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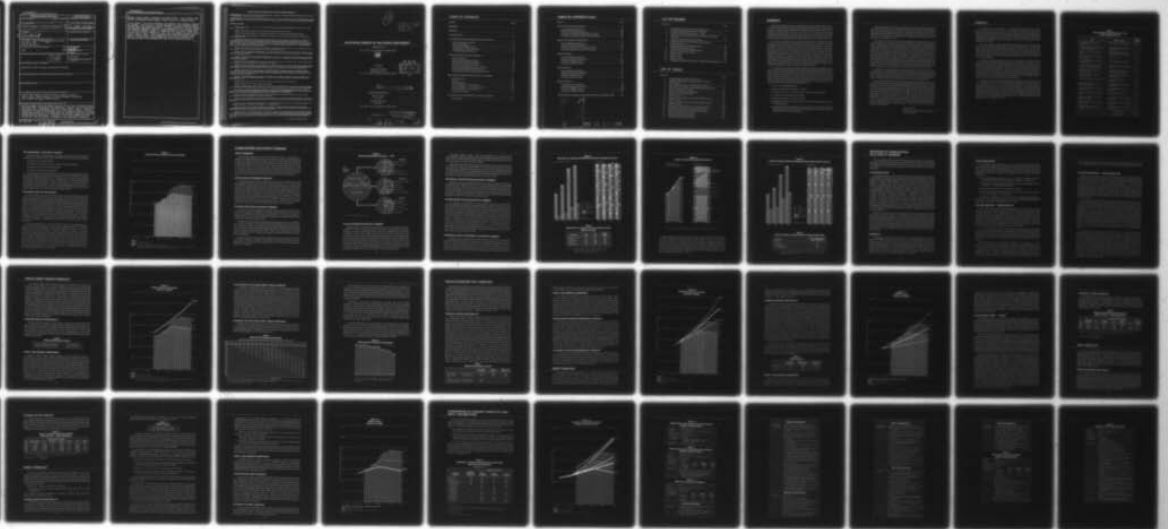
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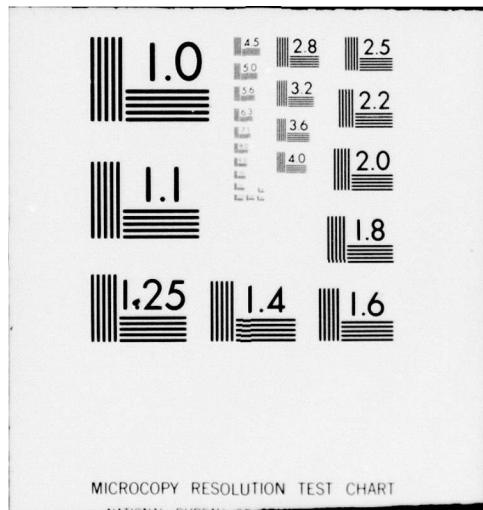
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IN THE PACIFIC NORTHWEST

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IN THIS BOOKLET, FIVE PACIFIC NORTHWEST LOAD FORECASTS ARE DESCRIBED, ANALYZED AND COMPARED. THEY ARE THE (1) PACIFIC NORTHWEST UTILITIES CONFERENCE COMMITTEE/WEST GROUP AREA (PNUCC/WEST GROUP); (2) PACIFIC NORTHWEST UTILITIES CONFERENCE COMMITTEE ECONOMETRIC FORECAST, (PNUCC/ECONOMETRIC); (3) NORTHWEST ENERGY POLICY PROJECT FORECAST, (NEPP); (4) WASHINGTON STATE UNIVERSITY "ENERGY PROJECTIONS FOR THE PACIFIC NORTHWEST", (WSU); AND (5) NATIONAL RESOURCES DEFENSE COUNCIL FORECAST (NRDC). INPUT ASSUMPTIONS AND FORECASTING METHODS (TREND ANALYSIS, END USE ANALYSIS AND ECONOMETRICS) USED FOR EACH PROJECTION ARE ANALYZED IN LIGHT OF THE INFLUENCE THEY HAVE ON THE RESULTING FORECAST.



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ELECTRICAL ENERGY IN THE PACIFIC NORTHWEST

PREPARED BY

U.S. Army Corps of Engineers, Seattle District



AUTHOR

George E. Marshall
Regional Economist

U.S. Army Corps of Engineers, Seattle District

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SUMMARY

One of the most difficult energy-related problems confronting decision makers in the Pacific Northwest is choosing an appropriate and reasonable rate of increase in electrical energy demand between now and the end of the century. Whatever the decision, it must be made very soon for it takes 10 to 15 years to bring a large powerplant into operation once a decision is made to start planning for it, and the capital investment required is large and gets larger every day. Equally important, the decision must be correct because the consequences of error could be enormous.

The Corps of Engineers is constantly confronted with this perplexing issue because of our involvement in planning in the hydroelectric field. There are a number of different views and forecasts of future electrical energy demand in the Pacific Northwest. Those who are deeply involved in energy planning are especially concerned about the conflicting forecasts of future demand and the vast array of assumptions upon which the forecasts are based. In this brochure, we have attempted to identify the five most prominent forecasts of regional electrical energy demand, discuss the methods used to make these forecasts, present the advantages and disadvantages of each method as determined by other non-Corps people who have evaluated the methods, highlight the assumptions used in each forecast, and graphically show how the various demand forecasts compare with the presently anticipated increase in supply of electrical energy.

In reviewing the available material, Seattle District has concluded that the growth in electrical energy demand in the Pacific Northwest for the remainder of the century should follow the PNUCC forecasts, which presently estimate an increase of approximately 4 percent per year, more closely than any other forecast. We expect gross energy consumption to increase about 3 percent per year. Our major concerns with the other forecasts which show lower growth rates are that they are new and untested, and some of the assumptions upon which they are based are too risky. Some of the more significant assumptions are:

- Low or zero population growth.
- High unemployment of perhaps 7 percent.
- Closure of 9 of the 11 aluminum plants in the Northwest by 1995.
- A high level of mandatory conservation.
- High price elasticity for electrical energy.
- Collapse of the OPEC oil cartel by 1985, with a nearly 50 percent reduction in oil and gas prices.
- Abundant supply of oil and gas due to future discoveries in Alaska, the Gulf of Alaska, and off the coast of the Pacific Northwest; and an accompanying shift toward direct use of oil and gas fuels.

It does not seem prudent to base our energy future on the chance that the above assumptions will prove valid or desirable. Conservation is the most cost-effective way to gain extra energy and should be strongly encouraged, but conservation expectations have already been taken into consideration and account for the major portion of the reductions in PNUCC/West Group growth forecasts which have occurred over the last few years.

The electrical sector is the area with the fastest growing demand for energy inputs. Production of electrical energy moved from about 13 percent of the Nation's primary energy sector to 26 percent between 1947 and 1973. The Department of Interior has estimated it will reach nearly 35 percent by 1985 and 42 percent by the year 2000. We believe this shift toward use of electrical energy will continue, reflecting the more rapid cost growth of other fuels, the cleaner nature of electrical energy, and the depleting stocks of petroleum and natural gas, coupled with a national energy policy to save oil and gas for higher priority uses, such as transportation and chemical feedstocks. This preference for electrical energy for new uses and the shift to electricity from direct use of other energy sources will keep the growth rate for electricity higher than that for gross energy consumption. The difference in the two rates will not be as large in the Pacific Northwest since this region is already twice as dependent on electricity as the Nation as a whole.

In addition to meeting electrical growth requirements, energy planners must simultaneously face the shift in type of fuel required to generate electricity. Phasing out of oil and gas and a shift to other primary energy sources for electrical generation will be required. However, this problem will be minimized in the Pacific Northwest, which is already utilizing other sources such as hydro and nuclear power.

In our graphical comparisons of electrical energy supply and demand, we have shown demand forecasts with growth rates ranging from 0.5 percent per year to 5.5 percent per year. Four of the five demand forecasts include some electrical energy demand scenarios which fall within a band of 2.9 percent to 5.5 percent growth rates from now until 1995. Although we feel a 4 percent growth rate is the most appropriate, if demand does grow at any rate in this range (a range most people feel is reasonable), there will be power deficits in 1995. Meeting these power deficits necessitates continued planning of structural power-producing alternatives, whether these alternatives be conventional (nuclear, coal, hydro) or unconventional (solar, wind, geothermal, etc). Given the 10- to 15-year lead time it takes to get any structural alternative built, if the power deficits of 1995 are to be met, the solutions must be planned today.

John A. Poteat
Colonel, U.S. Army Corps of Engineers
District Engineer

PREFACE

1973 was a year of awakening — in the Pacific Northwest and in the United States. During the summer, critically low streamflow conditions threatened the Northwest's electrical power supply. Then, in October, Arab oil producing nations banned crude oil shipments to the United States. Suddenly, everyone seemed to be talking about energy. Call it a crisis, a concern, a dilemma, a problem, or a situation, energy is still a celebrated and controversial issue in the Pacific Northwest and throughout the nation.

One way to judge an issue's importance is to find out how much is being written about it. Let's look at the energy issue. All the publications in Table 1, nearly 8,500 pages, say something meaningful about energy — and there are many thousand more pages in other publications as well. Unfortunately, very few people have the time or the expertise to go through all these pages and study the assumptions, methods, findings, conclusions, and recommendations so that they can find out what the message really is.

As we see it, all these publications have one common theme. Whether they talk about energy forecasting, energy conservation, energy planning, energy costs, or energy policy, all the discussion ultimately boils down to energy supply and demand. How much energy are we going to have and how much energy are we going to need? This brochure has two purposes — to take a close look at the future supply and demand for electrical energy in the Pacific Northwest, and document the existence and magnitude of electricity deficits between now and 1995. Although some parts of this brochure may seem a little technical or difficult to read, it is important to keep in mind that energy is a difficult and very complex issue.

The need, or lack of need, for additional power generating facilities has been the area of greatest concern in the Pacific Northwest. This brochure is unlikely to settle any debates on this issue, nor is it intended to substitute for over 8,000 pages of important energy studies. It is intended to examine the heart of the electrical energy debates by providing a concise description of the methods used to make alternative regional forecasts of electricity supply and demand, and the assumptions used to make these forecasts. By doing so, we hope to promote a better understanding of the fact that the most appropriate debate topic is not *if* additional electrical power generation will be needed but *when*.

Table 1
Energy Related Publications Since 1975
Pacific Northwest Only

Title	Author or Sponsor	Number of Pages
Bonneville Power Administration Role EIS, 1977	Bonneville Power Administration	3,208
Choosing an Electrical Energy Future for the Pacific Northwest, 1977	Lash, Beers/National Resources Defense Council	177
Electric Energy Conservation Study, 1976	Skidmore, Owings, and Merrill/ Bonneville Power Administration	325
Electric Energy Issues in the Pacific Northwest, 1977	Quist	39
Electric Energy Picture in the Pacific Northwest, 1976	Bonneville Power Administration	23
Electricity Forecasts and Alternatives for the Pacific Northwest, 1977	Washington Public Interest Research Group	225
Energy Projections for the Pacific Northwest, 1975	Hinman, Butcher, Swamidass/ Washington State University	204
Incentives for Electric Utilities to Overforecast, 1976	Ernst and Ernst/Bonneville Power Administration	34
Northwest Energy Policy Project, 1978	Pacific Northwest Regional Commission	3,066
Review of Energy Forecasting Methodologies, 1976	Ernst and Ernst/Bonneville Power Administration	336
Review of Power Planning in the Pacific Northwest, 1977	Pacific Northwest River Basins Commission	112
Thermal Power Conference Proceedings, 1976	Washington State University	193
West Group Forecast (11-year) "The Black Book," 1978	Pacific Northwest Utilities Conference Committee	85
West Group Econometric Electric Sales Forecast, 1978	Pacific Northwest Utilities Conference Committee	230
West Group Forecast (20-year) "The Blue Book," 1978	Pacific Northwest Utilities Conference Committee	187
	TOTAL PAGES	8,482
	THIS BROCHURE	46

INTRODUCTION

In 1975, the people in the Pacific Northwest consumed 1.65 quadrillion (1,650,000,000,000,000) British Thermal Units of energy.* Of this amount, petroleum accounted for 52 percent (mainly fuels used for transportation); electricity, 23 percent (about 12,300 average megawatts); natural gas, 18 percent; and wood residues and nonelectric use of coal, 7 percent. Although our overall per capita energy consumption was 7 percent less than the national average, our per capita consumption of electricity was double the national average. In the Pacific Northwest, electricity is the dominant fuel in homes and businesses, and it runs a very close second to natural gas in industry.

Since electricity is so important to the economy and public welfare of the Pacific Northwest, it is extremely important for us to know whether or not our future electricity supplies will be adequate to meet our future electricity needs. In order to determine this, we need to know how much electricity we are likely to use in the years ahead. Moreover, it takes 10 to 15 years (or even more) to develop energy resources or to build new power plants. To allow for these long lead times, utilities and agencies must make decisions today involving millions or billions of dollars, based on estimates of how much energy we will need 10, 15 or 20 years from now. Each day, these decisions become more costly, and it becomes ever more important to develop reliable demand forecasts. For these reasons, how much electricity we will need in the future, and how fast that demand will grow are two of the most fundamental and controversial energy issues in the Pacific Northwest.

*A British Thermal Unit (BTU) is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. The BTU is used by energy planners to convert different measures of energy (kilowatt-hours, cubic feet, barrels, and tons) into one common unit of measurement (BTU).

FUTURE PACIFIC NORTHWEST ELECTRICITY SUPPLY

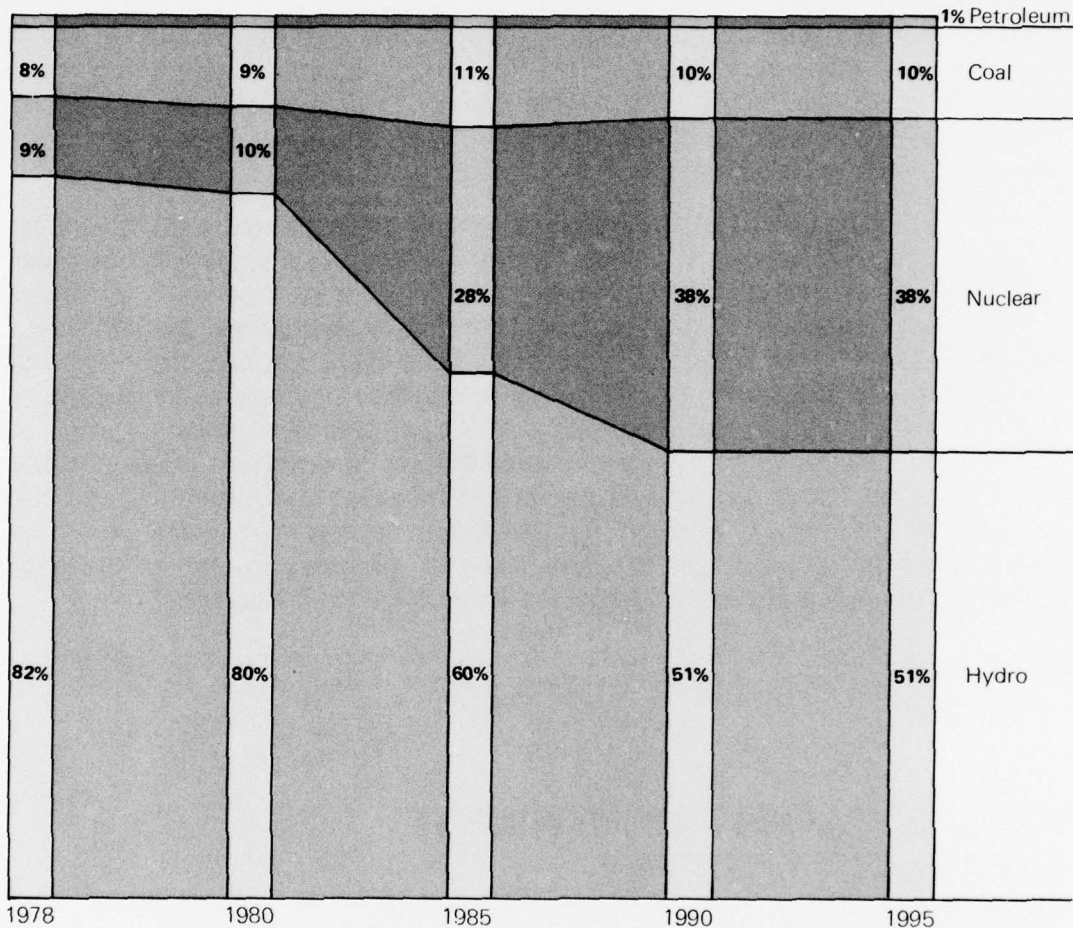
Before we examine projected electricity demand, we should look into the resources scheduled to be online to meet this future demand. Until now, hydroelectric power generation (hydropower) has met most of the Pacific Northwest's energy needs. Over the next 10 to 15 years, however, more than 95 percent of the electricity added to our existing supply is expected to come from nuclear and coal plants. The region's thermal resource (coal and nuclear power plants) is projected to grow from 17 percent of 1978's power generation to 48 percent by 1995 (Figure 1).

ELECTRICITY SUPPLY IS UNCERTAIN

The controversy surrounding load forecasts tends to give the impression that if only electricity demand were accurately projected, we would know precisely whether we have too much or too little generating capacity. This theory assumes that we can accurately determine future electric supply just by adding up the capacities of all the region's generating plants. Unfortunately, it's not quite that simple.

Figure 1
Projected Sources of Pacific Northwest Electricity

IN PERCENT



Source: Pacific Northwest Utilities Conference Committee, "The Blue Book," March, 1978.

Hydropower depends on continually changing water and streamflow conditions. Thermal generating plants face the uncertainties of unexpected outages in existing plants, and unpredictable construction delays with proposed thermal plants. Electricity supply projections are updated and revised each year by the Loads and Resources Subcommittee of the Pacific Northwest Utilities Conference Committee (PNUCC).^{*} Accounting for thermal plant delays is a major reason for updating the supply projections, but other reasons include accounting for new projects added to the schedule, accounting for retirement of old plants, adjustment to plant schedules to accommodate higher or lower load growth, revising plant capabilities when designs are changed or plants are modified, and accounting for reduced hydro capabilities due to irrigation depletions.

^{*}The PNUCC is a planning forum made up of utilities and power agencies in the region designated as the West Group area, shown in Figure 7.

CONSTRUCTION DELAYS

Most new thermal power plants have actually begun operation significantly later than their scheduled dates. Inflation translates these delays directly into higher construction costs — building costs rose about 28 percent from 1974 through 1977. This means that a typical nuclear plant which would have cost \$800 million in 1974 required an investment of over \$1 billion by 1977. Delays in thermal plant construction, the high cost of such delays, and the much larger role thermal plants must play in future regional energy supply will result in higher electricity rates to consumers in the Pacific Northwest.

THERMAL POWER PLANT TIMING

Thirteen thermal power plants have been planned to provide future electricity in the Pacific Northwest. If we compare the scheduled operation dates shown in Table 2, we get an indication of the delays encountered in planning and building thermal plants. Table 2 also distinguishes between thermal plants under construction and those in proposed or preconstruction status where necessary permits to start construction have not been issued.

Table 2
Installation Schedule for Pacific Northwest Thermal Power Plants

Project	Type or Fuel	Average Megawatts	Originally Scheduled Operation Date	Latest Scheduled Operation Date	Years Delayed To Date
Jim Bridger #4	Coal	350 ¹	1979	1979	—
Boardman (Carty)	Coal	358 ²	1978	1980	2
WNP #2 — Hanford	Nuclear	825	1979	1981	2
WNP #1 — Hanford	Nuclear	938	1980	1983	3
WNP #3 — Satsop	Nuclear	930	1981	1984	3
WNP #4 — Hanford	Nuclear	938	1982	1984	2
WNP #5 — Satsop	Nuclear	930	1983	1985	2
Proposed					
Colstrip #3	Coal	368 ³	1978	1982	4
Colstrip #4	Coal	368 ³	1978	1983	5
Skagit #1	Nuclear	966	1981	1985	4
Pebble Springs #1	Nuclear	945 ⁴	1980	1986	6
Skagit #2	Nuclear	966	1981	1987	6
Pebble Springs #2	Nuclear	945 ⁴	1985	1989	4

¹ Two-thirds of the output of the Jim Bridger plant in Wyoming will serve the West Group area. Boundaries of the West Group area are shown in Figure 7.

² Boardman is rated 530 MW and 90 percent will be used by West Group area. The remaining 10 percent is Idaho Power Company's share.

³ Colstrip Units #3 and #4 are rated 700 MW each; 70 percent will be used by West Group area; (the Environmental Protection Agency has refused to issue a construction permit for Colstrip Units #3 and #4).

⁴ Site selection has not been approved by all appropriate Government agencies.

Source: "BPA Administrator's Newsletter," May 1978.

NET RESOURCES = ELECTRICITY SUPPLY

PNUCC's annual forecast of electricity supply uses net resources (expressed in megawatts) to measure power supply. Net resources consist of four components:

- Electricity from existing plants
- Electricity imported from plants outside the Pacific Northwest
- Electricity from new hydropower plants
- Electricity from new thermal plants.

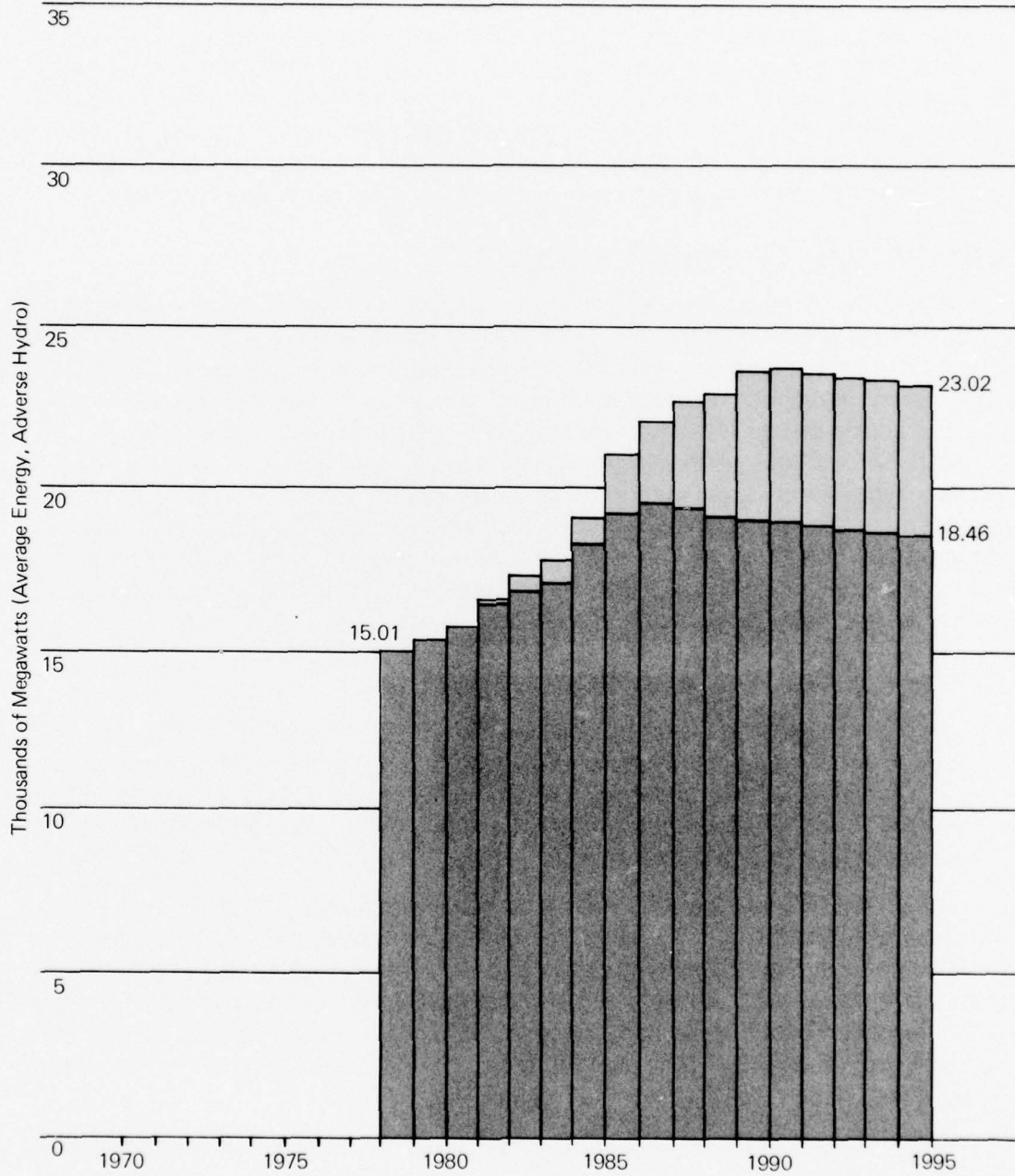
After totaling the electricity supplied from these four sources to get total (gross) resources, PNUCC deducts about two percent of the total. This deduction includes load growth reserves (a safety margin "set aside" for six months of unanticipated load growth) and adjustments to resource capabilities to cover hydropower plant maintenance and transmission losses. The resulting net resource figure is calculated for each year of an 11-year and a 20-year forecast period. In order to find out if a power surplus or deficit will occur in any year, PNUCC then subtracts the net resource figure from the projected electricity demand figure.

THE SUPPLY SIDE OF THE PICTURE

Projected electricity supply (net resources) for the Pacific Northwest through 1995 is shown graphically in Figure 2. The graph shows the average amount of electricity available or potentially available throughout each year. A very important feature of Figure 2 is that it distinguishes between existing and under construction power resources and proposed power resources. We made this distinction so that further on in the brochure we could show how much greater regional power deficits will be if the proposed thermal plants listed in Table 2 are not built. We should also point out that both the heavily shaded and lightly shaded parts of Figure 2 slope downward over time because electricity imported into the region — which is added to supply — declines over time, and reserves "set aside" for load growth — which are subtracted from supply — increase over time. Another reason for diminishing supply is increased irrigation withdrawals after 1990 which will reduce hydro energy production.

Hydropower production for each year shown in Figure 2 is estimated based on critical water conditions (adverse hydro). Since water conditions in the Pacific Northwest vary so unpredictably, critical water conditions are used to provide a standard, uniform base for estimating future hydroelectricity supply. An average water year would increase hydroelectricity supply (and total electricity supply) by about 2,000 megawatts (MW). Critical water conditions occurred in 1973 and again in 1977. Finally, the totals shown in Figure 2 are net resources minus electricity exports to utilities outside the Pacific Northwest. These firm exports, which decline to almost nothing by the late 1980's, can be mathematically handled by either adding them to demand projections, or by subtracting them from supply projections. We have subtracted exports from supply projections in order to simplify supply/demand comparisons made later in this brochure.

Figure 2
Projected Pacific Northwest Electricity Supply



Supply

- Proposed thermal plants
- Existing power plants or plants under construction

Source: "Long Range Projection of Power Loads and Resources for Thermal Planning," PNUCC West Group Area, 1978-79 through 1997-98, March 15, 1978, Table 1.

FORECASTING ELECTRICITY DEMAND

WHAT IS DEMAND?

Most energy studies refer to energy *demand, needs, or requirements* — words which suggest that we absolutely must have some specific amount of energy by that time (or period of time) no matter how much it costs. In fact, the demand for energy, like the demand for anything else depends to a certain degree on how much it costs (economists call this *price elastic*). As the price rises, people use less. On the other hand, if the price goes down, people will *demand, need, or require* more electricity. When an economist uses the word *demand* he means how much of a commodity people will be willing to buy at various prices over some specific period of time. This is how the word *demand* will be used in this brochure.

APPLICATIONS OF DEMAND FORECAST

Projecting electricity demand (called *load forecasting*) has been a critical part of long-range electricity planning in the Pacific Northwest since the 1940's. Load forecasts are compared with the electricity that will be available from existing power plants, plus what should be available from plants under construction, or planned for construction, in order to find out if we need to plan for more generating facilities. This comparison of electrical resources with demand for electricity is used to help plan the size, type, timing, and location of new facilities; to make revenue and cost forecasts; and to determine whether rates are high enough to cover future costs. These comparisons are made for the entire Pacific Northwest region, and for individual utilities' service areas. Since these figures are used in making so many important decisions, it is easy to see why reliable load forecasts are so important.

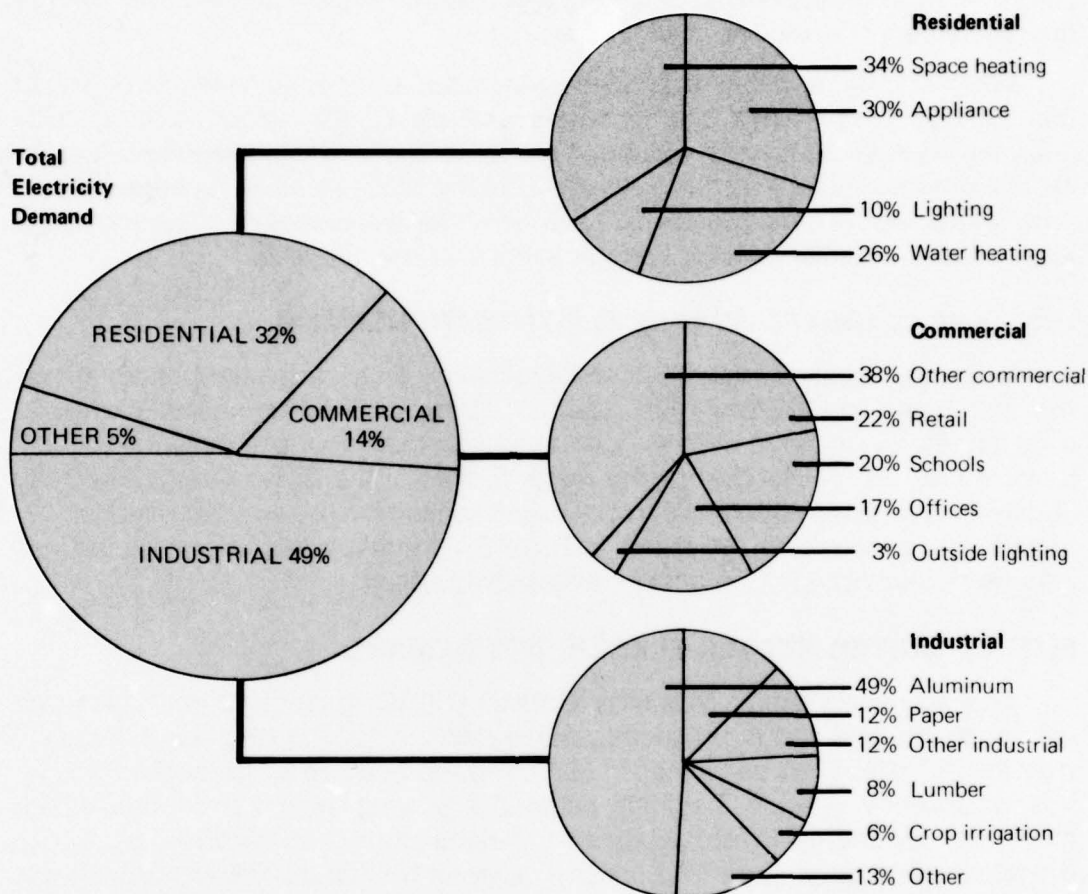
FACTORS AFFECTING ELECTRICITY DEMAND

Demand for electricity depends on literally hundreds of factors. On a day-to-day or week-to-week basis, the weather and people's daily habits (what time they cook meals or watch television) affect electricity demand. In the long term, population, employment, income, electricity prices, oil and gas prices, industrial efficiency, and conservation all become major factors.

Most forecasts split electricity demand into three groups of users — residential, commercial, and industrial. The amount of electricity used by each of these groups in 1975 is shown in Figure 3. Ninety percent of residential electricity was used to heat homes or operate water heaters and appliances. Space heating and water heating were the major commercial uses as well. Industry used 49 percent of the total electricity demand in 1975. The aluminum industry is the largest industrial user in the Pacific Northwest.

Electricity demand forecasts must consider all the factors that affect demand, the groups of people or industries that create this demand, and the long range significance of any factors which might either increase or decrease any group's demand for electricity.

Figure 3
Pacific Northwest Electricity Use — 1975



Source: Bonneville Power Administration

FLUCTUATIONS IN ELECTRICITY DEMAND

Between 1960 and 1970, demand for electricity in the United States more than doubled. Then came a growing economic recession, aggravated by the drastic increase in oil prices by the Organization of Petroleum Exporting Countries (OPEC) in the fall of 1973. In many parts of the country where fuel is used to generate electricity, cost increases in oil and other fuels brought on by the oil embargo pushed up electricity rates to consumers. Between 1973 and 1974, the nationwide average price of electricity increased 12.8 percent over and above the rate of inflation. The recession, conservation efforts, and higher electric rates all combined to cut the demand for electricity. Utilities generated only 0.47 percent more power in 1974 than they had in 1973, and in 1975, they generated only 3.2 percent more than in 1973 (compared to 1960-1970 when demand had increased 100 percent).

Decreased demand, higher costs, and uncertainties and lawsuits about environmental concerns forced many electrical utilities to delay construction of new plants. Then, in 1976, demand picked up again, increasing 6.4 percent over 1975 as the nation began to recover from the recession.

Whether long-term national electricity demand will or should resume growth at the 1960-1970 rates has stirred debate and dissension among electric utility analysts, energy forecasters, consumer groups, and environmental groups. Most of us would prefer to steer a course between the financial and environmental costs of having too much electricity available, and the social and monetary costs in terms of lost jobs and reduced industrial production if we have too little.

HISTORICAL UNITED STATES ELECTRICITY DEMAND

Before focusing on regional electricity demand, let's take a brief look at national demand. Between 1950 and 1975, total U.S. energy demand increased an average of 3 percent a year, while the average annual electricity demand increase was 5.7 percent (see Figure 4). One of the major factors in the faster rate of electricity demand was that the price of electricity rose less than the prices of bituminous coal, natural gas, or petroleum, as shown in Table 3. As a result, people substituted less expensive electricity for the costlier alternative fuels.

FUTURE UNITED STATES ELECTRICITY DEMAND

The National Electric Reliability Council (NERC) projects a net nationwide electricity demand of 405 billion megawatts (MW) in 1986, a 65 percent increase over the 257 billion MW consumed in 1977. This represents a 5.2 percent growth per year as shown in Figure 5. Electricity demand is growing faster than the demand for other forms of energy. In fact, production of electricity moved from 13.0 percent to the primary energy sector to 26.2 percent between 1947 and 1973, and is projected to reach 34.6 percent in 1985 and a phenomenal 41.9 percent by the year 2000. This growth in electricity demand reflects a preference for electricity over other energy sources in new uses and a switch away from petroleum, natural gas, and coal to electricity in existing uses. Coal is expected to remain the dominant power plant fuel, with demand for coal nearly doubling from 481 tons in 1977 to 879 million tons in 1986. NERC projects that nuclear generation will increase from 13 percent of total 1977 production to 28 percent in 1986, offsetting the smaller share of electricity generated by oil, gas, and hydropower.

HISTORICAL PACIFIC NORTHWEST ELECTRICITY DEMAND

Following the national trend, demand for electricity in the Pacific Northwest has grown faster than the demand for gross energy. Total Northwest energy demand as shown in Figure 6 increased 4.7 percent a year between 1960 and 1975, while electricity demand grew 5.8 percent per year. A major factor in the faster growth rate here is the relative abundance of clean, efficient, and comparatively inexpensive hydropower. Because of this abundance, industries which need large amounts of

Figure 4
Historical U.S. Energy and Electricity Demand and Supply by Source

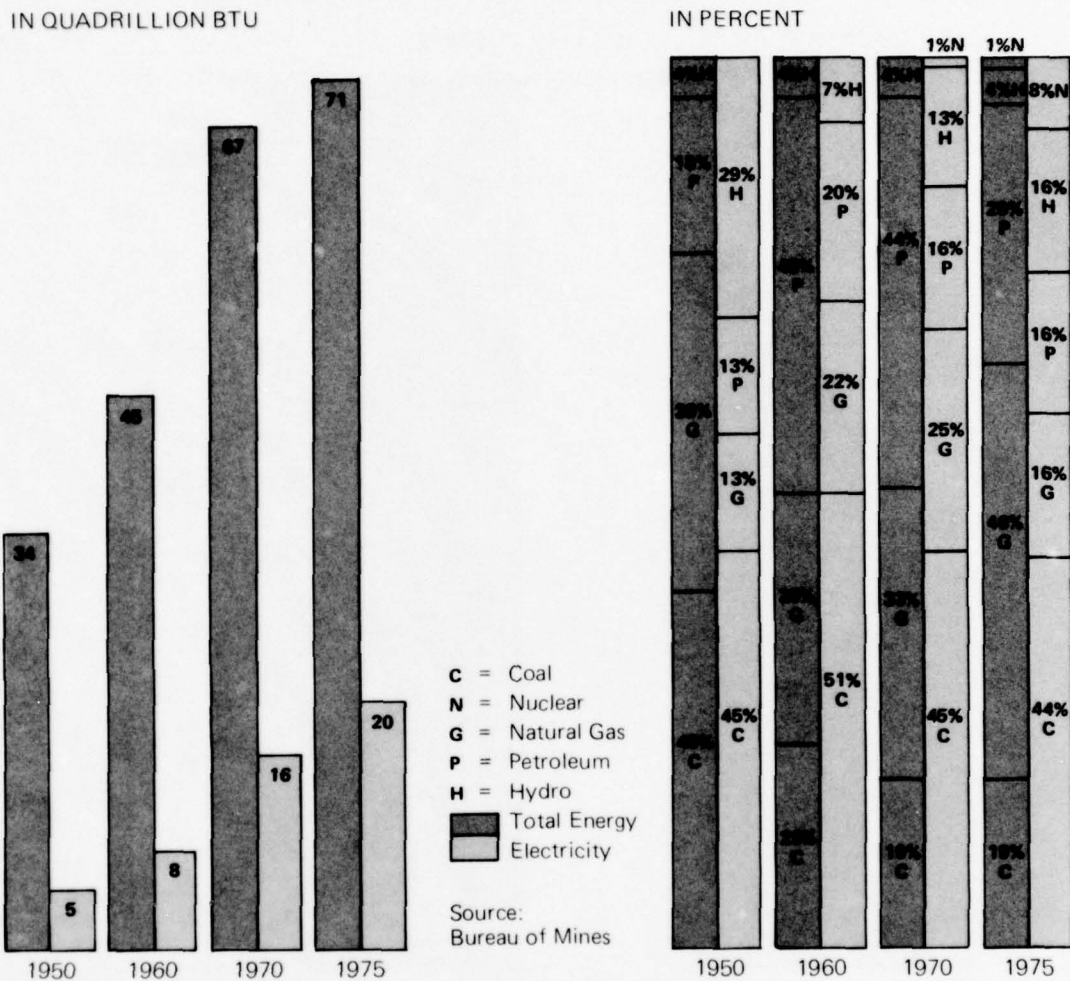
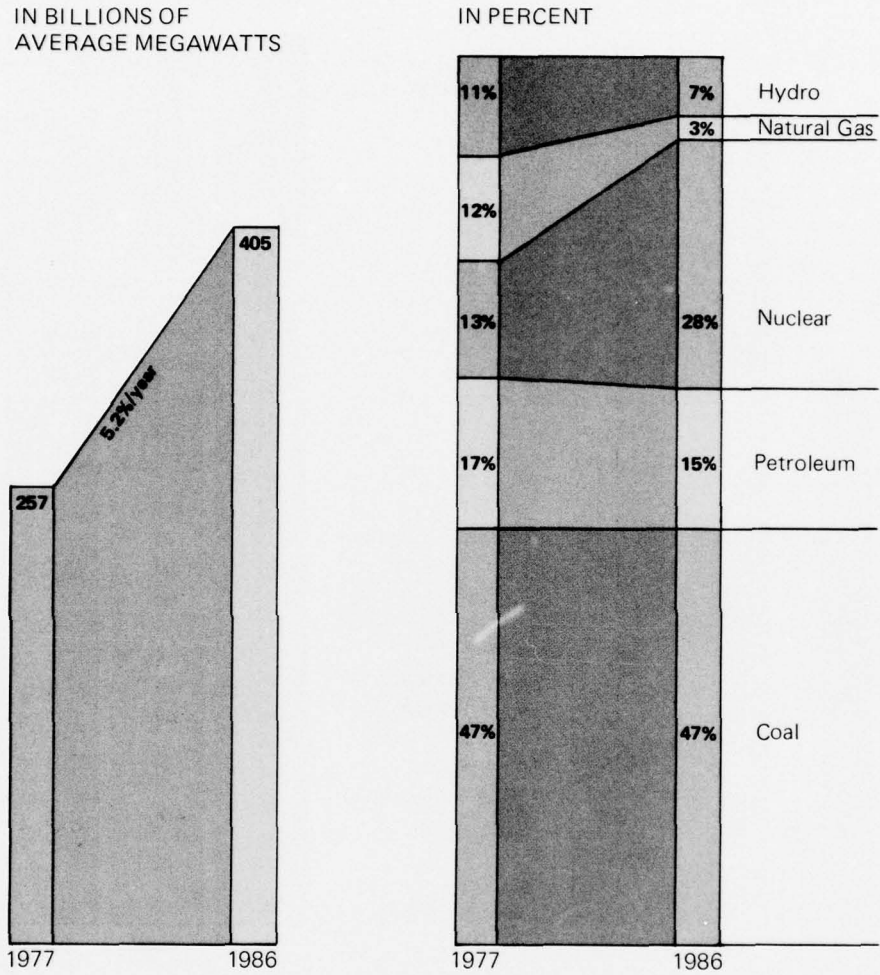


Table 3
Wholesale Price Indexes of Fuel and Electric Power
National Average

Commodity	1958	1975	Percent Increase
Bituminous coal	98	387	295
Natural gas	74	215	191
No. 2 Fuel oil	96	249	159
Crude oil	103	246	139
Electric power	100	193	93

Source: "Wholesale Prices and Price Indexes," Bureau of Labor Statistics. Base year of No. 2 Fuel Oil index is 1973. Base year of all other indexes is 1967.

**Figure 5
Future U.S. Electricity Demand by Source**



Source: National Electric Reliability Council, Seventh Annual Review, July 1977. p. 9

electricity, especially aluminum reduction plants, have located in the region. The 11 Pacific Northwest aluminum plants make almost one-third of America's aluminum, and consume about one-fourth of the region's electricity production. Another major factor in the growth of electricity demand in the Pacific Northwest is that other energy sources are relatively rare and cost more. We have few coal reserves and no significant oil or gas production. Between 1964 and 1974, the real price of electricity compared to natural gas and oil has actually decreased in the Pacific Northwest, as shown in Table 4.

Figure 6
Historical Pacific Northwest Energy and Electricity Demand by Source

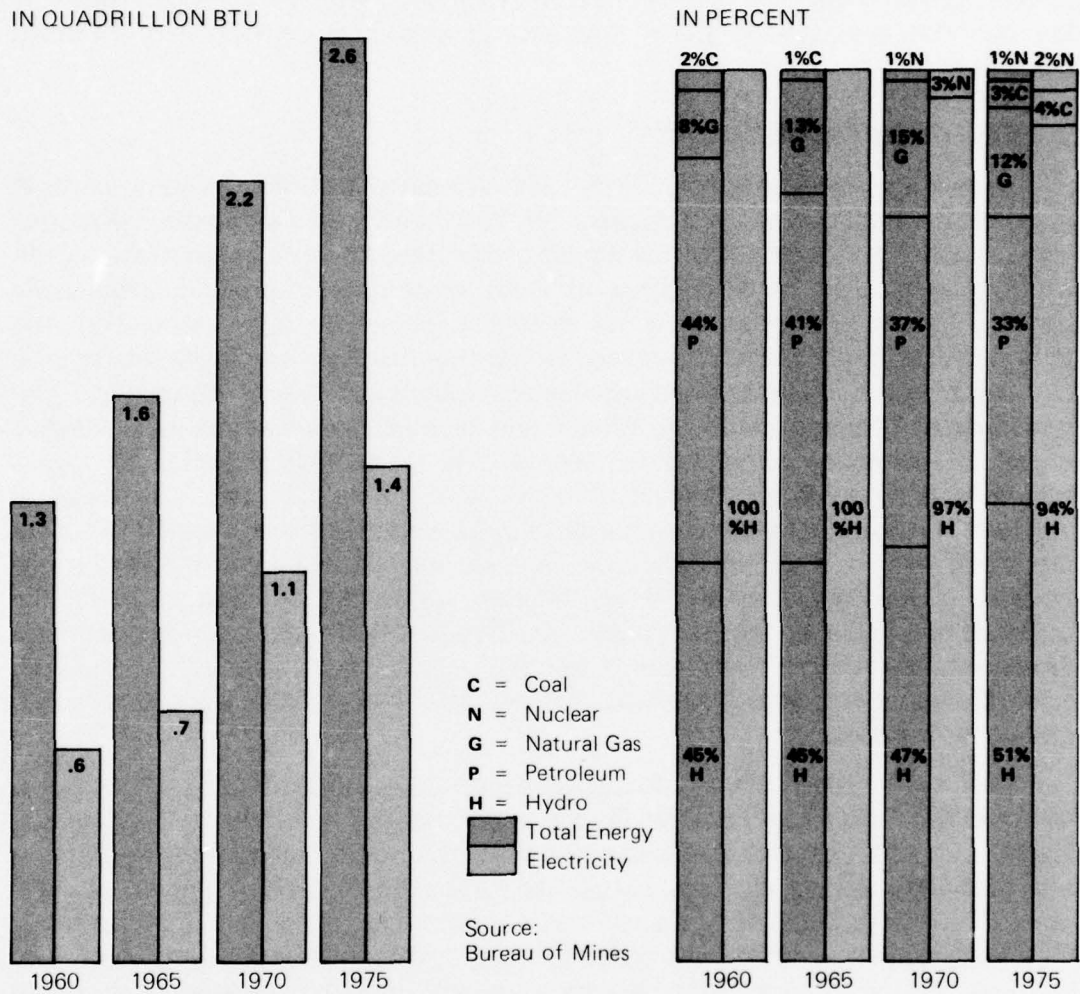


Table 4
Rate of Growth in Pacific Northwest Retail Energy Prices

Commodity	Average Annual Percentage Change 1964-1974
Electricity	-4.31
Natural Gas	-.17
Oil: Nontransportation	1.53
Transportation	.28

Source: "Energy Futures Northwest," Northwest Energy Policy Project, Portland, Oregon, May 1978, p. 65. Percentage changes computed from real prices expressed in 1967 dollars.

METHODS OF FORECASTING ELECTRICITY DEMAND

The three general electricity demand forecasting methods are: trend analysis, end-use analysis, and econometrics. In this section we will look at the techniques, advantages, and disadvantages of each method, then later sections will show how the methods are used to make forecasts of electricity demand in the Pacific Northwest.

A FEW DEFINITIONS

In making projections of electricity demand, energy planners use some words in a slightly different context and occasionally lean heavily on mathematics. A *model*, for example, is a mathematical description of how the complex elements of a real-life situation or problem might interplay at some future date. In projecting electricity demand, a modeler uses data on electricity prices, income, population, the economy, the growth rates for each and then varies the mix according to varying sets of assumptions. Different assumptions produce different outcomes. The relationships between electricity demand and the multitude of factors that influence or affect electricity demand are expressed in mathematical equations called *functions*. A model is a collection of functions. A function, in turn, is made up of *variables* — those factors which change or can be changed. *Independent variables* are those factors which influence the demand for electricity and the *dependent variable* is electricity demand itself. In other words, the demand for electricity *depends* on population, income, prices, etc. Finally, *elasticities* describe how much the dependent variable (electricity demand) changes in response to small changes in the independent variables. Elasticities are what the modeler uses to measure consumer behavior.

Demand for electricity is commonly expressed in terms of both *peak* demand and *average (or energy)* demand. *Peak* demand refers to short duration, high-level loads, and peak demand analyses are important for determining reserve margins and planning peaking generation (such as combustion turbine and hydro peaking units). *Energy* demand refers to sustained, average level loads. Although the reader may occasionally see analyses of peak (or capacity) demand in the literature, this brochure is based on forecasting electrical *energy* supply and demand. Peak supply and demand values are generally about thirty percent higher than corresponding energy values.

SCENARIOS

Energy planners often speak of *scenarios* — hypothetical pictures of the future based on different assumptions about economic or political events. They make different projections for each scenario. For example, a *low growth scenario* might assume high energy prices and slow population growth, while a *high growth scenario* would assume the opposite. These scenarios allow people to see how electricity demand might change if the different assumed economic and political events actually occur. All of the forecasting methods are capable of looking at different scenarios and do so by changing their basic assumptions.

LOAD FORECASTING

The purpose of load forecasting is to find out how much electricity demand there will be during a specific year in a particular place. We have used the terms *load* and *electricity demand* interchangeably in this brochure. Each of the three forecasting methods takes a different approach to come up with these results. Each forecasting method is also different in its handling of the four basic forecasting ingredients:

- The mathematical expressions of the relationship between electricity demand and the factors which influence or affect it — the functions
- The factors which actually influence electricity demand (population, income, prices, etc) — the independent variables
- Electricity demand itself — the dependent variable
- How much electricity demand changes in response to population, income, price, etc., changes — the elasticities.

To make the remaining text of this brochure as easily understandable as possible, we have used the technical terms of function, independent and dependent variables, and elasticities as sparing as we could.

THE FIRST METHOD — TREND ANALYSIS

Trend analysis (trending) extends past growth rates of electricity demand into the future, using techniques that range from hand-drawn straight lines to complex computer-produced curves. These extensions constitute the forecast. Trend analysis focuses on past changes or movements in electricity demand and uses them to predict future changes in electricity demand. Usually, there is not much explanation of why demand acts as it does, in the past or in the future. Trending is frequently modified by *informed judgment*, wherein utility forecasters modify their forecasts based on their knowledge of future developments which might make electricity demand behave differently than it has in the past.

ADVANTAGES. Trend analysis is simple and inexpensive, and it is useful when there is not enough data to use more sophisticated methods. Most utilities have odd-shaped service areas for which there is no published economic or demographic data and find this method useful for load forecasting. They also rely on it for information about the adequacy of existing or planned transmission, distribution, and substation facilities.

DISADVANTAGES. A trend forecast produces only one result — future electricity demand. It cannot help analyze why electricity demand behaves the way it does, and it provides no means to accurately measure how changes in energy prices or government policies (for instance) influence electricity demand. Since assumptions used to make the forecast (*informed judgments*) are usually not spelled out, there is no way to measure the impact of a change in one of these assumptions. Another shortcoming of trend analysis is that it relies on past patterns

of electricity demand to project future patterns of electricity demand. This simplified view of electrical energy use could lead to inaccurate forecasts in times of change.

THE SECOND METHOD — END-USE ANALYSIS

End-use analysis uses a *model* or mathematical description to represent things happening in the real world. Its basic idea is that the demand for electricity depends on what it is used for (the end-use). For instance, by studying historical data to find out how much electricity we use for electrical appliances in our homes, then multiplying that number by the projected number of appliances in each home and multiplying again by the projected number of homes, we can come up with an estimate of how much electricity will be needed to run all household appliances in the Pacific Northwest during any particular year in the future. Using similar techniques for electricity used in business and industry, then adding up the totals for residential, commercial, and industrial sectors, we come up with a total forecast of electricity demand.

ADVANTAGES. End-use analysis identifies exactly where electricity goes, how much is used for each purpose, and the potential of conservation for each end-use. End-use analysis provides specific information on how energy requirements can be reduced over time from conservation measures such as improved insulation levels, increased use of storm windows, building code changes, or improved appliance efficiencies. An end-use model also breaks down electricity into residential, commercial, and industrial demands. Such a model can be used to forecast load changes caused by changes within one sector (residential, for example) and load changes resulting indirectly from changes in the other two sectors. Commercial sector end-use models currently being developed promise to be capable of making energy demand forecasts by end-uses as specific as type of business and type of building. This is a big improvement over projecting only sector-wide energy consumption and using economic and demographic data for large geographical areas.

DISADVANTAGES. Many end-use models assume a constant relationship between electricity and end-use (electricity per appliance, or electricity used per dollar of industrial output). This might hold true over a few years, but over a 10- or 20-year period, energy saving technology or energy prices will undoubtedly change, and the relationships will not remain constant. End-use analysis also requires extensive data, since all relationships between electric load and all the many end-uses must be calculated as exactly as possible. In the Pacific Northwest, data on the existing stock of energy-consuming capital (buildings, machinery, etc.) is very sketchy. Also, some of the data needed for end-use analysis may not be up to date, it may not accurately reflect either present or future conditions, and this can affect the accuracy of the forecast. Finally, end-use analysis, without an econometric component (discussed next), does not take price changes in electricity or other competing fuels into consideration.

THE THIRD METHOD — ECONOMETRICS

Econometrics, which is another modeling technique, uses economics, mathematics, and statistics to forecast electricity demand. Econometrics is a combination of trend analysis and end-use analysis, but it does not make the trend-analyst's assumption that future electricity demand can be projected based on past demand. Moreover, unlike many end-use models, econometrics can allow for variations in the relationship between electricity input and end-use.

Econometrics uses a multitude of complex mathematical equations to show past relationships between electricity demand and the factors which influence that demand. For instance, an equation can show how electricity demand in the past reacted to population growth, price changes, etc. For each influencing factor, the equation can show whether the factor caused an increase or decrease in electricity demand, as well as the size (in percent) of the increase or decrease. For price changes, the equation can also show how long it took consumers to respond to the changes. The equation is then tested and *fine tuned* to make sure it is a reliable representation of the past relationships. Once this is done, projected values of demand-influencing factors (population, income, prices) are put into the equation to make the forecast. A similar procedure is followed for all the equations in the model.

ADVANTAGES. Econometrics provides information on future levels of electricity demand, why future electricity demand increases or decreases, how electricity demand is affected by all the various factors discussed in this brochure — and it provides separate load forecasts for residential, commercial, and industrial sectors. Since the econometric model is defined in terms of a multitude of factors (policy factors, prices factors, end-use factors), it is flexible and useful for analyzing load growth under different scenarios.

DISADVANTAGES. In order for an econometric forecast to be accurate, the changes in electricity demand caused by changes in the factors influencing that demand must remain the same in the forecast period as in the past. This assumption (which is called *constant elasticities*) may be hard to justify, especially where very large electricity price changes (as opposed to small, gradual changes) make consumers more sensitive to electricity prices. Also, the econometric load forecast can only be as accurate as the forecasts of factors which influence demand. Since we cannot know the future, projections of very important demand-influencing factors such as electricity, natural gas, or oil prices over a 10- or 20-year period are, at best, educated guesses. Finally, many of the demand-influencing factors which may be treated and projected individually in the mathematical equations could actually depend on each other and it is difficult to determine the nature of these interrelationships. For example, higher industrial electricity rates may decrease industrial employment, and projecting both of them to increase at the same time may be incorrect. A model which treats projected industrial electricity rates and industrial employment separately would not show this fact.

Econometric models work best when forecasting at national, regional, or state levels. For smaller geographical areas, meeting the extensive data needs of the

models can be a problem. Econometric models are a relatively new load-forecasting method, especially in the Pacific Northwest. A good econometric model is a valuable load forecasting method, but its drawbacks and difficulties indicate it is not the final answer to our load forecasting problems.

FORECASTING ACCURACY

The only way to determine the accuracy of any load forecast is to wait until the forecast year and compare the actual load to the forecast load. Even though the whole idea of forecasts is accuracy, we have not said anything in this comparison of the three forecasting methods about which method produces the most accurate forecasts. There are two reasons for this. First, the only thing certain about any long-range forecast is that it can never be absolutely precise. Forecasting accuracy depends on the quality and quantity of the historical data used, the validity of the forecasters' basic assumptions, and the accuracy of the forecasts of the demand-influencing factors (population, income, price, etc.). None of these is ever perfect. Consequently, regional load forecasts are reviewed continually, and some are revised yearly. Even so, there is simply no assurance that electricity demand will be exactly as forecast, no matter what method is used or who makes the forecast.

Second, load forecasting methods other than trend analysis have only recently been used in the Pacific Northwest. It takes at least ten years to make a valid check of forecasting accuracy, and the verdict on whether trend analysis, end-use analysis or econometrics produces the most accurate load forecasts must wait until at least the mid-1980's.

FUTURE PACIFIC NORTHWEST ELECTRICITY DEMAND

Up to this point, we have discussed future electricity supply for the Pacific Northwest, some general aspects of forecasting electricity demand and three methods used to forecast electricity demand. Now we will get into the specifics, showing load forecasts based on each method and graphically comparing forecasts of electricity supply and demand in the Pacific Northwest.

Much of the debate over expansion of electrical generating capacity in the Pacific Northwest revolves around different forecasts of future electricity demand. Since the forecasts cover somewhat different geographical areas and are made by different forecasters using different assumptions, the results of the forecasts naturally vary widely. The following pages discuss the only five Pacific Northwest load forecasts presently in published form, highlighting and clarifying the differences among them. The five forecasts and the abbreviations used for them in the text are:

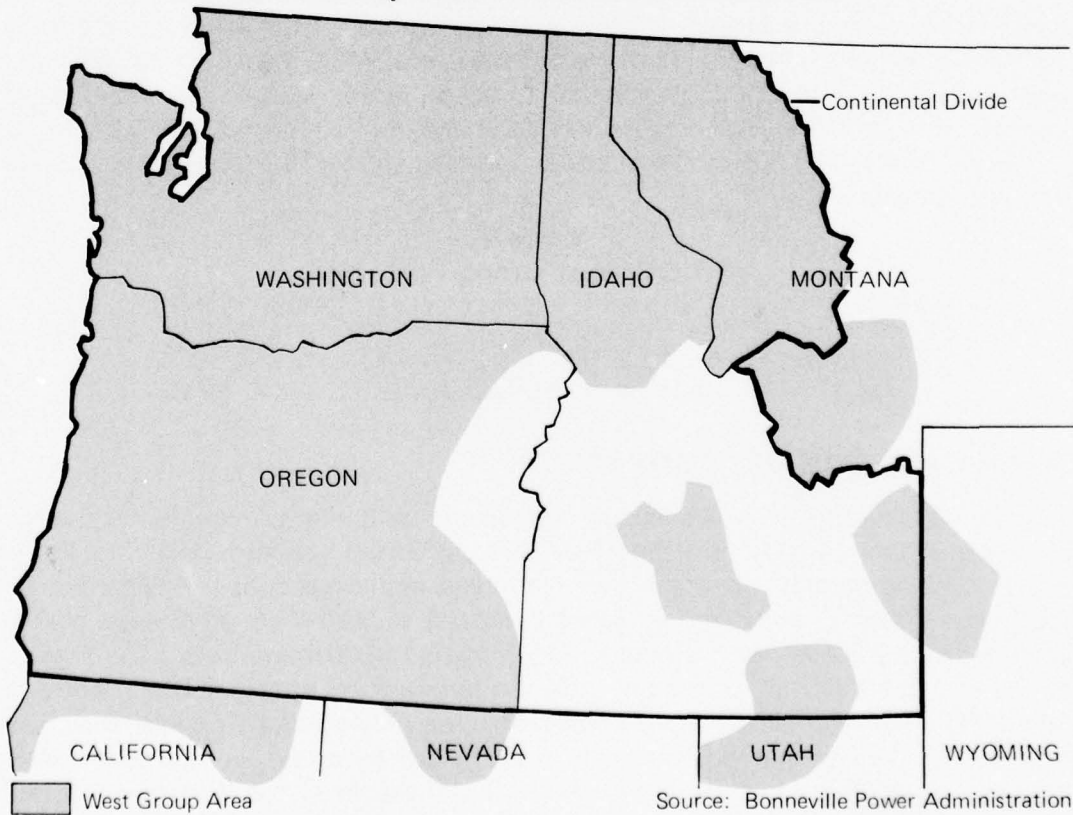
- Pacific Northwest Utilities Conference Committee/West Group Area Forecast (PNUCC/West Group)
- Pacific Northwest Utilities Conference Committee Econometric Forecast (PNUCC/Econometric)

- Northwest Energy Policy Project Forecast (NEPP)
- Washington State University "Energy Projections for the Pacific Northwest" (WSU)
- National Resources Defense Council Forecast (NRDC)

FORECAST AREA

The PNUCC/West Group, PNUCC/Econometric, and NRDC forecasts were made for the area served by utilities which are members of the Pacific Northwest Utilities Conference Committee. The PNUCC service area, known as the West Group Area, is shown in Figure 7. The NEPP and WSU forecasts were made for the Pacific Northwest, including only Washington, Oregon, and Idaho. Since the major population centers of the two areas are the same and total population of the two areas is approximately the same, the terms *West Group* and *Pacific Northwest* are commonly used interchangeably. More importantly, the load forecasts made for either area can be compared with each other.

Figure 7
West Group Area of Northwest Power Pool



The West Group area systems include Bonneville Power Administration, Pacific Power and Light Company, Washington Water Power Company, and 119 Public Agency Customers of BPA. The area presently served by these systems is shaded on the map. Each utility or system in the West Group area develops its own load forecast which the PNUCC then includes in the total system load forecast.

PNUCC/WEST GROUP FORECAST

The PNUCC/West Group forecast, prepared annually since 1954 by the PNUCC Subcommittee on Loads and Resources, was the only regional load forecast available until the mid-1970's. In 1968, the forecast period was extended from 11 to 20 years because the time required to get a generating unit on line had increased significantly. The West Group forecast is now published in two reports. The 11-year forecast, contained in the "Black Book," is generally published each February or March. The "Blue Book," published about a month later extends the forecast of loads and resources to 20 years. Utilities in the West Group area are directly or indirectly interconnected with one another and with the Bonneville Power Administration (BPA) by a network of power transmission lines operated by BPA. This transmission grid, which allows resources in the area to supply loads in the area, is in turn connected with thermal and hydroelectric generating facilities throughout the region. Because of this interdependence, load and resource planning must be done for the region as a whole and requires a high degree of coordination between utilities and Federal agencies. The PNUCC/West Group forecast is the vehicle which provides this coordination.

FORECAST METHOD AND RESULTS

The West Group forecast is the summation of individual forecasts sent to the subcommittee by 119 individual utilities, several federal agencies, and 18 direct-service industrial customers in the West Group area. While most of the utilities use trend analysis to make their forecasts, some larger utilities are now using econometric and end-use models to check the reasonableness of their trend forecasts. The 1978 PNUCC/West Group forecast showed the following electricity demand growth rates:

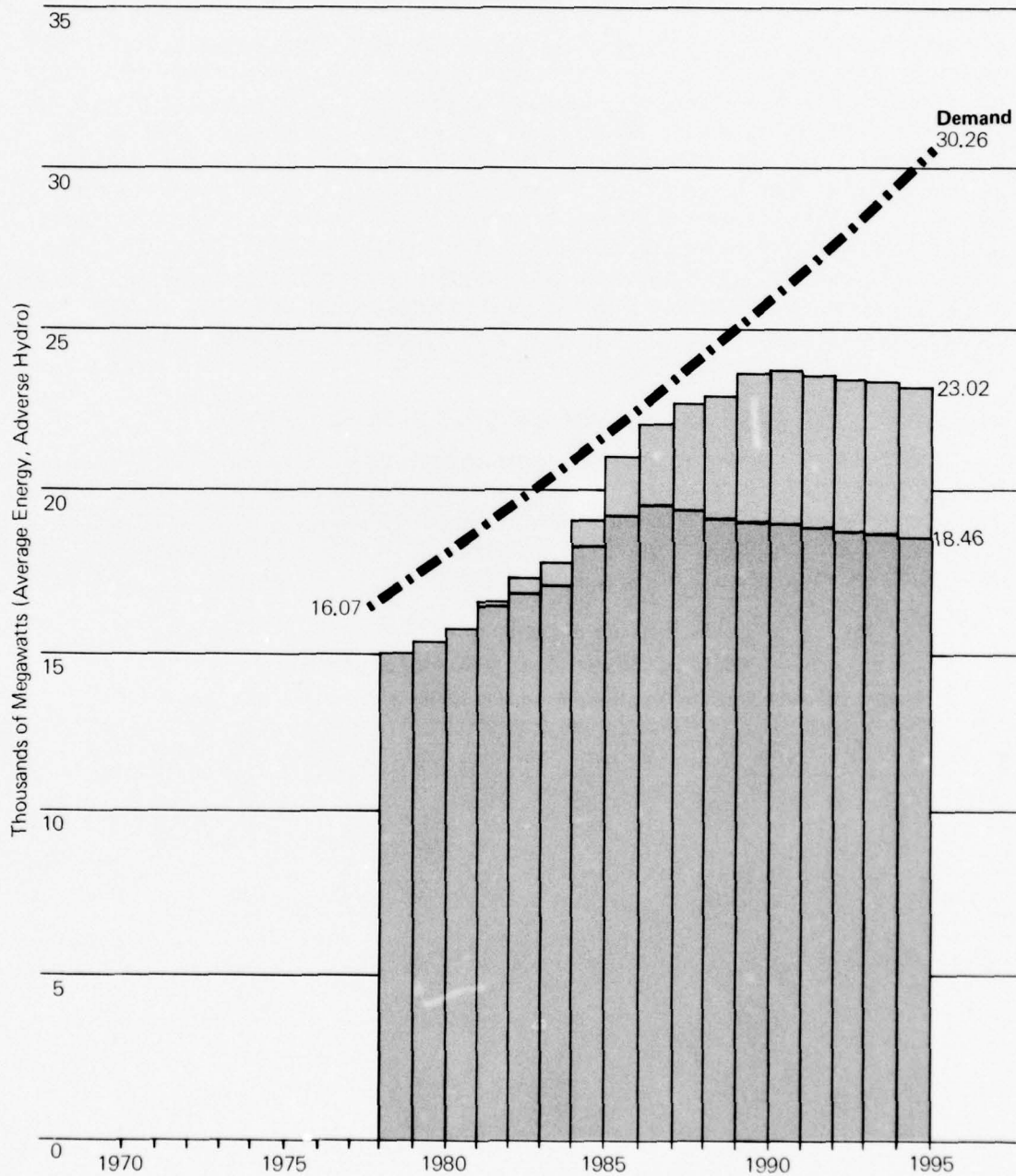
Table 5
PNUCC/West Group Forecast

1978-79 to 1988-89 (11-year forecast)	4.21 percent per year
1978-79 to 1997-98 (20-year forecast)	3.80 percent per year

SUPPLY AND DEMAND COMPARISON

Based on critical water supply conditions and the present schedule of generating plant construction, the PNUCC/West Group forecast shows that there will be more demand for electricity than Northwest plants can supply in every year of the forecast period, as shown in Figure 8. If none of the proposed thermal plants listed in Table 2 is built, the projected 1995 deficit is 11,800 megawatts (MW). Even if all the proposed thermal plants are built, the forecast still shows a 1995 deficit of about 7,200 MW. For illustration purposes only, we converted the deficits shown in Figure 8, and in similar figures in the rest of the brochure, into nuclear plant equivalents. A typical nuclear plant has a rated capacity of 1,250 megawatts, but its average output runs around 65 percent of capacity, or roughly 812 MW. A deficit of 11,800 MW is equivalent to the output of about 15 nuclear plants, while a 7,200 MW deficit represents about 9 such plants.

Figure 8
PNUCC/West Group Forecast
Demand vs Supply



Supply

- Proposed thermal plants
- Existing power plants or plants under construction

Source: "Long-Range Projection of Power Loads and Resources for Thermal Planning," PNUCC West Group Area, 1978-79 through 1997-98, March 15, 1978, Table 1.

EVALUATION OF THE PNUCC/WEST GROUP FORECAST

The PNUCC/West Group forecast is a compilation of many separate forecasts, so it can only be as sophisticated and accurate as the individual PNUCC members' forecasts, most of which are made using trend analysis. The forecasts made by the utilities, with some help from BPA, reflect different trends in business activity, population growth, past energy use, and other social and economic conditions within each utility's service area. Some of the utilities forecast rapid load growth and others slow load growth. The West Group forecast represents a general picture of regional electricity demand, but it does not tell us *why* electricity demand changes, nor can it be analyzed in detail since the member utilities do not use a standardized approach in selecting the data, basic assumptions, or the factors used to forecast electricity demand. The West Group forecast is prepared by the region's utilities who closely monitor the yearly changes in electricity demand, revise their forecasts as they perceive changes in future demand, and who are responsible for meeting the load growth in their service areas whether they forecast loads correctly or not. Their experience and responsibility for prudent electrical energy planning is an important factor in evaluating the West Group forecast.

ACCURACY OF PAST PNUCC/WEST GROUP FORECASTS

The difference between past forecasts and actual electricity use in the 19 years from 1958 to 1977 averaged ± 4.96 percent (see Table 6), which is slightly less than the actual load growth during that period of 5.65 percent per year. The cluster of underestimated loads for 1968-69 is a result of extremely cold weather that year which caused higher than normal electricity use.

Table 6
PNUCC/West Group Area Estimates

Percent Deviation Between Actual and Estimated 12 Months Average Firm Energy Loads¹

Year of Estimate	1958-59	59-60	60-61	61-62	62-63	63-64	64-65	65-66	66-67	67-68	68-69	69-70	70-71	71-72	72-73	73-74	74-75	75-76	76-77
1958	7.7	5.4	7.4	7.5	6.6	3.3	2.7	3.8	(0.1)	(4.4)	(9.4)								
1959		3.4	6.2	6.9	5.8	2.8	2.1	3.2	(0.9)	(5.2)	(10.5)	(10.0)							
1960			3.7	4.4	3.6	0.1	(0.2)	1.0	(3.4)	(7.8)	(12.8)	(12.4)	(11.3)						
1961				3.9	3.9	2.0	1.9	2.8	(1.5)	(5.8)	(11.2)	11.1	(10.2)	(6.1)					
1962					6.8	5.7	5.8	7.2	2.7	(1.0)	(6.1)	(5.8)	(4.7)	(0.7)	(0.9)				
1963						2.8	2.7	4.1	0	(3.9)	(8.4)	(7.6)	(6.3)	(1.9)	(2.0)	0.2			
1964							2.0	4.0	1.9	(1.2)	(4.3)	(3.2)	(1.5)	2.2	1.8	3.3	2.7		
1965								1.6	0.6	(2.2)	(7.3)	(5.0)	(2.4)	0.8	0.5	4.5	4.6	5.2	
1966									(0.4)	(2.1)	(3.4)	0	2.0	5.0	4.0	7.1	7.1	9.1	7.0
1967										1.9	(0.7)	1.5	2.7	3.3	4.5	8.7	9.8	11.5	13.3
1968											0.2	1.9	3.9	4.7	6.5	11.9	12.4	13.5	15.9
1969												(0.4)	1.9	3.0	4.6	8.1	9.1	9.7	10.7
1970													0.8	2.5	5.6	8.4	9.9	10.4	11.5
1971														1.0	3.1	6.4	7.1	8.0	9.0
1972															1.9	5.4	5.9	7.3	8.2
1973																5.7	5.5	7.0	8.1
1974																	4.9	6.2	9.6
1975																		4.5	6.2
1976																			4.6

¹ Parentheses () indicate actual loads greater than estimated loads, an underestimate. Percent deviation = $\frac{\text{Projected load} - \text{Actual load}}{\text{Projected load}}$

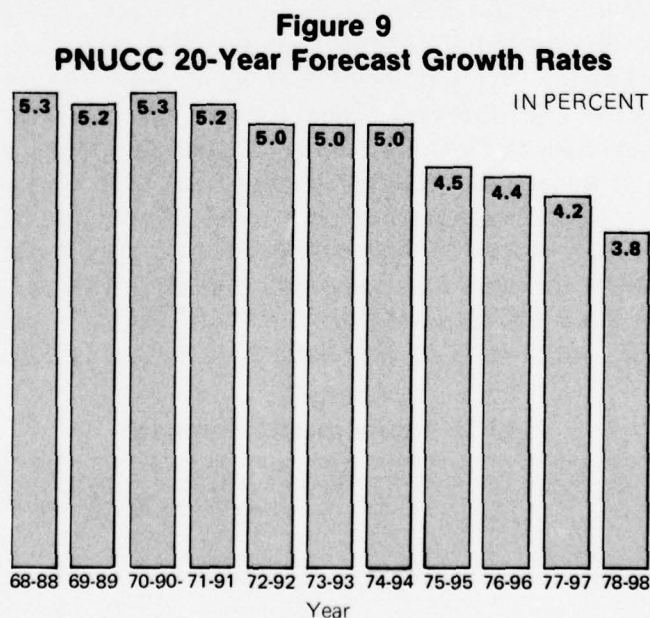
NOTE: Data prior to 1963 is Critical Period Average. Data 1963 through 1977 is a 12-month Average. Minimum temperatures of record occurred at a number of weather stations in the Pacific Northwest during December 1968. Estimates and actuals include U.S. Bureau of Reclamation South Idaho commencing in 1965.

Source: Bonneville Power Administration Requirements Section.

Electricity demand from 1973 to 1977 was overestimated by an average 7.85 percent. In 1973, a critical power shortage due to lack of water and the Arab oil embargo led to a crisis-induced conservation program throughout the region. About the same time, Pacific Northwest utilities began to increase their rates to pay for the higher cost thermal power plants they were building. These events, followed by the 1974-75 regional economic recession, all led to lower electricity consumption than had been projected.

Long-range, price-induced conservation combined with more efficient production and transmission technology partly account for declining West Group forecasts in recent years. Twenty-year forecasts made from 1968 through 1974 showed growth rates of 5.0 to 5.3 percent as shown in Figure 9. Forecasts produced in 1975 and 1976 (a period of rapidly rising electricity rates) were significantly lower, and the latest forecast (1978 to 1998) projects the lowest growth rate on record — 3.8 percent per year. A difference of one percent in annual growth rates compounded over 20 years is equal to about four 1,250-MW nuclear power plants costing over a billion dollars each.

In general, West Group forecasts tended to underestimate actual electricity demands until the mid-1960's, and overestimate them after that. Unfortunately, there are no other forecasts to compare with the 1958-1977 "track record" of West Group forecast accuracy. However, except for the 1973-1974 rate increases, the magnitude, timing and impact of the events which led to these underestimates and overestimates (bad weather, water shortage, embargo, recession) probably could not have been accurately predicted by any forecasting technique.



Source: "Review of Power Planning in the Pacific Northwest", Power Planning Committee, Pacific Northwest River Basins Commission

PNUCC/ECONOMETRIC FORECAST

Recognizing the limitations of a trend forecast of electricity demand and in the interest of exploring all possible means of improving the regional forecast, PNUCC in 1976 commissioned National Economic Research Associates (NERA), a consulting firm, to develop a regional econometric load forecasting model. In 1977, the PNUCC Model Review Subcommittee made some minor changes to the model, updated the base year data, adjusted all inputs to represent the West Group area, and revised the input selection process. Load forecasts made with this model are used to test the reasonableness of the West Group forecast. If the West Group forecast falls between the low and high forecast of the PNUCC/Econometric model, the West Group forecast is assumed to be reasonable. Readers interested in the details of the model are referred to the PNUCC publication "Econometric Model, Electric Sales Forecast for the West Group area," published in February 1978.

FORECAST METHOD AND RESULTS

Like any econometric model, the PNUCC/Econometric model uses historical data to relate electricity demand to the factors that influence it and then forecasts electricity demand using these relationships. The demand model is also *linked* to a supply model. This permits the determination of an equilibrium price of electricity that results from balancing the supply and demand for electricity. The ideas of *linked* models and *equilibrium* prices are discussed more fully in the NEPP forecast. The PNUCC model is unique in how some of the inputs of the model were selected for the 1978 forecast. Thirty-seven utility and non-utility people met and proposed future growth rates for seven major demand-influencing factors: population, persons per household, real income per capita, solar heating, saturation and use of electric cars, natural gas prices, and fuel oil prices. Conservation has since been added to this list and will be used in making the 1979 forecast. Each person estimated a separate most-probable growth rate for each of these factors. These estimates were fed into a computer which drew randomly from the estimates, put them in the model, and derived one possible load forecast. The process was repeated 500 times in developing 500 possible forecasts. From these, a mean (average) forecast and a 90 percent confidence band were determined and compared with the West Group forecast. A 90 percent confidence band means that 90 percent of the forecasts, or 450 of them, fell between the low and high forecasts. Growth rates for the 1978 PNUCC/Econometric forecast are compared with the West Group forecast in Table 7. Although the PNUCC/Econometric and PNUCC/West Group forecasts covered slightly different 11- and 20-year periods, both West Group forecast growth

Table 7
PNUCC/Econometric Forecast

		Lower Limit (% per year)	Mean (% per year)	Upper Limit (% per year)
1976 to 1987	(11-year forecast)	4.11	4.84	5.52
1976 to 1996	(20-year forecast)	3.47	4.55	5.46
vs.				
West Group Forecast	(11-year forecast)	4.21		
West Group Forecast	(20-year forecast)	3.80		

rates fell within the PNUCC/Econometric forecast upper and lower limits. Therefore, the 1978 West Group forecast was assumed to be reasonable.

SUPPLY AND DEMAND COMPARISON

The PNUCC/Econometric load forecast and the PNUCC/West Group resource forecast are compared in Figure 10. The resource, or electricity supply, values are based on critical water conditions and the present generating plant construction schedule. Electricity exports have been subtracted from the supply figures. By 1995, power deficits are projected to range from 6,200 to 16,600 MW (equivalent to 8 to 20 nuclear plants) if none of the proposed thermal plants listed in Table 2 is built. Under this no-build assumption, the mean (or most likely) demand forecast shows a power deficit occurring almost every year from 1980 through 1995. Even if all the proposed thermal plants are built, there would still be deficits in 1995 ranging from 1,600 to 12,000 MW (2 to 15 nuclear plants).

EVALUATION OF PNUCC/ECONOMETRIC FORECAST

The PNUCC/Econometric forecast is made with an econometric model which specifies the demand-influencing economic and demographic factors used in the forecast, states the projected direction and rate of change in these factors in the future, and then quantifies the effect these changes will have on future electricity demand. The model also provides separate forecasts for the residential, commercial, and industrial sectors. In addition, the forecast is *appropriate for evaluating* the reasonableness of the West Group forecast. Since the model was developed using data for the West Group area, the forecast can be directly compared with the PNUCC/West Group forecast because they cover the same geographical area. The PNUCC/Econometric forecast should be interpreted in light of the limitations of any econometric model which were discussed earlier. The wide range between the upper and lower forecasts in 1995 (about 10,000 MW) demonstrates the uncertainties in making long-range electricity demand forecasts.

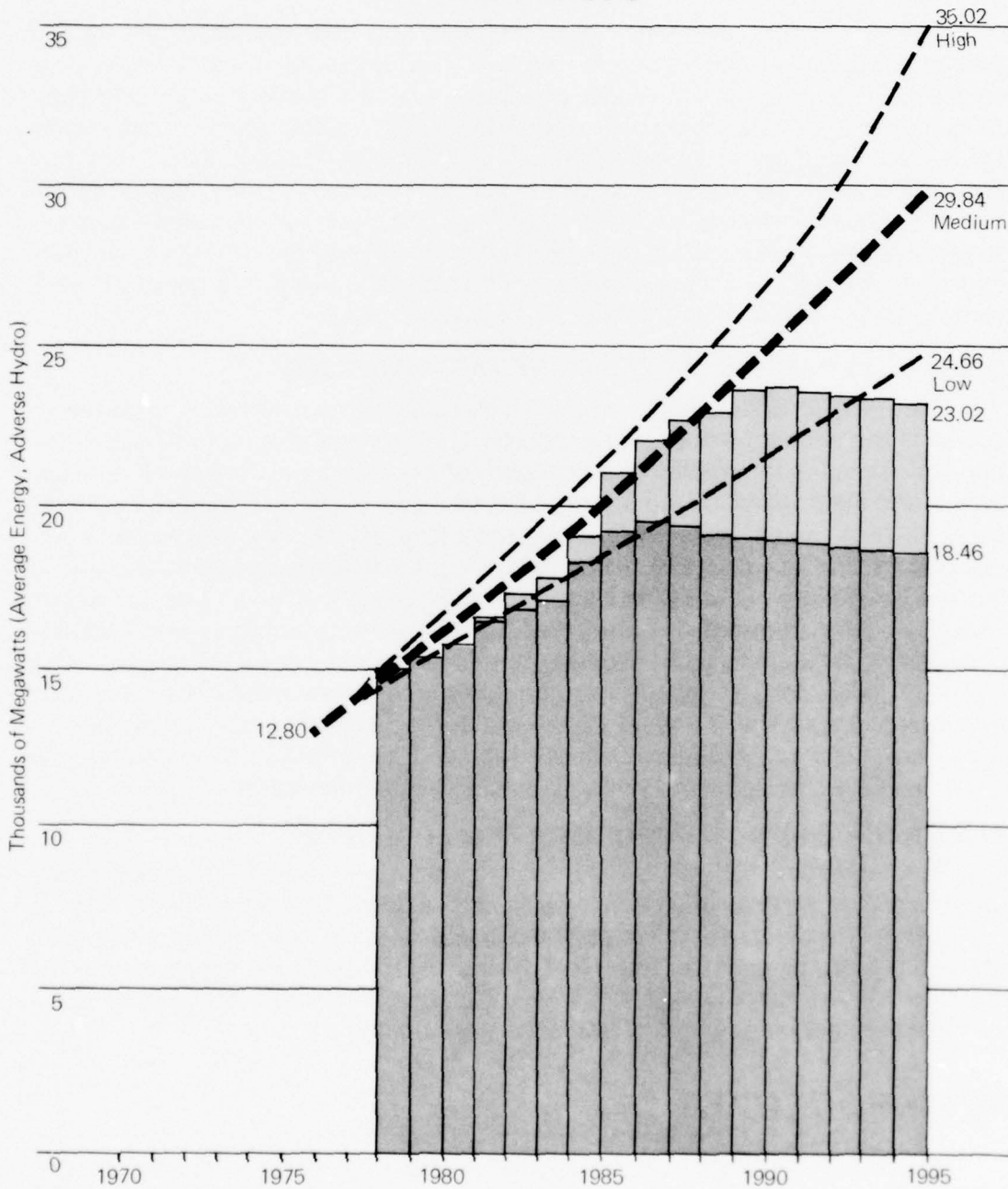
ACCURACY OF PNUCC/ECONOMETRIC FORECAST



The base year of the PNUCC/Econometric forecast was 1976, so electricity demand was actually estimated from 1977 through 1996. Therefore, 1977 is the only year for which projected demand can be compared with actual demand. Since 1977 electricity demand data for the West Group area was not available when this brochure was prepared, and a single year's comparison would not provide useful information on accuracy, no comparisons were made.

NEPP FORECAST

The Northwest Energy Policy Project, a 12-volume study completed in February 1978, provides a broad assessment of energy issues and policy options for the Pacific Northwest. One of the 12 reports, "Energy Demand Modeling and Forecasting," describes the NEPP econometric model and its forecasts. The NEPP model provides separate demand forecasts for all major fuels (electricity, natural gas, petroleum, coal, and wood), each consuming sector (residential, commercial,

Figure 10
PNUCC/Econometric Forecast
Demand vs Supply



Supply
 Proposed thermal plants
 Existing power plants or plants under construction
 Source: PNUCC

industrial, transportation, and irrigation), each Pacific Northwest state (Idaho, Oregon, Washington and combined forecasts for the whole region), and for five-year intervals until the year 2000. Forecasts were made under three energy growth scenarios — high, medium, and low.

FORECAST METHOD AND RESULTS

The NEPP forecast is made with an econometric model and an underlying set of assumptions for each energy growth scenario. Each low, medium, and high forecast depends on the assumed behavior of such demand-influencing factors as energy prices, population, employment, income, labor productivity, and persons per household. Altogether, some 850 different demand-influencing factors were used in making forecasts for all the major fuels. According to the NEPP study, the demand for natural gas and petroleum products in the Pacific Northwest is expected to have very little effect on regional oil and gas prices. However, demand for electricity will have a very large effect on regional electricity prices, and electricity prices will have a very large effect on demand. To represent this interaction, the NEPP electricity demand model was linked with a corresponding electricity supply model. The demand model indicated how much electricity was needed under each scenario, and the supply model provided electricity price projections based on the costs (extraction, generation, transmission, etc.) of meeting the need. The supply prices were then fed back into the demand model to interact with electricity demand. After a back and forth equilibrating process, the two models produced forecasts of electricity demand that were in balance with electricity supply and with the electricity prices appropriate for meeting those levels of demand.

The NEPP forecast anticipates a significant amount of voluntary energy conservation primarily in response to projected higher energy prices. The 1976 NEPP forecast showed the following growth rates for electricity and total energy in the Pacific Northwest. If new state and local energy conservation policies are adopted and successful, energy growth rates would be expected to be still lower than those shown in the NEPP forecast.

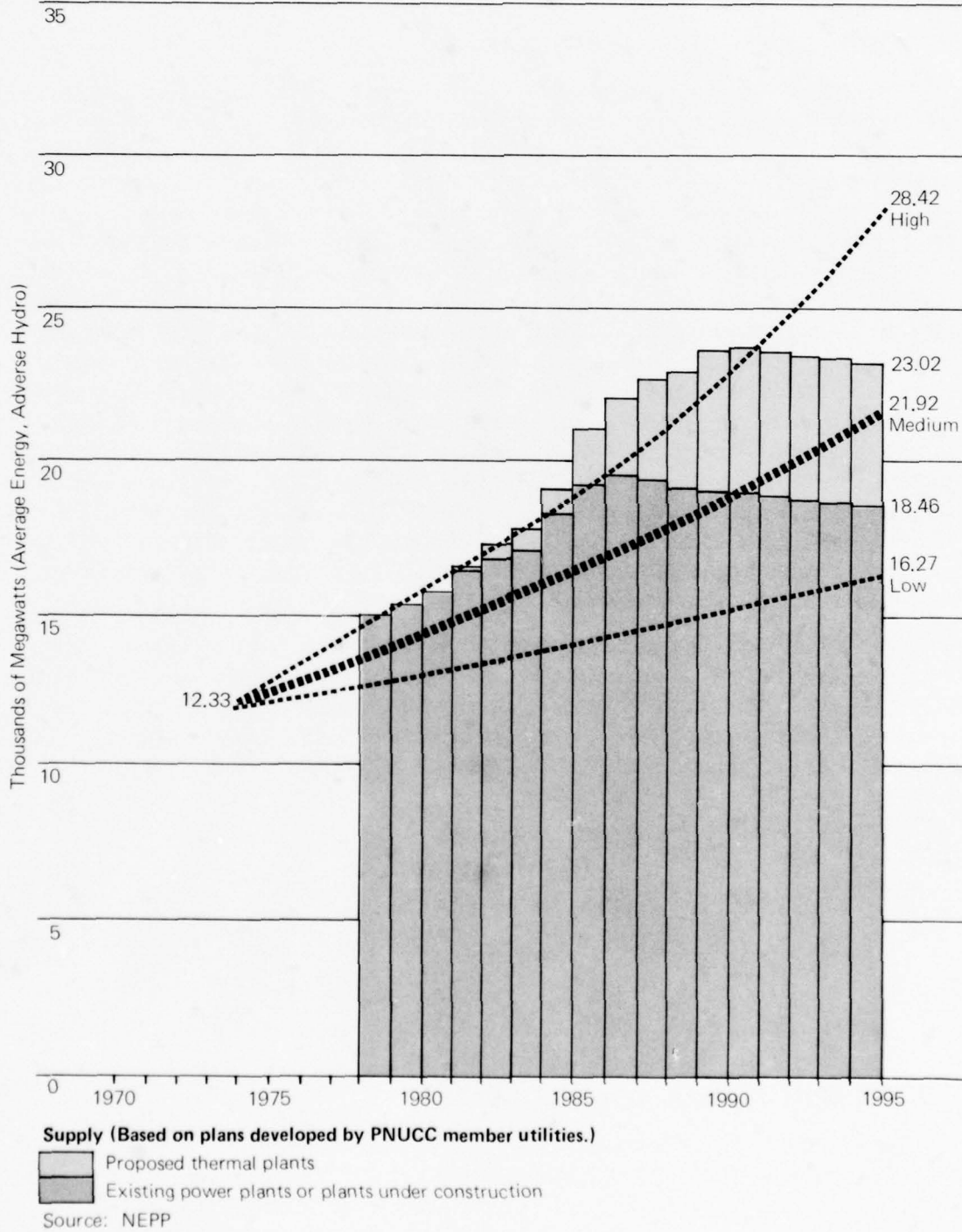
Table 8
NEPP Forecast

	Low Growth (% per year)	Medium Growth (% per year)	High Growth (% per year)
Total Energy	.90	2.62	4.56
Electricity	1.43	2.93	4.38

SUPPLY AND DEMAND COMPARISON

NEPP electricity demand forecasts are compared with projected electricity supply (using the PNUCC/West Group supply forecast as we have in the previous comparisons) on the graph in Figure 11. The PNUCC/West Group electricity supply forecast is based on critical water conditions and the present thermal plant

Figure 11
NEPP Forecast
Demand vs Supply



construction schedule. Electricity exports have been subtracted from supply. The medium and high growth scenarios show electric power deficits in 1995 ranging from 3,500 to 10,000 MW (4 to 12 nuclear plants) if none of the proposed thermal plants listed in Table 2 is built. If all these proposed plants are built, only the high growth scenario shows a 1995 power deficit — 5,400 MW (7 nuclear plants). The low growth forecast does not show any power deficits in 1995, either with or without the proposed thermal plants. Comparing NEPP demand forecast with the NEPP supply forecast would not show any surplus or deficit of electricity, since the models assume that supply will always increase to match demand, or demand will always decrease to match supply.

EVALUATION OF NEPP FORECAST

The NEPP econometric model is sophisticated and detailed, with all the inherent advantages and disadvantages of econometric models described earlier in this brochure. The model focuses on the factors that influence electricity demand, and explicitly states the assumptions used to make the forecast. The model is capable of making a variety of energy demand projections, depending on which assumptions are used, so it is useful for analyzing a variety of energy policies and presenting different growth scenarios.

The NEPP model forecasts much lower annual electricity demand growth rates than those previously experienced in the Pacific Northwest, 2.93 percent per year under the medium growth scenario, compared with 5.94 percent per year which actually occurred from 1964 to 1974. NEPP attributes a large degree of this demand decline to rising electricity prices. During the 1964-1974 period, electricity prices (corrected for inflation) fell by 4.3 percent per year. The NEPP medium growth scenario projects electricity prices will increase 2.34 percent per year on top of a projected 4 to 5 percent inflation rate. These higher prices are attributed to the high cost of thermal power plants scheduled for construction in the Pacific Northwest.

The NEPP high and low forecasts of electricity demand in 1995 are over 12,000 MW apart, equivalent to about fifteen 1,250-MW nuclear plants operating at 65 percent of capacity. A difference of this magnitude suggests several important aspects of the model. The model is in an early experimental stage of development and should not be relied upon uncritically. It is intended to supplement, not replace, other forecasting methods. The model is sensitive to different assumptions about demand-influencing factors, especially future electricity prices. Most observers expect electricity prices in the Northwest to go up in the future, and expect electricity demand to respond by increasing at a slower pace than in the past. However, if consumer response to higher prices is less dramatic or slower than the model assumes, the NEPP electricity demand growth estimates will be underestimated. Ongoing work on the NEPP model includes updating the data base of the model from 1974 — a year when regionally electricity demand was abnormally low — to 1976. Preliminary indications are that just revising the data base will increase electricity demand growth rates (in the medium growth scenario) from 2.93 percent per year to about 3.2 percent per year.

ACCURACY OF NEPP FORECAST

The NEPP load forecasting model is designed to explain fluctuations in electricity demand over an extended period of time. Projections of the demand-influencing factors reflect this philosophy and do not incorporate the short-run business cycles needed to forecast short-run electricity demand. The following comparison of NEPP projected loads with actual loads should be evaluated with these precautions in mind.

Table 9
Actual vs Projected Electricity Demand
NEPP Forecast — Pacific Northwest

Year	PNW Actual Demand ¹	Projected Demand (Avg MW)					
		Low	Percent Deviation ²	Medium	Percent Deviation	High	Percent Deviation
1974	12,134	--	Base Yr	--	Base Yr	--	Base Yr
1975	12,325	12,557	1.8	12,664	2.7	12,752	3.3
1976	13,218	12,789	-3.4	13,008	-1.6	13,189	-0.2

¹Source: Historical Sales Data in The Pacific Northwest, Bonneville Power Administration.

²Percent Deviation = $\frac{\text{Projected} - \text{Actual}}{\text{Projected}}$

WSU FORECAST

In 1975, the Washington State University Environmental Research Center published "Energy Projections for the Pacific Northwest," the first regional electricity demand forecast that could be compared with (or used as an alternative to) the PNUCC/West Group forecast. The WSU model provides separate forecasts for four major fuels (electricity, natural gas, petroleum, coal), four consuming sectors (residential, commercial, industrial, extractive), for each Northwest state (Idaho, Oregon, Washington, and a combined forecast for the entire region), and for the years 1980, 1990, and 2000.

FORECAST METHOD AND RESULTS

The WSU forecast uses an end-use model with each sector's electricity demand projected using the quantity of electricity consumed by each end-use multiplied by a projected value of that end-use. Population growth was the dominant factor in all sectors, so the WSU model uses two population growth-rate forecasts. One assumes that the birth rate will continue as it has in the past (Department of Commerce, Series C), while the other assumes zero population growth (Department of Commerce, Series E). An initial electricity demand forecast was determined for each population growth rate for each state and the region.

This initial gross (no price response) electricity demand forecast was then adjusted to account for the expected electricity price increases over the next 25 years. Using price elasticity coefficients from published econometric studies, the WSU study calculated a "price adjustment factor" for each sector. Multiplying this factor times gross electricity demand gave total actual electricity consumption. Price adjustment factors were made for two scenarios: first, that regional oil prices would fall to the pre-OPEC level of \$7 per barrel (in 1973 dollars), and second, that they would increase slightly to \$11 per barrel (1973 dollars). If the price remained lower, consumers were not expected to respond very much to oil price changes and a low elasticity value was assumed. In the \$11 per barrel case, consumers were expected to react more strongly and a higher elasticity value was assumed.

The WSU study made six regional load forecasts: a high, low, and zero price response for each of the two population growth rates. Table 10 compares the three load forecasts most closely resembling low, medium, and high energy growth scenarios with the WSU forecast of total energy demand.

Table 10
WSU Forecast

	Low¹ (% per year)	Medium² (% per year)	High³ (% per year)
Total Energy (1971 - 2000)	0.82	1.73	2.90
Electricity (1971 - 2000)	1.43	2.01	2.88

¹Series E population projection; high response to \$11 crude.

²Series E population projection; low response to \$7 crude.

³Series C population projection; no price response.

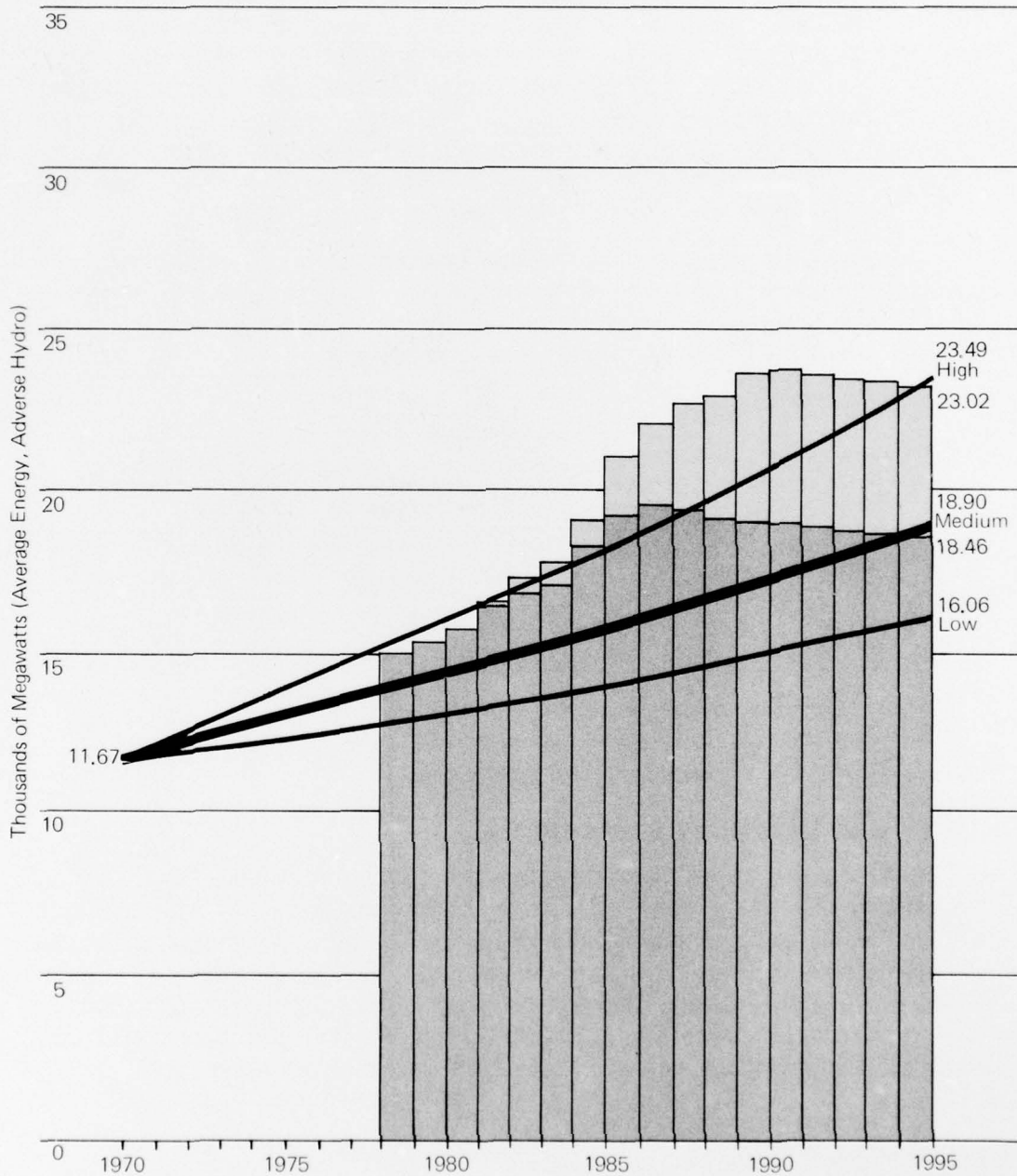
SUPPLY AND DEMAND COMPARISON

The WSU electricity demand forecasts are compared with the PNUCC/West Group supply forecast in Figure 12. The supply forecast is based on critical water conditions and the present thermal plant construction schedule. Electricity exports have been subtracted from the supply. Only the WSU high demand forecast shows a significant 1995 power deficit. If none of the proposed thermal plants listed in Table 2 is built, the deficit is projected at about 5,000 MW (about 6 nuclear plants), while if all plants are built, the deficit drops to about 500 MW (less than the output of one nuclear plant).

EVALUATION OF WSU FORECAST

The WSU forecast is made with an end-use model, and the general advantages and disadvantages of end-use modeling were discussed in the section on forecasting methods. Some of the specific assumptions which must be considered in evaluating the WSU forecast are discussed in this section.

**Figure 12
WSU Forecast
Demand vs Supply**



Supply (Based on plans developed by PNUCC member utilities.)

- Proposed thermal plants
- Existing power plants or plants under construction

Source: Energy Projections For The Pacific Northwest

PRICE ADJUSTMENT FACTORS. The WSU forecast multiplied gross electricity demand by two price adjustment factors to get net electricity demand. The price adjustment factors were based on crude oil prices of \$7 per barrel and \$11 per barrel (1973 dollars). The dockside price of imported crude oil was \$14.57 per barrel in March 1978, which equals \$10.50 per barrel in 1973 dollars. Since this price (which would be even higher at the regional level after adding on transportation and handling costs) significantly exceeds the \$7 per barrel figure used in the WSU forecast, it is clear the \$7 figure is too low to be used in forecasting electricity demand. The assumed \$11 per barrel figure is only 50 cents above today's price (\$10.50 in 1973 dollars). This allows very little room for crude oil price increases over the 22 years (1978-2000) remaining in the WSU forecast period, without invalidating the assumption. With more realistic (higher) estimates of future crude oil prices, the WSU projections of net electricity demand would probably have been much higher.

CONSTANT ENERGY INTENSITY. The WSU forecasts of commercial and industrial energy demand assumed that the ratio of energy consumed per dollar of output (energy intensity) would stay the same from 1971 to the year 2000. This is a valid assumption only if energy costs (adjusted for inflation) also remain constant over time, so this was assumed as well. As we have already seen, energy costs are presently increasing and will continue increasing, prompting business and industry to substitute other inputs (labor and capital, for instance) for higher-cost energy. Since this substitution reduces energy intensity, the assumption of constant energy intensity looks to be invalid.

CONSTANT ENERGY EFFICIENCY. The WSU forecast also assumed constant energy efficiency. The difference between intensity and efficiency is that a change in energy intensity requires a change in energy costs relative to other input costs. A change in energy efficiency requires a technological change and need not be accompanied by a change in energy costs. In other words, the WSU forecast did not take technological changes into account. Over a 29-year forecast period, however, energy saving technological developments should be quite common, as current improvements and federal requirements for future manufactured products have already demonstrated.

NO INTERFUEL SUBSTITUTION. Another major WSU assumption was that there would be no substitutions of one energy source for another. While natural gas use was projected to decrease, electricity was not considered to be a significant substitute. If any substitution were to be made, oil was assumed to be cheaper and would be used instead. Recent large increases in oil prices, and the proposed National Energy Plan's emphasis on conserving gas and oil, (which increase our dependence on electricity) weaken this assumption.

Overall, it is difficult to tell if the cumulative effect of these assumptions were load forecasts that were too high or too low. On balance, however, the WSU forecast provided the first regional load forecast that could be compared with the PNUCC/West Group forecast.

ACCURACY OF WSU FORECAST

Since the base year of the WSU forecast was 1971, a comparison of actual versus projected electricity demand can be made from 1972 through 1976. This is done in Table 11 where the projected demand figures were based on the WSU load growth estimates between 1971 and 1980. It should be emphasized that actual demand in the 1972-1976 period was lower than normal due to severe water conditions, rising energy prices, and a regional economic recession.

Table 11
Actual vs Projected Electricity Demand
WSU Forecast — Pacific Northwest

Year	Actual Demand ¹	Projected Demand (Avg MW)					
		Low	Deviation ²	Medium	Deviation	High	Deviation
1972	11,945	11,877	-1%	11,978	0%	12,111	1%
1973	12,300	12,045	-2%	12,279	0%	12,546	2%
1974	12,134	12,245	1%	12,613	4%	12,981	7%
1975	12,325	12,446	1%	12,914	5%	13,450	8%
1976	13,218	12,613	-5%	13,249	0%	13,952	5%

¹Source: Historical Sales Data in the Pacific Northwest, Bonneville Power Administration.

²Percent Deviation = $\frac{\text{Projected} - \text{Actual}}{\text{Projected}}$

NRDC FORECAST

In 1977, the National Resources Defense Council (NRDC) in Palo Alto, California published the report "Choosing An Electrical Energy Future For The Pacific Northwest: An Alternative Scenario." Unlike the four previous forecasts, the NRDC forecast was explicitly conservation oriented. The objective of the study was to show how much electricity would be needed in the West Group area in 1995 under two assumed conditions:

- Most of the waste of electricity is eliminated
- No thermal plants are built, except those already approved or under construction.

The forecast considered residential, commercial, industrial, and agricultural electricity use from 1975 to 1995.

FORECAST METHOD AND RESULTS

The NRDC forecast, an end-use analysis, relied heavily on published studies, especially a conservation study done for Bonneville Power Administration by the consulting firm of Skidmore, Owings, and Merrill (SOM). Future regional energy policies were also an integral part of the forecast, but since these policies could not always be predicted, they were explicitly assumed. Therefore, the NRDC forecast

was also based on a multitude of assumptions. The forecast showed the following growth rate for electricity demand in the West Group area.

Table 12
NRDC Forecast

1975 to 1985: 2.41 percent per year
1985 to 1995: -0.95 percent per year

The NRDC compared its electricity demand forecast with the PNUCC/West Group load forecast, stating that if NRDC's assumed conservation measures were adopted, regional power demand for 1995 could be reduced by 58 percent below that projected by the West Group forecast. NRDC estimated a 42 percent reduction in residential use, 63 percent in commercial use, 71 percent in industrial use, and 25 percent in agricultural use. The sources of these savings, as well as some of the assumptions that led to the savings, are highlighted below.

RESIDENTIAL. To estimate potential conservation in homes, the NRDC study assumed implementation of SOM "Strategy 6," which called for significant mandatory conservation measures such as storm windows; insulation in walls, ceilings, and floors; and weatherstripping. Other important NRDC assumptions were:

- Homes in 1995 would use electricity 45 to 55 percent more efficiently
- 51 percent of post-1975 housing units still standing in 1995 would be multiple family units (compared to only 27 percent in 1975)
- 95 percent of all post-1975 homes would use electric heat
- Heat pumps, solar collectors, and "total energy systems" would reduce electricity required for space heating by 6.8 percent.

Implementing these and other conservation measures and other assumptions produced the NRDC projection of a 42 percent reduction in residential electricity demand by 1995.

COMMERCIAL. Electricity demand in the commercial sector was forecasted approximately the same way as residential demand. To forecast commercial space heating requirements (commercial floor space was used as a proxy), NRDC again assumed "Strategy 6" mandatory conservation measures such as heat pumps, semiautomatic thermostats, and reduced glass area and lighting levels. Solar systems and "total energy systems" were assumed to produce 10 percent of commercial heating needs by 1995. Because of the large potential savings available in office buildings assuming mandatory conservation measures, NRDC projected a 63 percent reduction in commercial load by 1995.

INDUSTRIAL. One-half of NRDC's total electricity savings were made in the industrial sector. The savings resulted from increased efficiency, a shift away from industries requiring large amounts of electricity (NRDC assumed that 9 of the Northwest's 11 aluminum plants would be shut down by 1995), and by having industries generate more of their own power. Industrial electricity demand in 1995

was projected to be 10,430 average megawatts, or 71 percent below the PNUCC/West Group forecast. Part of this (3,075 average megawatts) was due to a decrease of the aluminum industry, but the remaining 7,365 megawatts was not accounted for. As a result, industrial sector savings seemed to depend mainly on the NRDC assertion that PNUCC overforecasted industrial load, rather than being dependent on assumed increases in efficiency.

AGRICULTURE. NRDC considered irrigation as the only agricultural use of electricity, and made these assumptions:

- By 1995 solar and wind power on farms would provide 10 percent of all electricity required for irrigation
- Electricity use per acre would grow 5.73 percent per year from 1968 to 1980, but only at 1.70 percent per year through 1995.

Because of these two assumptions, agricultural electricity demand was projected to be about 25 percent less than that shown by PNUCC. The agricultural sector accounts for only 3 percent of total regional load, so potential savings in this sector have relatively small impact.

SUPPLY AND DEMAND COMPARISON

The NRDC electricity demand forecast is compared with the PNUCC/West Group supply forecast in Figure 13. If all of NRDC's mandatory conservation measures were implemented and observed by all electricity users, the Pacific Northwest would experience a power surplus of about 5,000 MW in 1985, increasing to about 8,600 MW in 1995 if all the proposed thermo plants are built and a surplus of 4,100 MW if none of the plants is built.

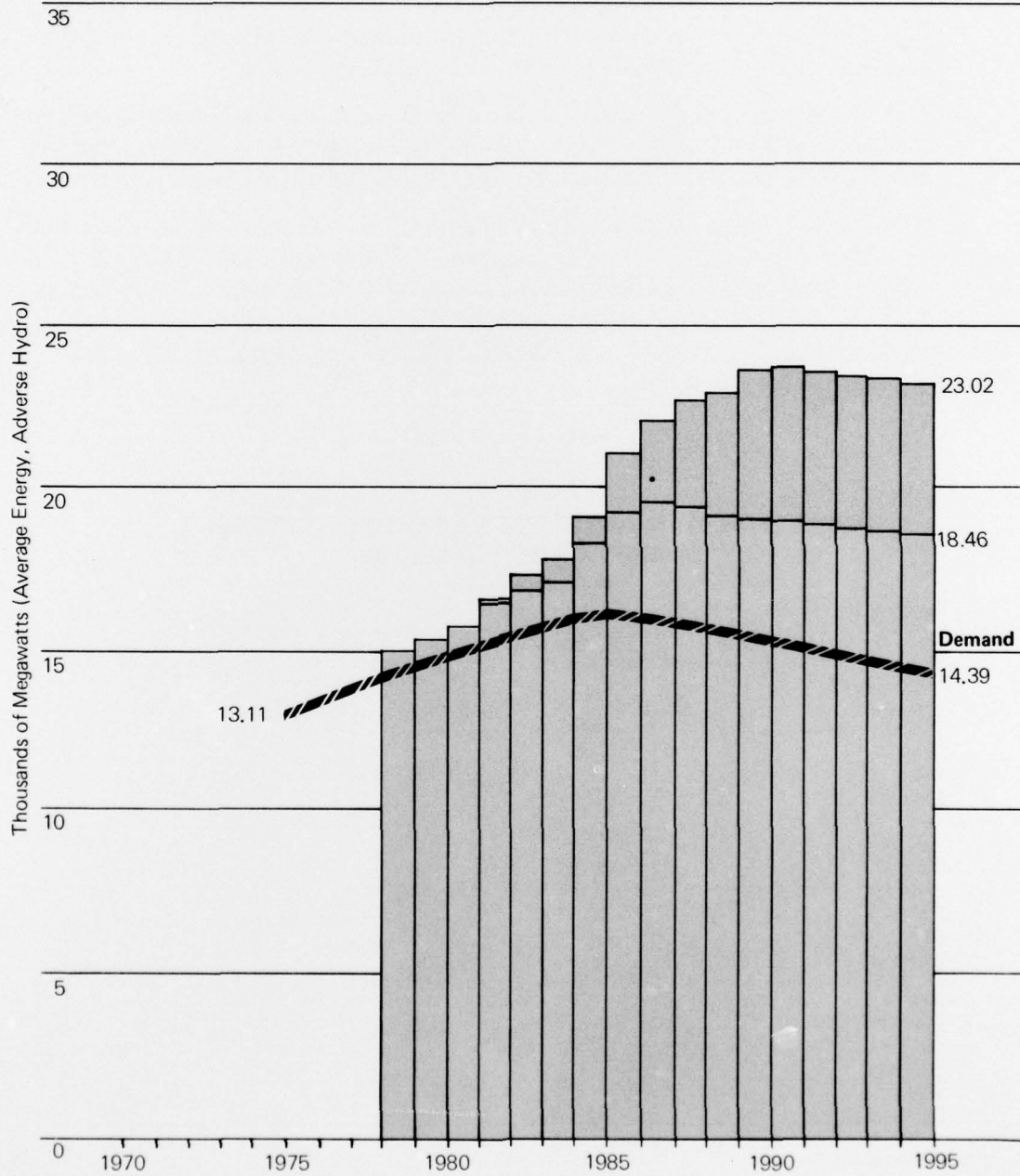
EVALUATION OF NRDC FORECAST

The savings of electricity estimated by NRDC are potential savings. Not only are they based on an assumption of significant mandatory conservation measures (SOM "Strategy 6"), but on full compliance in all sectors with these measures. The SOM conservation study assumed every state legislature in the Pacific Northwest would adopt conservation standards by 1977. So far, no state has. Each year away from 1977 without legislative action decreases the savings which might be achieved by 1995, both in the SOM study and the NRDC study. There is also evidence that NRDC overestimated existing waste of electricity because some of the improvements NRDC assumed would occur in the future have already been made. Overall, many NRDC assumptions appear unrealistic, but the study is useful in providing a scenario which probably reflects the lowest limit of electricity demand growth in the Pacific Northwest.

ACCURACY OF NRDC FORECAST

The base year of the NRDC forecast is 1975, so a comparison of actual versus projected demand could be made only for 1976. Electricity demand data for 1977 are not yet published. Since a one-year comparison would not provide any useful information on accuracy, no comparison was made.

**Figure 13
NRDC Forecast
Demand vs Supply**



Supply (Based on plans developed by PNUCC member utilities.)

- Proposed thermal plants
- Existing power plants or plants under construction

Source: NRDC

COMPARISON OF DEMAND FORECASTS AND INPUT ASSUMPTIONS

The medium growth projections of electricity demand produced by the five referenced studies to date (PNUCC/West Group, PNUCC/Econometric, NEPP, WSU, and NRDC) are compared with the PNUCC/West Group supply forecast in Figure 14. There are two basic reasons for their divergent results:

- The differences in the three forecasting methods (trend analysis, end-use analysis, and econometrics) which were discussed earlier.
- The differences in the basic assumptions used in the forecasts either explicitly as demand-influencing factors, or implicitly as subjective factors which prompted the forecasters to modify historical growth rates or patterns.

The most important demand-influencing factors are population, personal income, number of households, and energy prices. Table 13 lists the historical and projected growth rates of these factors for the forecasts that specified them. Tables 14 through 20 list the major input assumptions used in each forecast. Input assumptions cannot be listed for the PNUCC/West Group load forecast because they are not explicitly stated.

Table 13
Comparison of Historical and Projected Growth Rates
Medium Growth Scenarios
 (Percent per year)

Independent Variables	Historical Growth Rate (1964-1974)	Projected Growth Rate		
		PNUCC ¹ (1976-1996)	NEPP ² (1974-2000)	WSU (1971-2000)
Population	1.70	1.38	1.3	0.56
Households	2.55	2.15	1.9	NA
Per Capita Income	4.30	1.97	2.6	3.02
Total Personal Income	5.27	3.38	3.9	3.59
Electricity Prices	-4.31			
Residential		0.61	1.8	0.84
Commercial		1.77	1.8	0.77
Industrial		1.91	4.85	1.71
Petroleum Prices	1.53			
Residential		NA	2.53	0.71
Commercial		3.15	2.58	NA
Industrial		4.81 ³	4.6	1.51
Natural Gas Prices	-1.17			
Residential		3.93	2.98	1.55
Commercial		4.83	2.98	1.90
Industrial		4.81 ³	5.13	3.89

¹PNUCC Econometric.

²The NEPP forecasting model has different energy prices and growth rates entering the model for the three Northwest States. The price increases for the State of Washington were chosen for expositional purposes.

³Industrial Fuel Index.

NA – Not Available, or Not Applicable.

Figure 14
Comparison of Demand Forecasts
Medium Growth Scenarios

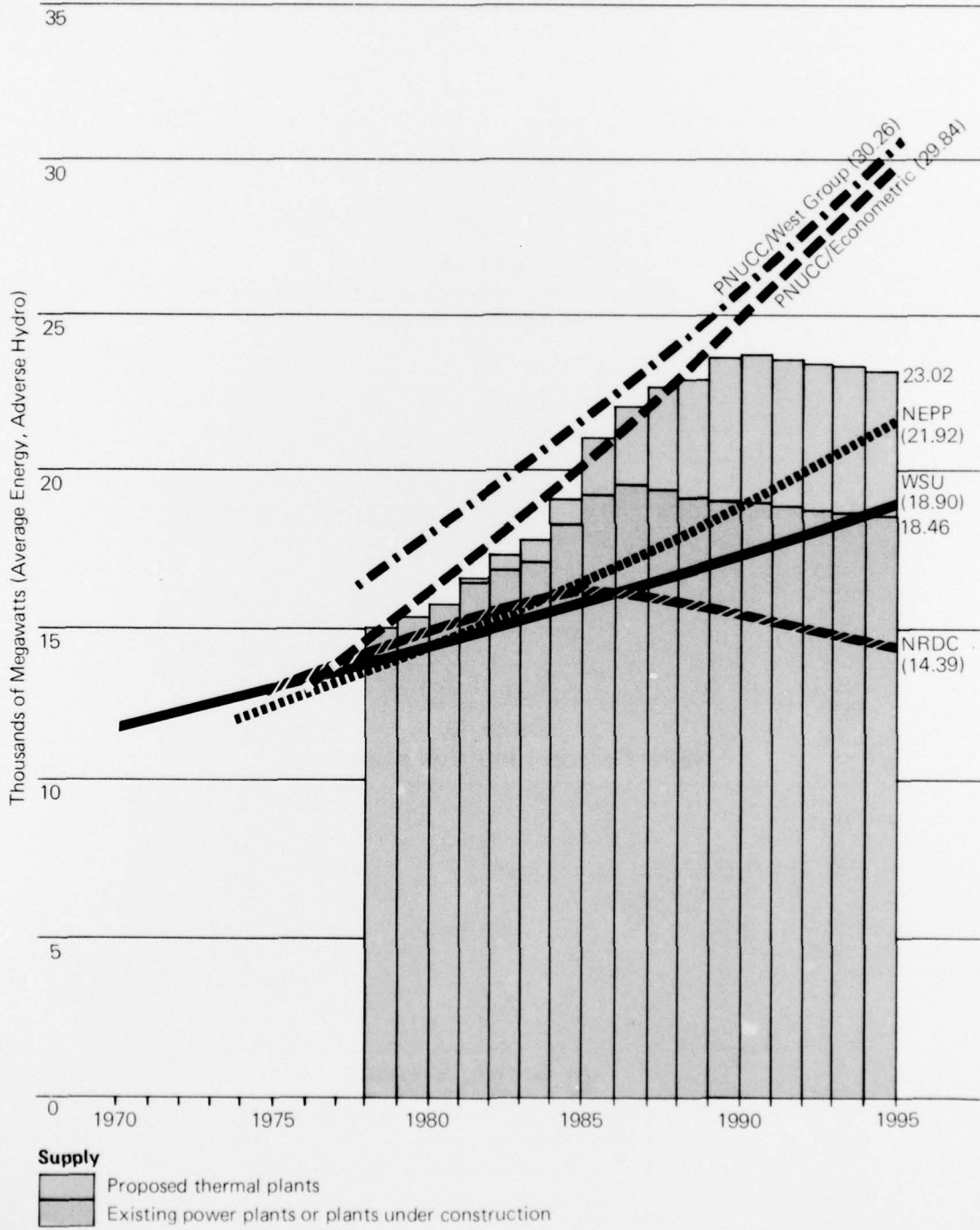


Table 14
PNUCC/West Group Forecast Input Assumptions
Medium Growth Scenario

Forecast:	PNUCC/West Group		
Sponsor:	Pacific Northwest Utilities Conference Committee		
Area of Forecast:	West Group Area		
Methodology:	Predominantly trending		
Forecast Results:	Electricity		
(% per year)	1978-1979 to 1988-1989	4.21	
	1978-1979 to 1997-1998	3.80	
Assumptions:	Not explicitly stated.		

Table 15
PNUCC/Econometric Forecast Input Assumptions
Medium Growth Scenario

Forecast:	PNUCC/Econometric			
Sponsor:	Pacific Northwest Utilities Conference Committee			
Area of Forecast:	West Group Area			
Methodology:	Econometric			
Forecast Results:	Electricity	Low	Medium	High
(% per year)	1976-1987	4.11	4.84	5.52
	1976-1996	3.47	4.55	5.46
Assumptions:	<ul style="list-style-type: none"> ● See Table 13. ● Aluminum companies use "Alcoa" process by 1980. ● Aluminum industry electricity demand based on long term contractual energy agreements with Bonneville Power Administration. 			

Table 16
NEPP Forecast Input Assumptions

Forecast:	NEPP			
Sponsor:	Pacific Northwest Regional Commission			
Area of Forecast:	Pacific Northwest			
Methodology:	Econometric			
Forecast Results:	Electricity	Low	Medium	High
(% per year)	1974-2000	1.43	2.93	4.38
	Energy			
	1974-2000	0.90	2.62	4.56

Low Growth Scenario

- Assumptions:
- Reclamation of surface mined land with original species and topography.
 - Present Federal nuclear licensing procedures continue.
 - Major coal transportation bottlenecks (relative to medium growth scenario).

Table 16 (Continued)

Assumptions:
(Continued)

- Current EPA air quality regulations continue.
- No additional nuclear fuel reprocessing facilities.
- Severe restrictions on electricity generation at coal mines.
- No new major discoveries of oil or gas in Alaska.
- Regulation of interstate natural gas continued.
- Maintenance of OPEC cartel with periodic oil embargoes.
- Foreign oil prices gradually increase to \$18 per barrel (1975 dollars).
- Canadian gas imports lower than medium growth case from 1990-2000.
- Domestic crude oil price rises gradually as per current 39-month plan and then deregulated.
- Federal legislation mandating additional conservation measures (not reflected in demand-supply forecasts).
- Federal energy good taxes increase faster than inflation rate (not reflected in demand-supply forecasts).
- 50 percent cut in Federal sales to Bonneville Power Administration industrial customers as contracts expire.
- No Alumax plant.
- Increased trade barriers. No West Coast ports expand.
- No commercial development of electric cars (not reflected in demand-supply forecasts).
- Increased voluntary conservation efforts.
- 7 percent unemployment through year 2000.
- 4 percent inflation until 1980; 2-3 percent thereafter.
- No significant increase in Alaskan economy and associated Pacific Northwest support activities.
- Gross National Product (1975 dollars) grows 2.5 percent per year through year 2000.
- Gross Regional Product (1975 dollars) grows 2.3 percent per year through year 2000.
- Pacific Northwest population growth of 0.4 percent per year through year 2000.

Medium Growth Scenario

Assumptions:

- See Table 13.
- Reclamation of surface-mined land.
- Present Federal nuclear licensing procedures continue.
- Adequate regional coal transportation facilities.
- Current EPA air quality regulations continue.
- Nuclear fuel reprocessing by 1985.
- Limited restrictions on electricity generation at coal mines.
- New offshore discoveries of oil and gas in Alaska.
- Interstate gas regulations phased out by 1985.

Table 16 (Continued)

Assumptions:
(Continued)

- Maintenance of OPEC cartel through 2000.
- Foreign oil prices increase 0.5 percent/year to 2000 (1975 dollars).
- Canadian gas delivered until 1989, reduced thereafter.
- Domestic crude oil equals world price from 1985 on.
- Mandatory parts of 1975 Energy Conservation Act met on time.
- Federal energy taxes increase at inflation rate.
- Continued sales to existing Bonneville Power Administration industrial customers.
- No Alumax plant.
- 2-5 percent saturation of electric cars by 2000.
- Present voluntary conservation efforts continue.
- 5 percent unemployment rate through 2000.
- 4-5 percent inflation rate through 2000.
- Gross National Product (1975 dollars) grows 3.5 percent per year through 2000.
- Gross Regional Product (1975 dollars) grows 3.9 percent per year through 2000.
- Increase in Alaskan economy and support activities in Pacific Northwest.

High Growth Scenario

Assumptions:

- Little or no reclamation of surface mined land.
- Current Federal nuclear licensing procedures continue; standard plant design reduces licensing time.
- More than adequate coal transportation facilities, relative to medium growth scenario.
- Air quality regulations relaxed.
- Capability of reprocessing spent fuel higher than medium growth scenario.
- No restrictions on electricity generation at coal mines (not reflected in demand-supply forecasts).
- Major discoveries of offshore oil and gas in Alaska, Oregon, and Washington.
- Breakup of OPEC cartel.
- Foreign oil price drops to \$8 per barrel in 1985 and then increases 0.5 percent per year through 2000 (1975 dollars).
- Domestic crude oil price regulated through year 2000.
- Mandatory parts of 1975 Energy Conservation Act delayed 3-5 years.
- No increase in Federal energy good taxes (not reflected in demand-supply forecasts).
- Continued sales to BPA industrial customers.
- Alumax plant built.
- Rapid increase in international trade; West Coast ports expand by year 2000.

Table 16 (Continued)

- Assumptions:
(Continued)
- 5-10 percent saturation of electric cars by year 2000 (not reflected in demand-supply forecasts).
 - Poor attitude towards energy conservation.
 - Major increase in Alaskan economy and associated Pacific Northwest support activities.
 - 3.5 percent unemployment rate through year 2000.
 - 6-7 percent inflation rate through year 2000.
 - Gross National Product (1975 dollars) grows 4.5 percent per year through year 2000.
 - Gross Regional Product (1975 dollars) grows 5.3 percent per year through year 2000.
 - Pacific Northwest population growth of 2.0 percent per year through year 2000.

Table 17
WSU Forecast Input Assumptions
Medium Growth Scenario

Forecast:	WSU			
Sponsor:	Washington State University			
Area of Forecast:	Pacific Northwest			
Methodology:	End-use			
Forecast Results: (% per year)		Low	Medium	High
	Electricity 1971-2000	1.43	2.01	2.88
	Energy 1971-2000	0.82	1.73	2.90
Assumptions:	<ul style="list-style-type: none"> ● See Table 13. ● Zero population growth. ● Low response to \$7 crude (1973 dollars). ● Maximum crude price of \$11/barrel (1973 dollars). ● Industrial sector <ul style="list-style-type: none"> ● Earnings an accurate proxy for output. ● Constant energy intensity. ● Constant energy efficiency. ● No interfuel substitutions. Possible substitution of oil for gas, but not electricity for gas. ● Constant efficiency of electrical appliances. ● Households become saturated with existing appliances. 			

Table 18
NRDC Forecast Input Assumptions

Forecast:	NRDC	
Sponsor:	National Resources Defense Council	
Area of Forecast:	West Group Area	
Methodology:	End-use	
Forecast Results:	Electricity	
(% per year)	1975-1985	2.41
	1985-1995	-0.95
Assumptions:	<ul style="list-style-type: none"> ● No response to energy prices. ● All conservation measures mandatory. ● Full compliance in all sectors. ● All potential conservation savings achieved. ● Population increases 1.3 percent annually. ● 6.5 percent reduction in space heating requirements, 1975-1995. ● 95 percent of post-1975 homes heated electrically. ● Pre-1975 homes convert to electricity at rate of 1 percent annually. ● 1995 homes 45-55 percent more energy efficient than 1975 homes. ● 51 percent of housing units in 1995 multiple-family versus 27 percent in 1975. ● 12 percent of home water heating by solar power in 1995. ● 10 percent of commercial space heating by solar power in 1995. ● Shift in source of energy for industrial sector from oil to electricity at 0.6 percent annually, 1975-1995. ● 9 of 11 aluminum plants gone by 1995. ● No thermal plants built beyond those already approved or under construction. ● Heat pumps, solar collectors, and total energy systems reduce residential space heating requirements by 6.8 percent. ● Industries generate more of their own power. ● Solar and wind provide 10 percent of farm power by 1995. ● Electricity use per acre grows 5.73 percent per year until 1980 and 1.70 percent per year to 1995. 	

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