissioning Cost (million $)	0.00	0.00
Amortization Life (yrs)	30	30
Operating Life (yrs)	30	30
Energy Cost (cents/kWh)[d]	3.1	13.0

[a]All costs are incremental; January 1985 dollars.
[b]Feasibility study and engineering design to equipment order.
[c]Operation and maintenance.
[d]Levelized lifetime energy costs for 1995 inservice date. Real interest rates, public ownership.

Table 6-3
Availability of Energy from Hydropower Efficiency Improvements

MEASURE	ENERGY (Average Megawatts) Cost Effective	Conditional	Promising	COMMENTS
Turbine Runner Replacement	85	0	—	Includes energy from the refined Bonneville Power Administration estimate for all pre-1960 units with the exception of Wells. The planned Wells upgrade is considered to be an assured resource.
Electronic 3-D Cams	27	—	28	Available energy is from units presently not equipped with mechanical 3-D cams. Promising energy is from units equipped with mechanical 3-D cams.
Windage Loss Reduction	0		46	0.2 percent efficiency gain from all pre-1980 units.
Generator Rewinding	0	5.0	—	Energy from all pre-1975 units thought not to have been rewound since 1975 is considered as conditionally promising. Assumes 0.05% efficiency gain.
Solid-state Excitors	0	0	9	Energy from all units thought not to have solid-state excitors is promising. Assumes 0.06% efficiency gain.
High Efficiency Transformers		16	—	Energy from all pre-1975 projects thought not to have post-1975 transformer replacement is conditionally promising.
Improved Water Usage			23	Energy from new gate position indicators at all projects is promising. Bypass water turbines are considered as a new hydropower resource.
Reduced Station Service			17	Energy from improved lighting and HVAC and high-efficiency motors at all pre-1980 units is promising.
Totals	112	21	123	

The levelized life cycle costs of the hydropower efficiency improvement measures appearing in Table 6-2 were estimated using the financial assumptions described in Chapter 4 of this volume. These costs indicate that all measures, with the exception of generator rewinding and main transformer replacement, meet the 4.5 cent per kilowatt-hour cost criterion. Certain measures, particularly electronic governors and improved gate position indicators, are so low cost that it may be desirable to install these measures during the current surplus.

Generator rewinding and replacement of main transformers do not appear to be cost effective if undertaken for the sole purpose of improving unit efficiency. Rewinds are occasionally required to restore degraded insulation. If rewinds are undertaken for this purpose, the energy savings shown in Table 6-1 can be obtained for a much lower cost than indicated. Similarly, if main transformer replacement is required for reasons other than improved efficiency, a high efficiency transformer can be obtained for a much smaller incremental investment than indicated in Table 6-2. The incremental capital costs and resulting levelized energy costs of other measures will likewise be lower than the full costs shown in the table.

Resource Availability

The Bonneville-Kaiser report derived potential regionwide energy savings resulting from hydropower efficiency improvements. This calculation was attempted through extrapolation of the estimated savings from the 100 megawatt generic unit, using an inventory of regional hydropower units. The resulting regionwide estimates of savings were questioned, however, because of inaccuracies in the inventory of regional units and, in certain cases, incorrect extrapolation.

The Council has received comments from Bonneville, the Pacific Northwest Utilities Conference Committee (PNUCC) and utilities identifying errors in the regional hydropower inventory. In 1985 a joint effort was undertaken involving the Council, Bonneville, PNUCC and regional hydropower operators to review and revise the inventory of hydropower units upon which the estimate of availability of regional savings is based.

The resulting revised estimates of regionwide potential savings appear in Table 6-3. Energy classified as "cost effective" in Table 6-3 is a discretionary resource that can be obtained when needed. Energy classified as "promising" appears to be cost effective, but requires further confirmation of availability or cost. "Conditional" energy is from measures (transformer replacement and generator rewind) that are likely to be cost effective only if the measure is undertaken for reasons other than efficiency improvement. This resource, therefore, may be a lost opportunity resource. Because a comprehensive inventory of candidates for transformer rewind and generator replacement is not available, energy from these measures is considered promising, not available.

Energy from potential hydropower efficiency improvements is an attractive resource because of its low cost and generally negligible environmental effects. Improvements in turbine design and operation allowing better operating efficiency may reduce the mortality of fish passing through the turbines. System efficiency improvements have promising optioning characteristics because of short lead times and the direct control of many hydropower projects by the region's utilities. However, much of the region's hydropower capacity is controlled by federal agencies, and improvements to these projects are subject to the federal budgeting process. Ways should be explored to better control the timing of improvements to federal projects.

The Council encourages further assessment of the cost and availability of the conditional and promising resources identified in Table 6-3. Methods of controlling the timing of the development of this resource should be investigated, and ways should be explored of transferring the resource to utilities likely to need additional capacity. The Council also encourages development and demonstration of advanced technologies leading to further improvements in the efficiency of hydropower units.

Conclusion

The Council has concluded that energy savings from turbine runner replacement and electronic governors should be included in the resource portfolio. All measures, with the exception of generator rewinds, transformer replacement, reservoir raising and bypass energy recovery units, are likely to be cost effective. Generator rewinds and transformer replacements are incrementally cost effective if required for reasons other than efficiency improvement. Measures involving increases in operating head (reservoir raising and head loss reduction) must be assessed individually. Bypass energy recovery units are considered in the hydropower assessment. The cost and availability of cost-effective hydropower efficiency improvements are summarized in Table 6-4.

Table 6-4
Cost and Availability of Hydropower Efficiency Improvements

LEVELIZED COST (cents/kWh)	HYDROPOWER (average megawatts)
0-1.0	112
1.0-2.0	0
2.0-3.0	0
3.0-4.0	0
4.0-5.0	0
TOTAL	112

Thermal Plant Efficiency Improvements

The efficiency of existing thermal plants may be upgraded to an extent depending upon age and design. This upgrading may reduce operating costs and increase plant capacity and energy output. The extent of upgrades may range from minor component replacement to complete repowering using advanced design heat sources such as fluidized bed combustors. Major process modifications such as repowering are unlikely to be cost effective at present because of the contemporary design of most of the region's thermal plants. Component upgrades typical of industrial conservation efforts, such as efficient motors, variable-speed motor controllers, efficient pumps and efficient lighting, may be cost effective.

Bonneville has proposed a pilot study of a typical regional coal-fired thermal plant, to be carried out subject to budget approval. The Council is not aware of any existing assessment of the regional potential for thermal plant upgrades.

Because of the lack of information regarding the availability and cost of thermal plant upgrades, the Council does not consider energy from this resource to be available at present. The Council encourages further study to establish preliminary estimates of the availability and cost effectiveness. The study should draw upon assessments that may have been performed elsewhere and would apply to regional coal plants.

Geothermal Electric Power

No geothermal-electric power plants are presently operating in the Pacific Northwest. Because the quality and extent of Northwest geothermal resources had not been demonstrated, the regional geothermal resource potential was not incorporated in the resource portfolio of the 1983 plan. However, the resource assessment prepared for Bonneville by the four Northwest states (The "Four State Study") indicates that approximately 4,400 megawatts of potentially cost-effective electrical energy could potentially be obtained through development of regional geothermal resource areas.

Table 6-5
Pacific Northwest Geothermal-Electric Resources[a]

PROJECT	COUNTY	STATE	POTENTIAL CAPACITY[b] (MW)	POTENTIAL ENERGY[b] (MWa)	ENERGY COST[c] (cents/kWh)
Cove and Crane Creek	Washington	ID	224	179	3.4
Big Creek Hot Springs	Lemhi	ID	29	23	3.5
Newberry Volcano	Deschutes	OR	1,946	1,557	3.8
Wart Peak Caldera	Lake	OR	145	116	4.1
Glass Buttes	Lake	OR	348	278	4.2
Raft River Area	Cassia	ID	15	12	4.3
Cappy-Burn Butte	Klamath	OR	473	378	4.3
Mickey Hot Springs	Harney	OR	138	110	4.4
Bearwallow Butte	Deschutes	OR	763	610	4.5
Melvin-Three Creek Buttes	Deschutes	OR	1,380	1,104	4.5
Boulder Hot Springs	Jefferson	MT	3	2	4.7
Vale Hot Springs	Malheur	OR	163	130	4.9
Klamath Falls Area	Klamath	OR	453	362	5.0
Olene Gap Hot Springs	Klamath	OR	26	21	5.0
Neal Hot Springs	Malheur	OR	43	34	5.0
Klamath Hills Area	Klamath	OR	366	293	5.1
Lakeview Area	Lake	OR	10	8	5.1
Crump Hot Springs	Lake	OR	79	63	5.1
Deer Creek Hot Springs	Boise	ID	3	2	5.2
Summer Lake Hot Springs	Lake	OR	5	4	5.2
Borax Lake Hot Springs	Harney	OR	83	66	5.2
Alvord Hot Springs	Harney	OR	35	28	5.3
Hallinan Hot Springs	Lake	OR	3	2	5.3
Trout Creek Area	Harney	OR	4	3	5.3
Fischer Hot Springs	Lake	OR	1	1	5.4
Ennis	Madison	MT	3	2	5.4
Barry Ranch Hot Springs	Lake	OR	1	1	5.4
Jackson Hot Springs	Beaverhead	MT	3	2	5.5
Crater Lake Area	Klamath	OR	45,300	36,240	5.5
Generic High Cascades[d]	Linn	OR	34	27	5.6
Mt. McLoughlin	Jackson	OR	17,598	14,078	5.6
Roystone Hot Springs	Gem	ID	3	2	5.6
Baker Hot Springs	Whatcom	WA	3	2	5.9
Mt. Hood	Clackamas	OR	6	5	6.2

(Table Continued)

Generation Technology

A central station geothermal plant consists of a wellfield, transmission piping and a power plant. Unit capacities typically range from 25 to 100 megawatts, with multiple units employed for larger fields.

Integrated wellhead units are also available, ranging in capacity from tens of kilowatts to several megawatts.

Three basic generation technologies are in use: dry steam plants, flashed steam plants and binary cycle plants. The choice of technology for a given development depends upon the quality of the resource. Pacific Northwest geothermal resources are anticipated to be of the low and intermediate temperature hydrothermal type. The intermediate temperature resources (150 - 210°C), offer the greatest potential for electricity generation. It is likely that flashed steam plants would be used for resources greater than 175°C and binary plants would be used for resources less than 175°C.

The choice of central station versus wellhead units would depend upon the capacity of the field and the development strategy. Wellhead units might be used for small site development, for serving small remote loads, for the early phases of development of large fields, and for reservoir confirmation work.

Flashed steam plants are a well-demonstrated, commercially available technology. Binary cycle plants are commercially available and demonstrated at wellhead scale. Commercial demonstration of central station binary cycle technology is underway at Heber, California.

Project Cost and Performance

The resource assessment prepared by the four states for Bonneville contains preliminary estimates of the cost of development and operation of 92 promising geothermal resource areas, based upon the limited information currently available. These cost estimates yield levelized energy costs as low as 3.4 cents per kilowatt-hour using the Council's revenue requirements methodology. Ten sites, producing a potential 4,370 megawatts of energy, are estimated to have levelized energy costs of 4.5 cents per kilowatt-hour or less.

The Four State Study[2] evaluated and ranked the known and suspected geothermal resource sites of the region. Of the 1,265 known or suspected geothermal sites evaluated, 245 warranted detailed analysis, indicating either development potential, cost effectiveness, or both. Sites were ranked on the basis of development potential and on cost. Seventy-eight electric power sites were identified as having "good" or "average" potential for development.

The Four State Study report contains levelized life cycle cost estimates for each of the electrical generating sites passing the study's site screening process. These costs, however, are not comparable to the levelized energy costs used elsewhere in this plan, largely because of somewhat different financial assumptions adopted by the Council. To obtain comparable cost estimates, the Council first compiled basic cost and performance data from the Four State Study. The cost estimates were adjusted to the January 1985 base used in this plan. Minor adjustments were made to the construction schedule and payout assumptions provided in the Four State Study to improve consistency with other resources assessed in this plan. The resulting data for a typical site are shown in Appendix 6E to this chapter. The resulting cost and performance estimates were used to calculate levelized life cycle costs using the Council's revenue requirements methodology. Investor-owned utility financing was assumed, as described in Chapter 4 of this volume, for consistency with the levelized life cycle cost estimates prepared for other resources. The resulting levelized life cycle costs are shown in Table 6-5 for all resource areas having an estimated electrical generation potential of one average megawatt or greater, and "good" or "average" potential for development. The locations of these areas are shown in Figure 6-1.

Ten of these electric power sites, estimated to be technically capable of generating approximately 4,370 megawatts of electrical energy, could be competitive with busbar costs of new conventional coal plants.

(Table Continued)

White Arrow	Gooding	ID	1	1	6.8
Indian Creek Hot Springs	Owyhee	ID	1	1	6.9
Squaw Creek Hot Springs	Franklin	ID	3	2	6.9
Norris Hot Springs	Madison	MT	1	1	7.0
Sharkey Hot Springs	Lemhi	ID	1	1	7.4
Crane Hot Springs	Harney	OR	3	2	7.4
Battle Creek Hot Springs	Franklin	ID	1	1	7.7
Umpqua Hot Springs	Douglas	OR	1	1	8.1
Magic Hot Springs	Camas	ID	3	2	8.1
Little Valley Area	Malheur	OR	1	1	8.2
O. J. Thomas Well	Harney	OR	1	1	8.3
Maple Grove Hot Springs	Franklin	ID	1	1	9.2
Murphy Hot Springs	Owyhee	ID	1	1	9.3
Marysville Well	Lewis & Clark	MT	5	4	9.9
Latty Hot Springs	Elmore	ID	1	1	10.8

[a]Sites having an estimated developable capacity of 1 MW or greater and assessed as having "good" or "average" development potential in the Four State Study.

[b]From Bonneville Power Administration, 1985, *Evaluation and Ranking of Geothermal Resources for Electrical Generation or Electrical Offset in Idaho, Montana, Oregon and Washington.*

[c]Levelized life cycle costs calculated using the estimates of development and operating costs appearing in Bonneville Power Administration, 1985, *Evaluation and Ranking of Geothermal Resources for Electrical generation or Electrical Offset in Idaho, Montana, Oregon and Washington.* These calculations assumed investor-owned utility financing, using the financial assumptions described in Chapter 4 of Volume II.

[d]Selected as a typical High Cascades site. Many additional sites of this type may exist.

Resource Availability

Current interpretations of available data suggest that a substantial and cost-effective geothermal resource is potentially available to the region. Appropriate conversion technology is available. However, the geothermal systems of the region must be further characterized, and reservoirs tested, before this resource can be considered to be available. Generic conceptual models of the physical characteristics of the region's geothermal systems must be confirmed.

Characterization of the cost, availability, and environmental effects of a geothermal resource is a multi-step process. First, basic geologic, geochemical, geophysical, and hydrological data must be gathered and analyzed to develop conceptual models of geothermal systems. Much of this preliminary effort is accomplished by what are referred to as surface reconnaissance techniques. Subsequently, models are created to explain the data. These conceptual models lay the foundation for directing exploratory drilling toward potential geothermal production sites. Exploration drilling defines the thermal, lithologic, and geochemical environment with the aim of pinpointing specific sites for geothermal fluid production wells. Finally, production wells are drilled and tested. Only at this stage is the resource confirmed. The conceptual generic models of the geothermal systems are also confirmed in this process.

The characteristics of geothermal energy—in terms of costs, geology, brine characteristics, and environmental concerns—cannot necessarily be extrapolated from one reservoir to another. Although geothermal resources of one geologic province (such as the Cascades) may have commonalities, each reservoir will be unique. Determination

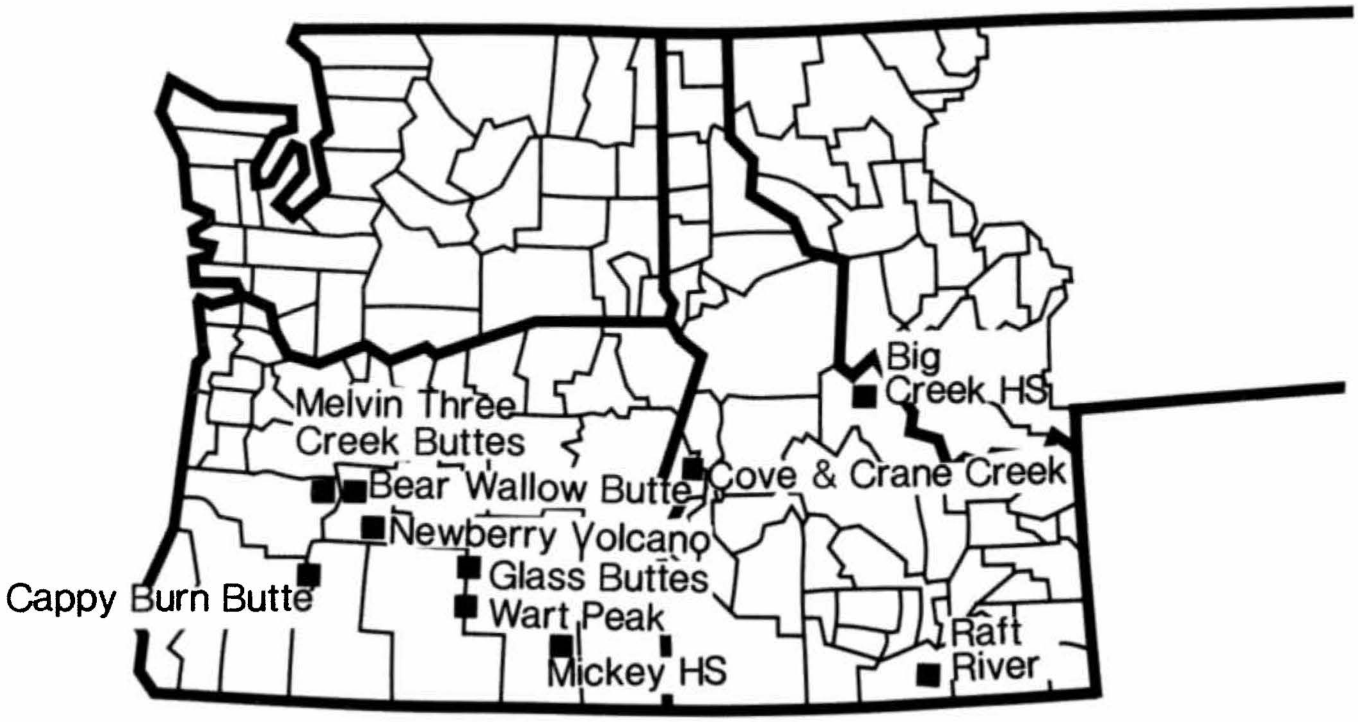


Figure 6-1
Pacific Northwest Geothermal Resource Areas

of regionwide geothermal energy availability and potential will require resource assessment on a reservoir-by-reservoir basis.

Strategies for assessing and developing geothermal resources have been developed for the Basin and Range geologic province. These strategies would apply to southeastern Oregon, southern Idaho, northern Nevada and northwestern Utah—a large geographic portion of the region within Bonneville's service area. However, no basic models exist yet for the Cascades province, where a significant resource is projected to exist.

Conclusion

The Council considers the geothermal resource potential of the region to be promising. The estimated cost and magnitude of this resource suggest that geothermal could play a major role in providing future energy needs of the region. However, because the information regarding the character and extent of regional geothermal resource areas used to prepare the estimates of cost and availability is very preliminary, this resource cannot yet be considered as available for the resource portfolio of this power plan. Because of the apparent magnitude and cost effectiveness of this resource, the Council encourages continuation of activities leading to confirmation of regional geothermal resource areas. The Four State Study should be maintained and refined as a repository and clearinghouse of information regarding the availability and costs of geothermal resource development. Effort should be made to obtain broad regional review and concurrence on this study.

Due to the large investment required to complete confirmation activities, it is clear geothermal resource developers will not undertake a full confirmation program without assurance of a substantial market for their resource to recover investment costs. Under conditions of extended power surplus, large markets for energy are not likely to emerge. Because it may be desirable to confirm this resource as an alternative to making decisions to construct new large conventional thermal resources, alternative methods of promoting the confirmation of geothermal resources should be explored. These methods might include offers similar to those called for by Action Item 17.1 of the 1983 plan (perhaps using well-head scale plants), additional resource assessment and research, development and demonstration activities, or granting developers conditional access to out-of-region markets.

A geothermal resource research and development agenda that includes ongoing scientific and technical investigations should be prepared to identify and sequence specific actions required to confirm this resource.

Hydroelectric Power

Existing and assured Pacific Northwest hydropower projects provide 29,800 megawatts of firm capacity and about 12,300 megawatts of firm energy (Appendix 6-A). Most environmentally acceptable large-scale hydropower sites have been developed. Remaining potential includes irrigation and flood control and other non-power water projects that could be retrofitted with generation equipment; addition of generating equipment to existing hydropower projects; plus many undeveloped sites potentially suitable for small-scale development.

The Council included 920 megawatts of firm energy from new hydropower in the 1983 Power Plan. These resources included approximately 255 megawatts representing the addition of generation to non-power projects and capacity additions to existing power projects. The balance consisted of projects at currently undeveloped sites.

Generation Technology

Hydropower projects extract energy from falling water and require operating head (vertical drop) and water flow. Project configuration may be of the instream, diversion or canal or conduit types. Instream projects use operating head created by a dam, which backs water up the stream channel. Sometimes the dam may impound sufficient water to permit regulation of streamflow so power can be generated when needed. Such projects are called storage projects. If sufficient reservoir storage is not present to allow streamflow regulation, power is generated as streamflow permits. Such projects are called run-of-river projects.

In a diversion project, water is diverted from the stream by a diversion structure (dam or weir) and transmitted to a downstream powerhouse by canals, conduits or other conveyance structures. The operating head is developed by the difference in elevation between the diversion structure and the powerhouse. Sometimes the diversion structure is a dam that may provide additional operating head and storage to permit regulated power production.

A canal or conduit project involves the construction of a powerhouse using potential operating head present on existing non-power water conveyance structures such as irrigation canals and water supply conduits.

Hydropower is a renewable energy source and is free from toxic emissions. However, its effect on stream characteristics may present environmental problems. Dams and reservoirs transform a portion of the stream from a free-flowing stream to a lake-like impoundment. This results in inundation of land and biologically significant changes to the stream. Water is diverted from the natural stream channel in a diversion project. Consideration must be given to maintaining adequate streamflows for biological and aesthetic purposes. Dams, diversions and powerhouses may form barriers to the natural movement of anadromous and resident fish. Provisions for fish passage and protection from turbines may be required. Canal and conduit projects are typically environmentally benign; however, because conduits and canals are themselves conveyance structures in a diversion project, consideration must be given to effects of project operation on instream flow.

Although hydropower technology has been in use for a century, improvements in turbine and generator design, materials and control systems have increased the efficiency of newer plants. These improvements create a potential for cost-effective upgrades of older plants. This potential is considered in the section concerning hydropower efficiency improvements.

Project Cost and Performance

The cost and performance and environmental effects of hydropower projects are highly site-specific and not amenable to generic assessment. Information currently available to the Council is from an assessment done for the 1983 Power Plan. This information was limited to sites for which the results of individual engineering studies were available.

To improve estimates of the cost and energy production potential of regional hydropower resources, the Council, in cooperation with the Corps of Engineers and the Bonneville Power Administration, is assembling the Pacific Northwest Hydropower Data Base and Analysis System. This data base will contain locational, cost, performance and other information on all Northwest hydropower projects that have been submitted to the Federal Energy Regulatory Commission permitting and licensing process, plus additional sites appearing in the Corps of Engineers National Hydropower Survey. In addition, cost and energy production estimating methods under development will allow costs and energy production to be estimated for projects without such estimates. This data base will be operational in 1986.

A review of recent hydropower development and proposed projects suggests that most new development will be sponsored by independent developers and purchased by contract. For this reason, until improved information is available, the Council will assume that new hydropower will arrive at a cost of 4.0 cents per kilowatt-hour, slightly less than the avoided cost of the marginal thermal resource (new coal).

Resource Availability

Because of concerns regarding the environmental impact of hydropower projects, especially the potential impact on fish and wildlife resources, hydropower resource potential may not approach the estimates appearing in the 1983 Power Plan. The Council and Bonneville are sponsoring the Pacific Northwest Hydropower Assessment Study to improve the ability to identify environmentally acceptable hydropower projects. This study is scheduled to be complete in 1986.

Until the Hydropower Data Base and the Hydropower Assessment Study are available, the Council will use a conservative estimate of 200 megawatts of firm energy potentially available from future hydropower development. This estimate is based on the estimate of 255 megawatts of cost-effective hydropower appearing in the 1983 Power Plan, representing potential development at

Table 6-6
Planning Assumptions: New Hydropower

Design:	Run-of-River Additions to Existing Developments	
Sponsor:	Independent Developers	
Capacity:	800 megawatts	
Firm Energy:	200 megawatts	
Seasonality:	January	6 percent
	February	7 percent
	March	8 percent
	April	12 percent
	May	12 percent
	June	12 percent
	July	13 percent
	August	7 percent
	September	6 percent
	October	5 percent
	November	6 percent
	December	6 percent
Cost:	4.0 cents/kilowatt-hour*	
Operating Life:	30 years	
Maximum Ramp-In:	20 megawatts/year	
Dispatch:	None	

*Levelized lifetime, real

existing non-power projects and additions to existing hydropower projects. The 255 megawatt figure was reduced to 200 megawatts to account for approximately 50 megawatts of firm energy from projects included in the 255 megawatt estimate that are now operating or under construction. As described above, this energy is assumed to be available at a real levelized cost of 4.0 cents per kilowatt-hour, slightly less than the cost of new coal.

The Council recognizes that the addition of power generating equipment to certain non-power projects may have adverse effects on fish and wildlife. It is likely, however, that the energy otherwise available from these sites can be obtained from environmentally acceptable projects at undeveloped sites.

Conclusion

The Council concludes that at least 200 megawatts of firm energy are available to the region from future cost-effective and environmentally acceptable hydropower development. This energy has been incorporated into the resource portfolio of this plan. The planning assumptions used for this resource are shown in Table 6-6.

Because of the uncertainty of this estimate, revised estimates based on improved inventories and cost estimating tools could show a greater potential. The Council encourages the continued development of information and planning tools leading to improved estimates of regional hydropower availability. The Council also encourages actions leading to better understanding of the possible environmental effects of hydropower development and available mitigation measures.

Municipal Solid Waste Electric Generation

Studies prepared for the Council for the 1983 Power Plan indicated that municipal solid waste (MSW) projects potentially producing an aggregate of 22 megawatts of energy were planned; projects potentially producing an additional 48 megawatts were under consideration. The Council did not include energy from MSW in the 1983 plan, given the uncertain public acceptance of these projects. No electric generation projects using MSW for fuel are yet operating in the region. Three, however, are scheduled to come into service within the next two years. The 13 megawatt Ogden-Martin (Trans-Energy) plant located near Salem, Oregon, is planned to come into service in January 1987. A small (less than 1 megawatt) unit in Coos County, Oregon, is scheduled to come into service in 1986. Tacoma, Washington, is converting a retired steam plant into a cogeneration facility that will co-fire coal, wood residue and refuse-derived fuel obtained from MSW.

Generation Technology

Direct-fired steam-electric plants continue to be the principal technology for generating electricity with municipal solid waste. Cogeneration improves their cost effectiveness. Direct-fired plants use shredded waste or refuse-derived fuel fired alone or co-fired with fuels such as coal. Mass-burning is the most common combustion technology in current use. Gasified and pelletized MSW fuels are being investigated. Production of electricity from municipal solid waste using direct-fired steam-electric power plants is an established process, especially in Europe, and to an increasing extent in the United States.

MSW-fired power plants can be a cost-effective and environmentally acceptable method of disposing of municipal solid wastes. These plants, however, present the potential for air pollution, noise, odor and traffic impacts, impairing their public acceptance. Air pollution remains a concern and a significant impediment to public acceptance of MSW generation facilities. Potential pollutants created by combustion of MSW include particulates, carbon monoxide, hydrocarbons, heavy metals, dioxin, chlorides and fluorides. Dust and microorganisms can also be released from fuel storage and handling systems. Control mechanisms are available, however. Conventional flue gas particulate removal technologies may be used to control particulates and heavy metals. Carbon monoxide, hydrocarbons and dioxins can be controlled by maintaining specific combustion conditions and by provision of afterburners. It is important to consider that many of these potential pollutants are present when municipal solid wastes are disposed by alternative means, such as in landfills, and that properly designed and operated MSW power plants may offer improved control.

Project Cost and Performance

The cost and performance characteristics of generic 1, 10 and 20 megawatt stand-alone, direct-fired steam-electric plants fired with MSW are described in the resource assessment prepared for the 1983 plan. For the 10 and 20 megawatt projects—a size range suitable for the waste load of larger metropolitan areas— energy costs were estimated to range from approximately 0.5 to 7.4 cents per kilowatt-hour (1980 dollars), depending upon project size and the tipping fee.[3] Equivalent 1985 costs would range from approximately 0.7 to 10 cents per kilowatt-hour.

The cost of electrical energy from these plants is highly sensitive to the tipping fee and to the size of the facility. The tipping fee is highly dependent on the local solid waste disposal situation, and can range from less than $1 to more than $5 per million British thermal units (Btu) of waste. This fee is determined by the avoided cost of alternative methods of waste disposal. Landfill is often the principal alternative to use of waste in an MSW generation plant. Landfill disposal costs for metropolitan areas will likely increase over time at a rate exceeding general inflation as the availability of landfill sites decreases. Costs for more rural areas, with a greater availability of suitable disposal sites, will likely pace general inflation. The more cost-effective projects will therefore likely be located near metropolitan areas. An additional factor contributing to the potentially greater cost effectiveness of MSW plants near major metropolitan areas is the greater volume of available waste. This will allow construction of larger and therefore more cost-effective projects.

Resource Availability

Estimates prepared for the 1983 Power Plan indicated that MSW sufficient to support 147 megawatts of electrical energy production would be available in the region by 1985. Regional MSW availability was expected to increase, due to population growth and other factors, to an amount capable of supporting 169 megawatts by the year 2000. These estimates remain the most current estimates of regional generation potential using MSW.

Conclusion

Although certain applications of MSW generation appear cost effective, the Council has not specifically included the electrical energy potential of the region's solid waste in the resource portfolio because of uncertainties regarding air quality effects and the difficulty of siting MSW generation projects. The three projects currently under development in the region (Ogden-Martin, Tacoma and Coos County) were included in the inventory leading to the estimated availability of cogeneration.[4] The remaining resource is considered promising, subject to resolution of questions regarding air quality effects and site selection. Development and implementation of siting and emission control standards for MSW plants throughout the region will assist confirmation of this resource.

Solar-Electric Power

Although gaps remain in regional coverage of solar data, enough is known to say that the potential is large. As an example, the southeastern Oregon and southwestern Idaho areas receive about 83 percent of the direct normal solar insolation received by Phoenix, Arizona. Areas west of the Cascades receive far less solar insolation. Western Oregon, for example receives only about 52 percent of the insolation received in Phoenix.

The high cost of solar-electric generation technology precluded it from consideration as an available resource in the 1983 plan. Recognizing its potential, however, the Council called for continuing the insolation data collection in the region. The Council also recommended that Bonneville monitor technology changes that may lead to cost breakthroughs.

Generation Technology

The two basic types of solar-electric technology are solar-thermal generation and solar-photovoltaic generation.

Solar-thermal plants use heat engines[5] to produce power from solar insolation. Major types of solar thermal systems include central receivers, parabolic troughs, parabolic dishes and solar ponds. Central receivers and solar ponds have not yet been demonstrated in the size and form required for commercial installations. One 10 megawatt prototype central receiver is operating in Barstow, California; a second, larger prototype was planned but has not been constructed due to funding difficulties. Because the size and cost of research prototypes and demonstration units is substantial, the rate of deployment of central receiver units and solar ponds for testing is likely to be slow.

Parabolic trough and dish designs, on the other hand, are inherently small scale and modular. Being smaller, and inherently less costly, these designs are likely to evolve more rapidly than central receiver or solar pond technologies. The modularity of parabolic trough and dish designs also presents the potential advantages of factory fabrication, short lead time and development to match rates of load growth.

At present, the leading design appears to be the parabolic trough design. A power plant employing parabolic troughs and developed under the auspices of Public Utility Regulatory Policies Act contracts and third party financing is in operation at Daggett, California. Phase I is on line with an installed capacity of approximately 14 megawatts; Phases II and III are under construction with an ultimate aggregate capacity of all three phases in excess of 74 megawatts. Several different prototype parabolic dish type units are being evaluated by Southern California Edison (SCE) for their respective manufacturers. Some of these designs have exhibited efficiencies in excess of 27 percent, greatly exceeding photovoltaic efficiencies but with the modular advantages of photovoltaics. The prototype parabolic dish units use Stirling engines to convert heat to mechanical energy. Since the Stirling engines can use any external heat source for power, hydrogen or natural or synthetic gas could be used to operate the units at night or during periods of limited solar insolation.

Table 6-7
Generic Solar Generating Projects: Cost and Performance Summary

TYPE	THERMAL	PHOTOVOLTAIC	PHOTOVOLTAIC	PHOTOVOLTAIC	THERMAL
Design	Central Receiver	Flat Plate (fixed)	Flat Plate (track)	Concentrating	Stirling Dish
Location	SE Oregon	SE Oregon	SE Oregon	SE Oregon	SE Oregon
Sponsor	IOU	IOU	IOU	IOU	IOU
Capacity (Net MW)	100	10	10	10	10
Heat Rate (Btu/kWh)	n/ap	n/ap	n/ap	n/ap	n/ap
Availability (%)[a]	83	95	95	95	95
Capacity Factor (%)	50	28	40	28	28
Option Lead Time (mos)[b]	24	24	24	24	24
Construction Lead Time (mos)	48	24	24	24	24
Option Cost (million $)	17	1	1	1	1
Construction Cost (million $)	843	136.0	144.5	48.5	38.8
Fixed Fuel Cost (million $/yr)	n/ap	n/ap	n/ap	n/ap	n/ap
Variable Fuel Cost ($/MMBtu)	n/ap	n/ap	n/ap	n/ap	n/ap
Fixed O&M[c] Cost (million $/yr)	0.0	0.05	0.05	0.05	0.0
Variable O&M Cost (cents/kWh)	1.0	0.2	0.2	0.2	1.1
Capital Replacement (million $/yr)	n/av	n/av	n/av	n/av	n/av
Decommissioning Cost (million $)	3.0	0.0	0.0	0.0	0.0
Amortization Life (yrs)	30	30	30	30	30
Operating Life (yrs)	30	30	30	30	30
Energy Cost (cents/kWh)[d]	15	38	29	14	12

[a]Equivalent Annual Availability.

[b]Site and license acquisition.

[c]Operation and maintenance.

[d]Levelized lifetime energy costs for 1995 inservice date.

Solar photovoltaic electricity is produced directly from solar insolation by using photosensitive materials. Photovoltaic electricity generation is attractive for several reasons: 1) It makes use of total solar radiation, not only direct sunlight; 2) Unlike solar-thermal designs, water is not required for cooling; and 3) Tracking devices are not required (though performance may be improved through the use of tracking). The modularity and solid state nature of photovoltaic technology suggests that rapid improvements in the technology are probable. Modularity also provides potential advantages of short lead time, factory fabrication and synchronization with load growth. Substantial basic physics and material science problems must be resolved if the efficiencies and per unit costs, which photovoltaics must achieve in order to become cost effective, are to be realized. Because the Pacific Northwest's marginal energy costs and solar insolation are both lower than the Southwest's, the technology will be cost effective in the Southwest before it becomes cost effective in this region.

Project Cost and Performance

The Oregon State Department of Energy has supplied current cost and performance estimates for five generic solar-electric central station units. These include a solar-thermal central receiver, a solar-thermal Stirling dish, and fixed, tracking and concentrating photovoltaic stations. Key cost and performance characteristics of these units are shown in Table 6-7. The costs shown in Table 6-7 represent present-day costs and do not reflect possible future cost reductions.

As is evident from Table 6-7, solar-electric technology is not yet cost-competitive with other resource alternatives for central-station electricity generation.

Resource Availability

The solar insolation received by this region, primarily in southeastern Oregon and southwestern Idaho, could support a large base of solar-electric generation. The resource potential has not been estimated.

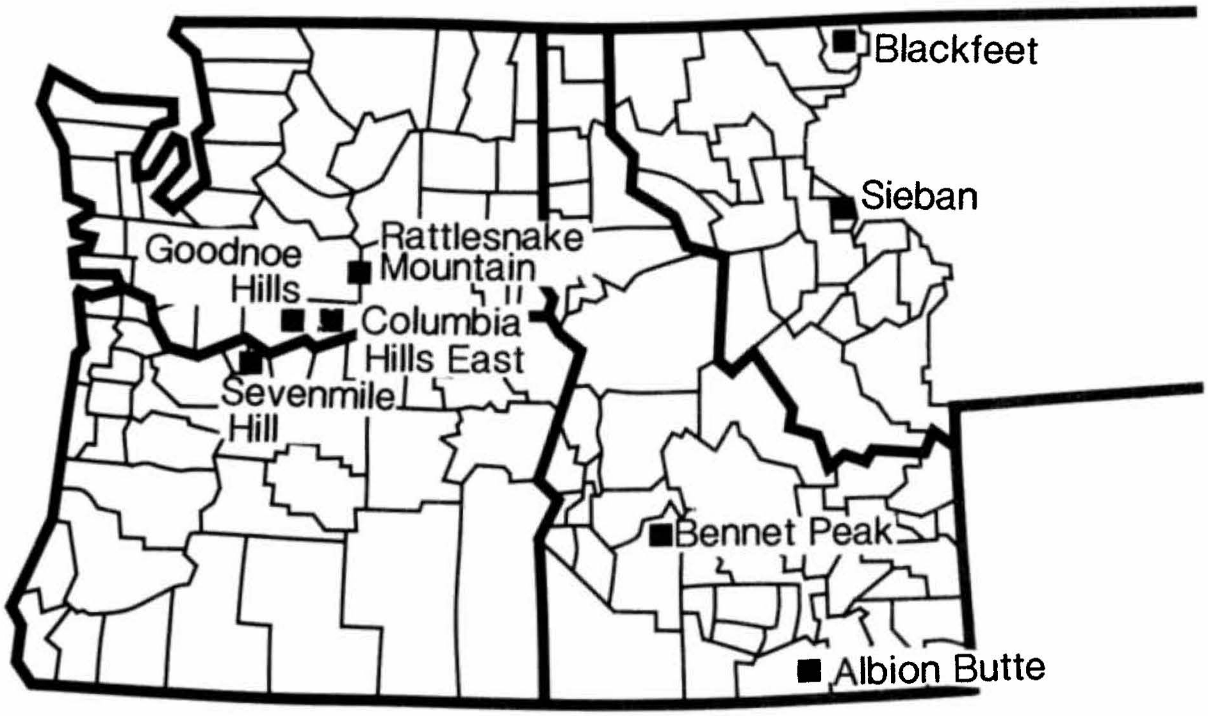


Figure 6-2
Pacific Northwest Wind Resource Areas

Conclusion

Solar energy is renewable and has relatively benign environmental effects. Furthermore, many of the leading solar-electric technologies have desirable planning characteristics such as small module size and short lead time. On the other hand, solar is an intermittent resource and is at its prime in areas of the region remote from major load centers. Despite these problems, solar electricity generation may be highly desirable if costs can be reduced. Only the currently high cost of solar electricity generation keeps the Council from further considering this resource in this plan.

Significant reductions in price for solar technologies have occurred in the past, and the region should continue to monitor further development of solar-electric technologies. The Action Plan calls for development of a solar resource research, development and demonstration agenda. Planning tools are needed to better assess the value of intermittent resources to the regional power system. Using these tools, the possible role of solar-electric generation and other intermittent resources can be assessed in future plans.

Wind-Electric Power

Two experimental wind projects and one windfarm are currently operating in the region. The experimental projects include the 7.5 megawatt capacity U.S. Department of Energy project at Goldendale, Washington, and the 0.2 megawatt capacity Whiskey Run Project on the Oregon coast. A 1.25-megawatt windfarm operated by private developers and contracted to Pacific Power and Light is also located at Whiskey Run. An 80 megawatt (capacity) commercial windfarm has been proposed at Cape Blanco. Many other locations in the Pacific Northwest have a wind resource sufficient for electrical power generation by wind turbines. The wind resource assessment conducted for the 1983 plan identified seven prime areas for the large scale development of windpower. Possible development scenarios were postulated, and potential energy production and levelized energy costs estimated for each. These costs, which were especially sensitive to wind turbine hardware costs, wind regime and deployment scenarios, ranged from 4.5 to 7 cents per kilowatt-hour in 1980 dollars. Current (1985) dollar equivalents would be approximately 6 to 9.3 cents per kilowatt-hour. Although the estimated cost of several of these sites was close to the cost of new coal, wind was not included in the resource portfolio of the 1983 plan, primarily because of the uncertain cost and performance characteristics of the turbines available at that time.

Generation Technology

There has been rapid development of windpower in California since 1981. This is due largely to the fortuitous combination of several key factors, including attractive state and U.S. income tax regulations, abundant in-state investment capital, high avoided cost for power purchased under the Public Utility Regulatory Policies Act provisions and a favorable wind resource near load centers. It is estimated that as of the end of 1985, approximately 13,000 turbines having an aggregate nameplate rating of approximately 1,100 megawatts will have been installed, representing about 98 percent of installed U.S. wind capacity. Because this development has been tax-shelter driven, it is not clear that it will continue with the pending expiration of federal energy tax credits.

Table 6-8
Representative Wind Turbine Cluster: Cost and Performance Summary

Design	100 — Nordtank Model 65/13 WTGs[a]
Fuel	n/ap
Location	Columbia Hills East, Washington
Sponsor	IOU
Capacity (Installed MW)	6.5
Capacity (Net MW)	6.2
Heat Rate (Btu/kWh)	n/ap
Availability (%)[b]	95
Capacity Factor (%)	35
Option Lead Time (mos)[c]	12
Construction Lead Time (mos)	24
Option Cost (million $)	0.1
Construction Cost (million $)	9.7
Fixed Fuel Cost (million $/yr)	n/ap
Variable Fuel Cost ($/MMBtu)	n/ap
Fixed O&M[d] Cost (million $/yr)	Inc. in variable O&M
Variable O&M Cost (cents/kWh)	1.2
Capital Replacement (million $/yr)	Inc. in variable O&M
Net Decommissioning Cost (million $)	Inc. in variable O&M
Land Royalty (% net cost of energy)	5
Amortization Life (yrs)	20
Operating Life (yrs)	20
Energy Cost (cents/kWh)[e]	5.5

[a]Wind turbine generators.

[b]Equivalent Annual Availability.

[c]Site and license acquisition.

[d]Operation and maintenance.

[e]Levelized lifetime energy costs for 1995 inservice date.

The California experience, however, has stimulated the evolution of the wind turbine from a novel machine of questionable reliability to a fairly well-proven generation technology. A somewhat unexpected development has been the evolution of the intermediate-scale machine (50 to 500 kilowatts) as the machine of preference. This contrasts with the utility-oriented research of the late 1970s that focused on megawatt-scale machines. Although multi-megawatt, utility-operated machines may become common in the future, the present trend is to intermediate-scale machines developed in windpark settings by independent developers. Windpower can now be considered as having a commercially-available and demonstrated technology.

Project Cost and Performance

The Oregon Department of Energy has prepared cost and performance estimates for a Nordtank 65/13 wind turbine generator. This European machine is representative of the better intermediate-scale horizontal axis machines available on the current market. Its cost and performance characteristics, adjusted to be comparable with other resources, are summarized for a representative wind resource area in Table 6-8 and described in detail in Appendix 6F.

Resource Availability

Regional wind resource areas have been surveyed and monitored by Oregon State University under the Bonneville Regional Wind Energy Assessment Program. Under this program, Oregon State University (OSU) has identified 46 areas in and adjacent to the region having good wind resource potential (Figure 6-2). The Oregon State Department of Energy has estimated the number of Nordtank turbines that could be installed at eight of the better areas and the resulting energy production (Table 6-9). The levelized cost of energy at the more favorable areas was estimated by the Council using the financial assumptions of Chapter 4 of this volume. Financing was assumed to be at investor-owned utility rates. An in-service date of 1995 was assumed, using present day machine cost and performance data. Estimated levelized energy costs ranged as low as 5.5 cents per kilowatt-hour.

Conclusion

Estimates of energy cost and availability from the better regional wind resource areas indicate that wind, though not presently cost effective, offers a large resource potential. Continuation of the cost reductions that have occurred in the wind generating equipment industry over the past several years may make this resource cost effective in the future. These projects would be highly modular and would likely be environmentally acceptable if properly developed. On the other hand, the resource is intermittent and the larger sites are extremely remote from load centers and located in harsh climates. In addition, many of these areas are not sufficiently well understood to allow their resource be considered confirmed.

The Council has not included wind in the resource portfolio, primarily because of cost, and to a lesser extent because of the limited information regarding site characteristics. However, the Council believes there is a good chance that wind will become cost effective in the future. For this reason, the region should take actions to ensure that the resource can be developed if cost effective. These actions include developing and implementing a wind resource research and development agenda, developing tools to assess the value to the regional power system of intermittent resources, and developing and implementing a resource acquisition policy by Bonneville to include intermittent resources. State and local governments are encouraged to implement siting and performance standards that ensure environmentally acceptable wind resource development.

Table 6-9

Cost and Availability of Energy From Better Pacific Northwest Wind Resource Areas

PROJECT	COUNTY	STATE	POTENTIAL CAPACITY (MW)	POTENTIAL ENERGY (MWa)	ENERGY COST (cents/kWh)
Columbia Hills East 1	Klickitat	WA	7	2	5.5
Albion Butte	Cassia	ID	38	12	5.6
Rattlesnake Mountain 1	Benton	WA	20	7	5.8
Sieban 1	Lewis and Clark	MT	120	36	6.4
Bennett Peak	Elmore	ID	4	1	6.4
Goodnoe Hills Addition	Klickitat	WA	10	3	6.4
Sevenmile Hill	Wasco	OR	56	15	6.7
Blackfeet Area 1	Glacier, Pondera	MT	15,800	4,370	6.7

*Because insufficient information is available concerning the amount of developable land in each wind resource area, actual potential may vary ±40 percent or more from values shown.

Wood

One utility-operated generation plant using wood residue (the 45 megawatt Kettle Falls Generating Station) is currently operating in the region. In addition, the output of several small stand-alone wood-fired plants operated by small power producers is contracted to regional utilities (Appendix 6-A). The total energy output of these plants is about 60 megawatts. Council studies for the 1983 plan estimated the total wood residue resource of the region to be sufficient to support generation of about 215 megawatts of energy, exclusive of projects then under construction.

No stand-alone wood-based generation was included in the 1983 plan other than the Kettle Falls Generating Station. However, wood accounted for a portion of the 400 megawatts of energy from renewable-based cogeneration included in the 1983 plan.

Previous studies by the Council have indicated that both stand-alone and cogeneration plants fired by wood are cost effective. There is however, considerable uncertainty regarding the cost and availability of this resource. This uncertainty is created by changing and competing uses of the resource (such as the apparent increase in the use of wood for residential heating in recent years) and changing economics within the forest products and pulp and paper industries. Better definition of the cost and availability of this resource, and the factors that impact cost and availability over time, are required. Until a better understanding of this resource is achieved, the Council will continue to include it in the promising category.

Cogeneration

Cogeneration is the simultaneous production of electricity and useful heat energy. The heat energy is typically used for industrial process or space heating applications. Cogeneration providing about 230 megawatts of capacity and 130 average megawatts of energy is currently contracted to regional utilities.[6,7] Additional projects, providing 80 megawatts of capacity and 60 megawatts of energy, are scheduled to come into service by 1989 (Appendix 6-A).[7] The Council included 500 megawatts of future cogeneration in the 1983 Power Plan under the high and medium-high load growth forecasts.

Cogeneration Technology

Cogeneration installations may employ either topping cycles or bottoming cycles. Topping cycles use heat energy first to produce electricity. Exhaust heat from the generation process is then used for industrial processes or other heating applications. Topping cycles may use steam-electric turbine equipment, gas turbines or internal combustion engines.

Bottoming cycles recover waste heat from industrial or other processes to use in generating electricity. This type of cogeneration installation consists of a heat recovery boiler powering a turbine, employing either steam or an organic working fluid.

Cogeneration technology is commercially available and mature. Development continues on advanced cogeneration concepts, such as fuel cells with waste heat recovery, and packaged units for both general and specialized applications.

Table 6-10
Planning Assumptions — New Cogeneration
(Sponsors: Independent Developers)

	LOAD GROWTH			
	Low	**Medium-Low**	**Medium-High**	**High**
Capacity:	200	290	290	510
Energy:	130	190	190	320
Seasonality:	None			
Cost:	4.0 cents/kilowatt-hour*			
Operating Life:	20 years			
Maximum Ramp-In:	32 megawatts/year			
Dispatch:	None			

*Levelized lifetime, real

Project Cost and Performance

Because of the variety of potential applications, technologies and unit sizes, the cost and performance characteristics of cogeneration installations is highly site-specific. Common Pacific Northwest industrial applications include wood-fired steam turbine topping cycles and natural gas-fired combustion turbine topping cycles. The current pattern of cogeneration development suggests that this resource will continue to be developed by independent small power producers—either industries having cogeneration opportunities, or third party developers contracting to both the utility purchasing the plant output and the industry served by the cogenerated energy. For this reason the Council assumes that most cogeneration will be marketed under the provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA), at the avoided cost of new utility resources as required by PURPA. Because of this assumption and because few potential cogeneration projects inventoried in the PNUCC study were less costly than new coal plants, the Council has assumed that cogeneration will be acquired at a levelized cost of 40 mills per kilowatt-hour—slightly less than the cost of new coal.

Resource Availability

The Council's assessment of the availability of cogeneration is based upon The Pacific Northwest Utilities Conference Committee (PNUCC) report, *Cogeneration Potential in the Pacific Northwest,* dated December 1984. The PNUCC assessment, which identifies approximately 1,000 megawatts of potential cogeneration, is based upon an inventory of regional industrial cogeneration potential. In a survey conducted by PNUCC member utilities, industries were asked how much cogeneration capacity they would consider providing at a given first year purchase price for power. Responses were grouped into categories of "assured," "planned," "prospective," "under consideration" and "potential," depending upon the current status of the proposed cogeneration project.

The Council estimates an available cogeneration resource of approximately 320 megawatts of energy. This includes, first, all projects reported as "assured" in the PNUCC inventory. To avoid double-counting, projects included as "assured" in the *Northwest Regional Forecast* of March 1985 (the source of the inventory of existing regional resources used for the system planning models) were deleted from the estimate. To the remaining projects were added all "planned," "prospective," "under consideration" and "potential" projects having estimated levelized life cycle costs of 5.5 cents per kilowatt-hour or less.[8] Excluded from this estimate were any projects reporting use of municipal solid waste, since this resource potential is considered separately.

Because of the dependence of cogeneration on industrial operation, adjustments should be made for different load scenarios: the higher the load growth, the more cogeneration is likely to be available. Based on the approach of the PNUCC Cogeneration Work Group to quantifying the constraints and uncertainties of resource development, the most likely amount of cogeneration that will be available to the region is estimated to be 190 megawatts of energy for medium rates of growth. Under low rates of growth, industries such as lumber products and pulp and paper are projected to decline. A 50 percent decrease in the potential for these industries is taken, reducing the estimate to approximately 130 megawatts of energy. For high rates of growth, industrial expansion will provide additional cogeneration opportunities. Adding an increment for industrial growth, as projected by the work group, increases the cogeneration estimate to approximately 320 megawatts.

These cogeneration assumptions result in a total available and cost-effective resource of approximately 320 megawatts of energy for high load growth conditions. This resource consists of approximately 210 megawatts of energy supplied by renewables (of which approximately 140 megawatts are supplied by wood), and 110 megawatts of energy supplied by non-renewables, primarily coal. One major project is included in the inventory of projects upon which this estimate was based. This project is the proposed coal-fired Crown Zellerbach project at Wauna, Oregon, of 100 megawatts installed capacity.

Addition of power generating equipment to the Fast Flux Test Facility (FFTF) located on the Hanford Reservation in Washington would provide an additional 101 megawatts of capacity and 65 to 70 average megawatts of energy. Because this project would use currently wasted heat, it would likely qualify as a cogeneration facility under provisions of PURPA and as a third-priority resource under provisions of the Northwest Power Act. Assuming that operation of the FFTF itself would continue to be funded by the federal government for research purposes, the cost of energy from the power addition would be well under the 4.5 cents screening criterion. Restrictions on the timing of the power addition give this resource some characteristics of a lost opportunity resource.

Conclusion

The Council concludes that approximately 320 megawatts of energy may be available to the region from future cogeneration development. Because of the sensitivity of this resource to economic activity, lesser amounts of cogeneration will likely be available under lower load growth conditions. The Council currently considers approximately 190 megawatts of energy to be available under medium levels of load growth and 130 megawatts to be available under low levels of load growth.

The planning data assumptions regarding cogeneration are shown in Table 6-10. Future assessments of cogeneration potential should consider the effect of economic activity on cogeneration potential. These assessments should also consider the effect of utility financing of cogeneration equipment upon the availability of this resource.

Coal-Fired Electric Generation

The Pacific Northwest power system currently includes 12 coal-fired units totaling 5,924 megawatts of nameplate capacity, capable of supplying about 2,480 megawatts of energy to the region. One additional unit is scheduled to come into service in 1986. This is Colstrip 4, at Colstrip, Montana. The regional share of this unit will be 490 megawatts of capacity, producing about 370 megawatts of energy (Appendix 6-A). Additional coal-fired projects have been proposed or licensed. These include additional units at Boardman, Oregon; the Creston Generating Station, at Creston, Washington; the Salem project, near Great Falls, Montana; an additional unit at the Wyodak site, near Gillette, Wyoming; and an eight-unit project at Thousand Springs, Nevada.

Proven reserves of coal, far in excess of those required to meet electricity needs for the foreseeable future, are available to the region. Coal resources sufficient to support electrical power generation are found in Montana, Utah, Wyoming, Washington, Alberta and British Columbia. Out-of-region coal resources could be used by generation plants located at the minemouth, with the electrical power transmitted into the region. Alternatively, out-of-region coal could be transported to power plants located nearer major load centers. In-region reserves could provide a future source of coal for electric power generation. However, because of the uncertainties associated with the availability and cost of in-region coal, the cost of potential future coal plants is based on Northern Great Plains coal delivered by unit-train to plant sites located in eastern Washington or Oregon.

Generation Technologies

The direct-fired steam-electric power plant is the established technology for producing electricity from coal. Although considered a mature technology, enhancements in plant control, efficiency and reliability have improved the cost and performance of new plants compared with earlier designs. A range of unit sizes is available, allowing capacity additions to be matched to load growth. Smaller plant sizes have somewhat shorter construction lead times and greater reliability, but are generally more costly to build and operate than larger units.

Alternative coal-based generating technologies under development include fluidized bed combustion designs, integrated coal gasification combined-cycle plants and magnetohydrodynamics.

Fluidized bed designs burn coarsely ground coal (or other fuel) in a bed of limestone particles suspended by air injection. The limestone removes sulfur from the coal, reducing or eliminating the need for flue gas desulfurization. In atmospheric fluidized bed combustion (AFBC), the fluidized bed operates near atmospheric pressure. The hot combustion gases power a steam boiler, as in a conventional power plant. In pressurized fluidized bed (PFBC) designs, fuel is burned at elevated pressure. This allows the hot combustion gases to power a gas turbine prior to final heat recovery in a steam boiler. This combined cycle design results in higher energy conversion efficiencies.

Cogeneration applications of AFBC technology are commercially available, and central-station electric generation atmospheric fluidized bed combustion power plants are being demonstrated. Two utility-scale AFBC units are currently under construction in the U.S., and many in the industry believe that the next generation of central-station coal plants will be largely of AFBC design. Development of PFBC designs is not as advanced; however, a 170 megawatt PFBC demonstration plant is expected to enter service in 1986.

Integrated coal gasification combined-cycle (IGCC) plants consist of a coal gasification plant powering gas turbines. Turbine exhaust heat recovery, using steam boilers, creates a highly efficient combined cycle. These plants feature a high degree of modularity, improved control of atmospheric emissions and high energy conversion efficiencies. Integrated coal gasification combined-cycle plants entered the demonstration stage in May 1984 when the 100 megawatt Cool Water plant was brought on-line in southern California.

Magnetohydrodynamics (MHD) is a process for converting heat energy directly into electricity. High combustion temperatures, combined-cycle operation and direct conversion of thermal energy to electrical energy offer the advantages of high energy conversion efficiency. The MHD concept also promises improved control of atmospheric emissions.

The components of a MHD power plant include a combustor, a MHD "channel," a heat recovery boiler and a steam turbine-generator. Pulverized coal would be burned at high temperature and pressure in the combustor. Potassium "seed" is injected to ionize the hot gas, creating an electrically conductive plasma. The plasma passes through the MHD channel, where a strong magnetic field would be established by use of superconducting magnets. The ionized gasses, moving rapidly through the magnetic field, create an electrical potential across electrodes installed in the channel. After exiting the channel, the hot plasma is passed through a heat recovery boiler. Steam from this boiler drives a conventional steam turbine-generator, augmenting the power production of the MHD channel. The potassium seed not only serves to ionize the combustion gasses but also scavenges sulfur by chemical reaction of sulfur and potassium.

Table 6-11
Generic Coal Projects: Cost and Performance Summary

Design	2-603 MW Direct-Fired Units	2-250 MW Direct Fired Units	1-110 MW Atmospheric FBC Unit
Fuel	Subbituminous Coal	Subbituminous Coal	Subbituminous Coal
Location	Eastern Oregon	Eastern Oregon	Eastern Oregon
Sponsor	IOU	IOU	IOU
Capacity (Net MW)	603	250	110
Heat Rate (Btu/kWh)	10,080	10,190	11,200
Availability (%)[a]	75	77	75
Capacity Factor (%)	70	72	70
Option Lead Time (mos)[b]	48	48	48
Construction Lead Time (mos)	72[d]	60[d]	72
Option Cost (million $)	47.3	27.6	4.2
Construction Cost (million $)	1,466.2	858.7	197.2
Fixed Fuel Cost (million $/yr)	0.0	0.0	0.0
Variable Fuel Cost ($/MMBtu)	2.00	2.00	2.00
Fixed O&M Cost (million $/yr)	11.1	9.1	3.6
Variable O&M Cost (cents/kWh)	0.1	0.2	0.1
Capital Replacement (million $/yr)	14.5	6.0	12.0
Net Decommissioning Cost (million $)	0.0	0.0	0.0
Amortization Life (yrs)	30	30	30
Operating Life (yrs)	40	40	40
Energy Cost (cents/kWh)[c]	4.6	5.4	6.0

[a]Equivalent Annual Availability.

[b]Site and license acquisition.

[c]Levelized lifetime energy costs for 1995 inservice date.

[d]Lead time shown is to completion of first unit; additional 12 months (minimum) required to complete second unit.

Limited proof-of-concept design work has been carried out over the past several years at two government-funded test facilities. The U.S. Department of Energy, after failing to promote MHD research for three years, proposed, in 1984, a five-year MHD research and development program that would culminate in the repowering of an existing conventional fossil plant with a MHD power train. Conceptual design of the project would start in 1986 with test operations complete by 1995. The Montana Power Company Frank Bird plant has been proposed as a candidate for this retrofit. The DOE proposal, though stricken from FY-86 budget recommendations, has been restored by Congress.

Project Cost and Performance

The Council, assisted by its Coal Options Task Force, assembled cost and performance characteristics for representative plants of each commercially-available design. These included a large conventional plant, consisting of two units of 603 megawatts of capacity each; an intermediate size conventional plant, consisting of two units of 250 megawatts each; and a small AFBC plant consisting of a single 110 megawatt unit. These plants are described in detail in Appendices 6B through 6D, and are summarized in Table 6-11. As evident in Table 6-11, the AFBC plant is clearly not yet cost-competitive with the two conventional designs. Although the 250 megawatt unit appeared to be somewhat more expensive than the 603 megawatt unit, these two units were compared using the decision model, since the somewhat shorter lead time of the 603 megawatt unit may have compensated for its greater construction and operating cost. This, however, was not found to be the case, and the 603 megawatt unit was subsequently used in the resource portfolio.

Resource Availability

Three sites, within or adjacent to the region, are either currently licensed for construction of new coal plants or appear to be capable of being readily licensed. These sites are as follows:

Boardman: Boardman, Oregon, is the site of the existing Portland General Electric 530 megawatt coal-fired Boardman Generating Station. The Site Certification Agreement for the Boardman site, issued in 1975, allows construction and operation of two additional thermal power units. The additional units are limited in capacity from 450 to 1,350 megawatts each, and are to be completed by August 31, 1991, and August 31, 1993, respectively. The site certification requires eight months' notice prior to commencement of construction, followed by a state and local government comment period and a public hearing. The state siting council would then issue a new or revised certificate, or revoke the certificate, as appropriate. The warranted completion date may be extended in this process.

Certain facilities that would be common to the existing and additional units have been constructed in conjunction with the existing Boardman unit. No specific design relative to the additional units has been undertaken.

Because it is unlikely that construction of an additional coal unit could now be completed at this site by the time requirements cited in the Site Certification Agreement, the Council chose not to consider this as a licensed site for purposes of developing the resource portfolio.

Creston Generating Station: The Washington Water Power Company (WWP) has pursued siting and licensing of a four-unit coal-fired project at a site near Creston, Washington. A Site Certification Agreement (SCA) for construction and operation of the Creston Generating Station was issued by the Washington State Energy Facility Site Evaluation Council (EFSEC) in February 1983. A Prevention of Significant Deterioration (PSD) permit for the project was issued by the U.S. Environmental Protection Agency in January 1983. Completion of the first unit was originally scheduled for 1988, but has since been indefinitely deferred. The SCA requires construction of the first unit to commence within five years of issue (February 1988) and the fourth unit within 15 years of issue (February 1998). Similar time limitations apply to the design of the emissions control system. The PSD permit was issued for the standard period of 18 months and was extended by the Environmental Protection Agency for an additional 18-month period in December 1984. Thirty-day written notice to EFSEC is required prior to commencement of construction; however, no additional public hearings are required unless it is necessary that the SCA be amended. The PSD permit requires a review of the emission control technology six months prior to beginning construction.

Ambient air quality considerations limited the original proposal to four units of approximately 508 (net) megawatts of capacity each. Proposed reclassification of the Spokane Indian Reservation airshed to PSD Class I will limit the capacity of the site to approximately half the originally planned capacity.

The Washington Water Power Company (WWP) has secured the site and has performed project feasibility studies. Detailed project engineering has not commenced. WWP and Puget Sound Power and Light Company are currently maintaining the site and associated permits, although these companies, commenting on the draft of this plan, indicated that they would likely not maintain the site and permits indefinitely. No constraints to continued maintenance of the site and permits for the first two units have been identified by the Council.

Wyodak: In 1981, Pacific Power and Light Company (PP&L) was granted all necessary permits for construction of a second unit at the Wyodak site. The proposed second unit would be of 332 megawatts rated capacity and would include a flue gas desulfurization system. Construction was originally scheduled to commence in late 1981 or early 1982, with completion scheduled for 1986. In November 1981, completion of the unit was deferred to 1989. An application to the Wyoming Department of Environmental Quality to extend the PSD permit was denied, and the permit has been allowed to expire. Current PP&L projections show no need for the plant until 1997.

Two additional projects have been proposed adjacent to the region:

Salem: A 330-megawatt coal-fired power plant has been proposed for a site near Great Falls, Montana, by the Montana Power Company (MPC). A portion of the site was acquired by the Company and an application for site certification was submitted to the Montana Department of Natural Resources (MDNR). Completion was originally scheduled for 1989, with full output intended for MPC loads. Processing of the application has since been suspended by mutual agreement of MPC and MDNR.

Thousand Springs: Sierra Pacific Resources has proposed construction of eight 250 megawatt coal units at Thousand Springs in northeastem Nevada. The company intends to market the output of the plant to customers throughout the West. Applications for permits have been initiated. Completion of the permitting process could be as early as 1988 with construction of the first unit complete by 1992. The plant is proposed to be developed by several non-utility partners plus Sierra Pacific Resources, the parent company of Sierra Pacific Power Company.

Conclusion

Coal resources adequate to meet any likely future need of the region for electricity are found in and adjacent to the region. Conventional and AFBC technologies are available to use this resource, if needed, and other promising technologies are under development. Conventional direct-fired steam-electric technologies continue to enjoy a cost advantage compared with AFBC technology. Comparison of large (603 megawatts) and small (250 megawatts) conventional units, using the Council's planning models, indicates that the larger units remain more cost effective even though they require a somewhat longer lead time for construction.

Table 6-12
Generic Combustion Turbine and Combined-Cycle Projects: Cost and Performance Summary

	COMBUSTION TURBINE	COMBINED CYCLE
Design	Open Cycle Industrial	2 Units, ea w/2 CTs & HRSG[d]
Fuel	Natural Gas/No.2 Fuel Oil	Natural Gas/No.2 Fuel Oil
Location	In-region	In-region
Sponsor	IOU	IOU
Capacity (Net MW)	2@105 ea. (nominal)	2@286 ea. (nominal)
Heat Rate (Btu/kWh)	10,700	9,800
Availability (%)[a]	85	83
Capacity Factor (%)	19[c]	19[c]
Option Lead Time (mos)[b]	24	24
Construction Lead Time (mos)	30 4	8
Option Cost (million $)	0.8	6.4
Construction Cost (million $)	52.5	362.2
Fixed Fuel Cost (million $/yr)	1.0	2.4
Variable Fuel Cost ($/MMBtu)	5.10 (gas)/5.70 (oil)	5.10 (gas)/5.70 (oil)
Fixed O&M[e] Cost (million $/yr)	0.3	4.8
Variable O&M Cost (cents/kWh)	0.2	<0.1
Capital Replacement (million $/yr)	0.3	2.0
Net Decommissioning Cost (million $)	0.0	0.0
Amortization Life (yrs)	20	20
Operating Life (yrs)	30	30

[a]Equivalent Annual Availability.

[b]Site and license acquisition.

[c]Average capacity factor when operated in hydrofirming mode, assuming sufficient turbines to firm about 700 MW of nonfirm energy.

[d]Heat recovery steam generator.

[e]Operation and maintenance.

Three sites in the region are either currently licensed for construction of new coal plants or appear capable of being readily licensed. Planning for two additional sites has been initiated. After reviewing the status of potential coal sites, the Council believes that sites in an essentially licensed condition could support construction of approximately 1,250 megawatts of new coal-fired generating capacity. This capacity could be expected to produce about 950 megawatts of energy that could be available to the region. This resource could be developed at a cost of approximately $1,216 per kilowatt—the cost of new 603 megawatt coal-fired units, excluding the cost of siting and licensing.

Additional partially licensed sites could support the construction of approximately 2,700 megawatts of new coal-fired generating capacity. This capacity would be capable of supplying about 2,025 megawatts of energy to the region. These sites could be developed for about $1,255 per kilowatt—the full cost of new 603 megawatt, coal-fired units.

Additional coal development, if required, would have to be located at new sites. In this plan, it is assumed that these sites could be developed at the full cost of new 603 megawatt, coal-fired units (about $1,255 per kilowatt). Actual development costs of these sites is, however, less certain than development costs at fully or partially licensed sites.

Gas-Fired Electric Generation

One combined-cycle plant and several combustion turbine plants in the region have access to natural gas (Appendix 6-A). (The remaining combustion turbines use fuel oil.) As these plants typically have been used only to meet peaking loads, natural gas has not played a substantial role in meeting the region's electrical loads. However, natural gas generating plants may be attractive for cogeneration, firming of secondary hydropower during low water years, and meeting unexpected high rates of load growth until more cost-effective alternatives can be developed. The high load growth case for the 1983 Power Plan included 1,050 megawatts of combustion turbines to meet unexpected load growth, and 100 megawatts of nonrenewable cogeneration, a portion of which would be gas-fired.

With the exception of a small producing field in Oregon, no natural gas is produced in the region. All major load centers in the region are, however, served by natural gas distribution systems receiving gas from both domestic and Canadian sources. Prospects for a continued supply of natural gas appear to be good, with the principal technical question relating to the adequacy of the regional gas transmission and distribution system. At 1983 consumption levels, recoverable domestic reserves should be adequate for more than 60 years. The Canadian supply should remain secure due to long-term contracts, an established transmission system, abundant Canadian resources and a close political relationship, although curtailments of Canadian exports have been experienced in the past due to internal political problems. Future gas supplies can be obtained by developing unconventional gas resources, including tight sands, Devonian shale gas, coalbed methane, synthetic gas (from coal) and geopressured gas. Longer-term gas resources may include gas hydrates and abiogenic methane.

Generation Technology

Generation technologies using natural gas have several attractive characteristics. The clean combustion characteristics of natural gas result in low maintenance costs, good reliability, siting flexibility and a modest environmental impact. Many have short lead times and low capital costs, and are available in unit sizes that can be closely matched to load growth. Further development of natural gas generating technologies is leading to improved fuel efficiency and reliability.

The conventional natural gas generating technologies include direct-fired steam-electric plants, combustion turbines and combined-cycle plants. All are commercially available and mature technologies. Development continues, however, especially for combustion turbines and combined cycle plants. A major objective of current work is to increase the efficiencies of these machines.

The fuel cell is the principal emerging generation technology using natural gas. Fuel cell plants emit no by-products other than water and carbon dioxide, are relatively quiet, highly modular and are forecast to be more efficient than combustion turbines. Capital costs, however, will have to decrease considerably for fuel cells to compete with combustion turbines or combined-cycle plants, especially for intermittent duty applications.

Natural gas may find application in the longer term as a secondary fuel for solar thermal units using Stirling engine-driven generators.

Project Cost and Performance

The Council assembled cost and performance characteristics for a twin unit combustion turbine plant and a twin unit combined-cycle plant. These are described in detail in Appendices 6G and 6H and are summarized in Table 6-12. Because of the high cost of fuel, the levelized life cycle costs of these plants is much greater than the 4.5 cent screen (Table 6-12). As described in Chapter 7 of Volume I, when used in hydrofirming applications, however, the net cost of firmed power would be much less than the levelized costs of Table 6-12.

Resource Availability

The near-term availability of new natural gas electric generating projects is potentially limited by provisions of the Powerplant and Industrial Fuel Use Act of 1978 and the regional natural gas transmission, distribution and storage system. Siting and environmental concerns do not generally appear significantly constraining. Limitations on urban siting may arise due to noise considerations; however, plants could likely be built at existing or licensed thermal sites in the region.

Provisions of the Fuel Use Act appear to be the most significant constraint on use of gas-fired generation. The Fuel Use Act has the objective of curtailing use of natural gas and petroleum-derived fuels for generation of electricity where acceptable substitutes are available; it prohibits the use of natural gas or petroleum-derived fuels as primary fuels for new electric generating plants, except under special exemptions subject to approval of the U.S. Department of Energy. Exemptions allowing plants to be built and operated for cogeneration or peak loads appear to be the best opportunities for qualifying new gas-fired generating plants for firming secondary hydropower (See Chapter 7 of Volume I).

In the long term, natural gas supplies could be augmented, if necessary, by gasification of coal. The cost of electricity generated by coal-gasification combined-cycle plants appears to impose a long-term cap on the cost of gas-fired generation.

Conclusion

Natural gas-fired generating plants use commercially available and well-demonstrated technology. These plants are not cost effective for baseload generation applications, nor are new plants permitted to be constructed for this application. Analysis using the System Analysis Model indicates that these plants would be a cost-effective alternative for firming secondary hydropower.

Potential constraints to the development of these plants for secondary hydropower firming include the future cost and availability of fuel, and provisions of the Fuel Use Act. Site availability appears to present a less significant constraint.

Table 6-13
Cost and Performance Characteristics of WNP-1 and WNP-3

	WNP-1	WNP-3
Type	Pressurized Water Reactor	Pressurized Water Reactor
Design	Babcock and Wilcox Model 205 Fuel Assembly	Combustion Engineering System 80
Location	Richland, Washington	Satsop, Washington
Sponsor	100% - 106 Public Utilities (net-billed)	70% - 103 Public Utilities (net-billed) 30% - 4 Investor-owned utilities
Capacity (Net MW)	1,250	1,240
Availability (%)	65%	65%
Expected Shelf Life	15 years, minimum	15 years, minimum
Construction Lead Time (mos)	54 + 9 mos remobilization	54 + 9 mos remobilization
Minimum Preservation Cost (million $/yr)[a]	12	12
Remobilization Cost	32	34
Construction Cost to Complete (million $)	1,383	1,310
Financing (Construction)	Bonds at 10.2% nominal	Bonds at 10.2% nominal (Public Share) 80% debt at 13.4% nominal (IOU Share) 20% equity at 14.95% nominal (IOU Share)
Fixed Fuel Cost (million $/yr)	35.4	38.9
Variable Fuel Cost ($/MMBtu)	0.0	0.0
Fixed O&M[b] Cost (million $/yr)	71.0	71.0
Variable O&M Cost (cents/kWh)	0.11	0.11
Capital Replacement (million $/yr)	21.0	21.0 (mature plant)
Net Decommissioning Cost (million $)	3.5	3.5
Amortization Life (yrs)	30	30
Operating Life (yrs)	40	40

[a]Recent estimates of the supply system indicate minimum preservation costs to be $10 million per year for WNP-1 and $14 million per year for WNP-3.

[b]Operation and Maintenance.

Nuclear

Three nuclear power plants of 2,980 megawatts aggregate installed capacity presently operate in the region (Appendix 6-A). The energy production potential of these plants is approximately 1,930 megawatts. Five years ago, eight additional commercial nuclear plants were in various stages of planning or construction. At present, all have been terminated with the exception of Washington Public Power Supply System Nuclear Projects 1 and 3 (WNP-1 and WNP-3).

The 1983 Power Plan included WNP-1 and WNP-3 in the resource portfolio since the public share of the plants had been acquired by Bonneville prior to the Northwest Power Act. In the 1983 Power Plan, the Council assumed that the projects would be completed as then scheduled—in 1991 and 1987, respectively. Although no special cost-effectiveness assessment was performed, comparisons of the levelized costs of these projects with the cost of alternative resources indicated the projects would be cost effective.

Events since adoption of the 1983 Power Plan have altered the status and potential cost effectiveness of WNP-1 and WNP-3. Construction has been suspended indefinitely, based upon the findings of a Bonneville study completed in November 1984. Because of the indefinite suspension of construction, the plants have become potential resource options to the region. Because the costs of preservation and completion of construction, and associated uncertainties, have affected the availability, reliability and cost effectiveness of these projects, it was necessary to reassess these projects for the 1986 Power Plan. This section focuses on the cost, performance and schedule characteristics of WNP-1 and WNP-3, and associated uncertainties. These assumptions are used for the analyses of Chapter 8 of this volume.

WNP-1

WNP-1 is a Babcock and Wilcox Model 205 Fuel Assembly pressurized water reactor nuclear power plant of 1,250 megawatts (net) capacity located on the Hanford Reservation in Washington. The plant, owned by 106 public utilities, is being constructed and will be operated by the Washington Public Power Supply System (Supply System). The plant is 100 percent net-billed[9] by Bonneville.

The plant was scheduled for commercial operation in June 1986 prior to the decision of May 1, 1982, to defer plant completion for up to five years. This decision was based on revised load forecasts showing lower electrical load growth than previously anticipated, and upon perceived difficulties in marketing bonds for continued construction financing. Construction was estimated to be 63 percent complete when suspended.

WNP-3

WNP-3 is a Combustion Engineering System 80 pressurized water reactor nuclear power plant of 1,240 megawatts (net) capacity located near Satsop, Washington. Seventy percent of the plant is owned by 103 public utilities and is net-billed by Bonneville. The remaining 30 percent is owned by four investor-owned utilities.[10] This plant is also being constructed and is to be operated by the Supply System.

The plant was scheduled for commercial operation in December 1986 prior to a slowdown order in February 1983. The slowdown was prompted by revised electrical load growth forecasts showing lower growth than previously estimated. On July 8, 1983, due to the inability of the Supply System to continue to market construction bonds, construction was suspended for three years or until financing became available. Construction is estimated to be 76.5 percent complete. Following suspension of construction on WNP-3, the Council studied the cost effectiveness of WNP-3. That study, adopted by the Council on November 21, 1983, found that eventual completion of the project would be cost effective to the region and the plant should be preserved.

Bonneville and the Supply System assumed construction restart dates for the two plants of July 1985 for WNP-3, and July 1986 for WNP-1. In June 1984, Bonneville announced it would study the assumptions regarding the construction schedules and methods of financing WNP-1 and WNP-3 to determine what assumptions should be used in the rate proposal for the period extending from July 1, 1985, through September 30, 1987. The results of the study were also used in preparing Bonneville budgets for fiscal years 1986 and 1987.

The Bonneville study considered three courses of action for each project: restart of construction in accordance with current assumptions, additional two-year delay, and termination. The study found that further deferral of these plants promised the greatest benefit to the region.

WNP-1 and WNP-3 Cost and Performance

The Council, with the cooperation of the Supply System, has assembled cost and performance characteristics for WNP-1 and WNP-3. This information, and the Council's analysis, has received extensive public review prior to incorporation into this plan. Detailed cost and performance characteristics of WNP-1 and WNP-3 are provided in Appendices 6I and 6J. These characteristics are summarized in Table 6-13. The cost effectiveness of these projects, using base case planning assumptions, is estimated to be 3.5 cents per kilowatt-hour for WNP-1 and 3.6 cents per kilowatt-hour for WNP-3. The estimate is based on an assumed inservice date of 2000 and includes preservation costs until construction resumes in 1995. Previous estimates assumed an earlier inservice date and therefore less preservation cost.

WNP-1 and WNP-3 Availability

A number of key uncertainties and their effect on project costs, schedules and performance were considered in assessing the role of WNP-1 and WNP-3 in the 1986 Power Plan. Several uncertainties were found to create barriers to the ability to preserve and complete the plants.

The principal uncertainties considered by the Council included the following:

Continued Ability to Finance Preservation

Preservation of WNP-1 is currently being financed from reinvested funds remaining from construction bond sales. These funds are expected to suffice for the planned level of preservation ($36 million per year) until 1988. Adoption of a reduced preservation budget will extend the period of time for which funds will be available for preservation financing. When funds are exhausted, preservation funding must come from another source, likely from Bonneville rates as is presently done for WNP-3 preservation.

Because WNP-3 has no residual funds from construction bond sales, WNP-3 preservation costs are funded from Bonneville rates. Under terms of the WNP-3 Settlement Agreement, the preservation costs of the investor-owned utility share are paid by Bonneville from rates.

Future load growth is more likely to occur in the investor-owned utility service territories than in the service territories of publicly-owned sponsors of WNP-1 and WNP-3. It is therefore likely that the utilities that are currently paying the preservation costs for these projects are not the utilities that will need the capability of these projects. For this reason, it is not clear that financing of preservation through Bonneville rates will continue to be politically feasible.

The Council regards this possibility as a very significant potential barrier to successful preservation of the projects. While it appears that physical preservation of the plants for an extended period is feasible (see below), the continued ability to fund preservation is questionable.

Resolution of this uncertainty will require the development and implementation of a policy for allocation of option acquisition and maintenance costs to those benefiting from the options.

Availability and Cost of Construction Financing

A significant potential constraint to completion of WNP-1 and WNP-3 is the lack of available and cost-effective financing. Because of current litigation and other institutional questions affecting these projects, it is unlikely that bonds to finance these projects could be marketed at present. Alternatively, construction of the projects could be financed directly through Bonneville rates. However, it is unlikely that Bonneville customers would accept the rate impacts of this alternative.

Some progress on the settlement of litigation has been made. Bonneville and the investor-owned utility sponsors of WNP-3 have negotiated a settlement regarding the utilities' breach-of-contract suit, although this settlement is being challenged in court. A settlement master has been appointed for the WNP-4/5 litigation. Litigation may be resolved by the time resumption of construction is required. It is likely, however, that a residual perception of investment risk will remain even following full settlement of outstanding litigation. The Council has assumed that a risk perception premium of 1.0 percent be assigned to capital borrowed to complete construction. The Council has concluded that it is unlikely that conventional financing for completion of WNP-1 and WNP-3 could be found at this time.

Physical Preservation

Prolonged suspension of construction could result in unacceptable deterioration of structures and equipment. Particular concern has been expressed regarding WNP-3, which is located in an area of high humidity. Specific concerns include the adequacy of the temporary roof and wall enclosures of the reactor building, temporary wall enclosures of the turbine building, and corrosion of exposed reinforcing steel.

Preservation programs are in place at both WNP-1 and WNP-3. Structures have been closed to the weather with temporary enclosures where necessary, and weather-sensitive material has been stockpiled within structures. Humidity in sensitive equipment is controlled by shrouding, heaters and dehumidification. Preservation maintenance procedures have been established for each item of equipment and are being implemented through a computerized monitoring system. Corrosion coupons have been placed throughout the plants to monitor corrosion of materials. Results to date indicate corrosion rates well within acceptable limits for long-term preservation.

An assessment of long-term preservation of equipment and structures, drawing upon the U.S. Navy's experience with its mothballed fleet, indicates that, with proper controls, excellent preservation of equipment and structures is possible. Certain products, such as rubber goods, have a limited shelf life and will have to be replaced, even under conditions of controlled humidity. Replacement costs are not expected to be significant, as these products are typically designed for periodic replacement during operation.

The current preservation program was established to preserve the plants for a relatively brief period. Continuation of this program appears generally adequate to ensure long-term preservation, although several specific problems remain to be resolved. These include the adequacy of the temporary roof of the WNP-3 reactor building and the need to protect exposed reinforcing steel from excessive corrosion. The current situation is acceptable for the near term, and there is time to resolve these problems.

The Council concludes that the projects can likely be physically maintained so that completion could be deferred through the 20-year planning period.

Maintenance of Site Certification Agreement

The Washington State Energy Facility Site Evaluation Council (EFSEC) has informed the Council of concerns regarding maintenance of the Site Certification Agreements. The principal concern is renewal of the National Pollutant Discharge Elimination System (NPDES) permit for WNP-3. EFSEC believes the NPDES permit has characteristics of a water right. Thus, a permit not in current use could be challenged by a competing beneficial use. Because there is no evidence of a potentially competing use, the Council views renewal of the WNP-3 NPDES permit and, consequently, maintenance of the site certification agreement, to be highly probable.

Claims Against WNP-1 or WNP-3 Assets by WNP-4/5 Bondholders

Successful prosecution of claims by bondholders of WNP-4 and WNP-5 for losses sustained upon default of the WNP-4/5 bonds could result in their reaching other assets of the Supply System, including WNP-1 and WNP-3. The ultimate effects are unclear, although successful claims would be sunk costs to the region. However, this unresolved litigation continues to preclude conventional financing of the projects.

NRC Construction Permit and Operating License

There appear to be no fundamental technical or legal considerations that would preclude maintaining the construction permits or obtaining the operating licenses of either WNP-1 or WNP-3. The principal licensing uncertainties concern the extent of unplanned design changes ultimately needed to obtain the operating licenses, and the effect of design changes on current estimates of costs and schedules to complete.

The Supply System has reviewed pending Nuclear Regulatory Commission (NRC) regulatory actions that might result in design changes, and has incorporated the likely effects into the costs and schedules shown in Appendices 6I and 6J. The potential impact of design changes mandated during the preservation period is tempered by the opportunity to complete engineering plans and specifications prior to resuming construction.

Questions remain concerning the compliance of current design with NRC standards, and the possibility of new design changes being mandated prior to granting of the operating licenses. Given the experience of the past decade, it could be expected that major new backfits would be required prior to receipt of operating licenses. The effects of such actions could range from minor to severe. Estimates of the historical impact of backfits on U.S. plants average $55 million per plant, but range upward to $1 billion for the worst cases. There is, however, evidence that past experience may not be typical of the future. Commercial nuclear power is a maturing technology, and the rates of change experienced during the developing phases of the technology will likely diminish as the technology matures. The appearance of standard plant designs—WNP-3 is one—is evidence of this trend. Also, efforts are underway to improve the nuclear regulatory process. For example:

- Application of the new "readiness review" concept to WNP-1 and WNP-3 is underway. Under "readiness review," completed construction will be reviewed for compliance with NRC standards.

- Standardized nuclear steam supply system (NSSS) designs are being adopted. For example, WNP-3 employs a standardized Combustion Engineering (CE) System 80 NSSS. This design received Final Design Approval (FDA) from NRC in December 1983. The FDA allows a standard safety analysis to be referenced for operating license approval.

Other factors that will contribute to continued licensability of these projects are the following:

- **Advanced reactor design.** The WNP-3 CE System 80 NSSS and the Babcock and Wilcox (B&W) 205 Fuel Assembly NSSS of WNP-1 are state-of-the-art pressurized light water reactor designs.

- **Existing lead plant experience.** The lead CE System 80 plant is Palo Verde 1, which has received its low-power operating license and is scheduled for service in 1986. Palo Verde 2 and 3 are of similar design and scheduled for service in 1986 and 1987, respectively. These plants should serve to "shake out" the System 80 design. The Tennessee Valley Authority's Bellefonte 1 and 2 units were the lead U.S. Model 205 units. Construction of the Bellefonte units has recently been suspended, and WNP-1 could become the lead U.S. Model 205 unit. The WNP-1 NSSS design, however, is substantially the same as the Muelheim-Kaerlich nuclear power plant, located in West Germany. This plant has completed hot functional tests and is scheduled for commercial operation in August 1986.

- **Formalized NRC treatment of plant preservation.** Informal discussions are underway between the U.S. Department of Energy, the Supply System and NRC regarding means by which the continued licensability of mothballed plants could be ensured. Though no formal NRC policy currently exists to ensure continued licensability of mothballed plants, a generic NRC policy statement is anticipated. This may lead to a more formal system involving NRC certification of preservation programs.

Based upon the above findings, the Council concludes there is an acceptable probability that WNP-1 and WNP-3 construction permits can be maintained and that operating licenses can be obtained if construction were completed.

More Stringent Seismic Design Criteria for WNP-3

The design-basis seismic event for WNP-3 was established on probable seismic activity from faulting in the Puget Sound Basin. Subsequent analysis of the relative motions of the Pacific, Juan de Fuca and North American crustal plates has raised the possibility of seismic events of greater magnitude resulting from interplate motion. Historically, the plate boundary has been quiet. One school of thought attributes the historical lack of seismicity to strong coupling between the plates. If present, this could lead to a future earthquake of great magnitude. A second school holds that an aseismic subduction[11] of the Juan de Fuca plate is occurring and, although the plates are in relative motion, no large-magnitude earthquakes will result from this motion. A program to assess the aseismic hypothesis has been developed by the Supply System in response to NRC queries. Implementation of this program is provided for in the Supply System budget for 1985, and in the proposed WNP-3 preservation program.

The costs have not been assessed for retrofitting and redesigning WNP-3, if required, to more stringent seismic design criteria. The present design of much of the structure and equipment may be adequate for a larger magnitude design seismic event, because of overdesign of existing equipment and because seismic resistance is often not the controlling design factor for equipment and structures. Redesign, replacement or rework of some structures and equipment would likely be required if the design-basis seismic event were changed significantly. The potential effect of this change on completion costs is not known.

WNP-1 would not be affected by a finding of a seismically-active plate interface.

Continued Availability of Nuclear Components

With the hiatus in U.S. orders for new nuclear plants, and the completion, suspension or abandonment of plants under construction, nuclear plant component and equipment production could dwindle to the point that completion of the projects would be affected by lack of design-specific equipment and materials.

Several arguments weigh against this event. First, the bulk of equipment for WNP-1 and WNP-3 has been procured. Second, a substantial inventory of plants is presently operating or nearing operation, including designs similar to WNP-3. The market for spares and replacements provided by these plants will encourage the continued availability of components and materials. Third, the Naval nuclear program will ensure the continuation of a nuclear component manufacturing industry. In addition, the foreign commercial nuclear power industry will provide a continuing market for U.S. manufacturers, as well as a potential source of equipment for the domestic industry. Finally, it will remain possible to retool and requalify for production, although components produced in limited production runs would be more expensive. Additional insurance could be provided by identifying and procuring critical equipment and material during the preservation period.

The Council concludes that there is an acceptable probability that nuclear plant components and materials will remain available.

Technical Continuity

Loss of technical continuity would require additional effort prior to resuming construction to reestablish the engineering status of the projects. Loss of technical continuity can be prevented by proper documentation, continuation of engineering and licensing efforts during the preservation period, and provision of a technical "ramp-up" prior to resumption of construction. The Supply System preservation proposals provide for technical continuity through a continuing engineering and licensing program and by a "hands-on" plant maintenance program.

The Council concludes that preservation programs incorporating continued licensing, engineering and maintenance will ensure technical continuity.

Litigation Regarding Shared Assets
The Participants' Agreement for WNP-4 and WNP-5 allowed cost sharing for certain joint services and facilities on the basis of respective benefit to the projects. Representatives for the WNP 4/5 bondholders argue the full costs of the shared services and facilities should be assumed by WNP-1 and WNP-3, because the WNP-4/5 interests are receiving no benefit. If successful, this suit could result in additional costs of $131 million for WNP-1 and of $269 million for WNP-3. These costs are not included in the capital costs-to-complete appearing in Appendices 6I and 6J. However, these costs may be "sunk" to the region, because their assignment to the region does not depend on completion of WNP-1 and 3.

Operating Life
It is possible that the plants, though completed, might not operate as designed for their intended 40-year physical life. Events leading to this result include: 1) Disqualification, or extended shutdown of a plant design for safety-related reasons; 2) Derating, for safety or environmental reasons; or 3) Permanent or extended outage due to major accident or equipment failure. The probability of such events is thought to be relatively low. Events 1 and 3 are accounted for by the data on plant performance used to develop the availability assumptions of Appendices 6I and 6J to the extent that they have occurred during the early part of the operating lives of large nuclear plants. The Council concludes that the assumptions regarding unscheduled outage rates (22 percent) adequately account for potential factors affecting the operating life of these plants. The cost effectiveness of the two plants is, however, highly sensitive to their operating availability. For this reason, the Council will continue to monitor the performance of similar plants.

Conclusion

The Council has assessed the cost, schedule and performance characteristics of WNP-1 and WNP-3 and has concluded the planning data provided in Appendices 6-I and 6-J are reasonable base case assumptions regarding the characteristics of those projects. As described in Chapters 7 of Volume I and Chapter 8 of Volume II, the Council has performed sensitivity analyses on cost and performance characteristics for which there is substantial uncertainty. The Council has also identified and assessed uncertainties possibly affecting the region's ability to preserve, complete and operate these plants. Based on this assessment, the Council has concluded that it is likely that the plants can be preserved, completed and operated even if completion were to be deferred until late in the planning period.

The principal constraints to the completion of these projects, given a need for power, are institutional. The most significant of these are uncertainty regarding continued preservation funding and litigation involving the plants that currently precludes conventional financing. The Council has concluded that these uncertainties are so significant that they currently preclude the projects from consideration in the resource portfolio.

Assessment of the value of those projects to the region (Volume I, Chapter 7, and Volume II, Chapter 8) indicates they could have significant present value. Because of this value, the Council recommends continued preservation of the plants and resolution of the barriers to preservation and construction.

Imports

The Northwest region is not an isolated system. Interconnecting transmission lines with neighboring systems allow power to be transferred between regions. Total resources available to this region include these transfers. Transfers can involve the sale or purchase of firm energy, or the sale or purchase of peaking capacity.

Energy Transfers

Transfers can take the form of transfers between utilities in different regions, intracompany transfers by utilities that serve both regional and extra-regional loads, and transfers of portions of thermal resources that are outside of the region's boundaries, but are intended to serve regional loads. Transfer agreements can include combinations of firm energy and peaking capacity transfers. Generally, three types of arrangements are made:

- **A peaking capacity exchange** in which the agreement is to return not only the borrowed energy, but also energy to "pay" for the cost of the exchange. This type of arrangement represents an energy import into the region.
- **A peaking capacity sale** in which the payment for the capacity is made in dollars instead of energy. This type of arrangement represents no long-term exchange of energy.
- **A firm energy sale or purchase** in which payment is made in dollars for long-term delivery or receipt of firm energy. This type of arrangement will affect the load/resource balance in the region.

Tables 6-14 through 6-17 summarize the extra-regional transfers of firm power and peaking capacity used for both the System Analysis Model and the Decision Model. In general the region imports more firm power than it exports. This is primarily due to imported energy from Pacific Power & Light's thermal resources outside the region, which are used to meet regional loads. The sum of all the power exchanges represents a net energy import to the region of about 1,200 megawatts in 1986. This amount decreases to a net of about 200 megawatts by the year 2005. These types of exchanges should not be confused with sales of surplus power to Southwest utilities.

Table 6-14
Summary of Firm Energy Exports
(Average Megawatts)

CONTRACTS	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
MPC EXPORT	0	0	0	0	0	0	0	0	0	0	0	7	7	7	7	7	7	2	2	2
EWEB TO SCM	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
WWP TO SCE	8	8	8	8	8	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PP&L TO PG&E	29	29	29	29	29	29	29	29	29	29	15	0	0	0	0	0	0	0	0	0
BPA TO MPC RESTORATION	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
BPA TO MPC	68	68	68	68	65	65	65	65	65	65	65	0	0	0	0	0	0	0	0	0
BPA TO BC HYDRO	0	0	0	0	0	0	0	0	0	0	0	0	5	47	124	119	115	137	204	201
TCL TO WAPA #1	28	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	19
TCL TO WAPA #2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
TCL TO WAPA #3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
BPA TO WAPA	100	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LONGVIEW TO WAPA	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	18
TOTAL	306	241	208	208	205	203	198	197	197	197	183	110	115	157	234	229	225	242	309	277

Table 6-15
Summary of Firm Energy Imports
(Average Megawatts)

CONTRACTS	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
SW TO BPA	193	184	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
S. DIEGO TO WWP	32	32	32	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MPC IMPORT	14	14	14	14	13	13	13	13	13	13	13	0	0	0	0	0	0	6	6	6
MPC TO BPA	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	29	15	0	0	0
PP&L (WYO) TO PP&L	879	806	743	705	660	664	609	617	567	552	489	484	426	438	392	382	323	323	276	419
SCE TO WWP	8	8	8	8	8	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCM TO EWEB	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
ARIZONA TO WWP	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BC HYDRO TO SCL	23	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36	36
TOTAL	1,197	1,123	894	811	760	764	701	709	659	644	581	563	505	517	471	461	388	379	332	475

Abbreviations: *(Tables 6-14 through 6-17)*

BC HYDRO—British Columbia Hydro Power Authority
BPA—Bonneville Power Administration
EWEB—Eugene Water and Electric Board
LONGVIEW—Longview Fiber
MPC—Montana Power Company
MPC RESTORATION—Due to coordination agreement
PGE—Portland General Electric
PG&E—Pacific Gas and Electric
PP&L—Pacific Power and Light
S. DIEGO—San Diego
SCE—Southern California Edison
SCL—Seattle City Light
SCM—Southern California Municipalities
SW—Southwestern Utilities
TCL—Tacoma City Light
WAPA—Western Area Power Agency
WWP—Washington Water Power
WYO—Wyoming

6-16
Summary of Peaking Capacity Exports
(Megawatts)

CONTRACTS	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
BPA TO SW	677	624	32	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP TO S. DIEGO	112	112	112	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PP&L to PG&E	100	100	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0
BPA TO MPC	80	80	80	80	80	77	77	77	77	77	77	0	0	0	0	0	0	0	0	0
BPA TO MPC	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	0	0	0	0
BPA TO MPC	0	0	0	0	0	0	0	0	0	25	50	0	0	0	0	0	0	0	0	0
BPA TO BC HYDRO	0	0	0	0	0	0	0	0	0	0	0	0	0	41	242	235	226	204	330	287
TCL TO WAPA #1	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
BPA TO WAPA	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LONGVIEW TO WAPA	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	0
TOTALS	1,229	1,076	484	340	340	337	337	337	337	362	287	160	160	201	402	395	286	264	390	302

Table 6-17
Summary of Peaking Capacity Imports
(Megawatts)

CONTRACTS	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
PP&L (WYO) TO PP&L	1,363	1,278	1,197	1,168	1,136	1,108	1,081	1,043	1,006	974	941	908	875	847	809	781	754	731	704	683
SCE TO PGE	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCE TO WWP	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BC HYDRO TO SCL	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195	195
TOTAL	1,738	1,653	1,572	1,543	1,511	1,483	1,276	1,238	1,201	1,169	1,136	1,103	1,070	1,042	1,004	976	949	926	899	878

Out-of-Region Imports

The previous section describes existing agreements for extra-regional power transfers. Potential exists for additional agreements between utilities within the region and utilities outside the region. An assessment of resources available to the region, therefore, should include an evaluation of the cost and availability of these potential out-of-region imports. Based on previous analysis,[12] it appears that substantial benefits could result from closer interaction of regional power systems. These potential benefits, however, may be constrained by inadequate interregional transmission capacity. In addition to this, the realization of out-of-region imports depends on complex agreements being reached with out-of-region suppliers. Because of these uncertainties, the Council has assumed, for the development of the resource portfolio, that existing contracts will not be renewed and that no new contracts will be available. Because of the potential benefits, however, further analysis should be pursued. Cooperation with other regions can only occur if both regions perceive that effort to be in their best interests. The Council encourages detailed discussions with out-of-region suppliers to evaluate potential benefits, especially when it appears that out-of-region resources are more cost effective than resources developed in the region. The Council plans to conduct a West Coast energy study in order to gain better understanding of the potential benefits of broader regional resource exchange and development.

1./ Levelized life cycle costs: The present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments. Unit levelized life cycle costs (cents per kilowatt-hour) are obtained by dividing this payment by annual kilowatt-hours saved or produced. Levelized life cycle costs permit comparisons of resources having different patterns of cash flow over their lifetimes. The term "levelized life cycle cost" as generally used in this chapter refers to unit levelized life cycle costs.

2./ Published as: Bonneville Power Administration, *Evaluation and Ranking of Geothermal Resources for Electrical Generation or Electrical Offset in Idaho, Montana, Oregon and Washington,* June 1985.

3./ The fee assessed for disposal of waste.

4./ The Transenergy (Ogden-Martin) plant has subsequently been redesigned as a stand-alone (non-cogeneration) plant.

5./ Heat engines are devices that convert thermal energy to mechanical energy. Examples include steam turbines, gas turbines, internal combustion engines, and Stirling engines.

6./ Additional cogenerators normally producing power for on-site use will occasionally contract for short-term power sales to local utilities when avoided cost electricity prices and fuel prices are favorable.

7./ Excluding Montana Power Company.

8./ The estimates of available cogeneration were prepared using a 5.5 cent per kilowatt-hour screen. Use of the current 4.5 cent per kilowatt-hour screen would lower the estimated availability of this resource. The PNUCC inventory upon which the estimates were based is implicitly based on industrial financing of cogeneration projects. Utility financing, using the financial assumptions of this plan, would likely reduce the cost of new cogeneration and increase its availability. For this reason, the Council considers the foregoing estimates to be reasonable.

9./ Net-billing is a process that allows Bonneville to underwrite the costs of electric generating projects. Under net-billing, the project participants purchase a percentage of a project's generating capability, for which the participant pays to the Supply System a pro rata share of the costs of constructing and operating the project. The participants assign their share of generating capability to Bonneville, which, in turn, reimburses the respective participants by crediting the participant's wholesale power bill. If the participant's obligation to the Supply System exceeds the participant's wholesale power bill, the balance is paid to the participant as cash.

10./ By the terms of the settlement negotiated between Bonneville and the investor-owned utility owners of WNP-3, in response to the breach of contract suit filed by these investor-owned utilities, Bonneville may, in the future, acquire the capability of the investor-owned utility share of WNP-3 in accordance with the provisions of section 6(c) of the Northwest Power Act.

11./ Subduction is the movement of one crustal plate beneath another.

12./ "Out-of-Region Imports/Exports," Northwest Power Planning Council issue paper, March 1985.

Key to Tables of Appendix 6-A

Utilities/Operators

Baker	City of Baker
Bonners Ferry	City of Bonners Ferry
BPA	Bonneville Power Administration
Centralia	City of Centralia
Chelan	Chelan County PUD #1
Clark	Clark County PUD #1
Cowlitz	Cowlitz County PUD #1
CPN	CP National
Douglas	Douglas County PUD #1
EWEB	Eugene Water and Electric Board
GECC	General Electric Credit Corporation
Grant	Grant County PUD #1
Idaho Falls	City of Idaho Falls
IPC	Idaho Power Company
Lower Valley	Lower Valley Power and Light Company
MPC	Montana Power Company
Pend Oreille	Pend Oreille County PUD #1
PGE	Portland General Electric Company
PNGC	Pacific Northwest Generating Cooperative
PP&L	Pacific Power and Light Company
PSPL	Puget Sound Power and Light Company
Seattle	Seattle City Light
Snohomish	Snohomish County PUD #1
SPPC	Sierra Pacific Power Company
Tacoma	City of Tacoma Light Division
USBI	U.S. Bureau of Indian Affairs
USBR	U.S. Bureau of Reclamation
USCE	U.S. Corps of Engineers
USTC	United States Trust Company
WPPSS	Washington Public Power Supply System
WWP	The Washington Water Power Company

Status

PP	Preliminary Permit
LC	Licensed
EX	Exempted (from Federal Energy Regulatory Commission license)
POL	Power on Line (Inservice)
UNC	Under Construction
PND	Pending
GTD	Granted

Table 6-A-1
Federal Hydropower Projects

	OPERATOR	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	AVERAGE ENERGY (MWa)[b]	CRITICAL ENERGY (MWa)[b]	STATUS	INSERVICE YEAR
Federal Columbia River Power System:							
Albeni Falls	USCE	43	27	27	26	POL	1955
Anderson Ranch	USBR	41	c	c	c	POL	1950
Big Cliff	USCE	18	4	12	10	POL	1954
Black Canyon	USBR	8	c	c	c	POL	1986
Boise Diversion	USBR	2	c	c	c	POL	1912
Bonneville	USCE	1,077	1,148	771	622	POL	1938
Chandler	USBR	12	9	8	7	POL	1956
Chief Joseph[f]	USCE	2,069	2,688	1,405	1,117	POL	1955
Cougar	USCE	25	6	17	13	POL	1964
Detroit	USCE	100	99	47	36	POL	1953
Dexter	USCE	15	6	99	84	POL	1955
Dworshak	USCE	400	460	240	181	POL	1974
Foster	USCE	20	6	14	12	POL	1968
Grand Coulee	USBR	6,580	6,632	2,286	1,870	POL	1941
Green Peter	USCE	80	78	29	22	POL	1967
Hills Creek	USCE	30	30	19	15	POL	1962
Hungry Horse[g]	USBR	285	328	108	99	POL	1952
Ice Harbor	USCE	603	693	309	207	POL	1961
John Day	USCE	2,160	249	1,232	911	POL	1968
Libby	USCE	525	461	219	180	POL	1975
Little Goose	USCE	810	930	320	209	POL	1970
Lookout Point	USCE	120	71	38	22	POL	1954
Lost Creek	USCE	49	18	35	22	POL	1977
Lower Granite	USCE	810	930	326	214	POL	1975
Lower Monumental	USCE	810	930	321	206	POL	1969
McNary	USCE	980	1,128	700	635	POL	1953
Minidoka	USBR	13	c	c	c	POL	1909
Palisades	USBR	119	49	73	68	POL	1957
Roza	USBR	11	3	96	4	POL	1958
The Dalles	USCE	1,807	2,076	1,005	747	POL	1957

(table continued on next page)

Table 6-A-1 (cont.)
Federal Hydropower Projects

	OPERATOR	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	AVERAGE ENERGY (MWa)[b]	CRITICAL ENERGY (MWa)[b]	STATUS	INSERVICE YEAR
Other Federal Hydropower:							
Big Creek	USBI	0	d	d	d	POL	1916
Green Springs[e]	USBR	16	18	7	7	POL	1960
Savage Rapids Diversion	USBR	N/A	N/A	<1	<1	POL	1955
Wapato Drop 2	USBI	2	N/A	1	1	POL	1942
Wapato Drop 3	USBI	1	N/A	<1	<1	POL	1932

[a]From PNUCC "Northwest Regional Forecast," March 1985.

[b]Average of estimated values for operating years 1986 through 2005 from PNUCC "Northwest Regional Forecast," March 1985. Peak capacity is for January.

[c]Joint peak capacity, average energy and critical period energy for Anderson Ranch Black Canyon, Big Cliff and Minidoka are 26 MW, 38 MWa, and 30 MWa, respectively.

[d]Totals for Flathead Irrigation Projects: 4 MW peak capacity; 2 MW average energy; and 2 MW critical period energy.

[e]Contracted to Pacific Power and Light Company.

[f] Includes uprating, scheduled for completion by September 1986.

[g]Includes uprating, scheduled for completion by August 1992.

Table 6-A-2
Investor-owned Utility Hydropower Projects

	UTILITY	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	AVERAGE ENERGY (MWa)[b]	CRITICAL ENERGY (MWa)[b]	STATUS	INSERVICE YEAR
Albany	PP&L	1	c	c	c	POL	1923
American Falls	IPC	92	0	42	34	POL	1978
Bend Power	PP&L	1	c	c	c	POL	1913
Big Fork	PP&L	4	c	c	c	POL	1910
Black Eagle	MPC	16.8	k	k	k	POL	n/a
Bliss	IPC	75	75	47	44	POL	1949
Brownlee	IPC	585	675	267	198	POL	1958
Bull Run	PGE	21	22	12	10	POL	1912
C.J. Strike	IPC	88	88	57	53	POL	1952
Cabinet Gorge	WWP	200	227	132	112	POL	1952
Cascade[j]	IPC	13	5	4	2	POL	1926
Cochrane	MPC	48.0	k	k	k	POL	n/a
Clear Lake	IPC	3	d	d	d	POL	1937
Clearwater 1	PP&L	15	e	e	e	POL	1953
Clearwater 2	PP&L	26	e	e	e	POL	1953
Cline Falls	PP&L	1	c	c	c	POL	1913
Condit	PP&L	10	c	c	c	POL	1913
Copco 1	PP&L	20	f	f	f	POL	1918
Copco 2	PP&L	27	f	f	f	POL	1925

(table continued on next page)

Table 6-A-2 (cont.)
Investor-owned Utility Hydropower Projects

	UTILITY	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	AVERAGE ENERGY (MWa)[b]	CRITICAL ENERGY (MWa)[b]	STATUS	INSERVICE YEAR
Eagle Point	PP&L	3	h	h	h	POL	1957
East Side	PP&L	3	f	f	f	POL	1924
Electron	PSPL	26	c	c	c	POL	1904
Fall Creek	PP&L	2	c	c	c	POL	1903
Faraday	PGE	35	43	23	17	POL	1907
Fish Creek	PP&L	11	e	e	e	POL	1952
Flint Creek	MPC	1.1	k	k	k	POL	1901
Hauser	MPC	17.0	k	k	k	POL	n/a
Hell's Canyon	IPC	392	389	214	157	POL	1967
Holter	MPC	38.4	k	k	k	POL	n/a
Iron Gate	PP&L	18	f	f	f	POL	1962
John C. Boyle	PP&L	80	f	f	f	POL	1958
Kerr	MPC	168.0	k	k	k	POL	1938
Lemolo 1	PP&L	29	e	e	e	POL	1955
Lemolo 2	PP&L	33	e	e	e	POL	1956
Little Falls	WWP	32	g	g	g	POL	1910
Long Lake	WWP	70	g	g	g	POL	1914
Lower Baker	PSPL	64	66	45	39	POL	1925
Lower Malad	IPC	14	d	d	d	POL	1911
Lower Salmon Falls	IPC	68	68	35	32	POL	1910
Madison	MPC	9.0	k	k	k	POL	n/a
Merwin	PP&L	136	136	792	626	POL	1931
Meyers Falls	WWP	1	1	63	50	POL	1915
Milltown	MPC	3.0	k	k	k	POL	1906
Monroe Street	WWP	7	g	g	g	POL	1890
Moroney	MPC	45.0	k	k	k	POL	n/a
Mystic Lake	MPC	10.0	k	k	k	POL	n/a
Naches	PP&L	6	c	c	c	POL	1909
Naches Drop	PP&L	1	c	c	c	POL	1914
Nine Mile	WWP	12	g	g	g	POL	1908
Nooksack	PSPL	2	c	c	c	POL	1906
North Fork	PGE	38	54	26	19	POL	1958
Noxon Rapids	WWP	397	530	215	156	POL	1960
Oak Grove	PGE	51	45	26	147	POL	1924
Oxbow	IPC	190	220	109	81	POL	1961
Pelton	PGE	97	97	36	31	POL	1957
Post Falls	WWP	15	g	g	g	POL	1906
Powerdale	PP&L	6	c	c	c	POL	1923

(table continued on next page)

Table 6-A-2 (cont.)
Investor-owned Utility Hydropower Projects

	UTILITY	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	AVERAGE ENERGY (MWa)[b]	CRITICAL ENERGY (MWa)[b]	STATUS	INSERVICE YEAR
Prospect 1	PP&L	4	h	h	h	POL	1912
Prospect 2	PP&L	32	h	h	h	POL	1920
Prospect 3	PP&L	7	h	h	h	POL	1932
Prospect 4	PP&L	1	h	h	h	POL	1944
Rainbow	MPC	36.5	k	k	k	POL	n/a
River Mill	PGE	19	23	13	10	POL	1911
Round Butte	PGE	247	290	96	83	POL	1964
Ryan	MPC	48.0	k	k	k	POL	n/a
Shoshone Falls	IPC	12	12	11	9	POL	1907
Slide Creek	PP&L	18	e	e	e	POL	1951
Snoqualmie Falls 1	PSPL	12	i	i	i	POL	1898
Snoqualmie Falls 2	PSPL	29	i	i	i	POL	1910
Soda Springs	PP&L	11	e	e	e	POL	1952
Stayton	PP&L	1	c	c	c	POL	1937
Swan Falls	IPC	10	10	11	10	POL	1910
Swift 1	PP&L	204	189	74	55	POL	1958
T.W. Sullivan	PGE	15	14	14	14	POL	1985
Thompson Falls	MPC	30.0	k	k	k	POL	1915
Thousand Springs	IPC	9	d	d	d	POL	1912
Toketee	PP&L	43	e	e	e	POL	1950
Twin Falls	IPC	10	10	6	7	POL	1935
Upper Baker	PSPL	94	84	41	34	POL	1959
Upper Falls	WWP	10	g	g	g	POL	1922
Upper Malad	IPC	7	d	d	d	POL	1948
Upper Salmon A	IPC	18	19	18	18	POL	1937
Upper Salmon B	IPC	17	15	15	15	POL	1947
Wallowa Falls	PP&L	1	c	c	c	POL	1921
West Side	PP&L	1	f	f	f	POL	1908
White River	PSPL	70	48	36	28	POL	1912
Yale	PP&L	108	117	64	53	POL	1953

[a]From PNUCC "Northwest Regional Forecast," March 1985.
[b]Average of estimated values for operating years 1986 through 2005 from PNUCC "Northwest Regional Forecast." Peak capacity is for January.
[c]Totals for Pacific Power and Light small projects: Peak, 33; Average, 27; Critical 26.
[d]Totals for Idaho Power Company Spring projects: Peak, 30; Average, 28; Critical, 29.
[e]Totals for Pacific Power and Light Umpqua River projects: Peak, 175; Average, 129; Critical, 97.
[f]Totals for Pacific Power and Light Klamath projects: Peak, 92; Average, 41; Critical, 42.
[g]Totals for Washington Water Power Spokane River projects: Peak, 154; Average, 112; Critical, 91.
[h]Totals for Pacific Power and Light Rogue River projects: Peak, 25; Average, 43; Critical, 35.
[i]Totals for Puget Sound Power and Light small projects: Peak, 72; Average, 54; Critical, 47.
[j]Includes 1984 expansion.
[k]Approximately 40% of the capability of Montana Power Company projects is available to serve regional load. In accordance with Northwest power planning convention, the output of these resources used to serve regional load is treated as import to the region.

Table 6-A-3
Publicly-owned Utility Hydropower Projects

PROJECT	UTILITY	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	AVERAGE ENERGY (MWa)[b]	CRITICAL ENERGY (MWa)[b]	STATUS	INSERVICE YEAR
Alder	Tacoma	50	34	24	18	POL	1945
Baker	Baker	<1	N/AV	N/AV	N/AV	POL	1934
Boundary[f]	Seattle	635	655	508	367	POL	1967
Box Canyon	Pend Oreille	60	71	48	46	POL	1955
Calispel Creek	Pend Oreille	1	c	c	c	POL	1920
Carmen-Smith	EWEB	80	40	27	20	POL	1963
Cedar Falls	Seattle	20	d	d	d	POL	1905
Chelan	Chelan	48	52	42	38	POL	1928
City	Idaho Falls	8	e	e	e	POL	1982
Cushman 1	Tacoma	43	27	11	10	POL	1926
Cushman 2	Tacoma	81	88	25	23	POL	1930
Diablo	Seattle	122	159	95	75	POL	1936
Gorge	Seattle	138	175	115	94	POL	1924
Henry M. Jackson	Snohomish	112	89	53	41	POL	1984
Idaho Falls Lower	Idaho Falls	11	e	e	e	POL	1904
Idaho Falls Upper	Idaho Falls	8	e	e	e	POL	1938
LaGrande	Tacoma	64	65	41	33	POL	1912
Leaburg Dam	EWEB	14	7	13	12	POL	1930
Mayfield Dam	Tacoma	162	172	97	65	POL	1963
Mossyrock	Tacoma	300	303	114	87	POL	1968
Moyie Falls 1-Upper	Bonner's Ferry	<1	c	c	c	POL	1921
Moyie Falls 2-Lower	Bonner's Ferry	2	c	c	c	POL	1941
Newhalem Creek	Seattle	2	d	d	d	POL	1921
Packwood Lake	WPPSS	26	30	11	7	POL	1964
Priest Rapids	Grant	789	912	580	506	POL	1959
Rock Island	Chelan	620	544	330	271	POL	1933
Rocky Reach	Chelan	1,212	1,266	693	560	POL	1961
Ross	Seattle	360	364	88	70	POL	1952
So. Fork Tolt River	Seattle	15	7	9	8	Assured	1989
Strawberry Creek	Lower Valley	2	e	e	e	POL	1951
Swift 2	Cowlitz	70	76	25	20	POL	1958
Trail Bridge	EWEB	10	3	6	4	POL	1963
Walterville	EWEB	8	5	8	7	POL	1911

(table continued on next page)

Table 6-A-3 (cont.
Publicly-owned Utility Hydropower Projects

PROJECT	UTILITY	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	AVERAGE ENERGY (MWa)[b]	CRITICAL ENERGY (MWa)[b]	STATUS	INSERVICE YEAR
Wanapum	Grant	831	986	611	514	POL	1963
Wells[g]	Douglas	774	820	457	386	POL	1967
Yelm	Centralia	10	10	9	9	POL	1930

[a]From PNUCC, "Northwest Regional Forecast," March 1985.
[b]Average of estimated values for operating years 1986 through 2005 from PNUCC "Northwest Regional Forecast," March 1985. Peak capacity is for January.
[c]Totals for Big Creek, Calispel Creek, Moyie Falls 1 and 2 (Flathead Irrigation Projects are: Peak, 4 MW; Average, 2 MWa; Critical, 2 MWa.
[d]Totals for Cedar Falls and Newhalem Creek are: Peak, 32 MW; Average, 13 MWa; Critical 8 MWa.
[e]Totals for City, Idaho Falls Upper, Idaho Falls Lower, and Strawberry Creek are: Peak 21 MW; Average, 21 MWa; Critical, 16 MWa.
[f]Includes Units 55 and 56.
[g] Includes upgrades scheduled for completion by 1989.

Table 6-A-4
Contracted Resources[a]

PROJECT	FUEL	CONTRACTING UTILITY	NAMEPLATE CAPACITY (MW)	AVERAGE ENERGY (MW)	STATUS	INSERVICE YEAR
Wind:						
Whiskey Run		PP&L (R&D Contract)	1.25	0.01	POL	1981
Subtotal, Wind			1.25	0.01		
Thermal: (* = cogeneration; ? = not known whether project is cogeneration)						
AEM Corporation (?)	Coal	MPC	12.0	n/av	POL	1985
Afton Generating Company (*)	Wood	IPC	6.0	5.8	POL	n/a
Big Horn Energy (?)	Coal	MPC	15.0	n/av	Planned	1986
Biomass One (*)	Wood	PP&L	25.0	18.3	POL	1986
Biosolar (*)	Biomas	PP&L	25.0	17.5	Planned	1987
Blue Mountain Forest Products (*)	Wood	CPN	3.5	3.2	Planned	1986
Boeing (Auburn) (*)	Gas	PSPL	9.0	8.0	POL	n/a
Boise Cascade (Emmett, ID.) (*)	Wood	IPC	9.1	5.0	POL	n/a
Boise Cascade (Medford)	Wood	PP&L	8.5	0.3	POL	n/a
Bozeman Woodwaste (?)	Wood	MPC	12.0	n/av	POL	1985
Cristad Enterprises (*)	Wood	CPN	3.0	2.7	POL	n/a
Daw Forest Products	Wood	PP&L	10.0	0.9	POL	n/a
Evergreen Forest Products (*)	Wood	IPC	5.0	5.0	POL	n/a
Gorge Energy (*)	Wood	PP&L	8.5	2.9	POL	n/a
Great Western Malting (*)	Gas	Clark	20.1	15.9	POL	n/a
Husky Industries (*)	Biomass	PP&L	5.0	3.8	Planned	1989
D. R. Johnson (CPN) (*)	Biomass	CPN	7.5	5.6	Planned	1986
D. R. Johnson (PP&L) (*)	Biomass	PP&L	7.5	5.7	Planned	1987
Kinzua (*)	Wood	PGE	10.0	7.4	POL	n/a

(table continued on next page)

Table 6-A-4 (cont.)
Contracted Resources[a]

PROJECT	FUEL	CONTRACTING UTILITY	NAMEPLATE CAPACITY (MW)	AVERAGE ENERGY (MW)	STATUS	INSERVICE YEAR
Lakeview Power Company (*)	Biomass	PP&L	15.0	11.3	Planned	1987
Lane Plywood (*)	n/av	EWEB	0.8	n/av	POL	n/a
Longview Fibre (*)	n/av	BPA	45	35.9	POL	n/a
Metro West Point (*)	Sewage Methane	Seattle	3.9	2.0	POL	n/a
Pacific Crown (Woodpower, Inc.) (*)	Wood	WWP	6.0	4.5	POL	n/a
Perkins Power (?)	Coal	MPC	12.0	n/av	POL	1985
Potlatch (Lewiston #1) (*)	n/av	WWP	36.5	9.1	POL	n/a
Red Lodge (?)	Coal	MPC	10.0	n/av	Planned	1986
Roseburg Lumber	Wood	PP&L	52.0	26.0	POL	n/a
St. Regis (Libby)	Wood	PP&L	13.3	1.8	POL	n/a
Vaagen Brothers Lumber (*)	Wood	WWP	4.0	2.0	POL	n/a
Warm Springs Forest Products	Wood	PP&L	9.0	0.5	POL	n/a
Weyco (*)	Pulping Liquor	EWEB	51.2	14.0	POL	n/a
Weyerhauser (Everett) (*)	n/av	Snohomish (Negotiating)	12.5	10.0	POL	n/a
Ogden-Martin	MSW	PGE	13.1	7.4	UNC	1986
Subtotal, Thermal			497.0	227.3		

PROJECT	FERC PERMIT NO.	CONTRACTING UTILITY	NAMEPLATE CAPACITY (MW)	AVERAGE ENERGY (MW)	STATUS	INSERVICE YEAR
Hydropower:						
Bend Diversion	3473	PP&L	2.8	1.4	LC-GTD	1986
Big Sheep Creek	5118	WWP	1.0	0.6	EX-UNC	1985
Cedar Draw Creek	8278	IPC	1.4	0.6	LC-POL	1984
Elk Creek	3503	IPC	2.0	1.9	EX-GTD	1986
Elk Creek Falls	6524	WWP	4.6	1.5	LC-PND	1986
Eltopia Branch Canal Mi. 4.6	3842	Seattle & Tacoma	2.2	1.0	LC-POL	1983
Falls Creek	6661	PP&L	4.1	1.7	EX-POL	1984
Farmers Irr. Dist. Project 2	7532	PP&L	2.5	1.0	EX-UNC	1986
Farmers Irr. Dist. Project 3	6801	PP&L	1.7	0.7	EX-UNC	1987
Galesville	7161	PP&L	1.8	0.7	LC-UNC	1986
Jim Boyd	7269	PP&L	1.1	0.5	LC-GTD	1986
Jim Ford Creek	7986	WWP	1.5	n/av	LC	1987
Kasel-Witherspoon	6410	IPC	1.0	1.2	EX-POL	1983
Koyle Ranch	4052	IPC	1.3	0.8	EX-POL	1983
L.Q. and L.S. Snake Drains	5767	IPC	2.0	1.3	EX-POL	1984
Lacomb Irrigation	6648	PP&L	1.0	0.6	EX-UNC	1986
Lateral #10	6250	IPC	1.6	1.2	EX-POL	1985

(table continued on next page)

Table 6-A-4 (cont.)
Contracted Resources[a]

PROJECT	FERC PERMIT NO.	CONTRACTING UTILITY	NAMEPLATE CAPACITY (MW)	AVERAGE ENERGY (MW)	STATUS	INSERVICE YEAR
Little Wood River	7427	IPC	2.4	0.5	EX-POL	1985
Lowline Canal Drop	3216	IPC	8.0	n/av	EX-POL	1985
Lucky Peak	2832	Seattle	87.0	32.2	LC-UNC	1988
Main Canal Headworks	2849	Seattle & Tacoma	26.0	9.8	LC-UNC	1986
Middle Fork Irrigation District	4458	PP&L	3.3	2.5	EX-GTD	1986
Mitchell Butte	5357	IPC	1.5	0.6	LC-PND	1987
N-32 Hydro (Marco Ranch)	7170	IPC	1.9	n/av	POL	1985
Opal Springs	5891	PP&L	5.0	3.7	LC-POL	1984
Owyhee Dam	4354	IPC	3.7	1.4	LC-UNC	1985
Owyhee Tunnel No. 1	4359	IPC	5.0	2.7	PP-GTD	1991
Pelton Reregulating	2030B	PP&L	19.6	9.3	LC-POL	1982
Portland Hydro	2821	PGE	35.6	12.6	LC-POL	1982
Portland Wellfield	7052	PGE	4.5	2.3	EX-UNC	1985
Potholes East Canal Headworks	2840	Seattle	7.5	2.8	LC-GTD	1984
Potholes East Canal Mile 66	3843	Seattle & Tacoma	2.4	1.3	LC-POL	1983
Rock Creek	6450	IPC	2.1	1.3	EX-POL	1983
Rocky Brook	3783	Seattle	1.5	n/av	EX-UNC	1986
Russell D. Smith	2926	Seattle & Tacoma	6.1	2.8	LC-POL	1981
Sandy Creek (Koma Kulshan)	3239	PSPL	17.6	9.2	LC-PND	1989
Shellrock Creek (L.M. Baker)	n/av	PGE	21.8	13.4	PP-GTD	1986
South Dry Creek	8831	MPC	1.8	c	EX-POL	1985
Summer Falls	3295	Seattle & Tacoma	90.0	37.0	LC-POL	1984
Twin Falls	4885	PSPL	20.0	8.8	LC-GTD	1989
Valsetz	7217	PP&L	3.9	1.9	EX-GTD	1987
Week Falls	7563	PSPL	3.4	1.6	LC-GTD	1988
Winchester	6775	PP&L	1.2	0.6	LC-POL	1984
Subtotal, Hydropower			416.3	174.7		
Total, Contracted Resources			915	402		

[a]Exclusive of projects of less than 1 MW capacity.

[b]From various sources compiled by the Council, including PNUCC *Thermal Resources Data Base,* October 1984; PNUCC *Northwest Regional Forecast,* March 1985; Pacific Northwest Hydropower Data Base; Idaho Public Utility Commission, Oregon Public Utility Commissioner, Montana Power Company, Washington State Energy Office.

[c]Approximately 40% of the capability of Montana Power Company resources is available to serve regional load. In accordance with Northwest power planning convention, the output of these resources used to serve regional load is treated as import to the region.

Table 6-A-5
Large Thermal Units

PROJECT & UNIT	FUEL	UTILITY	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	AVERAGE ENERGY (MWa)[b]	STATUS	INSERVICE YEAR
Boardman	Coal	PGE-65%; IPC-10%; PNGC-10%; GECC-15%	560	530	357[g]	POL	1980
Centralia 1	Coal	PP&L-47.5%; WWP-15%; PSPL-11%; Snohomish-8%; Tacoma-8%; Seattle-8%; PGE-2.5%	665	640	448	POL	1971
Centralia 2	Coal	PP&L-47.5%; WWP-15%; PSPL-11%; Snohomish-8%; Tacoma-8%; Seattle-8%; PGE-2.5%	665	640	448	POL	1972
Colstrip 1	Coal	MPC-50%; PSPL-50%	358	165[c]	110[c]	POL	1975
Colstrip 2	Coal	MPC-50%; PSPL-50%	358	165[c]	110[c]	POL	1976
Colstrip 3	Coal	MPC-30%; PSPL-25%; PGE-20%; WWP-15%; PP&L-10%	778	490[c]	368[c]	POL	1984
Colstrip 4	Coal	USTC-30%; PSPL-25%; PGE-20%; WWP-15%; PP&L-10%	778	490[c,h]	368[c,h]	LC-UNC	1986
J.E. Corette	Coal	MPC	172	[c]	[c]	POL	1968
Jim Bridger 1	Coal	PP&L-66⅔%; IPC-33⅓%	509	167[d]	113[d]	POL	1974
Jim Bridger 2	Coal	PP&L-66⅔%; IPC-33⅓%	509	167[d]	113[d]	POL	1975
Jim Bridger 3	Coal	PP&L-66⅔%; IPC-33⅓%	509	167[d]	113[d]	POL	1976
Jim Bridger 4	Coal	PP&L-66⅔%; IPC-33⅓%	509	167[d]	113[d]	POL	1979
Valmy 1	Coal	IPC-50%; SPPC-50%	254	127	89	POL	1981
Valmy 2	Coal	IPC-50%; SPPC-50%	250	138	96	POL	1985
Hanford[f]	Nuclear	WPPSS	800	0[e]	380	POL	1966
Trojan	Nuclear	PGE-67.5%; EWEB-30%; PP&L 2.5%	1,216	1,080	648	POL	1976
WNP-2	Nuclear	WPPSS	1,154	1,100	656	POL	1984
Kettle Falls	Wood	WWP	51	42.2	31.6	POL	1983

[a]From PNUCC *Thermal Resources Data Base,* October 1984.

[b]Declared (by sponsors) to be available to the region (from 1985 PNUCC *Northwest Regional Forecast,* March 1985).

[c]Approximately 40% of the capability of Montana Power Company resources is available to meet regional load. In accordance with Northwest power planning convention, the output of these resources used to serve regional load is treated as import to the region.

[d]The portion of the Pacific Power and Light Company share of Jim Bridger is treated as an import to the region in accordance with Northwest power planning convention.

[e]Operation of the N-reactor for plutonium production has priority over production of steam for electricty. Therefore, the firm capacity of Hanford Generating Project is zero.

[f]The Hanford Generating Project operating contract extends through June 1993 and can be terminated on a one-year notice. The resource is considered to be available until June 1993.

[g]General Electric Credit Corporation share to be sold to San Diego Gas and Electric on a 25-year contract beginning in 1989.

[h]United States Trust Company share of Colstrip 4 is leased back to Montana Power Company.

Table 6-A-6
Reserve Units

PROJECT AND UNIT	PRIMARY FUEL	UTILITY	NAMEPLATE CAPACITY (MW)[a]	PEAK CAPACITY (MW)[b]	FIRM ENERGY (MWa)[c]	RESERVE ENERGY (MWa)[d]	STATUS	INSERVICE YEAR
Combustion Turbine								
Bethel 1	Gas	PGE	56.7	75.0	9.5	12.9[e]	POL	1973
Bethel 2	Gas	PGE	56.7	75.0	9.5	12.9[e]	POL	1973
Frederickson 1	Gas	PSPL	85.0	89.0	2.1	14.2[f]	POL	1981
Frederickson 2	Gas	PSPL	85.0	89.0	2.1	14.2[f]	POL	1981
Fredonia 1	Gas	PSPL	129.0	124.0	2.9	17.8[f]	POL	1984
Fredonia 2	Gas	PSPL	129.0	124.0	2.9	17.8[f]	POL	1984
Libby	Oil	PP&L (leased)	24.0	24.0	0.0	16.2	POL	1972
Northeast	Gas	WWP	61.2	68.0	2.0	57.8	POL	1978
Othello	Oil	WWP	28.2	33.0	1.0	28.1	POL	1973
Point Whitehorn 1	Oil	PSPL	61.0	68.0	1.0	52.7	POL	1974
Point Whitehorn 2	Gas	PSPL	85.0	89.0	1.0	14.2[f]	POL	1981
Point Whitehorn 3	Gas	PSPL	85.0	89.0	1.0	14.2[f]	POL	1981
Whidbey Island	Oil	PSPL	27.0	29.0	1.0	23.0	POL	1972
Wood River	Gas	IPC	50.0	50.0	1.0	42.5	POL	1974
Diesel								
Bonners Ferry 1	OIl	Bonners Ferry	2.4	2.4	0.0	—	POL	1930
Bonners Ferry 2	Oil	Bonners Ferry	2.4	2.4	1.0	—	POL	1930
Bonners Ferry 3	Oil	Bonners Ferry	2.4	2.4	1.0	—	POL	1973
Crystal Mountain	Oil	PSPL	2.8	2.7	0.1	—	POL	1969
Summit 1	Oil	PGE	2.8	3.0	0.5	—	POL	1970
Summit 2	Oil	PGE	2.8	3.0	0.5	—	POL	1973
Steam-Electric								
Lake Union 1	Oil	Seattle	36.0	n/av	0.0	n/av	POL	1921
Lake Union 2	Oil	Seattle	36.0	n/av	0.0	n/av	POL	1921
Lake Union 3	Oil	Seattle	36.0	n/av	0.0	n/av	POL	1921
Shuffleton 1	Oil	PSPL	35.0	44.0	1.0	26.9[g]	POL	1930
Shuffleton 2	Oil	PSPL	35.0	44.0	1.0	26.9[g]	POL	1930
Combined Cycle								
Beaver	Gas	PGE	545	601	53	443	POL	1977
TOTALS:				1,129.9 MW	41.9 MW	845.1 MW		

[a]From PNUCC *Thermal Resource Data Base,* October 1984.

[b]From PNUCC *Northwest Regional Forecast,* March 1985.

[c]Declared by sponsor to be available as firm energy. From PNUCC "Northwest Regional Forecast," March 1985.

[d]Based on base load capacity (may be less than peak capacity) and the Council's assumptions regarding availability except as noted. The Council's availablity assumptions are as follows: combustion turbines-85%; diesel generators-87%; combined cycle plants-83%.

[e]Restricted to 2,000 hours of operation during any year operated.

[f]Constrained to a maximum of 1,500 hours per year operation by the Powerplant and Industrial Fuel Use Act of 1978.

[g]From PNUCC *Northwest Regional Forecast.*

APPENDIX 6-B
PLANNING ASSUMPTIONS — GENERIC CONVENTIONAL COAL PROJECT
TWO 603-MEGAWATT UNITS

GENERAL CHARACTERISTICS

Site	Eastern Oregon
Plant design	Two units, 650 megawatts (gross), 603 megawatts (net) nominal capacity each; pulverized coal fired; 2,400 psig, 1000°F/1000°F reheat, 3.5 HgA backpressure.
Fuel type	Wyoming subbituminous, 8,445 Btu/lb.
Fuel transport	Unit train
Heat rejection	Mechanical draft cooling towers; makeup from the Columbia River
Emission control	Fly ash — electrostatic precipitator SO2 — wet scrubbers NOX — combustion control
Transmission	Ten-mile, 500 kV double circuit interconnection.

TECHNICAL PERFORMANCE

Operating State	Capacity (MW, net) Per Unit	Capacity (MW, net) Project	Heat Rate (Btu/kWh, net)
Peak	633	1,266	10,210
Maximum sustainable	633	1,266	10,210
Rated (Least cost)	603	1,206	10,080
Minimum sustainable	151	302	11,940
Transition Times			
Cold start — Minimum sustainable	12 hours		
Hot start — Minimum sustainable	1 hour		
Minimum sustainable — Rated	1 hour		
Operating Availability			
Equivalent Annual Availability	75%		
Annual Maintenance Outage Period			
Normal	30 days		
Major Overhaul (every fifth year)	60 days		
Average	36 days		
Other Planned and Unscheduled Outages (Equivalent)	17%		

PROJECT DEVELOPMENT

	Option Phase I: License, Site Acquisition	Option Phase II: Initial Detailed Engineering
Period	48 mos	9 mos
Cash Flow Year 1	$ 11.8 million	$ 30.3 million
Year 2	11.8 million	
Year 3	11.8 million	
Year 4	11.8 million	
Total	$ 47.3 million ($39/kW)	$ 30.3 million ($25/kW)
Hold cost (excl. of return on investment)	$ 0.3 million/yr ($0.3/kW/yr)	$ 0.3 million/yr ($0.3/kW/yr)
Expected shelf life	5 years	2 years
Option close-out cost	negligible	negligible
	Construction from Option Phase I	**Construction from Option Phase II**
Construction period (Unit 1)	72 mos	60 mos
Lag to Unit 2 completion	12 mos	12 mos
Cash Flow Year 1	$ 58.6 million	$174.5 million
Year 2	$169.6 million	$258.6 million
Year 3	$250.9 million	$428.0 million
Year 4	$415.7 million	$412.0 million
Year 5	$400.5 million	$161.1 million
Year 6	$155.1 million	$ 16.8 million
Year 7	$ 15.6 million	$ 0.0 million
Construction Total	$1,466.2 million ($1,216/kW)	$1,451.0 million ($1,203/kW)

OPERATION

Fuel Inventory	90 days @ 1,206 MW
Fuel price (delivered)	$ 2.00/MMBtu
Fixed O&M	$11.1 million/yr ($9.20/kW/yr)
Variable O&M	$ 0.11 cents/kWh
Capital Replacement Cost	$14.5 million/yr ($12.00/kW/yr)
Amortization Life	30 years
Operating Life	40 years
General Inflation (nominal)	5.0 %/yr
Capital Escalation (real)	0.4 %/yr
O&M Escalation (real)	0.0 %/yr
Delivered Fuel Escalation (real)	1.0 %/yr

Site: As assumed in Kaiser Engineers Power Corporation, *Bonneville Power Administration Comparative Electric Generation Study,* January 1983 (KEPC, 1983).

Plant design: Per KEPC (1983).

Fuel type: Per KEPC (1983).

Fuel transportation: Per KEPC (1983).

Heat rejection: Per KEPC (1983).

Emission control: Per KEPC (1983).

Transmission: Assumes a site near the existing Boardman project, consistent with KEPC (1983).

Peak capacity: Capacity and heat rate per performance curves supplied by Bonneville, April 10, 1985.

Maximum sustainable capacity: Capacity and heat rate per performance curves supplied by Bonneville, April 10, 1985.

Rated capacity: Capacity and heat rate per performance curves supplied by Bonneville, April 10, 1985.

Minimum sustainable capacity: Capacity based on recommendation of the Coal Options Task Force. Heat rate per performance curves supplied by Bonneville, April 10, 1985.

Transition times: Cold start and hot start transition times are based on times estimated for Creston in Pacific Northwest Utilities Conference Committee. *Thermal Resources Data Base.* October 1984. (PNUCC, 1984a). Transition time from minimum sustainable to maximum sustainable is estimated.

Equivalent annual availability: Based on the North American Electric Reliability Council (NERC) Generating Availability Data System records for subcritical coal-fired plants, scrubbed, of 400 to 600 + megawatts capacity. In analyzing the NERC data, it was assumed that a typical well-maintained plant operating in a baseload mode would receive routine annual maintenance plus a major overhaul every five years of operation. The first ten years of plant life, encompassing two such five-year cycles, should therefore be representative of the operating availability of the plant during the portion of its life during which it is expected to operate in baseload mode. Equivalent annual availability was calculated by weighting the NERC equivalent annual availability data for operating years 1 through 10 in proportion to the number of operating years represented by the compiled statistics (i.e., statistics for operating years 1, 2 and 3 (compiled individually) each received a weight of "1;" statistics for years 4 through 10 (compiled in aggregate) received a weight of "7"). The resulting equivalent annual availability was 78 percent. The 78 percent was rounded down to 75 percent—first because of the limited operating history (6 unit-years) available for large (600 + megawatts) scrubbed units, and second, the expectation that a major plant rebuild or retrofit occurring at least once during the 40-year baseload life of the plant would reduce the lifetime availability below that observed during the first ten years of operation.

Annual maintenance outage period: The outage periods shown are assumed values, slightly more conservative than Pacific Northwest experience, as reflected in PNUCC (1984a).

Other planned and unscheduled outages: The rate of other planned and unscheduled outages is calculated from the equivalent unscheduled outage rate (based on NERC data, as described above) and the assumed average annual maintenance outage period.

Option development periods: Phase I includes conceptual development, completion of permitting and licensing, and site acquisition. The Phase I development period is based on the recommendation of Robert E. Henriques, The Washington Water Power Company, letter to Jeff King, Northwest Power Planning Council, dated August 15, 1984. Phase II includes engineering to major component order. The Phase II remobilization period is based upon estimates prepared for the Creston project by The Washington Water Power Company, provided in a letter from R. E. Henriques, The Washington Water Power Company, to J. C. King, Northwest Power Planning Council, dated February 27, 1985 (Henriques, 1985). The Phase II remobilization would occur only with a hold between Phases I and II. The Phase II development period is based on estimates prepared for the Creston project by the Washington Water Power Company, and provided in a letter from R. E. Henriques, The Washington Water Power Company, to J. C. King, Northwest Power Planning Council, dated August 15, 1984 (Henriques, 1984).

Option development cost: Phase I development costs are the sum of licensing costs plus land acquisition costs. Licensing costs are taken as 3 percent of total overnight capital costs, per Pacific Northwest Utilities Conference Committee "Working Paper, Development of Generic Resource Data," October 1984 (PNUCC, 1984b). Land costs are from KEPC (1983) (1984 update). Phase II remobilization costs are those estimated for Creston by R. E. Henriques, The Washington Water Power Company; telephone conversation on April 30, 1985. Phase II development costs are taken as 40 percent of engineering costs as estimated in KEPC (1983) (1984 update), escalated to 1/85 using the Handy Whitman Index.

Option hold cost: Based upon estimates prepared for Creston (Henriques, 1985).

Expected shelf life: Phase I: Expected shelf life is estimated time until one or more of the advanced coal technologies becomes fully established, requiring new feasibility and BACT studies. Phase II: Estimated time until the bulk of Phase II engineering would have to be reworked.

Option close-out cost: Close-out costs are assumed to be covered by the sale of the site.

Construction schedule: Based on discussions of the Coal Options Task Force. Consistent with Creston estimates.

Lag time to next unit: As estimated in KEPC (1983).

Construction cash flow: From Phase I: Based on KEPC (1983), (1984 cost update) as adjusted in PNUCC (1984b); further adjusted as follows: Land costs deleted (included in option development costs); coal inventory based on 90 days continuous operation at rated capacity (603 megawatts per unit at 10,080 Btu/kilowatt hour); cost of a ten-mile section of 500kV double circuit transmission line added (based on costs cited in letter from W. D. Beebe, Bonneville Power Administration, to J. C. King, Northwest Power Planning Council, dated April 26, 1985); costs escalated to January 1985 using appropriate Handy-Whitman cost indices. Payout schedule based on KEPC (1983) (licensing activities deleted). From Phase II: Costs derived as from Phase I, less 20 percent of engineering costs, per discussion of the Coal Options Task Force.

Fuel inventory: Inventory used in KEPC (1983); continuous operation at rated capacity assumed.

Fuel price: As recommended by the Coal Options Task Force. Midpoint of a range of coal costs obtained from technical reports and observation of current coal prices.

Fixed O&M cost: Seventy percent of labor and maintenance materials from KEPC (1983), (1984 cost update), escalated to 1985 using GNP deflator (1.05).

Variable O&M cost: Raw materials and chemicals, utilities, 30% of labor and maintenance materials and sludge and ash disposal from KEPC (1983), (1984 cost update), escalated to 1985 using GNP deflator (1.05).

Capital replacement cost: Based upon estimated routine annual replacements plus the levelized cost of a major refurbishment at year 20. The cost of routine replacements is estimated to be $5.00/kW/yr based upon historical replacement costs for Centralia and Bridger. Major refurbishment costs are estimated to be $300/kW, based upon recent estimates prepared for the U.S. Congress, Office of Technology Assessment (U.S. Congress, Office of Technology Assessment, 1985, *New Electric Power Technologies*). This cost is levelized over the operating life using a 3% discount rate.

Amortization life: Based on Electric Power Research Institute *Technical Assessment Guide*, May 1982 (EPRI, 1982) recommendations.

Operating life: Design life of major components (boiler and turbogenerator). Assumes a major refurbishment about year 20. Refurbishment costs are included in interim capital replacement costs.

Cost escalation: Values adopted by the Council for the 1986 Energy Plan.

APPENDIX 6-C
PLANNING ASSUMPTIONS — GENERIC CONVENTIONAL COAL PROJECT
TWO 250-MEGAWATT UNITS

GENERAL CHARACTERISTICS

Site	Eastern Oregon
Plant design	Two units, 270 MW (gross), 500 MW (net) nominal capacity each; pulverized coal fired; 2,400 psig, 1000oF/1000oF reheat, 3.5 HgA backpressure.
Fuel type	Wyoming subbituminous, 8,445 Btu/lb.
Fuel transport	Unit train
Heat rejection	Mechanical draft cooling towers; makeup from the Columbia River
Emission control	Fly ash — electrostatic precipitator SO2 — Wet scrubbers NOX — combustion control
Transmission	Ten-mile, 500 kV single circuit interconnection.

TECHNICAL PERFORMANCE

Operating State	Capacity (MW, net) Per Unit	Capacity (MW, net) Project	Heat Rate (Btu/kWh, net)
Peak	262	524	10,320
Maximum sustainable	262	524	10,320
Rated (Least cost)	250	500	10,190
Minimum sustainable	62.5	62.5	11,670
Transition Times			
Cold start — Minimum sustainable	12 hours		
Hot start — Minimum sustainable	1 hour		
Minimum sustainable — Rated	<1 hour		
Operating Availability			
Equivalent Annual Availability	77%		
Annual Maintenance Outage Period			
Normal	30 days		
Major Overhaul (every fifth year)	60 days		
Average	36 days		
Other Planned and Unscheduled Outages (Equivalent)	15%		

PROJECT DEVELOPMENT

	Option Phase I: License, Site Acquisition	Option Phase II: Init. Detailed Engineering
Period	48 mos	9 mos
Cash Flow Year 1	$ 6.9 million	$ 17.9 million
Year 2	6.9 million	
Year 3	6.9 million	
Year 4	6.9 million	
Total	$ 27.6 million ($55/kW)	$ 17.9 million ($36/kW)
Hold cost (excl. of return on investment)	$ 0.3 million/yr ($0.6/kW/yr)	$ 0.3 million/yr) ($0.6 kW/yr)
Expected shelf life	5 years	2 years
Option close-out cost	negligible	negligible
	Construction from Option Phase I	**Construction from Option Phase II**
Construction period (Unit 1)	60 mos	48 mos
Lag to Unit 2 completion	12 mos	12 mos
Cash Flow Year 1	$ 17.2 million	$ 42.9 million
Year 2	$ 42.9 million	$291.7 million
Year 3	$292.0 million	$360.7 million
Year 4	$360.7 million	$120.2 million
Year 5	$120.2 million	$ 26.1 million
Year 6	$ 25.8 million	
Construction Total	$858.7 million ($1,717/kW)	$841.6 million ($1,683/kW)

OPERATION

Fuel Inventory	90 days
Fuel Cost (delivered)	$2.00/MMBtu
Fixed O&M	$9.1 million/yr ($18.25/kW/yr)
Variable O&M	0.2 cents/kWh
Capital Replacement Cost	$6.0 million/yr ($12.00/kW/yr)
Amortization Life	30 years
Operating Life	40 years
General Inflation (nominal)	5.0%/yr
Capital Escalation (real)	0.4%/yr
O&M Escalation (real)	0.0%/yr
Delivered Fuel Escalation (real)	1.0%/yr

Site: As assumed in Kaiser Engineers Power Corporation, *Bonneville Power Administration Comparative Electric Generation Study,* January 1983 (KEPC, 1983).

Plant design: Per KEPC (1983).

Fuel type: Per KEPC (1983).

Fuel transportation: Per KEPC (1983).

Heat rejection: Per KEPC (1983).

Emission control: Per KEPC (1983).

Transmission: Assumes a site near the existing Boardman project, consistent with KEPC (1983).

Peak capacity: Capacity and heat rate per performance curves supplied by Bonneville, May 1, 1985.

Maximum sustainable capacity: Capacity and heat rate per performance curves supplied by Bonneville, May 1, 1985.

Rated capacity: Capacity and heat rate per performance curves supplied by Bonneville, May 1, 1985.

Minimum sustainable capacity: Capacity based on recommendation of the Coal Options Task Force. Heat rate per performance curves supplied by Bonneville, May 1, 1985.

Transition times: Cold start and hot start transition times are based on times reported for Valmy I in Pacific Northwest Utilities Conference Committee. *Thermal Resources Data Base.* October 1984. (PNUCC, 1984a). Transition time from minimum sustainable to maximum sustainable is estimated.

Equivalent annual availability: Based on the North American Electric Reliability Council (NERC) Generating Availability Data System records for subcritical coal-fired plants, scrubbed, of 200 to 399 MW capacity. In analysing the NERC data, it was assumed that a typical well-maintained plant operating in a baseload mode would receive routine annual maintenance plus a major overhaul every five years of operation. The first ten years of plant life, encompassing two such five-year cycles, should therefore be representative of the operating availability of the plant during the portion of its life during which it is expected to operate in baseload mode. Equivalent annual availability was calculated by weighting the NERC equivalent annual availability data for operating years 1 through 10 in proportion to the number of operating years represented by the compiled statistics (i.e., statistics for operating years 1, 2 and 3 (compiled individually) each received a weight of "1;" statistics for years 4 through 10 (compiled in aggregate) received a weight of "7"). The resulting equivalent annual availability was 79 percent for the type of plant described above. An equivalent availability of 77 percent was selected in consideration of the following: 1) Smaller units consistently show better availability than larger units; this relationship is preserved between the 77 percent recommended for smaller units and the 75 percent recommended for larger units. 2) Substantial operating experience (48 unit-years) is available for smaller units, lending credibility to the high reliability indicated for these size units by the FERC data. 3) The lifetime equivalent availability is likely to be somewhat lower than that documented for the first ten years of experience because of the possibility of major rebuilds later in plant life.

Annual maintenance outage period: The outage periods shown are assumed values, slightly more conservative than Pacific Northwest experience, as reflected in PNUCC (1984a).

Other planned and unscheduled outages: The rate of other planned and unscheduled outages is calculated from the equivalent unscheduled outage rate (based on NERC data, as described above) and the assumed average annual maintenance outage period.

Option development periods: Phase I includes conceptual development, completion of permitting and licensing, and site acquisition. The Phase I development period is based on the recommendation of Robert E. Henriques, The Washington Water Power Company, letter to Jeff King, Northwest Power Planning Council, dated August 15, 1984 (Henriques, 1984). Phase II includes engineering to major component order. The Phase II remobilization period is based upon estimates prepared for the Creston project by The Washington Water Power Company, provided in a letter from R. E. Henriques, The Washington Water Power Company, to J. C. King, Northwest Power Planning Council, dated February 27, 1985 (Henriques, 1985). The Phase II remobilization would occur only with a hold between Phases I and II. The Phase II development period is based on estimates prepared for the Creston project by the Washington Water Power Company, and provided in Henriques (1984).

Option development cost: Phase I development costs are the sum of licensing costs plus land acquisition costs. Licensing costs are taken as 3 percent of total overnight capital costs, per Pacific Northwest Utilities Conference Committee "Working Paper, Development of Generic Resource Data," October 1984 (PNUCC, 1984b). Land costs are from KEPC (1983) (1984 update). Phase II remobilization costs are those estimated for Creston by R. E. Henriques, The Washington Water Power Company; telephone conversation on April 30, 1985. Phase II development costs are taken as 40 percent of engineering costs as estimated in KEPC (1983) (1984 update), escalated to 1/85 using the Handy Whitman Index.

Option hold cost: Based on estimates prepared for Creston (Henriques, 1985).

Expected shelf life: Phase I: Expected shelf life is estimated time until one or more of the advanced coal technologies becomes fully established, requiring new feasibility and BACT studies. Phase II: Estimated time until the bulk of Phase II engineering would have to be reworked.

Option close-out cost: Close-out costs are assumed to be covered by the sale of the site.

Construction schedule: Per KEPC (1983).

Lag time to next unit: Per KEPC (1983).

Construction cash flow: From Phase I: Based on KEPC (1983), (1984 cost update) as adjusted in PNUCC (1984b); further adjusted as follows: Land costs deleted (included in option development costs); coal inventory based on 90 days continuous operation at rated capacity); cost of a ten-mile section of 500kV single circuit transmission line added (based on costs cited in letter from W. D. Beebe, Bonneville Power Administration to J. C. King, Northwest Power Planning Council, dated April 26, 1985); costs escalated to January 1985 using appropriate Handy-Whitman cost indices. Payout schedule based on KEPC (1983) (licensing activities deleted). From Phase II: Costs derived as from Phase I, less 20 percent of engineering costs, per recommendation of the Coal Options Task Force.

Fuel inventory: Inventory used in KEPC (1983); continuous operation at rated capacity assumed.

Fuel price: As recommended by the Coal Options Task Force. Midpoint of a range of coal costs obtained from technical reports and observation of current coal prices.

Fixed O&M cost: Seventy percent of labor and maintenance materials from KEPC (1983), (1984 cost update), escalated to 1985 using GNP deflator (1.05).

Variable O&M cost: Raw materials and chemicals, utilities, 30% of labor and maintenance mateials and services, and sludge and ash disposal from KEPC (1983), (1984 cost update), escalated to 1985 using GNP deflator (1.05).

Capital replacement cost: Same as unit cost estimated for the 603 MW generic plant. Includes cost of a major refurbishment at year 20.

Amortization life: Based on Electric Power Research Institute *Technical Assessment Guide,* May 1982 (EPRI, 1982) recommendations.

Operating life: Design life of major components (boiler and turbogenerator). Assumes a major refurbishment at year 20. Refurbishment costs are included in interim capital replacement costs.

Cost escalation: Values adopted by the Council for the 1986 Power Plan.

Appendix 6-D
Planning Assumptions — Generic AFBC Coal Project
Single 110-Megawatt Unit (January 1985 dollars)

GENERAL CHARACTERISTICS

Site	Eastern Oregon
Plant design	Single unit, 110 megawatt (net) capacity; coal-fired, atmospheric fluidized bed, steam-electric power plant; 1,500 psig, 1000°F steam, 2.0 HgA turbine back-pressure; zero makeup.
Fuel type	Wyoming subbituminous, 8,445 Btu/lb.
Fuel transport	Unit train
Heat rejection	Mechanical draft cooling towers; makeup from the Columbia River
Emission control	Particulates — cyclone separators and baghouse. SOX — Crushed limestone injection. NOX — Combustion temperature control.
Transmission	Located on existing regional grid.

TECHNICAL PERFORMANCE

Operating State	Capacity (MW, net)	Heat Rate (Btu/kWh, net)
Peak	n/av	n/av
Maximum Sustainable	n/av	n/av
Rated (Least Cost)	110	11,200
Minimum Sustainable	39	n/av

Transition Times	
Cold start — Minimum Sustainable	n/av
Hot start — Minimum Sustainable	n/av
Minimum sustainable — Rated	n/av
Operating Availability	
Equivalent Annual Availability	75%
Annual Maintenance Outage Period Normal	35 days
Major Overhaul	n/av
Average	35 days
Other Planned and Unscheduled Outages (Equivalent)	17%

PROJECT DEVELOPMENT

	Option Phase I License, Site Acquisition	Option Phase II Initial Engineering
Period	48 mos	n/av
Cash Flow Year 1	$ 1.1 million	n/av
Year 2	1.1 million	
Year 3	1.1 million	
Year 4	1.1 million	
Total	$ 4.4 million ($40/kW)	n/av
Hold cost (excl. of return on investment)	$ 0.1 million/yr ($0.9/kW/yr)	n/av
Expected shelf life	5 years	n/av
Option close-out cost	negligible	n/av
	Construction From Option Phase I	**Construction From Option Phase II**
Construction period	72 mos	n/av
Cash Flow Year 1	$ 0.2 million	n/av
Year 2	15.6 million	
Year 3	35.5 million	
Year 4	92.7 million	
Year 5	43.4 million	
Year 6	9.8 million	
Total	$197.2 million ($1,793/kW)	n/av

OPERATION

Fuel Inventory	90 days @ 110 MW
Fuel Cost (delivered)	$2.00 MMBtu
Fixed O&M	$3.6 million/yr ($33/kW/yr)
Variable O&M	0.1 cents/kWh
Capital Replacement Cost	$1.3 million/yr ($12.00/kW/yr)
Amortization Life	30 years
Operating Life	40 years
General Inflation (nominal)	5.0%/yr
Capital Escalation (real)	0.4%/yr
O&M Escalation (real)	0.0%/yr
Delivered Fuel Escalation	1.0%/yr

Site: As assumed in Kaiser Engineers Power Corporation. 1985. *Bonneville Power Administration Comparative Electric Generation Study (Supplemental Studies).* KEPC (1985).

Plant design: Per KEPC (1985).

Fuel type: Per KEPC (1985).

Fuel transport: Per KEPC (1985).

Heat rejection: Per KEPC (1985).

Emission control: Per KEPC (1985).

Transmission: Assumes a site near the existing Boardman site, consistent with KEPC (1985).

Peak Capacity: Not available.

Maximum sustainable capacity: Not available.

Rated capacity: Capacity and heat rate per KEPC (1985).

Minimum sustainable capacity: Based on the value reported for an AFBC plant in Electric Power Research Institute *Technical Assessment Guide,* May 1982 (EPRI, 1982).

Transition times: Not available.

Equivalent Annual Availability: Computed from annual maintenance outage period and other planned and unscheduled outages.

Annual maintenance outage period: From estimates reported in EPRI, 1982.

Other planned and unscheduled outages: From estimates reported in EPRI, 1982, rounded to nearest percent.

Option development period: Assumed to be similar to other generic coal units.

Option development cost: Assumes development of option to Node 2 (completion of permitting and licensing, acquisition of options on site). Cost to achieve Node 2 is based upon 1 percent to achieve Node 1 (conceptualization, feasibility study and environmental baseline data) and 1 percent for completion of permitting and licensing, as estimated in Battelle (1982) for coal steam-electrical power plants. To the above is added estimated land cost from KEPC (1985). (Land is assumed not have escalated in value between 1984 and 1985).

Option hold cost: Estimate includes project management ($100,000 per year); environmental monitoring ($15,000 per year), rounded to nearest 0.1 million.

Expected shelf life: The estimated time until significant advances might occur in a new technology such as AFBC, requiring new feasibility and BACT studies.

Option close-out cost: Sale of site assumed to offset close-out costs.

Construction schedule: Per KEPC (1985).

Construction cash flow: Based on KEPC (1985), adjusted in a manner consistent with the PNUCC *Thermal Resources Data Base,* further adjusted as follows: Land costs deleted (included in option development costs); coal inventory based on 90 days continuous operation at rated capacity (110 megawatts at 11,200 Btu/kilowatt-hours); costs escalated to January 1985 using appropriate Handy-Whitman cost indices. Payouts based on KEPC (1985).

Fuel inventory: Inventory used in KEPC (1985); continuous operation at rated capacity assumed.

Fuel Price: Council generic coal price.

Fixed O&M cost: KEPC (1985), escalated to 1985 using estimated general inflation deflator 1984-1985 (1.05).

Variable O&M cost: KEPC (1985), escalated to 1985 using estimated general inflation deflator 1984-1985 (1.05).

Capital replacement cost: Assumed to be similar to conventional station.

Amortization life: Based on EPRI, 1982.

Operating life: Design life of major plant components (boiler and turbogenerator). Assumes a major plant refurbishment at year 20. Refurbishment costs are included in interim capital replacement costs.

Cost escalation: Values adopted by the Council for the 1986 Power Plan.

Appendix 6-E
Planning Assumptions — Representative Geothermal-Electric Area (Newberry Volcano, Oregon)

GENERAL CHARACTERISTICS

Site	Newberry Volcano, Deschutes County, Oregon
Plant design	50 MW Central station, single flash, steam-electric geothermal plant and wellfield
Fuel type	Intermediate temperature hydrothermal geothermal resource.
Fuel transport	Not applicable
Heat rejection	Mechanical draft cooling
Emission control	n/av
Transmission	115 KV transmission interconnect to nearest line of 115 KV or greater

TECHNICAL PERFORMANCE

Operating State	Capacity (MW, net) Per Unit	Project	Heat Rate (Btu/kWh, net)
Peak	n/av	n/av	n/av
Maximum sustainable	n/av	n/av	n/av
Rated (Least cost)	50	1,940	n/av
Minimum sustainable	n/av	n/av	n/av
Transition Times			
Cold start — Minimum sustainable	n/av		
Hot start — Minimum sustainable	n/av		
Minimum sustainable — Rated	n/av		
Operating Availability			
Equivalent Annual Availability	80%		
Annual Maintenance Outage Period:	n/av		
Other Planned and Unscheduled Outages (Equivalent)	n/av		

PROJECT DEVELOPMENT

	Option Phase I: License, Site Acquisition	Option Phase II: Init. Detailed Engineering
Period (Completion of licensing)	36 months	n/av
Cash Flow: Year 1	$2.9 million	n/av
Year 2	$2.9 million	
Year 3	$2.9 million	
Total	$8.8 million ($176/kW)	n/av
Hold cost (excl. of return on investment)	n/av	
Expected shelf life	n/av	
Option close-out cost	n/av	
	Construction from Option Phase I	**Construction from Option Phase II**
Construction period	36 months	n/av
Cash Flow: Year 1	$ 29.3 million	n/av
Year 2	$ 44.0 million	
Year 3	$ 64.5 million	
Construction Total	$137.8 million ($2,756/kW)	n/av

OPERATION

Fuel Inventory	n/ap
Fuel price (delivered)	n/ap (included in capital cost)
Fixed O&M	$2.5 million/yr ($50/kW/yr)
Variable O&M	Included in fixed O&M
Capital Replacement Cost	n/av
Amortization Life	30 years
Operating Life	30 years
General Inflation (nominal)	5%/yr
Capital Escalation (real)	0.4%/yr
O&M Escalation (real)	0.0%/yr
Delivered Fuel Escalation (real)	n/ap

Plant design: From Bonneville Power Administration, 1984, *Evaluation and Ranking of Geothermal Resources for Electrical Generation or Electrical Offset in Idaho, Montana, Oregon and Washington.* ("Four State Study") (Binary and double flash units assumed for some locations).

Fuel type: From Four State Study.

Fuel transportation: Not applicable.

Heat rejection: From Four State Study.

Emission control: Not available.

Transmission: From Four State Study.

Peak capacity: Not available.

Maximum sustainable capacity: Not available.

Rated capacity: From Four State Study — varies by area.

Minimum sustainable capacity: Not available.

Transition times: Not available.

Equivalent annual availability: From the Four State Study.

Annual maintenance outages: Not available.

Equivalent unscheduled outage rates: Not available.

Option development period: Corresponds to 72-month total development period suggested in the Four State Study. 24 months used for locations developed with wellhead units.

Option development costs: Not available.

Expected shelf life: Not available.

Option close-out cost: Not available.

Construction period: From the Four State Study.

Construction cash flow: Estimated construction cost, which varies by site, was taken from the Four State Study. Figures were adjusted to January 1985 dollars. The construction payout was that recommended in the Four State Study, adjusted to account for the 36-month option development phase. A 12-month construction period, (one year payout) was used for sites assumed to be developed with wellhead units.

Fuel inventory: Not applicable.

Fuel price: Not applicable.

Fixed O&M cost: All operating and maintenance costs are fixed, as calculated in the Four State Study. Costs, which vary by site, were taken from the Four State Study and escalated to January 1985 dollars.

Variable O&M cost: Included in fixed O&M.

Capital replacement cost: Cost of replacement production and injection wells (including a "dry hole" allowance) is incorporated into plant capital costs.

Amortization life: Consistent with operating life assumptions.

Operating life: From the Four State Study.

Cost escalators: Values adopted by the Council for the 1986 Power Plan.

Appendix 6-F
Planning Assumptions — Representative Windpark (Columbia Hills East, Washington)

GENERAL CHARACTERISTICS

Site	Columbia Hills East-I, Washington
Plant design	Windpark, consisting of approximately 65 to 150 Nordtank 65/13 horizontal wind turbine generators
Fuel type	None
Fuel transport	None
Heat rejection	None
Emission control	None
Transmission	One mile intertie to existing grid

TECHNICAL PERFORMANCE

Operating State	Capacity (MW, net) Per Unit	Capacity (MW, net) Project	Heat Rate (Btu/kWh, net)
Peak	0.068	4.1-9.4	n/ap
Maximum sustainable	0.068	4.1-9.4	n/ap
Rated	0.065	4.0-9.0	n/ap
Minimum sustainable	0.0	0.0	n/ap

Transition Times	
Cold start — Minimum sustainable	n/ap
Hot start — Minimum sustainable	n/ap
Minimum sustainable — Rated	n/ap
Operating Availability	
Equivalent Annual Availability (Maturity)	95%
Capacity Factor	35%
Annual Maintenance Outage Period:	n/av
Other Planned and Unscheduled Outages (Equivalent)	n/av

PROJECT DEVELOPMENT

	Option Phase I: License, Site Acquisition	Option Phase II: Init. Detailed Engineering
Period (Completion of licensing)	12 months	n/av
Cost: Year 1	$0.06-0.14 million ($15/kW)	n/av
Total	$0.06-0.14 million ($15/kW)	n/av
Hold cost (excl. of return on investment)	n/av	n/av
Expected shelf life	n/av	n/av
Option close-out cost	n/av	n/av
	Construction from Option Phase I	**Construction from Option Phase II**
Construction period	24 months	
Cash Flow: Year 1	$2.5-5.6 million ($625/kW)	n/av
Year 2	$3.7-8.4 million ($930/kW)	
Construction Total	$6.2-14.0 million ($1,555/kW)	n/av

OPERATION

Fuel Inventory	n/ap
Fuel price (delivered)	n/ap
Fixed O&M	Included in variable O&M
Variable O&M	1.2 cents/kWh
Capital Replacement Cost	Included elsewhere
Royalty (Wind Right)	5% of total production cost
Amortization Life	20 years
Operating Life	20 years
General Inflation (nominal)	5%/yr
Capital Escalation (real)	0.4%/yr
O&M Escalation (real)	0.0%/yr
Delivered Fuel Escalation (real)	n/ap

Plant design: A Danish production machine, representative of the better machines currently on the market. Range of number of installed turbines reflects uncertainty regarding the percent of these sites suitable for turbine installation. A range of 40%-90% surface area is used for each case, as recommended by Oregon Department of Energy.

Fuel type: None.

Fuel transportation: None.

Heat rejection: None.

Emission control: None.

Transmission: Approximate distance from Columbia Hills East site to nearest substation as reported by Oregon State University.

Peak capacity: *Per Unit:* As reported for the Nordtank 65/13 by the manufacturer (Nordtank, Inc., Pacific Palisades, CA). *Plant:* Peak capacity of the fully developed site as estimated by Oregon State Department of Energy (ODOE). Site capacity derated by 5 percent to account for internal site electrical losses, as recommended by ODOE.

Maximum sustainable capacity: Same as peak.

Rated capacity: *Per Unit:* As reported for the Nordtank 65/13 by the manufacturer. *Plant:* Rated capacity of the fully developed site as estimated by ODOE. Site capacity derated by 5 percent to account for internal site electrical losses.

Minimum sustainable capacity: Output at cut-in speed (8.3 MPH).

Transition times: Not applicable (Plant is not dispatchable).

Equivalent annual availability: Ninety-eight percent availability was recommended by ODOE based on field experience to date with the Nordtank 65/13 and warranty insurance offered by manufacturer. Reduced to 95% by the Council to increase conservatism of the estimates.

Capacity factor: Calculated for each wind resource area by ODOE. Area wind data was acquired from Oregon State University. Corrected for altitude, integrated with the Nordtank power curve and adjusted for the 95% equivalent annual WTG availability.

Annual maintenance outages: Specific information not available.

Equivalent unscheduled outage rates: Specific information not available.

Option development period: As recommended by ODOE, based on California wind development experience.

Option development costs: One percent of total development costs as recommended by ODOE, based on California wind development experience.

Expected shelf life: Not available.

Option close-out cost: Not available.

Construction period: Twelve month construction period was recommended by ODOE based on California wind development experience. Extended to 24 months by the Council to account for remobilization time incurred if the development occurs as a two-phase option process, with the first phase being site selection and licensing, and the second phase being design, procurement, construction and testing.

Construction cash flow: Construction costs include wind turbine generator (WTG), balance of plant (BOP), transmission, access and contingency. WTG costs, including purchase, foundation, warranty installation and shipping were estimated by ODOE to be $1,023/kW (nameplate). Balance-of-plant (BOP) costs, exclusive of contingency and permit costs were estimated by ODOE to be 13% of WTG costs. Transmission interconnect and access development costs were estimated by the Council to be 2% of WTG + BOP costs. Contingency was assumed (by the Council) to be 25% of total development costs (including option development). The total costs were increased by 5 percent to adjust to net rated capacity of windpark. Construction costs were allocated at 40% for first year, 60% for second year.

Fuel inventory: Not applicable.

Fuel price: Not applicable.

Fixed O&M cost: All operation and maintenance costs are included as variable costs.

Variable O&M cost: As recommended by ODOE based on experience at better California wind developments.

Capital replacement cost: Capital replacement for first five years covered by manufacturer's warranty. Capital replacement for balance of plant life included in variable O&M estimate.

Royalties: As recommended by ODOE based on California experience.

Amortization life: Set equal to operating life.

Operating life: Design life of the major plant components (wind turbine generators), as reported by ODOE.

Cost escalators: Values adopted by the Council for the 1986 Power Plan.

Appendix 6-G
Planning Assumptions — Generic Combustion Turbine Project, Two 105-Megawatt (Nominal) Units (January 1985 dollars)

GENERAL CHARACTERISTICS

Site	Oregon or Washington
Plant design	Two units, each a single shaft, industrial-grade, open cycle combustion turbine-generator of 105 megawatt nominal capacity.
Fuel type	Primary — Natural gas; 950 Btu/scf (LHV). Secondary — No. 2 Fuel oil; 18,100 Btu/lb (LHV).
Fuel transport	Natural gas — High pressure pipeline. Fuel oil — Pipeline, rail or truck.
Heat rejection	To atmosphere.
Emission control	Particulates — None required. SOX — Low sulfur fuel oil. NOX — Water injection.
Transmission	Ten-mile, 230 kV single circuit grid connection.

TECHNICAL PERFORMANCE

Operating State	Capacity (NW, net) Per Unit	Capacity (NW, net) Project	Heat Rate @ LHV (Btu/kWh, net)
Peak(January)	124	248	10,530
Base Load	104	208	10,710
Minimum sustainable	5	10	62,000

Transition Times	
Cold start — Minimum sustainable	0.5 hour
Hot start — Minimum sustainable	0.5 hour
Minimum sustainable — Rated	<0.5 hour
Operating Availability	
Equivalent Annual Availability	85%
Annual Maintenance Outage Period	42 days
Normal	30 days
Major Overhaul (every fifth year)	90 days
Average	42 days
Other Planned and Unscheduled Outages (Equivalent)	4%

PROJECT DEVELOPMENT

	Option Phase I: License, Site Acquistion	Option Phase II: Init. Detailed Engineering
Period	24 mos	n/av
Cash Flow Year 1	$ 0.4 million	n/av
Year 2	0.4 million	
Total	$ 0.8 million ($4/kW)	n/av
Hold cost (excl. of return on investment)	$ 0.1 million/yr ($0.5/kW/yr)	n/av
Expected shelf life	5 years	n/av
Option close-out cost	negligible	n/av
	Construction from Option Phase I	**Construction from Option Phase II**
Construction period	30 mos	n/av
Lag to Unit 2 completion	none	n/av
Cash Flow Year 1	$18.4 million	n/av
Year 2	$31.5 million	
Year 3	$2.6 million	
Construction Total	$52.5 million ($250/kW)	n/av

OPERATION

Fuel Inventory	Gas: none	Oil: 14 days @ 208 MW
Fixed Fuel Cost	Gas: $0.53 million/yr ($2.50/kW/yr)	Oil: $0.53 million/yr ($2.50/kW/yr)
Variable Fuel Cost	Gas: $5.10/MMBtu	Oil: $5.70/MMBtu
Fixed O&M		$0.27 million/yr ($1.30/kW/yr)
Variable O&M		0.21 cents/kWh
Capital Replacement Cost		$0.27 million/yr ($1.30/kW/yr)
Amortization Life		20 years
Operating Life		30 years
General Inflation (nominal)		5.0 %/yr
Capital Escalation (real)		0.4 %/yr
O&M Escalation (real)		0.0 %/yr
Natural Gas Escalation (real)		1.8 %/yr
Fuel Oil Escalation (real)		1.6 %/yr

Site: Assumes that combustion turbines could be built at existing thermal plant sites.

Plant design: Based on twin Westinghouse W501D units as used for the Puget Power Fredonia project.

Fuel type: Typical combustion turbine fuel characteristics.

Fuel transportation: Typical of potential sites.

Heat rejection: Typical of an open-cycle combustion turbine.

Emission control: As practiced at the Fredonia project.

Transmission: Assumes a site near the regional transmission grid.

Peak Capacity: Capacity: Maximum sustainable capacity during cold weather conditions. Based on values reported for the Puget Power Fredonia project (Westinghouse W501D units) in the Pacific Northwest Utilities Conference Committee *Thermal Resources Data Base.* October 1984 (PNUCC 1984a). Heat rate: Based on values reported for Fredonia in PNUCC (1984a). Values given are based on lower heating value of fuel.

Base load capacity: Capacity: Rating of Fredonia units as reported in PNUCC (1984a). Heat rate: Based on values reported for Fredonia in PNUCC (1984a). Values given are based on lower heating value of fuel.

Minimum sustainable capacity: Capacity: Rating of Fredonia units as reported in PNUCC (1984a). Heat rate: Based on values reported for Fredonia in PNUCC (1984a). Values given are based on lower heating value of fuel.

Transition times: As reported for Fredonia in PNUCC (1984a). Values from minimum sustainable to maximum sustainable are estimated.

Equivalent annual availability: Based upon National Electric Reliability Council (NERC) Generating Availability Data System (GADS) records for combustion turbines. Equivalent annual availability was calculated by weighting the NERC equivalent annual availability data for operating years 1 through 10 in proportion to the the number of operating years represented by the compiled statistics. (i. e., statistics for operating years 1, 2 and 3, which are compiled individually, each received a weight of "1"; statistics for years 4 through 10, which are aggregated, received a weight of "7"). The resulting equivalent annual availability for all combustion turbine units is 85.6 percent. A value of 85 percent was chosen, considering the following: 1) The NERC data base represents a large number of unit-years of operating experience (8,261 unit-years for operating years one through ten); confidence in the statistics is therefore good. 2) The NERC data base includes data for both aircraft-derivative and industrial-type units, The generic turbine is an industrial-type unit, generally considered to be more reliable than the aircraft-derivative units; therefore, its performance can be expected to be as least as good as averages of aircraft-derivative and industrial units. 3) The NERC data base includes units subject to all modes of operation from peaking to continuous duty. Continuous duty operation — thought to be more typical of Northwest units employed for firming secondary hydro — generally results in more reliable operation.

Annual maintenance outage period: The schedule shown assumes an annual combustor inspection, a "hot path" inspection every fifth year and a major overhaul every tenth year. Periods are derived from estimates appearing in J.H. Borden "Outage Management Improves Turbine Availability," *Diesel and Gas Turbine Worldwide,* April 1982, and could be shortened by improved outage management.

Other planned and unscheduled outages: Calculated from the 85 percent equivalent annual availability and the average annual maintenance outage rate. The resulting value (4 percent) is somewhat more conservative than the 3 percent recommended by Westinghouse Electric Corporation Combustion Turbine Systems Division.

Option development schedule: Assumes development of option to Node 2 (Conceptualization, completion of permitting and licensing, acquisition of site). Based on Fredonia experience, as reported in the PNUCC "Working Paper, Development of Generic Resource Data," October 1984 (PNUCC 1984b).

Option development cost: Assumes development of option to Node 2 (Conceptualization, completion of permitting and licensing, acquisition of site). Cost to achieve Node 2 is based upon 1 percent of total capital costs as estimated in Battelle, Pacific Northwest Laboratories *Development and Characterization of Electric Power Conservation and Supply Resource Planning Options,* plus estimated purchase cost of 100 acres of land at $2,500 per acre.

Option hold cost: Estimate includes project management, EFSEC, environmental baseline and indirect costs, as follows. Project management taken as one engineering staff at $50,000 per year. EFSEC and environmental baseline costs scaled from 1984 Creston hold costs, as presented by The Washington Water Power Company to the Northwest Power Planning Council on July 17, 1984. Indirect costs taken at 11 percent as appearing in the Creston presentation.

Expected shelf life: Expected shelf life is estimated time until fuel cell technology becomes fully established, requiring new feasibility and environmental studies.

Option close-out cost: Revenues from the sale of land are assumed to cover close-out costs.

Construction schedule: Based on Puget Power experience for Fredonia as reported in PNUCC "Working Paper, Development of Generic Resource Data," October 1984 (1984b).

Construction cash flow: As estimated by Westinghouse Electric Corporation, Combustion Turbine Systems Division for twin Westinghouse W501D units, installed and ready to operate. Payout schedule based on actual timing of construction expenditures for Fredonia as reported in the PNUCC (1984b).

Fuel contract: Provisions stated are similar to Fredonia.

Fuel inventory: Similar to Fredonia.

Fuel cost (service charge):
Natural gas—Fixed fuel oil service charge experienced by the Fredonia project, from PNUCC (1984a). Thought to be typical of a contract with provision for short-term interruptibility. The service charge covers the cost of pipeline service to the project.

Fuel oil—Fixed fuel oil service charge experienced by the Fredonia project, from PNUCC (1984a). Thought to be typical of a contract with provision for delivery with advance notice. The service charge covers the cost of pipeline service to the project.

Fuel cost (variable):
Natural gas—NWPPC planning assumptions for industrial gas sold in Washington, medium-low and medium-high load growth cases.

Fuel oil—NWPPC planning assumptions for industrial oil sold in Washington, medium-low and medium-high load growth cases.

Fixed O&M cost: As reported for Fredonia in PNUCC (1984a), escalated to 1985 using the 1984-1985 GNP deflater (1.05).

Variable O&M cost: As reported for Fredonia in PNUCC (1984b), escalated to 1985 using the 1984-1985 GNP deflater (1.05).

Capital replacement cost: Based on one major overhaul every ten calendar years. Cost of overhaul assumed to be ten percent of original equipment cost ($37.8 million at 180 dollars per kilowatt), rounded to nearest million dollars. Levelized at 3 percent discount rate over the project life.

Amortization life: Based on Electric Power Research Institute *Technical Assessment Guide*, May 1982 (EPRI, 1982) recommendations.

Operating life: Likely physical life with major overhauls at ten-year increments and operated primarily for secondary firming.

Cost escalation: Assumptions are taken from the Council decision regarding financial variables.

Appendix 6-H
Planning Assumptions — Generic Combined Cycle Project
Two 286-Megawatt Units (January 1985 dollars)

GENERAL CHARACTERISTICS

Site	Oregon or Washington
Plant design	Two combined-cycle units, 286 megawatt nominal capacity each. Each unit consists of two single shaft, industrial-grade, open cycle combustion turbine-generators of 105 megawatt nominal capacity, two heat recovery steam generators and one steam turbine generator of 84 megawatts gross capacity. Steam conditions are 1,210 psig and 950°F.
Fuel type	Primary — Natural gas; 950 Btu/scf (LHV). Secondary — No. 2 Fuel oil; 18,100 Btu/lb (LHV).
Fuel transport	Natural gas — High pressure pipeline. Fuel oil — Pipeline, rail or truck.
Heat rejection	To atmosphere via heat recovery steam generators and mechanical draft cooling towers.
Emission control	Particulates — None required. SOX — Low sulfur fuel oil. NOX — Water injection.
Transmission	Ten-mile, 500 kV single-circuit grid connection.

TECHNICAL PERFORMANCE

Operating States — CT Mode: Operating State	Capacity (MW net) Per Unit	Project	Heat Rate (Btu/kWh, net)
Peak (January)	248	496	10,530
Base Load	208	416	10,710
Minimum sustainable	10	20	62,000
Operating States — Combined Cycle Mode:			
One CT, unfired boiler	116	232	9,530
One CT, fired boiler	144	288	9,270
Two CTs, unfired boiler	240	480	9,350
Two CTs, fired boiler	283	566	9,810
Average:			9,800

Transition Times — CT Mode:	
Cold start — Minimum sustainable	0.5 hour
Hot start — Minimum sustainable	0.5 hour
Minimum sustainable — Rated	<0.5 hour
Transition Times — Combined Cycle Mode:	
Cold start — Minimum sustainable	9 hours
Hot start — Minimum sustainable	3 hours
Minimum sustainable — Rated	3 hours
Operating Availability	
Equivalent Annual Availability	83%
Annual Maintenance Outage Period:	
Normal	30 days
Major Overhaul (every fifth year)	90 days
Average	42 days
Other Planned and Unscheduled Outages (Equivalent)	6%

PROJECT DEVELOPMENT

	Option Phase I: License, Site Acquisition	Option Phase II: Init. Detailed Engineering
Period	24 mos	n/av
Cash Flow: Year 1	$3.2 million	n/av
Year 2	3.2 million	
Total	$6.4 million ($11/kW)	n/av
Hold cost (excl. of return on investment)	$0.2 million/yr ($0.4/kW/yr)	n/av
Expected shelf life	5 years	n/av
Option close-out cost	negligible	n/av
	Construction from Option Phase I	**Construction from Option Phase II**
Const. period (Unit 1 insr.)	45 mos	n/av
Lag to second unit	3 mos	n/av
Cash Flow: Year 1	$ 14.5 million	n/av
Year 2	$115.9 million	
Year 3	$155.8 million	
Year 4	$ 76.0 million	
Construction Total	$362.2 million ($633/kW)	n/av

OPERATION

Fuel Inventory	Gas: none	Oil: 14 days @ 572 MW
Fixed Fuel Cost	Gas: $1.4 million/yr ($2.50/kW/yr)	Oil: $1.4 million/yr ($2.50/kW/yr)
Variable Fuel Cost (LHV)	Gas: $5.10/MMBtu	Oil: $5.70/MMBtu
Fixed O&M		$5.5 million/yr ($9.60/kW/yr)
Variable O&M		0.03 cents/kWh
Capital Replacement Cost		$2.4 million/yr ($4.20/kW/yr)
Amortization Life		30 years
Operating Life		30 years
General Inflation (nominal)		5.0 %/yr
Capital Escalation (real)		0.4 %/yr
O&M Escalation (real)		0.0 %/yr
Natural Gas Escalation (real)		1.8 %/yr
Fuel Oil Escalation (real)		1.6 %/yr

Site: Assumes that combined cycle plants could be constructed at existing licensed thermal sites.

Plant design: As described in Kaiser Engineers Power Corporation *Bonneville Power Administration Comparative Electric Generation Study (Supplemental Studies),* February 1985 (KEPC, 1985).

Fuel type and source: Typical of potential sites.

Heat rejection: per KEPC, 1985

Emission control: As practiced at the Fredonia project.

Transmission: Assumes a site near the regional transmission grid.

Capacities and Heat Rates:
CT Mode—Capacities and heat rates cited for the combustion turbines operating independently are as derived for the generic stand-alone combustion turbine plant.

CC Mode—Capacities and heat rates for combined cycle operation are based upon the four modes of operation reported for the El Paso Electric Newman station (*Gas Turbine World,* July 1981). The capacity states for the Newman station were adjusted by the ratio of nominal gross capacities of the Newman station (220 megawatts) and the station used in KEPC (1985) (296 megawatts) (Both are Westinghouse PACE package plants using W501D gas turbines). The resulting ratioed capacity was further adjusted by the ratio of net to gross plant output reported in KEPC (1985) to arrive at net capacity states.

Transition times:
CT Mode—As reported for Fredonia in PNUCC (1984a). Values from minimum sustainable to maximum sustainable are estimated.

CC Mode—As reported for El Paso Electric Newman Station in *Gas Turbine World,* July 1981.

Equivalent annual availability: A Westinghouse study ("Gas turbine combined cycle reliability has made impressive progress." *Modern Power Systems.* October 1982) reports average annual availabilities for combined cycle plants to be approximately 1 percent lower than for individual combustion turbines (86.5 percent vs. 87.6 percent). The recommended equivalent annual availability of 83 percent is derived from a more conservative 2 percent reduction of the 85 percent availability selected for the generic stand-alone combustion turbine.

Annual maintenance outage periods: The generic combined-cycle plant is assumed to operate in a manner similar to the generic stand-alone combustion turbine (i.e., as a unit primarily for firming secondary hydropower), operated approximately one year in four or five with fairly continuous operation when needed. The resulting maintenance schedule will therefore be similar to that developed for the stand-alone combustion turbine, consisting of an annual 30-day routine maintenance period and a major inspection following each year of secondary firming operation (estimated to be one in five years). The durations for these inspections are taken from "Outage management improves gas turbine availability," in *Diesel and Gas Turbine Worldwide,* April 1982. The outage durations are conservative and could be substantially shortened by increasing the spare parts stock.

Rate of other planned and unscheduled outages: Calculated as an equivalent outage rate from the equivalent annual availability and the annual maintenance outage schedule.

Option development schedule: Based on Fredonia experience as reported in PNUCC *Working Paper — Development of Generic Resource Data,* October, 1984 (PNUCC, 1984b).

Option development cost: opment of option to include tion, completion of permitting and acquisition of the site. C upon 1.7 percent of total capital c mated in Battelle, Pacific Northwe tories *Development and Characte Electric Power Conservation and Resource Planning Options,* Augus (Battelle, 1982), plus the estimated c 100 acres of land at $2,500 per acre.

Option hold cost: Estimate includes proje management ($100,000 per year), EFSEC ($25,000 per year), environmental baseline ($75,000 per year) and indirect costs at 11 percent of the foregoing. Rounded to the nearest 0.1 million per year. Return on investment is not included.

Expected shelf life: Expected shelf life is the estimated time until fuel cell technology becomes fully established. This is assumed to require new feasibility and environmental studies.

Option close-out cost: The value of the land is assumed to offset option close-out costs.

Construction schedule: Based on KEPC, 1985.

Construction cash flow: Based on KEPC (1985), adjusted in a manner consistent with PNUCC (1984b), further adjusted as follows: Land costs deleted (included in option development costs); fuel inventory based on two weeks operation at maximum sustainable capacity (572 megawatts at 8,030 Btu/kWh); costs escalated to January, 1985 using appropriate Handy-Whitman cost indices. Payout rate based on KEPC (1985).

Fuel inventory: As assumed in KEPC (1985), commensurate with natural gas contracts with provision for short-term interruption.

Fuel cost (service charge):
Natural gas—Fixed fuel oil service charge experienced by the Fredonia project, from PNUCC (1984a). Thought to be typical of a contract with provision for short-term interruptability. The service charge covers the cost of pipeline service to the project.

Fuel oil—Fixed fuel oil service charge experienced by the Fredonia project, from PNUCC (1984a). Thought to be typical of a contract with provision for delivery with advance notice. The service charge covers the cost of pipeline service to the project.

Fuel cost (variable):
Natural gas—NWPPC planning assumptions for industrial gas sold in Washington, medium-low and medium-high load growth cases.

Fuel oil—NWPPC planning assumptions for industrial oil sold in Washington, medium-low and medium-high load growth cases.

Fixed O&M cost: As estimated in KEPC (1985), escalated to 1985 using the 1984-1985 GNP deflator (1.05).

Variable O&M cost: As estimated in KEPC (1985), escalated to 1985 using the 1984-1985 GNP deflater (1.05).

Capital replacement cost: Based on one major overhaul every ten calendar years of operation. Cost of overhaul assumed to be 10 percent of original plant cost (362 million), rounded to nearest million dollars. Levelized at a 3 percent discount rate over the project life.

Amortization life: Based on value used for stand-alone generic combustion turbines (the limiting major component).

Operating life: Based on value used for stand-alone generic combustion turbines (the limiting major component).

Cost escalation: Assumptions are taken from the Council decision regarding financial variables.

Appendix 6-I
Planning Assumptions
Washington Public Power Supply System Nuclear Project No. 1

(January 1985 dollars)

GENERAL CHARACTERISTICS

Site	Richland, Washington
Ownership	Public utilities (net-billed) 100%
Plant design	1,338 megawatt (nameplate)/1,250 megawatt (net) capacity; pressurized water nuclear power plant. Babcock and Wilcox Model 205 Fuel Assembly.
Heat rejection	Mechanical draft cooling towers; makeup from the Columbia River
Transmission	Located on existing regional grid (Ashe substation).

TECHNICAL PERFORMANCE

Operating State	Capacity (MW, net)	Heat Rate (Btu/kWh, net)
Maximum sustainable	1,250	9,829
Rated (least cost)	1,250	9,829
Minimum sustainable	500	n/av
Transition Times		
Cold start — Minimum sustainable	24 hours	
Hot start — Minimum sustainable	5 hours	
Minimum sustainable — Maximum sustainable	n/av	
Operating Availability		
Equivalent Annual Availability	65%	
Annual Maintenance and Refueling Outage Period	60 days	
Annual Maintenance and Refueling Outage Timing	June-July	
Other Planned and Unscheduled Outages (Equivalent)	22 percent	

PRESERVATION

Expected Shelf Life	15 years, minimum	
Cash Flow (as planned):		
CY 1985	$60 million	
Jan 86 to Restart	$36 million/yr	(Earned value at $24 million per year beginning in July 1986 to be credited against costs to complete)
Cash Flow (minimum):		
CY 1985	$60 million	
CY 1986	$20 million)	(Includes $8 million for additional ramp-down to minimum preservation level)
Jan 87 to Remobilization	$12 million/yr	
Remobilization Year	$44 million	($32 million for ramp-up plus $12 million preservation)
Funding	Existing funds ($ 125 million) reinvested at 10.3% (nominal) rate. Bonneville rates if existing funds are depleted (No credit for existing funds taken for comparison of alternative resources)	

CONSTRUCTION

Construction Period	54 months
Cash Flow:	
1st 12 months	$ 237 million
2nd 12 months	$ 422 million
3rd 12 months	$ 402 million
4th 12 months	$ 244 million
Last 6 months	$ 78 million
Total	$1,383 million ($1,106/kW)
Financing	Bonds at 9.2% (nominal) plus 1% risk premium.

TERMINATION

Termination Period	24 months
Termination Costs	
Termination program	$ 33 million
Nominal site restoration	$ 15 million
Full site restoration	$100 million
Sale of assets (receipts)	$125 million
Funding	Existing funds ($125 million) reinvested at 9.2% (nominal). Bonneville rates if existing funds are depleted. (No credit for existing funds taken for comparison of alternative resources.)

OPERATION

Fixed fuel cost	$35.4 million/yr ($28.30/kW/yr)
Operating Costs	
Fixed O&M	$71.0 million/yr ($56.80/kW/yr)
Variable O&M	$ 0.0011/net kWh
Decommissioning fund	$ 3.5 million/yr ($2.80/kW/yr)
Capital Replacement Cost	
Operating year 1	$ 5 million
Operating year 2	$11 million
Operating year 3	$16 million
Operating year 4 and on	$21 million/yr ($16.80/kW/yr)
Amortization Life	30 years
Operating Life	40 years

COST ESCALATION

General Inflation (nominal)	5.0%/yr
Capital (real)	0.4%/yr
O&M (real)	0.0%/yr
Fuel (real)	None to 1993; 1%/yr thereafter

Maximum sustainable capacity: Capacities and heat rates are from Pacific Northwest Utilities Conference Committee *Thermal Resources Data Base.* October 1984 (PNUCC, 1984).

Rated capacity: Capacities and heat rates are from PNUCC, 1984.

Minimum sustainable capacity: Capacities are from PNUCC, 1984.

Transition times: From PNUCC, 1984.

Operating availability: The principal operating availability parameters are equivalent annual availability, planned outage rate and equivalent unscheduled outage rate. Equivalent annual availability represents the fraction of the year that a unit is available to operate at full power. Because a unit may occasionally be available for derated (partial power) operation, annual availability is expressed in equivalent full power hours. Equivalent annual availability is a function of planned outages (for maintenance, repair or refueling) and unplanned outages.

Of the three availability parameters, only planned outages (listed in this appendix as "Annual Maintenance and Refueling Outages") is readily available. One 60-day planned annual outage is scheduled for WNP-1.

The Council, for the 1983 cost-effectiveness assessment of WNP-4 and 5, undertook an extensive analysis of the equivalent annual availability and equivalent unplanned outage rate of large (1,000+ MW) nuclear power plants. That analysis included examination of performance data maintained by the Nuclear Regulatory Commission (NRC) and the North American Electric Reliability Council (NERC). The Council concluded, based on that analysis, that a 22 percent equivalent unplanned outage rate, a 60-day annual planned outage, and a 65 percent equivalent annual availability were representative of large nuclear plants.

In developing assumptions for this plan regarding the performance of WNP-1 and WNP-3, the Council chose to rely upon the assumptions developed earlier for the WNP-4 and 5 study, unless persuasive evidence was available suggesting that the earlier values should be modified. To determine if the earlier values should be modified, the Council examined operating histories of all large (1,000+ MW) pressurized water reactors with one year or more operating history, compiled in the NRC Grey Book. A comparison of the availabilities of these units through October 1984 with the Grey Book data through September 1982 studied earlier indicated no significant changes in the availability of these units. The Council therefore concluded that equivalent unplanned outage, and equivalent annual availability assumptions for WNP-1 and WNP-3 should remain unchanged from the assumptions used earlier for WNP-4 and WNP-5.

The planned annual maintenance and refueling outages are scheduled to coincide with the period of seasonal hydropower surplus.

Preservation shelf life: The Council concludes that the projects can be preserved for a minimum of 15 years (see discussion in this chapter).

Preservation cash flow: The Supply System has provided cash flows for "currently planned" and "minimum level" preservation programs.

The planned preservation program, at $36 million per year, includes licensing and regulatory activities leading to "earned value" credit against costs-to-complete. Following completion of the currently planned ramp-down to about 400 staff by July of 1986, the planned preservation program would continue to restart of construction at a rate of $36 million per year. Earned value of approximately $24 million per year would begin to accrue about mid-1986.

The minimum level preservation program at $12 million per year contains no provision for ongoing engineering and licensing activities and would evidently forego certain record update activities and maintenance staffing. Incremental ramp-down costs of $8 million would be experienced due to additional staff layoffs, and additional ramp-up costs of $32 million would be required prior to restart of construction to restore engineering and licensing staff to planned preservation levels. The Supply System has recently reestimated minimum preservation to be $10 million per year.

Preservation financing: Preservation at Project 1 would be financed initially from the current account balance of $125 million. These funds are reinvested and are expected to cover planned preservation costs at Project 1 through the first quarter 1988. Financing from Bonneville rates would follow exhaustion of this fund.

In comparing the cost effectiveness of WNP-1 with other alternatives, the Council chose not to credit the project with the current account balance, reasoning that these funds are not yet sunk, and could be recovered by the region if the project were terminated. An interest rate premium (discussed under construction financing) is added to the "standard" equity rate chosen by the Council for all other resources.

Construction period: The construction period for Project 1 has been reduced from 60 months to 54 months in accordance with updated estimates received from the Supply System in January 1985. The Council discussed with the Supply System the likelihood of maintaining the revised schedule. Learning that the critical path is hiring and training of operators, and considering the excellent construction rates achieved on Project 3 in the year prior to the decision to slow construction, the Council concluded that the schedule appears reasonable.

Construction cash flow: The Supply System has provided revised construction cash flows for the project. The project shows a modest decrease compared to earlier estimates. This is attributable to incorporation of earned value through January 1985; deduction of planned earned value activities through July 1985; minor scope changes; and use of consolidated construction methods using capped cost, risk-sharing contracts. The estimate to complete includes contingencies of approximately 9 percent and incorporates known and probable changes resulting from pending regulatory actions.

Construction financing: Financing is assumed to be by bonds. Direct financing by Bonneville rates was considered; however, in view of the considerable impact of rate financing on Bonneville rates, the likelihood of a prolonged preservation period (allowing time for the WNP-4/5 settlement to proceed), and equity questions regarding rate financing of capital investment, the Council concluded that financing should be assumed to be bonds.

A risk premium of 1 percent is added to all public and private debt and equity financing. This premium is based on statements by Seattle Northwest Securities Commission (financial advisors to the Supply System) and Salomon Brothers Inc.; Goldman, Sachs and Company; Merrill Lynch Capital Markets and Smith, Barney, Harris Upham and Company, Inc. (Senior Managing Underwriters). These firms concluded that the risk premium would not likely exceed 1/2 to 1 percent.

Termination period: As estimated by the Supply System.

Termination costs: As estimated by the Supply System.

Termination financing: Termination financing is assumed to be similar to preservation financing.

Fuel costs: Fuel cost estimates were provided to the Council by the Supply System and are based on operation at 65 percent capacity factor for a 40-year plant life.

Operation costs: Fixed operating costs are as provided by the Supply System. Variable operating costs consist of the federal fuel disposal charge. This latter charge is based on gross energy production and has been adjusted to represent costs based on net energy production.

Capital replacement costs: Capital replacement costs are as currently estimated by the Supply System.

Amortization life: The 30-year amortization life is based upon the recommendation of the Electric Power Research Institute and is consistent with values used by the Council for other resources. Actual bond maturity periods might vary.

Operating life: The Council has chosen a 40-year operating life to be consistent with design life of 40 years. Arguments regarding nuclear plant operating life were examined in some detail. First, the principal plant components—for example, the reactor vessel—are conservatively designed to withstand the conditions imposed by normal plant operation for a period of 40 years or more. Second, NRC operating licenses are for 40 years duration, based on the 40-year design life. Third, plant preservation should not impact the expected operating life. Finally, efforts are underway in the industry to extend plant operating life beyond 40 years.

On the other hand, there are arguments that 40 years is an optimistic assumption regarding operating life. Commercial nuclear plants have been operating only since 1957. Moreover, many of the commercial plants coming into service prior to 1969 were demonstration plants, such that operating experience on mature commercial plants is available only since the late 1960s. Given the relatively brief history of the technology, there is currently no statistically sound basis for judging the expected operating lives of the current generation of commercial nuclear plants.

It is also argued that the number of retirements of plants with operating lives of 25 years or less indicate that a 40-year operating life cannot be expected. Many of the retirements have been plants that were originally designed as demonstration plants that were not intended to remain economically competitive with later commercial units. Several commercial plants have been retired early (largely due to the economic consequence of required backfits) or shut down for prolonged periods for repair or regulatory reasons.

The Council, weighing these arguments, chose to consider a base case operating life of 40 years, but to explore the efforts of shorter operating lives on cost effectiveness through sensitivity analysis.

Cost escalation: Values for general inflation, capital and operation and maintenance are as adopted by the Council for the 1986 Power Plan. The Supply System recommended that the nuclear fuel escalation rate be equivalent to general inflation through 1993, citing the soft nuclear fuel market, and 1 percent real thereafter. The Council concurs with this argument.

Appendix 6-J
Planning Assumptions
Washington Public Power Supply System Nuclear Project No. 3
(January 1985 dollars)

GENERAL CHARACTERISTICS

Site	Satsop, Washington	
Ownership	Public Utilities (net-billed)	70%
	Investor-owned Utilities (capability proposed for acquisition by Bonneville)	30%
Plant design	1,324 megawatt (nameplate)/1,240 megawatt (net) capacity; pressurized water nuclear power plant. Combustion Engineering System 80.	
Heat rejection	Natural draft cooling tower; makeup from the wells adjacent to the Chehalis River.	
Transmission	Located on existing regional grid.	

TECHNICAL PERFORMANCE

Operating State	Capacity (WM, net)	Heat Rate (Btu/kWh, net)
Maximum sustainable	1,240	10,459
Rated (Least cost)	1,240	10,459
Minimum sustainable	500	n/av
Transition Times		
Cold start — Minimum sustainable	24 hours	
Hot start — Minimum sustaintable	5 hours	
Minimum sustainable — Maximum sustainable	n/av	
Operating Availability		
Equivalent Annual Availability	65%	
Annual Maintenance and Refueling Outage Period	60 days	
Annual Maintenance and Refueling Outage Timing	May-June	
Other Planned and Unscheduled Outages (Equivalent)	22 percent	

TERMINATION

Termination Period	24 months
Termination Costs	
Termination program	$ 31 million
Nominal site restoration	$ 20 million
Full site restoration	$100 million
Sale of assets (receipts)	$ 70 million
Funding	Similar to preservation financing.

OPERATION

Fixed Fuel Cost	$38.9 million/yr ($31.40/kW/yr)
Operating Costs	
Fixed O&M	$71.0 million/yr ($57.30/kW/yr)
Variable O&M	$ 0.0011/net kWh
Decommissioning fund	$ 3.5 million/yr ($2.80/kW/yr)
Capital Replacement Cost	
Operating year 1	$ 5 million
Operating year 2	$11 million
Operating year 3	$16 million
Operating year 4 and on	$21 million/yr ($16.90/kW/yr)
Amortization Life	30 years
Operating Life	40 years

COST ESCALATION

General Inflation (nominal)	5.0%/yr
Capital (real)	0.4%/yr
O&M (real)	0.0%/yr
Fuel (real)	None to 1993; 1%/yr thereafter

PRESERVATION

Expected Shelf Life	15 years, minimum	
Cash Flow (as planned)		
CY 1985	$61 million	
CY 1986	$48 million	(Includes balance of planned ramp-down ($30 million) plus 6 months planned preservation ($18 million).)
Jan 87 - Restart	$36 million/yr	(Earned value of $24 million per year beginning in July 1986 to be credited against costs to complete.)
Cash Flow (minimum)		
CY 1985	$61 million	
CY 1986	$57 million	(Includes balance of planned ramp-down ($30 million), 6 months minimum preservation ($6 million), $13 million capital expenditures, and $8 million for ramp-down to minimum preservation levels.)
Jan 87 to Remobilization	$12 million/yr	
Remobilization Year	$46 million	(Includes $34 million for ramp-up plus $12 million for preservation.)
Funding		
Publicly-owned utility share	Bonneville rates.	
Investor-owned utility share	Bonneville rates.	

CONSTRUCTION

Construction Period	54 months
Cash Flow	
1st 12 months	$ 133 million
2nd 12 months	$ 373 million
3rd 12 months	$ 396 million
4th 12 months	$ 322 million
Last 6 months	$ 86 million
Total	$1,310 million ($1,056/kW)
Financing	
POU Share	Bonds at 9.2% plus 1% risk premium.
IOU Share	Similar to preservation financing.

Maximum sustainable capacity: Capacities and heat rates are from Pacific Northwest Utilities Conference Committee *Thermal Resources Data Base*. October 1984 (PNUCC, 1984).

Rated capacity: Capacities and heat rates are from PNUCC, 1984.

Minimum sustainable capacity: Capacities are from PNUCC, 1984.

Transition times: From PNUCC, 1984.

Operating availability: (See discussion provided in Appendix 6-I for WNP-1.)

Preservation shelf life: With the exception of exposed rebar, no significant deterioration appears to have been experienced at WNP-3. At current rates of corrosion, the most severely corroded rebar could be expected to last 16 years without exceeding allowable metal loss. Application of protective coatings would prevent further deterioration of rebar, and in any event the rebar could be replaced at relatively minor cost. The Council concludes that the project can be preserved for a minimum of 15 years (see discussion in this chapter). Long-term minimum level preservation of WNP-3 would likely require improved closure of the reactor building and the turbine building.

Preservation cash flow: The Supply System has provided cash flows for "currently planned" and "minimum level" preservation programs.

The planned preservation program, at $36 million per year, includes licensing and regulatory activities leading to "earned value" credit against costs-to-complete. Following completion of the currently planned ramp-down to about 400 staff by July of 1986, the planned preservation program would continue to restart of construction at a rate of $36 million per year. Earned value of approximately $24 million per year would begin to accrue about mid-1986.

The minimum level preservation program at $12 million per year contains no provision for ongoing engineering and licensing activities and would evidently forego certain record update activities and maintenance staffing. Additional demobilization and remobilization costs would be incurred. Approximately $13 million would be required to place Project 3 into a condition suitable for long-term low-manpower preservation. Twelve million dollars of this would be earned value. Additionally, incremental ramp-down costs of $8 million would be experienced due to additional staff layoffs, and additional ramp-up costs of $32 million would be required prior to restart of construction to restore engineering and licensing staff to planned preservation levels. The Supply System has recently reestimated the cost of minimum preservation to be $14 million per year.

Preservation financing: Funding of the Supply System share of Project 3 would continue from Bonneville rates. Bonneville is assuming the preservation funding of the investor-owned utilities' share of Project 3 in accordance with the WNP-3 settlement.

Construction period: The Council discussed with the Supply System the likelihood of maintaining the 54-month schedule, estimated by the Supply System. Learning that the critical path is hiring and training of operators, and considering the excellent construction rates achieved on Project 3 in the year prior to the decision to slow construction, the Council concluded that the schedule appears reasonable.

Construction cash flow: The Supply System has provided revised construction cash flows for the project. The project shows a modest decrease compared to earlier estimates. This is attributable to incorporation of earned value through January 1985; deduction of earned value activities through July 1986; minor scope changes; and use of consolidated construction methods using capped cost, risk-sharing contracts. The estimates to complete include contingencies of approximately 9 percent and incorporate known and probable changes resulting from pending regulatory actions.

Construction financing: Financing of the Supply System share of the project is assumed to be by bonds. Alternative financing by Bonneville rates was considered; however, in view of the considerable impact of rate financing on Bonneville rates, the likelihood of a prolonged preservation period (allowing time for the WNP-4/5 settlement to proceed), and equity questions regarding rate financing of capital investment, the Council concluded that financing should be assumed to be bonds. The investor-owned utilities' share of Project 3 is assumed to be capitalized at 50 percent debt and 50 percent equity.

A risk premium of 1 percent is added to all public and private debt and equity financing. This premium is based on statements by Seattle Northwest Securities Commission (financial advisors to the Supply System) and Salomon Brothers Inc.; Goldman, Sachs and Company; Merrill Lynch Capital Markets and Smith, Barney, Harris Upham and Company, Inc. (Senior Managing Underwriters). These firms concluded that the risk premium would not likely exceed 1/2 to 1 percent.

Termination period: As estimated by the Supply System.

Termination costs: As estimated by the Supply System.

Termination financing: Termination financing is assumed to be similar to preservation financing.

Fuel costs: Fuel cost estimates were provided to the Council by the Supply System and are based on operation at 65 percent capacity factor for a 40-year plant life. Project 1 bonding resolutions prohibit transfer of Project 1 fuel to Project 3 were Project 1 to be terminated.

Operation costs: Fixed operating costs are as provided by the Supply System. Variable operating costs consist of the federal fuel disposal charge. This latter charge is based on gross energy production and has been adjusted to represent costs based on net energy production.

Capital replacement costs: Capital replacement costs are as currently estimated by the Supply System.

Amortization life: The 30-year amortization life is based upon the recommendation of the Electric Power Research Institute and is consistent with values used by the Council for other resources. Actual bond maturity periods might vary.

Operating life: (See discussion provided in Appendix 6-I for WNP-1).

Cost escalation: Values for general inflation, capital and operation and maintenance are as adopted by the Council for the 1986 Power Plan. The Supply System recommended that the nuclear fuel escalation rate be equivalent to general inflation through 1993, citing the soft nuclear fuel market, and 1 percent real, thereafter. The Council concurs with this argument.

Chapter 7
Better Use of the Hydropower System

Introduction: The Regional Power System

The electrical power system in the Pacific Northwest is dominated by hydropower. The Northwest system is unique in the United States because of this characteristic. Currently the hydropower system produces approximately 70 percent of the total electricity used by the region. Even with demand growth at the Council's high level, hydropower would still produce almost half the region's electricity at the turn of the century.

There are two key characteristics to the Northwest hydropower system. First, it varies widely in annual energy capability, depending upon rainfall and the snowpack accumulated in the region each year. The average annual output of the hydropower system since recordkeeping began in 1879 (and including the effect of the Council's water budget) is approximately 16,400 megawatts. This is about 4,100 megawatts, or 33 percent, greater than the critical period energy capability. During a good year the annual capability can be as much as 50 percent greater than critical period capability. "Critical period" refers to that sequence of low water conditions during which the lowest amount of firm load can be carried. The energy that can be generated during the critical period is called "firm" energy. Energy that can only be generated when water conditions are both better than critical conditions and sufficient to refill system reservoirs is called "nonfirm" energy.

A second characteristic, equally important, is that the variation within the year can be even greater than the variation across the water conditions from year to year.

Over half the annual firm energy from the Northwest hydropower system comes from natural streamflows; less than half comes from reservoir storage. Figure 7-1 shows the variation in natural streamflow at The Dalles on the lower Columbia. The relatively low amounts and low variability of natural streamflows between August or September and the onset of the spring runoff in March or April are important in considering the risks that can be taken in using the reservoir storage. (The 10, 25, 50, 75 and 90 percent lines represent percentage of time the flow is equalled or exceeded on that particular day. These lines are based on ten-day mean values.)

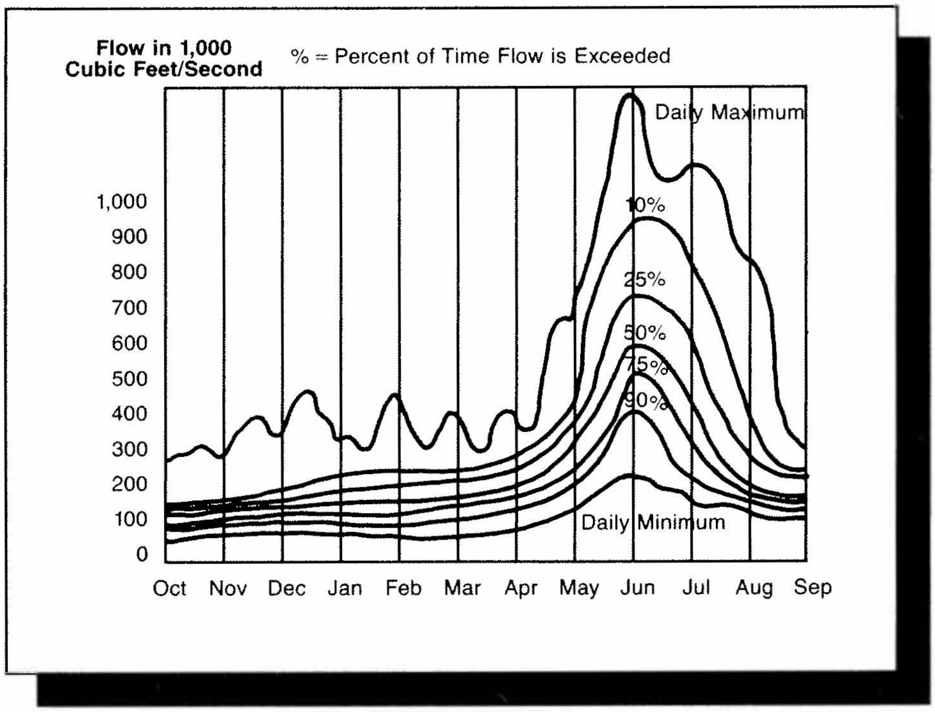


Figure 7-1
Average Daily Columbia River Natural Flow at The Dalles, Oregon

Historically, the Columbia River discharges about 73 percent of its natural runoff between April and October, and only 27 percent in the November to March winter period when electrical loads are highest. This ratio of 73:27 has been altered by upstream storage projects so that the regulated flow matches the pattern of the region's loads. However, the river and its storage system are managed for multiple purposes besides electricity generation. Flood control, irrigation, fish and wildlife requirements, recreation and navigation may limit the availability of upstream storage for power generation.

The reservoir storage itself is significantly limited. A large part of the hydropower system water supply comes from the snowpack in the upper Columbia and upper Snake river basins, in the mountains of British Columbia, Montana and Idaho. However, only 40 percent of even the average January to July runoff is storable in the system's reservoirs. This means large portions of the total annual water supply come during the spring runoff from April through July. Moreover, most of the water from the melting snow must pass through the generators or over the spillways if it cannot be used in the springtime, because it cannot be stored for use in the following fall and winter when demand is higher.

Figure 7-2 shows the amounts of electrical energy available at various probability levels above the critical period quantities over the 102-year historical record. The variability of the hydropower system has major effects on the economics of other existing and new resources, because it influences the way they operate.[1]

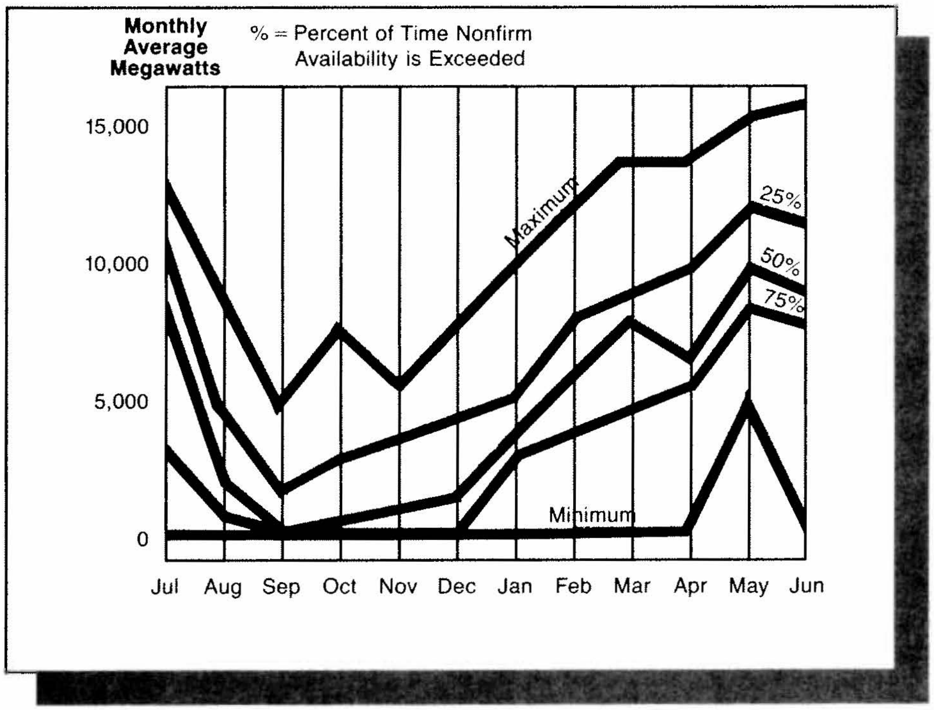


Figure 7-2
Probability of Nonfirm Energy Availability

Critical Period Planning

Power system planning is currently conducted on a critical period basis. To determine the total amount of energy resources required, it is assumed the hydropower system will not produce more energy than it did during the worst conditions of the past. Critical periods run from the beginning of the reservoir drawdown season in August or September to the beginning of the refill season—the onset of the spring runoff in March or April. The number of annual cycles of sequential dry years the system can support is a function of the amount of reservoir storage and generating resources (both existing facilities and new ones that come on-line during the period being studied). Currently, the worst conditions are either the four-year sequence from August 1928 to March 1932, or the more severe but shorter two-year sequence from September 1943 through April 1945.

However, the common reference to a four-year critical period in regional planning documents does not mean that the region will necessarily have four years to work out problems before the system's reservoirs are empty. An exact repetition of the water sequence from 1928 through 1932 is not required for the system to be in trouble. The wet fall of 1976 left reservoirs high enough to sell nonfirm energy, but the following spring runoff was the worst since recordkeeping began in 1879. By November 1977, reservoirs were within five months of going empty under continued low-water conditions.

Planning to critical water as described above does not guarantee that demands will always be met. Even worse water conditions could occur. The Northwest Power Pool uses the 1928-78 water sequence for planning, and the critical period currently being used is the worst four-year, two-year or occasionally three-year sequence of flows during that period.

To determine if that period is representative of the longer term, University of Washington researchers made an independent statistical examination of the complete historical record from 1879 to the present. They concluded that the currently used critical period is not an unlikely event; in fact, it is by no means the worst possible sequence that could occur. For instance, a two-year sequence worse than the 1943-45 water sequence (two-year critical period) could occur with approximately a 2.3 percent probability and would have a recurrence interval of approximately every 45 years. Moreover, approximately 16 percent of the years in the 102-year record start with reservoirs less than 95 percent full, indicating potential critical-water problems for system operators. There will generally be no nonfirm energy in the years that do not refill, except for that generated by water budget[2] flows from mid-April to mid-June.

Within the confines of system planning, the hydropower system can take some advantage of the increased energy expected above that available during the critical period. This flexibility in the hydropower system's operation means that, although the total number of megawatts of energy resources planned will be determined by the critical period energy capability, the kinds of resources used should take into account the various water conditions and the seasonal pattern of water availability.

Because the hydropower system's storage capability is only about 40 percent of the average annual runoff, the system's flexibility is limited. Moreover, the Canadian reservoirs, which constitute a major portion of the system storage capability, are only available to U.S. operators for limited use. The ability of the system to take advantage in the fall of the large quantities of nonfirm energy expected in the spring is limited by the risk that system operators are willing to take before the spring runoff begins. The maximum drawdown of the reservoirs for energy generation in the fall and winter is limited by the natural streamflow during the one-year critical period, 1936-37, the lowest single natural streamflow in the historical record. The hydropower system ran against this one-year critical period until the late 1960s when the Canadian treaty projects increased the storage capability of the system and increased the length of the critical period beyond one drawdown season.

Increasing drawdown in the fall and winter to the limits allowed by the 1936-37 critical period adds approximately 1,300 megawatts to the hydropower system's average firm energy capability over that eight-month period before the first year's runoff. This additional drawdown may be generically called "provisional draft," because it is borrowed from the following spring against the expectation of greater than critical runoff from the snowpack. Going beyond 1,300 megawatts moves the risk of emptying the reservoirs one year forward in time, from before the second year's runoff to before the first year's runoff. In recent years, up to about 1,000 megawatts of additional first-year drawdown were taken. Over the last several years, however, in response to the water budget and to utility efforts to maintain the high drawdown levels, the Corps of Engineers and the Bureau of Reclamation have sought to maintain reservoir refill levels. In order to protect these levels at the end of the first year, the Corps and Bureau have instituted further drawdown limits that restrict this "provisional draft" to approximately 300 megawatts in the first year.

The hydropower system has one additional characteristic that is very important for the analysis of resources. The total amount of water available to the system establishes a limit to the amount of energy that can be produced. In a thermal-based power system, energy is not limited. If energy demand exceeds projections, it can still be met, if adequate capacity is available, simply by providing more fuel to the power plants. In such a system, capacity is the most critical component, and providing sufficient capacity is the major consideration in generation planning. Conversely, in the hydropower system, if energy loads exceed the firm energy capability of the system during a period of adverse flows, there is no way in which demands can be met, regardless of how much installed hydropower capacity is available. Hence, firm energy capability is the critical quantity in planning the hydropower system.

In the Pacific Northwest power system, hydropower plants have been expanded to ensure that system peak loads can be met, that system capacity reserves will be adequate, and that a substantial portion of the nonfirm energy potential can be used. However, this capacity would be of limited usefulness unless system firm energy resources were sufficient to meet energy demand. Although the regional power system is evolving from a hydropower-based system to a hydrothermal system, hydropower will continue to be the dominant source. The experience has been, and further investigation is indicating that it will continue to be, that the binding constraint on the Northwest power system is the total firm energy load rather than the maximum peak load.

Nonfirm Strategies

Figure 7-2 shows the general distribution of nonfirm energy in time. The rights to nonfirm are roughly a function of ownership or contractual rights to output of the dams and are generally distributed as follows: 67 percent Bonneville, 10 percent generating public utilities and 23 percent investor-owned utilities. There are three major uses of the region's nonfirm energy at this time. The first is direct service load. The primary user is the first or top quartile of the direct service industry load which is served by nonfirm energy. There are also several smaller nonfirm loads such as electric boilers in industrial plants. The second major use is sales to extraregional markets, primarily California. The third major use is to shut down thermal plants in the Northwest to save the fuel cost.

The large amount of hydropower available in most years, in excess of critical period amounts, offers the Northwest a resource which could be put to better use than it has been previously. Council studies for the 1986 Power Plan assessed the risks and benefits of different strategies for doing this. This chapter discusses these strategies for using more nonfirm energy to meet some of this region's firm loads:

1. Intermittent use of energy imported from other regions, or of combustion turbines to back up the nonfirm energy;

2. Reducing demand for electricity when necessary, through rate surcharges or contract arrangements including arrangements with the direct service industries.

The benefit expected from these strategies would be regional savings due to reduced need for new thermal plants. Using about 700 megawatts of combustion turbines rather than the same amount of coal plants, for instance, could save the region approximately $175 million. The 700 megawatt value was derived using the Decision Model, which showed additional scheduling benefits not captured in the System Analysis Model. These savings take account of the existing uses of the nonfirm power.

The Council believes there is potential value in using more of this nonfirm energy in the region to serve firm loads. Several strategies could be used in conjunction with nonfirm energy to meet firm loads. This section of the plan will describe several of them.

The Council recognizes that these strategies will affect existing uses of the nonfirm energy; this has been considered in the analysis done by the Council. For instance, increased use of nonfirm energy to meet firm loads would decrease the amount of nonfirm energy that could be sold to the Southwest. While sales of nonfirm to the Southwest under the new Bonneville Intertie Access Policy have achieved higher prices than previously, it is not clear that market conditions in California, including competition from the other Southwest states, will allow much of an increase in prices from now on. Other existing uses, such as service to the direct service industries and displacement of thermal plants, have also been taken into account.

System Reliability and Its Implications

An essential beginning to making better economic use of nonfirm energy is to examine the power system's major reliability criterion, critical water. This examination gives insights into the system's current reliability level and the effects of changes in that level. This information will suggest which strategies might be more attractive for more economic use of nonfirm energy. Following this discussion, several strategies will be discussed in depth.

The Council reviewed the effects of the critical water criterion in the issue paper entitled "Critical Water Planning." This discussion looks at some non-dollar measures of the costs of relaxing the critical water criterion, such as the frequency and magnitude of failures to meet load, effects on reservoir refill and effects on the water budget.

Summary of Results

The results of the review suggest several conclusions.

The first conclusion is that critical water is a somewhat arbitrary point on a continuum. It does not yield 100 percent reliability. It is important and is used as the base in the following discussion because it is embedded in a number of contracts and institutional arrangements, *not* because it is completely reliable.

The second is that critical water is probably too stringent a criterion against which to operate the system. The hydro system could reasonably provide another 500 megawatts of energy for firm loads without backup generation before it is significantly stressed. A further 500 megawatts would not impose insurmountable problems but would be the limit of reasonable operation. The major caveat to this conclusion is that changing the critical water standard will significantly affect service to nonfirm loads such as the direct service industry top quartile, especially if the interruptible loads are increased. They are direct competitors for the water. Moreover, combustion turbines can operate economically up to the level of about 700 megawatts in the absence of firm deficits. The decision as to whether it is desirable to move off of critical water is very sensitive to the imputed cost of meeting or curtailing load, particularly top quartile loads. The Council has maintained the critical water standard in its analysis for the 1986 plan.

The third conclusion is that if the system were planned to operate using nonfirm energy to meet firm loads, some institutional mechanisms would need to be put in place to restrict or meet load during periods of extended low streamflow. This could be quite complicated institutionally, especially to the extent it involves adjusting loads down to available resources.

Moreover, as was noted during public comment on the original issue paper, the modeling may not convey the extent of this difficulty. System managers would naturally be risk conscious. They would call for load restriction measures in advance of actual need, with the expectation that longer, smaller restrictions would be preferable to shorter, more severe restrictions. Because of the uncertainty in the fall about the spring runoff, this action would often lead to restrictions that would not be justified by later events, just as most people's expenditures for home fire insurance are never "justified" by a fire. The model was risk neutral, in the sense that it simply failed to meet load, but only when resources were actually not available.

The fourth conclusion is that if the region were to plan to operate using nonfirm to meet firm loads, it would probably be wiser to limit the adaptive changes in system operation to avoid too much risk.

The fifth point of the analysis suggests that planning to take more risks with the hydropower system for higher and less likely loads would probably pay off. This conclusion stems from the Council's Decision Model, which shows the appropriate build level for resources is about the mean value, 50 percent of the load range, rather than some significantly higher level. In this model the costs of operating to higher than expected loads, given the build level, are weighted by the low probability of the loads.

Finally, a cautionary note is needed about the institutional matrix. Critical water is bound up in a number of institutions and will need to be examined more extensively by other parties before there is a possibility of widespread acceptance of any departures from it.

Background

In the 1983 plan the Council assumed critical water as the basis for all its studies, although it indicated it intended to review that decision for the 1986 plan. Since then, studies by other agencies have skirted the issue of critical water planning, while not addressing it directly. Bonneville did such a study as part of its 1984 resource strategy decision not to budget for options against high load growth. That study did not plan resources to meet firm loads in high load growth cases, but assumed that all curtailments indicated by the System Analysis Model were met by high cost purchases from some undetermined source.

For clarity, this analysis assumes a situation where no emergency resources are available to meet load. It focuses on potential failures to meet load. If emergency resources are presumed to be available, they can be used to meet the load or as a base from which further steps away from critical water can be taken. The value of combustion turbines and the availability of other backup resources are explored later in this chapter. Finally, this discussion is not a study of potential capacity problems but only energy problems.

Analysis

The analysis looked at the results from just one operating year (rather than the usual 20 years) and at five levels of loads and resources—a balanced case, and departures from critical water ("firm deficits") of 500, 1,000, 1,500 and 2,000 megawatts—to show in detail the effects of going off critical water by varying amounts. As described above, the system is operated in relation to the "critical period"—the historical period in which the lowest water sequences occurred. Usually the critical period is either four or two years (42 months or 20 months) long. The shorter period had more severe droughts than the longer. The two periods are almost identical in the amount of hydropower generation (Firm Energy Load Carrying Capability, or FELCC) they can produce from natural flows plus complete draft of the reservoirs from full to empty.

A two-year critical period is more likely, easier to conceptualize and, for convenience, was the period modeled in the System Analysis Model. Any operating year which starts with reservoirs full in September is a "first" year for operating purposes. Other years are "second" years. The single operating year for which results are shown below was modeled as the third operating year in a sequence of four. Depending on the water conditions drawn by the model, it either started full or not full and thus sometimes was a "first" year and sometimes was a "second" year. Thus, if the four water conditions drawn for the four-year sequence were all good, the system refilled at the end of each year, and each year was a "first" year. If the four water conditions were bad, the system started full with a "first" year and failed to refill three times, giving three succeeding "second" years.

Most of the studies used three different operating strategies that successively increased the adaptability of the system to operate with a firm deficit. The first strategy embodies the provisions of the Pacific Northwest Coordination Agreement,[3] which do not allow borrowing of water from later years of the critical period to cover firm deficits in the first year. The second strategy allows such borrowing but maintains the current restrictions imposed by the Corps of Engineers and the Bureau of Reclamation on maximum hydropower energy generation in the first year of the critical period. These restrictions limit the amount of "FELCC shift" or borrowing of water from later years of the critical period to the first year. The third case allows such borrowing and increases both the first year and annual generation limits by the amount of the firm deficit. This strategy acts as though there actually is more water in the river than before and goes the furthest in treating firm deficits as though they are balanced situations.

The first of the major variables summarized in this section is firm load curtailment. Firm load generally includes three quartiles of the direct service industry load. If the top quartile was previously served by borrowed water in the fall, there could be a restriction right against the third quartile, in which case it would not be considered a firm load, but rather a proxy for the top quartile. (Whether this occurs or not depends on whether the reservoirs started full and on subsequent water conditions.)

The second major variable is the direct service industry top quartile service. The top quartile is served by borrowed nonfirm in the fall and by priority access to nonfirm in the spring. It is particularly vulnerable to changes in the reliability level, since firm load deficits have a higher priority than nonfirm and because the borrowing for fall service is contingent on prior reservoir refill.

The third major variable is system refill. This is particularly of interest to the Corps of Engineers and the Bureau of Reclamation, the owners of the major U.S. storage projects. They are concerned that some of the multiple purposes for which reservoirs are operated, such as summer recreation, would be jeopardized by more frequent failures of the reservoirs to refill.

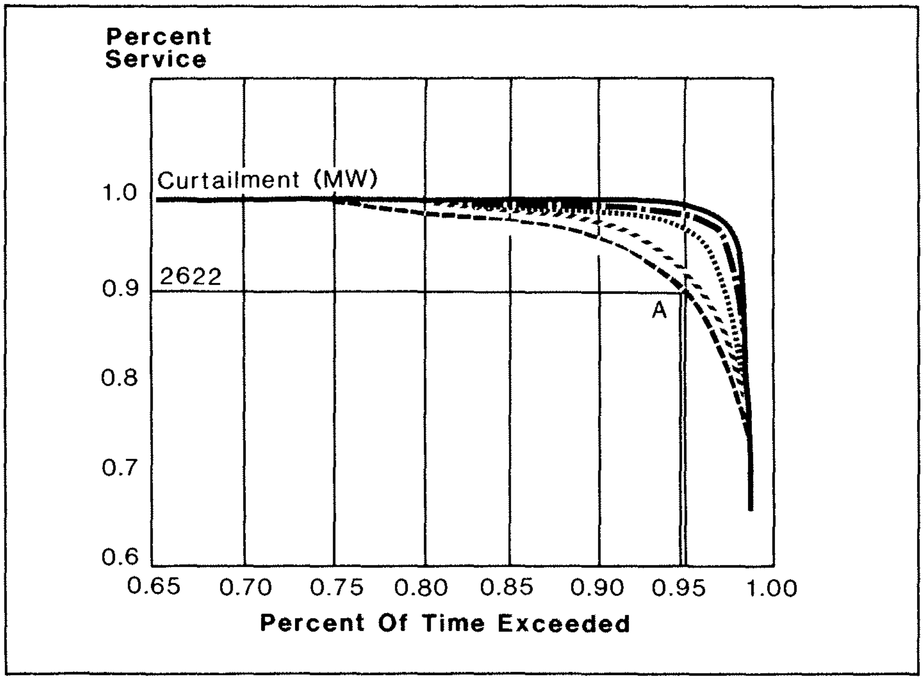
The fourth major variable of interest is the water budget flows for fish in the spring.

The results for various indicators of interest are plotted in Figures 7-3 through 7-14. Each figure is described below. The distribution of the results from 500 simulations is presented in a duration plot, a description of which follows (refer to Figure 7-3, "Firm Load Service").

A plot of ideal operation, showing no failures to meet load, would go straight across the top to 100 percent on the horizontal axis and would not drop at the right-hand end. The area above and to the right of the lines represents failure to meet load; the larger this area is, the more frequent and severe are the failures. Point A, the intersection of 0.9 on the vertical axis, 0.95 on the horizontal axis and the line labeled "Deficit: 2,000" in the legend, shows several perspectives on operating with a 2,000 megawatt firm deficit. First, at least 5 percent of the time, the average seasonal curtailment is greater than 10 percent of firm load (about 2,600 megawatts in the relatively high load used for the analysis). Viewed another way, 95 percent of the time the average seasonal curtailment is less than 10 percent of firm load and the load service is greater than 90 percent of firm load.

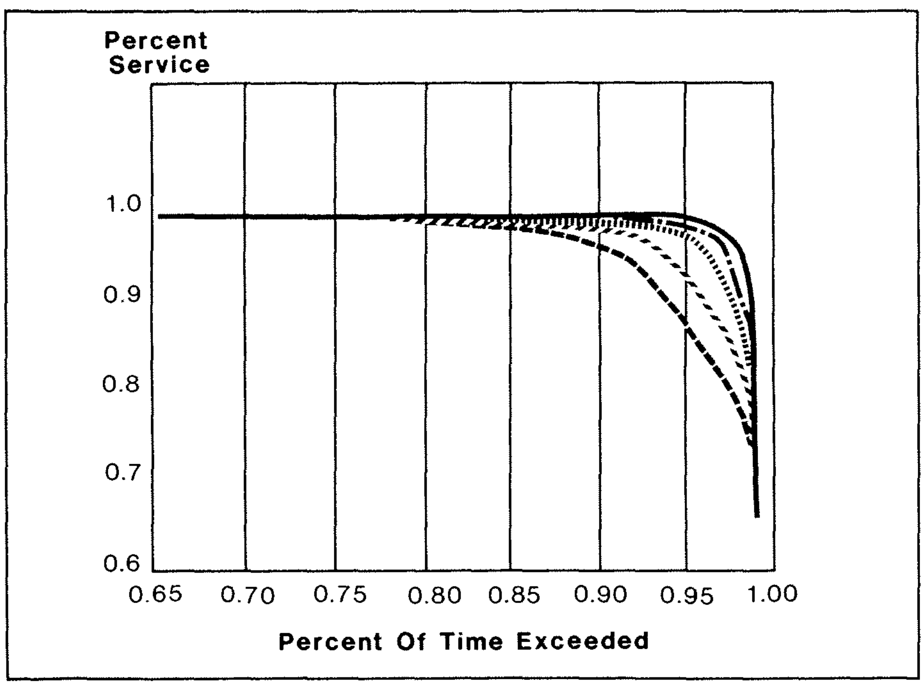
Curtailments are calculated as averages over a four-month season. It is important to note how this averaging affects the results. Averaging the original monthly results tends to treat curtailments caused by failures of thermal plants more realistically, since some of the results could be mitigated in the short term by drawing more water from the reservoirs. However, the averaging process masks potential large curtailments caused by emptying the reservoirs. The lower the reservoirs are, the more the system depends on natural flow, i.e., rainfall and snowmelt, to meet load. In these cases, large month-to-month curtailments are entirely realistic. This latter situation becomes more likely as the region departs further from critical water.

Refill plots tally July 31 reservoir elevations, and fish flow plots tally average May flows. Note that the scales in the various graphs differ from each other; most scales are truncated above zero. Figure 7-7 shows some perspective on the firm curtailment plots by using a 0-100 percent scale rather than the smaller scale employed for clarity in the earlier figures.



0 — 500 — 1,000 — 1,500 — 2,000

Figure 7-3
Firm Load Service—Current Rules



0 — 500 — 1,000 — 1,500 — 2,000

Figure 7-4
Firm Load Service—Shift for Deficit

The balanced case is not a guarantee against failure to meet load, as can be seen from the plot. This is a function of several things. First, some load uncertainty around a forecast load is realistic and is modeled in the System Analysis Model. Second, in planning, an expected availability for thermal plants is used. The model treats plant availability realistically as a random variable, with a distribution of possible states each month. Third, and importantly, critical water is defined to be the worst *historical* water sequence, not the worst possible water sequence.[4] The System Analysis Model allows repeated and out-of-sequence selection of water years, which simulate this effect.

Figure 7-3 has been described above. It shows that the curtailments under a 500 megawatt firm deficit are not very different from those under a balanced situation. The differences start getting more significant above 1,000 megawatts.

Figure 7-4, plotted on the same axes as Figure 7-3, shows little difference using a slightly more flexible operating strategy.

Figure 7-5, again on the same axes, shows the results of a considerably more flexible operating strategy. With this strategy, which attempts to operate to a firm deficit as though the system were in balance, more nonfirm sales are made in the fall than in the previous two examples. Both the frequency and the magnitude of the subsequent failures to meet load increase. This result shows up when the lines shift down toward the lower left corner of the plot. In general, the annual nonfirm sales are not larger because the increase in fall sales in good years is completely offset by the decrease in winter sales in bad years. This does not appear to be a good operating strategy for dealing with the deficits. Under repeated poor water conditions it can lead to empty reservoirs at the time of the region's winter loads, which are the highest of the year.

Figure 7-6 directly compares two operating strategies for a 500 megawatt case. The first strategy is that shown in Figure 7-3, characterized as "Current Rules," while the second is a hybrid between the second and third strategies described above. It allows the borrowing of water for deficits and an increase in the maximum first-year hydropower generation without attempting to operate the system completely to a larger amount of hydropower generation than can be met under critical water. This plot shows this operating flexibility decreases the magnitude and duration of the small curtailments but increases that of the large curtailments. By drafting reservoirs deeper in the first year of the critical period, early curtailments are avoided. However, this occurs at the expense of larger curtailments later, in those cases when reservoirs fail to refill followed by poor water conditions.

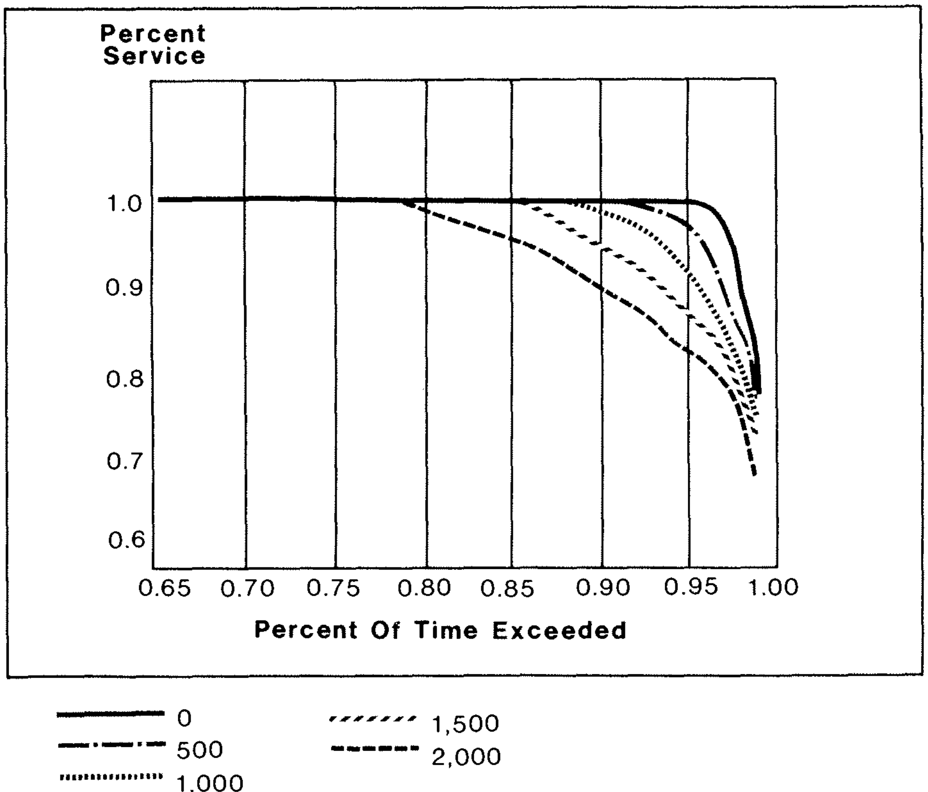


Figure 7-5
Firm Load Service—Shift for Deficit
Full Adjustment to Annual and 1st Year FELCC

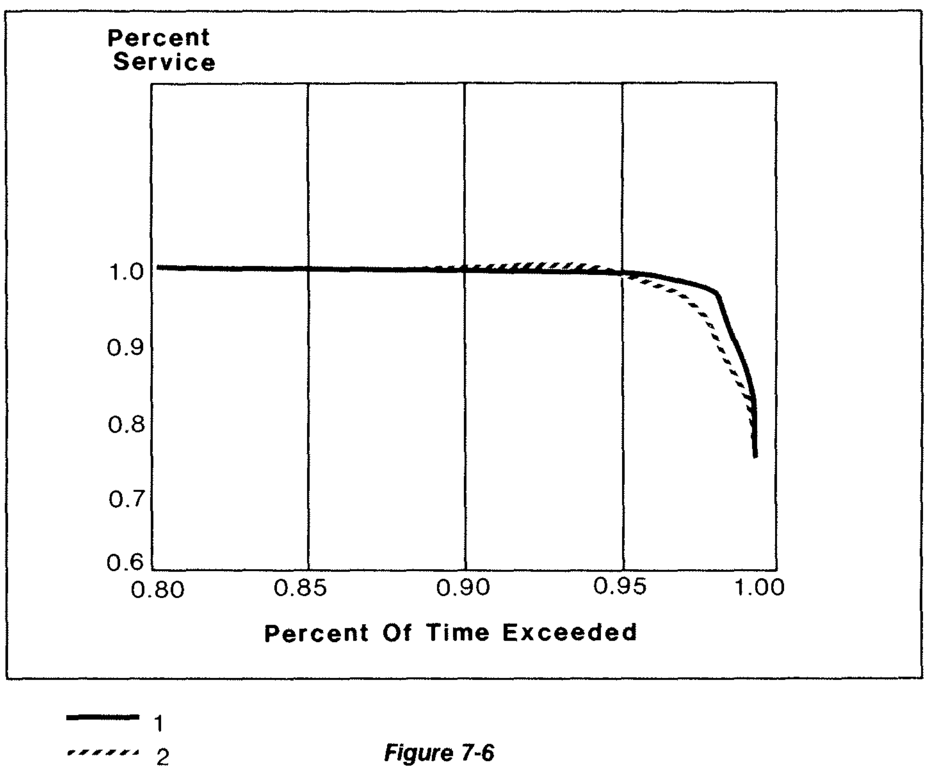


Figure 7-6
Firm Load Service—Current Rules
(1) Shift for Deficit + 500 MW 1st Year FELCC, (2) 500 MW Firm Deficit

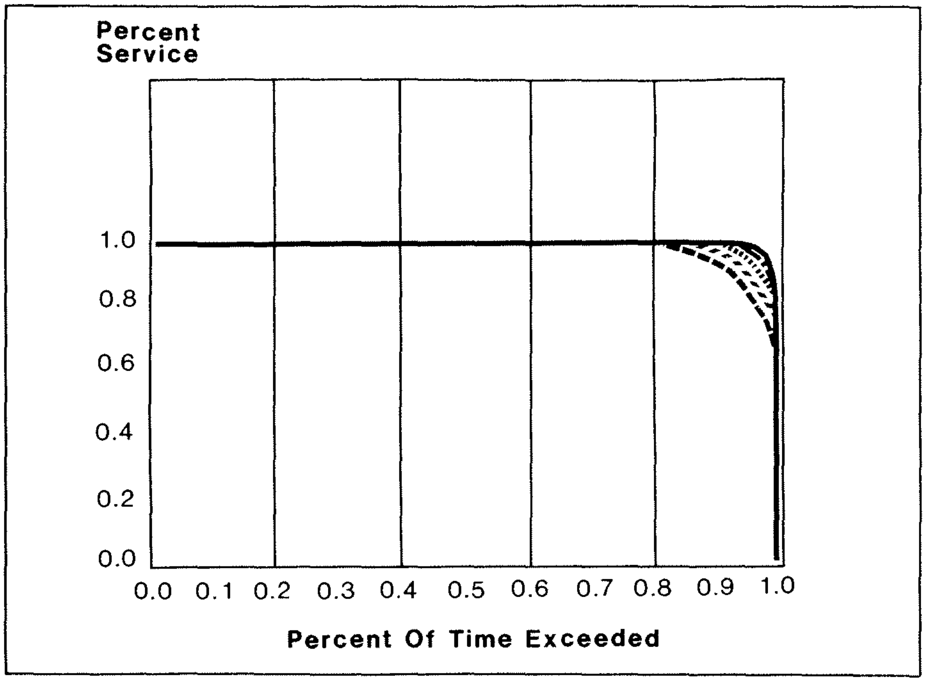


Figure 7-7
Firm Load Service, Current Rules (Full Scale)

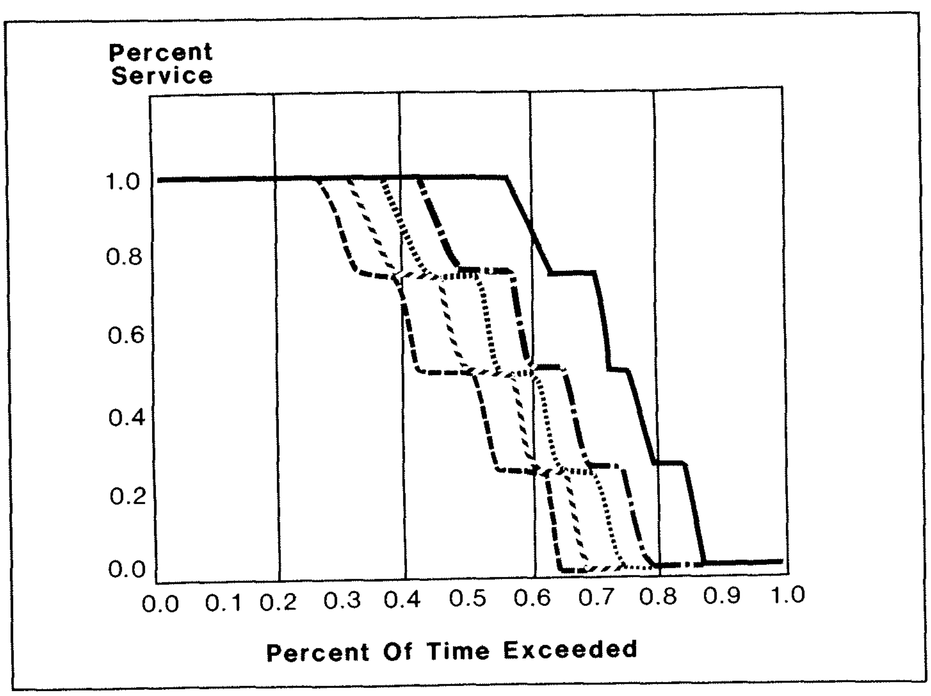


Figure 7-8
Top Quartile Service

Figure 7-7 puts the previous figures in perspective. It is simply a replotting of the data from Figure 7-3 onto axes that run from 0-100 percent rather than the close-up views in the previous figures.

Figure 7-8 shows annual average service to the direct service industry top quartile on a full scale of 0-100 percent under the base operating strategy. The step characteristics of the data are probably due to the model's logic, which serves either all or none of the top quartile for a season, depending on water conditions. This plot clearly shows how top quartile nonfirm service degrades with increasing levels of firm deficit.

Figure 7-9 shows another indicator of interest, system refill. This is a plot of July 31 reservoir contents under the base operating strategy. It suggests there is not much impact on system reservoirs when deficits remain under 1,000 megawatts.

Figure 7-10 shows the impact on system reservoirs under the third operating strategy, complete adaptation to firm deficits. These results begin to show significant changes from the balanced case even at the 500 megawatt firm deficit level.

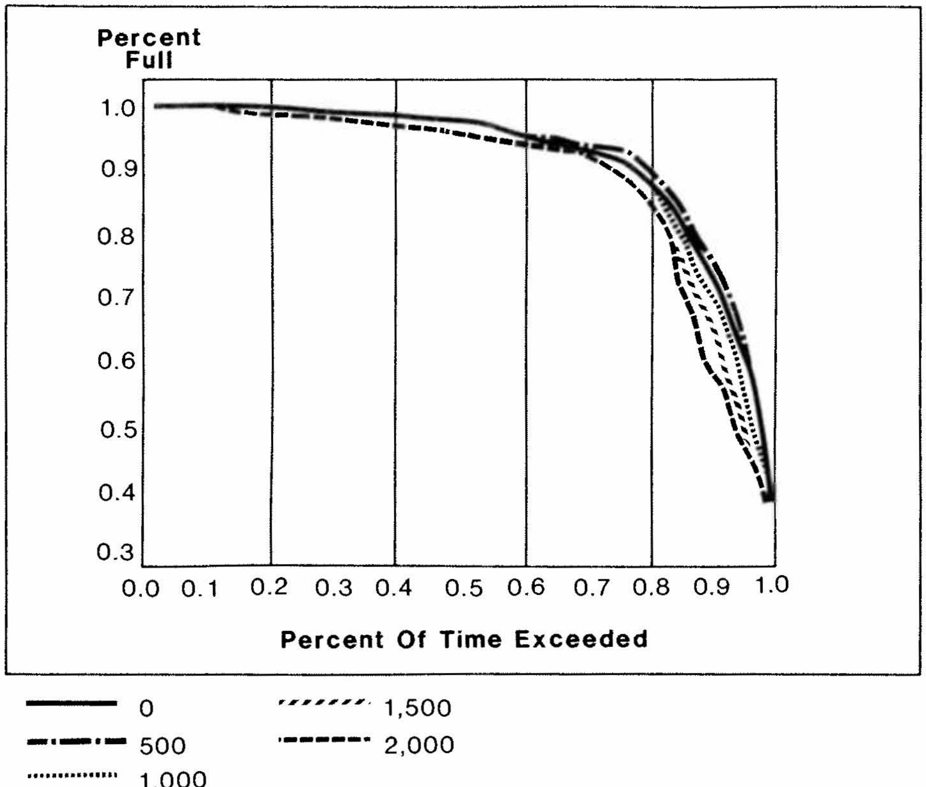


Figure 7-9
System Refill

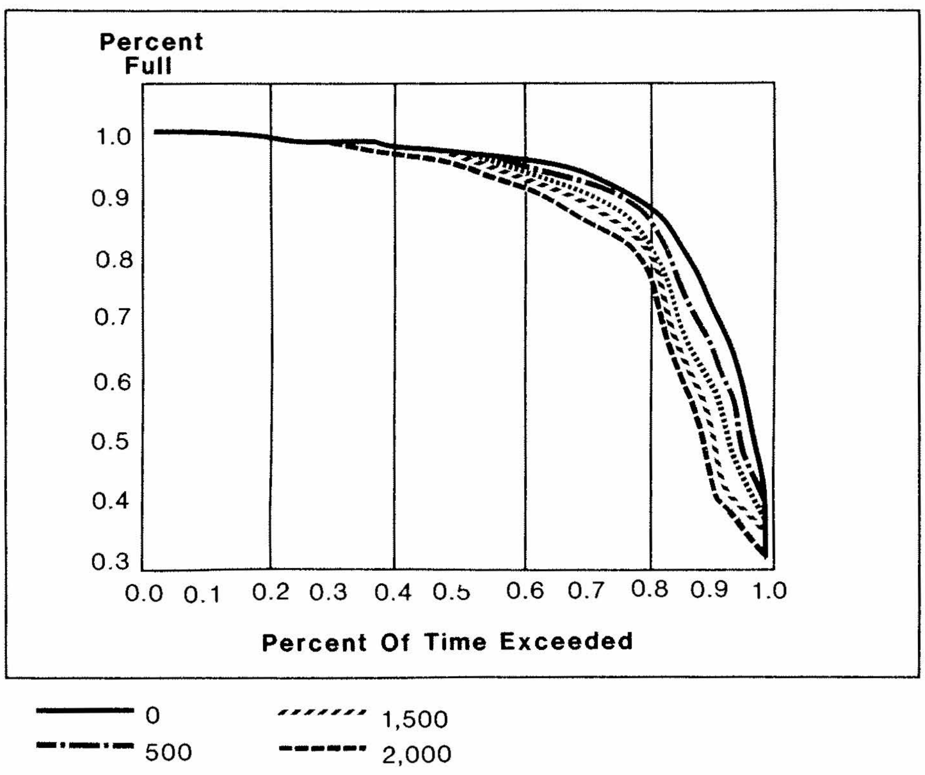


Figure 7-10
System Refill, Shift for Deficit
Full Adjustment to Annual and 1st Year FELCC

Figures 7-11 and 7-12 show the fish flow at the two check points during May under the base or "Current Rules" strategy. The horizontal lines indicate the level of the water budget. The increased firm deficits appear to have little effect at Priest Rapids and some effect at Lower Granite only above the 1,000 megawatt deficit level. It should be noted that the lower limit of the flows in these studies is the natural flow. If the water were used to refill reservoirs for future firm loads, as is likely, the natural flow would not be simply passed and the effects on fish migration could be much more severe. While the water budget has a higher priority than refill in the Fish and Wildlife Program, the program did not contemplate large firm deficits at the time it was adopted.

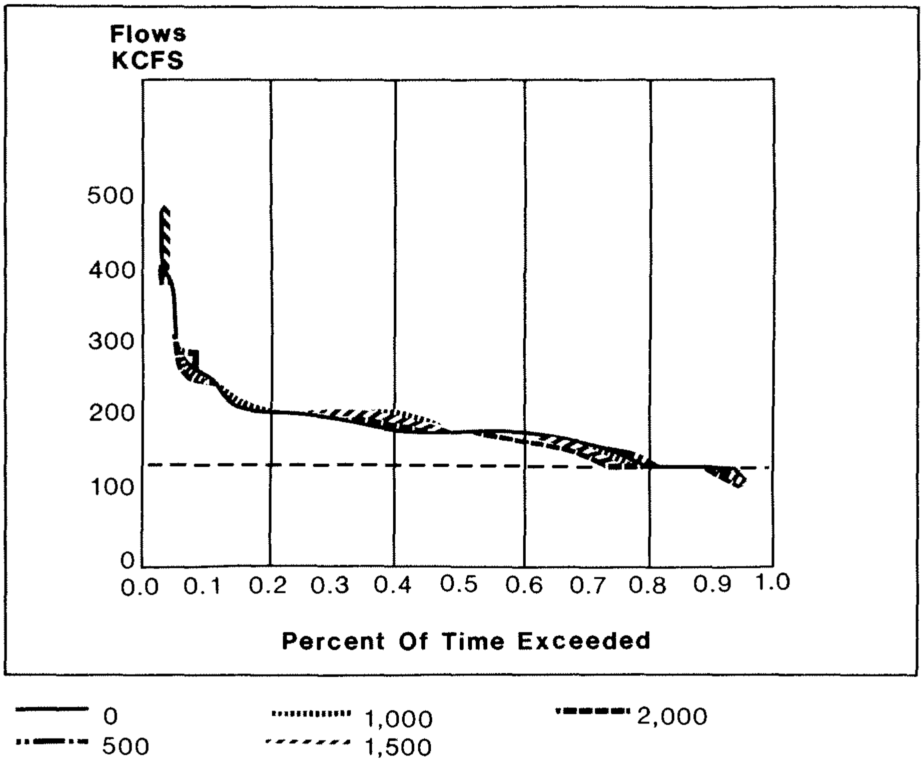


Figure 7-11
Priest Rapids Flow

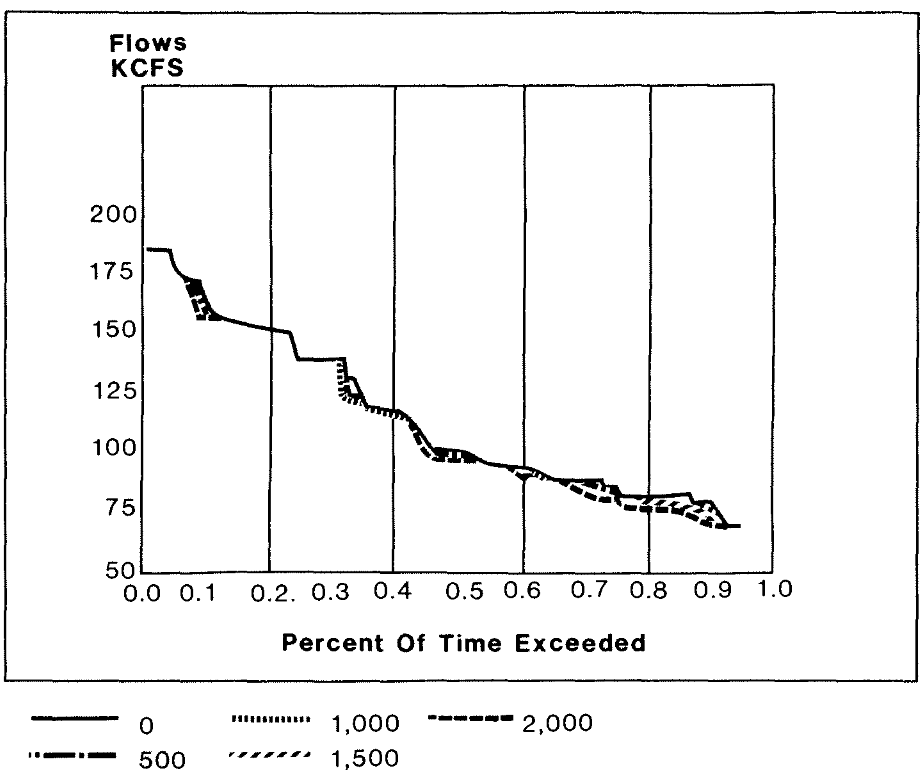


Figure 7-12
Lower Granite Flow

Figures 7-13 and 7-14 show the same thing for the fully adaptive third strategy. While the degradation remains small for Priest Rapids, it becomes more severe even at the 1,000 megawatt level for Lower Granite.

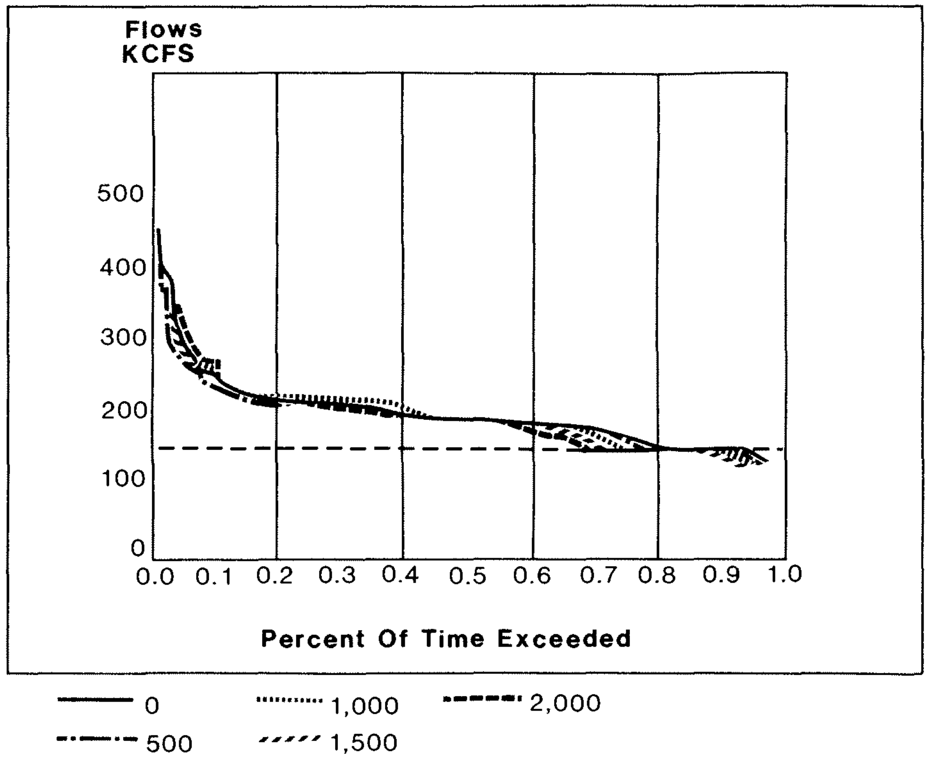


Figure 7-13
Priest Rapids Flow, Shift for Deficit
Full Adjustment to Annual and 1st Year FELCC

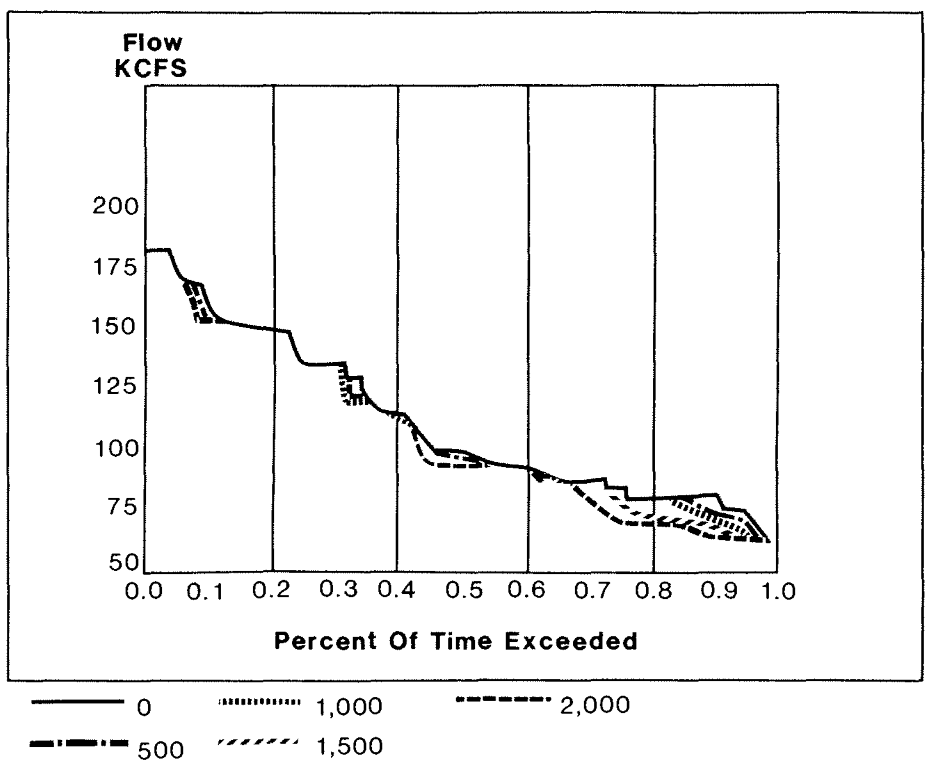


Figure 7-14
Lower Granite Flow, Shift for Deficit
Full Adjustment to Annual and 1st Year FELCC

Conclusions

Several conclusions can be drawn from the plots. For a 1,000 megawatt firm deficit, the firm curtailments differ substantially from the balanced case. With increasing levels of firm deficit, the direct service industry top quartile service degrades seriously. There would be a major incompatibility between any plans to increase the interruptibility of the direct service industries and go off critical water at the same time. System refill begins to be affected between the 500 and 1,000 megawatt level, especially if steps are taken to operate the system with the deficits.

The ability to meet fish flows is apparently not seriously affected by the increased firm deficits, unless a complete adjustment of operating procedures is made, although this result needs further examination. The analysis does not include the effect of imposing additional firm requirements for fish passage spill. Such potential requirements are assumed to be interim measures only. Finally, although additional operating flexibility (the third strategy described above) would seem to be an advantage given operation to firm deficits, it probably is not. A complete adaptation increases curtailments, decreases the probability of refill and probably adds little nonfirm revenue, although there may be other operating strategies that would be more effective. Even a partial adaptation appears to increase the magnitude and frequency of large curtailments while decreasing that of the smaller and less serious curtailments.

Institutional Issues

Formal departures from the critical water standard, to the extent they demand different operating procedures, would involve changes to the Coordination Agreement and probably the Canadian Treaty. Informal departures may not, although the extent of departure would depend on mutual acceptability to all parties, including the reservoir owners.

The analysis has generally assumed current flow requirements for downstream fish migration. There is currently a rough working agreement among the entities responsible for fish, power and reservoir conditions over the use of the water. Major policy shifts toward operating with firm deficits could require renegotiation of that rough agreement.

The distribution of the water in the region would make the situation more complex. Bonneville and the generating public utilities have approximately 75 percent of the nonfirm energy in the region, but the investor-owned utilities are expected to be deficit first. The match of the resource to the load is not particularly good. This issue is discussed further in Volume I, Chapter 1.

In addition, the Corps of Engineers and the Bureau of Reclamation have different perspectives on the costs and benefits than the utilities and the region's ratepayers. They are generally concerned with the refill of the system reservoirs for non-power reasons. While the deficit operating levels proposed in this section are not severe in their impacts on system refill, the Corps and the Bureau have not been willing to make many concessions on earlier issues involving refill of their reservoirs.

Strategies for the Increased Use of Nonfirm in the Region

There are two major kinds of strategies to achieve increased use of nonfirm energy in the region. The first uses generating resources with low capital cost and relatively high variable costs that can be displaced by nonfirm energy whenever it is available. In this case, the net cost to the region would be a relatively low fixed cost and some weighted average of the high variable cost and the lost nonfirm sales revenue. The example of this strategy examined in detail by the Council is the use of additional combustion turbines in the region. Other examples would be high-cost purchases from out of region—for example, British Columbia or California—to back up nonfirm energy.

The second approach involves reductions in demand for electricity whenever the nonfirm energy is not available. This kind of approach could involve either temporary rate increases to reduce demand or a contractual right to reduce service in exchange for a payment. Increasing the interruptibility of the direct service industries is an example of this approach.

The Council has done its resource portfolio studies for the draft plan using combustion turbines as the only nonfirm strategy. However, the Council believes that any combination of several uses of nonfirm to meet or reduce firm loads would be economical up to a maximum of about 700 megawatts.

Backup Generation: Combustion Turbines and Extra-Regional Purchases

The Council has analyzed the use of combustion turbines in detail during the preparation of the 1986 plan. This analysis was originally presented in an issue paper on "Combustion Turbine Cost Effectiveness." Since the original issue paper was completed, some of the cost and financing assumptions for coal plants and combustion turbines have been revised. Also, the System Analysis Model, used for this analysis, has been modified to assure a more accurate simulation of the power system. Because of these changes in assumptions and refinements in the model, the cost effectiveness of combustion turbines has been re-examined.

Background

One of the major issues of the 1983 plan was the use of combustion turbines in the region's resource portfolio. The benefits of combustion turbines can be evaluated in two ways:

- their cost effectiveness based on system operation; and
- their value in planning as a hedge against long-term load uncertainty.

In the 1983 plan, the Council recommended that combustion turbines be included in the resource portfolio only as a hedge against higher-than-expected rates of load growth. At that time it was unclear whether combustion turbines were cost effective on an operational basis. The Council did recognize, however, that short lead-time resources have a significant value in planning for unexpectedly high load growth. They recommended, therefore, that 1,050 megawatts of combustion turbine energy be included in the medium-high and the high load forecast scenarios.

Since the 1983 plan, fuel prices and their assumed real escalation rates have fallen, as have capital cost assumptions and their escalation rates. Because of these changes in assumptions and changes to the simulation model used for the analysis, the cost effectiveness of combustion turbines on an operational basis has been re-examined.

Analysis

The cost effectiveness of individual resources can only be determined by considering how they integrate with the entire system. Cost effectiveness is a relative quantity—that is, a resource is cost effective if it produces power at an "incremental system cost" less than another resource. As was done for the 1983 plan, the cost effectiveness of combustion turbines was determined by comparison to coal plants.

The System Analysis Model, used for the analysis, probabilistically simulates the operation of the region's power system to meet loads. For this analysis a comparison was made between two systems, one which met load growth with coal plants and the other which met load growth with combustion turbines. Total system costs were compared to compute net benefits. The comparison included the benefits of current uses of nonfirm power. This analysis was done for different levels of installed resource energy in order to determine the maximum amount of combustion turbine energy to include in the resource mix.

Table 7-1
Assumptions

ITEM	ASSUMED VALUE
Coal	
Life	40 years
Capacity	603 MW
Availability	75%
Capital cost (millions)	$757
Variable fuel cost ($/MMBtu)	2.0
Fuel real escalation rate	1.0%
Variable O&M (cents/kWh)	.11
Single Cycle Combustion Turbine	
Life	30 years
Capacity	210 MW
Availability	85%
Capital cost (millions)	$53
Variable fuel cost ($/MMBtu)	5.1
Fuel real escalation rate	1.8%
Variable O&M (cents/kWh)	.21
Other Thermal Data Assumptions	
Sponsorship	Private
Debt/equity ratio	80%/20%
Capital cost real escalation rate	0.4%
Variable O&M real escalation rate	0.0%
Curtailment Costs	
Firm load curtailment cost	5.67 cents/kWh
Firm curtailment cost real escalation rate	1.8%
Nonfirm load curtailment cost	2.20 cents/kWh
Nonfirm curtailment cost escalation rate	0.0%
Southwest Market	
Standard rate for Southwest sales	2.20 cents/kWh
Maximum rate for Southwest sales (approx.)	3.00 cents/kWh
Southwest price real escalation rate	1.0 to 1.8%
Southwest intertie capacity (by October 1989)	7,786 MW

Table 7-2
End Effect Corrections for Combustion Turbine Studies
(Millions of Dollars)

	178 MW	356 MW	534 MW	712 MW
Capital	11.0	22.0	33.0	44.0
Fixed Costs	4.7	9.4	14.1	18.8
Variable Costs	31.7	75.4	163.2	257.9
Total Adjustment	47.4	106.8	210.3	320.7

Table 7-3
Net Benefits

INSTALLED MW	178 MW	356 MW	534 MW	712 MW
Net Benefits (millions)	$112	$171	$194	$ -32
Capacity Factor				
Coal (%)	56.5	56.3	57.0	57.6
Turbine (%)	9.1	10.8	15.6	18.8
Degradation of Service				
Top Quartile (%)	-2.5	-5.4	-5.5	-6.8
Top Quartile (MW)	-16	-35	-36	-45
S.W. Sales (%)	-2.4	-4.8	-7.1	-8.8
S.W. Sales (MW)	-68	-132	-192	-237

The existing thermal resource mix was used, along with a set of loads which yielded a 2,550 megawatt surplus in the first year that decreased to a balanced condition by 1994. From that point until the end of the study period, the load/resource balance was approximately zero (slightly surplus). An incremental load growth in September of 2000 was met by the installation of an equal amount of coal or combustion turbine energy. Four scenarios were examined: one in which 178 megawatts of generic resource were used to meet load growth, one with 356 megawatts, one with 534 megawatts, and one with 712 megawatts. Two studies were performed for each scenario, one to determine system costs when coal was added and the other to determine system costs when combustion turbines were added. In order to compare equal amounts of coal and combustion turbine energy, a scaled-down coal plant was used. For this analysis, each coal plant had capital and operating costs based on the standard 603 megawatt capacity unit scaled down to a capacity of 237 megawatts, with an average availability of 75 percent (to yield a net energy of 178 megawatts). Each combustion turbine had a capacity of 210 megawatts with an average availability of 85 percent (to yield a net energy of 178 megawatts).

Undeclared existing combustion turbines were removed from the analysis along with the option to make out-of-region emergency power purchases. The resource mix includes 164 megawatts of existing firm combustion turbine energy.

Assumptions

Plant operating data and assumptions were obtained from the *Thermal Resources Data Base* publication (Pacific Northwest Utilities Conference Committee, October 1984). This data was updated to represent January 1985 values. Financial data assumptions are in Chapter 4 of this volume. Table 7-1 below lists other assumptions used for this analysis.

End Effects

In this analysis, an obvious end effect problem exists due to the different assumed lives of the two resources being compared. All of our cost analysis is based on the present value life cycle net revenue requirements computed by the System Analysis Model. Life cycle costs are based on a projected resource operation beyond the study period. During that period, the assumed operation of each resource is based on its average operation during the last five years of the study period. Operating costs are computed for each year that the resource is in existence. In this analysis, the combustion turbines expire ten years before the coal plants. The net revenue requirements for the coal studies, therefore, contain an additional ten years of operating costs.

To compensate for the shorter combustion turbine life, it was assumed that when the turbines expire, new combustion turbines would replace them. A separate calculation was made to determine the present value capital and operating costs of the first ten years' life of the replacement combustion turbines. It was assumed that the replacement turbines would operate at the same average capacity factor as the expired turbines. These additional costs were added to the present value life cycle net revenue requirements for the combustion turbine studies and are reflected in the summary of net benefits in Table 7-3. Adjustment costs for the combustion turbine studies due to end effect errors are summarized in Table 7-2.

In addition to this, the System Analysis Model only projects secondary revenues and curtailment costs 25 years beyond the study period. Since the new coal plants were installed in September of 2000, their operating costs are projected 35 years beyond the end of the study period, ten years beyond the point where the secondary revenues and curtailment costs stop. In order to correct this end effect, the model was modified to extend the projected secondary revenues and curtailment costs to 35 years beyond the study horizon period.

Results

Net benefits for combustion turbines were computed for each scenario and are summarized in Table 7-3 and in Figure 7-15. The optimum amount of additional combustion turbine energy to include in the resource mix is determined by the point where the benefits are greatest. That point appears to be somewhere close to 500 megawatts of additional combustion turbine energy.

Of course, there are also operational effects to consider. Since the variable cost of combustion turbines is greater than the Southwest is willing to pay for nonfirm power, turbines are never operated to meet Southwest nonfirm loads. Northwest coal plants, on the other hand, are generally operated to meet nonfirm loads because their variable operating costs are lower. Thus, as more combustion turbines are used to meet firm load growth (instead of coal plants), the service to the Southwest nonfirm markets will decrease. Figure 7-16 shows how the Southwest market would be affected by a combustion turbine scenario (based on comparisons to a coal scenario). At 534 megawatts of additional combustion turbine energy, Southwest sales decrease by about 7.1 percent (192 megawatts) on an expected value basis.

Service to the direct service industry's top quartile load is also affected in the combustion turbine scenario. The impact is relatively small, however, because the top quartile is served in the fall by borrowing rather than by nonfirm in every case when the hydro system refills, whether coal or combustion turbines are used in the mix. Combustion turbines are displaced by available nonfirm in the fall. In the winter and spring, nonfirm hydropower is used to displace combustion turbines prior to using it to serve the top quartile; but since the availability of nonfirm hydropower in these periods is significantly larger than in the fall, the relative priority has a small effect. Coal plants, on the other hand, would generally be operated to meet the direct service industry's top quartile load. Under a coal scenario, therefore, the service to the top quartile should not be affected. Figure 7-16 also shows how service to the direct service industry's top quartile load is affected for a combustion turbine scenario. At 534 megawatts of additional combustion turbine energy, top quartile service drops by about 5.5 percent (36 megawatts) on an expected

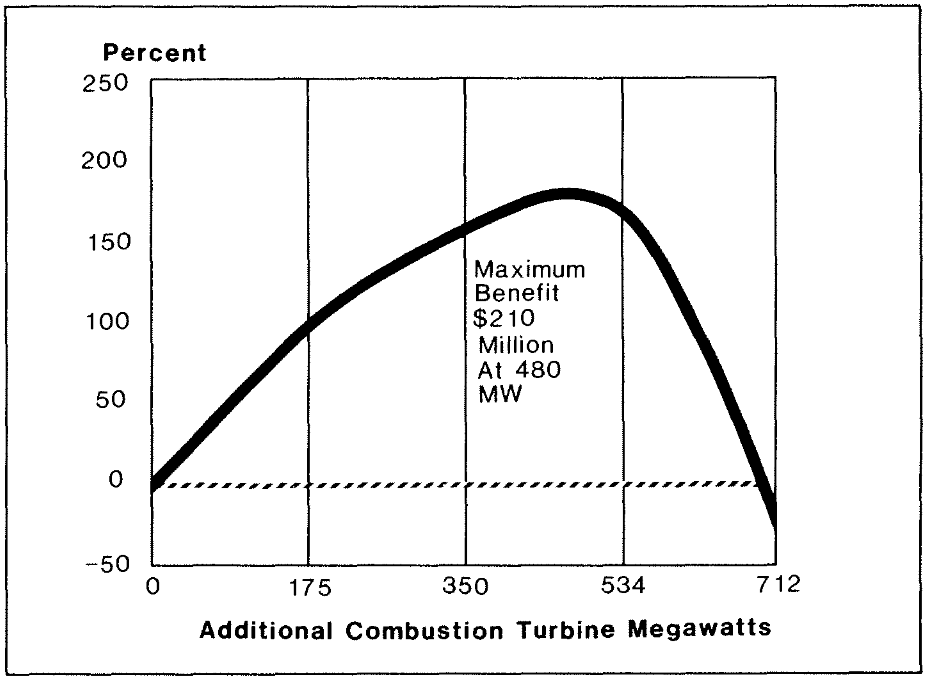


Figure 7-15
Net Benefits of Combustion Turbines vs. Coal
(Based on Comparison to Coal Plants)

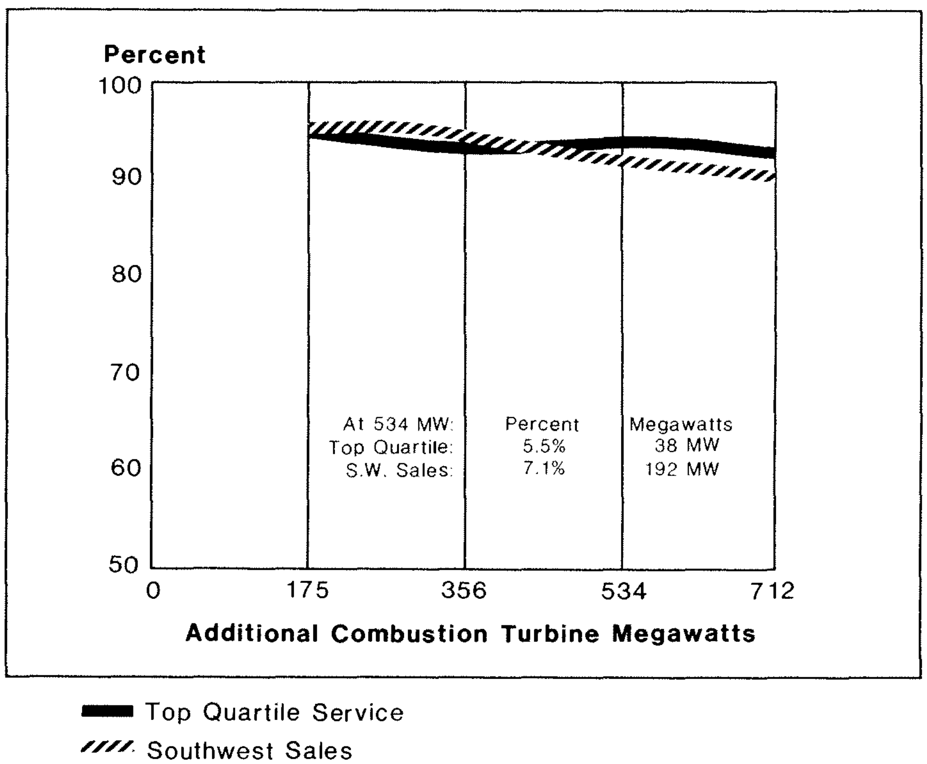


Figure 7-16
Impacts to Southwest Sales and Top Quartile Service
(Compared to a Coal Scenario)

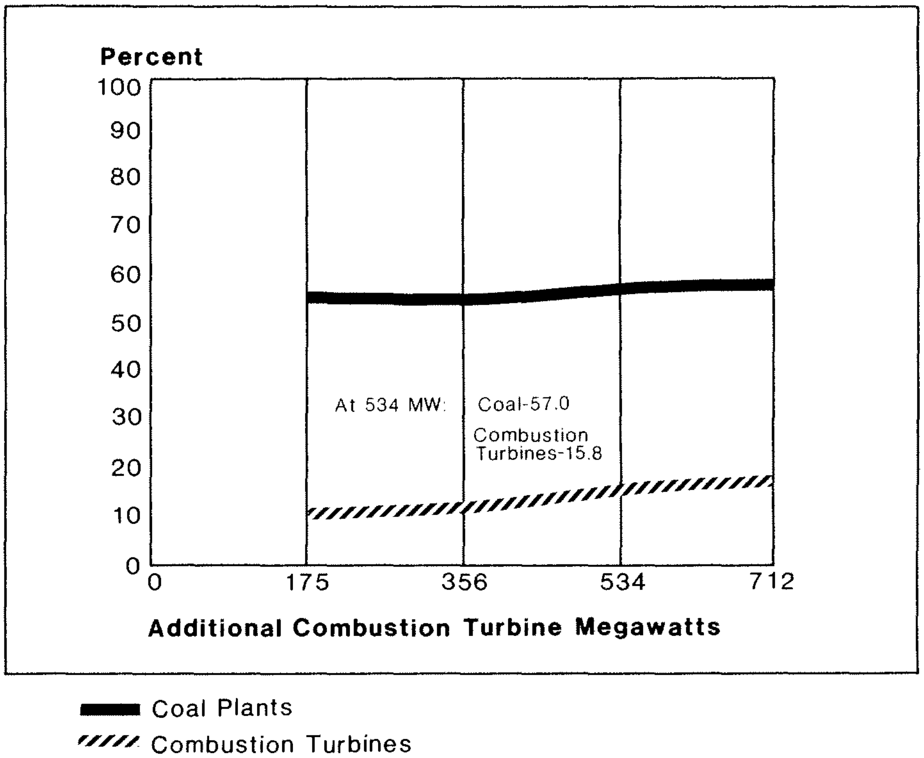


Figure 7-17
Average Capacity Factor of Coal and Combustion Turbine Plants
(All Additional Units)

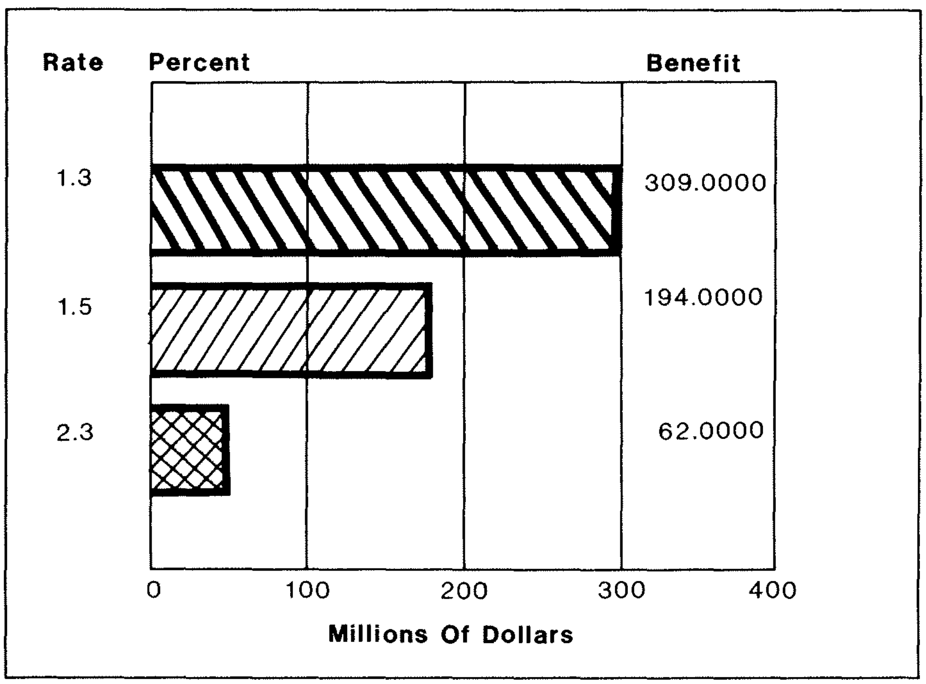


Figure 7-18
Sensitivity to Fuel Escalation Rate
(At 534 Megawatts of Additional Turbine Energy)

value basis. Unserved top quartile load was valued at 2.04 cents per kilowatt-hour in January 1985 dollars.

As the number of combustion turbines in the resource mix increases, the average capacity factor for the turbines also increases, i.e., they are operated more often. This occurs because of the limited amount of nonfirm hydropower which can be used to displace them. Once this nonfirm hydropower is used up, the remaining turbines must be operated to meet firm loads. As their capacity factor increases, the benefits quickly drop because their operating costs are so high. Figure 7-17 depicts the change in capacity factor for both coal plants and combustion turbines as a function of installed energy. At 534 megawatts of installed energy, the additional turbines are operated about 15.6 percent of the time on an expected value basis. Coal plants operate at about a 57.0 percent capacity factor.

Sensitivity Analysis

Coal plants have very high capital costs but moderately low operating costs, whereas combustion turbines have low capital costs but very high operating costs. Obviously, the advantage of combustion turbines is their low capital cost. Thus, turbines can be cost effective compared to coal as long as they are not operated at a high capacity factor. Any change in assumptions, which affects plant operation or plant capital cost, may cause the benefits to change significantly. The cost effectiveness of combustion turbines, therefore, should be very sensitive to coal capital cost and capital real escalation rates and to turbine fuel prices and their escalation rates.

The size of the Southwest market and the price that the Southwest is willing to pay for nonfirm power will also affect the cost effectiveness of combustion turbines. Normally a coal plant would be operated to serve Southwest nonfirm loads, whereas a combustion turbine would not because of its high operating costs. Revenues received from sales of coal generation to the Southwest offset other system revenue requirements. Thus, the greater the Southwest market and/or the higher the price, the greater are the benefits of having coal in the resource mix.

Conclusions

Based on this analysis, it appears that the addition of about 500 megawatts of combustion turbine energy to the existing resource mix would provide the region a net benefit of about $210 million. (Recall that 164 megawatts of firm combustion turbine energy is already present in the existing resource mix.) This analysis examines the value of combustion turbines on an operational basis only.

A similar analysis was done using the Decision Model, to show the value of combustion turbines in the portfolio. The conclusion was that 700 megawatts of new combustion turbine energy would be cost effective, with a benefit of $175 million. Since the two models are different in structure and complexity, a test was made of the operation of combustion turbines and coal plants in the two models, while forcing the cases to be as similar as the models allowed. The results from the two models, when presented with similar cases, were very close. The results used in the final portfolio were those from the Decision Model. The Decision Model showed benefits for a larger amount of combustion turbine energy, because it valued scheduling advantages inherent in short lead times, small plant size, and low capital cost in relationship to load forecast uncertainty, which the System Analysis Model did not account for.

Fuel Use Act

Exemptions to the Powerplant and Industrial Fuel Use Act are assumed to be available for combustion turbines. Through research of the Fuel Use Act and its regulations and through informal consultations with the U.S. Department of Energy's Economic Regulatory Administration, the Council determined that permanent exemptions most likely to be obtainable for the uses of combustion turbines envisioned under the Council's plan are those available for:

- maintenance of reliability of service;
- lack of alternate fuel at a cost not substantially above that of imported oil;
- cogeneration;
- fuel mixtures; and
- peaking.

Exemptions are granted only for proposed plants actually designed and nearing construction, and each exemption requires certain showings by the applicant as prerequisites.

Should the region decide to include an additional amount of combustion turbine energy in the portfolio, rather than some other strategy for using nonfirm, that energy could come from existing undeclared combustion turbines. Many of those turbines are "grandfathered" under the Fuel Use Act and may not face the problems associated with obtaining exemptions to the Fuel Use Act.

Other potential sources of back-up generation are out-of-region utilities, either in California and the Southwest or in British Columbia. There is a large amount of oil-fired generation in California which may be available. Although no energy was available from California during the two times in the 1970s when the region needed it (due to the oil embargo in 1973 and overlapping droughts in 1977), there is some indication that the correlation between the Northwest snowpack and the Sierra snowpack is small to nonexistent. There appears to be a similar indication about the correlation of the Northwest with the Peace River in British Columbia. Both these areas need further investigation before firm conclusions can be drawn. Bonneville is currently looking at the British Columbia situation. The Council expects to learn more about the potential during the next two years as part of its West Coast energy study.

Using Nonfirm Energy without Backup Generation: Load Management

An alternative approach to the increased use of nonfirm involves simply attempting to meet firm loads using nonfirm energy without backup generation. This would require some institutional mechanism for reducing loads when no nonfirm energy is available. This issue was addressed in the Council issue paper, "Critical Water Planning," and has been expanded for the plan.

A set of studies estimated the dollar benefits of relaxing the critical water criterion and the dollar costs of curtailment alone. These monthly plant life-cycle cost studies used the same five levels of load/resource balance described above in the system reliability section in approximately the last third of the 20-year simulation. Generally, the question of critical water is only significant when the region faces deficits and potential major resource acquisitions. Therefore, the study simulated some more-likely load cases than the high load. These studies used only the first (current) operating strategy. They are summarized in Tables 7-5, 7-6 and 7-8, which give 1985-dollar present values of the results.

The reliability plots (described in the section on critical water studies) were done because it is often difficult to establish a common denominator to compare such things as changes in refill and flows for fish. While there have been several studies of the cost to consumers of curtailments, including one done for the Council in 1982, there is no general agreement about that either. The three studies described below use three different approaches to the cost of curtailment. It is clear from the results that the conclusions are extremely sensitive to the imputed cost of curtailment and, in particular, to the cost of curtailing the direct service industry top quartile. This is so because service to the top quartile in the fall using the flexibility of the hydro system is dependent upon load/resource balance. With firm deficits, their fall service is dependent on secondary availability only.

Based on the previous analysis, it was observed that, of all the assumptions which could affect combustion turbine cost effectiveness, coal capital costs and combustion turbine fuel escalation rate assumptions were the most sensitive. Two sensitivity studies were designed to determine the effects of changing these two assumptions. Both sensitivity studies were performed for the 534 megawatt scenario.

The first parameter examined was the combustion turbine fuel real escalation rate. Two studies were performed: one with an escalation rate of 2.3 percent (an increase over the base case of almost 30 percent) and the other with an escalation rate of 1.3 percent. Results from these studies are depicted in Figure 7-18. Net benefits drop from $194 million to $62 million when the fuel escalation rate is increased to 2.3 percent. In the second study, when the escalation rate was dropped to 1.3 percent, the net benefits jumped to $309 million.

The second parameter examined was the capital finance assumption for the debt/equity ratio. For this study, this ratio was changed from 80/20 to 50/50 (which has the net effect of increasing capital costs). Results for this sensitivity study are shown in Figure 7-19. Since combustion turbine capital costs are low, this change in assumptions had little effect on the cost of the turbines. A more significant change in capital costs was observed in the coal studies. Net benefits of combustion turbines increased from $194 million to $458 million (a change of 126 percent).

As evident in Figures 7-18 and 7-19, the benefits of combustion turbines are very sensitive to coal capital costs and to combustion turbine fuel prices and their escalation rates. Any change to these assumptions may alter the results significantly.

As in the base case, an end effect problem exists in these sensitivity studies. To correct this, it was assumed that when the combustion turbines expire, new turbines would replace them. Adjustments to the capital and operating costs were computed and added to the present value net revenue requirements for the combustion turbine studies. Table 7-4 below summarizes the corrections used for the sensitivity analysis.

Table 7-4
End Effect Adjustments for Sensitivity Study
(For 534 Megawatts of Additional Combustion Turbines)
(Millions of Dollars)

	GAS ESCALATION RATE		DEBT/EQUITY RATIO
	2.3%	1.3%	50%
Capital	33.0	33.0	39.9
Fixed Costs	14.1	14.1	14.1
Variable Costs	181.2	148.2	163.2
Total Adjustment	228.3	195.3	217.2

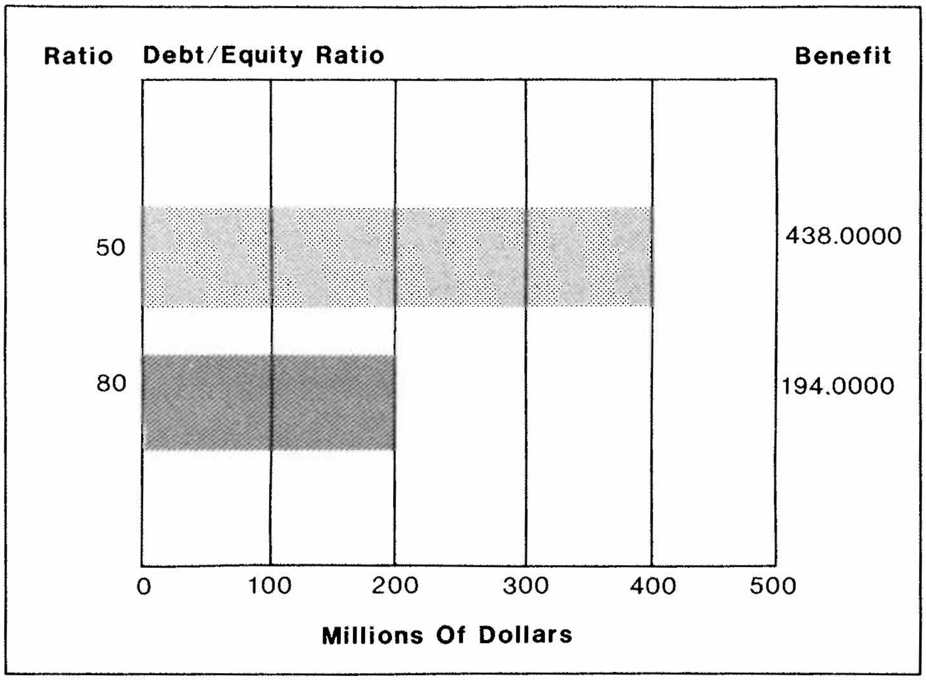


Figure 7-19
Sensitivity to Debt/Equity Ratio
(At 534 Megawatts of Additional Turbine Energy)

The key result of Table 7-5 is that the additional system revenue requirement declines continuously and significantly to the limit of the study, 2,000 megawatts of firm deficit. The sensitivity to the curtailment cost is shown in the lower part of the table. The underlined number identifies the lowest-cost point. This table uses a standard secondary rate of approximately 2.2 cents, the rate as of July 1985, and models the market structure that the region is currently seeing under Bonneville's near-term intertie access policy. It also assumes the full expansion of the intertie to 7,786 megawatts.

The base case curtailment cost (and real escalation) rate used for Table 7-5 is approximately the same as the operating cost of generic combustion turbines, 6.2 cents in January 1985 dollars. This rate is applied to firm curtailments (including the firm direct service industry load) and escalates at 1.8 percent per year in real terms, as does the combustion turbine fuel cost. The rate applied to top quartile and third quartile curtailments is 2.2 cents in January 1985 dollars, approximately the same as the direct service industry base rate as of July 1985. This remains constant in real terms, a reasonable expectation for the direct service industry rate. If the costs of curtailment are twice as high as these, the lowest cost point shifts to a 500 megawatt deficit, and if three times as high, it shifts to balance.

However, these results are quite sensitive to the imputed curtailment cost of the direct service industry top quartile. Table 7-6 shows the results for the same studies as reported in Table 7-5, except that the top quartile and third quartile curtailments were valued at the same rate, 6.2 cents escalating at 1.8 percent, as the firm load. The difference in results occurs because the primary impact of moving away from critical water is on the direct service industry top quartile load. With firm deficits, the top quartile service in the fall comes only from nonfirm energy rather than from borrowing energy against the third quartile of their load.

There are several perspectives that can be applied to evaluate these curtailment costs.

Table 7-5

Curtailment: Firm, 6.2 Cents and Top Quartile, 2.2 Cents
Present Values—Plant Life Cycle
System Analysis Model: Millions of September 1985 Dollars

COST	CASE Balance	500 MW Deficit	1,000 MW Deficit	1,500 MW Deficit	2,000 MW Deficit
Capital	$ 4,959	$ 3,743	$ 2,529	$ 1,345	$ 192
+ Production	22,348	21,487	20,429	19,386	18,031
+ Curtailment	1,167	1,853	2,787	3,992	5,506
− Nonfirm Revenue	12,427	11,803	11,215	10,596	9,807
Revenue Requirement	$16,046	$15,281	$14,530	$14,109	<u>$13,832</u>
SENSITIVITY OF REVENUE REQUIREMENT TO CURTAILMENT COST					
Revenue Requirements if Curtailment Cost Multiplied					
times 1.5	$16,630	$16,028	<u>$15,924</u>	$16,105	$16,585
times 2:	17,213	<u>17,134</u>	17,313	18,101	19,338
times 3:	<u>18,380</u>	18,987	20,104	22,093	24,844

Table 7-6

Curtailment: All Loads, 6.2 Cents
Present Values—Plant Life Cycle
System Analysis Model: Millions of September 1985 Dollars

COST	CASE Balance	500 MW Deficit	1,000 MW Deficit	1,500 MW Deficit	2,000 MW Deficit
Capital	$ 4,959	$ 3,743	$ 2,529	$ 1,345	$ 192
+ Production	22,348	21,487	20,429	19,386	18,031
+ Curtailment	3,257	5,298	7,098	8,838	10,651
− Nonfirm Revenue	12,427	11,803	11,215	10,596	9,807
Revenue Requirement	<u>$18,136</u>	$18,725	$18,841	$18,955	$18,977

The first perspective is that of short-run elasticity. This poses the question of what increase in price is needed to reduce demand in the short run by the required amount? With an elasticity of -0.1 and an assumed current average retail rate of 5 cents, a 5 percent decrease in firm load could be achieved by raising prices 50 percent and a 10 percent decrease by raising prices 100 percent. The distribution of firm curtailments shows that only about 6 percent of the curtailments are greater than 10 percent of load at the 1,000 megawatt deficit level and only 20 percent are above 10 percent of load at the 2,000 megawatt level. This result suggests that two times the original curtailment cost (two times 6.2 cents) is not out of line with what firm customers are willing to pay for service for the low end of the curtailment distribution. This could also be construed as the amount the power system could pay consumers to reduce service, although this total amount would consist of both payment and foregone revenue at a level equal to the assumed rate.

Table 7-7
Variable Cost of Direct Service Industries

COMPONENT		COST
Labor: 0.005 manhr/lb x 2,300 cents/manhr x 0.7 variable	=	8.1 cents/lb
Alumina: 20 cents/lb x 0.85 variable	=	17.0
Other costs: 22 cents/lb x 0.55 variable	=	12.1
Electricity: 2.2 cents/kWh x 8 kWh/lb	=	17.6
		54.8 cents/lb
At 75 cents/lb profit = 20 cents/lb	=	2.5 cents/kWh
variable wages = 8.1 cents/lb	=	1.0
lost revenue	=	2.2
		5.7 cents/kWh

Table 7-8
Curtailment: Firm, 10.0 Cents and Top Quartile, 5.7 Cents
Present Values—Plant Life Cycle
System Analysis Model: Millions of September 1985 Dollars

	CASE				
COST	Balance	500 MW Deficit	1,000 MW Deficit	1,500 MW Deficit	2,000 MW Deficit
Capital	$ 4,959	$ 3,743	$ 2,529	$ 1,345	$ 192
+ Production	22,348	21,487	20,429	19,386	18,031
+ Curtailment	2,624	4,185	5,747	7,429	9,329
− Nonfirm Revenue	12,427	11,803	11,215	10,596	9,807
Revenue Requirement	$17,504	$17,613	$17,490	$17,546	$17,655
SENSITIVITY OF REVENUE REQUIREMENT TO CURTAILMENT COST					
Revenue Requirements if Curtailment Cost Multiplied					
times 1.5:	$18,816	$19,706	$20,364	$21,261	$22,320

The second perspective focuses on the direct service industries. Both short-term elasticity and the required potential payment are functions of the state of the aluminum market. In recent years, the price of aluminum has been as high as $1 per pound, though forecasts of long-term average prices tend to be in the 75-80 cent per pound range. At 75 cents per pound for aluminum, the cost to the power system of making the direct service industries and their employees indifferent between operating and not operating would be about 5.7 cents per kilowatt-hour. This calculation is shown in Table 7-7, using roughly average data for the ten smelters from the Bonneville Direct Service Industry Options Study.

At $1 per pound of aluminum, the cost to the power system of making the direct service industries and their employees even would be on the order of 9 cents per kilowatt-hour for about 2,600 megawatts. The cost to the power system would include paying wages and profits, as well as the lost revenue from the foregone power sales. The variable portion of alumina and other costs would not be incurred, so they are not included in the calculation. Again, this indicates that at a maximum less than twice the original estimate of the curtailment cost (two times 6.2 cents) estimate is not unreasonable through most of the range of the curtailments, and as an expected value the original estimate is appropriate.

Because of this sensitivity, and taking into account the conclusions above, the studies were run a third time with firm curtailment costs set at 10 cents and the top quartile and third quartile curtailment costs set at 6.2 cents. The costs are in January 1985 dollars and, in this case, are held constant in real terms. Note in comparing the tables that, because the base numbers are higher, the multiplied values for the same multiplier are not comparable across tables. The results are shown in Table 7-8. In addition, this table is relatively conservative, because it values firm direct service industry curtailments (half the direct service industry load) at 10 cents per kilowatt-hour rather than 6.2 cents. The System Analysis Model does not distinguish firm direct service industry loads from non-direct service industry loads in this context.

The cost at the bad tail of the distribution is harder to estimate. The appropriate cost curve for curtailment for very large, but infrequent, events is probably severely non-linear. A 20 percent restriction of demand based on price alone could require a 200 percent increase in rates, with an elasticity of -0.1. The 20 percent curtailment level for firm load was exceeded only about 1 percent of the time even with a 2,000 megawatt firm deficit. A 200 percent increase in rates corresponds roughly to the multiplier of 3 in Table 7-5. However, this is probably an area in which the seasonal averaging distorts the results of the study, since some monthly failures to meet load could be much larger than shown on the plots, although correspondingly less frequent. Note on the other hand that the multiplier overstates the cost in the table, because it is applied to all curtailments, not just the very large ones.

Conclusions

This chapter has explored the characteristic variability of the Northwest hydropower system along with some uses of the nonfirm energy available because of that variability. The Council believes that its studies have demonstrated several strategies for increasing the value of the nonfirm energy to the region. The most promising strategy for the region at this point appears to be increased use of combustion turbines or extra-regional purchases to back up nonfirm energy to meet firm loads. Because of this, the Council has included about 700 megawatts of combustion turbine energy in its resource portfolio. Other strategies, such as load management or load buyback coupled with planning to somewhat better than critical water, should be explored further.

1./ When the Council reconsidered its interim spill objectives in early 1986, it did not change the interim mainstem fish passage objective at mainstem federal projects but did extend the objective to cover 80 percent of the fish runs up to August 15. As a result of the change, spill will be used to meet the objective even when only firm power is available.

2./ The water budget is a means of increasing survival of downstream migrating juvenile fish by increasing flow during the spring migration period. The Council proposed this practice and oversees it in conjunction with the U.S. Army Corps of Engineers, the fishery agencies and tribes, Bonneville, and the Bureau of Reclamation. The water budget is discussed in Section 304 of the Council's Columbia River Basin Fish and Wildlife Program.

3./ The Pacific Northwest Coordination Agreement is a contract among the U.S. Army Corps of Engineers and all the Northwest generating utilities (except the Idaho Power Company) that governs the operations of the region's hydroelectric system.

4./ "A Synthesis Flow Model for The Dalles Flows," unpublished letter from Dennis Lettenmaier (UW) to Ron Hicks (BPA). Also see L.A. Dean and J.A. Polos, "Frequency of Failure to Meet Firm Loads for the Pacific Northwest Hydroelectric System," unpublished paper, Dec. 6, 1983.

Chapter 8
Resource Portfolio

This chapter of the plan describes in detail the Council's resource portfolio. Section A describes the analysis that led to the Council's choice of the portfolio, and gives a brief overview of the computer models employed. Section B contains a description of sensitivity analyses performed on the portfolio. Section C gives details of the Council's analysis of the cost effectiveness of the two Washington Public Power Supply System's nuclear plants WNP-1 and WNP-3. Section D presents a more detailed description of the Decision Model. Finally, Section E discusses generating resource lost opportunities.

Section A: Resource Portfolio Analysis

Introduction

In the Council's 1983 Power Plan, the resource portfolio was presented as four different regional resource schedules, one for each of the four different load forecasts. In the 1986 plan, the portfolio is presented not just as a set of particular resource development schedules, but also as a set of resource priorities and decision rules. These can be used in conjunction with resource availabilities and evolving load forecasts, to guide the decision-making process toward the most economic resource decisions as the region's energy future unfolds.

In developing this resource portfolio, the Council's primary objective was to achieve the lowest present value expected cost across the wide range of uncertainty faced by the region. In addition, because future events are not likely to turn out as forecast, the Council's portfolio continues to exhibit a high degree of flexibility, allowing opportune responses to unforeseen changes in need and thereby maintaining a reliable, economic power system. The Council believes the concept of risk management should play an important role in the resource decision-making process. The flexible planning strategy that evolved out of the Council's 1983 plan is emphasized again in the 1986 Power Plan.

Generating resource characteristics which lead to enhanced flexibility and reduced risk are, primarily, short lead times and small unit size. Shorter lead times reduce the period over which the need for new resources must be forecast, and allow resource sponsors to move closer to the point of actual need before committing large amounts of capital for resource construction. Shorter lead times produce a greater likelihood that resources will actually be useful once they are ready for service. Resources with small plant sizes would allow the region to make many smaller decisions rather than a few large ones, and provide the ability to match resource development and load growth more closely.

The concept of resource options, developed and emphasized in the Council's 1983 plan, has as an important objective the reduction of resource lead times. The option concept permits the region to enter into the preliminary stages of resource development, siting, licensing and design, based on a relatively high projection of future load growth. This strategy is expected to prove cost effective, because the cost of acquiring options is low compared to the cost of actual resource construction. The options concept leads to a second decision point regarding the appropriate time to begin constructing a resource. After option acquisition, load forecasts would continue to be updated and the projected need for the resource reevaluated. If loads have not grown sufficiently to justify entering construction, the option would be held until it was either appropriate to construct the resource or the option was lost. The options concept enhances the flexibility of the Council's resource portfolio and continues to warrant additional analysis and policy development. Over the planning horizon, the ability to option resources will improve the ability to match the rate of resource development with resource need and reduce the cost of the resource portfolio.

Analytical Tools

For the resource portfolio analysis the Council relied primarily on two computer models.

The first of these, the System Analysis Model, is a large, very detailed model of the Pacific Northwest generation system. It was developed principally by the Bonneville Power Administration, the Intercompany Pool, and the Pacific Northwest Utilities Conference Committee (PNUCC). It uses complex models of Northwest hydro/thermal operation, and sophisticated techniques to capture the physical and economic effects of uncertain variables, such as hydro conditions, thermal plant availability, thermal plant arrival, and short-term fluctuations in load. It also uses detailed accounting methods to model the capital cost recovery streams required by the various types of utilities and resource sponsors in the Pacific Northwest. The System Analysis Model is an excellent tool for evaluating questions concerning system reliability, or to isolate the operation and cost of a particular resource and its impact on the system as a whole. In development of the plan, the System Analysis Model was used for analysis in the areas of combustion turbine cost effectiveness, relaxation of the critical water standard, value of additional interruptible load, and long-run marginal costs. A wide range of documentation for the model is available upon request from PNUCC.

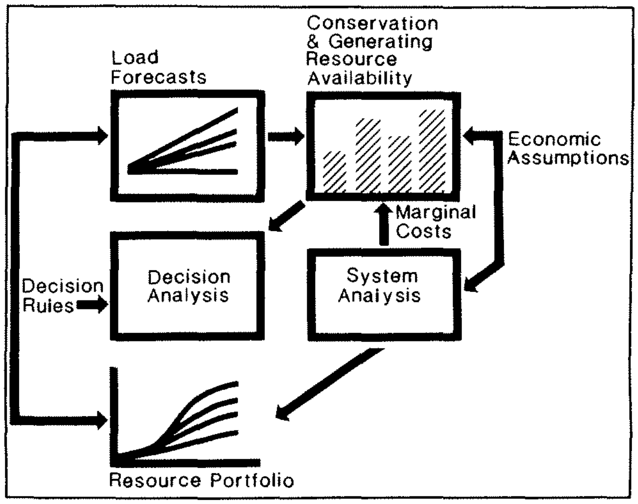


Figure 8-1
Northwest Power Planning Council
Resource Portfolio Development Process

The Decision Model was also used extensively by the Council for development of the resource portfolio. This relatively new model was developed over the last year by individuals from the Council staff, the Intercompany Pool, PNUCC and Bonneville. This model grew out of the Council's recognition of a need for the analytical capability to assess the impact of long-term load uncertainty on resource cost effectiveness. Related to this was a need for the ability to value characteristics which would enhance resource flexibility, such as shortened resource lead times and resource options, or small unit sizes. The Decision Model provides the capability to assess the load-related risk associated with a particular decision to option or build a resource, and the consequences of errors likely to occur in the resource planning process. It helps planners determine what types of resource strategies over the long term better enable the region to manage the risks imposed by load uncertainty. The model enhances strategic planning capability, and provides information flow to the decision-making process in an area which previously had to rely largely on intuition and judgment.

Section D of this chapter provides additional background, an overview of the model, and a brief description of the model's algorithms. More detailed documentation should be available sometime in the spring of 1986.

Together, the highly detailed nature of the System Analysis Model and the ability of the Decision Model to deal with load uncertainty provide the Council with a capacity for analysis over a wide array of resource planning issues.

Portfolio Development Process

The Council's resource portfolio development process consisted of four major interrelated activities. These are depicted graphically in Figure 8-1 and summarized below.

1. **Load Forecasts.** The process began with development of electricity demand forecasts for the region. Four forecasts were developed, each representing a possible regional future. A probability distribution for future loads was also developed. In order to focus on the obligations of the Bonneville Administrator, the forecasts were also broken down into demands of the public and investor-owned utilities. Volume II, Chapters 2 and 3, provide a detailed description of the forecasting process and its results.

2. **Avoided Cost Studies.** Next, long-run marginal cost studies for the region were performed. This analysis was performed with the System Analysis Model and used coal units with arrival dates near the year 2000 as the avoided resource. These studies estimated avoided costs to be 4 to 4.5 cents per kilowatt-hour. These studies are discussed in detail in Volume I, Chapter 8. The System Analysis Model was also used to derive levelized cost estimates for initial ranking of the generating resources for the portfolio analysis.

3. **Determination of Resource Availability.** Information from the load forecasts and the avoided cost estimates were used to screen resources for the portfolio analysis. Initial estimates of the amounts of cost-effective resources were developed for generating resources and conservation programs. For many conservation programs, the amount of efficiency improvement available depends on the level of economic activity modeled for that sector in the load forecast. This correlation between conservation availability and load level is used in the portfolio analysis. For a full discussion of the conservation and generating resource potential see, respectively, Chapters 5 and 6 of this volume.

4. **Portfolio Analysis.** The load forecast range, its probability distribution, and the conservation and resource availabilities and costs were used with the Decision Model to develop the Council's resource portfolio. The Decision Model is used here because it incorporates the effect of long-term load uncertainty, resource option and construction lead time, conservation program ramp rates, seasonality and system operating impacts into the cost-effectiveness analysis. The process involved several iterations back through the forecasting and resource screening activities to ensure consistency among the portfolio, loads and electricity prices, and conservation energy potentials. After the resource portfolio had stabilized, scheduling studies focused on the Administrator's obligations, to determine what actions might be required in the Action Plan for Bonneville.

Load Treatment

The third chapter of Volume II describes the development of the four load forecasts in detail. The forecasts provide the starting point for the portfolio analysis and obviously are a critical piece of information. However, these four specific forecasts are not used directly in the analytical process. Rather, they are incorporated into the analysis through definition of the probability distribution for regional loads.

As for any specific forecast, the likelihood is extremely small that future regional load will evolve exactly along any one of the four specific forecast paths. However, because of the philosophy underlying their development, the forecasts can readily be used to define a probability distribution for future electricity demand. The forecasts were developed in such a way that future load outcomes either below the low forecast or above the high were felt to have probabilities so low as to justify exclusion for planning purposes. In addition, the two medium level forecasts define the range of most likely load outcomes. These characteristics can be represented with the trapezoidal probability distribution shown in Figure 8-2. This distribution, expressed in terms of 20-year compound growth rates, has a uniform probability of occurrence for loads between the medium-low and medium-high, with probabilities dropping off linearly to zero at both the low and the high. This is a continuous distribution, implying that any load outcome across the entire range would be possible. The probability of a load occurrence between the low and medium-low is 31 percent; between the medium-low and medium-high, 42 percent; and between the medium-high and high, 27 percent.

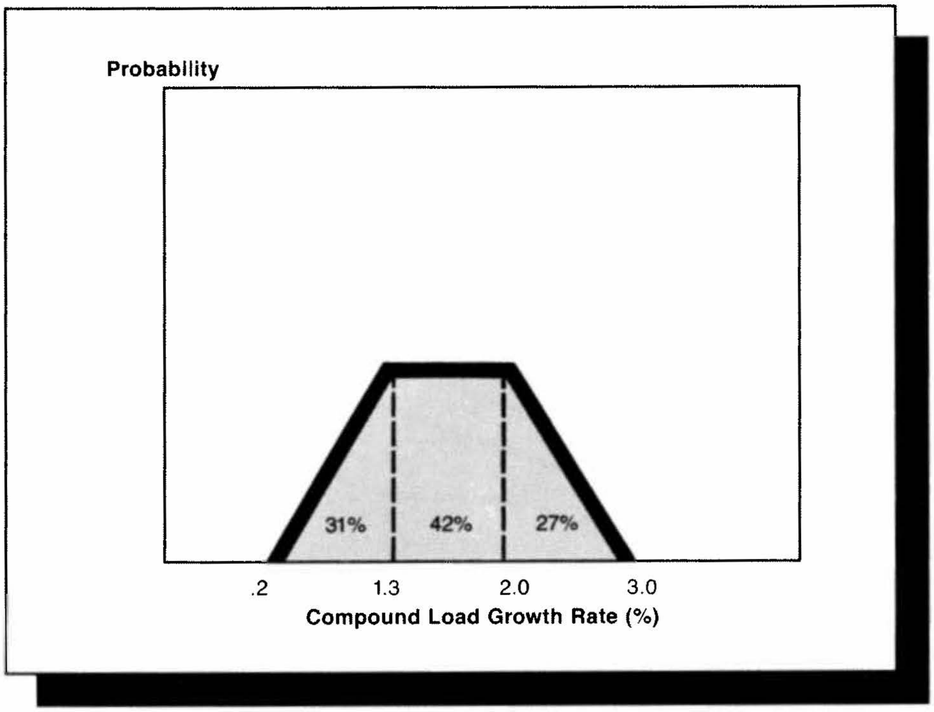


Figure 8-2
Load Growth Probability Distribution

Another component of load uncertainty included in the portfolio analysis is that of the direct service industries. The economic conditions driving this uncertainty are discussed in Volume II, Chapter 2. For analytical purposes, the Council has assumed at least half the load from aluminum producers will be present across the planning horizon; that is, a minimum of 50 percent of aluminum direct service industry firm load is included in all load cases. The remaining 50 percent is regarded as uncertain and is represented by

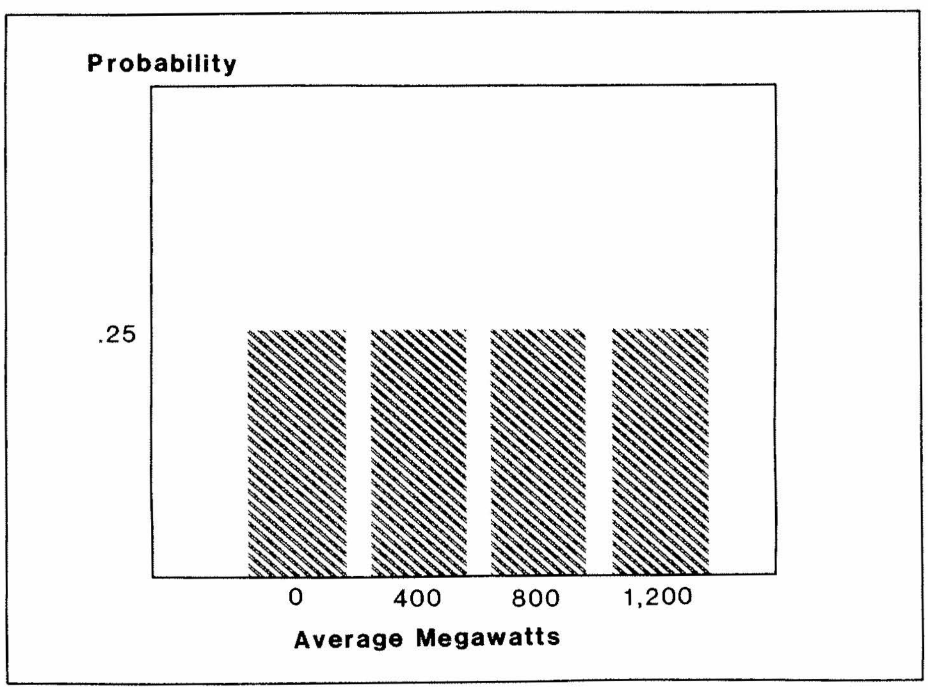


Figure 8-3
Distribution for Uncertain DSI Load

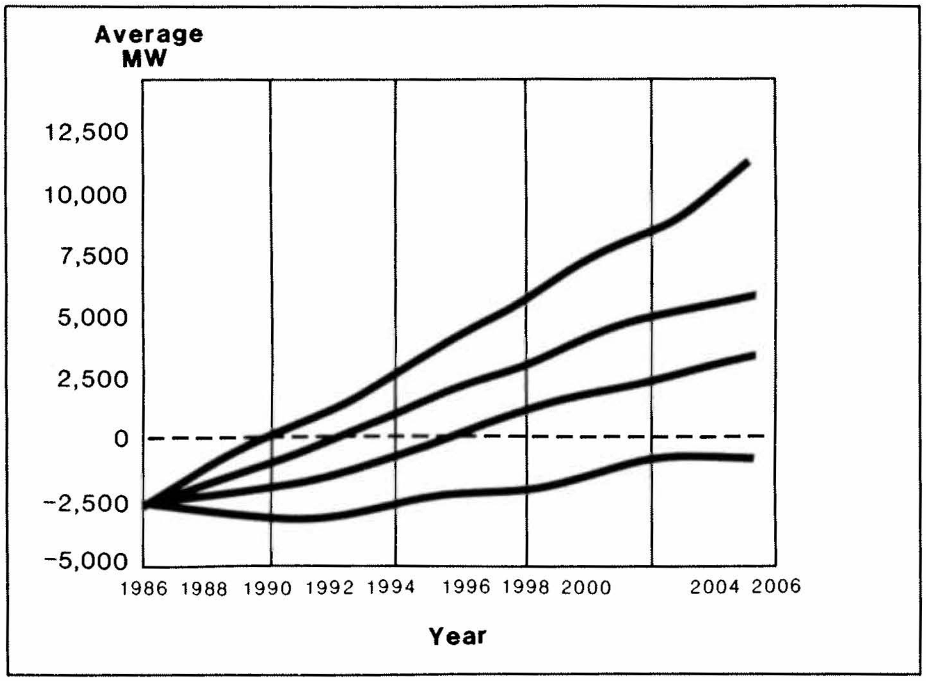


Figure 8-4
Regional Resource Requirements

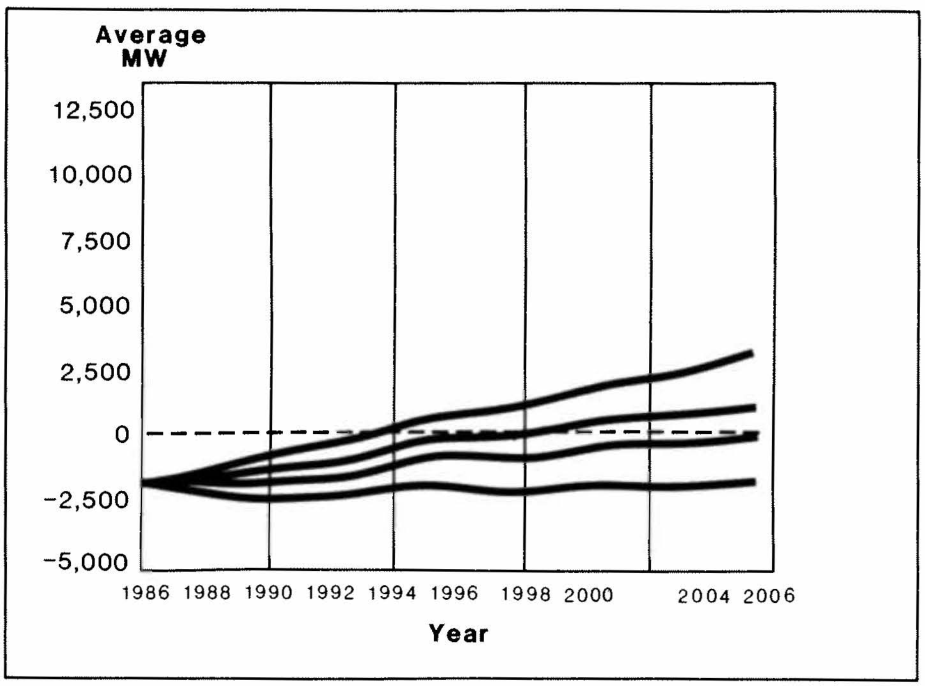


Figure 8-5
Public Utility Resource Requirements

the probability distribution shown in Figure 8-3. This is a discrete distribution, with only four possible outcomes: 0, 400, 800, and 1,200 average megawatts of firm load above the 50 percent base, with a constant 25 percent probability for each outcome. The discrete nature of the distribution is intended to reflect the nature of plant and potline size. This uncertain portion of direct service industry load is treated as independent of other regional load; the probability of observing a given direct service industry load is not affected by the level of other regional loads. This reflects the idea that Northwest aluminum industry activity will to a large extent be driven by factors outside of the Pacific Northwest economy.

Resource Requirements

Subtracting the capability of existing system resources over time from the Council's range of forecasts yields an estimate of the resource energy additions required to maintain the load/resource balance under each of the load scenarios. The loads used in this calculation were the frozen efficiency loads referred to in Volume II, Chapter 3, without adjustment for any conservation program energy savings. The estimates for capability of existing resources were based on the 1985 *Northwest Regional Forecast,* published by PNUCC in March 1985. (See Volume I, Chapter 5.)

Under the assumption that the investor-owned utilities place all of their resource needs above their current surplus on Bonneville, these regional values represent an upper bound to the potential range of Administrator obligations. Figure 8-4 depicts regional resource requirements and shows the current surplus lasting anywhere from four to more than 20 years, depending on demand growth and on the load path followed by the region. Under the high load forecast the first need for new resources occurs in about 1990. In the low load case there is no additional resource requirement. The total amount of resource additions that might be required over the 20-year planning horizon ranges from zero to almost 12,000 average megawatts.

In addition to regional requirements, the Council also estimated the resource needs of only Bonneville's public utility and direct service industry customers. In the event that no investor-owned utility loads are placed on Bonneville, these values provide a lower bound on the potential range of the Administrator's obligations. These public utility requirements are shown in Figure 8-5. Comparison of Figures 8-4 and 8-5 shows the Bonneville/public utility system to own the lion's share of the current surplus, with projections of deficits occurring at much later dates across the forecast range. In fact, no resource additions are required by the publics in either the low or the higher probability medium-low forecasts. While not shown here graphically, the investor-owned utilities are currently far less surplus than the publics and are forecast to have a higher proportion of regional load growth occur in their service territories. Most of the early resource development in the region is likely to be driven by investor-owned utility needs.

Resource Availability and Cost-Effectiveness Studies

The Council has undertaken a detailed analysis of the conservation program actions and generating resource development alternatives available to meet the region's energy needs over the planning horizon. These analyses were described in detail in Volume II, Chapters 5 and 6. A summary of the results is shown in Table 8-1. This table shows the amounts of cost-effective energy estimated to be available for each resource across the load forecast range. Except for cogeneration, the amount of energy available from generating resources does not vary with the load forecast. The amount of cogeneration available is dependent on the level of economic activity in the industrial sector and has an availability correlated to load growth. Likewise, many of the conservation program potentials are driven by the level of economic activity in their sectors; for example the rate of new building starts affects the energy available from the model conservation standards. Potential savings from many of the Council's conservation programs are directly correlated to the assumptions used in development of each of the load forecasts.

Table 8-1
Resource Availability (Average Megawatts)

	LOAD SCENARIO			
	High	**Medium-High**	**Medium-Low**	**Low**
Conservation Program				
MCS Residential	792	468	405	129
MCS Commercial	398	195	109	51
Refrigerators & Freezers	352	293	224	206
Water Heat	396	324	266	219
Manufactured Homes	35	36	32	13
Existing Residential	455	455	455	455
Existing Commercial	802	614	475	345
Existing Industrial (with DSIs @ 100%)	538	538	538	538
Agriculture	124	105	105	105
Transmission & Distribution	34	34	34	34
Efficiency Improvements				
Generating Resource				
Hydropower Efficiency Improvements	110	110	110	110
New Hydropower	200	200	200	200
Nonfirm Strategies	714	714	714	714
Cogeneration	320	190	190	130
Licensed Coal (2 Units)	905	905	905	905
Unlicensed Coal (10 units)	4,520	4,520	4,520	4,520

For the discussion in this chapter, conservation programs are described as either "discretionary" or "nondiscretionary." Nondiscretionary programs are used in the portfolio analysis to model implementation of building and appliance codes, or the forced acquisition of cost-effective lost opportunity resources. The development rates for the nondiscretionary programs are not subject to program management in response to resource need. These programs produce energy savings regardless of need. For example, once incorporated into building codes, the level of activity of the model conservation standards (MCS) would be driven primarily by the number of building starts. The MCS would automatically produce energy savings across the entire load range. It would produce more energy in the high than in the low, but would produce energy in the low even though no additional savings are required for the region in low load conditions. Many of the nondiscretionary programs automatically produce more energy savings as load levels increase because of the higher economic activity at those load levels. This automatic correlation of savings to load can add to the value of a resource and is captured in the portfolio analysis. Additionally, all nondiscretionary programs have equal and top priority in the resource development order in the portfolio analysis. For modeling purposes in the portfolio development, the residential MCS, commercial MCS, manufactured homes, refrigerator/freezers, and water heaters are all treated as nondiscretionary resources.

Table 8-2
Resource Priority Order

NONDISCRETIONARY RESOURCES
Residential MCS
Commercial MCS
Refrigerators & Freezers
Water Heat
Manufactured Homes
DISCRETIONARY RESOURCES
Hydropower Efficiency Improvements
Agriculture Conservation
Existing Commercial Conservation
Transmission & Distribution (T&D) Efficiency Improvements
Existing Residential Conservation
Existing Industrial Conservation
Combustion Turbines
Small Hydropower
Cogeneration
Licensed Coal
Unlicensed Coal

Discretionary programs are those programs whose development is managed in response to need. These programs are targeted primarily at the existing sectors (e.g., existing residential weatherization or existing industrial) where a savings potential already exists and can be developed as needed. Delay on implementation of these programs is not likely to produce large lost opportunity impacts. These are programs which are likely to be subject to direct program management and whose energy contributions can be developed in response to need.

A large portion of the industrial conservation potential comes from direct service industry (DSI) load. Because the portfolio assumptions regard 50 percent of DSI load as uncertain, the level of industrial conservation is uncertain as well. In load outcomes where all DSI loads remain throughout the entire planning horizon, there is more industrial conservation potential than in load cases where only half the DSIs remain. This correlation between DSI loads and industrial conservation potential is captured in the Decision Model.

The estimates of resource availability in Table 8-1 can be thought of as individual investment opportunities to be used in developing the regional resource portfolio. A number of cost-effectiveness studies were performed using the Decision Model to determine the best priority order for resource development.

These studies were conducted by making pairwise comparisons of programs and generating resources until the order was found that led to lowest expected value system cost. This priority order analysis involved only the discretionary conservation programs and generating resources. The nondiscretionary programs were excluded from the priority order tests; however, they were included in the model runs to ensure that their system effects and impact on the cost effectiveness of other resources would be included. The initial priority order was based on levelized cost estimates for the programs and resources, and the process allowed the generating resources to compete with conservation programs for priority order. A limit of at least a $10 million improvement in system cost was judgmentally imposed as the minimum improvement to justify a switch in priority order between two competing programs and/or resources.

Except for the amount of energy available for several of the resources, the conservation program assumptions for this analysis were consistent with the data described in Volume II, Chapter 5, and generating resource assumptions were consistent with Volume II, Chapter 6. For programs and generating resources in which the energy available was less than 200 average megawatts, the energy availability for these studies was raised to 200 average megawatts to ensure that the system effects of the resource would be captured in the present values. This increase in energy availability pertains only to these priority order studies. After the priority order was determined, the energy limits were again set back to those in Table 8-1 for further portfolio analysis. All sponsorship and financing assumptions were consistent with those described in Volume II, Chapter 4.

The results of this analysis are shown in Table 8-2. This is the priority order that was found to produce the lowest expected present value system cost across the entire load range, under the Council's base data assumptions and given the constraints mentioned above. This order was used as the basis for developing the resource portfolio, conducting sensitivity analysis, and development of Action Plan items. As stated earlier, the nondiscretionary programs are all given equal and top priority in resource development, and are only shown in the table for the sake of completeness.

The results of the last pass through the pairwise comparisons are shown in Table 8-3. This table shows the impact of switching the priority order of all contiguous pairs of discretionary resources in the portfolio. For example, moving existing industrial conservation ahead of existing residential conservation in the priority order, with all other resources in their original positions, causes a present value $35 million increase in the expected value of system costs. Note that cost differences due to a switch of the order for any pair of resources are generally quite small. This results primarily because the resources are already ordered according to cost effectiveness. Moving unlicensed coal to the top of the discretionary resource list would have a very large cost impact. Other factors which would tend to produce small cost changes are similarity of resource costs, relatively small amounts of energy for some programs and generating resources, and parallel resource development schedules.

Because development on many of the resources in the portfolio occurs simultaneously, a switch in priority order may lead only to small timing differences in resource development over most of the load range. Given that the same total amounts of two resources that have similar costs are developed, small changes in the timing of development will generally produce only small present value impacts.

The resource portfolio priority order shown in Table 8-2 represents a general order for development of resources during periods of acquisition. It does not mean that all of the potential of one type of conservation program or generating resource should be exhausted before moving to the next. As mentioned above, constraints on program development rates and resource lead times are likely to require parallel development paths for many of the resources in the portfolio.

Additionally, the methodology used in this analysis necessarily treats programs and resources as generic blocks. For instance, all of the potential cogeneration units have the same physical characteristics, capital costs, operating costs, lead times, seasonal distributions, etc. In reality, there are likely to be significant differences between individual cogeneration installations competing for resource acquisition. In the actual acquisition decision, all projects should be evaluated on their own merits, taking their own unique characteristics into account.

Option and Build Decision Rules

In addition to the order of resource priorities, two other decision rules are required to define the resource portfolio. These are referred to as the option and build levels.

The option level governs the amount of resource for which options would be acquired and held in inventory. The build level governs the amount of resource moved out of inventory and into actual construction. The option and build levels represent levels within the range of load uncertainty to use as guides for making resource decisions.

A hypothetical example is shown in Figure 8-6. In this example, the region has moved out along a somewhat random load path and finds itself at load level L in time period T. The future load path is still unknown and decisions must be made in the face of this uncertainty. To do this, a range forecast is first made from period T and a probability distribution is applied to the forecast range. Within this range forecast, two additional forecasts are made, one corresponding to the option level and the other to the build level. In this example, the option level of 90 percent would mean that, of all the possible

Table 8-3
Priority Order Studies

RESOURCES SWITCHES INPRIORTY ORDER			CHANGE IN SYSTEM COST (millions of present value $)
Agriculture	ahead of	Hydropower Efficiency	15
Existing Commercial	ahead of	Agriculture	-3
T&D Efficiency	ahead of	Existing Commercial	-2
Existing Residential	ahead of	T&D Efficiency	11
Existing Industrial	ahead of	Existing Residential	35
Combustion Turbines	ahead of	Existing Industrial	19
Small Hydropower	ahead of	Combustion Turbines	12
Cogeneration	ahead of	Small Hydropower	-1
Licensed Coal	ahead of	Cogeneration	2
Unlicensed Coal	ahead of	Licensed Coal	32

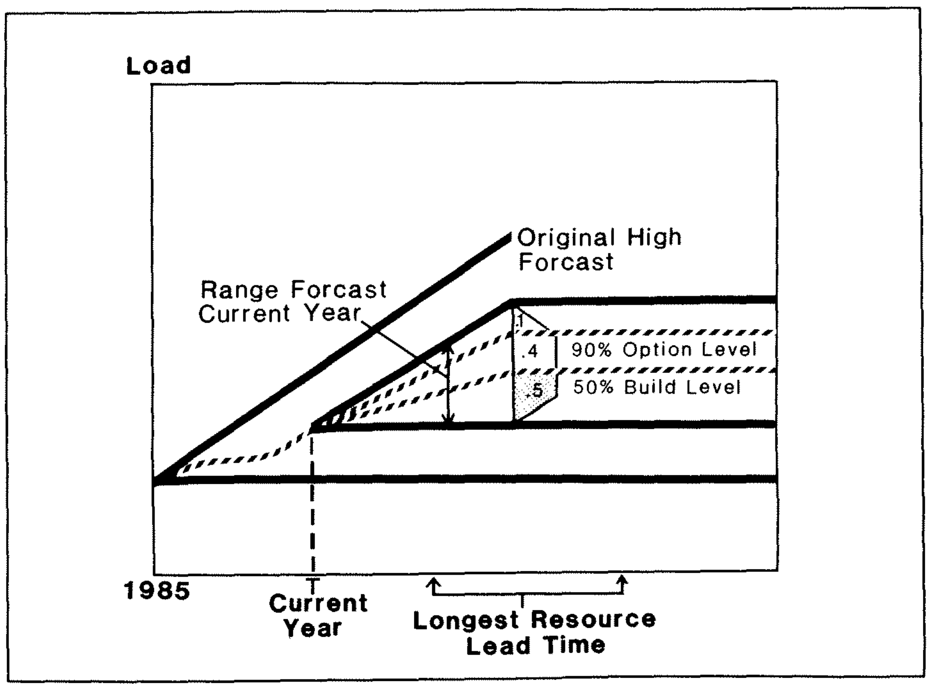


Figure 8-6
Option and Build Level

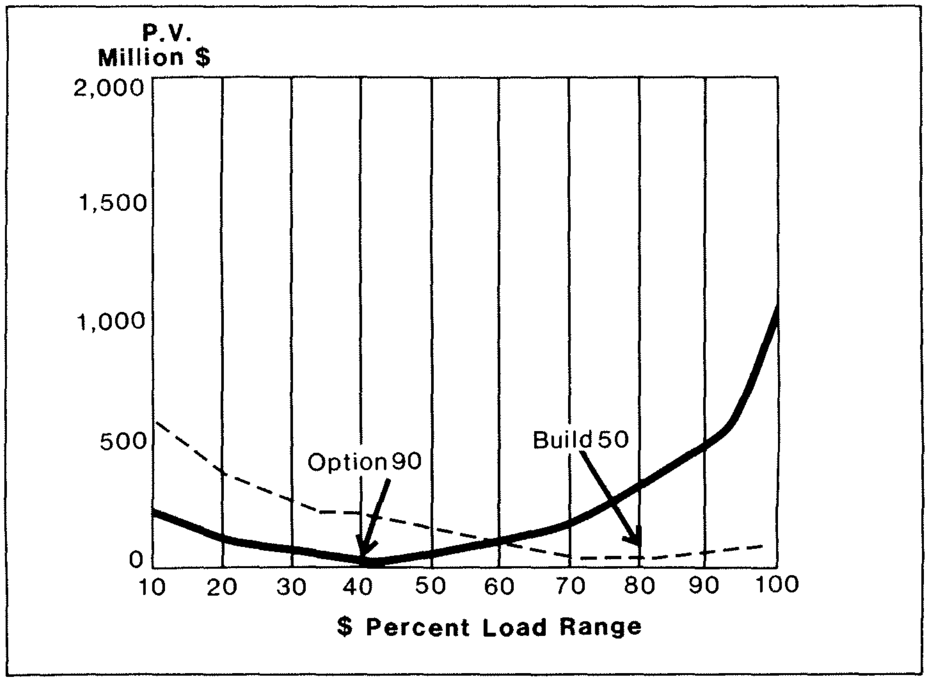


Figure 8-7
Cost of Option/Build Level Combinations

load paths from T forward, 90 percent would fall below the option level forecast and 10 percent above it. Similarly, a build level of 50 percent implies that there would be an equal chance of observing a load path either above or below the build level forecast.

Once these forecasts have been made, the resource priorities, resource availabilities, and option and construction lead times are used to make resource decisions. In the example, enough resources would be optioned to ensure that if the future loads did not exceed the 90 percent option level, there would be enough resources in inventory to meet the region's needs. Construction decisions, however, would be made only to cover the more conservative 50 percent build level, leaving an equal risk of being either surplus or deficit at some future time period.

The Council conducted a number of studies at various combinations of build and option levels to determine which combination would result in the lowest present value cost on an expected value basis. The results are shown in Figure 8-7. The solid line shows the system cost impact of holding the option level constant at 90 percent and changing the build level from 0 to 100 percent in 10 percent increments. The dashed line shows the cost impact of holding the build level constant at 50 percent and changing the option level in 10 percent increments. The graph illustrates that, generally, option levels toward the higher end of the load range and build levels toward the middle of the load range produce lower system costs. This result makes intuitive sense because the option cost of the resources in the portfolio is much less than the cost of their actual construction.

Options can be thought of as a relatively cheap form of insurance that reduce resource lead time and allow the region to guard against unanticipated periods of rapid load growth. It appears cost effective to "over option" resources and build an inventory that exceeds expected need in order to assure flexibility in the resource acquisition process. However, because of the much higher costs associated with build decisions, they should be guided by using more conservative load level targets, near the expected value of load, to produce the most cost-effective portfolio on an expected value basis across the wide range of possible load outcomes.

Figure 8-7 also shows that the expected value of system costs is quite stable across build levels from 30 to 60 percent and for option levels from 70 to 100 percent, for the set of data used in this analysis. The shapes of these curves will be driven by the data that influence the relative costs of underbuilding and overbuilding, such as option costs, the structure and price of the secondary market, availability of extra-regional purchases, cost of curtailment of interruptible and firm load, and the fixed/variable cost ratios of resources in the portfolio. System costs will also be influenced by characteristics of resources in the portfolio that affect the ability to correct for errors in the planning process, such as generating resource lead time and conservation program ramp rate constraints. For example a portfolio comprised totally of ten-year lead time resources will show a much higher variance in the load/resource balance than a portfolio comprised primarily of two- or three-year lead time resources. For a 50 percent build level, the ten-year lead time portfolio will show much higher levels of overbuilding in low load conditions and much higher levels of underbuilding in high load conditions. This occurs because short-term forecasts are likely to be much more accurate than long-term forecasts, and the degree of expected forecast error will diminish rapidly with shorter lead times.

Insufficient time was available in development of the 1986 plan to perform the extensive sensitivity analysis required to investigate all of these issues more fully. For purposes of portfolio analysis in this plan the Council has assumed the use of a 90 percent option level and a 50 percent build level. The level of the current surplus allows time for further study of the appropriate levels within the load forecast range to use as guides in resource decision making.

Description of the Resource Portfolio

Because the resource portfolio is defined through the availability of resources, the priority order for resource development, and the option and build decision rules, resource activity contained in the portfolio can be described in a number of ways. Perhaps the most straightforward description is to present the implied resource schedules required to meet load under several different load scenarios. Figure 8-8 illustrates the regional

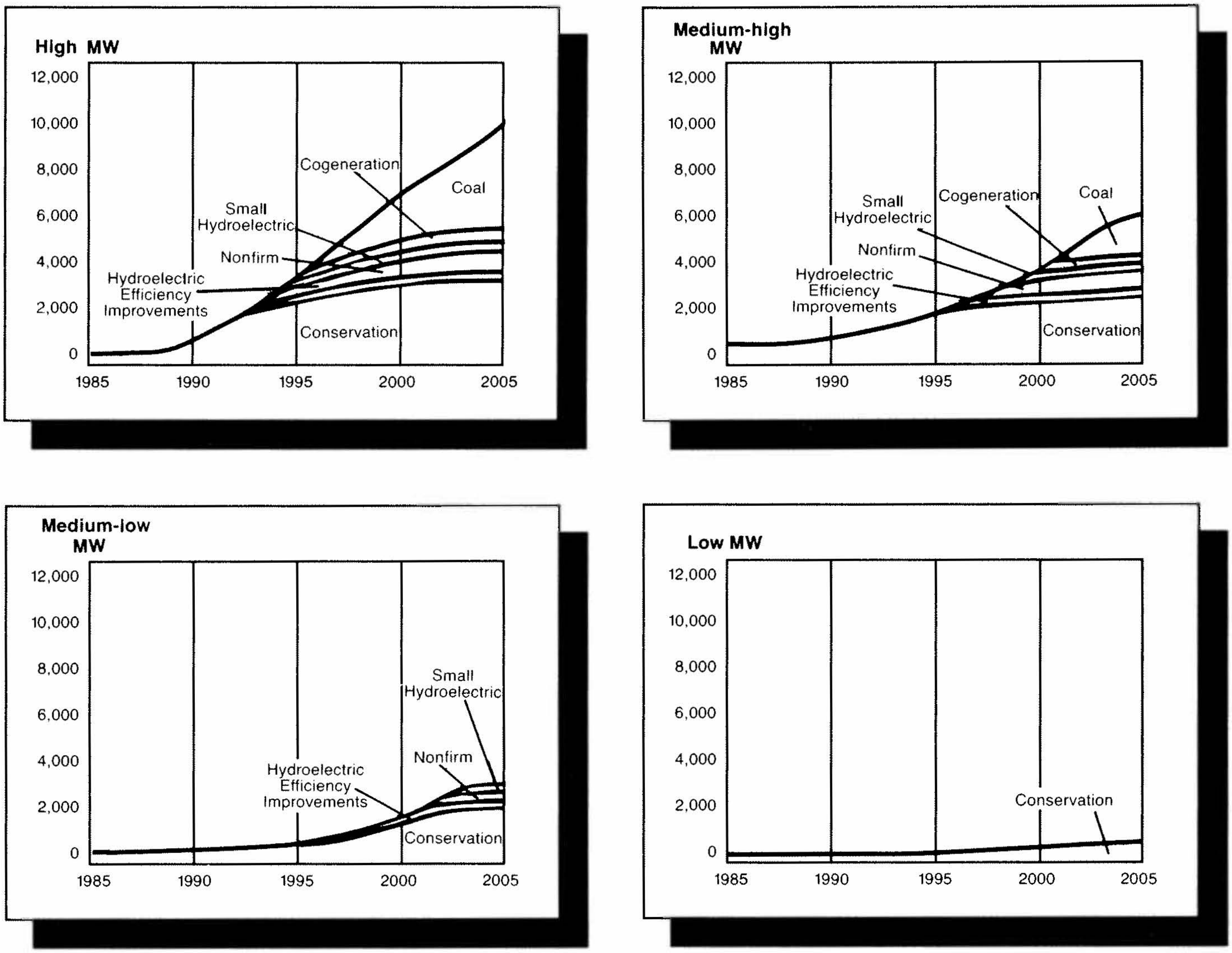


Figure 8-8
Regional Resource Schedules: High, Medium-High, Medium-Low, Low

resource development that would be required to attain load/resource balance under each of the four regional load forecasts. A very wide range of resource activity is apparent, moving from only nondiscretionary conservation programs such as the model conservation standards in the low forecast, to full development of all conservation programs, small hydropower, additional nonfirm energy, and cogeneration, along with 12 new coal units, in the high forecast. These data, showing the annual loads, year by year development for each of the resources, and the resulting load/resource balance, are presented in tabular form in Appendix 8-A.

In Figure 8-9, this same set of resource schedules is shown for Bonneville with obligations for only public utility loads. Because of the large current surplus on the federal system and the lower levels of load increases for the the public utilities, the only resources developed through the medium-high forecast are public utility conservation and a small amount of hydropower efficiency improvement. In the high forecast, some generating resources are developed, but this development is much later than in the regional cases. The tabular data supporting Figure 8-9 are also contained in Appendix 8-A.

Note that the resource schedules as shown in Figure 8-8 and 8-9 are not based on the 90/50 option/build decision rule. The schedules shown here produce load/resource balance in all but the low case, where the region is surplus for the entire planning horizon without addition of new resources. These schedules contain an implicit assumption of perfect knowledge of where long-term loads will eventually lead before the resource decisions are made. Given the uncertainty in long-term load, this is an unrealistic assumption. The schedules are represented this way because public comment received on the

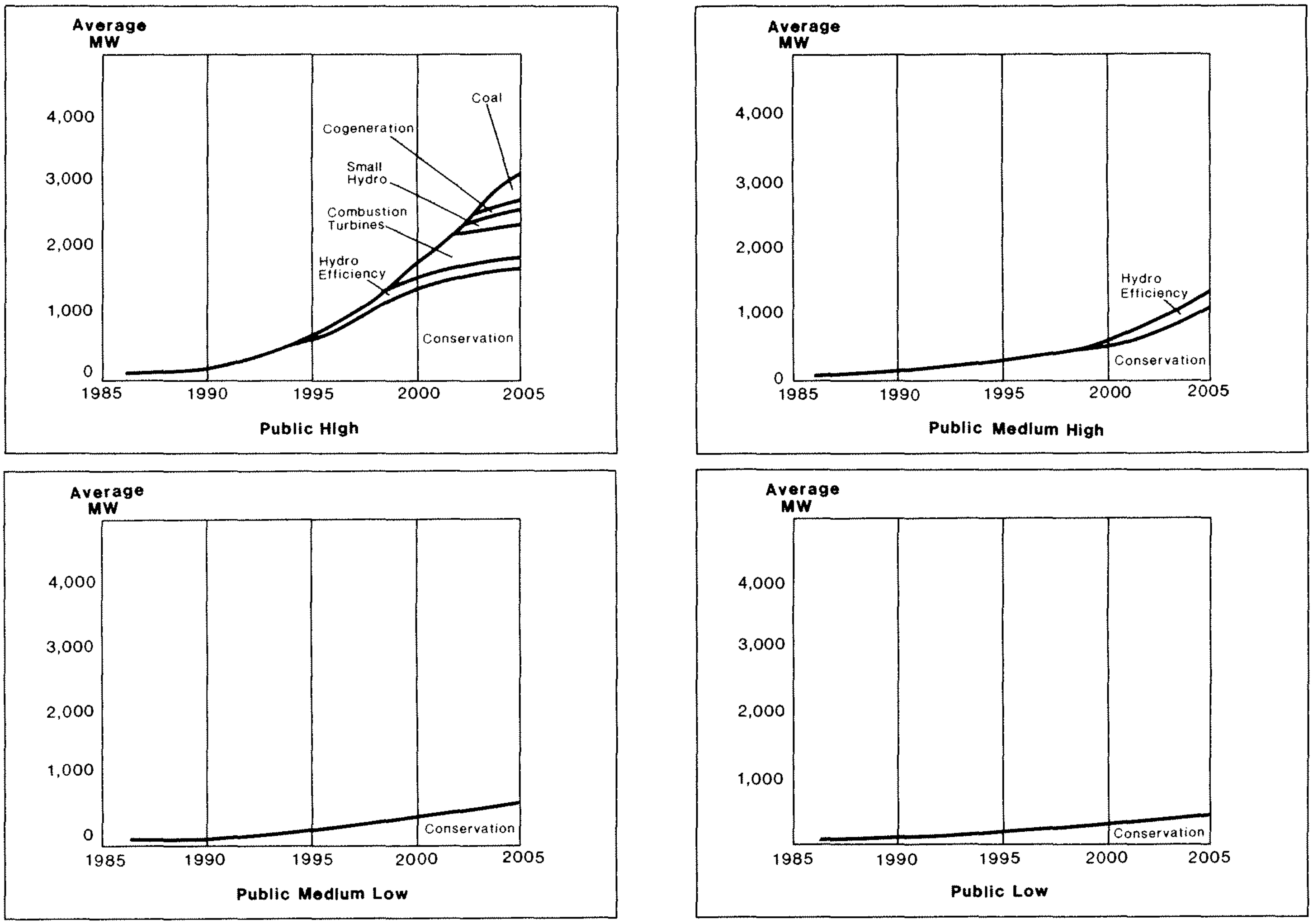


Figure 8-9
Public Utility Resource Schedules: High, Medium-High, Medium-Low, Low

draft plan urged the Council to indicate the amount of resource development needed to meet the high forecast and argued that showing resource schedules which did not meet the high understated the risk inherent in the resource portfolio.

The Council agrees that there is certain information value in providing illustrations of the amounts and types of resources needed to meet load in the high and has done so here. However, the reader should be aware that, given imperfect knowledge of load, a non-zero probability of loads at or near the high, and resource lead times approaching ten years for some programs and generating resources, the only way the high forecast can be met with certainty is to commit to resource build decisions that would cover a high load event, well in advance of any indication that high loads would actually occur. The Council would argue that a strategy that committed resource decisions to cover the very low probability event of a high load outcome is a much riskier strategy than one that builds to a dynamic expected value of load (a 50 percent build level). Building to the high would be likely to lead to the kind of overbuilding that led the region to the condition in which it finds itself today: a 2,500 megawatt surplus, two nuclear units on hold, and several others terminated. The Council's analysis, as illustrated in Figure 8-7, shows that the policy of building to the high (100 percent build level) has an expected value penalty approaching $1.7 billion.

For purposes of illustrating resource schedules, the Council has used an assumption of perfect knowledge of load. However, all of the portfolio analysis and any sensitivity studies use the more realistic assumption of imperfect knowledge of load and employ the 90 percent option and 50 percent build decision rules.

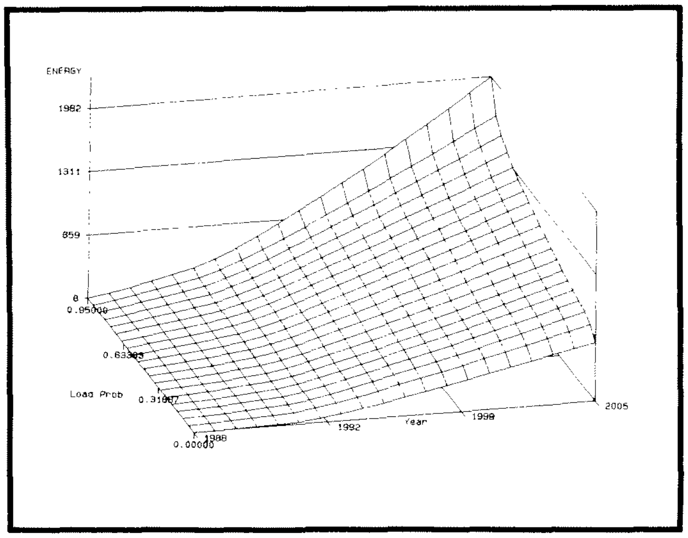


Figure 8-10
Nondiscretionary Conservation Program Energy as a Function of Load Path

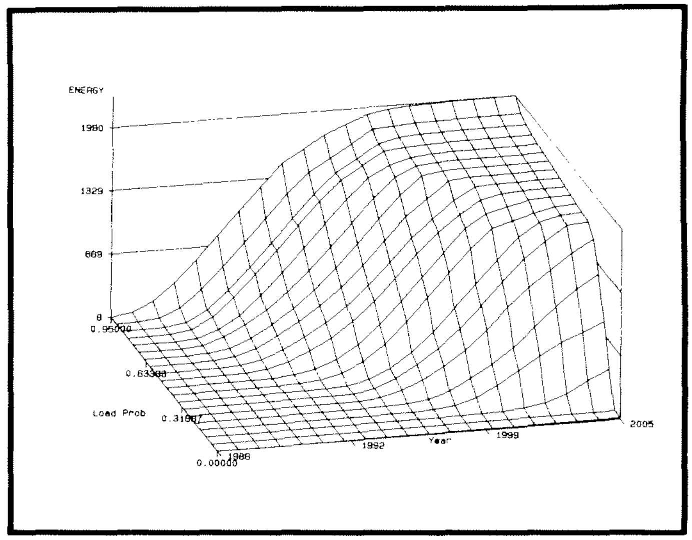


Figure 8-11
Discretionary Conservation Program Energy as a Function of Load Path

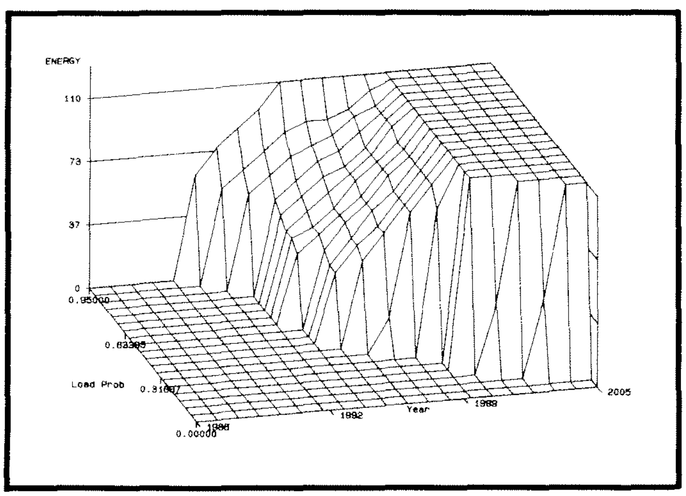


Figure 8-12
Hydropower Efficiency Energy as a Function of Load Path

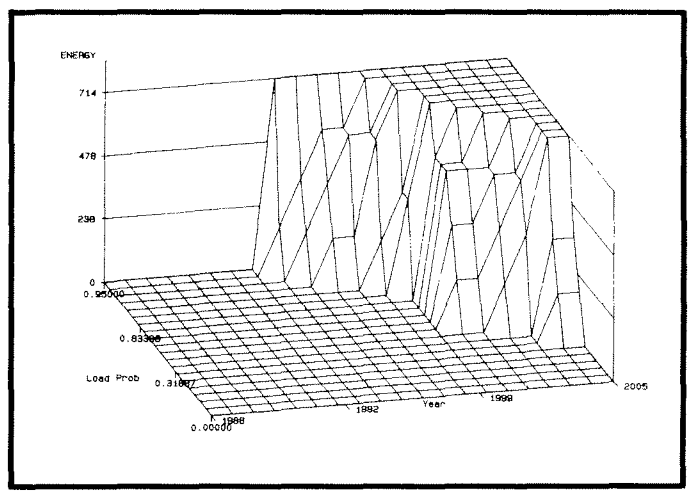


Figure 8-13
Combustion Turbine (Nonfirm) Energy as a Function of Load Path

The four specific scenarios just presented are indications of resource development actions should a particular load scenario occur. In fact, the likelihood is extremely small that any of these specific regional load paths, and the associated resource actions, will occur. The actual portfolio analysis is conducted across a large number of load paths and the resource schedules vary continuously across the entire load range. A more complete illustration of the portfolio's impact is illustrated in Figures 8-10 through 8-16. These three-dimensional surfaces show the timing and amount of energy additions for each resource as a function of load.

Figure 8-10 shows the effect of the nondiscretionary conservation programs through time. This graph includes the effects of both the residential and commercial model conservation standards as well as energy savings from the water heater, refrigerator/freezer, and manufactured home programs. The axis going across the page is time, moving from 1985 to 2005. The axis going into the page represents the cumulative probability for load and ranges from 0 to 1.0. A value on this axis of 0 would represent the low load forecast, and value of 1.0 would represent the high. Finally, the vertical axis shows the average megawatts of resource developed in the particular combination of future year and load level. For readability, the data for these graphics were developed based on only 20 load scenarios. Each line moving across the

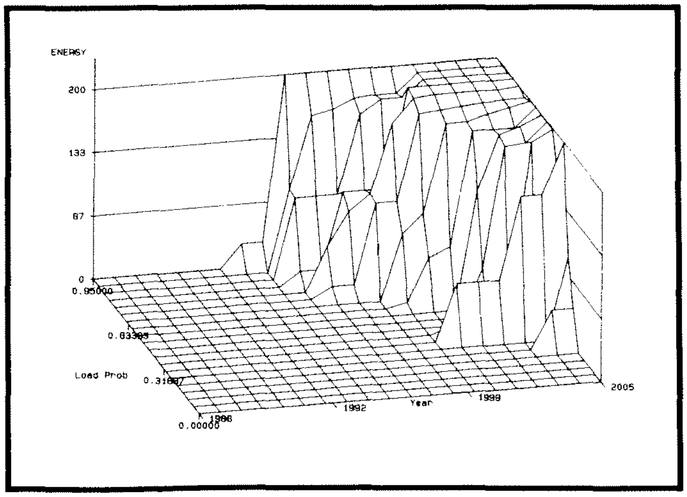


Figure 8-14
Small Hydropower Energy as a Function of Load Path

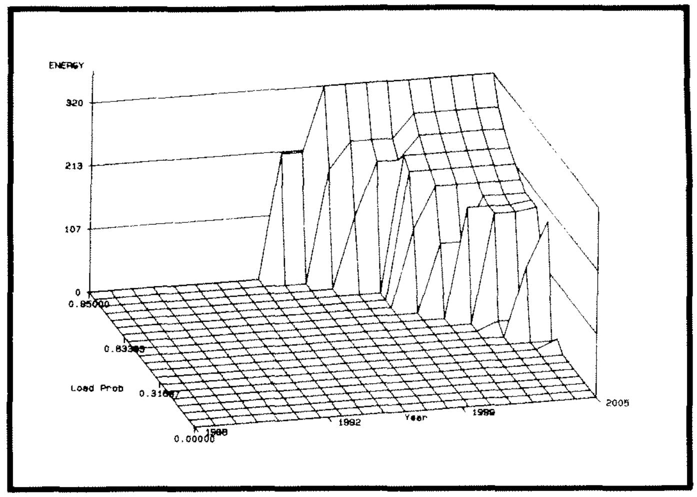


Figure 8-15
Cogeneration Energy as a Function of Load Path

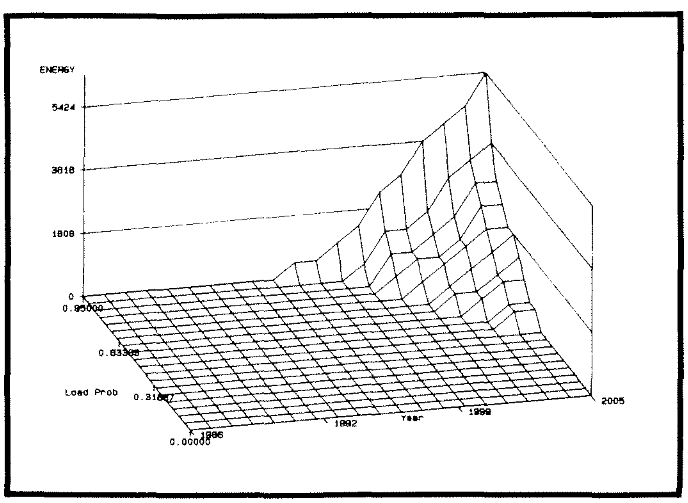


Figure 8-16
Coal Energy as a Function of Load Path

study period represents one of these scenarios. However, the actual portfolio analysis is conducted across hundreds of different load paths.

Because of the continuity of savings across the load range, the graph of the model conservation standards is a relatively smooth surface. The graph also illustrates the ability of the standards to respond to load, providing increased savings at higher loads and lesser amounts of savings at the lower load levels.

Other resources, such as combustion turbines and small hydropower (Figures 8-13 and 8-14), show different characteristics. Because of their discretionary nature, they do not automatically respond to load, but are brought on line as triggered by forecast need. Because of their lower position in the priority list, they are generally scheduled either later or only in the higher forecasts, as shown by their position in the back right-hand corner of the figures. This is especially pronounced in the case of coal, as shown in Figure 8-16.

While the three-dimensional surfaces imply that the resource priorities regarded to be most cost effective are generally followed, this does not necessarily mean that all of one resource is exhausted before moving to the next. For instance, limitations on conservation program development rates may mean that small hydropower or nonfirm strategies have to be developed in parallel. Additionally, to maintain an approximate load/resource balance in periods of rapid load growth, lead time considerations may require low priority resources with short lead times to be developed ahead of higher priority resources with longer lead times. The uneven surfaces for small hydropower and cogeneration are due partly to this, plus the relatively small amounts of energy available for these resources and the exaggerated scales on the graphs.

Up to this point, the description of the portfolio has focused primarily on the timing of firm energy contributions that could be expected from the various resources at different load levels. Equally important are the decision schedules required to achieve these contributions.

Figure 8-17 illustrates the timing of discretionary conservation program start-ups required for both the region as a whole and for the public utilities only. The start-ups are shown as a function of the load path followed, with high loads represented by a probability of 1.0 and low loads by a probability of 0. If regional loads were to follow the high forecast, some conservation programs would start up or increase over current activity levels as early as 1987. This start-up date slides to 1999 at about a 10 percent load probability level. This is the lowest point in the load range for which any new conservation is required during the planning horizon. The most probable time period for regional need to increase activity in conservation programs is the early 1990s.

For public utility needs only, the conservation start-up dates are much later. If high loads were to develop, the earliest start-up dates would be around 1990. This date slides out rapidly to 1995 at the 90 percent load probability level, indicating only a 10 percent chance of a need for new conservation activity in the public sector before 1995. No new activity at all is required in the lower half of the load range to meet public utility needs within the planning horizon.

Information regarding the timing of initial decision points for all the generating resources is shown in Figures 8-18 through 8-23. These figures depict the first new option and build decisions needed for both the region as a whole and also for just the

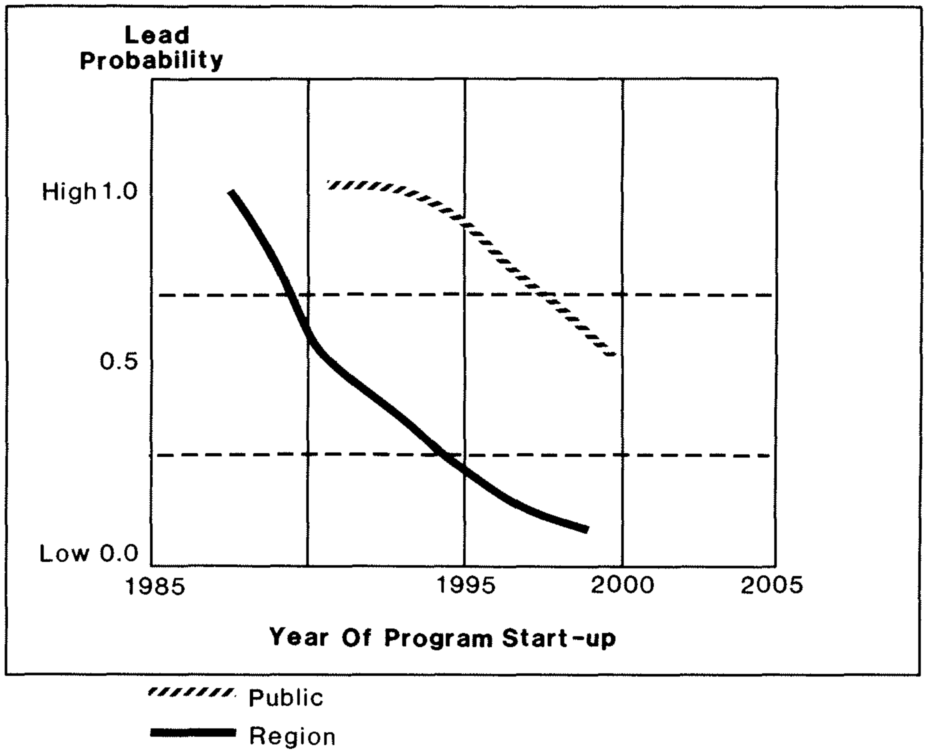


Figure 8-17
Conservation Program Start-ups

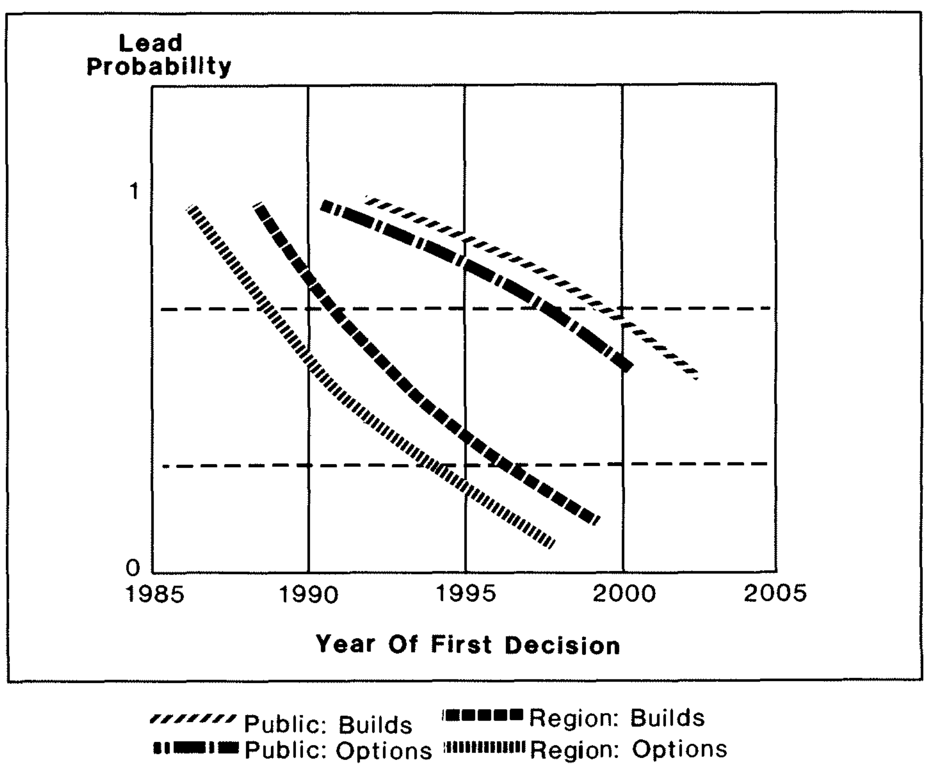


Figure 8-18
Initial Decisions, Hydropower Efficiency Improvements

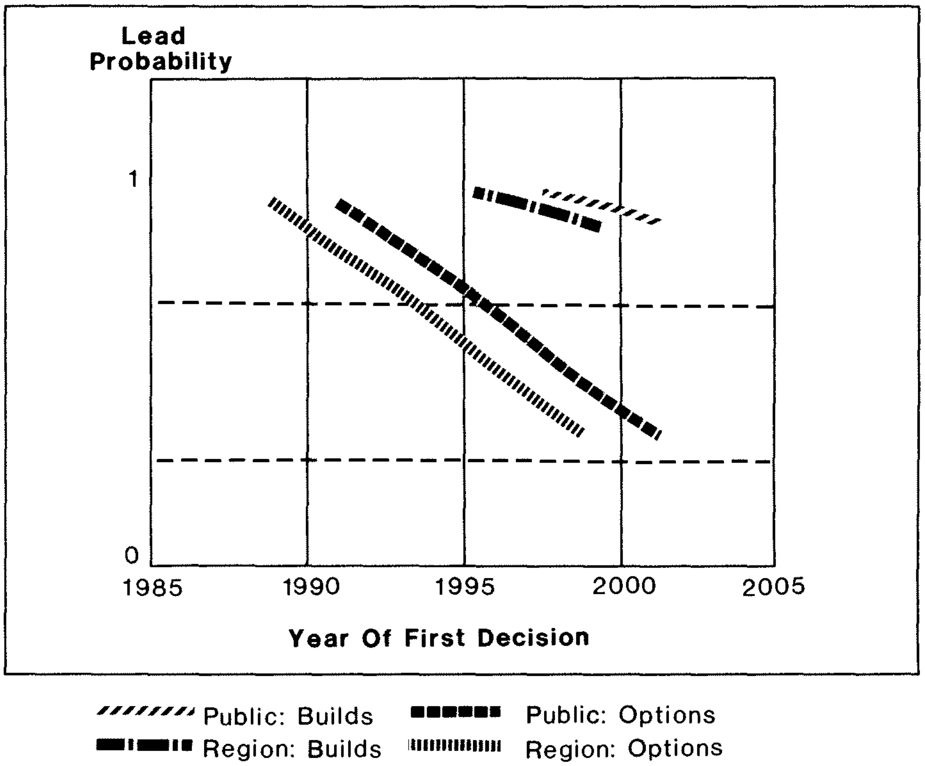


Figure 8-19
Initial Decisions, Combustion Turbines (Nonfirm)

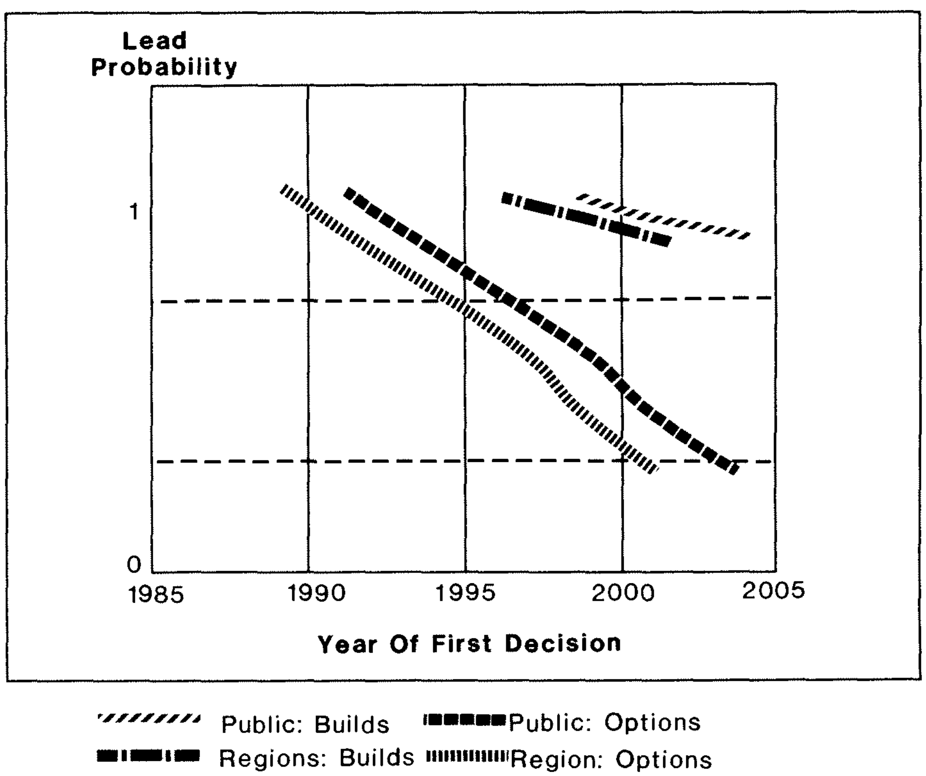
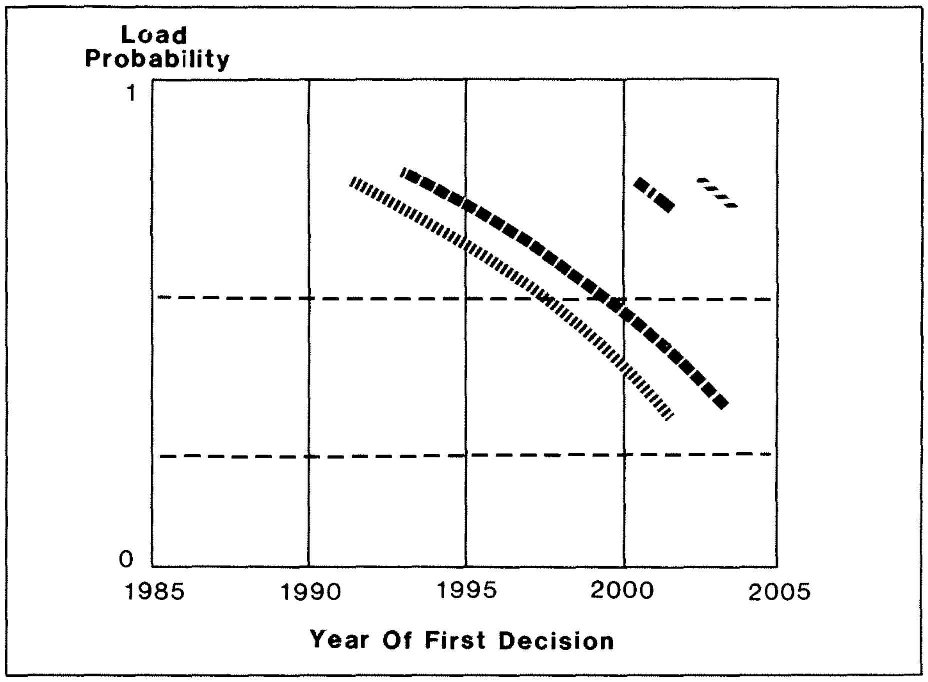


Figure 8-20
Initial Decisions, Small Hydropower

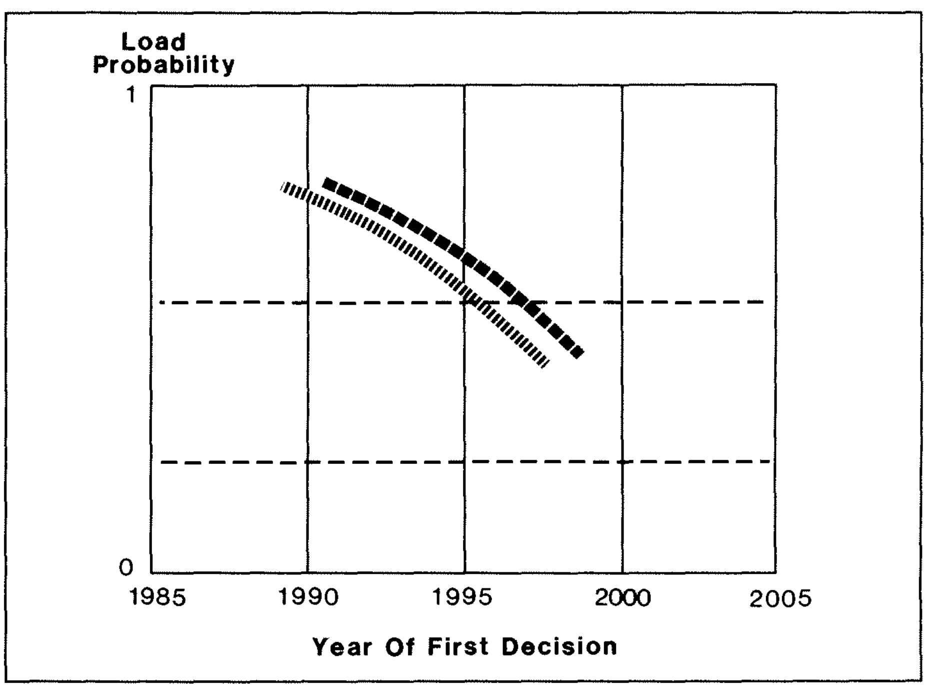
public utilities. The information is again displayed as a function of load path, with low loads represented by a probability of 0 and high loads by a probability of 1. Figure 8-18 shows the timing of decisions on the highest priority discretionary resource in the portfolio, hydropower efficiency improvements. In a high load case, the first option decisions needed to meet regional load are made in 1987 and the first build decisions occur two years later in 1989. The initial option and build decision dates move out to 1998 and 2000 respectively in the lowest load condition in which hydropower efficiency improvements are needed, a load probability of about 8 percent. Because hydropower efficiency is a higher priority resource than any of the discretionary conservation programs, activity extends slightly further down into the load range than for conservation programs. For the public utilities, the first option decisions made under high load conditions occur as early as 1990, with build decisions following in 1992. These dates move out ten years to 2000 and 2002 at about a 50 percent load probability level.

Most of the other generating resources show decision activity occurring several years later than that on hydropower efficiency, and across a narrower portion of the load range, primarily because of their lower priority. Note also that, for coal, if the region follows a load path in the upper end of the load range, option activity may be called for as early as 1989. Even though coal is the lowest priority resource in the portfolio, the length of its lead time may require decisions in the earlier years of the planning horizon.



Decision — Public: Builds — Public: Options — Region: Builds — Region: Options

Figure 8-21
Initial Decisions, Cogeneration



Decision — Public: Builds — Public: Options — Region: Builds — Region: Options

Figure 8-22
Initial Decisions, Licensed Coal

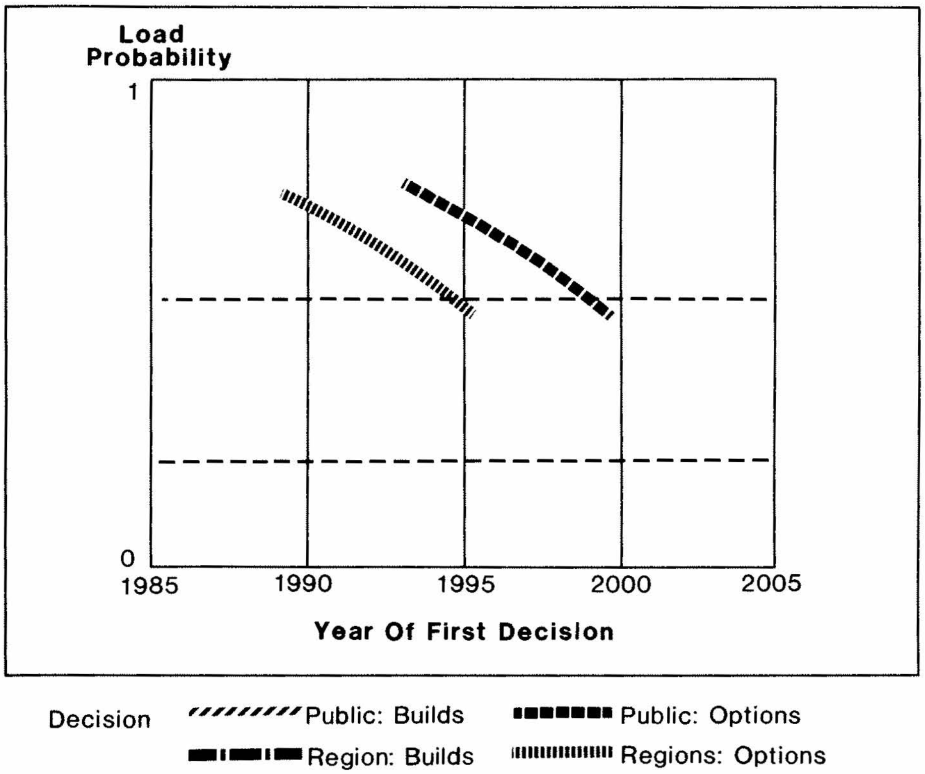


Figure 8-23
Initial Decisions, Unlicensed Coal

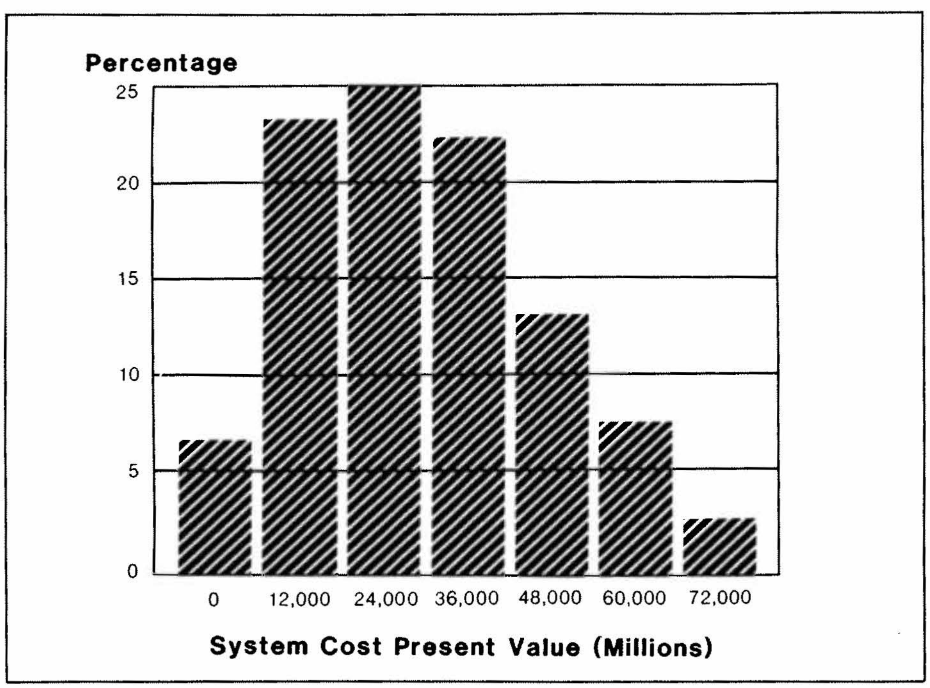


Figure 8-24
System Cost Distribution

Section B: Portfolio Uncertainty

As has been stated previously, the Council believes that recognition of the large uncertainties inherent in long range resource planning is imperative to producing an effective and adaptable power plan. Most of the uncertainty directly included in the analysis leading to the final portfolio concerns future load and the large impact it has on the types and amounts of resources that might be needed. Resource uncertainty has been included in the analysis to the extent that conservation and generating resource supply can vary with the economics and demographics across changing load forecasts (e.g., more energy available from the model conservation standards in the high than in the low). However, the planning models are deterministic for resource availability on a specific load path. While the Council feels that the data development process has produced reasonable and balanced estimates of future resource supply, there's no question that a range of uncertainty exists around these values as well.

Based on the public comment received on the draft plan, the Council performed a number of sensitivity analyses on the resource portfolio. These studies were designed primarily to investigate the impact of differing levels of conservation supply than projected in the final portfolio, or of having less flexibility in development of resources. Additional studies were performed to estimate the impact of having more uncertainty on direct service industry load than is assumed in the base portfolio, the impact of not being able to secure resource options, and the consequences of failing to attain regional cooperation on resource development. These studies were all performed using the Decision Model, and, except as noted, used the same data, resource priorities, and decision rules used in the final resource portfolio. All studies were performed using 100 load paths, with the same set of load paths in each case. The parameters of interest in each study were the changes in cost from the base portfolio and the changes in the timing of resource decisions.

Figure 8-24 is a frequency distribution for system cost present values under the base portfolio assumptions, using 100 load paths. It has has an expected value of nearly $30 billion, with a range from $0 to $72 billion. The variation in system cost is driven primarily by variation in load. Loads in the low end of the load range will require very little additional resource development, will have relatively low production and purchase costs, and will exhibit high levels of secondary revenue. High loads require intensive resource development and high levels of capital expenditure, have high production costs, and generate lesser amounts of secondary revenue because of the shorter duration of the surplus.

The impact on the frequency distribution of initial unlicensed coal options was isolated and used as an indicator of the impact on timing of resource decisions. This is because an option on a coal unit may be required in the relatively near future (due to the length of its lead time, as early or before option decisions on most other generating resources — see Figure 8-23), and because of the amount of energy represented in the unit size of this resource. Figure 8-25 shows a histogram for the timing of the first options taken on unlicensed coal units in the base portfolio across the various load paths. It is not based on all the coal option decisions made in the simulation; those histograms would have more density toward the mid 1990s. It is based only on the timing of the first coal option taken, if any, in the load paths experienced by the model. The last period in which coal option decisions occur is 1995 because, with a ten-year total lead time, decisions made after this point would be targeted for dates outside the planning horizon. The size of the bar to the far right represents the probability that no coal options are taken in the planning horizon, and shows that, in the base portfolio, no options are needed on unlicensed coal about one-third of the time. The sum of the probabilities between 1986 and 1990 yield an estimate of the probability that at least one coal option is needed by 1990. For the base case portfolio, that value is about 30 percent.

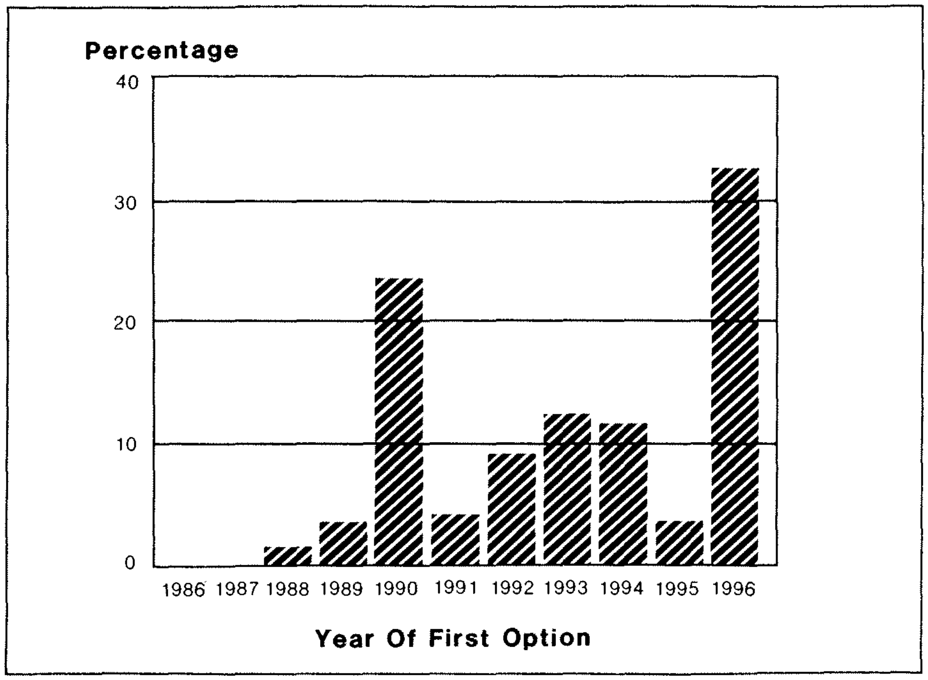


Figure 8-25
First Coal Options, Base Portfolio

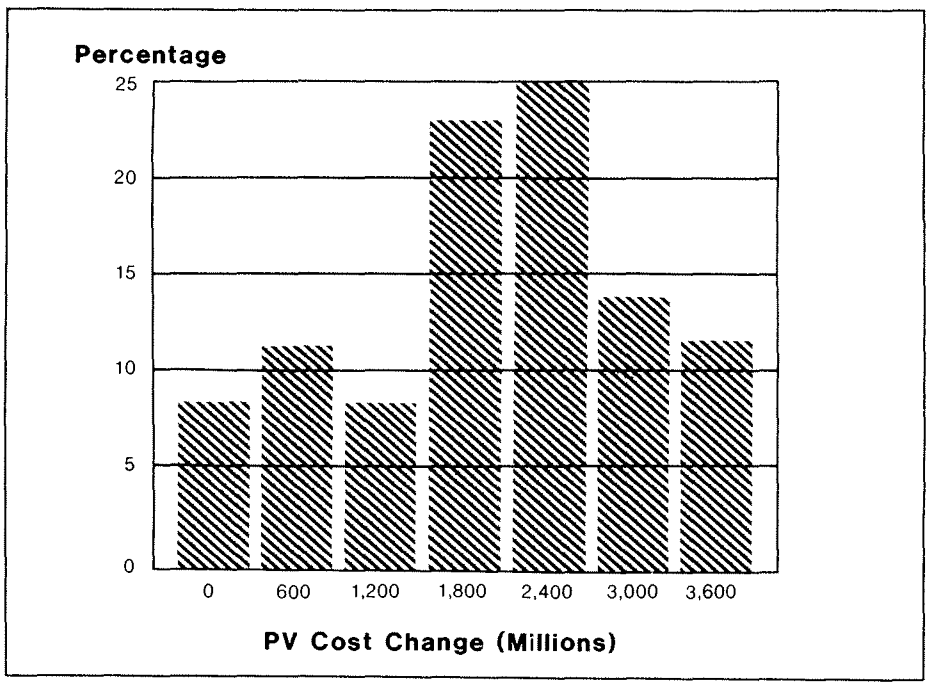


Figure 8-26
Cost Impact of One-Third Less Conservation

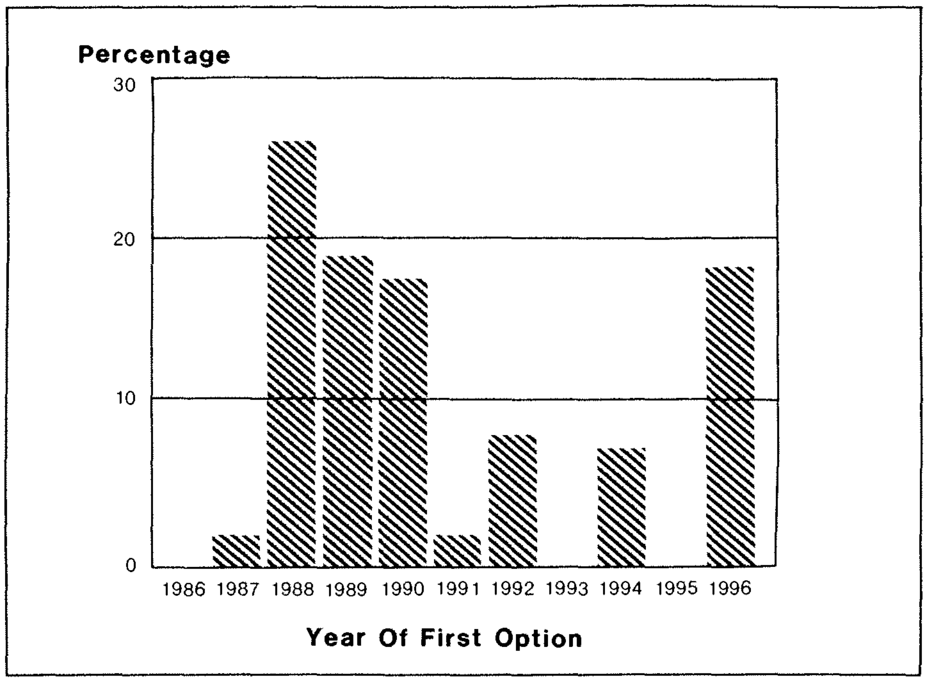


Figure 8-27
First Coal Options, One-Third Less Conservation

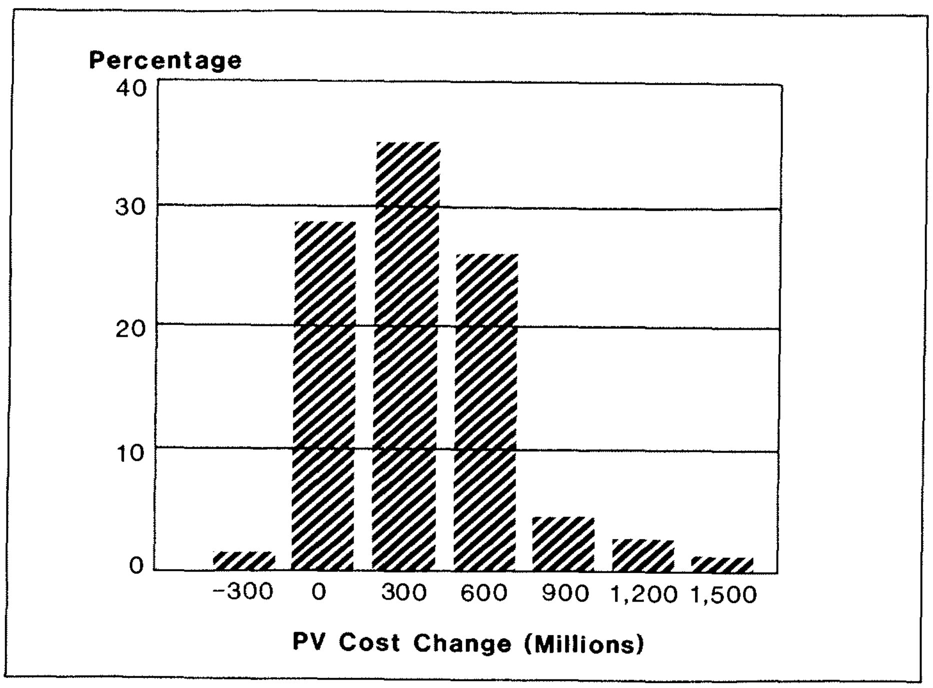


Figure 8-28
Cost Impact of Slower Conservation Ramp Rates

Impact of Less Conservation Supply

One analysis was performed under the assumption that one-third less energy would be available in all of the conservation programs in the resource portfolio. The study changed only the total energy supply, it did not affect the cost effectiveness of individual conservation programs. The results of the analysis are shown in Figures 8-26 and 8-27. Figure 8-26 shows the present value cost impact of this reduction in conservation supply to have an expected value system cost increase of $2 billion to the region, with the possible cost penalty ranging from $0 to over $3.6 billion. Figure 8-27 shows a frequency distribution for the first unlicensed coal options needed with one-third less conservation supply. The probability here that a coal option will be needed by 1990 is about 65 percent, compared to about 30 percent for the base portfolio.

Impact of Slower Conservation Ramp Rates

The Council's assumptions for the maximum activity levels of conservation programs and the rates at which the programs can be accelerated to those activity levels, yield an average of about ten years total development time to capture the bulk of the energy in the existing sector conservation programs. While there is very little data available on this subject, some public comment indicated that this was an optimistic assumption, and that total lead times of 15 to 20 years were more reasonable. A sensitivity analysis was conducted by reducing the existing sector program ramp rates by 50 percent, which would yield total program lead times of about 20 years. The impact is shown in Figures 8-28 and 8-29. The cost impact ranges from $0 to an increase of $1.5 billion, with a mean increase of about $340 million. The distribution for first coal options is shown in Figure 8-29 and indicates a probability of about 50 percent that a coal option would be needed by 1990.

Impact of Less Conservation Combined with Slower Ramp Rates

The assumptions in the two previous sensitivity analyses were combined to determine the impact of having both one-third less conservation supply available and 20-year ramp rates on the remaining conservation supply. Impacts of the previous two sensitivities are not directly additive, because in this case the reduced ramp rates act on a reduced conservation supply. The cost and schedule impacts are shown in Figures 8-30 and 8-31. The cost impact shows an expected value increase of about $2.25 billion, with a potential range from $0 to over $4.2 billion. Probability of need for a coal option by 1990 increases to 85 percent.

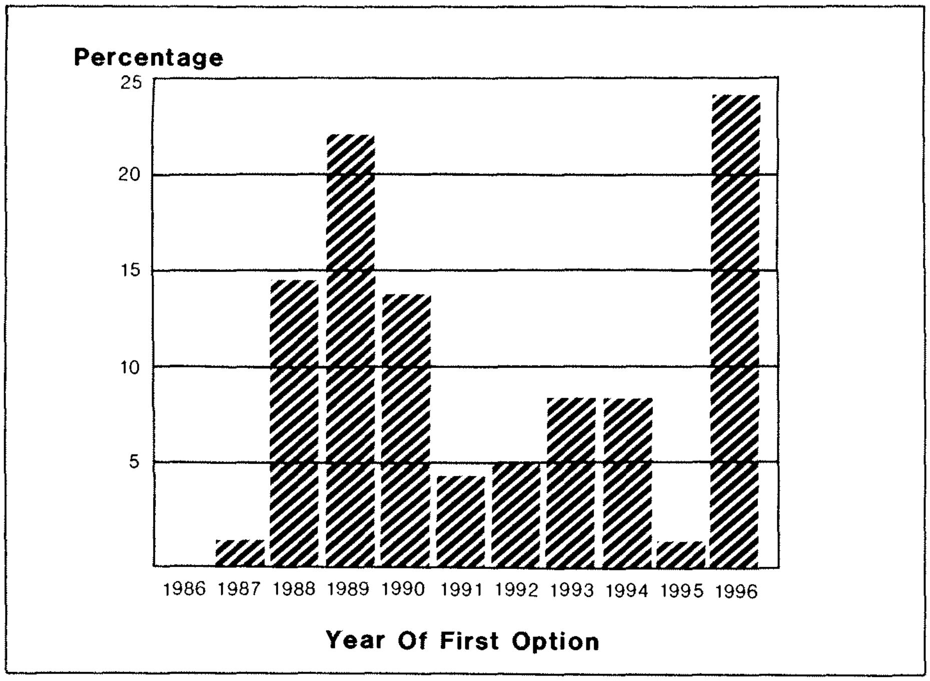


Figure 8-29
First Coal Options, Slower Conservation Ramp Rates

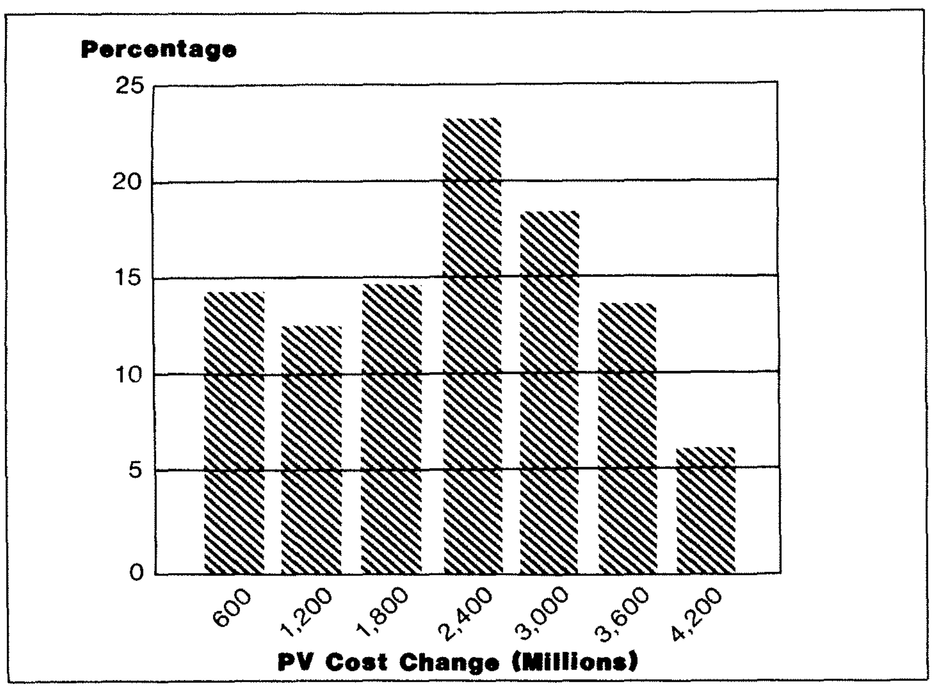


Figure 8-30
Cost Impact of Less Conservation and Slower Ramp Rates

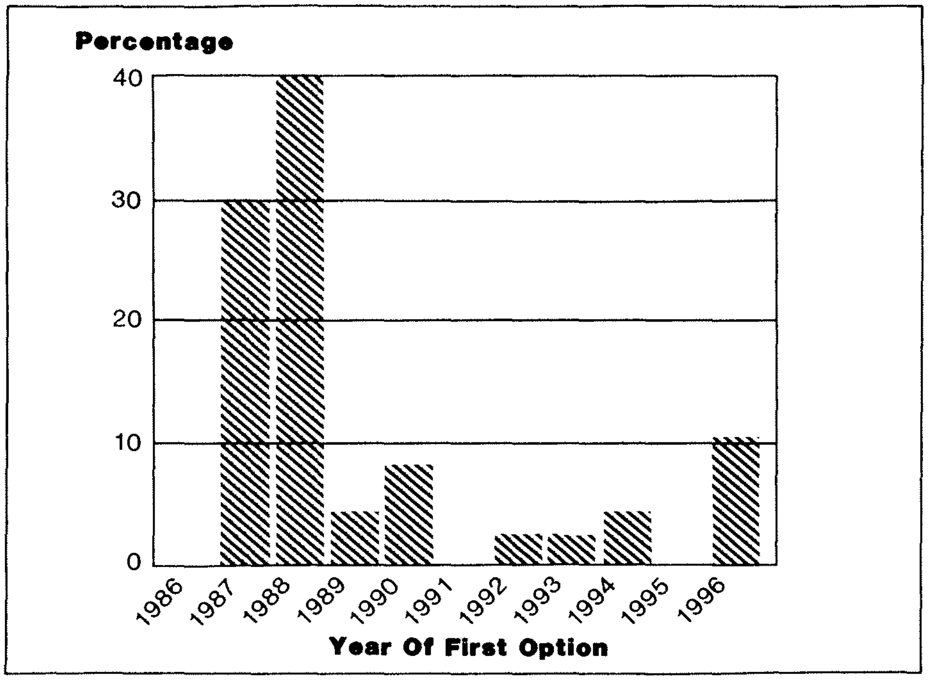


Figure 8-31
First Coal Options, Less Conservation and Slower Ramp Rates

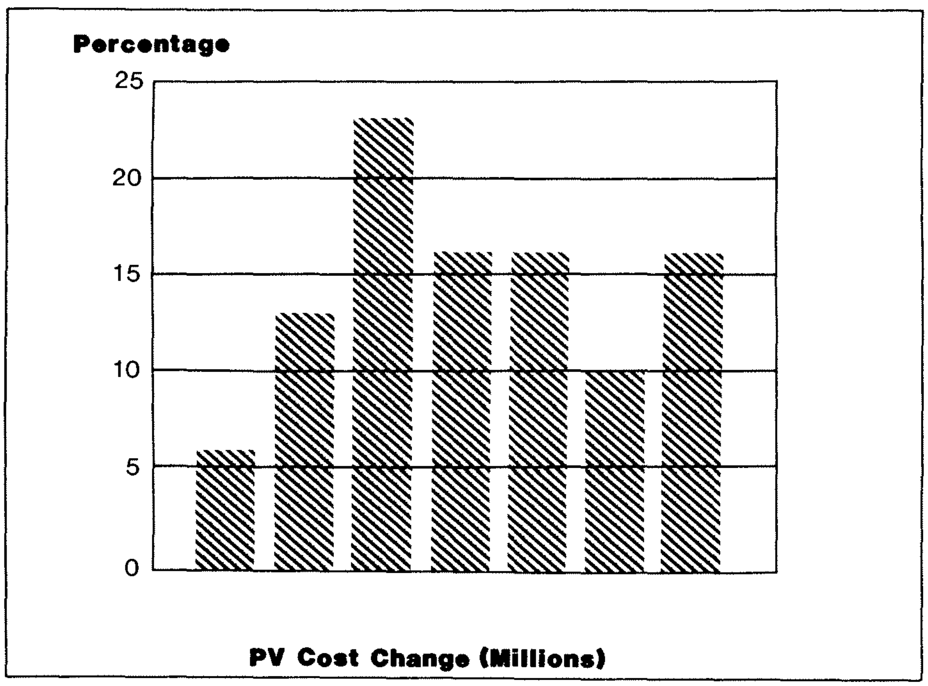


Figure 8-32
Cost Impact of One-Third More Conservation

Impact of Higher Conservation Supply

It is also possible that the Council has underestimated the amounts of cost-effective conservation supply available over the study horizon. A study was performed under the assumption that one-third more energy was available in each of the programs in the portfolio, at their current average cost. The results are summarized in Figures 8-32 and 8-33. The cost impact ranges from $0 to a cost savings of $3.6 billion, with an expected value savings of $1.71 billion. The probability of need for a coal option by 1990 falls to under 5 percent.

Impact of Delay in Implementation of the MCS

The impact of delayed implementation of the model conservation standards (MCS) was investigated by assuming that no energy savings would be produced by either the residential or commercial MCS before September 1991. The interim energy savings were treated as a lost opportunity resource, and would be replaced by resources lower in the portfolio priority list as needed across the forecast range. The cost and schedule impacts are represented in Figures 8-34 and 8-35. The cost impact ranges from a cost reduction of $120 million to increased costs of $600 million, with an expected value cost increase of $175 million. Because the MCS is a nondiscretionary resource, with energy savings and costs accruing regardless of need, delay of the MCS produces present value cost reductions at the lower end of the load range, where the regional surplus continues throughout the planning horizon and there is no need for any MCS savings. However, the cost savings in low load conditions are more than offset by the cost increases occurring in medium and high load cases, where the MCS energy lost during the delay is replaced with more expensive resources. Under the MCS delay assumptions, the probability of need for a coal option by 1990 is about the same as in the base case, approximately 30 percent.

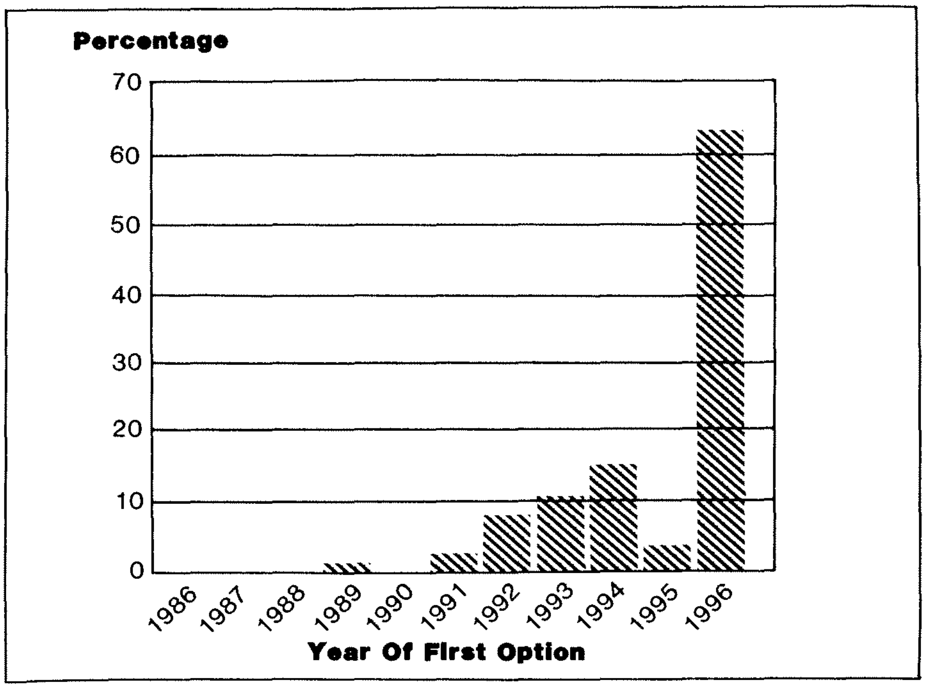


Figure 8-33
First Coal Options, One-Third More Conservation

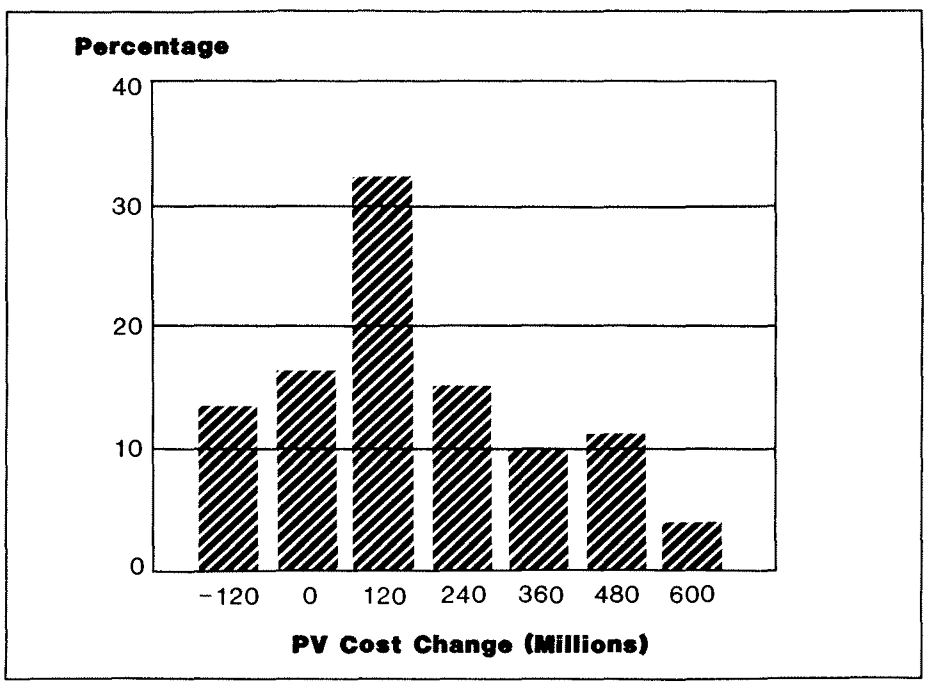


Figure 8-34
Cost Impact of MCS Delay

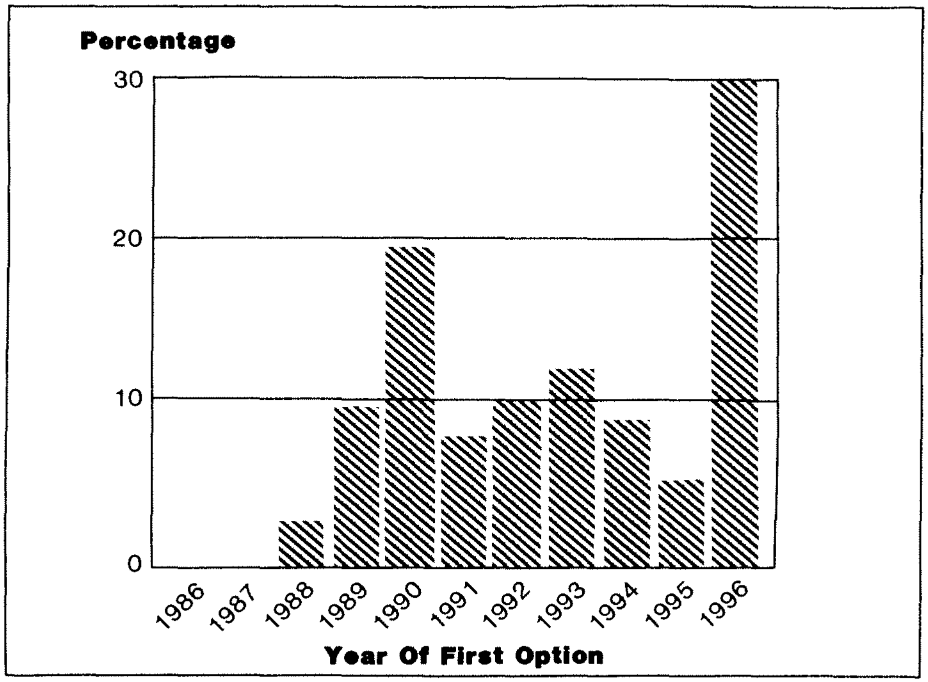


Figure 8-35
First Coal Options, MCS Delay

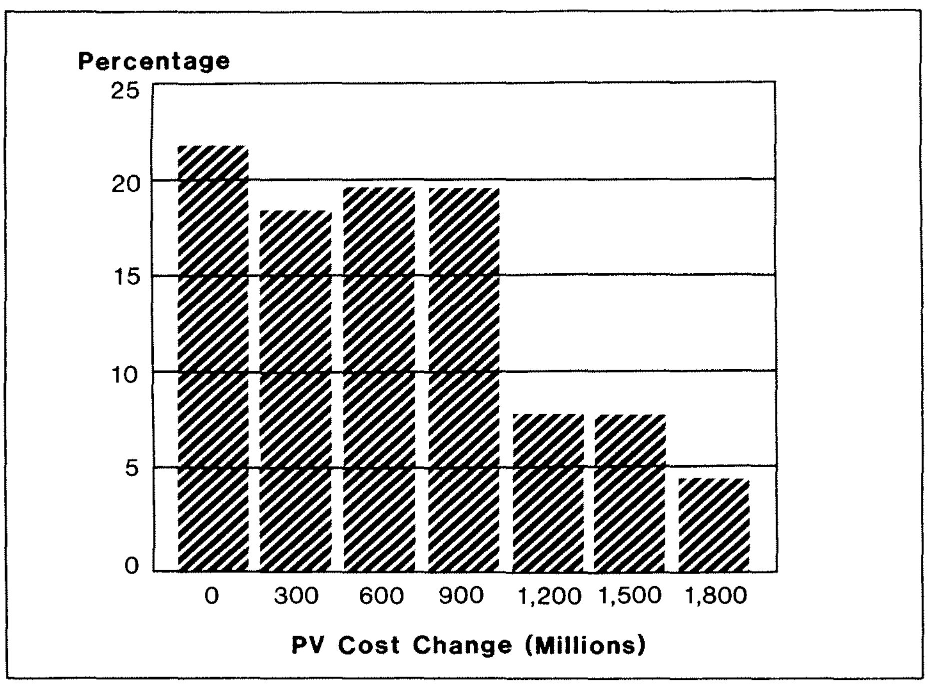


Figure 8-36
Cost Impact of Losing the MCS

Impact of Losing the MCS

Another sensitivity was performed by completely eliminating both the residential and commercial MCS from the portfolio. This case is represented in Figures 8-36 and 8-37. The cost impact ranges from $0 to a cost increase of $1.8 billion, with an expected value increase of about $620 million. This gives an indication of the cost effectiveness of the package of MCS measures to the region. The likelihood of need for a coal option by 1990 without the MCS is about 40 percent.

Impact of Not Being Able to Option Generating Resources

One of the important attributes of the resource portfolio is its reliance on the ability to obtain resource options. The option process provides the opportunity for two-stage decision making on resources, enhances flexibility and improves the ability to match capital intensive generating resource construction decisions to load growth. The ability to option resources reliably should reduce the probability and magnitude of errors likely to occur in the planning process. The Council believes the optioning process can be a workable and reliable one; however, the option concept is still largely an unproven one.

A sensitivity study was performed to evaluate the impact of not being able to option resources. This was done by setting the construction lead times for the generating resources in the portfolio equal to the sum of their option and construction lead times in the base case, and eliminating the option lead time. The effect is a commitment to build decisions significantly earlier than would be required in an option environment, resulting in systems that show a higher variance in the load/resource balance. The cost impact is depicted in Figure 8-38. It ranges from $0 in the cases where no generating resources are required to a maximum cost increase of $3.6 billion. The expected value is a cost increase of about $710 million over the base portfolio.

The impact on the schedule of decisions can be shown by comparing the initial resource build decisions instead of the option decisions as in the previous sensitivities. Figure 8-39 shows the differences in the distribution of first coal build decisions between the no options case and the base portfolio. The bars moving from above the axis in the early 1990s to below the axis in the late 1990s reflect movement in time of the build decisions in the no options case. Simply because of the longer lead times involved, the no options case moves most of the probability for builds into the early years of the study horizon, even though the information about where future loads will eventually lead is of much poorer quality in that time period.

The analysis above is directed essentially at the system cost impact of longer resource lead times. It assumes that, if the option process does not work, only one decision point will exist for a resource, and that it will move forward in time to the point where the option decision would otherwise have been made. The premise is that, without guaranteed compensation for siting, licensing and design, resource developers will move directly into construction after completion of these activities.

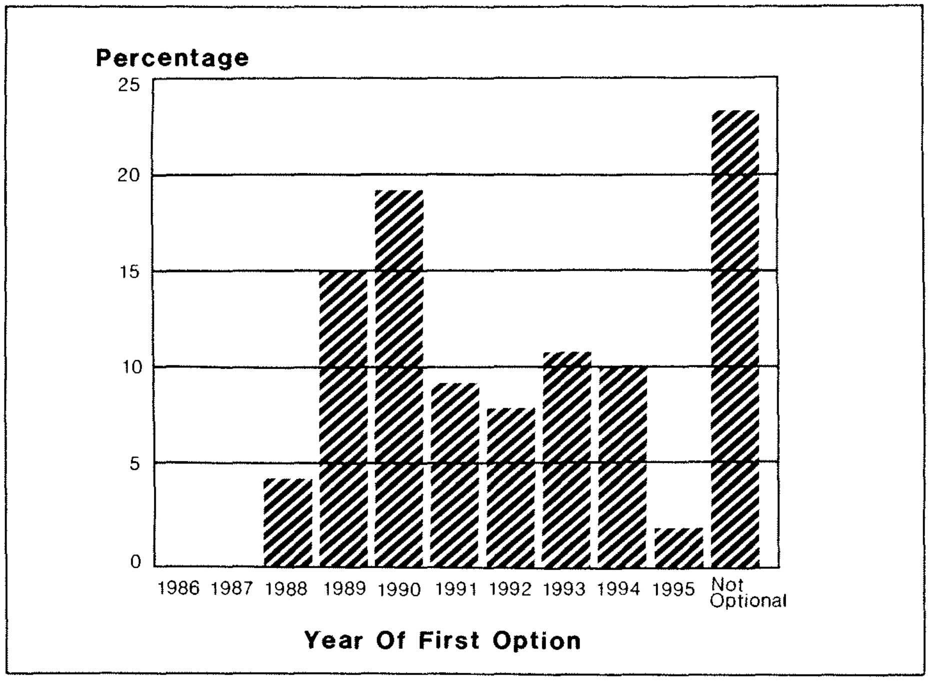


Figure 8-37
First Coal Options, No MCS

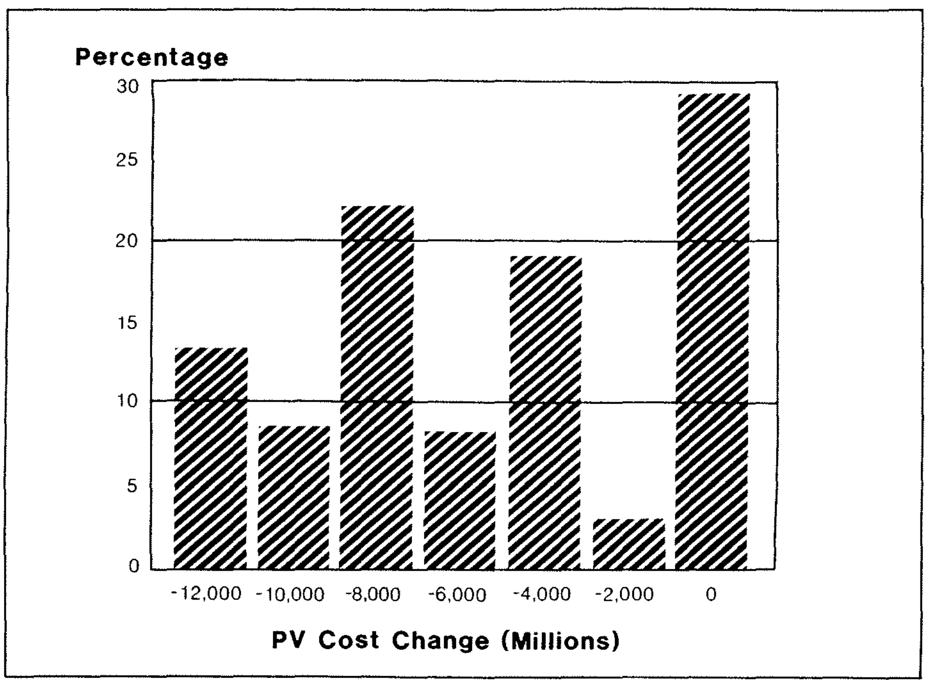


Figure 8-38
Cost Impact of Inability to Option

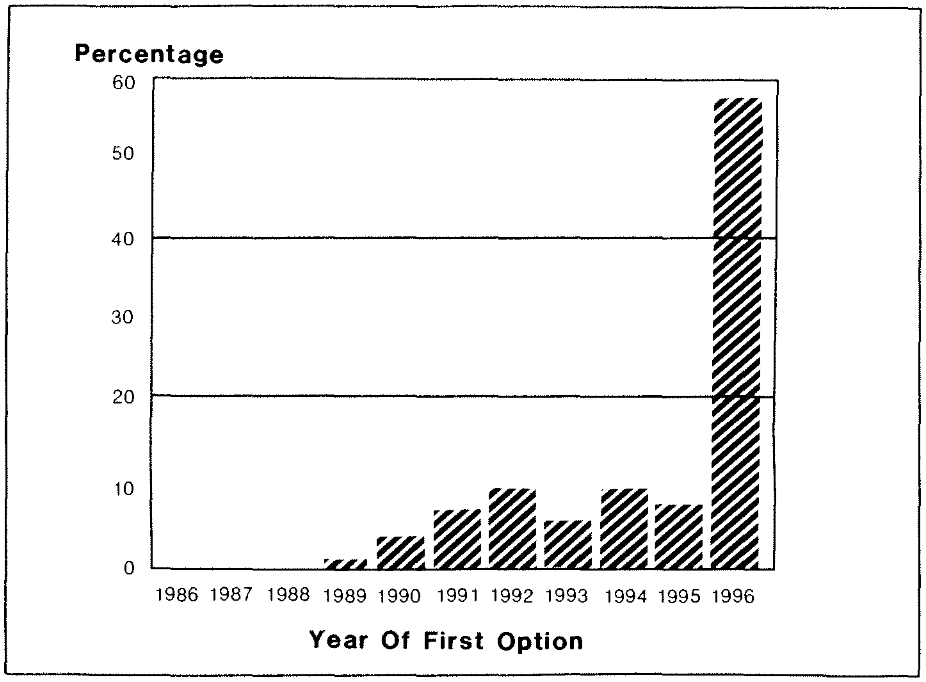


Figure 8-39
Build Decision Impact of Inability to Option

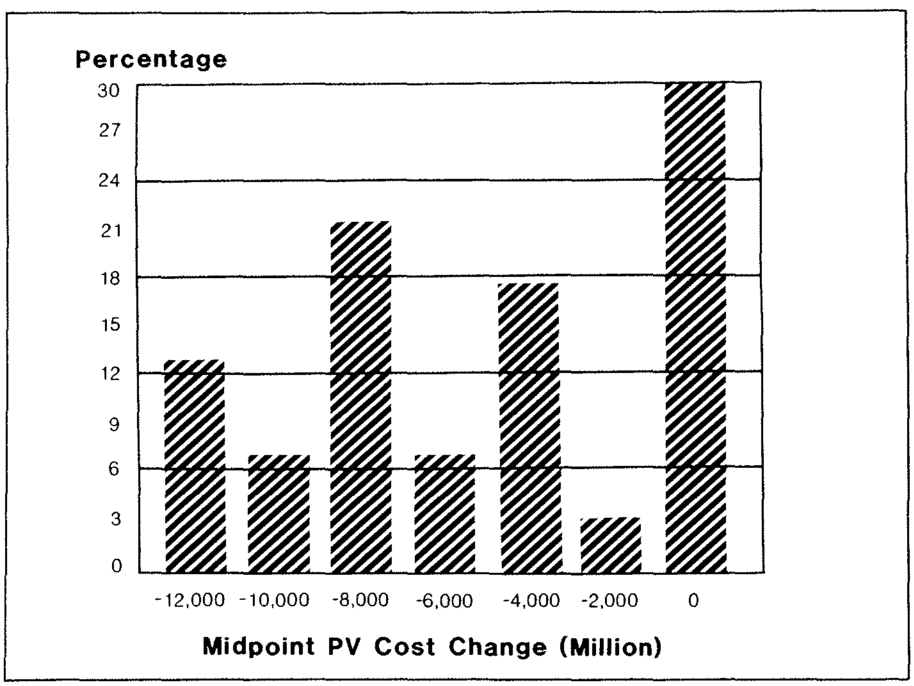


Figure 8-40
Cost Impact of 100 Percent DSI Uncertainty

Another potential difficulty with the option process is that siting agencies may not allow resource options to be held idly in inventory for long periods of time, and then moved rapidly into construction upon indication of need. Changes in technology or social or political climate may require extensive review of the resource before moving ahead with construction. A possible scenario may be that two-stage decisions still take place, but that build decisions must occur immediately after completion of siting, licensing, and design or the options are lost. In effect, the options would have a very short shelf life. This would probably result in the loss of many options, but would retain the lead time and better load knowledge advantage for those options which actually moved into construction. An additional study was performed under the assumption that there would only be one opportunity for a build decision on all resource options. This single build opportunity would come at the end of the option process, with failure to build immediately resulting in loss of the option.

The expected value cost impact of this sensitivity was an increase of approximately $100 million over the base portfolio. This $100 million increase for zero shelf life, versus the $710 million increase for longer lead times described above, implies that most of the benefit in the optioning process results from reductions in resource lead time, and that any resource development process that captures the advantages of reduced resource lead time is likely to prove valuable to the region.

Impact of Increased Direct Service Industry Uncertainty

As discussed earlier in this chapter, the Council's base planning assumptions for direct service industry (DSI) load are that at least 50 percent of the DSIs will remain as firm energy customers in the region throughout the planning horizon, with a uniform probability of occurrence applied to loads above the 50 percent level. A sensitivity was conducted with 100 percent of DSI load uncertain, rather than only 50 percent uncertain, with a uniform probability distribution applied to the entire DSI load range. This has the effect of changing the expected value of DSI load remaining at the end of the study horizon from 75 percent of maximum to 50 percent of maximum and produces a significant number of load cases where DSI loads are much lower than in the base portfolio. The system cost impact is depicted in Figures 8-40. The expected value impact is a reduction in system cost of about $5.8 billion, with a range from $0 to about $14 billion. The values at the upper end of the range result from cases where regional non-DSI load is quite high and DSI load is very low, allowing the region to use the drop-off in DSI load to avoid the need for new resources.

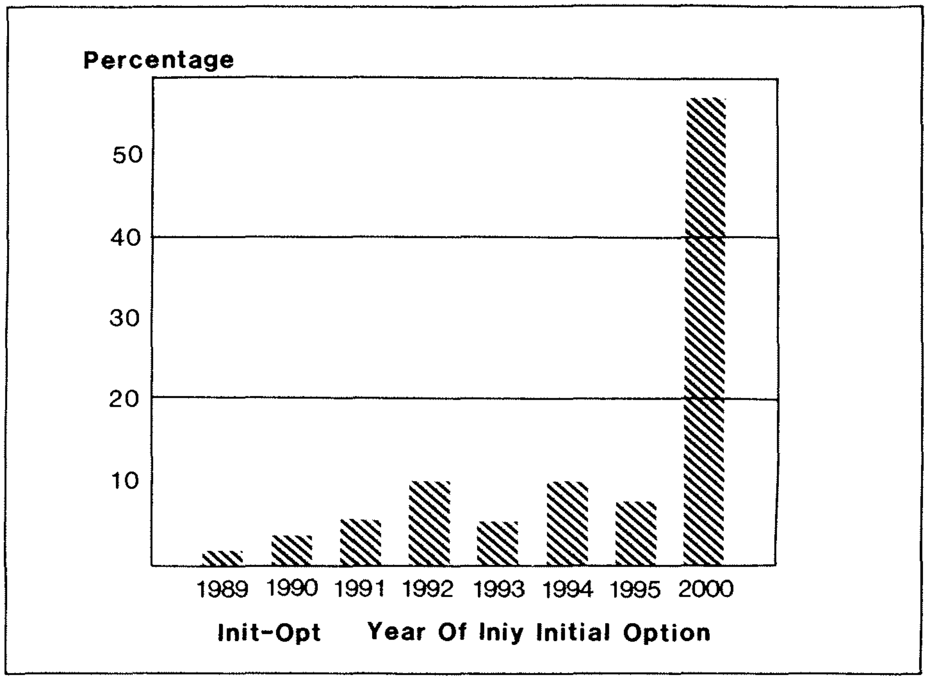


Figure 8-41
First Coal Options, DSIs 100 Percent Uncertain

Note that these values are from a regional generating system perspective. They do not include any effects of short-term lost revenue when DSI loads fall off and before other regional loads can grow to replace them, or any of the primary and secondary economic effects due to the loss of jobs these industries represent. The impact on timing of a coal option is depicted in Figure 8-41. Under this scenario, the probability of needing an option by 1990 is about 10 percent.

Lack of Regional Cooperation

The portfolio development process employed by the Council treats the region as homogeneous, with no differentiation between public and investor-owned utility loads and resources. The methodology makes the implicit assumption that the Bonneville acquisition process will allow full development of the region's least expensive conservation programs and generating resources before having to turn to the more expensive thermal resources, regardless of which customer groups lay claim to the resources or which groups exhibit needs. Because the investor-owned utilities as a group exhibit an earlier need for resources, the Council's regional perspective results in public conservation program energy and nonfirm potential being developed to meet load growth in the investor-owned utility sectors. This assumption of full cooperation in resource development between the region's customer groups is an optimistic one, but is important because it leads to the lowest cost energy future for the region.

Studies were performed to determine the value of regional cooperation. Using public sector scheduling studies to determine which resources the public utilities would develop to meet only their own load growth across the load range, new conservation and generating resource data bases were developed that would not allow development of public resources for investor-owned utility needs. This causes the deferral of some conservation and nonfirm energy in a significant portion of the load range, with subsequent earlier and higher development of coal. The assumption was also made that the investor-owned utilities would not use the acquisition process and would maintain a capital structure of 50/50 debt to equity rather than the Council's base assumption of 80/20. Portfolio studies were then rerun with the new data assumptions to determine the cost and schedule impact on the portfolio.

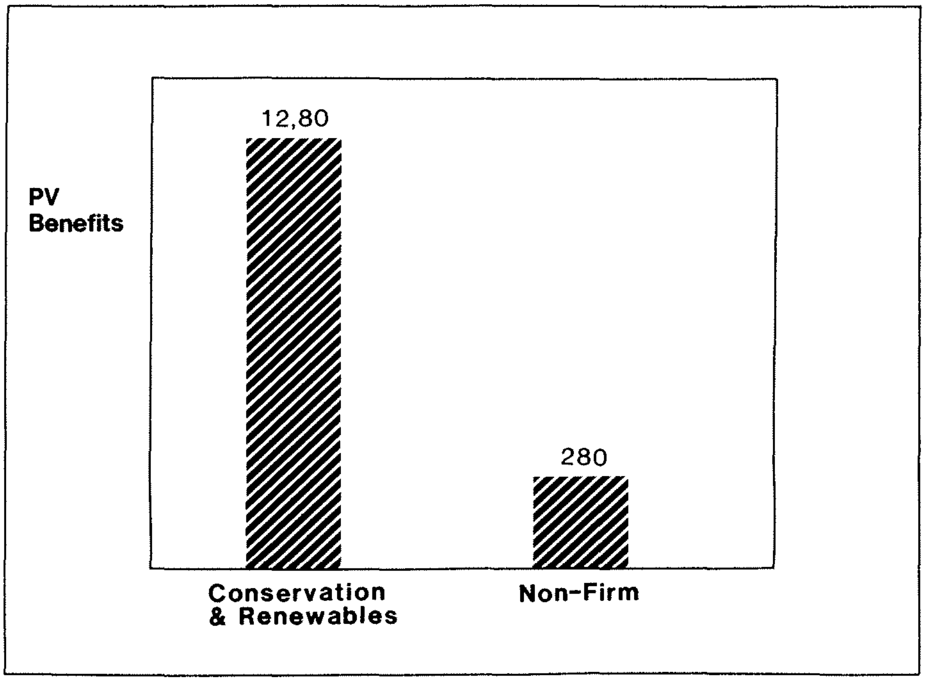


Figure 8-42
Expected Value of Regional Cooperation

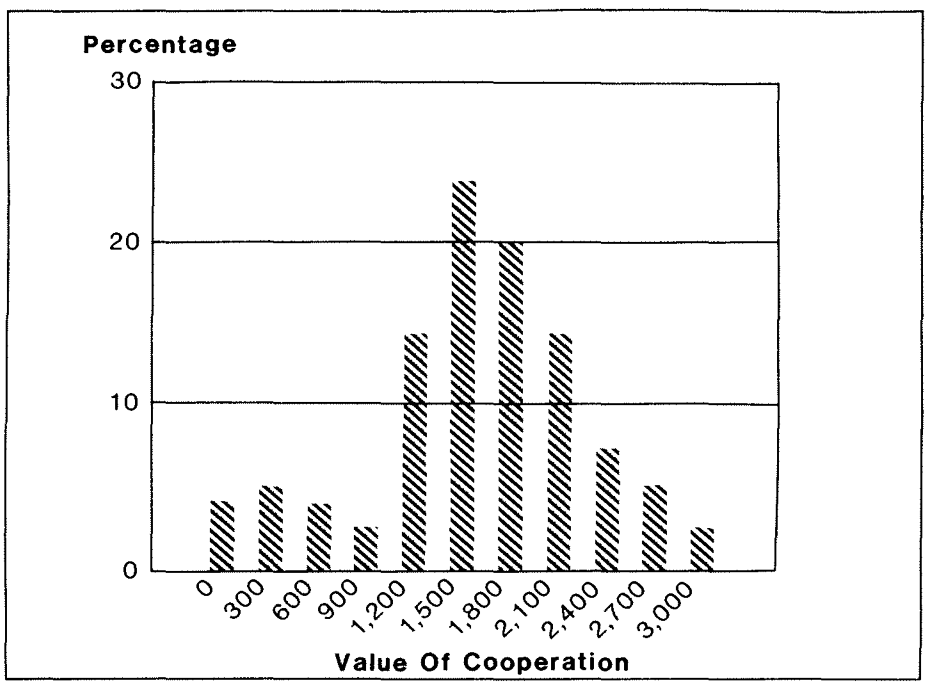


Figure 8-43
Distribution of Benefits Due to Regional Cooperation

The cost impacts are summarized in Figure 8-42. Two components of the value of regional cooperation were isolated. Cooperation on conservation and renewable development has an expected value benefit of $1.28 billion. Because the cost of renewables in the portfolio is close to that of coal, most of this value derives from the conservation programs. The value of nonfirm cooperation shows an expected value benefit of about $280 million. This value is higher than the $175 million benefit attributed to nonfirm in Chapter 7, because here it competes with new coal under a 50/50 debt-equity ratio for the investor-owned utilities. The analysis described in Chapter 7 used the Council's base assumption of an 80/20 debt-equity ratio for new coal financing.

Figure 8-43 is a histogram of the combined benefits of cooperation on conservation, renewables, and nonfirm. This distribution has a mean of $1.56 billion and a range from $0 to over $3 billion. An important point, although not discernible from the histogram, is that a significant portion of the value to cooperation comes from the relatively high probability middle load range outcomes. This results because very little resource development is needed in the low load cases, and in the higher load cases all of the utility groups develop all of their resources with or without cooperation. It's in the middle of the load range, where the public utilities have surplus conservation and the investor-owned utilities can use it, that most of the benefits of cooperation are derived.

Figure 8-44 is a histogram of the first coal option decisions without regional cooperation. The probability of need for an option by 1990 is about 65 percent.

Section C: WNP-1 and WNP-3 Cost Effectiveness

The Council devoted a significant amount of effort to study of the two unfinished Washington Public Power Supply System nuclear plants, WNP-1 and WNP-3. A number of issues regarding the economic and physical characteristics of the units were examined and numerous sensitivity analyses were performed. This section provides the detailed analysis of cost effectiveness supporting Volume I, Chapter 7.

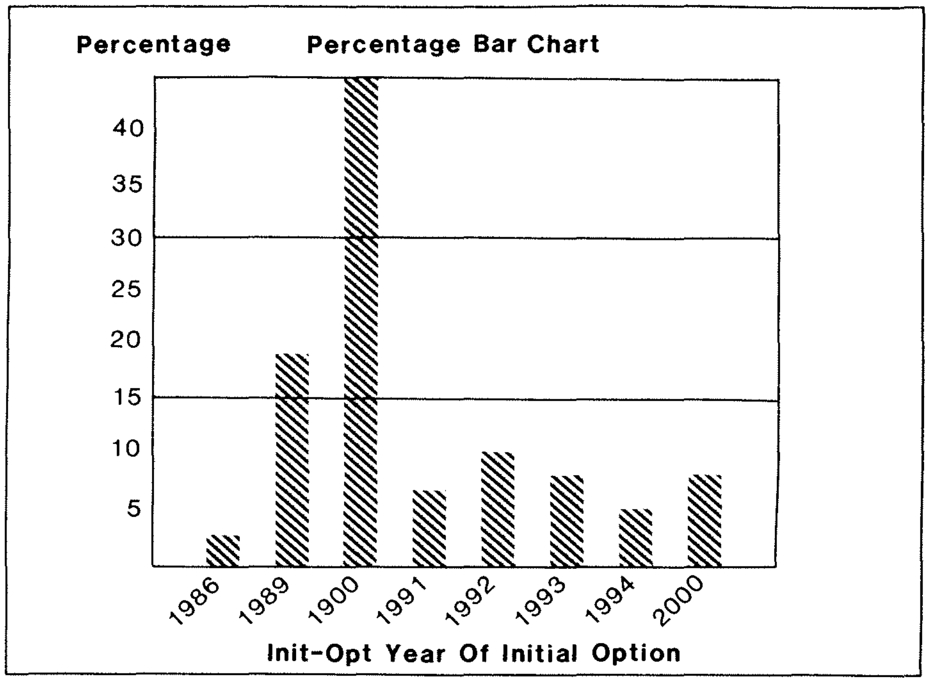


Figure 8-44
First Coal Options, No Regional Cooperation

Generally, both WNP-1 and WNP-3 appear to be cost-effective resources for the Pacific Northwest as a region. Under the Council's base set of assumptions, maintaining both units as options until and if they are needed to meet regional load has an estimated present value benefit of $630 million. Most of the sensitivity studies performed continued to show present value benefits from these plants; however, the range of potential outcomes is very wide. The sensitivity analyses show expected value outcomes ranging from benefits of over $1.5 billion to losses of nearly $1.3 billion. WNP-1 and WNP-3 are not included as firm resources in the draft resource portfolio. Instead, they are included in the plan as potential options due to their potential value to the region. As discussed in Volume I, Chapter 7, their exclusion from the portfolio is based on significant barriers to their development, not on their cost effectiveness. The rest of this section will be devoted to description of the cost-effectiveness analysis and results.

Methodology

All of the WNP-1 and 3 studies used the Council's Decision Model. This model provides the capability to assess the impact of a specific resource strategy or decision over a wide range of load futures. It is particularly well-suited for studies of this nature, where issues such as plant shelf life or forced restart are of interest. The Decision Model attempts to simulate the resource decision process and representative errors in the resource planning process, estimating the consequences of being wrong, and incorporating the impact of load uncertainty, resource lead time, and unit size on the cost effectiveness of a resource strategy. (See Section D for a more complete description.)

The criterion used to compare alternatives in all cases was the expected value of the present value of incremental system cost. Under the accounting methods used in the Decision Model, this quantity consists of the production costs associated with all existing and new resources, revenue from secondary sales to the Pacific Southwest, and the cost of imports required to meet regional needs when deficits and poor water conditions occur simultaneously. Also included are the capital costs for the optioning and construction of all new generating resources and conservation programs. To deal with end-effects of the study, the method included the costs associated with replacement resources to a time beyond which all systems would be identical.

Assumptions

The economic and physical assumptions used for conservation programs and generating resources were consistent with those described in Volume II, Chapters 5 and 6, respectively. The base case cost assumptions for WNP-1 and 3 were as described in Chapter 6, except as noted in the sensitivity cases. The load assumptions and probability distribution for load was consistent with that discussed in Volume II, Chapter 3. In addition there were a number of other assumptions needed to perform the studies.

These included (any costs specified are in January 1985 dollars):

1. Option Level: 90 percent

2. Build Level: 50 percent

3. Resource Priorities:

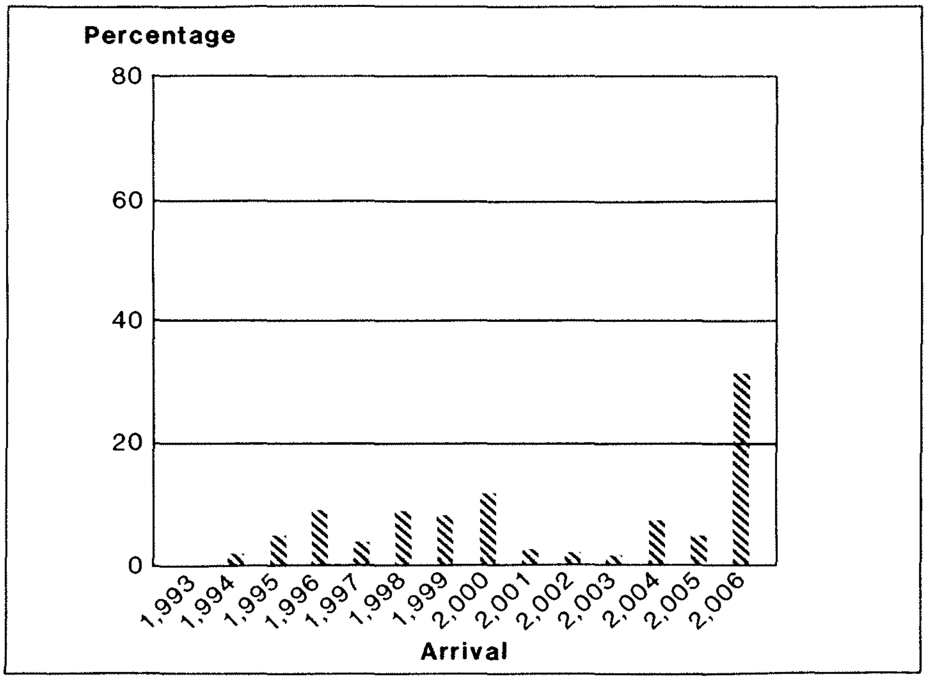


Figure 8-45
Arrival Distribution of First WNP Unit

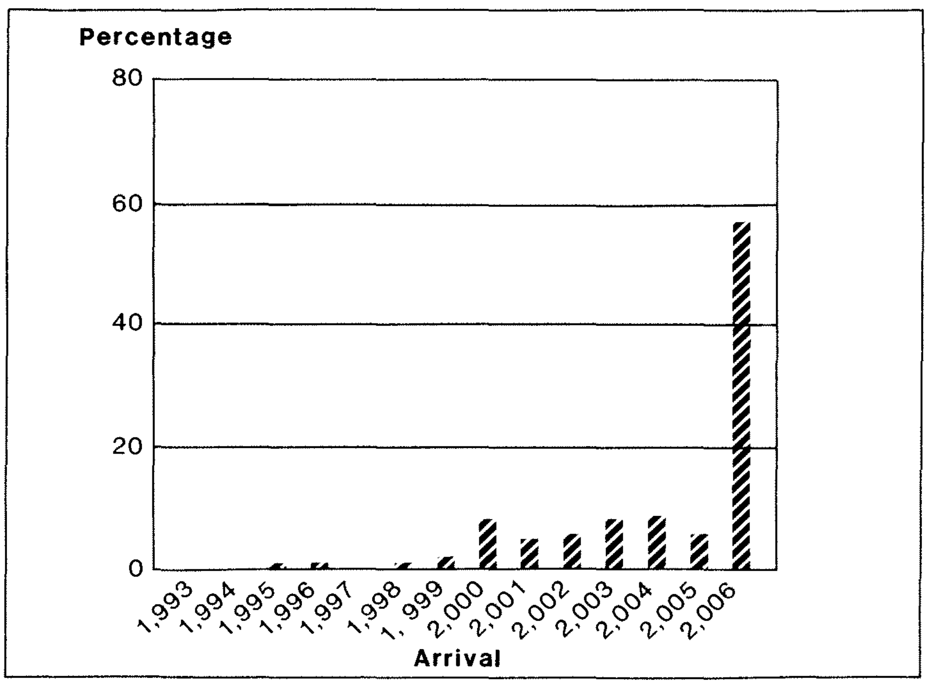


Figure 8-46
Arrival Distribution of Second WNP Unit

Analysis was performed to find the location for WNP-1 and WNP-3 in the priority order which would minimize system cost (and maximize their benefit). These studies were conducted in the same manner as those used to determine the priority order for the resource portfolio. WNP-1 and WNP-3 were treated as separate units, and allowed to compete with each other as well as all of the other conservation programs and generating resources for priority order. The priority order for the discretionary programs and resources which produced the lowest expected value portfolio cost was: hydropower efficiency improvements, agriculture, existing commercial, transmission and distribution efficiency improvements, existing residential, existing industrial, WNP-1, WNP-3, combustion turbines, small hydropower, cogeneration, licensed coal, and unlicensed coal.

4. Cost of Out-of-Region Purchases:

   15 cents per kilowatt-hour to meet firm load.
   2.5 cents per kilowatt-hour to meet non-firm load.

5. Replacement Resource:

   A 4.0 cent per kilowatt-hour load reduction resource.

6. Number of Simulations: 300

7. Inflation: 5 percent

8. Real Discount Rate: 3 percent

Probability of Need for WNP-1 and WNP-3

Figures 8-45 and 8-46 show the arrival distributions for WNP-1 and WNP-3 for a study with 300 simulations. These arrival distributions for the plants would be the same for all studies, with the exception of the forced restart and limited shelf life studies. It is important to point out that, while for modeling purposes the studies assume WNP-1 would be restarted ahead of WNP-3, the levelized cost estimates are nearly equal for both units. The Council has adopted no position on which of the units should be completed first. The results of these studies would change very little if the order were reversed.

The height of the vertical bars in Figures 8-45 and 8-46 represents the percentage of time that the unit arrives in-service in a particular year. The bar at the far right represents the probability that the unit is not needed within the 20-year study horizon. The arrivals for the first unit range from 1994 to 2005, with a most likely arrival near 2000. With five-year lead times, this would imply a most likely construction restart in the mid 1990s. The second unit's arrival tends to lag the first unit by two or three years. Its earliest arrival is 1995 or 1996, with a most likely arrival around 2003. This implies a late 1990s restart of construction for the second unit. The probability that neither unit is needed before 2006 is the same as the probability that the first unit is not needed—about 35 percent.

Results

Option Value of WNP-1 and WNP-3

The value of WNP-1 and 3 depends in part on how long they can be preserved and still be restarted. The shorter their shelf life, the less likely that they will be available to meet regional load when needed, and the more likely that no return will be realized on payment of additional hold costs. Three studies analyzed this issue, at five, ten and 15-year shelf lives for each unit. (With a construction lead time of five years, a 15-year shelf life ensures that the plants will be available for service anytime within the 20-year planning horizon.) Additional studies were performed including only one unit in the portfolio, to isolate the relative value of each unit. The results are summarized in Figure 8-47. The ability to hold the plants for five years results in a benefit of \$330 million, a ten-year shelf life yields benefits of \$570 million, and a 15-year shelf life benefits of \$630 million. Of the \$630 million benefit produced by both plants, \$440 million is derived from the first unit and \$190 million from the second. This higher marginal value for the first unit arises from the fact that it is needed in more of the load paths, and also that its total hold costs will generally be less. The same type of pattern is seen in the five and ten-year shelf life single unit studies.

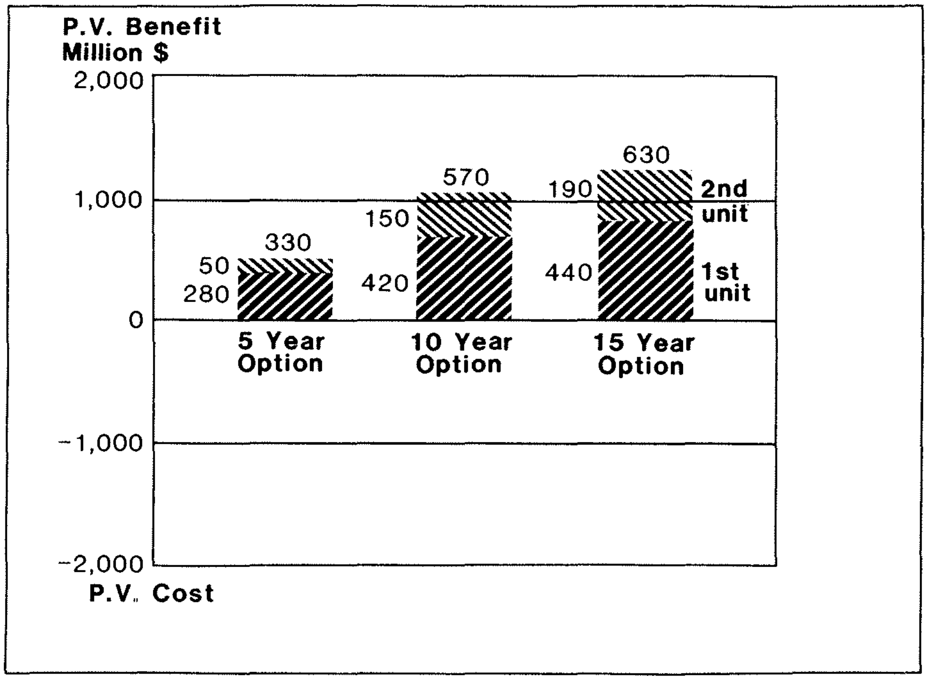


Figure 8-47
WNP-1 and WNP-3 Option Value

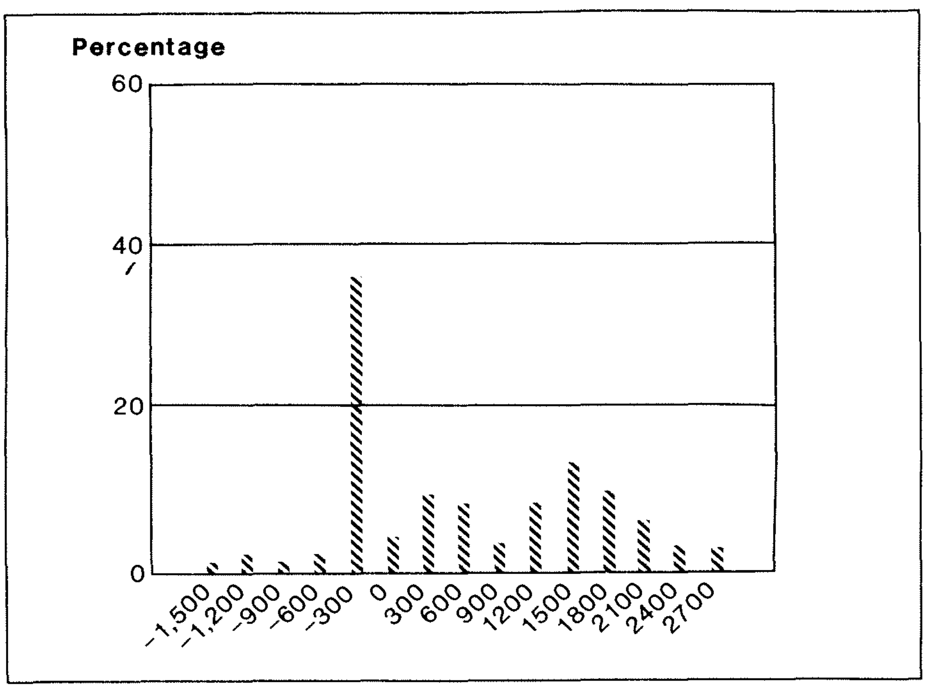


Figure 8-48
Value of WNP-1 and WNP-3

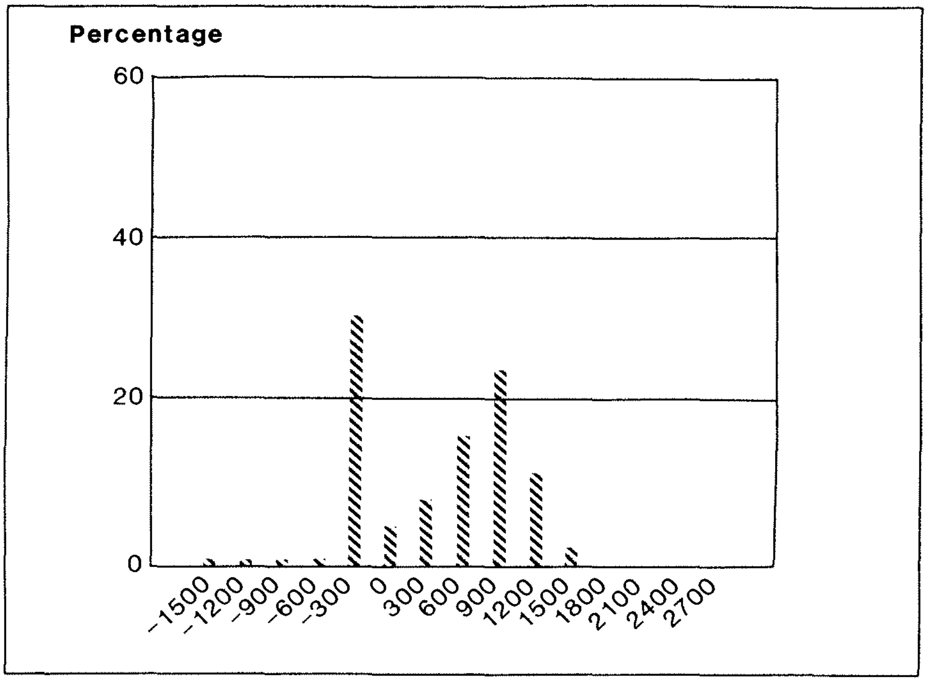


Figure 8-49
Value of First Unit

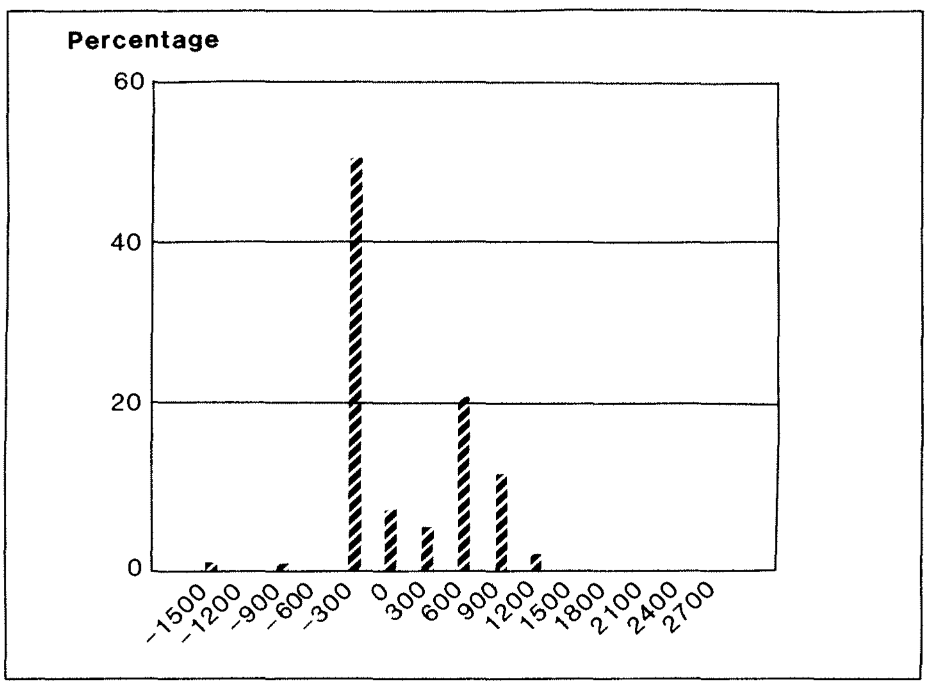


Figure 8-50
Value of Second Unit

The range of potential costs and benefits for the individual units is shown in Figures 8-49 and 8-50. The means of these distributions are $440 and $190 million for the first and second units respectively, as shown in Figure 8-47. The first unit is built more frequently than the second, shows a higher probability of producing some benefit for the region, and a lower probability that the investment in its hold costs will be wasted.

The $630 million benefit of both units under a 15-year shelf life scenario is the Council's estimate of the expected value of the benefit across the entire load range. In reality, there is a very wide range of potential outcomes for the value of these units. In low load cases, it is likely that the units may never be needed and may be held for a long period of time with eventual termination. This would result in a net loss to the region consisting primarily of the hold costs. On the other hand, in the event of higher load growth scenarios the units may be held for a relatively short period of time; successful restart and construction would avoid the need for more expensive coal units and could yield large benefits to the region.

Figure 8-48 shows a frequency distribution for the value to the region of being able to hold WNP-1 and 3 for 15 years. Its mean is the $630 million benefit mentioned above, and it shows a range anywhere from a loss of $1.5 billion to benefits of $2.7 billion. The spike at -$300 million represents the cases where the units are not needed and the hold costs become a wasted investment. The larger negative values of $-1.2 to $-1.5 billion are occurrences where loads begin to come up, the plants are restarted and constructed, loads fall back off and the plants are not needed. These cases represent occurrences of the kinds of resource planning errors the Decision Model was designed to evaluate. The higher load outcomes are represented at the upper end of the benefits distribution. Both WNP-1 and WNP-3 are built early, hold costs are kept to a minimum, the units ultimately displace high cost coal and produce large regional benefits of approximately $2.7 billion.

Impact of the Future Status of the Direct Service Industries

Another issue which has considerable impact on the value of WNP-1 and 3 is the future of the aluminum industry in the Northwest. The aluminum industry uses large amounts of electricity, and the industry's needs must be taken into account in long-range resource planning. However, there is currently significant uncertainty regarding the long-term operating viability of a portion of the Northwest aluminum industry. (See Volume II, Chapter 2, for more discussion.) This uncertainty should be taken into account in the planning process. It would be a poor economic outcome to embark on construction of long lead time, large thermal units such as WNP-1 and 3, only to find out as they near completion that a portion of the load which justified their completion is gone. Eventually, load growth may again produce a need for the plants, but in the meantime the region would have incurred significant costs with little benefit.

The Council performed two studies to estimate the impact of the future of the direct service industries (the majority of which are the aluminum producers) on WNP-1 and 3. Both assumed all direct service industry loads would fall to zero after 2001, the year the current industry contracts expire. In the first study, WNP-1 and 3 were used as resources in the portfolio, with the arrival schedules depicted in Figures 8-45 and 8-46, even though frequently there would be little need for the plants once they had arrived. In the second study, the availability of a short-term purchase was substituted for WNP-1 and 3. It was modeled as a revolving account limited to a maximum of 1,600 average megawatts (the energy capability of WNP-1 and 3), with a two-year negotiation lead time, two-year contract duration, reservation costs equal to the annual capital costs of combustion turbines, and displaceable energy costs of 6.5 cents per kilowatt-hour. This short-term purchase was more expensive than WNP-1 and 3 on an annual basis, but in most cases would have been needed for only a short period of time. Because of the two-year contract life, such a resource would represent a much more flexible strategy and would allow the region to move back toward load resource balance much more quickly after the direct service industry load had fallen off.

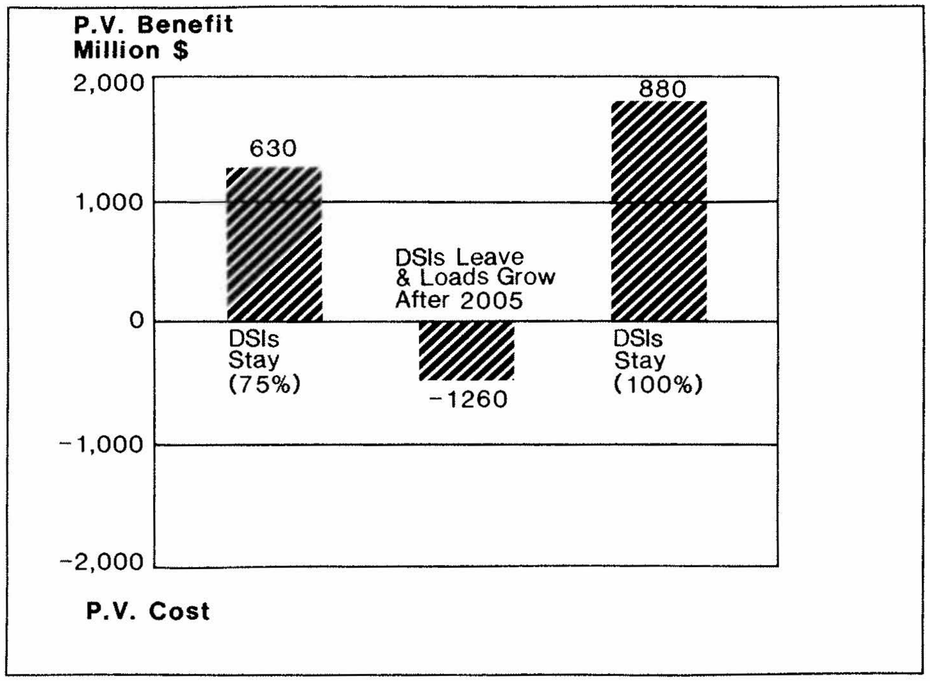


Figure 8-51
Impact of DSIs on WNP-1 and WNP-3

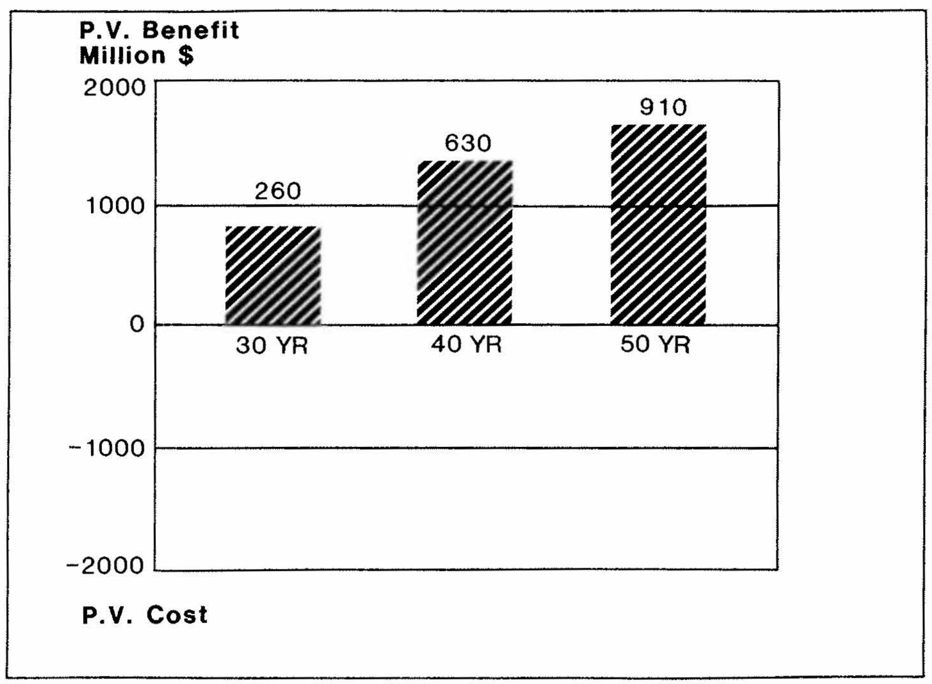


Figure 8-52
Impact of Plant Lives

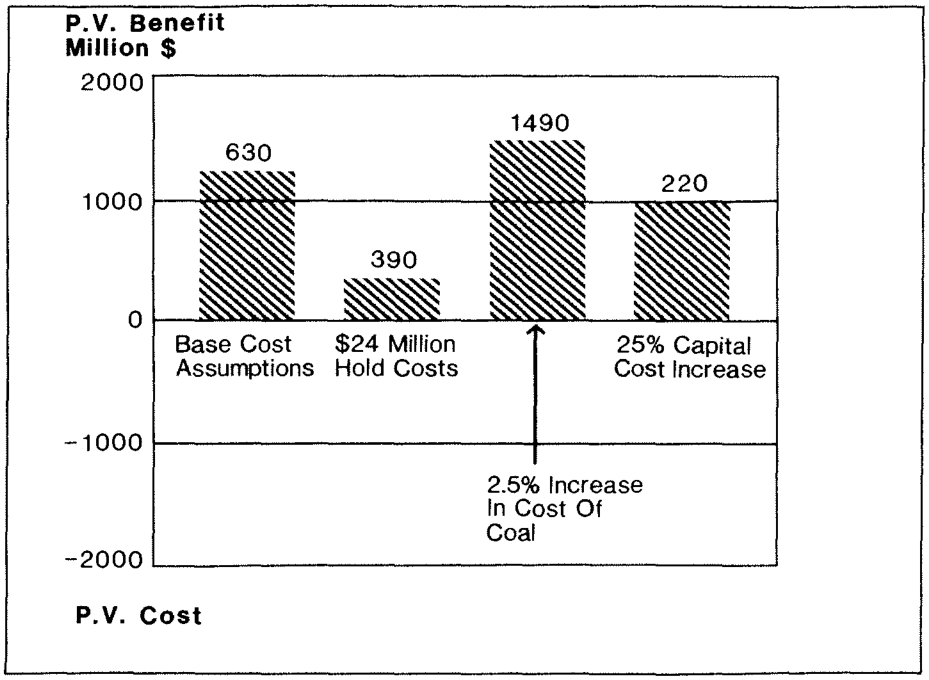


Figure 8-53
Impact of Changing Cost Assumptions

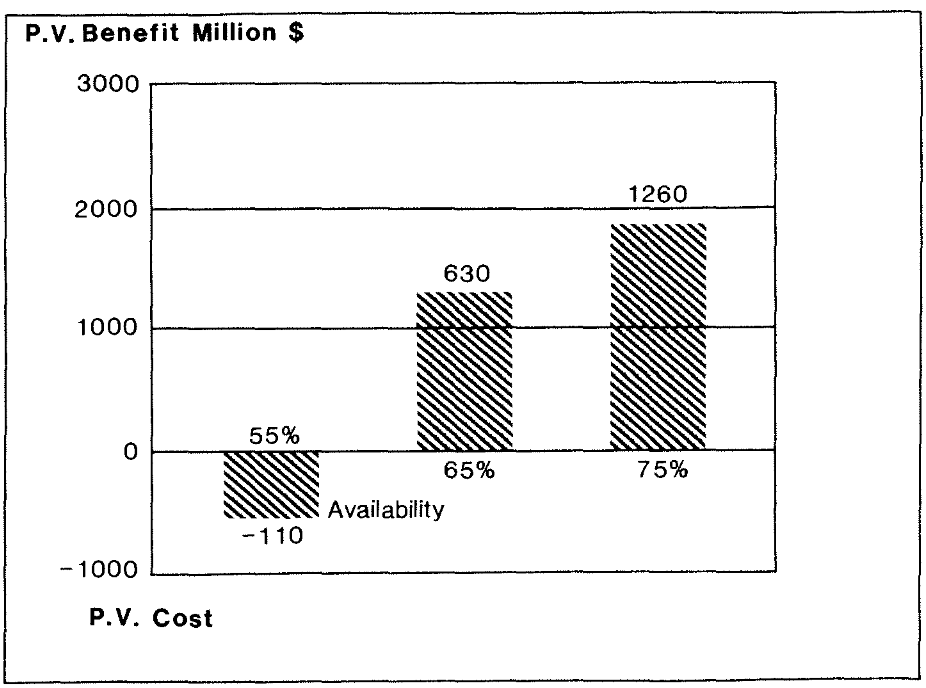


Figure 8-54
Impact of Equivalent Availability

The results of these studies are shown in Figure 8-51. The $630 million benefit is the benefit of WNP-1 and 3 in the portfolio, if the direct service industry loads remain after 2002. The remaining DSI load is a random variable, but would average 75 percent remaining across all load cases. The middle bar represents the differences in costs between using the short-term purchase strategy and using WNP-1 and 3 in cases where the direct service industries leave. In this case, the short-term purchase strategy costs the region about $1.3 billion less than using WNP-1 and 3. As one additional comparison, the bar to the right represents the value of WNP-1 and 3 as options with 100 percent of the DSI load remaining at the end of the planning horizon, and shows a benefit to the units of $880 million.

Impact of Plant Operating Life

The Council's base assumption for WNP-1 and 3 operating life is 40 years. With shorter operating lives the plants would produce less benefit because the fuel savings would be limited, and other, more expensive, resources would be needed to replace them more quickly. Conversely, with longer operating lives the plants would have more value. Sensitivity studies were performed using 30 and 50-year operating lives for the plants. The results are depicted in Figure 8-52. With a 30-year life the plants have a benefit of $260 million, and a 50-year life raises the value to $910 million.

Sensitivity to Cost Assumptions

The value of WNP-1 and 3 will be influenced not only by their cost to complete but also by the costs of competing resources in the resource portfolio. Three studies were performed here. The first was a sensitivity on the construction costs required to complete the units. Arguments have been made that the current Supply System budgets may underestimate costs to complete by as much as 25 percent. As shown in Figure 8-53, if remaining construction costs were actually 25 percent higher than current estimates, this would reduce the value of the plants to $220 million.

The second sensitivity was on hold costs for the units. The analysis to this point has been based on hold costs of $12 million per year per plant. This also assumes that the hold costs result in no earned value credit; that is, future costs to complete are not reduced through expenditure of the hold costs. Current Supply System and Bonneville budgets call for expenditures of approximately $24 million per year per plant, and it's estimated that this will result in earned value credit. A pessimistic outcome would be that the $24 million would result in no earned value credit. This case was examined and resulted in lowering the benefit of the units to $390 million.

The third sensitivity investigated the value of WNP-1 and WNP-3 if the construction and operating costs of new coal units turned out to be 25 percent higher than the the Council's current estimates. This assumption increases the combined value of both units to $1.49 billion.

Impact of Equivalent Availability
Because of the large unit size of WNP-1 and 3, the amount of time the plants are actually available for operation once in service will have a significant impact on their cost effectiveness. The Council's base assumption for equivalent availability for both WNP-1 and 3 is 65 percent. Lower equivalent availabilities would reduce benefits from the plants through more frequent operation of higher variable cost resources or from losses in secondary revenues. Additionally, lower availabilities may require the construction of other resources to maintain system reliability. Higher availabilities would have the opposite effect. The Council performed two sensitivity studies on equivalent availability for the plants, one at 55 percent and the other at 75 percent. The results are portrayed in Figure 8-54, and show a loss to the units of $110 million at 55 percent availability, and a benefit of $1.26 billion at 75 percent.

Value of Forced Restart
A set of studies concerning the economics of forced restart was also performed. The term "forced restart" as used here implies an unconditional construction restart of a unit at a specific date, regardless of load path or anticipated need for the unit. These studies evaluated a series of forced restart dates for both units, to determine both the cost impact of forced restart and to investigate the appropriate timing, if any, for a forced restart. The first set of studies was performed by removing the second WPPSS unit from the portfolio and forcing the first unit across a series of system arrival dates ranging from 1992 to 2005. The second set was performed by forcing the arrival of the first WPPSS unit in the year 2000, and forcing the arrival of the second unit in the years post-2000.

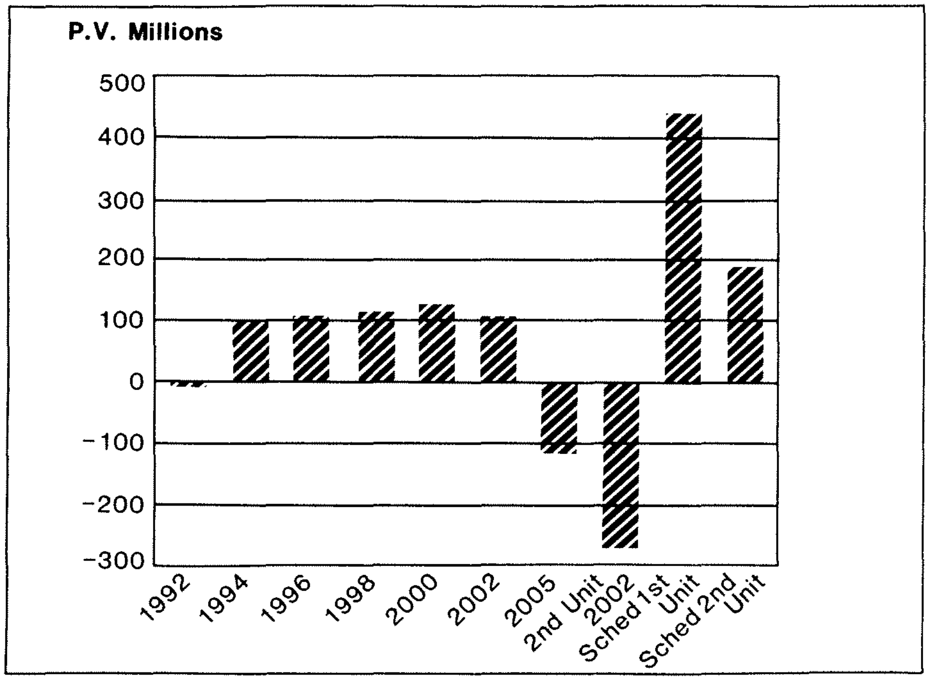


Figure 8-55
Impact of Forced Restart

The results of these studies are shown in Figure 8-55. The bars to the far right represent the value of the units if the restart date is allowed to float; that is, the units are scheduled and built only in anticipation of future need. These are the $440 and $190 million values shown on Figure 8-47. The bars labeled 1992 to 2005 represent the value of forcing the first WPPSS unit into the system at selected points across the study horizon. The labels here represent the resource arrival or in-service dates. Construction restart dates would occur five years earlier.

Forcing an arrival of the first unit in 1992 has an expected value loss over the base portfolio of $5 million. Forcing it in 1994 produces an expected benefit of about $90 million, and this value slowly rises to a maximum of $120 million in the year 2000. However, this value is far below the $440 million benefit obtained when the first unit is scheduled in anticipation of need. This occurs because forced construction in the lower portion of the load range causes unnecessary overbuilding, and in the middle portion of the load ranges causes displacement of more cost-effective conservation program energy. This effect is even more pronounced in the case of the second unit. The second unit has an incremental value of $190 million when both units are allowed to float. However, when the first unit has a forced arrival in 2000 and the second unit is forced in 2002, its has a negative value of $270 million.

Summary

Using the Council's base set of assumptions, the inclusion of WNP-1 and 3 in the regional resource portfolio reduces the present value of portfolio costs by $630 million. In addition, the cost effectiveness of these plants appears to be fairly robust. While several of the sensitivities performed here show negative value to maintaining the plants as options, the majority of the studies continue to show varying degrees of benefits to the plants.

All of the sensitivity analyses described here were performed by changing a single parameter at a time and comparing to the base case to isolate the impact of the change in only that parameter. Modest changes in parameters such as equivalent availability, operating life, capital costs, or costs in competing resources can result in large shifts in present value benefits. Due to the interrelated nature of most of these parameters, the reader is cautioned against direct addition of the individual changes presented here to estimate the impact of simultaneously changing parameters.

While not presented formally here, another important factor for the cost effectiveness of WNP-1 and 3 is the nature of future load uncertainty. These units derive most of their benefit through the displacement of coal, and to a lesser extent combustion turbines, small hydropower and cogeneration. This happens primarily in the higher load cases. If for some reason the range of load forecasts were to fall, or even simply narrow, the value of maintaining WNP-1 and 3 would fall as well. Conversely, higher loads or a wider load range would yield higher benefits.

Section D: Decision Model

Introduction

One of the important attributes of the Council's 1983 plan was the formal recognition of regional load uncertainty and the incorporation of this uncertainty into the planning process. This is evidenced by the range of load forecasts used in the plan, the emphasis placed on flexible, short lead time resources, and development of the options concept.

During development of the 1983 plan, analytical tools were available to the Council that helped characterize the nature of the load uncertainty faced by the region. In general, these were the models contained within the demand forecasting system. However, once the analytical process moved over to the supply side and began the evaluation of resource alternatives to meet future load growth, there was limited analytical capability to assess the effect of this newly defined load uncertainty on the various alternatives.

The Council recognized this deficiency and, in the 1983 Two-Year Action Plan Item 29.1, directed its staff to develop a model capable of dealing with load uncertainty and its interaction with resource decisions. The Decision Model is intended to be that tool. It has been developed to date in a joint effort by individuals from Council staff, the Intercompany Pool, the Pacific Northwest Utilities Conference Committee, and Bonneville. The model has also been influenced by activities and discussions within the Council's Options Evaluation Task Force. Council staff has taken responsibility for coordination and oversight.

The major benefit of the model lies in providing planners with the ability to assess the load-related risks associated with particular resource option or acquisition decisions. It automatically evaluates the consequences of errors that are likely to occur in the resource planning process. It assists in determining what types of long-term resource strategies better enable the region to manage the risks imposed by load uncertainty. The model enhances strategic planning capability and provides an information flow to the decision-making process in an area which previously had to rely largely on intuition and judgment.

The remainder of this section will outline briefly some of the load-related shortcomings of traditional analytical methods and indicate how the Decision Model contributes to the planning process. It will provide an overview of the model, discuss some of the major features within the model, and briefly describe the major algorithms used in the modeling process.

Background

The Council's 1983 plan included four different load forecasts and, correspondingly, four different resource schedules. The range of forecasts acknowledged the highly uncertain nature of the assumptions underlying the forecast, and began to move away from the idea of point forecasting and planning resources to a specific load level with little consideration of other possible load outcomes. It recognized the possibility of alternative futures and the large impact those futures will have on the types and amounts of resources that will need to be developed.

The 1983 plan also placed an emphasis on flexible, short lead time resources. It relied on the premise that the most efficient condition for the region to maintain is one of approximate load resource balance. Shorter lead time resources reduce the period over which the need for new resources must be forecast, and allow resource sponsors to move closer to the point of actual need before committing large amounts of capital for construction. The less lead time needed for resource development, the better that development can be matched with load.

However, quantitative estimates of the economic value of lead time are difficult to obtain with the analytical methods used in the 1983 plan. The analytical process stopped short of complete incorporation of future load uncertainty. The major resource models used in the first plan were designed to schedule or evaluate resources under one specific load condition or forecast, and load uncertainty was in large part handled outside of the planning models.

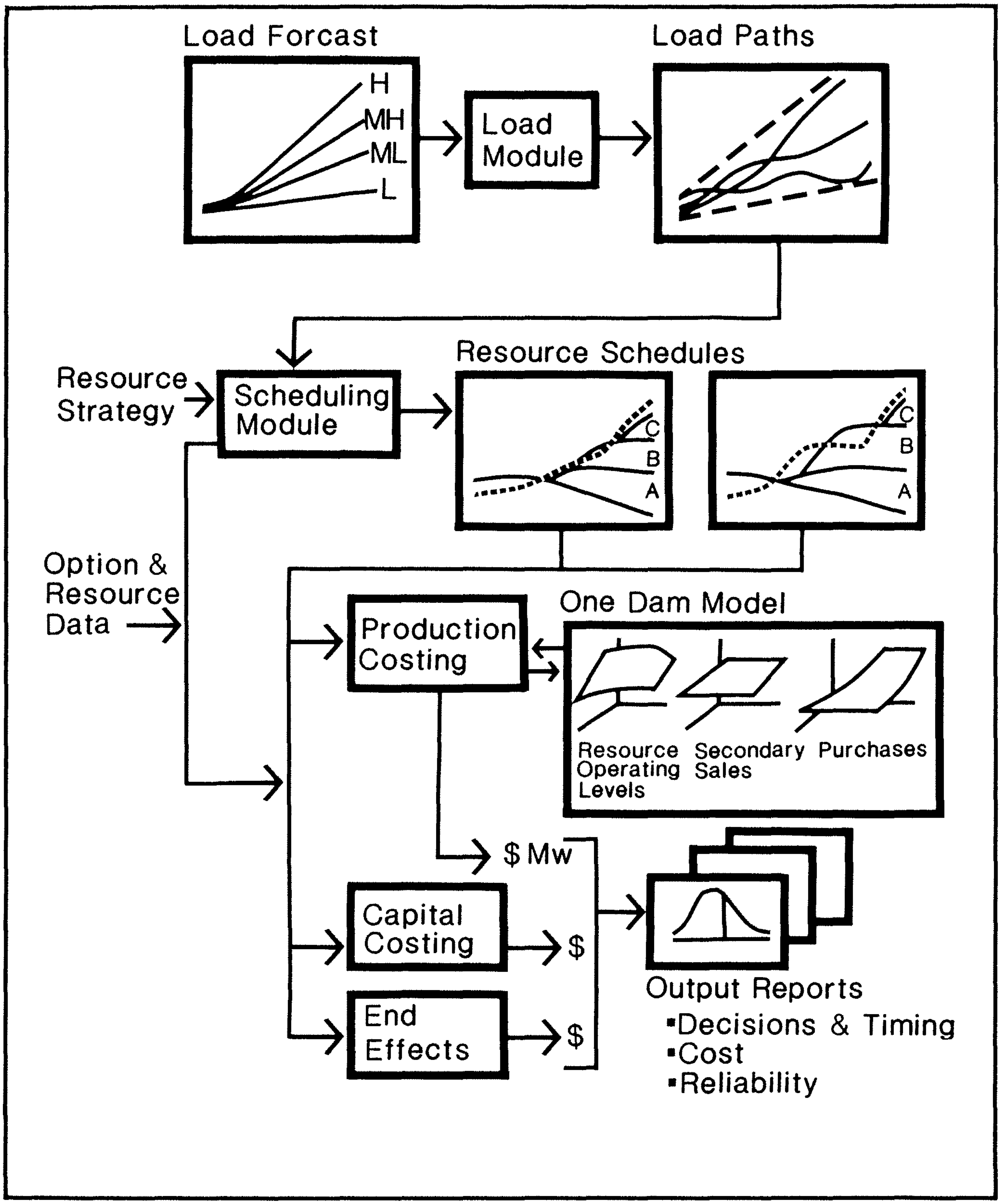


Figure 8-56
Decision Model Overview

In developing the resource schedules for the first plan, it became necessary to make the assumption that after the first few years the region would know which of the four load paths it was on and would not deviate from that path. Essentially, all of the load uncertainty was resolved in the near term and had little impact over the remainder of the planning horizon. This perfect knowledge of load led to resource schedules which provided virtually perfect load/resource balance in each load case, once the surplus was exhausted.

This type of study structure reflects none of the benefits inherent in short lead time resources. A study that assumes perfect information on load will show no economic difference between two resources that have the same total cost, regardless of any differences in lead time.

It's very difficult to evaluate the effects of load uncertainty and its impact on cost effectiveness with single load path models. The important effects to capture are the consequences of being wrong. It would be possible to manually set up studies which reflect errors in the resource planning process, resulting in systems that are out of load/resource balance. However, it would be very time consuming to set up and run enough studies to be sure of a representative set of wrong outcomes. Most of the planning studies performed in the region were done under an assumption of perfect knowledge. It is possible to model the single way of being right. It is virtually impossible to model all the different ways of being wrong. However, there is little doubt that the prediction of future conditions used to justify today's planning decisions will turn out to have some degree of error.

Decision Model Overview

An overview of the Decision Model and the general modeling process is shown schematically in Figure 8-56. The process starts with the input of a load forecast range and the probability distribution for that range. Analogous to the Council's planning assumption for the region, the actual load experienced within the model might be anywhere in the forecast range. Because it is now possible in the model for the load to have wide variations in outcomes, it is no longer possible to specify a fixed resource schedule to be implemented regardless of load outcome. So, instead of a fixed schedule, the user specifies a "resource strategy" that, in general terms, defines the types of resources that should be scheduled as a function of time and load level.

The model then moves through the future along a somewhat random load path, making decisions as consistently as possible with the resource strategy. It is essentially blind to the future within the limits of the load forecast range, and the predictions it uses for decisions will generally turn out to have some degree of error. How well the model can match resources to load will depend in large part on the size and lead time of resources combined with the potential variation in load.

Costing routines are used to keep track of the capital and production costs associated with the particular load/resource configuration, as well as secondary sales and need for purchases. When the model has completed one pass through the planning time horizon, it will have simulated the effect of the resource strategy under one set of future conditions. Because of the large number of possible alternative futures, it is necessary to make many passes through the future to ensure statistical reliability for the results.

A model of this nature is useful in answering questions such as the following:

- How are today's resource decisions affected by load uncertainty?
- What is the value of reduced resource lead time?
- What types of options should the region pursue?
- What level of options inventory should the region hold?
- Given the uncertainty in long-term load, to what level of load should the region be prepared to commit resources?

The overall modeling approach is one that combines features of decision analysis and simulation. Decision analysis is a branch of operations research involving the evaluation of a decision in light of the uncertainty that confronts the decision maker. It allows estimation of the consequences of a decision across a range of outcomes for uncertain variables and, given the probabilities for those outcomes, allows calculation of the expected value of the decision. This is essentially the problem to be solved here. What are the expected cost consequences of a particular resource decision or set of decisions in light of future load uncertainty?

It should be pointed out that the model is not intended to be an optimizer. It does not attempt independently to find the best resource decision or decision strategy. The decisions or strategies are user-defined inputs to the model, and the model is simply a tool to allow the evaluation of the actions represented in the input. By comparing the results produced by one set of decisions versus another, it is possible to discern the advantages of one over another.

Major Features

Load Uncertainty

The uncertainty represented here is the one inherent in the long-term load trend. Alternative load paths all start at the current load level but may end up at any point between the low and high forecasts. The user has control over the size of the load range, the shape of the distribution of ending load values, and the amount of variation present in the individual load paths. However, the model has little knowledge about where a load path will eventually lead. It has limited forecasting ability and continually updates forecasts as it moves through time, but it is blind to the future load within the limits of the forecast range.

Two-Stage Resource Decisions

For any particular resource, decisions are made in two steps: a decision to initiate an option, and a decision to start construction or build. Once an option decision is made, the resource passes through an option period before it moves into the option inventory. Once in inventory, it becomes available to build. If it is not built before the end of its shelf life, it expires and is no longer available as a regional resource.

Conservation Program Management

Conservation is generally thought of as a very flexible, short lead time resource. However, in periods of rapid load growth and high need, its flexibility will be influenced by program acceleration characteristics and the maximum rates for program development. Conversely, during periods of surplus, conservation flexibility is dependent on how quickly programs can be decelerated, and the minimum levels at which they can be run. The model applies user-defined maximum and minimum program development rates, accelerations, and decelerations as constraints to manage program activity. In this way the flexibility or limitations of program scheduling characteristics can be valued in cost-effectiveness analysis.

Major Decision Variables

The following are the major inputs available to the user to control definition of studies.

- **Option Level:** The level of load within the forecast range for which options should be secured.

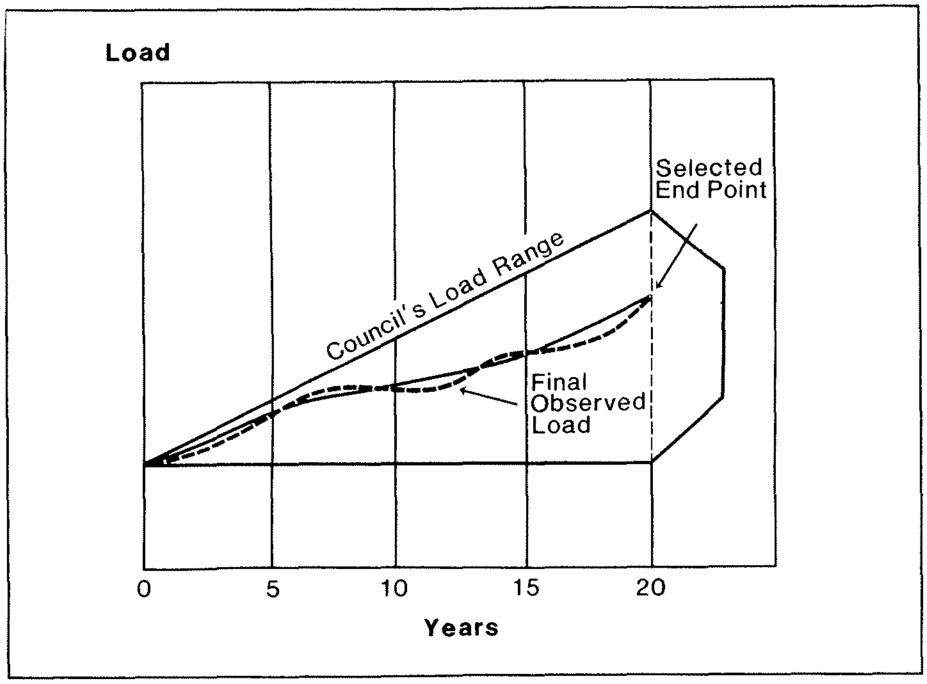


Figure 8-57
Decision Model Load Selection

- **Build Level:** The level of load within the forecast range for which resources should be built.

- **Resource Strategy:** Specification of the preferred conservation programs and generating resources as a function of time and load level. Resource supply limits as a function of load can be used to differentiate resource preferences across the load range; e.g., build 1,000 megawatts of combustion turbines in a high load case, but build none in the low.

- **Forced Option and Build Decisions:** Specific option and build decisions to be made regardless of load level or need.

A Typical Model Simulation

This section will briefly describe a typical Decision Model simulation, giving more detail than the sections above. It describes six general steps: load selection, option and build requirements, resource choice, capital costing, production costing and treatment of end effects.

Load Selection

The first step the model takes is the selection of a load. This process is shown on Figure 8-57. The model will choose a load end point consisting of two components. It chooses values separately for loads, exclusive of the direct service industries, and direct service industry loads. The model assumes independence between non-direct service industry and direct service industry loads.

The model then determines four five-year trends to reflect the general time structure of the forecast, which does not have constant load growth rates over the entire planning horizon, and the time pattern of the industry's activity reflected in the forecasts. Finally, the model applies a load shape from one of three sets to the five-year trends to give the load actually observed by the model for planning and costing. The three sets of load shapes have low, medium and high volatility in their deviations from the load trends. The user selects the set from which to draw. The Council's studies have been done using medium volatility. Figure 8-58 illustrates some examples of observed load paths generated by the model.

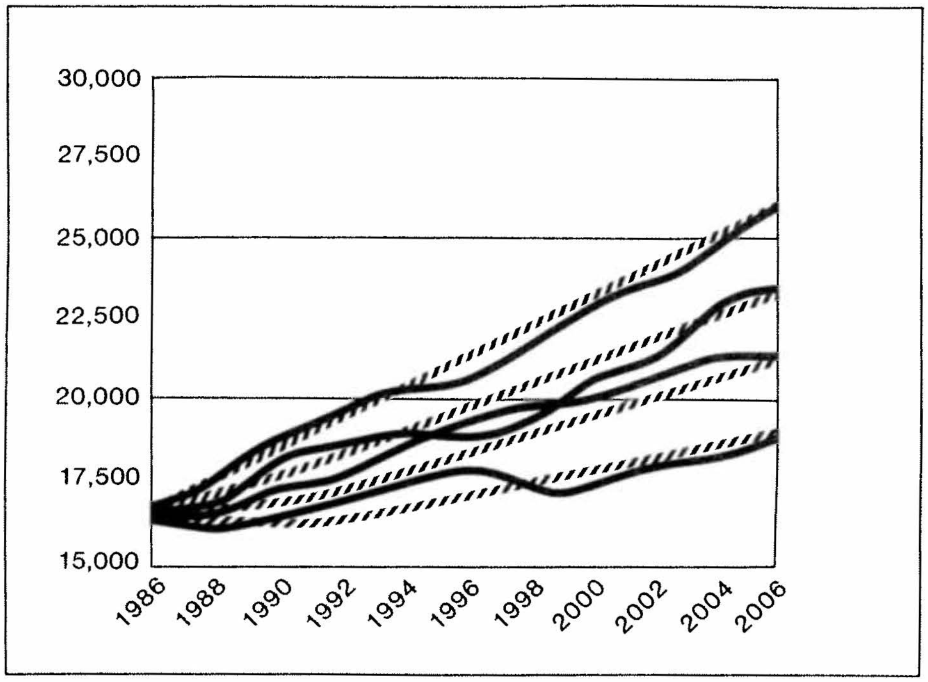


Figure 8-58
Example Decision Model Load Paths

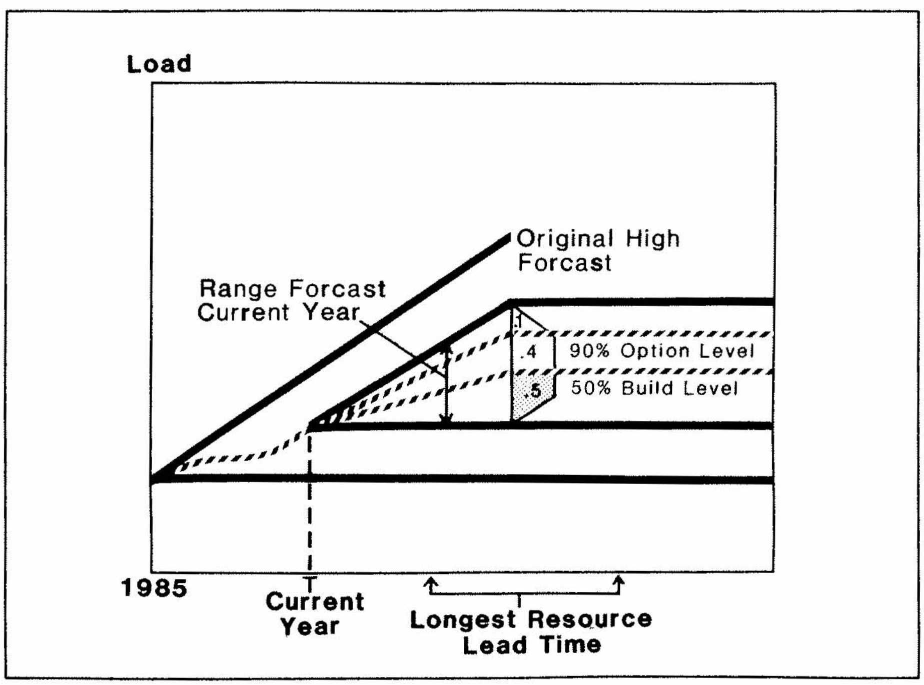


Figure 8-59
Decision Model Option and Build Level

Option and Build Requirements
The selection of option and build requirements is depicted in Figures 8-59 and 8-60. Figure 8-59 shows the use of the option and build levels at a point part way through the model's simulation. The model has followed a varying load path from 1985 to the current year. It still sees a forecast range as it looks forward the length of the longest lead time of the resources it has available to it. However, the megawatt range is narrower than the original range. The high growth rate still is achievable, but since the model is now at a middle point in the range it can never reach the Council's high load itself. The option level and build level are selected by the user, and the current Council values are shown.

Figure 8-60 repeats part of Figure 8-59 and shows an example of the actual resource and build decisions, given a set of previous decisions. This diagram shows a set of existing resources plus a set of build decisions that were made in previous years. Since option decisions were also made in previous years, there are some resources now in the option inventory from which to choose in making the build decision. As shown in this example, while there are sufficient options available to build to the forecast 50 percent build level, additional options will need to be acquired to maintain the option level at 90 percent. The model makes all these decisions, calculates production costs and capital costs for the current year at the observed load, then steps forward another year, discovers a new load, and repeats the process.

Resource Choice
Figure 8-61 is a simplified illustration of the process of resource choice. Resources are ranked in priority order in an input file. The model only sees the priority order for its option and build choices; these choices are not made by the model on the basis of relative cost. The resource priority order is determined externally to the model by the user. The Council determined the order through a process using simple screening of levelized cost, more complex comparison of resources with the System Analysis Model, and multiple trials of priority orders using the Decision Model.

Once this priority order is established, the model attempts to choose the resources in this order. In the example shown in Figure 8-61, energy from nondiscretionary conservation programs or forced resource decisions, represented by block A, would be scheduled automatically. Energy from discretionary conservation programs, represented as block B, would be managed to meet energy targets for the individual conservation programs, subject to program penetration constraints. Resource C, a generating resource with a three-year lead time, has its first point of need beyond its lead time, and would require no decision other than to continue to hold in inventory. Resource D, however, is projected to be needed at its lead time of six years, and a decision to initiate construction would be made.

There can be occurrences where the resource priority is not followed explicitly. Events such as sudden spurts in load growth may require scheduling resources with lower priority, but shorter lead time, in order to maintain balance with respect to the option and build levels specified. It is also possible that reductions in observed load growth may cause options to expire before they can be used, and may lead to resource choice out of order.

Capital Costing

Figure 8-62 is a rough illustration of the process of calculating capital costs in the Decision Model. The top portion of the figure shows various important time points for the capital costing of a resource: option decision, option arrival, build decision, build arrival or in-service date, and retirement. The lower portion of the figure identifies the nominal dollar capital revenue requirements that are observed by the model in each year from the option decision to retirement of the resource. The figure is only to scale in a very general sense.

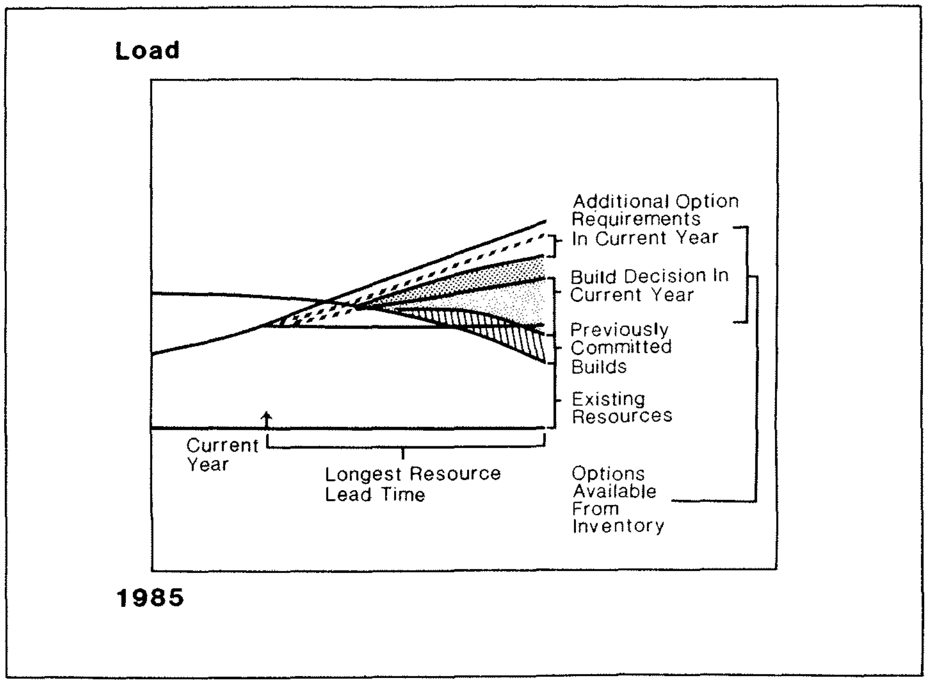
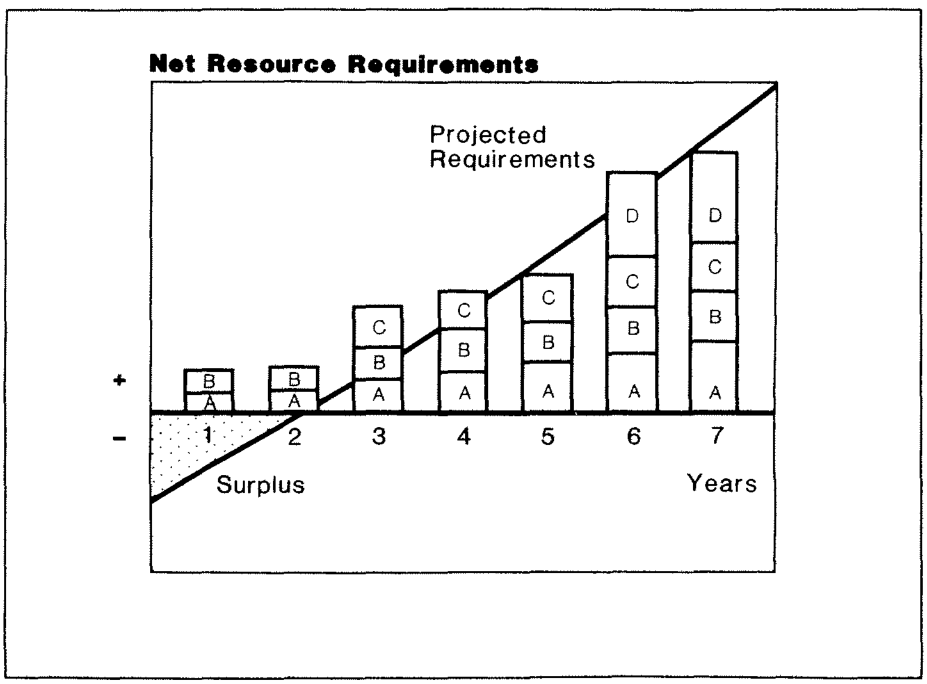


Figure 8-60
Decision Model Option and Build Requirements



Resource Additions
A. Non-discretionary conservation programs or forced resource decision
B. Discretionary conservation programs
C. Generating resource - 3 year lead time
D. Generating resource - 6 year lead time

Figure 8-61
Decision Model Build Decisions

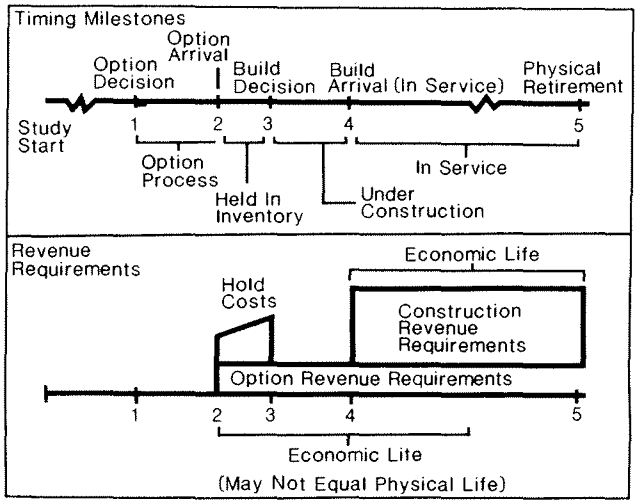


Figure 8-62
Decision Model Process of Calculating Capital Costs

Figure 8-62 shows that revenue requirements for options begin at the end of the option lead time; payments during that time are assumed capitalized until then. The option costs are put into revenue requirements over a period equal to the economic life of the resource. If the resource is never built, the remaining unrecovered option costs are placed directly into revenue requirements in the year the option is lost. Option revenue requirements are calculated using a nominal levelized fixed charge rate. (Chapter 4 of this volume gives background on the concepts of "nominal," "real," and "levelized.") Hold costs are put directly into revenue requirements each year as they are incurred and are shown as increasing in nominal terms because of assumed inflation. Finally, construction costs are capitalized to the in-service date of the resource, and then converted to annual revenue requirements over the economic life of the resource using a nominal levelized fixed charge rate, similar to the treatment of option costs.

The model will eventually have the ability to convert levelized fixed charge rates to the uneven pattern of actual nominal revenue requirements (see Volume II, Chapter 4), but this capability has not been completed yet.

Production Costing

Production costing is based on a composite system model similar to that used for seasonal studies in the System Analysis Model. Because of the dominance of energy issues in Northwest power planning, it is an energy model only; there is currently no treatment of capacity. Simulation of hydropower system operation is based on a one dam model in which total hydro energy capability, natural streamflow energy, reservoir draft, and limits on draft and refill for the entire system are specified as single values for the various seasons and water conditions. Data for the hydropower model are based on the result of critical period studies and the 40-year hydro regulation studies performed as part of the Northwest Regional Forecast. To capture the impact of streamflow variability, the model uses complete enumeration of ten representative water conditions, and weights the results in accordance with the 102-year water record. Four discrete time periods are used for evaluation within each operating year: September-December, January-April, May, and June-August. May is modeled separately to provide better resolution on the system impact of the spring fish flows.

Thermal units are modeled with deration for equivalent availability and are shaped seasonally according to specified maintenance schedules. Nuclear units are treated as must run; all other thermal operation is modeled with economic dispatch against firm, interruptible, and secondary market load blocks, as needed under the various hydro conditions. The secondary market is modeled as a four-tiered market with prices and seasonally shaped demand blocks changing through time. Conservation programs and renewable generating resources are typically treated as seasonally shaped load reduction resources. Any firm load not met with regional resources is assumed to be met with an out-of-region purchase at a specifiable price. (The Council currently uses 150 mills, or 15 cents, per kilowatt-hour.) Curtailments of interruptible load are priced near interruptible rates.

Treatment of End Effects

End effects are incurred in any model because resources have different lives and, in addition, many of them last beyond the study horizon of the model. A resource that costs the same amount but lasts twice as long as another will be more valuable. But if both resources retire outside the study horizon of a model, the model will not be able to tell. One means of dealing with this problem, used in the end effects treatment for the System Analysis Model and in the Decision Model, is to extend the simulation period in a simplified way until all resources constructed during the study horizon have retired. These resources are all replaced by the same kind of resource and the study is then truncated after the only remaining resources are the replacement resources. The use of constant real levelized capital costs for these replacement resources ensures that studies with resources of different lifetimes are comparable.

There is an additional end effects problem to be dealt with in the Decision Model. Since the model options and builds resources under load uncertainty, some simulations will end up surplus at the end of the study horizon and some simulations will end up deficit. This distribution of ending load/resource balances can be a function of the resource strategy employed, i.e., the option and build levels, the resource priorities, forced resource decisions, and the amount of load variation present.

While production and capital costing is carried out beyond the study horizon (normally 20 years), the forecasting and option and build steps stop at the study horizon. To the extent that strategies being tested have consequences like persistent overbuilding or underbuilding, the surpluses or deficits need to be carried beyond the study horizon to the end of the terminal horizon. (This can be as long as an additional 70 years to deal with the issues mentioned in the previous paragraph.) In some uses of the model, however, the user may wish to ensure that a certain level of load/resource balance is attained for the post-study horizon period.

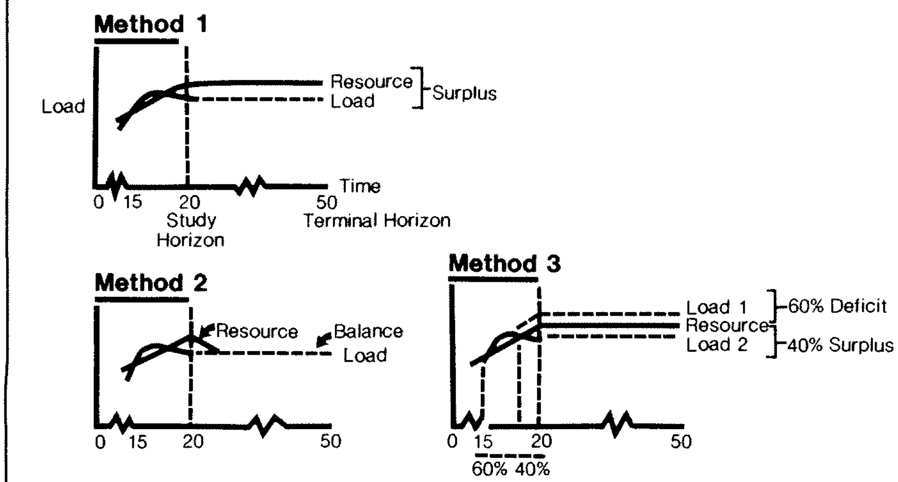


Figure 8-63
Decision Model End Effects Treatments

Because of these varying requirements, there are three methods available to calculate the terminal horizon load/resource balance. The three methods are illustrated in Figure 8-63 for a simulation that varies from deficit to surplus over the last five years of the study horizon, but that ends in surplus.

The first method simply extends each simulation's observed twentieth year surplus or deficit to the terminal horizon for that simulation. This is illustrated in the top diagram in Figure 8-63.

The second method adjusts each simulation's twentieth year surplus or deficit to an input target load/resource balance. In this case, the target was zero surplus or deficit. It does this by building additional resources in the twenty-first year if more resources are needed, or by not replacing resources as they retire if fewer resources are needed. The latter process usually reaches the target within ten years after the study horizon.

The third method is an elaboration of the first. It is illustrated in the bottom diagram in Figure 8-63. This method calculates the average surplus and the average deficit over the last five years of the study horizon. (The number of years is a user input; the Council uses five.) It then conducts its production costing twice for the terminal horizon period: once using the average surplus and once the average deficit value. Finally, the model weights the two results by the percent of time in the last five years of the study horizon that the simulation was surplus and was deficit. While this is a more precise calculation than the first method, it has the disadvantage of requiring substantially more computer time because of the doubled terminal horizon production costing for each simulation.

Section E: Lost Opportunity Resources

A lost opportunity resource is a potential electric power generating resource or a potential electric power conservation measure which is currently available to the region and which, if not acquired or otherwise secured now, will no longer be available and cost-effective to the region. If a lost opportunity resource is not secured, it will have to be replaced in the future by a less cost-effective resource. A lost opportunity resource is cost effective and should be secured if the present value system cost of the investment to secure and maintain the resource by the region, as determined by the Council, is less than the present value system cost of all other resources included in the Council's resource portfolio that might have to replace it. Avoided cost studies, regarding the economics of lost opportunity resources and their value during the current surplus, were discussed in Volume I, Chapter 8. This section presents a general description of the various types of lost opportunity generating resources.

Table 8-4
Inventory of Potential Lost Opportunity Resources[a]

TYPE OF RESOURCE	ENERGY (average megawatts)
Loss of Generation Potential[b]	
Municipal water systems (28 projects)	80.0
Biomass incineration (2 projects)	10.0[c]
Solid waste disposal (4 projects)	62.0
Cogeneration and misc. (5 projects)	45.7[c]
Out-of-Region Sale	
Coal (2 projects)	138.7[c]
Hydropower (2 projects)	21.3[c]
Loss of Development Rights	
Licensed thermal sites (3 projects)	1,406.0
Loss of Development Incentives	
(3 hydropower projects)	53.4[c]
Generation in Lieu of Transmission	
(1 project)	—[c]
TOTAL	1,817.1

[a]The projects and energy listed in this table are taken from the Bonneville preliminary inventory of lost opportunity resources, and do not necessarily agree with current Council inventories of these resources.

[b]Not included is 65 megawatts from the proposed Fast Flux Test Facility (FFTF) power addition project, earlier evaluated by Bonneville as a potential lost opportunity resource. Uncertainties regarding long-term Congressional funding of the FFTF project are considered by Bonneville to be to great to justify acquisition of this resource.

[c]The energy production of one or more projects within this category was not estimated; thus the actual total would be greater than indicated.

Availability of Potential Lost Opportunity Resources

The availability and cost effectiveness of potential lost opportunity conservation resources in the residential and commercial sectors were well understood at the time of the 1983 Power Plan, leading the Council to call for the acquisition of these resources, where cost effective, through implementation of conservation standards. In contrast, the extent and cost effectiveness of potential lost opportunity generating resources remain less well understood.

In order to gain additional information on potential lost opportunity resources, the Council included Action Item 13.3 in the 1983 Power Plan. This action item called upon Bonneville to:

Identify, by project, specific resources which may be lost to the region if decisions to acquire an option or to acquire the resources are not made. This inventory should recognize each resource sponsor's requirements for keeping the resource available to the region.

In response to this action item, Bonneville has compiled a preliminary inventory of potential lost opportunity generation resources. This inventory, summarized into five classes of potential lost opportunities, is shown in Table 8-4.

Loss of Generation Potential

The projects representing loss of generation potential are related to scheduled non-power developments that could be modified to produce electric power as a byproduct. These projects include: 1) municipal and hatchery water supply systems with an available water head that could be used for hydropower generation; 2) proposed solid waste incinerators that could be modified to recover energy for power generation; 3) landfills that could be provided with methane collection systems for use in powering generation equipment; and 4) industrial facilities that could be modified to accommodate cogeneration. Not included in the present inventory are planned irrigation projects with the potential for associated hydropower development, building cogeneration potential or planned transmission and generation projects with additional system efficiency improvement potential.

Because the basic power source exists for other purposes, the incremental lead time, cost and environmental impact are potentially less than for facilities constructed specifically for power generation. This gives projects in this category desirable planning qualities, including short development lead times, small increments of capacity, low cost and modest incremental environmental impact.

The power generation capability of these projects can be secured by incorporating design features during initial construction to facilitate later addition of power generation equipment. For example, taps could be provided in a new municipal water supply system to accommodate later addition of turbines. The power generation equipment can be added when need-for-power dictates.

Out-of-Region Sales

Potential lost opportunities for out-of-region sales include two types of projects. One type is existing regional power generation resources currently offered for sale as excess to the needs of the current owners. All projects of this type on the current Bonneville inventory are coal-fired power plants. The capability of these plants may be sold outside, and potentially lost to the region. Regional acquisition of the capability of these projects would likely be cost effective if a sale of power outside the region, incorporating callback provisions, could be arranged after acquisition. With such an arrangement, these resources would appear to be quite valuable. Power could be made available to the region with short lead time (the time period negotiated in the callback provisions) and in appropriate increments. Incremental environmental impact within the region would be negligible. Costs would be representative of existing thermal plants.

A second type of out-of-region sale project is proposed projects potentially qualifying for sale under the provisions of the Public Utility Regulatory Policies Act (PURPA). These projects could be lost to the region if sales to out-of-region purchasers were negotiated. All such projects in the current inventory are hydropower projects, although other qualifying facilities, such as cogeneration, might materialize. Acquisition of these projects is advantageous to the region to the extent that they are cost effective.

Loss of Development Rights

These opportunities consist of currently undeveloped sites for which land rights, preliminary engineering design, baseline environmental data and licenses have been partly or fully obtained. Currently there are three thermal sites in the inventory: Creston, Washington; Wyodak, Wyoming; and Boardman, Oregon. Not included are the Salem, Montana, thermal site or numerous partially or fully licensed hydropower sites in the region.

If the present value cost of acquisition and maintenance of the development rights is found to be less than the present value cost of reacquisition of these assets, if and when needed, the development rights should be acquired and maintained as an option by the region. In assessing the value of development rights, consideration should be given to the suitability of thermal sites for siting secondary hydropower firming resources such as combustion turbines.

Loss of Development Incentives

These opportunities consist of several hydropower projects for which special incentives may expire unless exercised. Securing this type of lost opportunity would likely require construction of the project. Because of this, acquisition would likely be cost effective under the present surplus only for very low-cost projects.

Generation in Lieu of Transmission

This opportunity presently includes one prospective cogeneration project located in an area needing transmission upgrade to serve increased load. Construction of the project, offsetting the transmission load, may be more cost effective than the planned transmission expansion. The reliability of the project must be considered in assessing the cost effectiveness of the project in comparison with upgraded transmission.

Additional Resource Information

The current inventory, while adequate for initial identification of potential lost opportunity generation resources, is not adequate to determine if specific resources should be acquired. Additional information required includes:

- The timing and duration of the present "window of opportunity" for each resource.
- The nature and cost of actions that might be taken to secure the resource.
- The cost, availability and shelf life of the resource if actions are taken to secure the resource or to extend the window of opportunity.
- The cost, availability and shelf life of the resource if actions are not taken to secure the resource.

Bonneville should expand its efforts to include the above information in the lost opportunity data base.

The data base should be expanded to include the following resource types:

- Planned irrigation development with power potential.
- Planned generation, transmission and distribution system upgrades with additional system efficiency improvement potential.
- Hydropower development rights.
- Building cogeneration potential.

Lost opportunity resources are not, by definition, static. For this reason it is desirable to periodically update the lost opportunity resource data base.

Resource Evaluation and Acquisition

Acquisition of certain lost opportunity resources may be cost effective even during the current period of surplus. Resources would likely be cost effective if their acquisition results in a present value system cost less than the forecast present value system cost without acquisition. This determination can be made using available system planning models. Certain resources may have energy costs less than the value of surplus energy. Immediate development of such a resource may be cost effective. For example, preliminary information on the cost of system efficiency improvements indicates that the cost of certain improvements of this type is extremely low, with resulting costs of energy less than the value of surplus.

Because near-term acquisition of certain lost opportunity resources may be cost effective, actions should be taken to develop the institutional mechanisms to acquire lost opportunity resources. This will require a methodology for the evaluation of lost opportunity resources and adoption of a policy for lost opportunity resource acquisition. The policy should include consistent criteria for determining when a lost opportunity resource should be acquired. These activities are called for in Volume I, Chapter 9.

The tables in this appendix contain the data supporting the resource portfolio graphics, figures 8-8 and 8-9. Eight tables are included, one for each of the four load forecasts for the region as a whole, and for just the public utility and direct service industry customers of the Bonneville Power Administration. The loads shown are firm loads only and have been adjusted for transmission and distribution losses. The "existing resource" category contains hydro Firm Energy Load Carrying Capability (FELCC), existing thermal, miscellaneous resources, and imports net of exports. Values for existing resources were derived based on the 1985 *Northwest Regional Forecast*, compiled and published by PNUCC.

The resource schedules shown here are based on the assumption of perfect knowledge of load, and they attain load/resource balance in all load conditions within the constraints of the current surplus and generating resource unit size. Line item entries for conservation programs show cumulative energy developed through time for each program. Each line item entry for the generating resource represents the energy associated with a set of new additions.

Table 8-A-1
Regional High (1985-1995)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Observed Load	16,258	16,634	17,262	17,915	18,592	19,117	19,614	20,157	20,726	21,380
Observed Rate	0.00%	2.31%	3.78%	3.78%	3.78%	2.82%	2.60%	2.77%	2.82%	3.16%
Resources:										
Existing	18,824	18,834	18,605	18,555	18,531	18,522	18,461	18,415	18,006	18,011
Conservation Programs:										
MCS Single Family	5	22	41	64	91	120	151	183	217	254
MCS Multifamily	1	3	6	8	12	15	19	23	27	31
MCS Commercial	0	15	36	57	78	98	118	139	161	183
Refrigerators/Freezers	0	0	0	0	0	0	10	26	49	72
Water Heat	0	0	0	0	0	0	11	29	53	79
Manufactured Homes	0	0	1	3	4	5	7	9	10	12
Agricultural	0	2	10	20	30	40	50	60	70	80
Existing Commercial	0	15	60	125	195	265	335	405	475	545
Trans & Distr Efficiency	0	1	4	8	13	18	23	28	33	34
Existing Space Heat	8	16	34	64	109	159	209	259	309	359
Existing Industrial	0	0	20	80	170	270	370	450	450	450
Subtotal	14	74	212	429	702	990	1,303	1,611	1,854	2,099
Generating Resources:										
Hydropower Efficiency	0	0	0	0	0	60	60	60	60	60
Hydropower Efficiency	0	0	0	0	0	0	15	15	15	15
Hydropower Efficiency	0	0	0	0	0	0	0	10	10	10
Hydropower Efficiency	0	0	0	0	0	0	0	0	15	15
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	10
Subtotal	0	0	0	0	0	60	75	85	100	110
Combustion Turbines	0	0	0	0	0	0	0	0	714	714
Subtotal	0	0	0	0	0	0	0	0	714	714
Small Hydropower	0	0	0	0	0	0	0	52	52	52
Small Hydropower	0	0	0	0	0	0	0	0	7	7
Small Hydropower	0	0	0	0	0	0	0	0	0	140
Subtotal	0	0	0	0	0	0	0	52	59	199

(table continued on next page)

Table 8-A-1 (continued)
Regional High (1985-1995)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Cogeneration	0	0	0	0	0	0	0	0	0	255
Cogeneration	0	0	0	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	255
Licensed Coal	0	0	0	0	0	0	0	0	0	0
Licensed Coal	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	18,838	18,908	18,817	18,984	19,233	19,572	19,839	20,163	20,733	21,388
Load/Resource Balance	2,580	2,274	1,555	1,069	641	455	225	6	7	8

Regional High (1995-2005)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Observed Load	22,027	22,738	23,388	24,033	24,849	25,375	26,045	26,746	27,485	28,260
Observed Rate	3.03%	3.23%	2.86%	2.76%	3.40%	2.12%	2.64%	2.69%	2.76%	2.82%
Resources:										
Existing	17,991	18,012	17,948	17,916	17,784	17,796	17,780	17,740	17,643	17,790
Conservation Programs:										
MCS Single Family	295	337	381	425	470	515	560	607	656	705
MCS Multifamily	36	42	47	53	58	64	69	75	81	87
MCS Commercial	206	229	253	277	303	328	354	380	392	398
Refrigerators/Freezers	97	122	148	176	204	233	261	291	321	352
Water Heat	106	135	165	196	227	259	292	326	361	396
Manufactured Homes	14	16	19	21	23	26	28	30	33	35
Agricultural	90	100	110	120	123	123	124	124	124	124
Existing Commercial	615	685	755	801	801	801	802	802	802	802
Trans & Distr Efficiency	34	34	34	34	34	34	34	34	34	34
Existing Space Heat	409	455	455	455	455	455	455	455	455	455
Existing Industrial	450	450	450	450	450	450	450	450	450	450
Subtotal	2,352	2,605	2,817	3,008	3,148	3,288	3,429	3,574	3,709	3,838

(table continued on next page)

Table 8-A-1 (continued)
Regional High (1995-2005)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Generating Resources:										
Hydropower Efficiency	60	60	60	60	60	60	60	60	60	60
Hydropower Efficiency	15	15	15	15	15	15	15	15	15	15
Hydropower Efficiency	10	10	10	10	10	10	10	10	10	10
Hydropower Efficiency	15	15	15	15	15	15	15	15	15	15
Hydropower Efficiency	10	10	10	10	10	10	10	10	10	10
Subtotal	110	110	110	110	110	110	110	110	110	110
Combustion Turbines	714	714	714	714	714	714	714	714	714	714
Subtotal	714	714	714	714	714	714	714	714	714	714
Small Hydropower	52	52	52	52	52	52	52	52	52	52
Small Hydropower	7	7	7	7	7	7	7	7	7	7
Small Hydropower	140	140	140	140	140	140	140	140	140	140
Subtotal	199	199	199	199	199	199	199	199	199	199
Cogeneration	255	255	255	255	255	255	255	255	255	255
Cogeneration	0	0	5	5	5	5	5	5	5	5
Cogeneration	0	0	0	40	40	40	40	40	40	40
Cogeneration	0	0	0	0	0	0	0	20	20	20
Subtotal	255	255	260	300	300	300	300	320	320	320
Licensed Coal	452	452	452	452	452	452	452	452	452	452
Licensed Coal	0	452	452	452	452	452	452	452	452	452
Subtotal	452	904	904	904	904	904	904	904	904	904
Unlicensed Coal	0	0	452	452	452	452	452	452	452	452
Unlicensed Coal	0	0	0	452	452	452	452	452	452	452
Unlicensed Coal	0	0	0	0	904	904	904	904	904	904
Unlicensed Coal	0	0	0	0	0	452	452	452	452	452
Unlicensed Coal	0	0	0	0	0	0	452	452	452	452
Unlicensed Coal	0	0	0	0	0	0	0	452	452	452
Unlicensed Coal	0	0	0	0	0	0	0	0	904	904
Unlicensed Coal	0	0	0	0	0	0	0	0	0	452
Subtotal	0	0	452	904	1,808	2,260	2,712	3,164	4,068	4,520
Total Firm Resources	22,073	22,799	23,404	24,055	24,967	25,571	26,148	26,725	27,667	28,395
Load/Resource Balance	46	61	16	22	118	196	103	-21	182	135

Table 8-A-2
Regional Medium-High (1985-1995)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Observed Load	16,258	16,466	16,833	17,208	17,591	17,969	18,345	18,727	19,108	19,580
Observed Rate	0.00%	1.28%	2.23%	2.23%	2.23%	2.15%	2.09%	2.08%	2.03%	2.47%
Resources:										
Existing	18,824	18,834	18,605	18,555	18,531	18,522	18,461	18,415	18,006	18,011
Conservation Programs:										
MCS Single Family	5	17	32	48	68	88	109	131	153	176
MCS Multifamily	1	3	6	10	14	18	22	26	31	35
MCS Commercial	0	7	17	28	39	50	61	73	85	96
Refrigerators/Freezers	0	0	0	0	0	0	10	25	47	69
Water Heat	0	0	0	0	0	0	10	27	49	72
Manufactured Homes	0	1	2	3	5	7	9	11	13	15
Agricultural	0	0	0	2	10	20	30	40	50	60
Existing Commercial	0	0	0	15	60	125	195	265	335	405
Trans & Distr Efficiency	0	0	0	1	4	8	13	18	23	28
Existing Space Heat	8	16	28	41	69	113	163	213	263	313
Existing Industrial	0	0	0	0	0	20	80	170	270	370
Subtotal	14	44	85	148	269	449	702	999	1,319	1,639
Generating Resources:										
Hydropower Efficiency	0	0	0	0	0	0	0	0	55	55
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	5
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	55	60
Combustion Turbines	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Licensed Coal	0	0	0	0	0	0	0	0	0	0
Licensed Coal	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Unlicensed Coal	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	18,838	18,878	18,690	18,703	18,800	18,971	19,163	19,414	19,380	19,710
Load/Resource Balance	2,580	2,412	1,857	1,495	1,209	1,002	818	687	272	130

(table continued on next page)

Regional Medium-High (1995-2005)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Observed Load	20,006	20,471	20,863	21,240	21,766	21,990	22,342	22,708	23,094	23,498
Observed Rate	2.18%	2.32%	1.91%	1.81%	2.48%	1.03%	1.60%	1.64%	1.70%	1.75%
Resources:										
Existing	17,991	18,012	17,948	17,916	17,784	17,796	17,780	17,740	17,643	17,790
Conservation Programs:										
MCS Single Family	199	223	246	269	290	310	329	348	368	387
MCS Multifamily	40	45	49	54	59	63	67	72	76	81
MCS Commercial	108	120	131	143	155	167	178	189	194	195
Refrigerators/Freezers	91	114	137	161	184	207	228	250	272	293
Water Heat	95	120	145	171	196	222	247	273	299	324
Manufactured Homes	17	19	22	24	26	28	30	32	34	36
Agricultural	70	80	90	100	105	105	105	105	105	105
Existing Commercial	475	545	611	611	611	611	611	611	611	611
Trans & Distr Efficiency	33	34	34	34	34	34	34	34	34	34
Existing Space Heat	363	413	455	455	455	455	455	455	455	455
Existing Industrial	450	450	450	450	450	450	450	450	450	450
Subtotal	1,941	2,163	2,370	2,472	2,565	2,652	2,734	2,819	2,898	2,971
Generating Resources:										
Hydropower Efficiency	55	55	55	55	55	55	55	55	55	55
Hydropower Efficiency	5	5	5	5	5	5	5	5	5	5
Hydropower Efficiency	10	10	10	10	10	10	10	10	10	10
Hydropower Efficiency	0	10	10	10	10	10	10	10	10	10
Hydropower Efficiency	0	0	10	10	10	10	10	10	10	10
Hydropower Efficiency	0	0	0	10	10	10	10	10	10	10
Hydropower Efficiency	0	0	0	0	10	10	10	10	10	10
Subtotal	70	80	90	100	110	110	110	110	110	110
Combustion Turbines	0	178	178	178	178	178	178	178	178	178
Combustion Turbines	0	0	178	178	178	178	178	178	178	178
Combustion Turbines	0	0	0	357	357	357	357	357	357	357
Subtotal	0	178	356	713	713	713	713	713	713	713
Small Hydropower	7	7	7	7	7	7	7	7	7	7
Small Hydropower	0	37	37	37	37	37	37	37	37	37
Small Hydropower	0	0	55	55	55	55	55	55	55	55
Small Hydropower	0	0	0	0	95	95	95	95	95	95
Small Hydropower	0	0	0	0	0	0	0	0	2	2
Small Hydropower	0	0	0	0	0	0	0	0	0	2
Subtotal	7	44	99	99	194	194	194	194	196	198
Cogeneration	0	0	0	0	210	210	210	210	210	210
Subtotal	0	0	0	0	210	210	210	210	210	210
Licensed Coal	0	0	0	0	0	452	452	452	452	452
Licensed Coal	0	0	0	0	0	0	0	452	452	452
Subtotal	0	0	0	0	0	452	452	904	904	904
Unlicensed Coal	0	0	0	0	0	0	0	0	452	452
Subtotal	0	0	0	0	0	0	0	0	452	452
Total Firm Resources	20,009	20,477	20,863	21,300	21,576	22,127	22,193	22,690	23,126	23,348
Load/Resource Balance	3	6	0	60	-190	137	-149	-18	32	-150

Table 8-A-3
Regional Medium-Low (1985-1995)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Observed Load	16,258	16,282	16,367	16,454	16,540	16,721	16,956	17,213	17,346	17,798
Observed Rate	0.00%	0.15%	0.52%	0.53%	0.52%	1.09%	1.41%	1.52%	0.77%	2.61%
Resources:										
Existing	18,824	18,834	18,605	18,555	18,531	18,522	18,461	18,415	18,006	18,011
Conservation Programs:										
MCS Single Family	5	10	16	24	34	44	56	68	80	92
MCS Multifamily	1	3	5	8	12	16	20	24	28	33
MCS Commercial	0	2	5	10	14	20	25	31	37	44
Refrigerators/Freezers	0	0	0	0	0	0	7	19	35	51
Water Heat	0	0	0	0	0	0	8	21	39	57
Manufactured Homes	0	0	1	2	4	6	7	9	11	13
Agricultural	0	0	0	0	0	0	0	2	10	20
Existing Commercial	0	0	0	0	0	0	0	0	15	60
Trans & Distr Efficiency	0	0	0	0	0	0	0	0	1	4
Existing Space Heat	8	16	28	36	44	52	60	68	76	94
Existing Industrial	0	0	0	0	0	0	0	0	0	0
Subtotal	14	31	55	80	108	138	183	242	332	468
Generating Resources:										
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	18,838	18,865	18,660	18,635	18,639	18,660	18,644	18,657	18,338	18,479
Load/Resource Balance	2,580	2,583	2,293	2,181	2,099	1,939	1,688	1,444	992	681

(table continued on next page)

Regional Medium-Low (1995-2005)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Observed Load	18,158	18,489	18,773	19,047	19,465	19,612	19,899	20,197	20,503	20,811
Observed Rate	2.02%	1.82%	1.54%	1.46%	2.19%	0.76%	1.46%	1.50%	1.52%	1.50%
Resources:										
Existing	17,991	18,012	17,948	17,916	17,784	17,796	17,780	17,740	17,643	17,790
Conservation Programs:										
MCS Single Family	105	118	131	144	157	171	184	197	211	225
MCS Multifamily	37	41	46	50	55	60	65	70	75	80
MCS Commercial	50	57	64	71	78	85	92	99	104	109
Refrigerators/Freezers	68	84	101	118	135	153	170	188	206	224
Water Heat	76	96	116	136	157	179	200	222	244	266
Manufactured Homes	14	16	18	20	22	24	26	28	30	32
Agricultural	30	40	50	60	70	80	90	100	105	105
Existing Commercial	125	195	265	335	405	475	475	475	475	475
Trans & Distr Efficiency	8	13	18	23	28	33	34	34	34	34
Existing Space Heat	132	181	231	281	331	381	431	455	455	455
Existing Industrial	0	0	20	80	170	270	370	450	450	450
Subtotal	645	841	1,060	1,318	1,608	1,911	2,137	2,318	2,389	2,455
Generating Resources:										
Hydropower Efficiency	0	0	80	80	80	80	80	80	80	80
Hydropower Efficiency	0	0	0	15	15	15	15	15	15	15
Hydropower Efficiency	0	0	0	0	15	15	15	15	15	15
Subtotal	0	0	80	95	110	110	110	110	110	110
Combustion Turbines	0	0	0	0	0	0	0	0	357	357
Subtotal	0	0	0	0	0	0	0	0	357	357
Small Hydropower	0	0	0	0	0	0	0	22	22	22
Small Hydropower	0	0	0	0	0	0	0	0	0	87
Subtotal	0	0	0	0	0	0	0	22	22	109
Total Firm Resources	18,636	18,853	19,088	19,329	19,502	19,817	20,027	20,190	20,521	20,821
Load/Resource Balance	478	364	315	282	37	205	128	-7	18	10

Table 8-A-4

Regional Low (1985-1995)

System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Observed Load	16,258	16,064	15,826	15,591	15,360	15,295	15,322	15,367	15,436	15,587
Observed Rate	0.00%	-1.19%	-1.48%	-1.48%	-1.48%	-0.42%	0.18%	0.29%	0.45%	0.98%
Resources:										
Existing	18,824	18,834	18,605	18,555	18,531	18,522	18,461	18,415	18,006	18,011
Conservation Programs:										
MCS Single Family	5	6	6	7	10	13	18	22	27	32
MCS Multifamily	1	1	1	2	3	4	6	8	9	11
MCS Commercial	0	1	2	4	6	8	10	13	15	18
Refrigerators/Freezers	0	0	0	0	0	0	7	18	34	49
Water Heat	0	0	0	0	0	0	6	17	31	45
Manufactured Homes	0	0	0	0	0	1	2	2	3	4
Agricultural	0	0	0	0	0	0	0	0	0	0
Existing Commercial	0	0	0	0	0	0	0	0	0	0
Trans & Distr Efficiency	0	0	0	0	0	0	0	0	0	0
Existing Space Heat	8	16	28	36	44	52	60	68	76	84
Existing Industrial	0	0	0	0	0	0	0	0	0	0
Subtotal	14	24	37	49	63	78	109	148	195	243
Total Firm Resources	18,838	18,858	18,642	18,604	18,594	18,600	18,570	18,563	18,201	18,254
Load/Resource Balance	2,580	2,794	2,816	3,013	3,234	3,305	3,248	3,196	2,765	2,667

Regional Low (1995-2005)

System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Observed Load	15,604	15,699	15,792	15,894	16,153	16,149	16,290	16,443	16,601	16,775
Observed Rate	0.11%	0.61%	0.59%	0.65%	1.63%	-0.02%	0.87%	0.94%	0.96%	1.05%
Resources:										
Existing	17,991	18,012	17,948	17,916	17,784	17,796	17,780	17,740	17,643	17,790
Conservation Programs:										
MCS Single Family	38	43	49	55	61	68	74	81	87	94
MCS Multifamily	13	16	18	20	22	25	27	30	32	35
MCS Commercial	21	24	27	30	34	38	41	45	48	51
Refrigerators/Freezers	65	81	98	114	130	146	161	176	191	206
Water Heat	60	76	92	110	127	145	163	182	200	219
Manufactured Homes	4	5	6	7	8	9	10	11	12	13
Agricultural	0	0	0	0	0	0	0	0	0	0
Existing Commercial	0	0	0	0	0	0	0	0	0	0
Trans & Distr Efficiency	0	0	0	0	0	0	0	0	0	0
Existing Space Heat	92	100	108	116	124	132	140	148	156	164
Existing Industrial	0	0	0	0	0	0	0	0	0	0
Subtotal	293	345	398	452	506	563	616	673	726	782
Total Firm Resources	18,284	18,357	18,346	18,368	18,290	18,359	18,396	18,413	18,369	18,572
Load/Resource Balance	2,680	2,658	2,554	2,474	2,137	2,210	2,106	1,970	1,768	1,797

Table 8-A-5
Public High (1985-1995)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Observed Load	8,444	8,548	8,809	9,079	9,356	9,576	9,784	10,011	10,252	10,568
Observed Rate	0.00%	1.23%	3.05%	3.07%	3.05%	2.35%	2.17%	2.32%	2.41%	3.08%
Resources:										
Existing	10,303	10,345	10,190	10,212	10,231	10,238	10,244	10,233	9,957	9,982
Conservation Programs:										
MCS Single Family	2	9	18	28	39	52	64	78	92	108
MCS Multifamily	0	1	3	4	6	7	9	11	13	15
MCS Commercial	0	6	15	23	31	39	47	56	64	73
Refrigerators/Freezers	0	0	0	0	0	2	6	12	21	31
Water Heat	0	0	0	0	0	2	6	14	23	34
Manufactured Homes	0	1	1	2	3	4	5	6	7	8
Agricultural	0	0	0	0	1	4	8	12	16	20
Existing Commercial	0	0	0	0	6	24	50	78	106	134
Trans & Distr Efficiency	0	0	0	0	0	2	4	6	8	10
Existing Space Heat	4	8	13	16	19	26	41	61	81	101
Existing Industrial	0	0	0	0	0	0	0	0	0	15
Subtotal	6	25	50	73	105	162	240	334	431	549
Generating Resources:										
Hydropower Efficiency	0	0	0	0	0	0	0	0	30	30
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	40
Subtotal	0	0	0	0	0	0	0	0	30	70
Combustion Turbines	0	0	0	0	0	0	0	0	0	0
Combustion Turbines	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Small Hydropower	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Licensed Coal	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	10,309	10,370	10,240	10,285	10,336	10,400	10,484	10,567	10,418	10,601
Load/Resource Balance	1,865	1,822	1,431	1,206	980	824	700	556	166	33

(table continued on next page)

Public High (1995-2005)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Observed Load	10,811	11,116	11,387	11,652	12,070	12,207	12,479	12,761	13,057	13,364
Observed Rate	2.30%	2.82%	2.44%	2.33%	3.59%	1.14%	2.23%	2.26%	2.32%	2.35%
Resources:										
Existing	10,063	10,367	10,364	10,351	10,315	10,340	10,364	10,351	10,290	10,296
Conservation Programs:										
MCS Single Family	125	143	161	180	198	217	236	256	276	297
MCS Multifamily	18	20	23	25	28	31	33	36	39	42
MCS Commercial	82	91	101	111	121	131	141	152	156	158
Refrigerators/Freezers	40	51	61	72	84	95	107	119	131	143
Water Heat	45	57	69	82	95	108	121	135	149	164
Manufactured Homes	9	11	12	13	15	16	18	19	21	22
Agricultural	24	28	32	36	40	44	48	49	49	50
Existing Commercial	162	190	218	246	274	302	320	320	320	321
Trans & Distr Efficiency	12	14	14	14	14	14	14	14	14	14
Existing Space Heat	121	141	161	181	182	182	182	182	182	182
Existing Industrial	60	130	210	290	337	337	337	337	337	337
Subtotal	698	876	1,062	1,250	1,388	1,477	1,557	1,619	1,674	1,730
Generating Resources:										
Hydropower Efficiency	30	30	30	30	30	30	30	30	30	30
Hydropower Efficiency	40	40	40	40	40	40	40	40	40	40
Subtotal	70	70	70	70	70	70	70	70	70	70
Combustion Turbines	0	0	0	0	357	357	357	357	357	357
Combustion Turbines	0	0	0	0	0	0	178	178	178	178
Subtotal	0	0	0	0	357	357	535	535	535	535
Small Hydropower	0	0	0	5	5	5	5	5	5	5
Small Hydropower	0	0	0	0	0	0	0	155	155	155
Subtotal	0	0	0	5	5	5	5	160	160	160
Cogeneration	0	0	0	0	0	0	0	60	60	60
Cogeneration	0	0	0	0	0	0	0	0	0	50
Subtotal	0	0	0	0	0	0	0	60	60	110
Licensed Coal	0	0	0	0	0	0	0	0	452	452
Subtotal	0	0	0	0	0	0	0	0	452	452
Total Firm Resources	10,831	11,313	11,496	11,676	12,135	12,249	12,531	12,795	13,241	13,353
Load/Resource Balance	20	197	109	24	65	42	52	34	184	-11

Table 8-A-6
Public Medium-High (1985-1995)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Observed Load	8,444	8,473	8,618	8,766	8,916	9,071	9,230	9,391	9,554	9,795
Observed Rate	0.00%	0.34%	1.71%	1.72%	1.71%	1.74%	1.75%	1.74%	1.74%	2.52%
Resources:										
Existing	10,303	10,345	10,190	10,212	10,231	10,238	10,244	10,233	9,957	9,982
Conservation Programs:										
MCS Single Family	2	7	13	21	29	38	47	56	66	75
MCS Multifamily	0	1	3	5	7	8	10	12	15	17
MCS Commercial	0	3	7	12	16	21	25	30	35	40
Refrigerators/Freezers	0	0	0	0	0	2	6	12	21	29
Water Heat	0	0	0	0	0	2	6	13	22	31
Manufactured Homes	0	1	2	3	4	6	7	8	10	11
Agricultural	0	0	0	0	0	0	0	0	0	0
Existing Commercial	0	0	0	0	0	0	0	0	0	0
Trans & Distr Efficiency	0	0	0	0	0	0	0	0	0	0
Existing Space Heat	4	8	13	16	19	22	25	28	31	34
Existing Industrial	0	0	0	0	0	0	0	0	0	0
Subtotal	6	20	38	57	75	99	126	159	200	237
Generating Resources:										
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Hydropower Efficiency	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0
Total Firm Resources	10,309	10,365	10,228	10,269	10,306	10,337	10,370	10,392	10,157	10,219
Load/Resource Balance	1,865	1,892	1,610	1,503	1,390	1,266	1,140	1,001	603	424

(table continued on next page)

Public Medium-High (1995-2005)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Observed Load	9,948	10,154	10,322	10,480	10,784	10,803	10,955	11,113	11,279	11,450
Observed Rate	1.56%	2.07%	1.65%	1.53%	2.90%	0.18%	1.41%	1.44%	1.49%	1.52%
Resources:										
Existing	10,063	10,367	10,364	10,351	10,315	10,340	10,364	10,351	10,290	10,296
Conservation Programs:										
MCS Single Family	85	95	105	114	123	132	140	148	156	164
MCS Multifamily	19	21	24	26	28	30	33	35	37	39
MCS Commercial	44	49	54	58	63	68	72	77	78	79
Refrigerators/Freezers	38	48	57	67	76	85	94	103	112	121
Water Heat	41	51	61	72	83	93	104	114	125	136
Manufactured Homes	13	15	16	18	20	21	23	24	26	27
Agricultural	0	1	4	8	12	16	20	24	28	32
Existing Commercial	0	0	6	24	50	78	106	134	162	190
Trans & Distr Efficiency	0	0	0	2	4	6	8	10	12	14
Existing Space Heat	37	40	43	50	65	85	105	125	145	165
Existing Industrial	0	0	0	0	0	0	3	26	78	152
Subtotal	277	320	370	439	524	614	708	820	959	1,119

(table continued on next page)

Public Medium-High (1995-2005) (continued)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Generating Resources:										
Hydropower Efficiency	0	0	0	0	40	40	40	40	40	40
Hydropower Efficiency	0	0	0	0	0	0	30	30	30	30
Subtotal	0	0	0	0	40	40	70	70	70	70
Total Firm Resources	10,340	10,687	10,734	10,790	10,879	10,994	11,142	11,241	11,319	11,485
Load/Resource Balance	392	533	412	310	95	191	187	128	40	35

Table 8-A-7
Public Medium-Low (1985-1995)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Observed Load	8,444	8,394	8,418	8,443	8,468	8,545	8,647	8,757	8,728	9,012
Observed Rate	0.00%	-0.59%	0.29%	0.30%	0.30%	0.91%	1.19%	1.27%	-0.33%	3.25%
Resources:										
Existing	10,303	10,345	10,190	10,212	10,231	10,238	10,244	10,233	9,957	9,982
Conservation Programs:										
MCS Single Family	2	4	7	11	16	22	27	32	37	42
MCS Multifamily	0	1	2	4	6	8	10	12	14	16
MCS Commercial	0	1	2	4	7	9	12	14	16	19
Refrigerators/Freezers	0	0	0	0	0	1	4	9	15	22
Water Heat	0	0	0	0	0	1	5	10	17	25
Manufactured Homes	0	1	1	2	3	5	6	7	8	10
Agricultural	0	0	0	0	0	0	0	0	0	0
Existing Commercial	0	0	0	0	0	0	0	0	0	0
Trans & Distr Efficiency	0	0	0	0	0	0	0	0	0	0
Existing Space Heat	4	8	13	16	19	22	25	28	31	34
Existing Industrial	0	0	0	0	0	0	0	0	0	0
Subtotal	6	15	25	37	51	68	89	112	138	168
Total Firm Resources	10,309	10,360	10,215	10,249	10,282	10,306	10,333	10,345	10,095	10,150
Load/Resource Balance	1,865	1,966	1,797	1,806	1,814	1,761	1,686	1,588	1,367	1,138

Public Medium-Low (1995-2005)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Observed Load	9,195	9,352	9,475	9,590	9,847	9,833	9,955	10,082	10,210	10,337
Observed Rate	2.03%	1.71%	1.32%	1.21%	2.68%	-0.14%	1.24%	1.28%	1.27%	1.24%
Resources:										
Existing	10,063	10,367	10,364	10,351	10,315	10,340	10,364	10,351	10,290	10,296
Conservation Programs:										
MCS Single Family	48	54	60	65	71	77	83	89	95	101
MCS Multifamily	18	21	23	25	28	30	33	35	38	40
MCS Commercial	22	24	27	30	33	36	39	42	43	45
Refrigerators/Freezers	29	36	43	50	57	64	71	79	86	94
Water Heat	33	41	50	58	67	76	85	95	104	113
Manufactured Homes	11	12	14	15	17	18	20	21	23	24
Agricultural	0	0	0	0	0	0	0	0	0	0
Existing Commercial	0	0	0	0	0	0	0	0	0	0
Trans & Distr Efficiency	0	0	0	0	0	0	0	0	0	0
Existing Space Heat	37	40	43	46	49	52	55	58	61	64
Existing Industrial	0	0	0	0	0	0	0	0	0	0
Subtotal	198	228	260	289	322	353	386	419	450	481
Total Firm Resources	10,261	10,595	10,624	10,640	10,637	10,693	10,750	10,770	10,740	10,777
Load/Resource Balance	1,066	1,243	1,149	1,050	790	860	795	688	530	440

Table 8-A-8
Public Low (1985-1995)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95
Observed Load	8,444	8,283	8,142	8,005	7,869	7,832	7,849	7,876	7,917	8,037
Observed Rate	0.00%	-1.91%	-1.70%	-1.68%	-1.70%	-0.47%	0.22%	0.34%	0.52%	1.52%
Resources:										
Existing	10,303	10,345	10,190	10,212	10,231	10,238	10,244	10,233	9,957	9,982
Conservation Programs:										
MCS Single Family	2	2	2	3	4	5	7	9	11	14
MCS Multifamily	0	0	0	1	1	2	3	4	4	5
MCS Commercial	0	0	1	1	2	3	4	5	6	7
Refrigerators/Freezers	0	0	0	0	0	1	4	9	15	21
Water Heat	0	0	0	0	0	1	4	8	14	19
Manufactured Homes	0	0	0	0	0	1	1	2	2	3
Agricultural	0	0	0	0	0	0	0	0	0	0
Existing Commercial	0	0	0	0	0	0	0	0	0	0
Trans & Distr Efficiency	0	0	0	0	0	0	0	0	0	0
Existing Space Heat	4	8	13	16	19	22	25	28	31	34
Existing Industrial	0	0	0	0	0	0	0	0	0	0
Subtotal	6	10	16	21	26	35	48	65	83	103
Total Firm Resources	10,309	10,355	10,206	10,233	10,257	10,273	10,292	10,298	10,040	10,085
Load/Resource Balance	1,865	2,072	2,064	2,228	2,388	2,441	2,443	2,422	2,123	2,048

Public Low (1995-2005)
System Summary: Observed Loads and Resources (Average Megawatts)

PERIOD	95-96	96-97	97-98	98-99	99-00	00-01	01-02	02-03	03-04	04-05
Observed Load	8,047	8,120	8,173	8,223	8,421	8,347	8,412	8,481	8,550	8,624
Observed Rate	0.12%	0.91%	0.65%	0.61%	2.41%	-0.88%	0.78%	0.82%	0.81%	0.87%
Resources:										
Existing	10,063	10,367	10,364	10,351	10,315	10,340	10,364	10,351	10,290	10,296
Conservation Programs:										
MCS Single Family	16	19	21	24	26	29	32	34	37	40
MCS Multifamily	7	8	9	10	11	12	13	14	16	17
MCS Commercial	8	9	10	12	13	15	16	18	19	20
Refrigerators/Freezers	27	34	40	47	53	60	66	72	78	84
Water Heat	25	32	39	46	53	60	68	75	83	90
Manufactured Homes	4	4	5	5	6	7	7	8	9	10
Agricultural	0	0	0	0	0	0	0	0	0	0
Existing Commercial	0	0	0	0	0	0	0	0	0	0
Trans & Distr Efficiency	0	0	0	0	0	0	0	0	0	0
Existing Space Heat	37	40	43	46	49	52	55	58	61	64
Existing Industrial	0	0	0	0	0	0	0	0	0	0
Subtotal	124	146	167	190	211	235	257	279	303	325
Total Firm Resources	10,187	10,513	10,531	10,541	10,526	10,575	10,621	10,630	10,593	10,621
Load/Resource Balance	2,140	2,393	2,358	2,318	2,105	2,228	2,209	2,149	2,043	1,997

Chapter 9
Consideration of Environmental Quality and Fish and Wildlife

An essential element of the Northwest Power Act is the careful balance between electrical power planning and environmental and fish and wildlife protection. The Act requires that the Council give due consideration in its power plan to environmental quality and the protection, mitigation and enhancement of fish and wildlife. The Council complied with this mandate throughout development of its 1983 plan and this 1986 plan. The Act also requires the Council to consider the compatibility of the planned resources with the existing regional power system, to choose the most cost-effective resources, and to follow certain priorities in selecting those resources. For this reason, selection of the resource portfolio involved not only choosing those resources that were most environmentally sound or most protective of fish and wildlife, but also balancing these concerns with the other requirements. This balancing means that, because of new overriding factors such as lost resource opportunities or relative ease of project construction, some resources may be chosen even if they lead to some adverse environmental effects.

In addition, the Act requires that all resource cost-effectiveness evaluations must include quantification of environmental costs and benefits. Costs for pollution abatement equipment and fish and wildlife mitigation required under state and federal regulations were included in the Council's estimates of resource costs. The Act further specifies that the Council must develop a method to be used by Bonneville to quantify these environmental costs and benefits in measuring the cost effectiveness of specific resource acquisition decisions. This method, developed by the Council, is presented as Appendix II-A. The Council expects Bonneville to use this method in evaluating each resource and resource site prior to acquisition. This chapter describes the process the Council has used in giving due consideration to environmental quality and fish and wildlife in its selection of resources.

Environmental Quality

Due Consideration Process

When the Council drafted its first plan in 1983, it performed studies in support of the plan to identify the potential environmental and fish and wildlife effects of particular types of resources. These studies and important issues arising from them were subjected to public review and comment and guided the Council as it drafted its resource portfolio for the 1983 plan. Additional public comment was sought as the Council revised its resource portfolio for this 1986 plan.

During the public comment period on the 1983 draft plan, many comments and considerable data were received regarding the environmental effects of the various resources discussed in the plan. In particular, many public commentors offered data documenting the environmental effects of hydropower dams, coal-fired power plants, and high-voltage transmission lines. In addition, a public consultation attended by representatives of environmental groups, Indian tribes, utilities, and an agricultural organization presented views and data which assisted the Council in furthering its consideration of environmental quality and fish and wildlife concerns. All this information was carefully considered by the Council in forming its original plan and was reconsidered by the Council in addition to comments and data which were submitted during the public comment period on the draft version of this power plan. No resource is without its potential adverse effects. In giving due consideration to environmental quality, the Council examined the relative magnitudes of various effects and the practicality of mitigation.

Analysis and Resource Alternatives

While selecting the individual components of its resource portfolio, the Council assessed all available energy technologies, including their environmental benefits and impacts. The Council also considered the amounts of power to be expected from each resource type, how effects on environmental quality and fish and wildlife could be mitigated, and how mitigation measures may affect energy production. Although not included as major components of the Council's plan at this time, the environmental costs and benefits of alternative resources such as geothermal, solar-electric generation and wind resources were considered. These alternative resources will be closely monitored and assessed in the future for their environmental effects as well as for their increased cost effectiveness and feasibility. As they become eligible for inclusion in the Council's resource portfolio, these resources again will be subject to environmental considerations.

This section discusses some of the mitigation measures that the Council expects Bonneville to consider in any resource acquisition or other actions that are required by the Act to be consistent with the plan. While the Council has adopted specific standards only for protection of fish and wildlife in hydropower development (see Appendix II-B), it is expected that the implementing agencies will be guided by all the considerations set forth in this chapter.

During the course of developing this 1986 Power Plan, the Council considered establishing a general set of resource acquisition criteria for nonhydropower resources. (See December 12, 1984, staff issue paper, "Environmental Criteria for Resource Acquisition.") However, the Council decided to rely on existing federal, state and local regulation of the development of nonhydropower electrical generation resources and to take no specific action relative to additional environmental controls other than the evaluation of environmental effects inherent in the development of the resource portfolio. Among the reasons for the Council's decision were concerns about the Council's role in the possible acquisition of nonmajor resources and of resources not in the Council's portfolio.

The Council was also concerned about a possible duplication of effort in regulatory matters.

The analysis that follows first discusses the resources that are included in the 1986 Action Plan and then discusses the resources identified in the Council's portfolio for acquisition in later years if higher growth occurs.

Conservation

The Council expects that conservation will contribute the largest share of energy to the resource portfolio. To that end, the Action Plan includes measures in the residential sector to weatherize existing homes and to build new homes to the model conservation standards. The Action Plan calls for weatherization of existing homes at a reduced rate because of the current energy surplus and because efficiency standards for both new homes and homes converting to electrical space heating will save more energy than weatherizing existing houses. In both the residential and commercial sector, the Council has emphasized the model conservation standards for new buildings. The plan provides that programs for existing commercial buildings should be implemented only to build the capability to acquire this resource when it is needed by the region. The Action Plan also calls for building capability in the industrial and agricultural sectors to achieve conservation savings. The Council recognizes that the model conservation standards and programs to build capability to acquire conservation in the various sectors represent important lost opportunity resources that if not acquired now, may no longer be available and cost-effective to the region. These conservation actions were developed by the Council with full consideration of their potential environmental costs and benefits.

The environmental benefits of conservation are substantial. First, reduction of electrical demand due to conservation measures can help the region avoid construction and operation of new energy resources with their accompanying environmental impacts. Conservation "generates" electricity without requiring transmission lines; without creating significant air or water pollution, noise, solid waste, or land use impacts; and without creating the array of adverse impacts imposed on fish and wildlife by hydropower development and generation. In addition, buildings containing conservation measures tend to be more comfortable.

The environmental costs of conservation can be negligible if appropriate provisions are made for acceptable indoor air quality and adequate ventilation in energy efficient buildings that have less air leakage than ordinary buildings. In buildings with less natural air leakage, the potential exists that there will be higher concentrations of normally occurring indoor air pollutants than would be the case in buildings with ordinary levels of air leakage.

Formaldehyde, radon, and combustion byproducts such as benzo(a)pyrene are the indoor air pollutants considered the major potential health risks. Health effects of inhaling higher than average concentrations of these chemicals can range from headaches and sore throats to increased chances of incurring lung cancer. Moisture (i.e., humidity) is also perceived as an indoor air pollutant when it becomes excessive, contributing to the growth of molds, mildews and fungi.

Pollutants can enter a home from a variety of sources. These include the materials used to build the home, the appliances and furnishings within it, materials smoked in the home, chemicals brought into the home, cooking and even the taking of showers. In general, new energy efficient homes and new conventional homes do not differ significantly in their sources of pollutants.

The amount of pollution within a building depends on three factors: the strength of the source, the ventilation rate of the building and the rate at which the pollutant is removed from the air by chemical reaction or physical processes. The source of the pollutant is a very important factor. If there is no source in the home to start with, there is no need to remove it. Although some pollutant sources are unavoidable, many pollutant sources can be avoided or minimized at the time a building is constructed to meet the model conservation standards. For example, formaldehyde off-gassing can be reduced through the use of "10W fuming" formaldehyde wood products rather than the use of ordinary plywood and particle board.

Many studies have been undertaken during the past five years, both in the United States and Canada, to better understand the relationship between indoor air quality and energy conservation. These studies are showing that energy-efficient homes with whole-house mechanical ventilation are no more prone to indoor air quality problems than non-energy-efficient homes. Furthermore, the studies are showing that very leaky houses, with hourly air change rates (ACH) of two can have indoor air pollution problems, while relatively tight homes with .5 ACH can have very low levels of pollutants. These findings indicate that strong pollutant sources can overwhelm ventilation. However, at lower pollutant levels, ventilation is one important means for pollution control.

To date, there are no widely accepted standards that establish a "bad" or unhealthy level of indoor air pollutants. Proposed guidelines from the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) and the Environmental Protection Agency (EPA) standards are frequently mentioned in discussions on indoor air quality. Although the ASHRAE guidelines were developed for assuring good indoor air quality, they proved to be highly controversial because provisions were lacking on how to implement these guidelines.

It is one thing to adopt a guideline of two pico curies per liter for radon, but another matter to use it. (The *curie* is the unit of measure for radioactivity; a pico curie is one trillionth of a curie.) Currently, the only way of knowing that the guideline is being met is to monitor a building for radon after it is built.

New houses constructed under the Uniform Building Code are required to provide mechanical ventilation in bathrooms and kitchens, if windows are not present or operative. These fans are not sized to ventilate the entire house, and, under current building practice, whole-house ventilation depends primarily on unreliable factors such as wind. Current codes provide no assurance of either sufficient ventilation or sound indoor air quality.

To guard against worsening indoor air quality, the Council has recommended that mechanical ventilation be used in houses with tight construction. Model conservation standard houses with this mechanical ventilation that were built in the Residential Standards Demonstration Program (RSDP) are being monitored and compared to a control group of houses built to current practice. The early data from both the RSDP and from the Canadian R-2000 program show no significant differences in indoor air quality between houses built to the level of energy efficient standards and houses built to current practice. The Council has designed a research program in the Action Plan to address remaining concerns about indoor air quality.

On June 20 and 21, 1985, Council staff and some Council members were briefed on possible health impacts of the model conservation standards by five recognized indoor air quality experts. Discussions at this meeting supported the conclusion that pollutant source strength is a primary determinant of indoor air quality. However, both source strength and ventilation rate are important, and strategies to control pollutant levels should focus on both factors. The group also emphasized the need to design programs to minimize source entry of pollutants and to improve the reliability and performance of heat recovery ventilators.

Though the production of conservation devices (insulation, storm windows, etc.) may have some environmental impacts, the Council recognizes that the amount of electricity "produced" by conservation is more environmentally acceptable than, for example, the equivalent amount of energy generated by a coal-fired power plant or hydropower dam. The 3,920 average megawatts of energy expected to be contributed by conservation under the Council's high growth forecast is equivalent to the output of more than eight coal-fired power plants that produce 452 average megawatts each (the size of plants assumed by the Council if increments of coal-fired generation are required). (See Volume II, Chapter 6.)

On balance, conservation can be an environmentally acceptable resource. The potential for indoor air quality problems can be reduced or mitigated through planning for mechanical ventilation to control such pollutants as carbon dioxide and moisture, and through source control strategies for such pollutants as radon and formaldehyde. The energy conserved through energy-efficient building design means that the need for additional generating facilities and transmission lines will be reduced, thereby reducing the effects on land, air, water, and fish and wildlife resources.

Better Uses of the Hydropower System

The Council's plan includes considerations involving improved uses of the hydroelectric system. Although the Council has not delineated specific strategies at this time, some strategies for increasing the region's reliance on nonfirm energy, such as using combustion turbines to back up nonfirm energy, may have effects on the environment.

Developing new uses for nonfirm energy could affect the willingness of hydropower system managers to provide flows and spill for fish passage. The more the hydroelectric system is put to high-valued uses such as meeting firm loads or shutting down combustion turbines, the greater the potential conflict with its use for flows and spills needed for fish passage. This is a concern that the Council will monitor to assure consistency with its plan and program. Environmental effects resulting from hydropower development and operation are discussed more fully below.

The plan includes combustion turbines as one possible means of firming up nonfirm hydropower supplies, in order to make possible more economical uses of the nonfirm energy. The combustion turbines are not the only means of backing up nonfirm energy, but their costs provide an upper planning limit for the costs of implementing firming strategies on average. Over the long term, it is expected that the combustion turbines would only be operated at most 19 percent of the year. Because of their flexibility, combustion turbines can also be used as a "planning hedge" against rapid growth.

Fueled by natural gas or oil, combustion turbines are expected to emit certain air pollutants. To date, the Council's data show that emissions of natural gas-fired turbines are minimal compared to those of oil-fired turbines or coal plants. Combustion of natural gas releases small amounts of nitrogen oxides and about half the amount of carbon dioxide emitted by coal plants. The Council's data have suggested that nitrogen oxides from gas-fired turbines can be reduced to comply with air quality regulations by reducing the temperature of combustion air, recirculating flue gas, or injecting demineralized water.

Oil-fired turbines release larger amounts of these pollutants, plus sulfur dioxide. According to Council studies, sulfur dioxide emissions from oil-fired turbines can be minimized by limiting the sulfur content of fuel oil used. Noise impact may be mitigated by siting the plants away from population centers, installing mufflers, and developing buffer zones.

Use of combustion turbines fueled with natural gas or oil also raises certain environmental concerns in connection with exploration, development and transportation of the fuel. The Council notes that off-shore exploration and development of fossil fuels can interfere with commercial and recreational fishing and could cause aesthetic impacts on shoreline areas. On-shore exploration and development can intrude on roadless areas and wildlife habitat and affect the aesthetics of natural areas. If reliance is placed on imports, there also may be increased risk of oil spills from tanker accidents. Transportation by pipeline involves potential spills and can disrupt existing land uses and cause some aesthetic impacts.

Combustion turbines are included as a potentially low-cost option for firming secondary hydropower and as insurance to meet unexpected load growth. Merely preserving the potential for using these turbines can postpone or avoid construction and operation of large-scale coal or nuclear facilities. The Council chose combustion turbines as one strategy for firming nonfirm hydropower because they can be brought on-line quickly and operated in harmony with the hydropower system. This flexibility and avoidance of other impacts, in the Council's judgment, outweighs the effects of combustion turbines on environmental quality and fish and wildlife.

Hydropower Development

As with the 1983 plan, the Council's 1986 Action Plan directs Bonneville to secure options on hydropower projects at several sites, although Bonneville is not to acquire power from these sites at this time. The development process for the Council's Columbia River Basin Fish and Wildlife Program, adopted November 15, 1982, and amended October 10, 1984, provided a wealth of information on the effects of hydropower development on fish and wildlife as well as measures for mitigating those effects. Those considerations have also been taken into account in this plan to the extent they are appropriate outside the Columbia Basin. Some measures adopted by the Council for the Columbia River Basin and the rest of the region are more fully described in the discussion of fish and wildlife impacts in a later section of this chapter. For a more complete description of the impacts and mitigation measures applicable to the Columbia River Basin, see the Council's Columbia River Basin Fish and Wildlife Program.

The effects of hydropower generation are limited generally to the stream and fisheries affected by a dam. That is, no serious air pollution or solid waste problems are raised by hydropower projects, and they do not rely on a finite fossil fuel. Dams can alter gravel recruitment patterns, because they block downstream movement of gravel and some sediment. Loss of fish spawning and rearing habitat may occur. This effect can be mitigated somewhat by habitat restoration projects downstream.

Among the adverse impacts on migrating and resident fish are turbine-related mortality, migration barriers, dewatering of streams, alteration of flows, inundation of habitat and the effects of increased travel time. Although they are not entirely effective or feasible in all locations, mitigation measures include fish screening and bypass systems, spill for passage, fish ladders, establishment of minimum flows, and flow augmentation.

Construction of a hydropower project may also result in erosion and sedimentation near the stream, causing increased water turbidity. These effects can reduce the aesthetic quality of the stream as well as harm its value for fish, wildlife, and recreational uses. Sometimes, these effects are limited to the period of construction and are not considered significant enough by themselves to warrant foregoing otherwise feasible hydropower sites.

In addition, the transformation of a river to a deep, still reservoir can alter the temperature of the water. Because of reduced flows, increased temperatures, and the buildup of sediment, many reservoirs become excessively productive, sometimes turning eutrophic. The use of special structures, reservoir draft techniques, and control of upstream nutrient sources through better land management practices can mitigate these effects.

Another impact is nitrogen supersaturation caused by excessive spilling of water over the dam. Though lethal to fish, it can be mitigated with the use of devices that deflect spilled water.

Altered water temperatures and nitrogen supersaturation are generally limited to large hydropower projects involving reservoirs, while the Council expects many new hydropower projects will be small stream diversions without reservoirs. These smaller projects are not necessarily benign. Their effects can become cumulative when considered in combination with other projects. (See Columbia River Basin Fish and Wildlife Program, Sections 1200-1204.)

Federal law prevents licensing hydropower projects on or directly affecting wild and scenic rivers, and special consideration is required when Indian lands, Indian fisheries, historic or archaeological sites, national wildlife refuges, national monuments, national recreation areas, endangered species habitat, or lands adjacent to wilderness are involved. In estimating the amount of hydropower potential for the 1983 plan, the Council accordingly eliminated such areas from consideration. This estimate was reduced even further for this 1986 plan, pending completion of the Pacific Northwest Hydropower Assessment Study being conducted by the Council and Bonneville. The study will help rank potential hydropower sites according to impacts on fish and wildlife. With the exception of the hydropower options described earlier, which will not be producing power under the Action Plan, only hydropower from existing facilities is included in the 1986 resource portfolio.

Installation of hydropower projects on a previously free-flowing stream also can reduce or eliminate the stream's value for kayaking, rafting, and some types of fishing, as well as reduce the forest land base and destroy Indian religious sites through inundation. Also, although the effects of particular projects may be relatively minor, the cumulative effects of several hydropower dams on a single stream or in a single basin, drainage or subbasin, can be serious. As a result, this plan includes measures to support future hydropower development only at the least sensitive locations and with minimum environmental impact.

Because of these safeguards, the Council believes needed additional hydropower development can occur in an environmentally sound manner. The first hydropower included in the plan would not be needed until the early 1990s. This allows sufficient time to study the impacts of hydropower and to refine methods for alleviating those impacts.

Industrial Cogeneration

The Council expects about 80 percent of the available cogeneration to be fueled with biomass such as wood waste. Particulates would be emitted from combustion of wood chips or other biomass fuel, but the effects of these emissions could be controlled to a large extent by pollution control technology. Cyclone separators can remove larger particles, while wet scrubbers, electrostatic precipitators, and baghouses can remove smaller ones. However, control technology for cogeneration may not be as sophisticated as it is for larger central station thermal plants, and some residual effects may remain. Also, cogeneration units are more likely to be located near population centers. Use of coal as a backup fuel would entail the air quality impacts discussed below regarding coal.

Timber harvesting raises concerns regarding erosion, sedimentation, aesthetic impacts, and destruction of wildlife habitat. Because biomass fuels are usually byproducts of lumber processing, the Council believes most of these effects would not be attributable to biomass electrical generation. Nonetheless, if and when biomass harvesting involves picking up fallen wood in forests, it may independently cause the effects described above.

Use of cogeneration to generate electricity would reduce the need to construct coal-fired or nuclear plants, which, for the reasons stated below, may be less environmentally sound. Some cogeneration projects may be coal-fired and could thus have many, if not more, of the environmental effects associated with coal-fired power plants, discussed below. Nevertheless, cogeneration, even coal-fired, can entail fewer environmental risks than the separate production of electricity and process steam. Because cogeneration depends largely upon existing facilities, it normally does not include the "boom town" impacts or major transmission lines associated with larger thermal plants. The Council also recognizes that, unlike fossil fuel-fired generators, some cogeneration has the advantage of using a renewable resource.

Coal-Fired Power Plants

Coal-fired generation was the most controversial resource included in the Council's resource portfolio. As considered by the Council, the environmental effects of coal-fired generation span the entire fuel cycle. Coal to fuel regional generators most likely will come from strip-mines in eastern Montana or Wyoming. Exploration for coal can include drilling and blasting that risk contamination of groundwater. Strip-mining coal involves removing large amounts of soil and other materials overlying the coalbeds. Federal law requires reclamation of strip-mined lands and includes procedures for refilling and regrading, water protection, and revegetation, as well as prohibitions against mining sensitive lands, such as alluvial valley floors and prime farm land. However, there is some question whether these reclaimed lands can sustain long-term productivity or establish a diversity of species characteristic of native range.

Because coalbeds often serve as aquifers, their removal by mining often disrupts groundwater and can dry up neighboring wells used for domestic or stock water uses. The resaturation of soils when mined pits are refilled can degrade water quality. The Council's data indicated that acid mine runoff can contaminate local surface and groundwater, and toxic materials exposed by mining can both contaminate nearby water sources and hamper later efforts to reclaim the land. In addition, extraction of coal releases large quantities of dust into the air, hindering nearby livestock operations and decreasing local visibility. Opening mines in rural communities can disrupt the agricultural economy.

Council studies have shown that transportation of coal to the generating plant incurs various environmental effects, depending upon the location of the generators. Plants located where the coal is mined include fewer transportation effects. However, they concentrate the effects of both mining and generation in one community and increase the number of transmission lines required. Load-center generation, where the coal is transported long distances from the mine for generation in the area where the electricity is needed, somewhat eases the effects on the community where the coal is mined but increases transportation-related effects. Most coal is transported via railroad, and in some areas new mines require additional rail spurs. These lines can disrupt local farms and ranches by consuming valuable bottom land, hindering drainage, increasing noise, and bisecting fields and pastures. Use of unit trains consisting of up to one hundred coal cars can increase noise, coal dust pollution, and railroad crossing accidents and traffic tie-ups in the rural towns they pass through.

Coal slurry pipelines have been proposed to carry crushed coal suspended in water from the Great Plains coal fields to generating plants in Washington and Oregon. Council reports indicated that such pipelines would require large quantities of water and could pose serious water pollution problems at the terminus where the water must be removed from the coal. Also, the pumping systems required for such pipelines would need large amounts of energy to transport the coal several hundred miles. Such pipelines would require rights-of-way that could disrupt local land uses and affect aesthetics.

Coal generation can also have air quality impacts. Though federal and state laws require pollution control, all coal plants emit sulfur dioxide, nitrogen oxide, particulates (small particles), carbon dioxide, and trace elements. Sulfur dioxide has demonstrated detrimental effects on some crops and is known, in many instances, to be harmful to human health. Along with nitrogen oxide, sulfur dioxide can react in the atmosphere to form sulfates and nitrates, which in turn cause acid rain downwind from coal-fired generators. Acid rain appears to be capable of harming fish, vegetation, soil, surface water and other materials. Particulates can cause respiratory ailments in humans and reduce the traditionally excellent visibility in rural areas of the Great Plains. Sulfates can also reduce visibility.

Although sulfur dioxide emissions can be reduced through the use of flue gas desulfurization equipment, these devices may in turn produce large amounts of sludge as a byproduct. This sulfur-laden sludge poses a solid waste disposal problem because it must be prevented from leaching into local water supplies. Advanced combustion technologies such as fluidized bed combustion can reduce or eliminate production of sludge. Also, fly ash left over from combustion of coal contains various trace metals and also must be disposed of in a safe manner. Public comments from Montana suggested that water demands for power plant cooling could conflict with water needs for irrigation and other purposes such as fish and wildlife protection, and that ponds used to store cooling water can alter local water tables.

As with coal strip-mining, construction and operation of coal-fired generators in rural communities can cause boom and bust impacts. When the plant ceases operation, it can cause rapid out-migration, unemployment and declining tax base.

Because coal plants are generally sited away from load centers, electricity generated at most coal-fired power plants must be transported long distances to load centers using high-voltage transmission lines. Council reports have indicated that siting these lines can change local land use patterns, disrupt agricultural operations, and cause aesthetic impacts. Construction of lines through mountainous areas can cause erosion as well as interrupt wildlife habitat and recreational pursuits, and clearing rights-of-way often involves use of controversial herbicides detrimental to fish and wildlife. Transmission line corridors may interfere with migratory patterns of birds or big game. High-voltage transmission lines may produce noise, interference with local television and radio reception, and risk of electrical shock.

The Council, in part because of its concern for these effects of coal-fired generation, has only included coal in the energy plan to meet loads under the high growth scenario in 1995 and under the medium-high growth scenario in the year 2000. Even in those cases, the 1986 plan calls for development of coal plants at already-licensed sites first. This would cause lower construction and mining impacts, such as boom-town problems, than starting from an undeveloped site.

Nuclear Power Plants

Although not included in the resource portfolio, Washington Public Power Supply System Nuclear Plants 1 and 3 are retained as potential resources in the 20-year power plan. The environmental effects of nuclear power, described in data analyzed by the Council, also span the entire fuel cycle. Uranium, the fuel source for nuclear generators, is extracted by surface or open pit mining. Exploration can involve drilling, blasting and road building that may contaminate groundwater and disrupt wildlife habitat. The Council's data indicated that many of the same water pollution, air pollution and reclamation problems are encountered in uranium mining as in coal mining; the scale of uranium mining is substantially smaller, however, for a given energy content in the fuel. Also, the radioactive nature of uranium ore poses potential health risks to miners and persons living near uranium mines. Uranium ore processing results in large amounts of tailings that contain radioactive waste materials. These tailings may raise human health concerns and must be disposed of properly to avoid contamination of water sources or transportation by the wind.

Construction of a nuclear power plant is a major undertaking and, because of large plant sizes, can create more severe "boom and bust" social and environmental effects than coal plants. Significant local socioeconomic impacts have already been experienced at Washington Nuclear Projects (WNP) 1 and 3. WNP-1 is located, however, in a community with a long-term commitment to nuclear work, and mechanisms for adjusting to economic fluctuations due to construction may be better developed there than elsewhere. Some central station power developments (including nuclear plants) require high-voltage transmission lines and their associated effects. Operation of nuclear power plants may also require large amounts of water for cooling. Council studies have indicated that water intake structures have the potential to harm fish, and any thermal water discharges also have the potential to be detrimental to fish. Cooling systems can also discharge chemical blowdown, which may contaminate air and water.

Spent fuel and other radioactive wastes from plant operations require safe disposal. Spent fuel must either be reprocessed to recover uranium and plutonium or it must be treated as waste. Transport to disposal sites or reprocessing plants raises concerns regarding highway accidents, accidental spillage, and theft.

Some radioactive wastes must be isolated for thousands of years. Pursuant to federal statute, work is now underway to choose suitable disposal sites for spent nuclear fuel and high-level wastes. One method of decommissioning a nuclear plant requires the removal of all fuel. Next, the plant is sealed and cooled for ten years, during which time the site must be monitored and isolated. The reactor building is then covered to withstand natural forces for 200 years.

Other Resources

Other resource technologies, although not included in the Council's resource portfolio because of their high-cost or technical infeasibility at this time, were nonetheless considered by the Council for their potential impacts.

Geothermal Energy

Pursuant to the 1983 Action Plan, Bonneville has designed an assessment and acquisition program for geothermal power. The Bonneville-sponsored assessment by the combined states highlights the potential of the region's geothermal resource, the paucity of verified data pertaining to this resource, and the general sequence required for geothermal exploration, discovery and development. Federal agencies with responsibilities for characterizing and verifying regional geothermal resources are directing their attention to various parts of the region, with an emphasis on the Cascade Mountains. Their findings, coupled with new information from other sources, will describe the geothermal environment of specific drilling locales, and also the general nature of hydrothermal reservoirs associated with broader geologic regimes. From this information, appropriate conversion technologies can be determined and related environmental issues will be identified.

Council studies have indicated that electrical generation from geothermal sources, where either dry steam or flashed steam conversion processes are used, can cause emission of a variety of gases, including hydrogen sulfide. At low concentrations, this pollutant causes an offensive odor and can be harmful to the human respiratory system and to local wildlife. However, the Council's analysis suggests that current pollution control technology can achieve 90 percent hydrogen sulfide removal. Even with this technology, there are some residual effects from the use of geothermal resources. Many of these are discussed above in the context of coal-fired power plants.

Clearing of land and construction of roads and pipelines required to tie the numerous geothermal wells to central generators could destroy wildlife habitat and create barriers to wildlife migration. After geothermal water or steam is used to generate electricity, it is usually reinjected into the earth. Studies suggest that the impacts of fluid disposal are site-specific, depending largely upon the chemical nature of the fluids. Though reinjection is normally preferred, the Council's data noted that other disposal techniques deserve study.

Venting of steam or water vapor can create noise, having a potential impact on recreational areas and wildlife populations. Noise can be controlled, however, by installation of noise attenuation equipment and proper operation. Some geothermal projects may require large quantities of water for cooling, although dry cooling can be used in water-scarce areas. Extraction of geothermal steam or water may cause the earth to settle.

Also, geothermal development may disrupt scenic and recreational areas and expose workers to risk of injury while working near steam or hot water.

Wind Power
The Council estimates that wind generators would cause only minor environmental effects. Though operation of some wind turbines may create low-frequency noise, this effect may be minor because generators will likely be located far from population centers. Future wind power studies should examine these potential effects further, and mitigation techniques should be identified. Wind turbines may alter the aesthetics of shorelines, mountains, gorges and other areas with typically high winds. Also, the need to avoid obstructions around wind generators may require restrictions on certain types of land use. The Council recognizes that wind generators do not pollute the air, use water, create solid waste, and probably would not cause severe "boom town" effects. With proper control, erosion, siltation and water pollution can be avoided. They do not affect free-flowing rivers and can probably be sited with minimal impact on wildlife habitat. When costs are reduced, the Council expects wind power to be a desired energy resource for the region.

Solar Power
Solar-electric generation is another resource not yet included in the Council's portfolio because of present high costs and immature technology. The Council's data indicated that this technology also would have relatively minor environmental impacts. Solar systems using fluids to exchange heat raise a possibility of contamination of water and land, albeit minor. A typical large-scale, solar-electric generation plant will require installation of solar reflectors or cells on large land areas, and could affect land use, wildlife habitat, and aesthetics. However, because such plants would not include major water or air pollution or solid waste disposal problems, the Council expects that the impacts of solar-electric generation would be minor compared to the wide range of serious effects associated with large-scale thermal-electric generation. As this and other emerging technologies mature, the Council will gather additional, more detailed data concerning their environmental effects, which will receive consideration in all future Council decisions regarding these resources. The Council welcomes comments regarding the development of these resources.

Additional Fish and Wildlife Concerns

Due Consideration Process

The requirement of due consideration for fish and wildlife is in addition to the Act's mandate that the Council adopt a Columbia River Basin Fish and Wildlife Program. That program was adopted by the Council on November 15, 1982, and amended on October 10, 1984.

The fish and wildlife program is limited by law to the Columbia River Basin. The power plan, on the other hand, must cover the entire region. Also, the plan covers all types of generating resources, while the fish and wildlife program deals only with the effects of the hydropower system. Under the Northwest Power Act and the Council's power plan, resource acquisitions by Bonneville generally must be consistent with the plan's environmental and fish and wildlife provisions. Those acquisitions proposed within the Columbia River Basin must also be consistent with the provisions of the Council's fish and wildlife program.

The Council's consideration of the relationship between energy supply and development and the protection of fish and wildlife began with its development of the Columbia River Basin Fish and Wildlife Program. Federal hydropower project operators and regulators (i.e., Bonneville, Bureau of Reclamation, Corps of Engineers and the Federal Energy Regulatory Commission) must take that program into account at each relevant stage of decision making to the fullest extent practicable. Also, Bonneville must use its legal and financial powers to protect, mitigate and enhance fish and wildlife consistently with the program.

On December 16, 1982, the Council released an "Environmental Document for the Columbia River Basin Fish and Wildlife Program." That document described consideration of the fish and wildlife and environmental impacts of the Council's Columbia River Basin Fish and Wildlife Program. It noted that, while some minor environmental impacts might result from implementation of the Council's program, its overall effect was to remedy environmental effects that had gone largely unmitigated for decades. The document noted numerous ways in which the Council's program would benefit fish and wildlife in the Columbia River Basin.

The effects of the Council's fish and wildlife program were considered as the Council developed and revised its energy plan. For example, annually 250-270 average megawatts of energy capability are estimated to be lost due to use of the Council's water budget to provide adequate flows for migrating anadromous fish. This was taken into account in the Council's estimate of the amount of hydropower available to meet future demands.

In addition, the costs of fish and wildlife mitigation and protection measures required in the fish and wildlife program were included as the Council estimated costs of various resources. As previously noted, included in the Council's resource cost calculations were the costs of pollution control technology required by existing law. These measures will benefit fish and wildlife by reducing or preventing air and water pollution.

Analysis of the Fish and Wildlife Impacts of Hydropower Development

Hydropower development can have serious effects on fish and wildlife. As noted in the fish and wildlife program, hydropower projects can hinder migration of fish. Juvenile anadromous fish passing downstream may be slowed by the reservoirs or killed while passing through the turbines. Successive dams and reservoirs in a single drainage or basin can eliminate the natural flushing of migrating juvenile fish to the ocean during the spring months. Without adequate passage facilities, dams present barriers to upstream migration as well. Water level fluctuations above or below hydropower dams can disrupt fish spawning and strand wildlife populations. Water impoundments caused by hydropower dams can alter water temperatures to the detriment of fish. Construction of dams may create reservoirs that inundate important wildlife habitat. However, as previously noted, the Council expects many of the new hydropower projects to be stream diversion projects without reservoirs.

Many comments from fish and wildlife agencies, Indian tribes, and environmental groups have expressed concern over the role of hydropower in the Council's resource portfolio. Some have suggested that the cumulative effects of many small hydropower projects on certain stream reaches could be catastrophic to both anadromous and resident fish, as well as other environmental and cultural values.

Within the Columbia River Basin, the Council's fish and wildlife program includes a water budget for the Columbia and Snake rivers designed to provide adequate flows for downstream migration. The Council's program includes other specific measures to assist fish migration. These measures incorporate provisions for flows, spill, structural bypass systems, ladders and transportation. The Council's program includes measures applicable to the Columbia Basin to minimize the harmful effects of water level fluctuations and temperature control measures for specific Columbia Basin dams. The Council recently completed rulemaking concerning spill measures, which should provide interim fish protection until permanent bypass facilities are in place. In addition, the Electric Power Research Institute (EPRI) is currently funding projects in the areas of: 1) fish screens, 2) minimum stream flow requirements, 3) downstream migration and 4) fish passage through turbines.

All future hydropower projects within the Columbia Basin will be subject to specific provisions in the Council's program to avoid or mitigate the above effects. The program calls for consolidated review of all applications or proposals for hydropower development in a single river drainage within the Basin. The Council intends that such review will assess cumulative effects of existing and proposed hydropower development on fish and wildlife. In conformance with the program, Bonneville has funded a study, currently being performed by Argonne National Laboratory, to propose criteria and methods for assessing potential cumulative effects of hydropower development.

The Council and Bonneville have undertaken a study to help collect the information needed for classifying and designating certain streams and wildlife habitat in the basin for protection from future hydropower development, based upon their value for fish and wildlife and their hydropower potential. As part of its Pacific Northwest Hydropower Assessment Study, the Council will study the existing and potential productivity of stream reaches for anadromous fish. The Pacific Northwest Rivers Study, the portion of the Hydropower Assessment Study conducted by Bonneville, will study non-anadromous values, including resident fish, wildlife, natural and cultural features, recreation, and institutional constraints. In addition, the Council will study Indian tribal and cultural values. These studies will enable the Council to designate stream reaches and wildlife habitat within the Columbia Basin to be protected from further hydropower development. Finally, the program calls on the Federal Energy Regulatory Commission to require all license applicants within the Basin to demonstrate how their proposed projects would take the Council's program into account to the fullest extent practicable at each relevant stage of decision making.

The conditions for Bonneville's support of hydropower within the entire region (included in Appendix II-B) are designed to avoid or mitigate the kinds of effects described above when they occur outside the Columbia River Basin. The Council's Hydropower Assessment Study will also result in a ranking of sites within the entire region in terms of their relative fish and wildlife values.

Although hydropower development includes serious risks to fish and wildlife, the Council believes that the provisions of this plan will minimize the effects of any future hydropower development.

Chapter 10
Public Involvement

One of the fundamental purposes of the Northwest Power Act of 1980 was to provide for the participation of the four Northwest states, their local governments, consumers, the Bonneville Power Administration's customers, the users of the Columbia River system (including Indian tribes and fish and wildlife agencies), and the public in the development of regional power policies. The Northwest Power Planning Council plays a crucial role in this process.

The Act specifically directs the Council to inform the region's publics about major regional electrical energy issues, obtain their views concerning those issues, and consult with them. The Council fulfilled each of these obligations in the development of the 1986 Power Plan and will continue its commitment to involve and inform the public about regional energy issues in the future.

From the time of its formation, the Council has dedicated itself to an active public information and involvement program. It does not wait for people to come to it, but actively seeks people out to involve them in its process.

The Council's structure is built around this commitment to involve the region in its work. It meets in public every three weeks, rotating among the Northwest states. These meetings are announced in the *Federal Register* and the Council newsletters, and are promoted by an agenda sent to 11,000 people, including the region's media. All decisions, except those exempted under the "Government in the Sunshine" portion of the Administrative Procedure Act, are made in these meetings, with public comment opportunities provided. A calendar of public meetings is presented in Table 10-1.

Throughout development of the 1986 Power Plan, the Council has held consultations with the utility and industrial customers of Bonneville, consumer and environmental groups, state and local governments, and the Bonneville Power Administration. These have involved both regionwide sessions as well as state-level meetings in each of the four Northwest States. Consultations have included Council meetings with regional policymakers and other members of the public, as well as staff-to-staff meetings between the Council and other organizations.

In addition, beginning in the summer of 1984, several advisory committees and task forces were formed to examine and advise the Council on specific issues related to drafting the 1986 plan. Committee members were chosen to represent a wide range of interests as well as for their expertise. These 11 committees, along with several committees focusing on fish and wildlife issues, make up the Scientific and Statistical Advisory Committee called for in the Northwest Power Act.

Approximately 140 people sit on these committees. Subjects covered include conservation in all sectors, economic and demand forecasting, and resource optioning.

Because support at the state level is crucial for implementation of the plan, the views of the state energy and regulatory agencies must be considered in the plan's development. To ensure this involvement and to improve ongoing communication, the Council established a State Agency Advisory Committee made up of members of the Northwest states' public utility commissions.

In developing its electrical demand forecast, the Council requested projections of economic growth from approximately 300 businesses and industries in the region. The responses were used in developing and validating the Council's economic and demographic projections, which are the backbone of the Council's electrical demand forecast.

The Council's newsletters are used to keep people informed about the Council's work. *Northwest Energy News,* a bimonthly 32-page magazine, provides background information to 15,000 people. It focuses on regional energy and fish and wildlife news, major issues and the Council's activities.

In November 1984, the newsletter *Update!* was initiated to list reports and papers available from the Council, public involvement opportunities, and upcoming meetings. It also accompanies a synopsis of the previous Council meeting and an agenda of the coming meeting. More than 11,000 people receive *Update!* every three weeks.

The November/December 1984 issue of *Northwest Energy News* included a questionnaire designed to publicize the start of the power plan process and gain insight on how the public involvement program was perceived by the region. Most of the respondents felt the Council's information system kept them well informed, but some had suggestions for improvements and others were not aware of all the opportunities available for public involvement. Subsequently, every issue of *Energy News* has carried information about the power planning and fish and wildlife processes, including opportunities for involvement.

Both *Update!* and *Northwest Energy News* were used to announce over 20 discussion papers describing various issues relating to the 1986 Power Plan. See Table 10-2 for a list of papers published. These issue papers were circulated widely in the region and to interested parties in other states (a total of over 4,000 people). Comments were solicited and used by the Council in making preliminary decisions on the issues. All comments were entered in the administrative record and distributed to the appropriate staff and Council members. Those people who sent in written comment received verification that their comment was being entered in the record.

Council "Backgrounders" were developed to supplement issue papers and help non-technical readers understand the issues. These Backgrounders were used as handouts and were available at Council meetings.

The Council's preliminary decisions were incorporated in the draft plan, adopted in August and distributed for further public comment. The comment period closed on October 25, following hearings in each state. Comments from over 150 groups and individuals were received. The final plan was adopted in January 1986.

Early in 1985, an advertisement was run in 12 regional newspapers and magazines announcing the 1985-86 power planning process and opportunities for involvement in it. Both *Update!* and the draft plan mailing lists were expanded with 325 responses to these ads. Two other advertisements were run in the summer to publicize the availability of the draft plan and to announce public hearings. The latter was a full page ad.

At the same time that the 1986 Power Plan was being developed, the Council considered an amendment to the model conservation standards contained in the 1983 Power Plan. This amendment was adopted at the Council's December 4, 1985, meeting and was incorporated into the 1986 plan.

In March 1985 an issue paper reviewing the model conservation standards was released for public comment. Subsequently, two addenda to that paper were also released. Over 600 copies of the issue paper and addenda were distributed. On July 11, 1985, the Council voted to consider amending the standards and initiated a public comment period that ended on September 25, 1985. Hearings were held in each state with over 20 groups testifying. Announcements describing the proposed amendment were sent to more than 300 people. In addition, announcements were published in the Council's magazine, *Northwest Energy News,* and newsletter, *Update.* Press releases, which covered the amendment proceedings extensively, were sent to the Northwest's media.

Based on the responses received, the Council decided to revise the amendment and reopen the comment period. Testimony was again taken on the standards at the power plan hearings in October 1985. In total, 150 groups and individuals commented on the proposed amendments.

Throughout this entire process, Council members and staff met frequently with local governments, utilities, and other interested parties to keep them informed on the Council's decision process and to solicit their input.

The Council's mailing list has been updated and improved to better target specific groups affected by the issues. For example, a special mailing was sent to 1,600 members of the region's homebuilding industry to inform them that the Council was reviewing the model conservation standards and to invite their comment and participation. To ensure widespread participation in the planning process, the Council hired a contractor to help identify under-represented groups and set up meetings between these groups and Council members and staff.

To assure accurate media coverage of the Council's activities, key media people were briefed on the power plan process. At each meeting, a press kit was distributed to attending media people and mailed to others. Council issues generated a great deal of coverage in the region's newspapers and television and radio stations. The Council maintains a newspaper clipping file of this coverage, which is available for public review.

The Council is continuing its ongoing efforts to work closely with the region's local governments. Through its local government liaison, the Council provides timely information on the issues to the region's local governments and consults with them individually and collectively, working principally through the state local government associations.

The Council maintains a public reading room at its central office in Portland where the public can review staff and contractors' studies, as well as comments received relating to the development of the energy plan.

The Council also maintains toll-free telephone lines (1-800-222-3355 for Idaho, Montana, and Washington and 1-800-452-2324 in Oregon) to encourage public access to the Council.

With the development of the 1986 Power Plan, the Council reaffirms its strong commitment to an active public involvement and information program. After adopting the plan in January 1986, the Council has continued to hold regular public meetings throughout the region. These meetings are a forum for the Council to discuss ideas and hear proposals on major energy and fish and wildlife issues from state and federal agencies, Indian tribes, Bonneville and Bonneville customers, local governments, and the public. Consultations are continuing with these interested parties on major issues.

Concurrently with publication of the Draft Power Plan, the Council began the amendment process for its Columbia Basin Fish and Wildlife Program. Equivalent public involvement activities are addressed in that program.

The Council knows that this plan is not a static document. As conditions change or if resources do not perform as expected, revisions to the plan may be needed. To encourage increased public involvement, the Council will publicize widely its process for making revisions to the power plan. The public will be informed of proposed revisions through published material and public briefing sessions. Throughout this process, comments will be solicited from the public on proposed changes to the plan prior to Council adoption.

Table 10-1
Council and Advisory Committee Meetings
1986 Power Plan

November 28-29	Council Meeting, Portland, Oregon
November 30	Coal Options Task Force
December 3	Demand Forecasting Advisory Committee
December 11	Hydropower Assessment Steering Committee
December 11	Council Hearing on the Pacific Northwest/Southwest Intertie and Out-of-region Sales, Portland, Oregon
December 18	Economic Forecasting Advisory Committee
December 19-20	Council Meeting, Boise, Idaho
January 9-10	Council Meeting, Portland, Oregon
January 15	Hydropower Assessment Steering Committee
January 15	Economic Forecasting Advisory Committee
January 18	Demand Forecasting Advisory Committee
January 24	Public Utility Commissions Task Force
January 30-31	Council Meeting, Seattle, Washington
February 13	Demand Forecasting Advisory Committee
February 13	Coal Options Task Force
February 14	Conservation Programs Task Force
February 14	Options Evaluation Task Force
February 14	Public Utility Commissions Task Force
February 19	Options Evaluation Task Force
February 20-21	Council Meeting, Boise, Idaho
March 7	Demand Forecasting Advisory Committee
March 7	Conservation Programs Task Force
March 8	Coal Options Task Force
March 13-14	Council Meeting, Portland, Oregon
March 26	Hydropower Assessment Advisory Committee
March 27	Conservation Programs Task Force
March 28	Public Utility Commissions Task Force
March 28	Demand Forecasting Advisory Committee
April 1	Model Conservation Standards Task Force
April 2	Economic Forecasting Advisory Committee
April 2	Coal Options Task Force
April 3-4	Council Meeting, Missoula, Montana
April 18	Coal Options Task Force
April 22-23	Conservation Programs Task Force
April 24-25	Council Meeting, Seattle, Washington
April 29	Options Evaluation Task Force
April 30	Demand Forecasting Advisory Committee
April 30	Losses and Goals Advisory Committee

May 1	Resident Fish Substitutions Advisory Committee
May 3	Model Conservation Standards Task Force
May 8	Production Planning Advisory Committee
May 14	Hydro Assessment Steering Committee
May 15-16	Council Meeting, Portland, Oregon
May 29	Resident Fish Substitutions Advisory Committee
May 30	Options Evaluation Task Force
May 31	Losses and Goals Advisory Committee
June 5-6	Council Meeting, Portland, Oregon
June 12	Production Planning Advisory Committee
June 18	Hydropower Assessment Steering Committee
June 19	Resident Fish Substitution Advisory Committee
June 20	Losses and Goals Advisory Committee
June 26-27	Council Meeting, Seattle, Washington
July 10-11	Council Meeting, Missoula, Montana
July 15	Production Planning Advisory Committee
July 19	Resident Fish Substitutions Advisory Committee
July 29	Losses and Goals Advisory Committee
August 7-8	Council Meeting, Portland, Oregon
August 13	Hydropower Assessment Steering Committee
August 14	Production Planning Advisory Committee
August 20	Resident Fish Substitutions Advisory Committee
August 22	Losses and Goals Advisory Committee
August 28-29	Council Meeting, Coeur d'Alene, Idaho
September 4	Mainstem Passage Advisory Committee
September 18-19	Council Meeting, Portland, Oregon
September 20	Mainstem Passage Advisory Committee
September 24	Hydropower Assessment Steering Committee
September 26	Losses and Goals Advisory Committee
October 1	Resident Fish Substitutions Advisory Committee
October 2	Demand Forecasting Advisory Committee
October 3	Mainstem Passage Advisory Committee
October 3	Economic Forecasting Advisory Committee
October 3	State Agency Advisory Committee
October 3	Conservation Programs Task Force
October 9-10	Council Meeting, Missoula, Montana
October 21	Losses and Goals Advisory Committee
October 25	Mainstem Passage Advisory Committee
October 29	Production Planning Advisory Committee
October 30	Council Meeting, Boise, Idaho
October 31	Mainstem Passage Advisory Committee

November 5	Resident Fish Substitutions Advisory Committee
November 6-7	Council Meeting, Portland, Oregon
November 13-14	Council Meeting, Portland, Oregon
November 18	Mainstem Passage Advisory Committee
November 20-21	Council Meeting, Portland, Oregon
December 2	Production Planning Advisory Committee
December 3	Mainstem Passage Advisory Committee
December 4-5	Council Meeting, Portland, Oregon
December 11-12	Council Meeting, Portland, Oregon
December 20	Losses and Goals Advisory Committee
January 8-9	Council Meeting, Portland, Oregon
January 23	Council Meeting, Portland, Oregon

Table 10-2
Issue Paper List for Draft Power Plan

- 1985 Action Plan: Conservation Resources
- 1985 Action Plan: Generation Resources
- Assumptions for Financial Variables
- Combustion Turbine Cost Effectiveness
- Conservation Supply Curves
- Cost & Availability of Generation Resources
- Cost of Delaying the Model Conservation Standards until 01/01/88
- Critical Water Planning
- Economic, Demographic & Fuel Price Assumptions
- Environmental Criteria for Resource Acquisition
- Hood River, Elmhurst & ELCAP Projects
- Intertie Access Policy
- Long-Term Achievable Conservation Targets
- Lost Opportunity Resources
- Model Conservation Standards Review
- Out-of-Region Imports/Exports
- Preliminary Demand Forecasts
- Research, Development & Demonstration of Promising Resources
- Role of Power Institutions in the 1985 Power Plan
- Value of Additional Direct Service Industry Interruptibility
- WNP-1 & WNP-3 Planning Assumptions

Appendix II-A
Method for Determining Quantifiable Environmental Costs and Benefits

Priority is given in the plan to resources that are cost effective. The Bonneville Power Administrator is required to estimate all direct costs of a resource or measure over its effective life in order to determine if a resource or measure is cost effective. Quantifiable environmental costs and benefits are among the direct costs of a resource or measure. The Act requires the Council to include "a methodology for determining quantifiable environmental costs and benefits" in the plan. This methodology will be used by the Administrator to quantify all environmental costs and benefits directly attributable to a measure or resource.

Proposed Method

A. Identify the characteristics (technical, economic, environmental, and other) of the resource or measure in question. Quantify each identified environmental effect in terms of the physical units involved (e.g., acres of habitat, tons of sulfur dioxide, change in water temperature).

B. Identify all potential environmental costs and benefits (e.g., the economic value of the effects of changes in the environment) that will result from the resource or measure. Each one of the environmental studies previously completed by the Council should be regularly subjected to public review, comment, and improvement. Research to identify the environmental costs and benefits of each resource should be continued by Bonneville in light of advancing knowledge about environmental impacts and of technical changes in resources.

C. Screen the identified environmental costs and benefits to determine whether a meaningful economic evaluation can be performed. In making this determination, reference should be made to the work products of the Council — Study Module VI, Nero and Associates, Inc., Reports to Council (Tasks 1-6) on Quantification of Environmental Costs and Benefits, Contract 82-020. In particular, consideration should be given to whether economic techniques are sufficiently developed to allow for a meaningful analysis of the environmental cost or benefit.

D. Determine whether environmental costs and benefits which can be meaningfully evaluated in monetary terms will be so analyzed. This determination should include consideration of:

1. whether sufficient information exists or can reasonably be obtained to allow for an analysis of the environmental cost or benefit;

2. whether the relative cost effectiveness of alternative resources is such that the as yet unquantified environmental costs and benefits would likely affect the decision on resource cost effectiveness; and

3. whether significant costs or benefits remain after considering the effect state or local standards may have on the environmental cost.

E. For each environmental cost and benefit that can be quantified, an information base should be assembled by the Administrator that analyzes the amount of information available to quantify each cost or benefit and assesses the uncertainty affecting the ultimate quantity estimates. Federal, state, and local studies of such environmental costs and benefits, scholarly and professional quantifications, and data obtained as a result of public comment should be used to the extent appropriate.

F. A specific economic evaluation method should then be selected by the Administrator based on the type of environmental cost or benefit, data available to characterize the environmental effect and related environmental cost or benefit, experience with the method (e.g., has it been successfully used in the past), and type of uncertainties involved. It is recognized that the strengths and limitations of the evaluation method will vary with each environmental impact, and this should be documented. More than one evaluation method may be needed to cross check and verify results.

G. For those environmental costs and benefits where it is not possible to develop monetary values, key physical and biological parameters should be described and, if possible, quantified.

H. The application of the evaluation methods should then take place. A record should be compiled that describes the resource, indicates what impacts were identified and which measurement methods were selected, documents each aspect of the calculation, and supports the final result. Throughout this process, the Administrator should consult with the Council, the resource sponsor, interested persons, Bonneville customers, consumers, states, and local political subdivisions. The Administrator should involve the public to the maximum extent appropriate.

I. All quantified environmental costs and benefits should then be included in the decision on resource cost effectiveness. Where the environmental costs or benefits have been quantified in other than monetary terms, the Administrator should make a decision about the cost effectiveness of each resource or measure by comparing the dollar cost of resources or measures with such costs or benefits to the dollar cost of competing resources or measures. A determination should then be made as to whether the quantifiable but unpriceable costs or benefits are sufficient to make an otherwise less expensive resource or measure, with such unpriceable environmental costs or benefits, more "costly" than the next most "costly" resource or measure.

J. To the extent that no quantification on any terms is possible, the environmental costs and benefits should be identified and described and an assessment should be made on their probable magnitude in relative terms. The environmental costs and benefits of a resource should be given due consideration by the Administrator before the resource is acquired. Such environmental costs and benefits will be weighed in the decision to acquire.

In 1983 and 1984, Bonneville conducted case studies on the environmental costs and benefits of four existing individual resources—a coal plant, a combustion turbine, a nuclear plant and a hydroelectric dam. These studies tested the feasibility of trying to assess environmental costs, using specific estimating techniques. The studies made environmental cost and benefit estimates for each of the four facilities. Generally, the case studies showed that it should be possible to establish costs for environmental impacts.

In 1985, Bonneville undertook to estimate environmental costs for various types of resources on a generic basis. Bonneville hired consultants and conducted a public involvement process to develop generic environmental costs for hydroelectric, geothermal, cogeneration, biomass, wind and solar resources. Draft reports have been released, and additional public input is now being sought. See BPA Issue Backgrounder, June 1985, "Counting the Costs—How BPA Performs Environmental Cost Analysis."

Appendix II-B
Conditions for Bonneville Financial Assistance To Hydropower Development in the Region

The Council includes the following conditions in its plan in response to the Northwest Power Act, which requires due consideration for protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish.

1. Protection, mitigation, and enhancement of fish:

Bonneville should not agree to acquire power from, grant billing credits for, or take any other actions under section 6 of the Act concerning any hydropower development in the region without providing for:

A. Consultation with interested fish and wildlife agencies and tribes, state water management agencies, and the Council throughout study, design, construction, and operation of the project;

B Specific plans for flows and fish facilities prior to construction;

C. The best available means for aiding downstream and upstream migration of salmon and steelhead;

D. Flows and reservoir levels of sufficient quantity and quality to protect spawning, incubation, rearing, and migration;

E. Full compensation for unavoidable fish or fish habitat losses through habitat restoration or replacement, appropriate propagation, or similar measures which give preference to natural propagation over artificial production of fish;

F. Assurance that the project will not inundate the usual and accustomed fishing and hunting places of any tribe;

G. Assurance that the project will not degrade fish habitat or reduce numbers of fish in such a way that the exercise of treaty rights will be diminished; and

H. Assurance that all fish protection and mitigation measures will be fully operational at the time the project commences.

2. Protection, mitigation, and enhancement of wildlife:

Bonneville should not agree to acquire power from, grant billing credits for, or take other actions under section 6 of the Act concerning any hydropower development in the region without providing for:

A. Consultation with interested wildlife agencies and tribes, state water management agencies, and the Council throughout study, design, construction, and operation of the project;

B. Avoiding inundation of wildlife habitat, such as winter range or migration routes essential to sustain local or migratory populations of significant wildlife species, insofar as practical;

C. Timing construction activities, insofar as practical, to reduce adverse effects on nesting and wintering grounds;

D. Locating temporary access roads in areas to be inundated;

E. Constructing subimpoundments and using all suitable excavated material to create islands, if appropriate, before the reservoir is filled;

F. Avoiding all unnecessary or premature clearing of all land before filling the reservoir;

G. Providing artificial nest structures when appropriate;

H. Avoiding construction, insofar as practical, within 250 meters of active raptor nests;

I. Avoiding critical riparian habitat (as defined in consultation with the wildlife agencies and tribes) when clearing, riprapping, dredging, disposing of spoils and wastes, constructing diversions, and relocating structures and facilities;

J. Replacing riparian vegetation if natural revegetation is inadequate;

K. Creating subimpoundments by diking backwater slough areas, creating islands, level ditchings, and nesting structures and areas;

L. Regulating water levels to reduce adverse effects on wildlife during critical wildlife periods (as defined in consultation with the fish and wildlife agencies and tribes);

M. Improving the wildlife carrying capacity of undisturbed portions of new project areas (through such activities as managing vegetation, reducing disturbance, and supplying food, cover, and water) as compensation for otherwise unmitigated harm to wildlife and habitat in other parts of the project area;

N. Acquiring land or management rights where necessary to compensate for lost wildlife habitat at the same time other project land is acquired and including the associated costs in project cost estimates;

O. Funding operation and management of the acquired wildlife land for the life of the project;

P. Granting management easement rights on the acquired wildlife lands to appropriate management entities; and

Q. Collecting data needed to monitor and evaluate the results of the wildlife protection efforts.

3. All proposals for Bonneville support of hydropower development should:

A. Take fully into account the results of the Council's Hydropower Assessment Study to ensure that future hydropower development occurs only at the least sensitive locations with minimum environmental impact.

B. Explain in detail how these provisions will be accomplished or, where exceptions are allowed, the reasons why the provisions cannot be incorporated into the project.