BY THE COMPTROLLER GENERAL

Report To The Congress

OF THE UNITED STATES

110627

Electrical Energy Development In The Pacific Southwest

GAO analyzed the Pacific Southwest to see how the Western Area Power Administration, the only Federal power agency in the area, could implement the National Energy Principles of electricity conservation and development of renewable resources, such as solar and wind power.

GAO concluded the Power Administration should act as a lead agency for implementing conservation practices and for commercializing solar and wind technology in its marketing area. This would result in lower overall electricity costs to consumers in the Pacific Southwest.

UNITED STATES GENERAL ACCOUNTING OFFICE

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COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON, D.C. 20548

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To the President of the Senate and the
Speaker of the House of Representatives

This report analyzes electrical energy options for the Pacific Southwest and how the Western Area Power Adminstration could implement options identified in the national energy principles such as electricity conservation and development or renewable resources for meeting the demand.

We are sending copies of this report to the Director, Office of Management and Budget; the Secretary of Energy; the Administrator of Western Area Power Administration; Governors of Pacific Southwest States; and the House and Senate committees and subcommittees having oversight responsibilities for the matters discussed in the report.

Sincerely yours,

Comptroller General
of the United States

Enclosure

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COMPTROLLER GENERAL'S REPORT TO THE CONGRESS

ELECTRICAL ENERGY DEVELOPMENT IN THE PACIFIC SOUTHWEST

D I G E S T

GAO's review was performed as part of its effort to assess past and potential roles for Federal power agencies within their respective geographic regions, using as assessment criteria, the 10 energy principles initially cited in the administration's April 1977 National Energy Plan. This report discusses the role of the Western Area Power Administration and chooses the Pacific Southwest as the area for study.

AZ CA NV

Utility companies in Arizona, California, and Nevada plan to rely heavily on coal, oil, and nuclear energy to provide for their fast-growing power needs through the 1990s. These plans are becoming more uncertain, however, because of (1) the unreliability of oil imports, (2) escalating fuel and plant construction costs, (3) environmental concerns, and (4) long delays in obtaining approval for constructing nuclear powerplants.

Increasingly, the utility companies, the three State governments, and the Federal Government are considering conservation and the development of renewable resources. Arizona, California, and Nevada have indicated that conservation measures could reduce their electrical usage by about 23, 12, and 7 percent, respectively, by 1985. In addition, all three States have recognized that solar power has great potential for development in the area. Wind, geothermal energy, and biomass are other possible sources of renewable energy.

Utility companies, however, have doubts about how much energy can be saved through conservation and how swiftly renewable resources can be developed. Moreover, the only Federal power marketing agency in the area, the Western Area Power Administration, does not have a program to foster

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conservation or develop renewable resources. Its current practice of marketing Federal power at the lowest possible rate for the widest possible use provides customers with some of the lowest priced power in the United States and, as such, does not encourage conservation.

REDUCING RELIANCE ON OIL, GAS, AND NUCLEAR FUEL

GAO analyzed two alternative electrical energy policy sets for the Pacific Southwest as it approaches the year 2000. One set of policies (Scenario I) assumes electricity will continue to be managed as suggested by the States or utility companies; the other set (Scenario II) encourages more aggressive conservation and development of renewable resources.

Scenario I policies, in essence, restate current State utility energy policies. As we near 2000, these policies contemplate heavy reliance on coal and nuclear resources. There would also be efforts to conserve energy and develop minimal amounts of alternative solar and wind resources. Scenario II encourages more aggressive conservation and development of renewable resources. It assumes there will be a conscious effort by the public, private industry, and Government to foster more aggressive energy conservation and develop more alternative renewable sources of energy.

GAO's analysis demonstrated that an aggressive conservation and renewable resource program provides greater benefits in terms of risk, equity, and environmental impact. These benefits could be obtained at a lower cost to the consumer than under the coal and nuclear policies, and without substantial change in current policies at the local, State, Federal and utility levels, and require little change in lifestyle for the general public.

Costs

The total costs of meeting electricity needs in 2000 under Scenario II are estimated at $11.4 billion in supply system costs, and $2.8 billion for additional conservation measures not yet included in Scenario I. In contrast, total electricity supply system costs in Scenario I are estimated to be $20.4 billion.

Scenario II involves more costs for specific conservation measures outside the electricity supply system and for a general effort to maximize the efficient use of electricity. Scenario II also requires more intervention in prices and policies to channel the electricity future of the region toward what is felt to be more consistent with national energy objectives. To do this, Scenario II assumes more involvement by the Western Area Power Administration in furthering conservation and use of alternative energy sources.

Options For Funding Scenario II

3 alternatives

The existing structure as established and chartered is not equipped to generate the money necessary to conceive and implement Scenario II. There are a number of funding alternatives. Under one alternative, the utilities would generate or finance the capital necessary to implement the conservation and renewable resources. The capital outlays could be recouped through the power rates for electrical power. (1)

This alternative would utilize an existing institutional structure and minimize Federal Government involvement. It would spread the cost of the program among the consumers of the region, and the overall cost would be lower than for Scenario I. This alternative might be difficult to achieve, however, since it does not provide a focal point to implement the scenario. Also, the utilities may not be anxious to take the lead in implementing Scenario II because it would reduce their projected growth and reduce their financial base.

Under another funding alternative, the Western Area Power Administration could be granted bonding authority to (1) finance the implementation and adoption of conservation measures and (2) finance and assume responsibility for three-fourths of the solar and wind program. Assuming the Power Administration customers would pay for this program, they would be paying a power rate which would be competitive with utility company customers by the end of the century.

2

This approach would use the Power Administration as a "showcase" to demonstrate the Federal Government's commitment to conservation and renewable resources. It would focus funding and programs under that one agency.

Under a third funding alternative, the Power Administration would carry out the energy programs through annual appropriations from the Congress. This alternative recognizes the likelihood that consumers and business institutions may resist the move toward conservation and development of new technologies. Since appropriations of Federal funds would be within the Federal sector, this alternative, theoretically, would provide for better focusing of effort to meet Scenario II objectives. However, the appropriation process offers no assurance of providing the needed money because of changing priorities, national pressures, and the need for annual approval. In addition, actions to perpetuate the low prices of Federal power and pledge Federal assistance could be viewed as energy subsidies by the national public and would be sought by all regions.

3

RECOMMENDATIONS TO THE CONGRESS

The problems incurred in the development of oil, coal, and nuclear resources make conservation and development of renewable resources attractive (Scenario II). By cooperating with State governments and the utilities, and providing, through the Western Area Power Administration, an example of good electricity management, the Federal Government could help the Southwest and other areas served by Power Administrations meet their energy needs. To accomplish this, the Power Administration will have to be given a broad charter by the Congress. Therefore, GAO recommends that the Congress:

--Relieve the Western Area Power Administration of its charter responsibility for encouraging the widest possible use of electricity at the lowest possible cost and direct it to undertake programs to examine the most appropriate structure of its rates to encourage conservation, consistent with the Public Utility Regulatory Policy Act, and to implement those rates.

--Provide the Power Administration with bonding authority and direct it to act as a lead agency in its marketing area to help finance conservation and the development of solar and wind resources, and allow funds to be repaid through the power revenues.

--Provide the Power Administration with authority to exercise flexibility in power charges. Implementation of programs recommended would result in a gradual increase in the Administration's rates leading to parity with average utility rates prevailing in its marketing area by the year 2000.

--Direct the Power Administration to report yearly to the Congress and the executive branch on its progress toward implementing these recommendations.

In implementing these recommendations, GAO suggests that the Power Administration coordinate with existing programs of the Department of Energy and other Federal agencies, State governments, and the utility companies.

Adoption of these recommendations will likely require restaffing or additional staffing of the Power Administration. Before requesting such staff changes, GAO believes the Power Administration should first look to the Department of Energy's existing resources for maximum technical support.

AGENCY COMMENTS

The Department of Energy believes the report accurately points out that the Western Area Power Administration is not fostering conservation or development of new resources, but questions whether this is a proper role for the Administration. It believes, however, that the Administration could arrive at such a role through an evolutionary process. GAO continues to believe the role outlined in its recommendations for the Western Area Power Administration is a proper one in light of the current energy dilemma and a change in its legislative charter is needed to bring the Administration in-line with the principles of the National Energy Plan. The Department's comments are discussed further in chapter 6. In addition, GAO revised the report, where applicable, to reflect the Department's comments; the recommendations remained basically the same. Copies of the draft of this report were also provided to the Governors of Arizona, California, and Nevada for comment. No comments were received, although inquiries were made concerning the States' comments.

Contents

ABBREVIATIONS

Btu	British thermal unit
DOE	Department of Energy
GAO	General Accounting Office
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
MW	megawatt
MWh	megawatt-hour
NEA	National Energy Act
WAPA	Western Area Power Administration

GLOSSARY

ambient	Conditions in the vicinity.
average cost pricing	1. In an economic context, the dividing of total cost by the number of units sold in the same period to obtain a unit cost and then applying this unit cost directly as a price. 2. In a utility context, the pricing of the service without regard for the structure of the market, to recover those portions of total costs associated with each service in order to make total revenues equal to total costs.
baseload	The minimum load in a power system over a given period of time.
biomass conversion	The process by which plant materials are burned for direct energy use or electrical generation or by which these materials are converted to synthetic natural gas.
blackout	The disconnection of the source of electricity from all the electrical loads in a certain geographical area.
British thermal unit (Btu)	The standard unit for measuring quantity of heat energy in the English system. It is the amount of heat energy necessary to raise the temperature of 1 pound of water 1 degree Fahrenheit (3,412 Btus are equal to 1 kilowatt-hour).

brownout	An intentional reduction of energy loads in an area by the partial reduction of electrical voltages, which results in lights dimming and motor-driven devices slowing down.
capacity	Maximum power output, expressed in kilowatts or megawatts. Equivalent terms: peak capability, peak generation, firm peakload, and carrying capability. In transmission, the maximum load a transmission line is capable of carrying.
capacity factor	The ratio of the average load on a generation resource to its capacity rating during a specified period of time, expressed in percent.
combined cycle	Combination of a steam turbine and a gas turbine in an electrical generation plant.
conservation	Improving the efficiency of energy use; using less energy to produce the same product.
constant dollars	Dollars whose purchasing power is expressed in terms of the monetary values which prevailed in a specified base year after adjusting for the effects of general inflation. Constant dollar values are often obtained using the consumer price index (CPI) to deflate current dollar values, the values (prices) actually quoted in a given year. For example, suppose the 1975 current dollar price of regular gasoline were \$0.60 per gallon. In addition, assume that the CPI for 1975 with 1967 as the base year was 160. The

real price in 1967 constant dollars would equal $0.60/160 x 100, or $0.38. The price of any product in constant dollars is often referred to as the real price.

demand

1. In an economic context, the quantity of a product that can be purchased at a given price at a particular point in time.

2. In a public utility context, the rate at which electric energy is delivered to or by a system, expressed in kilowatts, megawatts, or kilovoltamperes over any designated period.

econometrics

The application of mathematical and statistical methods to the study of economics.

emission

A discharge of pollutants into the atmosphere, usually as a result of burning or the operation of internal combustion engines.

energy

The ability to do work; the average power production over a stated interval of time; expressed in kilowatt-hours, megawatt-hours, average kilowatts, or average megawatts. Equivalent terms: energy capability, average generation, and firm-energy-load-carrying capability.

energy capability

The net average output ability of a generating plant or plants during a specified period, in no case less than a day. Energy capability may be limited by available water supply, plant characteristics, maintenance, or fuel supply.

firm power — Power intended to be available at all times during the period covered by a commitment even under adverse conditions, except for reason of certain uncontrollable forces or service provisions. Equivalent terms: prime power, continuous power, and assured power. Component terms: firm energy, firm capacity, and dependable capacity.

flue gases — Gases usually carbon dioxide, water vapor, oxides of nitrogen, and other trace gases which result from combustion processes.

forced outage — An outage that results from emergency conditions directly associated with a component requiring that the component be taken out of service immediately or as soon as switching operations can be performed.

fossil fuels — Coal, oil, natural gas, and other fuels originating from fossilized geologic deposits and depending on oxidation for release of energy.

fuel cycle — The series of steps involved in supplying fuel for nuclear power reactors. It includes mining, processing, and enriching; the original fabrication of fuel elements; their use in a reactor; chemical processing to recover the fissionable materials remaining in the spent fuel; re-enrichment of the fuel material; and refabrication into fuel elements.

hydrocarbons — Any of a vast family of compounds containing carbon and hydrogen in various combinations, found especially in fossil fuels. Hydrocarbons in the atmosphere resulting from incomplete combustion are a major source of air pollution.

hydroelectric plant	An electric powerplant in which the turbine-generator units are driven by falling water. --A conventional hydroelectric plant is one in which all the power is produced from natural streamflow as regulated by available storage. --A pumped storage hydroelectric plant is one in which power is produced during peakload periods by using water previously pumped from a lower reservoir to an upper reservoir during offpeak periods.
hydropower	A term used to identify a type of generating station or power or energy output in which the prime mover is driven by water power.
industrial energy use	In general, energy use by customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product. A more specific definition is used in chapter 3.
investor-owned utility	A utility which is organized under State laws as a corporation for the purpose of earning a profit for its stockholders.
Kilovolt (kV)	The electromotive unit of force equal to 1,000 volts.
kilowatt (kW)	The electrical unit of power which equals 1,000 watts.
kilowatt-hour (kWh)	A basic unit of electrical energy, which equals 1 kilowatt of power applied for 1 hour.
load	The amount of electric power delivered to a given point on a system.

load factor	The ratio of the average load to the peakload during a specified period of time, expressed in percent.
load growth reserves	A supply of electric power and energy held in reserve for the unanticipated load growth of a utility having limited resources. If such reserves are available when requested, BPA may sell them to qualified utilities under Schedule EC7 (Reserve Power Rate).
load management	Influencing the level and state of the demand for electrical energy so that demand conforms to individual present supply situations and long-run objectives and constraints.
long-run incremental cost pricing	Pricing associated with meeting the cost of customer requirements for additional increments in utility service on a continuing basis, when the utility has fully adjusted its operation and facilities to the most efficient means of meeting the increased total demand. It includes the immediate expenses the utility incurs in taking on new customers, as well as the cost of utility plant and associated costs necessary to provide and maintain utility service.
marginal cost pricing	A system of pricing whereby each additional unit of a product is priced equal to the incremental cost of producing that unit, or charging a price for all units of a product equal to the incremental cost of producing the last unit.
megawatt (MW)	The electrical unit of power which equals 1,000,000 watts or 1,000 kilowatts.
megawatt-hour (MWh)	A basic unit of electrical energy which equals 1 megawatt of power applied for 1 hour.

mill	A monetary unit equaling one-tenth of a cent ($0.001).
municipal utility	A utility owned and operated by a city.
nameplate rating	The full-load continuous rating of a generator under specified conditions as designated by the manufacturer. It is usually indicated on a nameplate attached mechanically to the individual machine or device.
National Energy Act	For the purposes of the report, the National Energy Act (NEA) includes the five acts signed into law on November 9, 1978 (National Energy Conservation Policy Act, Public Utility Regulatory Policy Act of 1978, Powerplant and Industrial Fuel Use Act of 1978, Energy Tax Act of 1978, and Natural Gas Policy Act of 1978).
nitrogen oxides (NOx)	Compounds produced by combustion, particularly when there is an excess of air or when combustion temperatures are very high. Nitrogen oxides are primary air pollutants.
nuclear reactor	A device in which a fission chain reaction can be initiated, maintained, and controlled. Its essential component is a core with fissionable fuel.
offpeak	A period of relatively low system demand for electrical energy as specified by the supplier, such as in the middle of the night.
outage	In a power system, the state of a component (such as a generating unit or a transmission line) when it is not available to perform its function due to some event directly associated with the component.

particulates	Finely divided solid or liquid particles in the air or in an emission. Particulates include dust, smoke, fumes, mist, spray, and fog.
peaking	Operation of generating facilities to meet maximum instantaneous electrical demands.
peaking capability	The maximum peakload that can be supplied by a generating unit, station, or system in a stated time period. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.
peaking capacity	Generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on a round-the-clock basis.
peakload	The maximum electrical load consumed or produced in a stated period of time. It may be the maximum instantaneous load (or the maximum average load) within a designated interval of the stated period of time.
pollutant	A residue (usually of human activity) which has an undesirable effect upon the environment (particularly of concern when in excess of the natural capacity of the environment to render it innocuous).
power	The time rate of transferring or transforming energy; for electricity, expressed in watts. Power, in contrast to energy, always designates a definite quantity at a given time.

preference	The preferential use of Federal resources by public bodies and cooperatives, as accorded to such entities in Federal power legislation.
radiation	Particulate or electromagnetic energy emitted from atomic or nuclear processes. Examples are neutrons, gamma rays, and light.
reliability	Generally the ability of an item to perform a required function under stated conditions for a stated period of time. In a power system, the ability of the system to continue operation while some lines or generators are out of service.
reserve capacity	Extra generating capacity available to meet unanticipated demands for power or to generate power in the event of loss of generation resulting from scheduled or unscheduled outages of regularly used generating capacity. Reserve capacity provided to meet the latter is also known as forced outage reserve.
reserves	Resources which are known in location, quantity, and quality and which are economically recoverable under currently available technologies.
residential energy use	In general, energy use by domestic dwellings for space heating, air-conditioning, cooking, water heating, and other domestic uses.
storage reservoir	A reservoir in which storage is held over from the annual high-water season to the following low-water season. Storage reservoirs which refill at the end of each annual high-water season are annual storage reservoirs. Those which cannot refill all usable power storage by the end of each annual high-water season are cyclic storage reservoirs.

sulfur oxides (SO_2)	Compounds of sulfur combined with oxygen that have a significant influence on air pollution.
surplus energy	Electric energy generated at Federal hydroelectric plants in the Pacific Northwest which cannot be conserved. This energy would otherwise be wasted because of the lack of market for it in the Pacific Northwest at any established rate. When the nonfirm energy needs of the Pacific Northwest entities are satisfied, surplus energy then becomes available for marketing outside the Pacific Northwest.
surplus power	Power that is in excess of the needs of the producing system. For the region surplus power would be exported to serve markets in adjacent areas. Sometimes used as an interchangeable term with "secondary power."
system reserve capacity	The difference between the available dependable capacity of the system, including net firm power purchases, and the actual or anticipated peakload for a specified period.
thermal efficiency	The ratio of the electric power produced by a powerplant to the amount of heat produced by the fuels; a measure of the efficiency with which the plant converts thermal to electrical energy.
thermal generation	Generation of electricity by applying heat to a fluid or gas to drive a turbine generator.
thermal pollution	The warming of the environment, especially streams and other bodies of water, by waste heat from powerplants and factories. Drastic thermal pollution endangers many species of aquatic life.

time-of-day pricing	Rates imposing higher charges during those periods of the day when the higher costs to the utility are incurred.
transmission grid	An interconnected system of electric transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points of demand.
turbine	A rotary engine activated by the reaction and/or impulse of a current of pressurized fluid (water, steam, liquid, metal, etc.) and usually made with a series of curved vanes on a central rotating spindle.
volt	The unit of electromotive force or electric pressure analogous to water pressure in pounds per square inch. It is the electromotive force which, if steadily applied to a circuit having a resistance of 1 ohm, will produce a current of 1 ampere.
waste, high-level radioactive	Wastes having radioactivity concentrations of hundreds to thousands of microcuries per gallon or cubic foot.
waste, low-level radioactive	Wastes having radioactivity concentrations in the range of 1 microcurie per gallon or cubic foot.

CHAPTER 1

INTRODUCTION

Concern has arisen in recent years regarding this Nation's ability to reduce its dependence on imported fuels. This concern was manifested in the National Energy Plan, the administration's April 1977 major plan outlining strategies for reducing the United States' dependence on foreign energy supplies. In July 1977 the General Accounting Office (GAO) endorsed many of the plan's concepts in a report entitled "An Evaluation of the National Energy Plan." The Congress approved portions of the National Energy Plan in October 1978 and it was signed into law in November 1978.

In August 1977 the Congress passed legislation to create the Department of Energy (DOE). The purposes of the legislation were to (1) establish a permanent Department of Energy in the executive branch, (2) manage the Federal Government's energy functions, and (3) provide a mechanism through which a coordinated national policy could be formulated and implemented to deal with the Nation's energy problems.

THE WESTERN AREA POWER ADMINISTRATION

Among the functions transferred to DOE was the responsibility for the sale and transmission of electrical energy from the Bureau of Reclamation multipurpose water projects. The Western Area Power Administration (WAPA) was created within DOE to market electrical power generated at Federal pro projects in 15 western States to wholesale customers. WAPA was also given the responsibility of maintaining and operating its high-voltage transmission system in the 15 western States, and constructing any additional transmission facilities needed in the future to market energy produced by new Federal facilities.

WAPA markets energy from 46 powerplants operated by the U.S. Bureau of Reclamation or the U.S. Army Corps of Engineers and from one powerplant operated by the International Boundary and Water Commission in Texas. Most of the Reclamation and Corps projects are multipurpose; that is, they are designed to provide flood control, navigation, irrigation, municipal and industrial water supplies, fish and wildlife enhancement, pollution control, recreation and other public benefits, as well as generate power.

Because the resource projects were financed from appropriated funds, WAPA is required to repay the U.S. Treasury, with interest, the Government's investment in the power facilities. WAPA repays these expenditures from revenues received from its marketing activities. Power revenues also repay a substantial share of the construction costs of Federal irrigation projects.

The 46 powerplants in the WAPA system have a total installed capacity of 7,235 megawatts and a peaking capacity of 8,320 megawatts. This power is moved over 15,982 circuit miles of transmission lines with voltage ratings of up to 500,000 volts. WAPA maintains 206 substations throughout the system to serve 426 preference customers who in turn deliver electric power to over 7 million customers. In 1977, WAPA marketed 35.9 billion kilowatt-hours (kWh) for annual revenue from power sales totaling $247 million. Figure 1-1 shows WAPA's marketing area, which makes up an area of 1,269,958 square miles.

WAPA has its headquarters office in Golden, Colorado, and area offices in Denver, Colorado, Salt Lake City, Utah, Billings, Montana, Sacramento, California, and Boulder City, Nevada. The WAPA system and mission were transferred from the Bureau of Reclamation to DOE on October 1, 1977.

SCOPE OF REVIEW

This review was undertaken as part of our continuing effort to evaluate the role of Federal power marketing agencies. We wanted to find out what role WAPA could play, if any, in carrying out national energy objectives, and whether its charter is in keeping with today's energy outlook. We wanted to determine:

--What are the issues affecting electrical energy development?

--What are the opportunities to reduce reliance on conventional sources of power?

--What progress has been made to reduce dependence on conventional resources?

--What role might WAPA play to foster principles of the National Energy Plan?

In lieu of evaluating all of WAPA, we selected the three States of Arizona, California, and Nevada to evaluate (see figure 1.2). These States, which make up two of the five WAPA regions, receive about 50 percent of WAPA's power.

To obtain a broad outlook on energy programs at local, State, and Federal levels, we contacted numerous private and public organizations (see app. IV). We also employed a team of energy consultants (see app. V) to develop and analyze a set of electricity policy options for the Pacific Southwest. One policy set was based on traditional energy policy options, and the second was based on the basic principles cited in the National Energy Plan (see table 1-1).

Figure 1–1

FEDERAL MARKETING AREAS

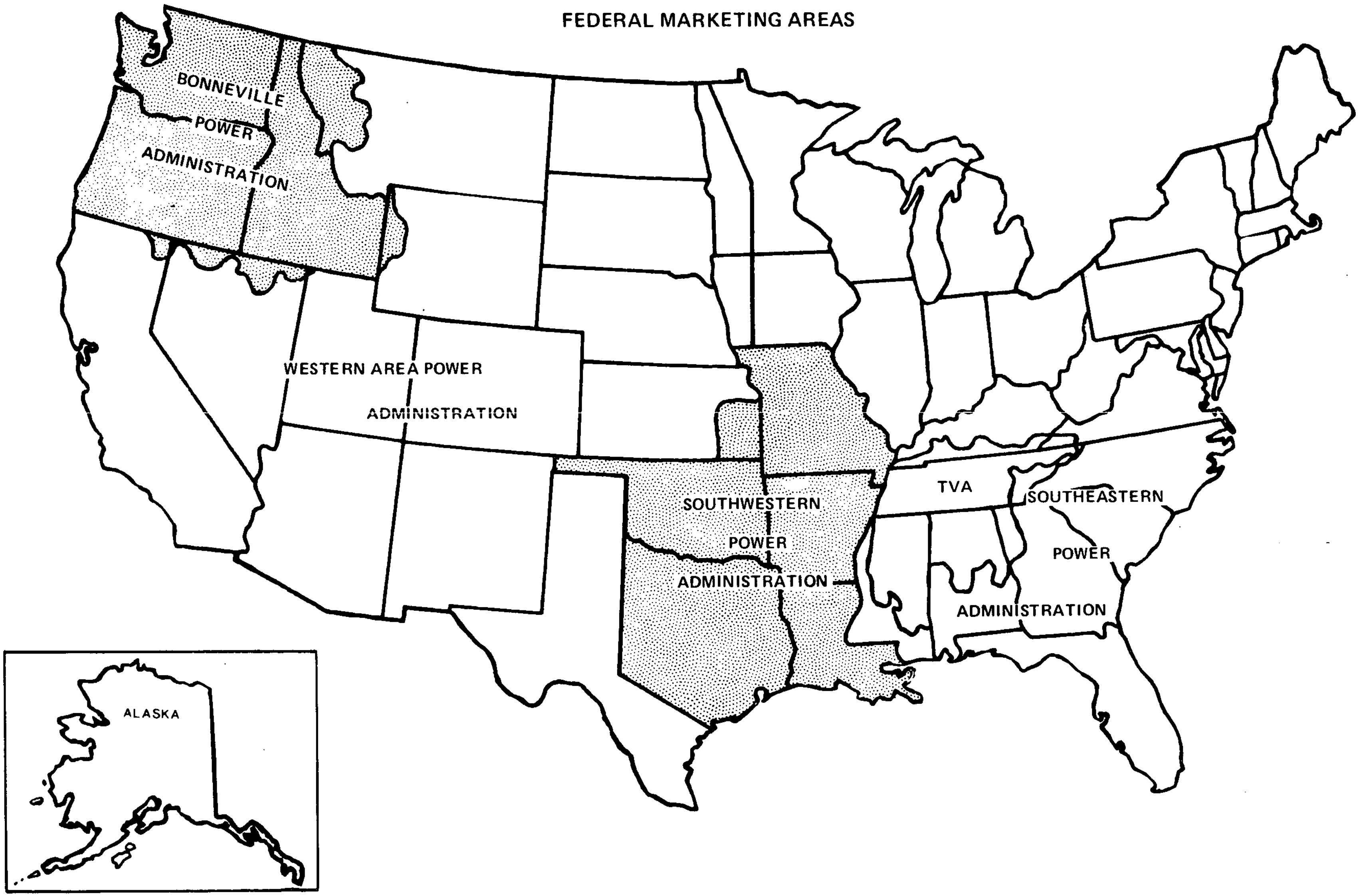


Table 1-1

Basic Principles Cited in the Administration's National Energy Plan

Principle

1. The energy problem can be effectively addressed only by a government that accepts responsibility for dealing with it comprehensively, and by a public that understands its seriousness and is ready to make necessary sacrifices.

2. Healthy economic growth must continue.

3. National policies for the protection of the environment must be maintained.

4. The United States must reduce its vulnerability to potentially devastating supply interruptions.

5. The United States must solve its energy problems in a manner that is equitable to all regions, sectors, and income groups.

6. The cornerstone of National Energy Policy is that the growth of energy demand must be restrained through conservation and improved energy efficiency.

7. Energy prices should generally reflect the true replacement cost of energy.

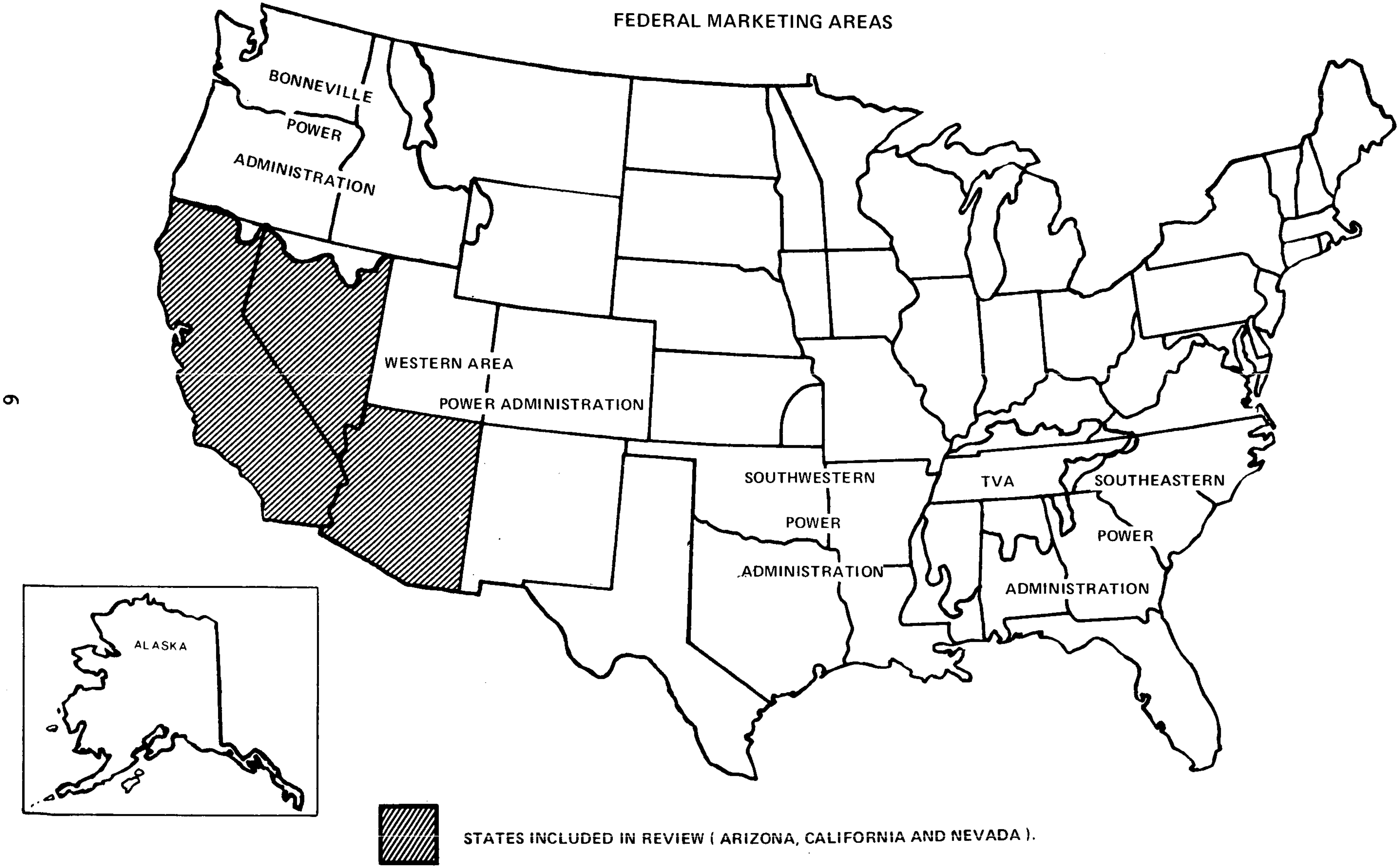
8. Both energy producers and consumers are entitled to reasonable certainty as to Government policy.

9. Resources in plentiful supply must be used more widely, and the Nation must begin the process of moderating its use of those in short supply.

10. The use of nonconventional sources of energy must be vigorously expanded.

Figure 1–2

FEDERAL MARKETING AREAS



CHAPTER 2

BACKGROUND AND PERSPECTIVE

The constantly growing economy in Arizona, California, and Nevada has resulted in increased electricity demands, which have traditionally been met by conventional power resources such as oil, gas, coal, and nuclear power. Supplies of oil and gas are shrinking, and the utilities' continued reliance on the other two conventional sources, coal and nuclear energy, to meet additional future demand is proving questionable.

Reliance on any of the fossil fuels is not the sure thing it once was because of supply shortages, rising prices, and environmental concerns. Problems are also acute for the future of nuclear plants in view of high construction costs, lengthy regulatory approval processes, waste disposal difficulties, questions on decommissioning, and the public's concern over nuclear safety.

Because of these concerns, many believe that conservation and development of renewable resources such as solar and wind will play an increasingly large part in meeting the three State's future electricity needs. This report analyzes the rates of increased future demand predicted for the three States by year 2000, and the ways in which conservation methods as well as fossil fuel and renewable energy sources can meet this demand.

The climate of the three States selected for this study is varied. Northwestern California and the northern parts of the Sierra Nevada Mountains receive more than 40 inches of precipitation in an average year, which results in substantial runoff. The Central Valley of California and most of the remainder of the three States are arid or semi-arid. Arizona and Nevada are quite arid; the two States receive only 3 to 12 inches of precipitation in an average year.

The three States vary substantially in population density. In 1976 California had 187.6 persons per square mile, Arizona had 20.0, and Nevada 5.6. Over 67 percent of the area's population live along the central and southern California coast, which includes the major population centers of San Francisco, Oakland, San Jose, Los Angeles, and San Diego. From 1960 to 1975 the area's population grew 37 percent compared to the Nation's 18 percent.

POWER DEVELOPMENT IN THE SOUTHWEST

Since the 1920s electrical power development in Arizona, California, and Nevada has grown substantially. Electric capacity in the three States increased from a little more than 1,000 megawatts in 1920 to over 45,000 megawatts in 1975. Figure 2-1 depicts the relative growth of thermal and hydropower.

In recent decades the area has continued its rapid growth. The area's (1) population grew five times larger between 1920 and 1970, (2) per capita earnings and the number of major industries roughly tripled between 1950 and 1970, (3) electrical generating capacity has grown even faster, and (4) the three States' capacity for electrical generation grew approximately twice as fast as the rate of general industrial growth for the area between 1950 and 1975.

Early power development in the three States was essentially hydro-based, supplemented with thermal plants. As figure 2-1 shows, the three States had shifted primarily to thermal systems by the 1960s.

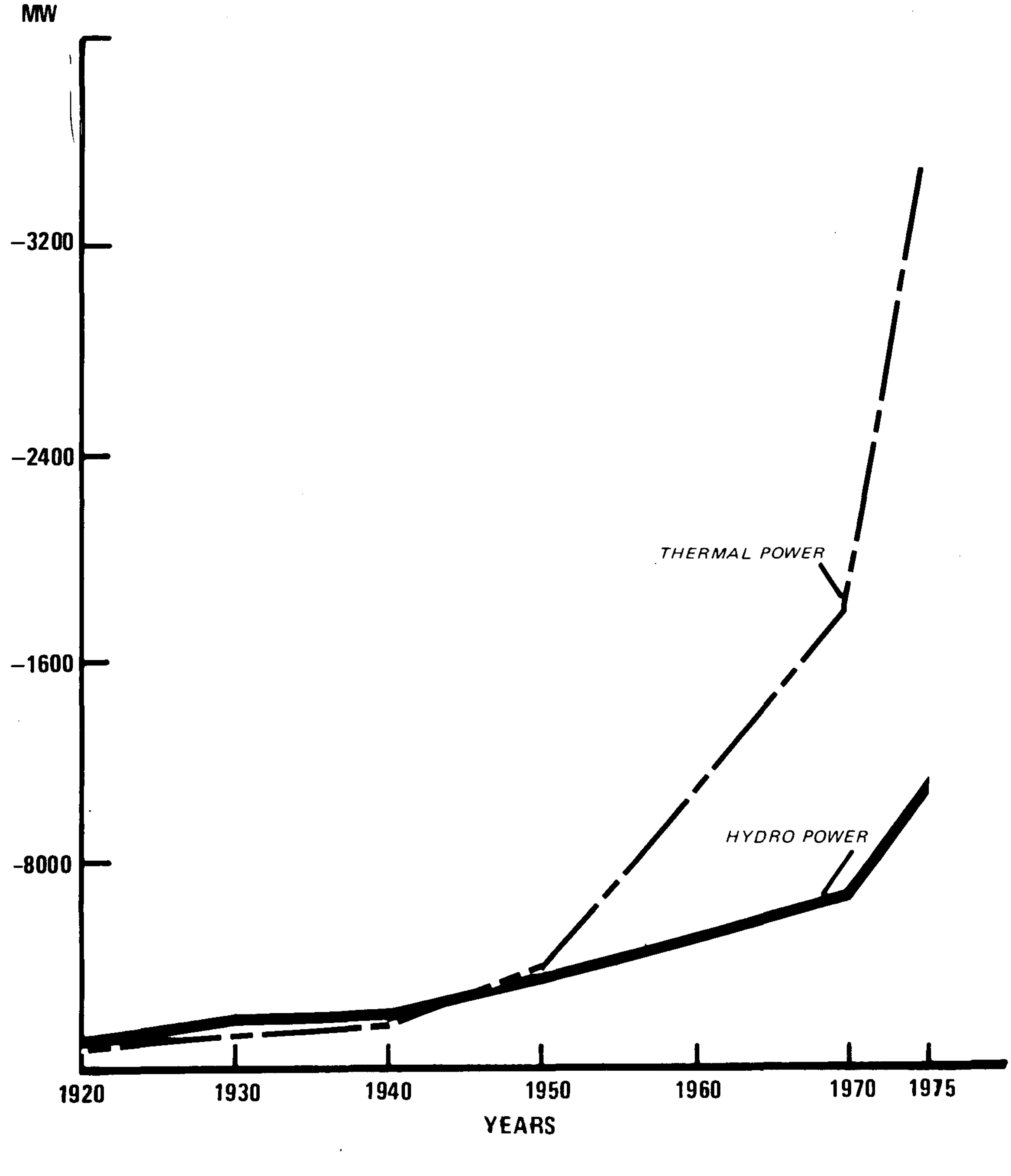
The growth of irrigated agriculture and the droughts of the 1920s increased California's need for power to pump irrigation water. But because of the drought, utilities lacked normally available hydropower to run irrigation pumps. As a result, the utilities had to fire up fossil fuel powered steam plants, some of which had been out of service for years. This marked the beginning of California's transition to thermal electrical generation.

The primary source of additional power gradually shifted from hydro to oil and gas, because of the availability of cheap oil and natural gas from California well fields. By 1965, over 70 percent of the electrical capacity in Arizona, California, and Nevada was from thermal, steam-powered generating plants. From 1965 to 1975, the three States added 17,000 megawatts (MW) of thermal capacity and 4,000 MW of hydro.

The move from hydroelectric to thermal generation went smoothly. From 1910 to 1940, California used gas or oil from local well fields, which was available at low costs of about $2 a barrel for oil and about $.10 per 1,000 cubic feet for gas. Lacking local production, Arizona and Nevada relied on imports from Texas and Canada. By 1975 California had also become a significant importer of oil and gas.

Figure 2-1

ELECTRICAL DEVELOPMENT IN ARIZONA CALIFORNIA AND NEVADA 1920--1975



As the years passed, the cost of oil and gas began to prove to be expensive. By 1977, for a large California utility, the average cost of oil had risen to over $14 a barrel, and the cost of gas to $1.60 for 1,000 cubic feet. Also, the use of dwindling supplies of these fuels for electrical generation is being questioned.

Unfortunately, coal and nuclear also have their problems. Theoretically, utilities could switch to coal, but many find they cannot, because of environmental concerns and air quality standards, especially in California. Concurrently, the nuclear alternative is meeting with growing public concern, and cost, environmental, and technical difficulties.

The Federal Government, through the Bureau of Reclamation, has developed hydropower in Arizona, California, and Nevada. Of the 7,000 MW of hydropower capacity existing in the three States in 1950, Federal projects provided nearly 1,700 MW. By 1965, Federal hydropower had reached over 4,000 MW as shown below:

Federal Hydropower
Developed in Arizona,
California, and Nevada

Facility	Year(s) developed	Installed capacity (megawatts)
Shasta	1944, 1948-49	456
Keswick	1949-50	75
Folsom	1955	199
Nimbus	1955	14
Carr	1963	141
Spring Creek	1964	150
Trinity	1964	106
O'Neill	1967-68	25
San Luis	1968	202
Boulder-Canyon	1936-39, 1941-44, 1952, 1961	1,345
Parker-Davis	1942-43, 1951	354
Glen Canyon	1964-66	950
Senator Wash	1965	7
Total		4,024

Lately, the Federal Government has slowed the development of hydro resources because of environmental and funding constraints, and also the best sites for hydropower have already been developed. Many of the remaining sites are protected by Federal and State wild and scenic river legislation.

The wholesale rate for power marketed by WAPA in the three States averaged less than seven mills per kWh in fiscal year 1977. In contrast, the average wholesale rate for all power sold in the three States was about 25 mills per kWh. Its comparatively low cost makes Federal hydropower an attractive bargain in today's market. The quantity, however, cannot be increased.

Factors affecting fuel supplies

Natural gas was the major fossil fuel used for producing electricity before 1970. Because of gas supply decline, and because natural gas's highest priority use is for heating, its use for the production of electricity has sharply declined. This decline in the use of natural gas has been offset by increased use of fuel oil.

Arizona and Nevada have considerable uranium deposits; however, uranium is a very specialized energy material and is extremely costly to handle and process. Presently, for example, uranium prices and shipping costs are not at levels conducive to profitable mining in Nevada. Arizona, the only State with appreciable coal deposits, foresees difficulties taking advantage of this resource. Some of the more important resource areas are located on lands that are now the subject of litigation between two Indian tribes who have the right to use the land jointly. Onsite studies to determine the quantity and quality of the resource cannot be conducted without the consent of the jurisdictional owners. The State has yet to obtain consent to extract coal there. Nevada imports coal primarily from Northern Arizona and New Mexico, and new powerplants are expected to draw on Utah's coal deposits.

Utility companies planning to use oil to fuel powerplants in the future face a Federal policy aimed at preventing the construction of new oil-fired powerplants and forcing plants currently using oil to convert to coal. To deal with current Government clean air standards, utility companies have to rely on foreign imports to obtain oil that can meet environmental standards. New Source Performance Standards, promulgated by the Environmental Protection Agency after passage of the Clean Air Act Amendments of 1977, requires newly built plants burning high-sulfur fuels to achieve a higher percentage emission reduction than if low-sulfur fuels are used. Further restrictions on fuels have been imposed by current emission standards in several regions of California and by the high ambient levels of pollutants already present in parts of Arizona and California.

As a result of these constraints, utilities may continue to purchase foreign, low-sulfur oil, or to purchase oil from refineries that in turn buy foreign oil to achieve acceptable product standards through blending.

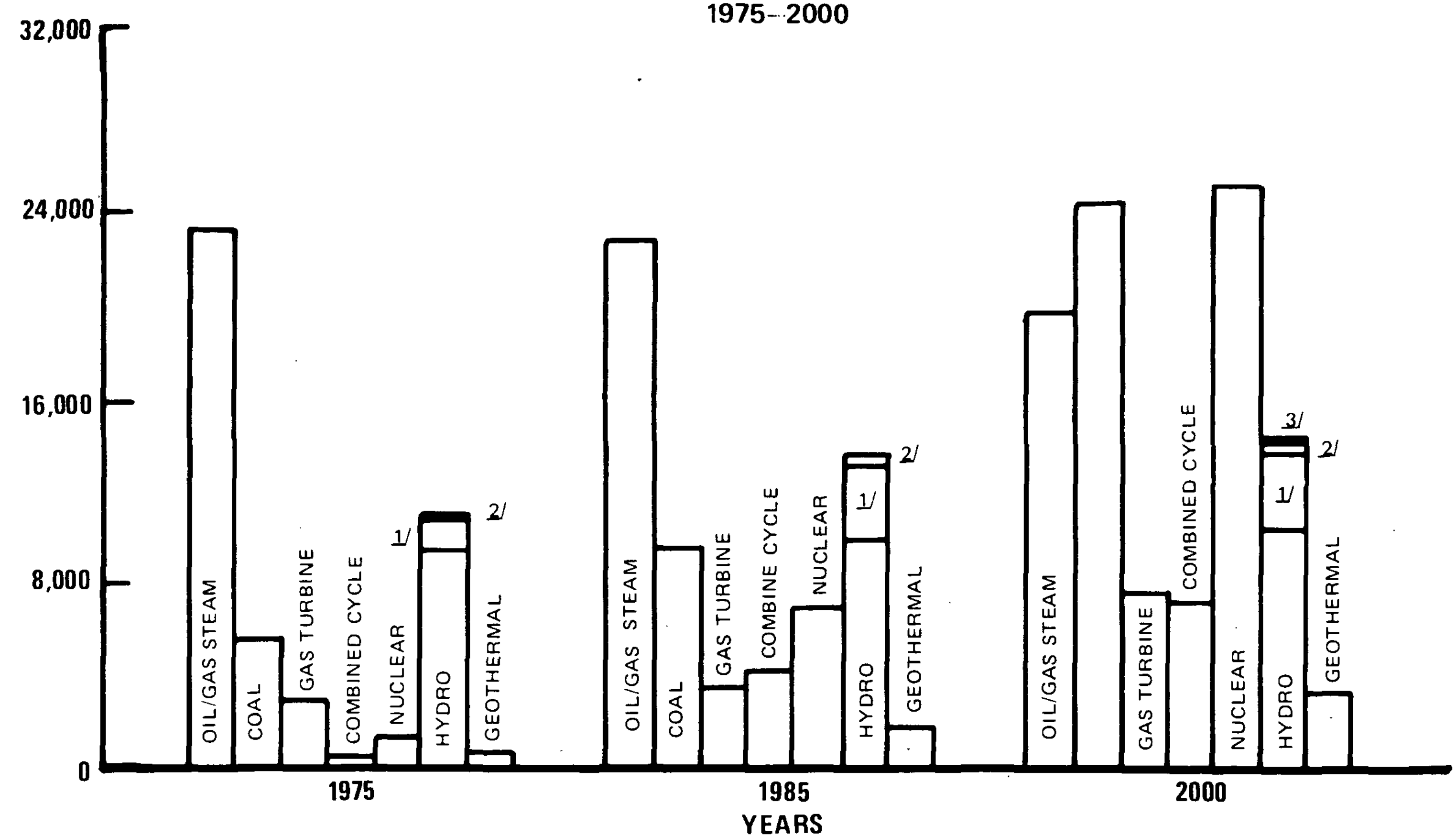
Unfortunately, the Alaskan North Slope oil now available on the West Coast does not qualify as a substitute for light, low-sulfur foreign crude oils. It is high in sulfur content and it does not produce a high distillate fraction when refined because most of the West Coast refineries at present do not have the capabilities to provide the desired mix.

HOW UTILITIES PLAN TO MEET FUTURE ELECTRICAL DEMAND

Utilities in the Southwest are relying heavily on coal, nuclear and oil to provide additional power through the 1980s and 1990s. Only California utilities include a small amount of solar and wind generated power in their energy supply projections. The following figure depicts the utilities' supply projections for the three States.

Figure 2-2

PROJECTED ELECTRICAL DEVELOPMENT* ARIZONA, CALIFORNIA, AND NEVADA
1975–2000



1/ PUMPED STORAGE
2/ BIOMASS/COGENERATION
3/ SOLAR/WIND

* BASED ON COMPOSITE OF STATE AND UTILITY DATA AS DISCUSSED IN APPENDICES I AND II

The availability of coal and nuclear resources as new sources of energy is uncertain because of (1) concerns with the environmental impact of coal and nuclear powerplants, (2) escalating fuel and construction costs, and (3) long delays in the approval and construction of new powerplants, especially nuclear plants.

Coal

If projections are to be realized, coal will have to provide an additional 19,400 MW in the three States between 1975 and 2000. This would necessitate building some 38 plants (assuming 500 MW per plant) at construction costs which may near 15 billion dollars.

Because of recent controversy over the environmental effects of proposed coal-fired generating plants, we suspect utilities may encounter difficulty trying to obtain approval for planned additions. Most of the controversy over proposed coal plants has centered around air quality effects. Environmental groups opposed one proposed site in southern Utah that would have provided 3,000 MW to California and Arizona utilities. One writer, who labeled the project "the ultimate obscenity," claimed that the proposed plant would cause far-reaching effects, ranging from despoiled air quality, including a permanent haze over the entire Lake Powell-Grand Canyon region and dense air pollution in nearby national parks, to health threats and contamination of game fish in Lake Powell from the toxic trace element mercury. The proposed plant was cancelled in April 1976 because of delays in regulatory approval, an environmental lawsuit, and expected regulatory opposition at Federal and State levels.

In California the construction of coal-fired plants is complicated by air quality problems. A recent staff report by the California Energy Commission states that coal plants with a capacity of 800 MW or better may have difficulty complying with emission standards in several counties. For example, the nitrogen oxides emission limitation for Kern, Merced, and Stanislaus counties is 140 pounds per hour. Under the best available technology an 800-MW coal plant produces 1,215 pounds per hour. Furthermore, staff members of California's Energy Commission question whether plants could comply with some areas' particulate standards, even with new technologies that are claimed to achieve 99 percent efficiency in particulate removal.

We discussed some of these problems in a 1977 report "U.S. Coal Development--Promises and Uncertainties," EMD-77-43, September 22, 1977. We covered three categories of environmental problems associated with coal:

--Air pollution caused when coal is burned.

--Adverse impacts from underground and surface mining operations.

--Sludge accumulation in air pollution control devices.

The report pointed out that bringing these environmental problems under control will be expensive. For example, air pollution control devices can make up a significant portion of the capital investment of a coal-fired steamplant. Maintenance of control devices and mining reclamation activities could run as much as $42 billion annually nationwide by the year 2000. Another problem is the huge amount of sludge that control devices produce. The sludge produced each year by coal-fired steamplants could be as much as the total amount of municipal solid waste produced in America each year by 1985, and by the year 2000, could cost as much as $3.4 billion annually to dispose of. In addition, DOE believes a growing scarcity of freshwater resulting from an intense competition over its use and acquisition is a growing concern.

Furthermore, our report suggested that coal would likely be developed at a slower rate than was suggested in the administration's National Energy Plan. For example, the Edison Electric Institute projected coal production lower than the Energy Plan assessments. The Institute stated that the Western States' 1974 production of about 83 million tons of coal would be increased to 294 million tons by 1985 and to about 381 million tons by 2000. Our report indicated that even the Institute's projections would not likely be achieved in the short time specified.

In short, although it is plentiful, coal may not be a practical means of meeting forecasted future electricity needs in the three States studied.

Nuclear

Projections call for about 24,000 MW of nuclear plant additions between 1975 and 2000. About 25 percent of the capacity is expected to be built in Arizona and 75 percent in California. Whether the nuclear plants Arizona and California utilities want to build will be available on time--or at all--is questionable, however, in view of heavy construction costs, lengthy regulatory proceedings, and nuclear waste disposal problems.

Approval of nuclear facilities by Federal and State regulatory agencies can be a lengthy process. One California utility company estimates it now takes a total leadtime from site studies to plant operation of over 15 years for nuclear facilities--if there are no court appeals. Any court appeals extend the time required for regulatory processing even more.

In addition to the difficulty posed by lengthy leadtime requirements, utilities are currently faced with technical problems in disposing of nuclear waste. These problems, for instance, forced a California utility to recently abandon plans to build the proposed Sun Desert nuclear project in southern California. The Sun Desert plan was originally reviewed and approved by several Government agencies for site acceptability, environmental effects, financial solvency, and feasible alternatives between 1974 and 1978. But despite these agencies' approval and the arguments of Sun Desert's largest participant that the plant was needed to meet projected future demand, the California Energy Commission, in February 1978, recommended that the project should not be exempted from a California law that prohibits nuclear plant construction until an adequate waste disposal system has been developed and in use. The Commission also contended that energy conservation and alternative sources, such as upgrading current plants and developing more coal and geothermal resources, could be used in lieu of the nuclear plant to meet the demand projected by the utility.

Another argument against relying on nuclear plants to meet future needs is that nuclear plants are costly. Based on an estimated cost of about $1,000 per KW of installed capacity, a 1,000-MW nuclear plant would cost about $1 billion. Using current projections of the number of nuclear plants needed, Arizona and California utilities would need to arrange for about $24 billion in financing over the next 22 years.

Because of these serious problems with nuclear power and the drawbacks on nonrenewable sources of power, conservation and the development of renewable sources such as solar and wind are becoming more attractive alternatives. Yet there is skepticism over how much these alternatives can be relied upon to meet future electrical demand. The potential roles conservation and alternative sources of energy can play in meeting the three States' future needs are discussed in the next chapter.

CHAPTER 3

ALTERNATIVES TO CONVENTIONAL POWER RESOURCES

Opportunities to move from an energy system based on conventional electrical generation to one based on conservation and such renewable resources as solar and wind power are tremendous. In this chapter we discuss how conservation techniques, including techniques to improve the efficiency of existing electrical systems through load management, interconnections, and power pooling, can reduce the growing demand for electricity. We also discuss potential energy savings achievable by developing renewable resources of power.

CONSERVATION

Energy conservation includes not only improving the efficiency of energy use, but also making such modest life-style adjustments as lowering thermostats in winter, raising thermostats in summer, and turning off unneeded lights. Energy conserving measures make homes, businesses, and industrial processes more energy efficient by using less energy to achieve essentially the same results. Typical conservation measures include improving residential insulation and weatherization, using more energy-efficient appliances, adjusting thermostats, modernizing production facilities, recycling materials, and using waste heat from industrial processes. Saving wasted energy through conservation, as the Administration's National Energy Plan points out, constitutes the least costly, most flexible, and most environmentally acceptable energy resource available.

Although there is general agreement on the need to conserve energy, estimates of how much conservation could be achieved differ. The Electric Power Research Institute, an industry-funded research group, estimates that up to 40 percent of our future electric and non-electric energy demand could be eliminated by the year 2000 if nationwide conservation measures were adopted. The institute considers 20 percent a reasonable target. State energy forecasts prepared for the States of Arizona, California, and Nevada have indicated that conservation measures could reduce electrical usage by about 23, 12, and 7 percent, respectively, by 1985.

Estimating conservation savings is a relatively new and unsettled procedure. Thus the above differences in the three States' estimated potential conservation savings can be attributed to differences in conditions, such as climate, population, patterns of energy use, and estimating techniques. For example, rather than basing estimates of energy savings on specific conservation measures, Arizona based them on the assumption that conservation will offset the normal growth in demand that accompanies rising income. California's estimates were made jointly by the State's Energy Commission and major utilities on the basis of specific current and planned future programs. Nevada's estimates were based on the State's conservation experience during the 1973 oil embargo.

About one-third of the total electrical energy consumed in the three States goes for residential uses, one-third for commercial uses, and one-third for industrial (including agricultural) uses. Data is available on energy conservation savings that can be achieved in residential homes. Somewhat less, though, is known about potential conservation energy savings in the commercial sector, and even less is known in the industrial sector. As a result, detailed potential savings have not been predicted for these sectors. While this is so, it is generally acknowledged that changes in operating procedures and increased insulation could provide significant opportunities for energy savings in the commercial sector. Similarly, preliminary research indicates conservation measures such as process improvements, cogeneration, and waste heat recovery could significantly reduce industrial sector consumption. Load management by utility companies can also provide opportunities for conservation in all three sectors by encouraging shifts in electricity use from high demand hours of the day to lower demand periods.

Conservation in residences

Extensive studies of energy conservation opportunities of residences in California and other areas indicate that retrofitting existing residences with insulation, especially above ceilings, can have very high returns per dollar invested and provide an opportunity for fast savings in the near future. Even the added expense of using more insulation than present standards call for, and using special conservation designs in building is cost effective when measured against the cost of unnecessary energy used for the life of the building. The scope of potential electricity savings in the three States studied, however, is limited by the low percentage of electrically heated residences in the area. Nevertheless, savings from using extra insulation and conservation designs could reduce projected electric heat and air conditioning loads in the year 2000 by between 10 and 20 percent of those expected.

The greatest opportunities for reducing residential electricity consumption are through more efficient appliances and more efficient use of them. Standards of required energy efficiency are now in effect in California for refrigerators, freezers, and air conditioners, and are forthcoming for other major appliances. Federal standards are also expected in the near future. Overall, a 20-percent improvement in the energy efficiency of appliances seems almost certain as soon as new, more efficient models replace older ones. By the year 2000, more than 95 percent of the models in operation will have been built after 1980. Additional design improvements may also appear over the next few years, in time to bring about further efficiency gains for the units installed in the latter portion of the 1980-2000 period.

Retrofitting existing water heaters with more insulation, installing shower constrictors, and turning down thermostats can save up to 20 percent of the energy otherwise used to heat water. If adopted, these measures could produce fast savings. But even greater long-term energy savings will be realized when existing units (retrofitted or not) are gradually replaced with water heaters built to meet new, more efficient standards. In this area, the two conservation measures with the greatest energy savings potential for the long run are new water heaters with higher thermal efficiency and households adopting frugal hot water usage habits.

Solar heating is especially suited to Arizona, California, and Nevada because of these three States' high percentage of sunny days and relatively low heating requirements. Active solar units can save up to 70 percent of the energy used for space and water heating, but the investment cost of an active solar system unit makes them at best marginally profitable at the present time. Adoption of active solar systems will probably be slow, but may rise to include as many as 10 percent of new residences with electric space heating or water heating because of Federal and State financial inducements, and the cost-decreasing effects of mass production. The economics of passive solar systems are much more attractive because changes in building orientation, window designs, etc., can save 15 to 20 percent of heating loads, often with little or no net increase in total construction costs.

Conservation in commercial and public buildings

Many of the energy conservation measures for residences are also appropriate for commercial and public buildings. For example, retrofitting commercial buildings with insulation can reduce the amount of electricity required for heating and air conditioning. However, because of their varied types of construction, commercial buildings are sometimes more difficult and expensive to retrofit than residence. It may also be more difficult to convince commercial building owners to make the investment required.

Installing more insulation and efficient comfort control systems in new commercial and public buildings as they are being constructed is another opportunity to save energy. In this way a 20 percent reduction in energy use for heating and air conditioning is easily achievable at a small cost that may actually be directly offset by savings due to the resultant reduced need for heating, air conditioning, and ventilation.

Commercial customers also use appliances which can be made more efficient. Furthermore, considerable energy savings are potentially realized by reducing lighting levels in commercial buildings, where excessive illumination and display lighting has become commonplace. California estimates that removing unnecessary lights would save a significant portion of the projected 1975 electricity consumption by commercial customers. An added inducement for this measure is that it saves not only electricity used for lights, but also the cost of bulbs and the amount of energy used for cooling the heat load added by the operation of the excess lights.

Commercial customers can also save substantial energy by operating their heat, ventilation, and air conditioning systems more conservatively. Thermostat settings can be adjusted (warmer in summer, cooler in winter), ventilation levels reduced, and systems turned off when buildings are unoccuppied. Considerable savings can be achieved by operational changes alone, but some equipment and control system changes may be helpful, especially in large, more complex buildings.

Conservation in the industrial sector

Identifying opportunities for conserving electricity in the industrial sector is very difficult because of the great diversity in processes used, plant layouts, etc. However, experience since 1974 has shown that industries can and will find ways to conserve energy as more information becomes available and higher energy prices provide an incentive for reducing the amount of energy used per unit of product. Demand response studies, including an analysis by the California Energy Commission, all expect further significant reductions in the rate of electricity use per unit of product. Engineering studies of specific industries' processes have also found substantial opportunities for cost effective energy savings.

Reducing electrical demand through load management

Since the demand for electrical energy varies between different times of the day and between seasons, electrical generating facilities are built and designed with enough capacity to meet the heaviest demand, or load. Efforts to reschedule electricity use so as to reduce the total amount of energy demanded at any time are called load management. The heaviest electrical demand during a day, season, or year is referred to as the system peak. For example, peak demand in California occurs on hot summer afternoons when heavy air conditioning loads are added to the normal electrical load that exists independent of the temperature.

Load management generally does not save energy. Some of the energy used during peak periods is simply shifted and used during periods of lower demand. Reducing the growth rate of peak demand or spreading the load more evenly can save money by delaying the need for new powerplants and by allowing utilities to meet energy demands with more economical baseload plants.

Although large coal, oil/gas, and nuclear plants are more efficient in converting raw fuel energy into electricity than smaller quick-starting gas turbines, the smaller gas turbines are generally used to meet high energy demands during peak hours. This is because the large steam turbine plants' expensive capital recovery costs per kWh are prohibitively high if the plant is only used during a few peak hours. So gas turbines, which have low capital costs, are built to meet peak loads.

If loads are spread evenly, more electrical demand can be met by operating baseload plants. Fewer relatively inefficient peaking units are then required. Load management also reduces the need for the scarce oil or natural gas that invariably is used in peaking units. The fuel thus saved can be allocated to other uses.

Measures to shift the load from on-peak to off-peak periods include cycling appliances, running swimming pool filters and agricultural pumps during off-peak hours, storing energy, and imposing time of use utility rates for peak consumption. Appliance cycling involves installing remote control devices or clock timers on such appliances as residential air conditioners, space heaters, and water heaters. Using these remote control devices, a utility can shutoff appliances that contribute heavily to the load. For example, air conditioners, which contribute to summer peak loads could be cycled off 10 minutes every half hour.

Reductions in peak demand can be achieved if consumers operate swimming pool filter pumps and agricultural pumps during off-peak hours. Since swimming pool pumps usually operate between 4 and 12 hours daily, often during peak hours, the use of cycling devices offers potential for reductions in peak energy demand. Similarly, some farmers use electricity during both peak and off-peak hours for irrigation pumping. It has been estimated that in California as much as 30 percent of the present contribution of agricultural pumping to peak demand could be eliminated by 1985 if farmers used irrigation pumps only during off-peak periods, whenever possible.

Time-of-day use rates that are based on the cost of new generating capacity facilities may also reduce peak load by increasing the price of energy consumed during periods of heavy demand. The cost of the metering devices needed to keep track of the time-of-day use rate is estimated at $165 per meter.

RENEWABLE ENERGY POTENTIAL

Alternatives to fossil and nuclear fuels include solar and geothermal energy sources. Solar energy striking the earth and its atmosphere is directly useful in countless ways; plant photosynthesis and heating and lighting the earth are only a few of the most obvious ways we benefit from the sun. Solar energy furthermore produces rain and wind which we tap by building hydroelectric projects and windmills. We also release solar energy stored in plants by burning wood and other biomass materials to provide heat or generate electricity. Geothermal energy appears in three forms--dry steam, hot water and wet steam, and hot and dry rocks--all of which can be used under varying conditions to meet our energy needs.

Solar and geothermal energy are present in virtually unlimited amounts and are distributed in varying forms and amounts throughout the world. The capture and use of solar energy and some applications of geothermal energy generally entail less serious impacts on the environment and human health than more conventional fossil fuel and nuclear powerplants. Many renewable energy applications, such as windmills, wood fuels, water mills, and solar water heaters were widely used in the past. Over the last 40 years, they were largely replaced by electric utility services, oil, and natural gas.

Although precise cost and technical data still need to be developed for specific site applications, available evidence suggests that hydroelectric, wind, biomass, solar, radiation, and geothermal energy sources have tremendous potential for development in the Southwest.

Increasing hydroelectric's role

Hydroelectric power has played an important role in electric power development in the Southwest, and will continue in the future. In 1973, for example, one-fourth of the Southwest's installed capacity and total electric generation came from hydroelectric facilities. Recent studies have shown that the Southwest's hydroelectric capability could be substantially increased by (1) uprating existing units, (2) constructing conventional facilities at new and existing sites, (3) constructing pumped storage powerplants at new or existing sites, and (4) constructing small hydroelectric powerplants using conventional and low-head generating equipment.

Technological advances since the 1930s have resulted in improved turbine and generator designs and materials. Because of these advances, many hydroelectric plants could be uprated to increase power production. For example, generators at Shasta Powerplant in California which were built in the late 1930s were originally rated at 75 MW. After rewinding, these same generators were uprated to 95 MW, and engineers currently see a possibility of uprating them to 118 MW.

In March 1977 we reported 1/ on the issue of increasing power production at Federal dams by modernizing turbines and generators. We recommended that the appropriate agencies evaluate opportunities to improve hydropower production, and act on those that were economically justified. Further, we suggested that the value of fossil-fuel displaced by increased hydropower production be considered in the evaluation. In their July 1977 response to our report, the Army Corps of Engineers reported that in the Southwest an additional 938 MW of capacity and 3,763,000 MWh of energy could be produced if existing facilities were rehabilitated and uprated.

Hydroelectric power production can also be increased through constructing conventional facilities at both new and existing sites. Conventional hydroelectric facilities are those in which water is stored in an upstream reservoir or otherwise diverted upstream of a powerplant, passed through the powerplant, and allowed to continue downstream. In its July 1977 report, the Army Corps of Engineers estimated that by expanding existing facilities and installing them at non-power dams, an additional 1,544 MW of capacity and 5,858,000 MWh of energy could be made available in the Southwest, mainly in California.

The Federal Power Commission (now the Federal Energy Regulatory Commission) reported in 1975 that undeveloped sites contain almost as much hydroelectric capability as those developed thus far in the Southwest. Of the three States covered in our review, California has the greatest potential for additional conventional hydroelectric power development. In 1974 a California Department of Water Resources study found that if all the identified potential were developed, hydroelectric power production could be increased from 33 billion kWh to 64.2 billion kWh, or approximately 20 percent of the State's forecasted electric energy requirements by the year 1995. About 18.5 billion kWh of the identified potential, however, is located on State and Federal designated wild and scenic rivers, which by law are not available for development.

1/"Power Production At Federal Dams Could Be Increased By Modernizing Turbines And Generators" (EMD-77-22, Mar. 1977).

Another technique that can increase hydroelectric power is pumped storage. Pumped storage powerplants pump water into an upper reservoir by reversible pump-turbine units in the powerplant, and then, when power is needed, release water back down through the powerplant to generate electricity. Pumped storage powerplants can help meet peak demands by releasing water through turbines during peak periods, and thermal generators can be operated more efficiently as they are used to pump water back into the storage reservoir during off-peak periods. In this manner, a pumped storage facility is used as a storage battery, reducing the number of powerplants necessary to meet the load. A drawback of pumped-storage, however, is that it uses more energy than it produces; about 4 kWhs are used for every 3 kWhs generated.

This net energy drawback coupled with the escalating costs of the oil used to power the pumps has reduced pumped storage's current utility as an energy storing device. However, small pumped-storage facilities can be attractive as a "storage battery" for supply when solar or wind powerplants are not generating or when the peak demand does not occur at the same time the sun is the hottest or the wind is the strongest.

In 1975 the Federal Power Commission reported that the States of Arizona, California, Nevada, and Utah had some 155 potential pumped storage sites with a combined potential capacity of 341,000 MW. A February 1977 report by the Bureau of Reclamation entitled "Western Energy Expansion Study" estimated that 8,400 MW of pumped storage could be developed by 1995.

Finally, undeveloped hydroelectric opportunities can be exploited by constructing small powerplants using conventional and low-head generating equipment. The Corps of Engineers has estimated that small powerplants could potentially add 172 MW of capacity and generate 705,000 kWh of energy at existing dams in Arizona and Nevada. Evaluations are currently being performed by the Bureau of Reclamation at 10 existing damsites in California. Preliminary data shows that 91 MW of capacity and 290,000 kWh of energy could potentially be added using small powerplants at those 10 sites.

The promise of windpower

Wind-powered generation of electrical energy appears promising in several types of locations through the West. Wind-driven generators located in gaps in mountain ranges that naturally funnel the wind and large wind generator "farms" (200 MW and more) on windy plains are two types of locations where large-scale wind generation may be feasible. Since wind is a variable resource, several wind generators located at widely separated geographical sites may help to smooth out individual unit fluctuation and enhance the marketability of windpower.

More research is needed to fully assess the potential of wind-generated electricity. Because wind characteristics vary greatly from location to location, much more wind data collection and evaluation is needed. Programs are also needed to develop and demonstrate the required technology and to integrate wind-generated electricity into existing electrical systems. While estimates of wind potential in Arizona and Nevada were not available, the California Energy Commission estimates wind potential, without regard to reliability, in California at 40,000 MW, an amount equal to the present total electric-generating capacity in the State. With an all-out program, the California Energy Commission estimated that between 9 and 15 percent of California's electric energy could be supplied by wind in the year 1995.

Windpower can also be employed directly in mechanical uses which otherwise would consume electricity. Pumping water for agricultural irrigation is an example of such a mechanical use. Wind energy could also be used at pumped-storage hydroelectric projects to pump water from lower reservoirs to higher reservoirs for use during peak-load periods.

Future uses of biomass

A variety of available resources, including municipal waste, sewage sludge, agricultural and forest products, and animal residue, can be burned directly or converted to synthetic liquid and gaseous fuels. Depending upon the type of process and the product that is created, fuels from biomass can be used to replace fossil fuels for electrical generation and industrial process-heat applications, natural gas used for water heating and space conditioning, and petroleum products used in the transportation sector and in the manufacture of chemicals.

The locations of biomass resources in California (data was not available for Arizona and Nevada) are depicted in figure 3-1. As shown, more than 42 million tons of biomass are generated in California each year. This is equivalent to 120 million barrels of oil. Estimates prepared by the California Energy Commission show that an actively supported biomass program could provide as much as a quadrillion Btu's each year by the year 2000. This is equivalent to 180 million barrels of oil, or roughly equal to the total amount of oil imported into California in 1975.

Ultimately the role biomass plays in future energy production will be affected significantly by the competition for biomass materials in the products sector. For example, more wood waste and forest residue is being used in the production of paper and other wood products. Because of this competition, it is difficult at this time to predict with any certainty how much biomass will be used to produce energy, especially electrical energy.

Solar radiation's future contribution

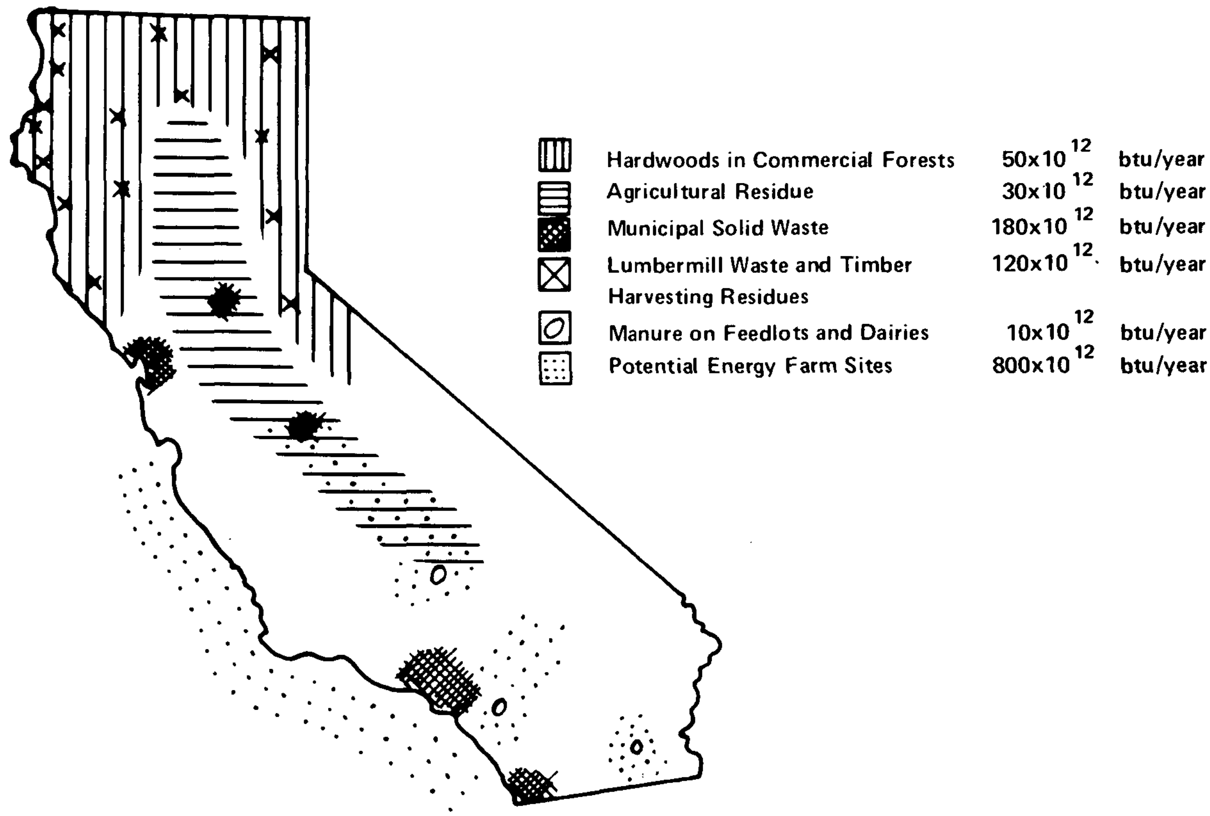
Solar radiation can be used to generate electricity or displace electricity or primary fuels in such uses as space and water heating, crop drying, and food processing. Solar radiation also has potential for space cooling, which has a much greater contribution to energy demand in the Southwest than heating solar radiation that can be used either actively (through mechanical or electrical devices) or passively (through building design).

Solar radiation has the greatest future potential of all the renewable energy sources, because of its flexibility. Arizona's enormous potential for capturing and using solar energy is rivalled by only a few other places around the world. Nevada's solar energy potential is also great, especially in the southern part of the State. The total solar radiation California receives in a year amounts to about 2,550 quadrillion Btus. This contrasts with California's present total energy consumption of 7.3 quadrillion Btus per year. The ultimate electric potential from solar-thermal facilities in California is approximately 500,000 MW. This is in contrast to California's current installed capacity of about 36,500 MW.

By the year 1995, California's Energy Commission has estimated that with an all-out program as much as 50 percent

Figure 3—1

LOCATION OF BIOMASS RESOURCES IN CALIFORNIA



ANNUAL SOURCES OF CALIFORNIA BIOMASS RESOURCES

Municipal Solid Waste (MSW)	18.6 million tons
Agricultural Field Residue	8.6
Agricultural Industry Residue	2.1
Animal Manure	3.6
Lumbermill Residues	4.6
Timber-Harvesting Residue	5.1
	42.6

Source: Stanford Research Institute, Program Definition for Fuels From Biomass, for ERCDC (October 1976).

of the State's space heating for buildings and 8 percent of the State's process heat for industry could come from solar radiation. Furthermore, the Commission estimated that as much as 3,000 MW of installed solar-thermal electric capacity could be on line by the year 1995.

Two methods of using solar radiation that show great promise for the future are passive solar design and photovoltaic cells. Passive solar systems are based on the deliberate design of a building to directly achieve natural heat gains in the winter and natural heat losses in the summer. Houses properly designed may meet as much as 70 percent of their heating and cooling requirements at much less cost than conventionally designed houses with active solar systems. Photovoltaics, another promising technology, is a non-thermal conversion process in which electricity is produced directly from sunlight using a solar cell composed mainly of a semiconductor material such as silicon. Photovoltaic, or solar, cells have been used in the space program for many years and are commercially available; however, their tremendous cost currently makes them uncompetitive for general electric application. On the other hand, because photovoltaic generation is a non-thermal conversion process, no water is necessary. This makes photovoltaics extremely attractive for development in the arid areas of the Southwest.

Geothermal potentials

The potential for producing power from geothermal resources is impressive. In 1972 a report sponsored by the National Science Foundation entitled "Geothermal Energy" estimated that under a vigorous geothermal research and development program as much as 395,000 MW of geothermal electrical power could be on line by the year 2000 in the United States. Geothermal energy exists everywhere beneath the earth's crust, but in most places the heat is too diffused or too deep to be usable. Geothermal resources are classified as hydrothermal (dry steam and hot mineralized water), hot dry rock, and geopressured zones. Active volcanic regions, rare in the United States but in other nations, also are a source of geothermal energy, referred to as molten magma. Although geothermal resources have practically unlimited energy potential, the hydrothermal classification will likely be the most promising for power production between now and the year 1995.

Most of the Nation's hydrothermal resources are located in the Western States. More than 70 percent are located in California, and almost 10 percent are located in Nevada. A map depicting known and potential geothermal resources areas in California, Nevada, and Arizona is shown in figure 3-2.

Currently the only place electrical energy is being developed from geothermal resources in the United States is at the Geysers, California, a dry-steam field which was producing a little more than 500 MW in 1977. An additional 1,300 MW is planned to be on line at the geysers by 1985. No other major dry-steam fields suitable for commercial production have been identified in the United States.

Nevada's geothermal resources are currently used only for heating. At Truckee Meadows in Nevada's Washoe County some 38 geothermal wells provide approximately 32 homes and 3 commercial buildings with space heating, water heating, and pool heating. At Wabuska in Lyon County and at Wally's Hot Springs in Douglas County geothermal heat is used in greenhouses for year-round production of vegetables.

The California Energy Commission estimated the ultimate potential for hydrothermal geothermal resources in California at 30,000 MW. The Commission estimated that another 34 quadrillion Btus of energy from geothermal resources may be available for direct heat applications. More specifically, the Energy Commission staff members have estimated that under an all-out program 5,600 MW could be developed by 1990. Concerning geothermal potential in Nevada, a quote in a recent State report entitled "Energy in Nevada" states

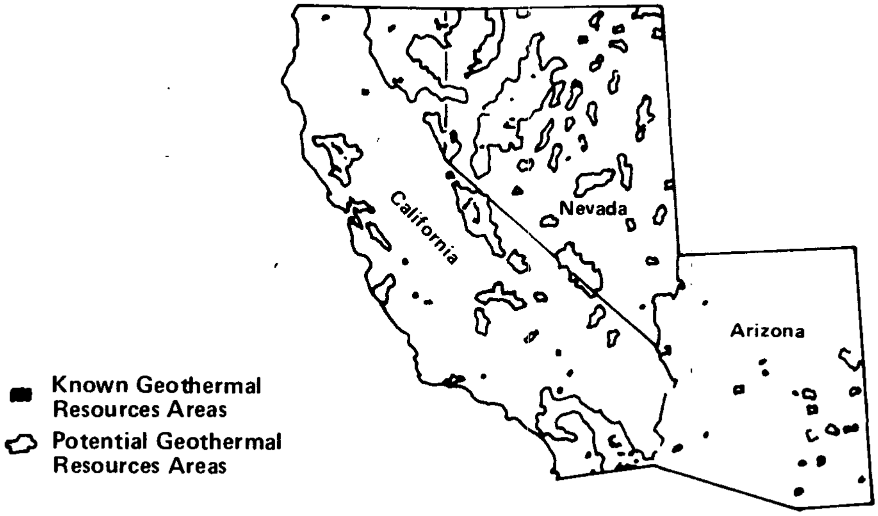
> "Assuming that reliable technology can be developed within the next decade and that favorable regulation of geothermal resources is established, Nevada may be found in the favorable position of not needing to construct additional fossil fuel-fired generation, other than those already planned, and installing only geothermal powerplants as needed for 1985."

OTHER OPPORTUNITIES

Opportunities such as interconnections and power pooling can help reduce the need for additional generating facilities in the Southwest. Interconnecting electrical power systems is not a new idea. As they grew in size, systems began to intertie with systems in other regions in order to share resources and improve reliability. Power pooling is not new

Figure 3-2

KGRAS AND POTENTIAL GEOTHERMAL RESOURCE AREAS



	ACRES	
	KGRA	POTENTIAL GEOTHERMAL RESOURCE AREAS
CALIFORNIA	1 ,051,533	15,737,000
NEVADA	344,027	13,468,000
ARIZONA	38,160	1,473,000
TOTAL	1,433,720	30,678,000

either. In areas throughout the United States utilities have formed power pooling agreements in order to achieve the benefits of integrated planning and operation.

Interconnections

Power exchanges between the Southwest and the Northwest can provide considerable benefits to both regions, some of which have already been realized. The Northwest's hydroelectric resources, when coupled with the region's coal and nuclear powered generation, oftentimes produce energy surpluses. These surpluses occur during certain periods of low energy demand as well as in years with above average rain and snow fall. Recognizing this fact, utilities in the Northwest have formed agreements with California utilities to send unneeded surpluses to California over interconnected powerlines.

Currently the Northwest and California have an interconnection capacity of 3,900 MW. Under this arrangement, California purchases Northwest surpluses, and both regions share reserves and peaking support. This benefits both regions because of the large load diversity between the two regions. California and the Southwest as a whole are characterized by a summer peak demand for power, while the Northwest is characterized by a winter peak.

Surplus energy sales to California, which were limited by the 3,900 MW capacity of existing transmission interties, peaked at 19 billion kWh in 1976. This amount was roughly equal to 13 percent of California's 1976 electrical energy requirements. In concrete terms, the surplus energy sold to California in 1976 displaced 31 million barrels of oil that normally would have been burned to produce electricity in California.

Current and projected expansion in Federal dams in the Northwest will further increase the amount of surplus energy available. Preliminary analyses show that about 5,000 MW of peaking support and reserve sharing could be realized because of the load diversity between the two regions. The California Energy Commission has suggested that additional interconnections would be necessary to take full advantage of Northwest hydroelectric expansion and to maximize the benefits of the expected load and generation diversity between the two regions.

There are three proposed interconnection projects between the Northwest and the Southwest. Altogether the three projects would add about 4,700 MW of interconnection capacity to the present intertie system. One of the proposals commonly referred to as the Celio-Mead transmission line was approved by the Congress for construction in 1964 as part of the intertie program. Originally, the Secretary of the Interior reported to the Congress that the project would be financially feasible and self-liquidating over 50 years. We, however, recommended 1/ that prior to construction of the line the Secretary obtain commitments from the potential users for the use they would make of the project. Commitments were not obtained and construction was stopped in 1969.

In 1975 an Economic Evaluations Task Force, made up of members from the Bonneville Power Administration, Bureau of Reclamation, Nevada Power Company, Salt River Project, and Arizona Public Service Company, began to restudy the economic feasibility of the line. The study, which was completed in 1976, reported that the line had a benefit-to-cost ratio of approximately 2 to 1. Benefits evaluated were:

1. Exchanges of summer-winter surplus peaking between the Northwest and Southwest to reduce capital expenditure for new generating capacity.

2. Sale of surplus Northwest secondary energy to Southwest utilities.

3. Sale of available surplus Southwest energy to the Northwest to firm up peaking hydro sources during critical water years.

In a 1977 review of interconnection systems in the United States we reported 2/ that there is little or no consensus concerning the economics for additional interconnection. This conclusion derived in part from our belief

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1/"Assurances Needed that Cost of Celilo-Mead Transmission Line Project Will be Recovered," Aug. 5, 1969, B-164064.

2/"Problems in Planning and Constructing Transmission Lines Which Interconnect Utilities," June 9, 1977, B-180228.

that the Federal Power Commission (now the Federal Energy Regulatory Commission) had not effectively carried out its responsibilities of promoting and coordinating interconnections. We reported that financial, environmental, and institutional factors are affecting the utility industry's ability to construct interconnections. We recommended that the Power Commission

--take the lead in promoting joint Federal-industry studies to identify and evaluate new interconnections and changes in existing interconnections;

--follow up on completed studies to resolve objections which might frustrate the adoption of study recommendations;

--work with utilities to establish criteria for interconnection studies, which will adequately consider national goals and identify factors which may adversely affect proposed interconnections; and

--work with utilities to make sure they use the criteria in both industry and Federal studies.

With respect to the interconnection potential between the Northwest and the Southwest, one of the major institutional constraints is Public Law 88-552 (16 U.S.C. 837). The act limits the Bonneville Power Administration in transferring surplus energy from the Pacific Northwest, and therefore, restricts utilities outside the Pacific Northwest from either constructing additional interconnections or increasing the capacity of the existing interconnections.

The act requires the Bonneville Power Administration to serve the requirements of the Pacific Northwest before marketing such power and energy outside the region. The act states that the export of Federal hydroelectric power in the Pacific Northwest is limited to surplus energy and surplus peaking capacity, and the Secretary of the Interior (now the Secretary of Energy) can stop delivery of the surplus energy by giving notice, within 60 days, of any conditions that may impair the Northwest's energy, and that the Secretary may terminate any contract of surplus peaking capacity upon notice within 5 years.

The 5-year provision, while protecting the Northwest, removes opportunities for new long-term contracts for power with Southwestern utilities. Without the assurance of a long-term contract, utilities we contacted state they would have no guarantees to meet their energy needs and justify their investment in new interconnections.

Power pooling

A power pool is a group of electric utilities formed to achieve the benefits of integrated planning and operation through interconnection. Power pooling allows the members of the pool to achieve greater economy and reliability. One prerequisite to achieving coordinated operations is adequate transmission interconnections between member utilities. The experience of a major power pool on the east coast shows the following benefits can be derived from a well integrated power pool operation.

--Improved network reliability.

--Greater operating efficiency.

--Economies of scale.

--Better scheduling of additions.

--Flexibility in maintenance programs.

--Improved use of manpower and money.

--Lower cost to the customer.

In 1964 three major private utilities in California joined together to form the California Power Pool in order to coordinate their generation planning, reserve sharing, and day-to-day operations, including economy energy exchanges. The existing California Power Pool Agreement has specific limitations, however:

--It (the California Power Pool) does not include the State's municipal utilities or specify a mechanism for their inclusion.

--It provides no contractual mechanism for central load dispatching, coordinated planning and joint ownership of generation and transmission facilities, and maintenance and scheduling among the three current pool members.

--Pool members must bear a penalty charge for utilizing pool emergency service for more than 2 hours or exceeding their spinning reserve entitlements for more than one-half hour, which serves as a disincentive to sharing of reserve capacity during emergencies.

The California Energy Commission has concluded that while major net benefits do not appear to be achievable by closer pooling arrangements, benefits from closer coordination of California utilities, including public utilities, appears possible. They suggest that further work is required to determine whether improved pool operation and inclusion of municipal utilities would reduce the need to want new facilities in California.

A recent engineering study performed for the Arizona Corporation Commission by R. W. Beck and Associates, an engineering consulting firm, showed that the four major utilities in Arizona could have reduced their 1976 electric generation requirement by some 36 million kWh and saved almost $22 million if they had fully pooled their operations.

CHAPTER 4

REDUCING RELIANCE ON

CONVENTIONAL RESOURCES

Utility companies and Federal and State governments agree that conserving energy and developing renewable sources of energy is desirable. Their activities reveal wide disparities, however, in how much they believe energy conservation can save and how swiftly renewable resources can be developed.

California, Arizona, and Nevada take a positive stance toward conservation and alternative energy resources. They have different approaches, however, to study, plan, and make policy decisions about energy sources and future energy needs. California, with a large cadre of energy planners, has conducted extensive studies and adopted numerous energy laws. Arizona and Nevada have much smaller staffs, and have made more limited studies and conducted public information programs.

Utility companies, on the other hand, doubt that conservation can significantly reduce future energy demand. They are in the business of meeting customer load growth, and are hesitant to be caught short if conservation estimates fail to materialize. Furthermore, the utilities have little financial incentive to foster conservation. They might see it as working to reduce their sales and to limit the number of additional powerplants--the yardsticks by which profits are measured. Utilities do not expect renewable resources such as solar and wind to be reliable, cost effective, or commercially feasible until after the year 2000. Their projections of energy supply for the next 20 years include little energy from such sources. Utilities generally plan to continue financing large thermal facilities such as coal and nuclear plants and do not currently contemplate financing renewable technologies except as research projects.

Electrical energy customers also have doubts. They question the severity of the Nation's energy problem, and have faith in the country's ability to solve energy problems through technology. Furthermore, they believe the high costs of conservation discourage customers from taking advantage of conservation opportunities.

The activities of WAPA, the only Federal power agency in the area, do not foster conservation or development of new renewable sources of power in the three States. WAPA's current practice is to market Federal power at the lowest possible rate for the widest possible use. This practice results in some consumers receiving some of the lowest priced power in the United States and, in our opinion, does not encourage conservation or development of new sources of power.

STATE ENERGY PLANNING AND PROGRAMS DIFFER

California has extensively studied its energy needs and problems. California's Energy Commission, which has about 550 employees, is responsible for: (1) forecasting and assessing energy demand, (2) conserving energy resources, (3) evaluating and certifying siting of powerplants, (4) developing and coordinating research and development, (5) developing contingency plans to deal with possible shortages of electricity, (6) evaluating policies governing the establishment of rates for electric power, and (7) evaluating problems posed by nuclear fuel processing and waste disposal.

The efforts of Arizona and Nevada have been more limited. As of November 1978 Arizona had an Energy Program Office and a Solar Energy Commission with a combined staff of about 17 under the Office of the Governor. Thus far, the State's activities have included (1) solar application demonstration projects involving participation in federally sponsored programs or grants to State universities and (2) public information programs to answer inquiries about ways to save energy. In July 1977 Nevada established the Nevada Department of Energy. Since its inception, the Department has developed a State conservation plan, conducted research for Nevada's new building energy conservation standards, developed an energy extension service, coordinated studies on the electrical potential of Nevada, and encouraged the utilization of renewable resources through information programs. As of January 1979 the Department had a staff of 11.

Forecasting

Planning for adequate future resources requires forecasts of future energy needs. Methods of forecasting range from simply using historical trends in demand for electricity to analyzing in detail future technological, economic, and population trends.

The States have reached varying levels of sophistication in forecasting. Arizona and Nevada have used historical trends for their forecast studies. To determine how much energy will likely be saved by future conservation efforts, they assume energy savings achieved during the 1973 oil embargo would be achievable in the future. The California Energy Commission has used end-use forecasting for the residential sector and is developing similar end-use models for the commercial and industrial sectors. This approach leads to significant reductions in the amount of demand forecast. (See ch. 5.) The Energy Commission states that, through these advanced forecasting techniques, more (1) accurate forecasts can be made, (2) specific conservation programs can be outlined, and (3) cost-effective policies can be adopted. The California Energy Commission is responsible for determining the accuracy and acceptability of load forecasts and resources of the State's electrical utility companies.

Conservation

None of the States have been able to measure how much conservation has been achieved as a result of State and Federal programs. In a June 1978 report entitled "The Federal Government Should Establish and Meet Energy Conservation Goals," we reported on the difficulty of obtaining data:

> "* * * With regards to conservation efforts, our analysis of industrial energy conservation activity since 1972 at selected companies indicated that while most, if not all companies had undertaken activities to conserve energy, for the most part these actions involved measures requiring little or no cost. The amount of energy saved as a result of these actions could not be determined because either (1) energy consumption data collected by these companies were not in sufficient detail or form to make such an assessment or (2) the companies did not provide us with detailed energy consumption data because they said such data were considered proprietary."

The report showed that energy consumption increased 8.5 percent between 1972 and 1976. The report observed that:

"* * * the programs in effect during the 1972-76 time period, although generally relying on voluntary actions by residential consumers, may have had some success in stimulating conservation activities, particularly in 1974 * * *. However, we believe many of the actions taken during that time (operational measures) have not been sustained * * *."

Several State-sponsored studies have made a case for conservation.

California

In 1977 California estimated that demand for electricity and natural gas could be reduced 10 percent by 1985 through measures such as

--improved conservation standards for new buildings,

--retrofit of existing residential and commerical buildings,

--appliance efficiency standards,

--improved efficiency of existing electrical generation, transmission, and distribution systems,

--energy conservation information program for primary and secondary schools, and

--reform training and licensing procedures for architects, building contractors, engineers, and other professional groups whose decisions affect energy use.

The State also recognized market constraints which limit energy conservation, and may require governmental action to overcome. Some of these were

--inadequate information for customers,

--loan financing difficulty,

--energy prices which do not reflect the relative costs of new energy supply and conservation,

--legal and other barriers to market entry by private firms involved in conservation,

--"spillover costs" whereby those who would have to pay for conservation do not obtain full energy cost reduction, and

--public attitudes which do not reflect understanding of the long-term energy problem.

The Commission noted that each of these constraints suggested a need for positive Government action to stimulate energy conservation. Possible actions could include providing the public with information and technical assistance, creating economic and other incentives and, in some cases, direct regulation.

As of August 1978 the State Energy Commission could not measure how much energy was being conserved in California. The Commission was studying ways to measure conservation results without being misled by the many elements such as weather that impinge on the use of energy.

A September 1976 study report entitled "Energy in Nevada," concluded that, "Conservation is the single greatest contribution that Nevadans can make individually toward solving statewide and national energy problems." The study revealed that savings in electrical consumption ranging from 6 to 8 percent had been achieved in the commercial and residential sectors during the 1974 oil embargo. In its analysis of what was needed to increase energy conservation, the study noted that greater levels of conservation could be achieved through more radical price increases, mandatory curtailment, or a greater commitment to voluntary curtailment than already experienced.

State efforts to develop new sources of energy vary. The State of California Energy Commission has recommended a windpower commercialization program. It would identify wind resources, fund the development of prototype wind machines, and develop guidelines for utility involvement in wind-generated commercialization. The Commission predicts wind-generated electricity could provide 9 to 15 percent of the State's total electricity needs by 1995.

The Commission considers solar technology to be in the development stage for central-station power. In coordination with State utility companies and the Federal Government, the State is building a $120-million, 10-MW solar electric plant at Barstow, California.

The State Commission has encouraged solar space and water heating through an income tax credit. The Commission also favors use of power rates by the State's private utility companies through their rates in solar space and water heating.

The Commission intends to support various pieces of legislation on solar rights, solar devices, and tax credits for new structures with passive solar design. It also intends to encourage the inclusion of solar energy in licensing standards for professionals such as architects and assessors.

Arizona

A study prepared for the State of Arizona by the University of Arizona in 1977 described the benefits of conservation. It assumed that energy consumption would remain at the reduced level achieved in 1974 immediately following the energy crisis and projected savings of about 23 percent by 1985 for electrical customers. It also visualized that about 5,800 MW would be available by 1991 to the State by adding 12 coal and three nuclear plants. Additionally, the inventory assumed that 686 MW could be available from out-of-State steamplants.

The inventory acknowledged that the State was in a strong position to map out and begin to implement a program for the application of solar energy. Initially, the program would concentrate on heating homes and buildings and may require tax relief to ease the financial burden on the homeowner. With regard to converting the sun's energy into electricity, the report pointed out that the 10-MW solar powerplant near Barstow was more costly than conventional energy. The report pointed out that, as time passes, this gap will tend to narrow as conventional power becomes more expensive and solar power becomes less expensive with increased experience and larger installations.

The report recognized a potential for geothermal energy but did not estimate how much. It noted that progress has been slow in determining whether this resource could make a contribution to Arizona energy needs. The report also identified 1,470 MW of capacity, which could be available to Arizona should Bridge Canyon and Marble Canyon dams be built. These projects have been under consideration since 1956. Conflicts with the city of Los Angeles over the Bridge Canyon site, with the U.S. Bureau of Reclamation's proposed Central Arizona Project, and with environmental issues have delayed further consideration of these projects. In 1975 the Federal Power Commission identified 22 sites in Arizona with potential for pumped-storage. These would meet peak load demand.

Overall, the State of Arizona looks to coal as its major resource to meet future demand. Arizona ranks 15th among the 50 States for coal resources in terms of energy value and tonnage. The report estimates gross coal resources at about 21 billion short tons. Actual coal reserves are estimated at 350 to 400 million short tons.

Nevada

In September 1976 the State of Nevada sponsored "A Summary of Historical Energy Consumption and Projections of Future Energy Consumption" which included alternative energy forms. The summary recognized that utilization of Nevada's geothermal resources had been fairly limited. It also recognized that most forecasts of geothermal energy production did not show significant contributions by geothermal resources until after 1985. In 1978 the State, through the Nevada Bureau of Mines and Geology, was contributing to a study of potential geothermal sites in the State.

UTILITIES STRESS CONVENTIONAL GROWTH RATHER THAN CONSERVATION AND APPLICATION OF RENEWABLE RESOURCES

Utility companies have made conservation efforts, but have done little to measure program effectiveness. They are reluctant to rely on conservation to reduce future energy demand. The National Electric Reliability Council, an industry association, supports this view. In its seventh Annual Review the council suggests that conservation and load management measures will have an effect after several years, but until then, the industry must assume that sufficient power will be available to reliably meet the demand.

One reason why investor-owned utilities emphasize plant additions rather than conservation may be that they are allowed return on their investment in plant facilities. Although in California the rate of return may be adjusted for conservation activities, plant investment remains the central determinant of allowable profits. Conservation and load management, by reducing the need for new facilities, thus can limit future utility profits. For example, in a recent annual report by a California utility, consumer conservation which occurred during the 1977 drought was cited as the chief reason for a decrease in investment in new generating capability.

Utilities support research and development efforts on alternative resources, but are more concerned with meeting future load growth with proven technologies such as additional coal and nuclear plants. Coal and nuclear technologies are available now, while alternative sources are perceived to be plagued with many of techological and financial barriers. Utilities see them as holding little promise before the end of the century.

For example, the Electric Power Research Institute states that geothermal brine may be an important energy supplement in the Southwestern States if problems with corrosion and scaling are overcome. The Institute is less optimistic about solar energy except for space and water heating applications. As an Institute article states:

> "Solar energy is manifested in several forms * * *. All are technically capable of producing energy, but at costs that substantially exceed other alternatives."

As discussed below, utility involvement in alternative technologies has been limited compared to development of conventional resources.

A large utility company in Nevada, for example, intends to about double its capacity by 1986 from about 2,400 to 4,900 MW by adding six coal-generating plants. Conversely, the company's involvement in alternative technologies has consisted of (1) assessing the environmental impact of alternatives, (2) developing a solar energy reference library, (3) conducting a feasibility study on using solar collectors to preheat boiler water for a conventional powerplant, (4) participating in a DOE-funded project to encourage faster application of solar and wind energy in the Southwest, and (5) expressing (along with exploration and engineering firms) an interest in developing a geothermal field--with DOE assistance. While the company's activities indicate an interest in alternatives, future capacity will be acquired using coal.

Similarly, a utility in Arizona is relying on four and possibly five coal plants and three nuclear plants to meet electrical need to about 1993. Cost for coal plants is estimated in the $1.2 billion range, and $2.8 billion for nuclear. Conversely, the utility's involvement in renewable resources is limited to monitoring solar radiation at two stations (about $12,000 worth of equipment) and to financially supporting the Electric Power Research Institute research effort ($566,349).

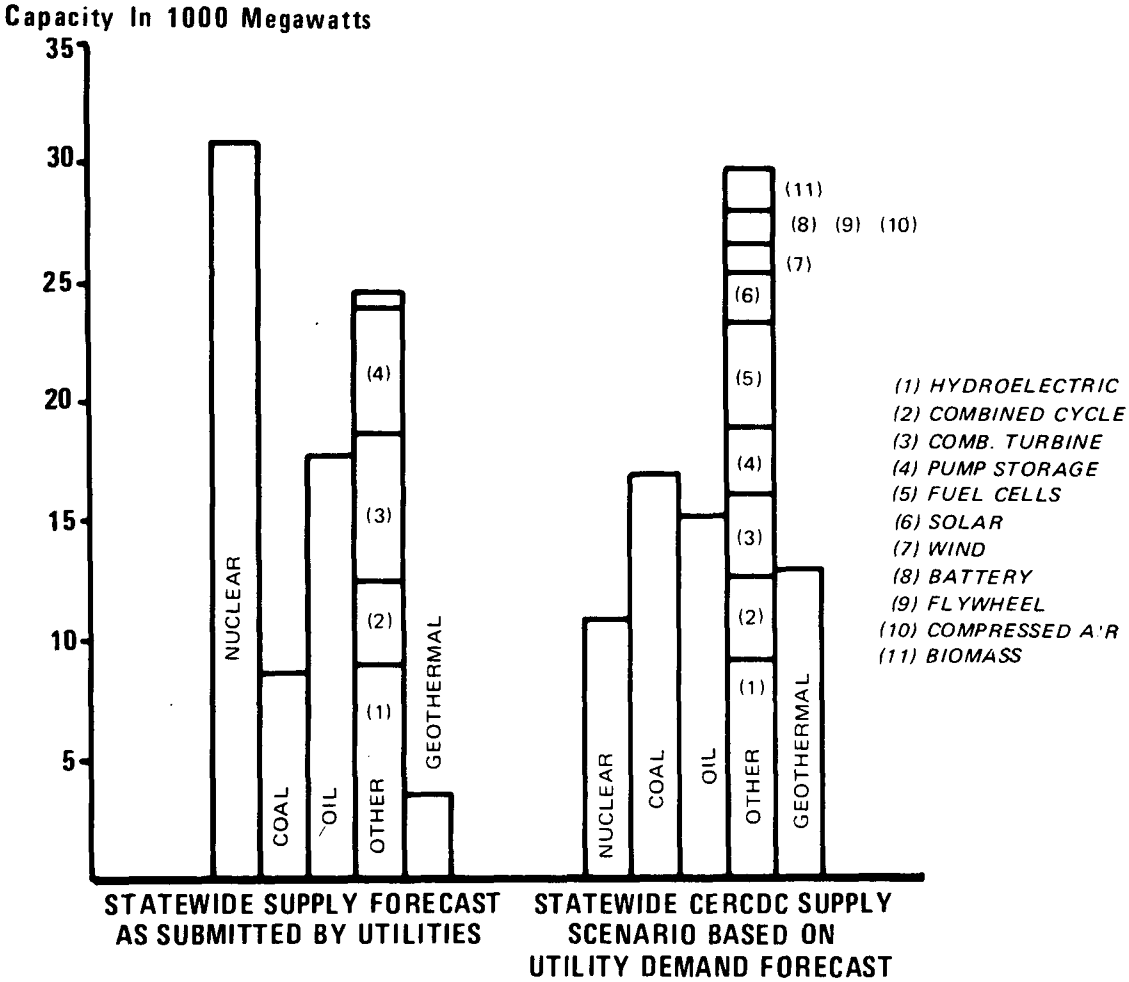
Projections of installed capacity by five major utilities indicate that coal, hydro, nuclear, and oil will provide about 66,000 MW of the 85,000-MW capacity projected by 1995 for California. Geothermal is expected to contribute about 3,500 MW and solar and wind about 300 MW. Overall, by 1995 the utilities expect nuclear power to be the dominant technology with some 31,000 MW of projected capacity.

A major Municipal Utility District in Northern California has expressed interest in participating with Federal and State Governments in demonstration projects for solar, wind, biomass, refuse, and hot water geothermal sources. A large utility company in Southern California includes solar and wind sources in its supply forecasts after 1986. However, utilities hesitate to commit resources to their development while costs are high, the technologies are of unproven reliability, and conventional technologies and fuels are still available.

These attitudes are reflected in how the utility companies forecast demand and supply. For example, the major Municipal Utility District in Northern California has forecast energy demand growth somewhat higher than has the California Energy Commission. The District foresees higher residential energy usage than does the Commission, and lower acceptance of conservation. A Southern California utility company submitted two forecasts, one using the State Commission's methodology, the other using assumptions approved by the utility's management. The company-forecasted growth rate was lower than the State Commission's because it did not expect the area's economy and population to rise as fast as the State estimated. It arrived at this estimate even though it projected that conservation measures would reduce demand less than the State expected. The company provided a supply forecast also. It was the only one of the five major utilities to include solar and wind energy in these projections. The forecast was made in accordance

Figure 4--1

COMPARISON OF CALIFORNIA ENERGY COMMISSION
AND CALIFORNIA UTILITY SUPPLY FORECASTS
INSTALLED CAPACITY IN 1995



SOURCE: CALIFORNIA ENERGY TRENDS AND CHOICES VOLUME 2 ELECTRICITY FORECASTING AND PLANNING 1977 BIENNIAL REPORT OF THE STATE ENERGY COMMISSION PAGE 155 with Energy Commission regulations, but the company cautioned the reader that "under no circumstances should any individual rely upon such information in making an investment decision."

These differences, especially the varied views about supply options are quite apparent in the California State Energy Commission comparison of utility companies and State supply forecasts. (See figure 4-1.)

CUSTOMER ATTITUDES MAY BE A BARRIER TO CONSERVATION

As it now stands, many energy-conserving activities must be initiated by individuals, not Government or utility companies. These perceptions are clues to the severity of our long-term energy problems, the costs and benefits of conservation opportunities, and the capability of research to yield acceptable technological solutions to energy problems. All may affect the level of conservation activity one could expect in the public at large.

A number of surveys have shown the lack of a sense of urgency in American attitudes on energy issues. In a 1976 study of California households, two-thirds of those interviewed expressed little concern over electrical energy shortages. A 1977 nationwide survey indicated many people believe energy will some day be a very important issue, but not now. Several studies indicate customers have confidence in new technology to solve our energy problems. Most participants of a 1976 survey of a Southern California utility company, for example, believed our energy problems will be solved once the Nation focuses its technical know-how on our energy needs.

Furthermore, the initial costs of conservation opportunities may discourage customers. For example, 57 percent of those surveyed in the above-mentioned study said utility bill savings resulting from conservation measures were not enough to encourage them to change their lifestyle. Another study noted skepticism about conservation efforts and programs because (1) they may be unnecessary since technology will solve the problems, (2) they may be a way of justifying rate increases, and (3) they have caused frustration when customers' efforts were not reflected in utility bills. Many respondents felt conservation was unnecessary because the energy problem is not real--or if real could readily be solved by industry.

FEDERAL MARKETING POLICIES

DOE and WAPA currently have conflicting goals. DOE is chartered with the responsibility of promoting the conservation of this Nation's energy resources while WAPA's practice is to promote the most widespread use of electric energy at the lowest possible rate.

Power generated at reclamation projects is dedicated first to meeting its power requirements. The remainder is sold to preference customers. Any surplus is sold to investor-owned utilites. WAPA currently has about 400 preference power customers such as military installations, irrigation districts, cooperatives, municipalities, educational institutions, penal institutions, and Federal research facilities.

Reclamation law and administrative policy provide that costs allocated to certain multipurpose areas, principally irrigation, municipal and industrial water, and power, are to be repaid by the users. Rates are set to produce revenues to pay all operating and investment costs over a given period of time. A 50-year period for repayment of power costs has been selected as a matter of reclamation policy; thus power rates are intended to be established at a level which will repay power costs in that time. Rates also cover whatever money is needed to repay irrigation investment costs beyond the repayment capability of irrigators. When power additions are made to the basic system, the new costs are averaged with all other costs, the repayment period is extended, and the rates are determined accordingly.

Federal power rates are a bargain when compared to utility wholesale power rates. For example, in fiscal year 1977, the average rate for WAPA power was about seven mills per kWh, while the average rate for alternative supplies in the three States was about 25 mills. Low Federal power rates not only fail to provide preference customers with the incentive to conserve, but also create most disparities between utility bills paid by private and public power consumers. There are basically three reasons why Federal power rates are so low.

1. Most of the Federal facilities were constructed prior to 1965 so that installed capacity costs are relatively low compared to more current construction.

2. Hydroelectric energy unlike energy produced from fossil fuels is environmentally clean, efficient, inexpensive, and renewable.

3. Federal facilities are multipurpose so much of their cost is either allocated to nonreimbursable features such as flood control or to non-interest-bearing features such as irrigation. In addition, interest-bearing features such as municipal and industrial water and power are financed at subsidized interest rates.

Federal power allocations and the accompanying low prices are guarded jealously by the preference customers. This can be seen readily in California where one municipality is suing the Federal Government for withdrawing what it considers to be its entitled share of the Central Valley Project (CVP). Several CVP preference customers have also banded together to fight proposed rate increases, and have succeeded in blocking them on the basis that rate-making procedures followed by Federal power markets were improper. These contests between WAPA and its customers require much of its administrative time.

During a recent review of electrical energy options in the Pacific Northwest, 1/ we found that the disparity between Federal power rates and private power rates has created a significant conflict between consumers. We reported that this conflict has clouded the more important issues of planning the energy future for the Northwest. Accordingly, we recommended that the Congress relieve the Bonneville Power Administration (BPA) of its charter responsibility for encouraging the widest possible use of electricity, and instead charge the agency with encouraging conservation and the most efficient use of electricity region-wide, and with marketing its power at rates that reflect energy conservation objectives.

1/"Region at the Crossroads--The Pacific Northwest Searches for New Sources of Electric Energy" (EMD-78-76, August 10, 1978).

CHAPTER 5

ANALYSIS OF TWO ALTERNATIVE ELECTRICAL ENERGY POLICIES

We analyzed two alternative electrical energy policy sets, developed by a team of energy consultants for the Pacific Southwest as it approaches year 2000. One set assumes electricity will continue to be managed as suggested by the States or utility companies; the other encourages more aggressive conservation and more development of renewable resources.

The two policy sets are not intended to forecast the future, but rather are informed estimates of the consequences of the application of particular policies upon the energy environment. Predicting the next 20 years is difficult, because energy demand depends on complicated factors, such as population growth, lifestyle, and overall economic conditions. However, as our base, we have used data which best reflect the State and utility forecasts.

SCENARIO I

This scenario is in essence a restatement of current State and utility energy policies. As we near the year 2000, Scenario I policies contemplate heavy reliance on oil, coal, and nuclear resources. There would also be efforts to conserve energy and develop minimal amounts of alternative solar and wind resources. There is no vision of significant Government efforts to change these trends. Utilities would continue to sell power at average cost; that is, old and new plant construction costs would be averaged into the rate.

SCENARIO II

This scenario envisions a conscious effort by the public, private industry, and Government to foster more aggressive energy conservation and develop more alternative renewable sources of energy.

To encourage conservation--which includes solar water and space heating--Government institutions and the utilities would expand current information programs to reach more people. Financial incentives would include more Government or utility financed development of renewable resources, tax incentives, and loans or grants for conservation programs. The States and local governments would develop stricter building codes, establish appliance standards, and develop retrofit conservation programs for residences, businesses, and industry.

Conservation costs under this policy would be much smaller than the costs necessary under Scenario I to develop the coal and nuclear powerplants contemplated to produce an equivalent amount of power. Renewable resources, however, such as solar central powerplants, are not currently competitive with conventional resources. Therefore, Scenario II introduces renewable technology based upon studies of when this technology can be technically and economically developed. This means no large quantities of electricity would be produced from these sources by the year 2000. Nevertheless, the quantities would be significantly larger than those forecast in Scenario I.

COMPARISON OF THE TWO POLICIES

We evaluated the two scenarios in terms of:

--Demand for electricity.

--Supply mix, including the cost of generating and conserving electricity.

--Economic impacts.

--Equity and distribution of impact.

--Environmental quality and the electricity supply system.

--Risk and impact of shortfall or surplus capacity.

Our conclusions and recommendations are in chapter 6. The technical data underlying our evaluation is presented in appendixes I, II, and III, which were prepared by the team of consultants. All dollar figures presented are in constant 1977 dollars.

Demand for electricity

Demand for electrical energy was categorized by the type of consumer in Arizona, California, and Nevada and was projected to the year 2000. Estimates were based on available information about present consumption, and on official or semiofficial load forecasts. For Scenario II, a set of "end-use" projections were prepared and conservation savings were estimated. Tables 5-1 and 5-2 show the energy used by final consumers and the peak demand under each of the scenarios.

Energy used by final customers

Scenario I

In Arizona there was no official State forecast of energy demands. The major electric utility forecasts were used for projections in Scenario I. A survey of electrical power used in Arizona in 1975 provided sales and peak load components that were not included in the three major utility forecasts.

In California, an adopted forecast had been developed by the Energy Commission and coordinated with the major utility forecasts. The California forecasts extend to 1995. We extrapolated to 2000 by assuming that demand growth from 1995 to 2000 would equal the growth projected from 1990 to 1995. The projections were categorized by residential, commercial, industrial, and other customers for each utility service area.

In Nevada, we used a statewide projection prepared for the Nevada Public Service Commission. These projections were prepared by sector to the year 2000.

Under Scenario I, energy demand is projected to grow at an average annual rate of 3.7 percent per year. Arizona has the highest rate of growth among the States due to rapid growth, and a widespread switch from natural gas to electricity for several applications. This conversion is reflected in particularly high projected rates of growth in the Arizona commercial and residential sectors. For the three-State area, energy demand is projected to grow to 426 billion kWh by 2000 compared to 170 billion kWh in 1975.

Scenario II

The estimates of future electricity demand in Scenario II were made using "end-use" methods. End-use forecasting methods involve a disaggregation of the major consuming sectors, (residential, commercial, etc.), according to the

Table 5-1

Energy Used by Final Consumers
(in billion kWh)

	1975			1985			2000		
	AR	CA	NV	AR	CA	NV	AR	CA	NV
Scenario I:									
Residential	7.3	44	2.8	14.3	61	4.8	24.8	86	7.2
Commercial	5.8	42	2.9	12.5	70	4.9	25.1	125	7.9
Industrial	5.7	36	1.9	10.2	58	2.7	13.6	99	3.4
Agricultural	2.3	7	.2	2.7	7	.2	3.3	7	.2
Other	.6	11		.8	16		1.2	22	
Total	21.7	140	7.8	40.5	212	12.6	68.0	339	18.7
Scenario II:									
Residential	7.3	44	2.8	12.0	58	4.1	18.5	76	5.4
Commercial	5.8	42	2.9	7.8	48	3.6	12.4	57	4.7
Industrial	5.7	36	1.9	9.9	42	2.4	13.0	45	3.1
Agricultural	2.3	7	.2	2.4	7	.2	3.0	7	.2
Other	.6	11		.7	16		1.1	22	
Total	21.7	140	7.8	32.8	171	10.3	48.0	207	13.4

Table 5-2

Power Used at Peak Periods
(Coincident Peaks at Load)
(in 1,000 MW)

	1975			1985			2000		
	AR	CA	NV	AR	CA	NV	AR	CA	NV
Scenario I:									
Residential	2.1	9.5	.7	3.8	13.4	1.2	6.2	18.8	1.8
Commercial	1.3	8.7	.6	2.4	15.5	.9	5.1	26.7	1.5
Industrial	.8	6.6	.3	1.8	10.6	.3	2.6	18.0	.5
Agricultural	.6	1.8	.06	.8	1.8	.06	1.0	1.8	.06
Other	.2			.2			.3		
Total	5.0	26.6	1.66	9.0	41.3	2.46	15.2	65.3	3.86
Scenario II:									
Residential	2.1	9.5	.7	3.3	11.7	1.0	4.8	14.8	1.4
Commercial	1.3	8.7	.6	1.3	10.2	.7	1.7	10.8	.9
Industrial	.8	6.6	.3	1.5	7.8	.3	2.0	9.4	.4
Agricultural	.6	1.8	.06	.7	1.6	.05	.9	1.6	.05
Other	.2			.2			.3		
Other load management				-.2			-.4		
Total	5.0	26.6	1.66	6.8	31.3	2.05	10.2	36.6	2.75

final uses of the energy (space heating, lighting, refrigeration, etc.). Future requirements are then forecast for each end-use and the results are reaggregated to obtain the major sector requirements. This method has the advantage that it permits a realistic simulation of the actual situation including the effects of new policy. End-use forecasting is an alternative to trend forecasting, which extends into the future past trends in comsumption by the major sectors. It also is an alternative to aggregated econometric forecasting, which focuses on establishing, by statistical methods, the dependence of electric consumption in a sector on certain explanatory variables. Aggregated econometric forecasting differs from end-use forecasting in that it emphasizes statistical methods for finding the best fit of actual data to relatively simple forecasting equations for aggregated sectors whereas end-use forecasting emphasizes realistic simulation of end-use requirements even if modeling rather than regression methods must be used to completely define the forecasting equations.

However, there is no reason why the two methods cannot be blended, and in fact, they often are. Thus unknown coefficients in end-use forecasting equations can be established by econometric methods. The "end-use" projections for most sectors in this report are carried out in two steps. In the first step we assume that there is no increase in electricity consumption (1) per electrical appliance in residences, (2) per square foot of commercial floor space, or (3) per unit of industrial output. In the second step, we identify specific conservation opportunities and estimate the potential reduction in rate of demand for end-use category.

In Scenario II, the average annual rate of growth is 1.9 percent per year. The growth rate is somewhat higher for Arizona, as it was in Scenario I. Among sectors, the greatest reduction is for the commercial sector. By 2000, energy consumption in Scenario II is projected to be 269 billion kWh, which is 58 percent above the 1975 level of 170 billion kWh, but 37 percent below the Scenario I projection of 426 billion kWh for 2000.

Power used at peak periods

Scenario I

Peak loads are projected to grow under Scenario I at about the same rate as total energy consumption. By 2000, the three-State peak load is projected at 84,400 MW for Scenario I which is 51,200 MW over the 1975 level. If this rate of growth is realized, 59,800 MW of additional capacity would be required by the end of the century.

Scenario II

Under this scenario, peak load for the three-State area is 96 percent above the 1975 level. This is a slightly smaller growth than for energy due to shifting away from high-peak loads and due to a small saving by load management. The average annual rate of growth in peak power is 1.5 percent per year under Scenario II. Scenario II projections indicate that 25,700 MW of capacity will need to be added between 1975 and 2000. This is 34,100 MW less than the capacity needs indicated under Scenario I.

Approximately two-thirds of the decrease in Scenario II is due to basing commercial and industrial projections on constant rather than on increasing energy use per unit of end-use activity. This raises a critical question for the Pacific Southwest. Will energy prices, policies, and businessmen's attitudes forestall further intensification in electricity use?

Supply mix, including the cost of generating and conserving electricity

Not only does Scenario II result in less demand for electricity than Scenario I, but it also results in a more diversified supply mix, as shown in table 5.3. Scenario II shifts from the traditional oil and gas, coal, and nuclear energy to renewable resources.

The high cost of oil has the effect of phasing out the use of this fuel over time. This is in line with Federal policy, and occurs because it becomes less expensive to operate plants that use coal, nuclear fuel or other resources.

The cost of meeting the demand under Scenario II is much lower than under Scenario I because the cost of conservation is less when compared to building additional capacity. This is reflected in the schedule below.

Table 5-3

Electricity Production from Various Energy Resources under Scenarios I and II, Arizona, California and Nevada (billion kWh)

Resource	1975 Actual	1985 Scenario I	1985 Scenario II	2000 Scenario I	2000 Scenario II
Oil/gas	87.0	132.1	90.7	52.9	35.4
Coal	27.6	54.5	43.5	169.4	65.8
Nuclear	5.9	48.5	48.5	174.2	54.7
Geothermal	3.2	11.6	6.8	23.9	52.6
Hydro	41.2	36.2	36.2	37.8	42.8
Solar	-	-	-	1.1	23.1
Wind	-	-	-	.1	10.1
Biomass	.7	1.8	1.8	3.0	3.0

Table 5-4

Annualized Cost of Meeting Electrical Demand in Three States under Scenario I and II
(in millions of dollars)

	1975	1985	2000
Arizona			
Scenario I	$ 612	$1,755	$ 3,464
Scenario II	612	1,641	2,624
California			
Scenario I	4,174	8,977	16,137
Scenario II	4,174	7,874	10,918
Nevada			
Scenario I	266	536	898
Scenario II	266	473	635

As the table illustrates, the costs of Scenario II are consistently and significantly lower than those of Scenario I for each State. In California this is attributable to the shift from construction of facilities, especially nuclear, toward conservation. As a result, the annualized cost of nuclear power goes from $6.8 billion in the year 2000 under Scenario I to $2 billion under Scenario II; the cost of coal goes from $5.7 billion to about $2 billion under Scenario II; and the cost of conservation rises to about $2.8 billion.

While the total cost of conventional sources of power is less under Scenario II than under Scenario I, the cost of developing geothermal, solar, and wind renewable resources is more. Under Scenario I Arizona and Nevada did not contemplate developing wind or solar resources by the year 2000; in California, we identified about $423 million in annualized costs for geothermal in 2000 and $49 million for solar-central. In Scenario II we increase these estimates as follows by the year 2000.

Table 5-5

Annualized Cost Estimates of developing Renewable Resources under Scenario II (in millions of dollars)

	Geothermal	Solar	Wind	Total
Arizona	$ 13	$ 50	-	$ 63
California	846	796	$340	1,982
Nevada	72	50	-	122
Total	$931	$896	$340	$2,167

Conservation

Under Scenario I, policies to encourage energy conservation are already in effect in these States or appear likely to be adopted in the near future. Mandatory energy efficiency standards for new major appliances have been adopted in California. In addition, California has proposed a "utility outreach and appliance labeling" program. It could save 1,200 MW by 1985 simply by increasing consumers' awareness of opportunities for selecting more energy-efficient appliances.

In addition, mandatory energy efficiency standards for new buildings have been in effect since 1976 in California. There are also Federal standards for residential buildings financed under Federal Housing Administration mortgage loans. The design standards followed in most new construction of commercial and public buildings have also been recently revised to significantly improve energy efficiency.

A tax credit for solar systems equaling 55 percent of the cost incurred, up to $3,000, is provided in California. A 15-percent Federal tax credit is available. Purchasers would presumably be eligible for both credits.

All utilities in the three-State area have conservation programs. These usually include information and energy audit programs for customers. In addition, several utilities are planning or considering programs to assist customers in retrofitting existing residences.

Under Scenario II, conservation programs reduce the cost of power significantly by the year 2000 as shown in the following schedule.

Annualized Cost of Conservation
(in millions of dollars)

Consumer sector	Arizona 1985	Arizona 2000	California 1985	California 2000	Nevada 1985	Nevada 2000
Residential	$ 87	$303	$306	$ 839	$27	$ 85
Commercial	4	15	57	220	2	8
Industrial	10	23	410	1,280	9	9
Total	$101	$341	$773	$2,339	$38	$102

In the residential sector, electricity conservation is achievable mostly by improving the thermal efficiency of housing units that are heated or cooled with electricity and by improving the operating efficiency of electrical appliances in all residences.

The potential for savings is affected by how many housing units will be built and how many will be equipped for energy conservation. The number of residences equipped with various electrical appliances, especially the number electrically heated and cooled, is also important.

Conservation measures for the residential sector under Scenario II include

--retrofit of existing residences with ceiling insulation,

--retrofit of walls, floors, doors and windows, etc.,

--improved insulation and thermal efficiency standards for all future residential construction,

--super insulation and energy-efficiency design of new residences,

--substitution of heat pumps for resistance-type electric space heating,

--solar-assisted space heating,

--retrofit insulation of water heater, set back of thermostats 10 degrees, and reduction of hot water use,

--solar assistance for water heating, and

--improved energy efficiency in appliances.

Electricity conservation in the commercial sector proposed under Scenario II is to limit electricity use per square foot of floor space to current average levels. Other measures include:

--Adopting standards for new buildings similar to those in title 24 and 20 of the California Administration Code. Title 24 sets standards for envelope insulation, heating, ventilation and air conditioning systems in new non-residential buildings. It also covers equipment, service water heating, electrical distribution systems, and lighting levels.

--Initiating a retrofit program to reduce lighting levels and air conditioning requirements in existing buildings. "Delamping" is a relatively simple process, but making other changes to reduce electricity used for air conditioning will be difficult in many buildings.

--Extending the coverage of title 24 standards to hotels, motels, and hospitals, and encouraging further savings in electricity use for air conditioning in auto repair shops, warehouses, and schools.

The amount of savings in electricity achieved with each of these measures is computed in appendix I, table I-7.

Electricity savings in the industrial sector was based on a recent study performed by the Committee on Nuclear and Alternate Energy Systems (CONAES). In the CONAES project savings were compared to consumption that would be expected if industries maintained constant energy intensity, i.e., constant use of energy per unit of production, from 1975 to 2010. We modified the CONAES projection to fit Scenario II. The reduction in energy intensity we finally adopted and estimates of energy conservation savings for the industrial sector are shown in appendix I, tables I-8 and I-9.

Reasons other than response to higher electricity prices could reduce demand for irrigated agriculture. Water conservation in the arid Southwest is a high priority. Actions to increase efficiency and reduce water use would of course decrease the use of energy to lift the water for delivery to the land. The opportunities for such savings in California have been estimated at 1.1 million acre-feet 1/ of water in basin consumption. Other States in the area also could probably save large amounts of water.

Some of the energy conservation programs under Scenario II will be regulatory. For example, programs promoting thermal efficiency for new construction and energy efficiency for new appliances would set mandatory conservation standards. Other programs, such as retrofitting existing buildings, are not well suited to regulation and hence will most likely seek voluntary cooperation by the building or company owner.

The financial situation of individual customers, idiosyncrasies of specific applications, tenure arrangements, differences in knowledge about conservation, and the like may cause individuals to choose not to conserve even though it would generally benefit them economically. In such cases subsidies can be used to overcome various deterrents to conservation by making it less expensive and more attractive. Some subsidies are already available.

In Scenario II, if one assumes the continuance of average cost pricing, subsidies would be required to encourage retrofitting residential buildings and installing solar assist measures. The same is true of retrofitting commercial buildings and adopting industrial conservation measures. However, under incremental cost pricing of power, such subsidies would not be required.

In the residential sector, it is assumed that a 25-percent subsidy on the costs of the retrofit and solar assist measures would gain voluntary compliance. In the commercial sector, a 50-percent subsidy would be required to bring the payback period for most retrofit measures

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1/One acre-foot is the amount of water needed to cover 1 acre with 12 inches of water. It is about 325,000 gallons.

down from 10 to 20 years to the 3 to 5 year payback period that commercial firms are generally seeking. In the industrial sector, a 25-percent cost subsidy would bring the benefit-cost ratio up to the level that would be attained with incremental cost pricing.

The total conservation subsidies required with these criteria are:

Table 5-7

Required Annual Outlay for Finance Subsidies
($ million year)

State	Residential 1985	Residential 2000	Commercial 1985	Commercial 2000	Industrial 1985	Industrial 2000	Total 1985	Total 2000
Arizona	$ 4	$ 12	$ 2	$ 8	$ 2	$ 6	$ 8	$ 26
California	24	70	28	110	13	75	65	255
Nevada	1	3	1	4	2	2	4	9
Total	$ 29	$ 85	$ 31	$122	$ 17	$ 83	$ 77	$290

The above costs are stated in terms of average annual outlay that would be required for interest and principal repayment over the life of a loan or bond. This outlay represents an amount sufficient to finance the subsidized portion of the initial investment in conservation devices.

Economic impacts of electricity scenarios

There is considerable concern that electricity policies aimed at reducing the rate of growth in electricity use will depress economic growth and cause unemployment. The concern probably arises from the correlation between economic activity and electricity use. Rich nations use more electricity than poor nations, and poor nations use more electricity as they become richer. The rate of growth in use of electricity quickens and lags more or less in step with the booms and recessions of the economy.

This correlation is commonly used as a basis for forecasting future electricity demand. However, the question is whether energy policy actions that decrease electricity consumption will necessarily retard economic growth.

The effect of energy availability and energy policy on the economy has not been studied until quite recently. In the last few years, however, there have been several such energy/economic analyses. These studies indicate that long-term increases in costs have relatively small effects on the overall level of economic activity.

These predictions of small economic impacts from relative large changes in the energy supply situation are borne out by experience since 1973. The price of oil and natural gas suddenly increased two-fold for most customers, and supplies sometimes were not available. Since then, energy use has grown much more slowly than in the 1960s. Nevertheless, it would be difficult to attribute any more than a brief lag in economic activity to the price increases and the lower energy growth rates that have applied ever since.

In the short run, a sharp economic shift to more conservation and less electricity production will require adjustments. Some workers, equipment, and plants would need to be employed for different purposes, such as producing insulation and heat pumps instead of power plants and electric furnaces. These shifts could not all occur immediately so some workers and facilities might be stranded--committed to producing products in greater amounts than are needed after directions change.

Scenario I foresees a continuation of past policies and only slightly reduced rates of growth in electricity use. This growth between now and 2000 is projected at 4.7 percent per year in Arizona and 3.6 percent per year in California and Nevada. This is only slightly above projected rates of growth in total State output, so electricity use is expected to grow in proportion to industrial production and personal income. But more expensive means will have to be used to generate the additional electricity, so the costs of electricity supply will rise about 50 percent faster than will the quantity supplied. Total electricity supply costs in the three States are projected to rise four-fold from $5 billion in 1975 to $20.5 billion in 2000 (measured in 1977 dollars). The economic impact of the projected growth in electricity supply will be determined more by the rapidly growing expenditures of the industry rather than by the more slowly growing quantity of electricity supplies. The hiring of workers and purchase of goods and services from other sectors will grow more rapidly than in the economy in general. In the short run, rapid growth by a sector can be beneficial for resolving problems of unemployment and idle capacity. However, in the case of electric utility growth envisioned in Scenario I, there are some offsetting negative aspects to the growth.

Scenario II is characterized by (1) much less electricity use, only 63 percent as much as Scenario I in 2000, (2) real costs of electricity supply that are less per kWh in 2000 than in Scenario I; and (3) costs of $2.8 billion per year for additional conservation (over and above the conservation included in Scenario I). As a result of these differences, the economic impacts of Scenario II would differ significantly from those of Scenario I.

Under Scenario II, the electric utilities will represent a smaller share of the total economy in 2000 than they do at present. Their revenues and costs, are projected to be 2.2 times the 1975 level. The total costs of meeting electricity needs in 2000 are estimated at $14.2 billion, for the three States, including $11.4 billion in supply system costs, and $2.8 billion for additional conservation measures not already included in Scenario I. In contrast, total electricity supply system costs in Scenario I are estimated to be $20.4 billion.

<u>Observations on the impact of each scenario and policies</u>

Under Scenario II, the slow growth of electricity supply and of the value of utilities' sales (which must equal costs) means that the utilities will be a decreasing factor in the States' economies. Utilities will employ fewer workers and do less business with other sectors than they would if a Scenario I type of energy future were realized. However, this does not mean that there would be a sudden gap in employment and business activity. Electricity supply and conservation costs together would account for about the same share of total regional production and income as they did in 1975. Thus, meeting electricity needs under this scenario will require very little adjustment of the economy as it was in 1975. Furthermore, electricity system growth in Scenarios I and II is much more similar until 1985 than it is after that time.

There is concern that policies designed to direct the States' energy future toward Scenario II will hinder industrial production and retard economic growth. For example, rationing energy to industrial users could cause some firms to receive less than the minimum needed to run their businesses. "Brown-outs" and interruptions might occur if reserve capacity is inadequate. This would damage business by far more than the value of the power involved. In view of the seriousness of these impacts, Scenario II concentrates on reducing demand while providing adequate supply to meet the demand.

Another possible policy move that arouses concern is an "OPEC-style" price increase. Electricity prices could be increased to encourage conservation and discourage consumption. The effect of an increase to meet rising costs has already been discussed above. Even if the increase amounted to a relatively small share of total production or living costs, there would be economic contractions, or reduced growth, as an ultimate response. However, the ultimate impact on the economy can be quite different if the price increase is not necessitated by higher costs but instead is "recycled" back to the economy. The recycling could take the form of subsidies for the adopters of cost-effective conservation measures or investors in desired renewable energy resources. Alternatively, funds obtained through charging a price that is above average cost might be used for general tax relief, for a "dividend." (As long as it is not distributed in proportion to electricity use.) The "recycled" revenues would either decrease someone's costs or increase someone's income. This would set in motion economic expansion that would tend to offset the contractionary effects of the electricity rate increase. The expansion might take place in different sectors than the contraction. (For example, a general rate increase might lead to contraction in the electric utilities, electro-process industries, and generating equipment manufacturers, and to expansion for insulation, construction, and electrical equipment manufacturing.) However, the overall impact on the economy should about balance out as long as the excess revenues collected through a designed price increase are refunded into the same economy that they came from.

The most threatening price increases are those for which the added revenues are not refunded in any form. They could be increases that push the system into higher cost-generating modes, as in Scenario I, or unwise allocations of the revenues to very costly and/or relatively useless programs or reallocation of the increases to other regions.

Equity and distribution of impacts

It is very likely that the costs of supplying electricity will be, on the average, much higher during the next 20 years than they have been in the past. Policies that facilitate less expensive supply options can help reduce the size of the cost increase, but it is very unlikely that it can be completely avoided. The added costs must be paid, somehow, by the electricity customers. Rate or pricing policies will determine the distribution of that added cost among various classes and types of customers. The only way to avoid an adverse impact for some groups is to have others shoulder a larger share of the added costs through higher utility rates or increased taxes. This raises the difficult issue of equity.

Some aspects of equity are:

--Should every individual bear a fair share of the costs caused by his or her activities (i.e., no freeloaders or special favors)?

--Should individuals and industries be protected from sudden, unexpected financial disasters (i.e., no wipeouts)?

--Should poor people, lagging regions, and struggling industries be helped whenever possible and, at least, protected from the pressure of further increases in their costs?

Under Scenario I, the added costs of future supplies are assumed to be paid directly by customers in the form of higher rates. However, there is no rate reform except as required to cover the added costs. So differences that now exist among customers will tend to be carried forward. Specifically, customers with contracts for low-cost WAPA power will be able to continue to get that power at the costs of hydro-generation.

Arguments over equity in Scenario I are likely to center around (1) the impact of power cost increases on individuals and businesses and (2) the growing disparity between rates of average customers and the few customers who are in a position to get inexpensive power from WAPA.

In Scenario I, the average cost of electricity supply increases from 29.7 mills/kWh in 1975, to 48.2 mills/kWh in 2000. Two-thirds of the increase occurs by 1985 as more expensive generating systems are rapidly expanded to form a large fraction of the 1985 rate base. A few electricity customers will be hit hard by these rate increases. Irrigators that do not have access to guaranteed low-cost power will find electricity too expensive to continue high-lift pumping for any except high-value fruit and vegetable crops. The cost increase will be enough to drive a few irrigators out of business. More often, irrigators will switch to alternate fuels, if available, or make increased effort to conserve both water and energy in their farming operations. There would be very few new high-lift irrigation developments at these rates.

Most industries and commercial businesses would not be seriously affected by such rate increases. They would not likely be driven out of business by them. They might, however, be caused to seriously seek ways to avoid the projected increases in electricity use per unit of production.

The average residential customer's electricity bills would more than double by the end of the century under Scenario I. The increase would come from projected higher rates plus increased usage per household. An expected movement toward electric space and water heating is a factor, especially in Arizona where all new residences are expected to be forced to use electricity due to a moratorium on new gas hook-ups.

In Scenario I, there could be serious adverse impacts on individuals or industries that are already having economic difficulties. Some owners of irrigated land fall into this category. Most industries do not. Some low-income house owners that are already in financial difficulty might be hurt by the anticipated rate increase. Still, average electric bills will be only about $35 per month (in 1977 dollars) in California. Even a low-income family by year 2000 standards would not find this to be a large portion of its monthly budget. But there is always the possibility that public opinion would favor the use of electricity rates as a means of helping the needy by shifting some of the costs of their needs over to others through special rates or through a tax/subsidy program.

Under Scenario II, the average cost of supplying a kWh of electricity rises rapidly to 1985 but then stays almost constant to the end of the century. Therefore, the rates that must be charged to cover the average costs of supplying electricity need not rise as much as they would under Scenario I. Furthermore, demand for electricity grows much less rapidly, due to conservation, so that total electric bills need to be only about 60 percent as large as in Scenario I to cover all supply system costs. There are conservation costs as well, but they are quite small compared to electricity supply costs. Thus, overall costs of meeting energy needs with a combination of electricity supply and conservation will average much less under Scenario II than under Scenario I. In fact, costs of electricity supply and conservation per kWh of Scenario II-type base demand are only slightly above the average 1975 cost/kWh.

Lower costs under Scenario II mean it could have less general impact and less likelihood that needy individuals or weak industries would be put in jeopardy by rising power costs. Impacts of that sort will be considerably less than under Scenario I. However, Scenario II involves more costs outside the electricity supply system for specific conservation measures and for a general effort to hold down the increase in electricity use. Scenario II also more explicitly includes intervention in prices and policies to channel the electricity future of the region more toward national energy objectives. These emphases could affect some customers in ways that could be questioned on equity grounds.

One of the anticipated changes in Scenario II is more involvement of WAPA in the furtherance of conservation and alternative energy sources. This would result in WAPA rates rising in order to cover the added costs. If WAPA financed the cost subsidies that are required to get adoption of conservation by users and built a substantial fraction of the solar and wind powered generating plants scheduled in Scenario II, WAPA rates would have to rise to about the same level as other utilities in the area. This would eliminate disparities and reduce the conflict that would arise if WAPA rates came to be only about one-fourth as high as those of other suppliers. But an increase of 2 or 3 cents/kWh in the price of electricity to a long time WAPA customer would be quite a "disappointment."

The most noticeable impact of a substantial WAPA rate increase would fall on irrigators, who use about one-fourth of all WAPA power. They would be hard hit by a rate increase because the amount of electricity they use can be quite large relative to the value of production. For example, an irrigator who is lifting water 500 feet and applying 4 acre-feet per acre will use about 5,000 kWh of electricity per year to produce crops that average (in 1976 figures) $700 gross value per acre. Electricity use is about 7 kWh per dollar of output, which is above the use rates of even the electricity-intensive industries. Each 1-cent per kWh rate increase, in this case, would represent a cost increase equal to 7 percent of gross returns. If the farmers happen to be producing low-value grain and forage crops, value might be $300 per acre per year, and electricity consumption becomes 17 kWh per dollar of output. Costs would increase by 17 percent of gross value for each 1 cent per kWh increase in power rates. An increase of 3 cents per kWh, which is not inconceivable, would increase power costs by an amount equal to 50 percent of gross value.

Many irrigators in all three States are much less affected by power rate increases than this example indicates. They do little or no pumping, or they are producing crops with high values that completely overshadow the effects of rate increases. Several California hydrologic basins, parts of Arizona, and most of Nevada obtain irrigation water with less than 100 feet of pump lift. Pumping energy requirements in these areas are less than 1,000 kWh/acre/year, and a 1-cent per kWh rate increase will cause only a $10 per acre per year cost increase. In other areas, fruit and vegetable producers have crop values ranging from $1,000 to $4,000 per acre. Even if power costs double, the cost of electricity is only a small fraction of total costs and gross returns.

Analyses by G.D. Knutsen, et al., 1/ include estimates of pumping energy requirements for different crops, water sources, and application methods in each of California's hydrologic basins. The areas under most pressure to

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1/Knutsen, G.D., R.G. Curley, E.B. Roberts, R.M. Hagan, and V. Cervinlaca, Pumping Energy Requirements for Irrigation in California, U. of Calif., Div. of Agric. Sci., Spec. Pub. 3215, Rev., Feb. 1978.

respond will be those where large amounts of electricity are used to produce low-value crops.

The resources were not available for an indepth study of irrigators' most profitable and probable response to higher power rates. However, results of a study in the Bonneville Power Administration service area 2/ indicate that irrigators will first take actions that reduce energy use without affecting production patterns. Measures that improve water and energy efficiency are profitable for everyone as long as they cost less than continued purchase of power at new, higher rates. A 10-percent average savings is reasonable to expect by this means if a moderate rate increase is combined with information and demonstration programs. Beyond that, further energy savings may entail expensive facilities, such as drip systems, crop changes, or land abandonment.

The next line of response would generally be shifting crop acreages and making permanent changes that improve pumping efficiencies. Low-pressure systems and improvements to pumping plants become more attractive as power costs rise. Farms will reduce production of grains and forages, partly by substituting other crops and partly by reducing land irrigated in the high-cost areas that have a limited range of cropping alternatives. A rate increase in the range from 1.5 cents to 3 cents per kWh would put considerable pressure on Southern California areas. They require high pumping lifts for importing water from Northern California and the Colorado River. Pressure would also fall upon areas in Arizona that are lifting water 300 to 500 feet out of rapidly declining groundwater aquafers.

The most dramatic response and effect will be where there is a reduction in land irrigated due to a water and energy cost crunch. In Southern California and parts of Arizona the effect could be softened because land and water are already being converted from agriculture to urban

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2/Departments of Agriculture Economics, University of Idaho, Oregon State University, and Washington State University, Demand for Electricity by Pacific Northwest Agriculture, Report for Bonneville Power Administration, EIS on Rate Increase, Portland, June 1978.

use at a substantial rate. If high-value crops can be concentrated on the land that remains in agriculture, the specter of dried up farms may be avoided.

Actually, the largest economic change would be the effect of higher power rates on the irrigators who continue to operate with few adjustments. These irrigators will find that their costs increase, perhaps by more than $200 per acre per year, and hence, their net returns will be reduced. This decline will soon be reflected in the value of land, at a capitalized rate that is several times as large as the change in annual income. This impact on land values will affect all power users, although it will be proportionately less for those irrigators that use only small amounts of power. If a rate increase of 1 cent per kWh were applied to the entire 10,000 million kWh used for irrigation pumping in the three-State area, irrigators' costs would be increased by $100 million per year. This implies a decrease of about $1 billion in the market value of irrigated farmland. Actually, some of the cost increase can be avoided by measures that were discussed above. In some cases the threatened cost increases are larger than the total profit now realized from farming the land. Still, even if the impact only amounts to $500 million less land value than would have otherwise been enjoyed, it is a substantial loss to owners of the area's 10 million acres of irrigated land. Also, the impact is very unevenly distributed, so it will fall hard on some land owners. On the other hand, it can be argued that land values have been rising rapidly due to inflation. Therefore an adverse impact now will tend to offset only very recent gains. Furthermore, there is the possibility of gradually phasing the rate increases so that their impacts are offset by the general increase in land prices.

Environmental quality and the electricity supply system

The environmental effects of electricity generation in the Southwest will depend on the number and types of powerplants being used. The more plants constructed and operated, the more significant the effects. Scenario I therefore has a more detrimental impact on the environment than does Scenario II. Yet, it should be recognized that some of the technologies promoted in Scenario II such as geothermal, solar, and wind energy also harm the environment somewhat--especially aesthetically.

The environmental effects of various energy-producing technologies can be direct, such as lung irritation produced by air pollutants, or indirect, such as the exercise of police power to prevent theft of nuclear materials. Some of the environmental effects of various energy sources are discussed below. (The environmental impact associated with the major sources of electric power in the Southwest are discussed in detail in app. III.)

Hydroelectric generation

The adverse environmental impacts of hydroelectric power are generally related to the (1) welfare of fish and wildlife, (2) loss of the use of land that is inundated, (3) loss of free-flowing streams, and (4) other aesthetic changes and recreational problems. New energy capability that comes about as a result of installing more generators in existing dams can be expected to be, on the whole, less disruptive than energy produced by raising the height of existing dams or by constructing new dams.

Coal fuel cycle

In addition to the environmental issues discussed in chapter 2 which deal with the various views about coal, we have analyzed some of the environmental impacts of coal generation in technical terms, with special emphasis on pollutant emissions.

The relative impact of coal for each scenario can be expressed in terms of the number of coal fuel cycle plants required under each. Scenario I would require construction of some 39 additional plants in the three States instead of the 11 plants required under Scenario II assuming each plant could produce 500 MW.

Coal-fired plants will add particulates, sulfur dioxide, nitrogen oxides, hydrocarbons, and trace amounts of other toxic elements to the air in their vicinities, and the stock emissions can be expected to produce effects on health, aesthetics, and property.

Nuclear fuel cycle

Scenario I would require the construction of some 24 additional nuclear plants in Arizona and California--assuming each plant could produce about 1,000 MW. Scenario II requires construction of seven nuclear plants.

The principal environmental effects of nuclear power arise from uncertainty that government can cope with the consequences of malfunctions and misapplications of the technology. A derivative concern is that covert investigations, invasions of privacy, and massive emergency exercise of police power may be necessary to prevent the diversion of nuclear weapons-grade material in a nuclear economy employing spent-fuel processing and plutonium separation. There will also be some effects on health that arise from routine plant operation, but they will be small.

Catastrophic malfunctions of nuclear powerplants or diversions of material have a low probability. Events leading to enormous disasters can be conceived, but the likelihood of their occurrence is estimated by most (but not all) analysts to be infinitesimally small. One faction focuses on the major consequences of a reactor core meltdown, nuclear blackmail of a major city, or contamination of a regional water supply by a leaking radioactive waste disposal site. The opposite faction emphasizes redundant safety features, elaborate security measures, and stable geologic formations. The first side fears the complex nuclear technology and mistrusts the Government security that surrounds it. The second side sees few problems with either.

In view of this uncertainty, the two scenarios simply describe the potential effects caused by the number of nuclear reactors in the region. In a somewhat arbitrary way, a qualitative distinction is made between having fewer than 5 nuclear reactors, or 5 to 20, or more than 20 in the three-State region. Fewer than five are regarded as manageable on an individual basis. If there are from five to 20, all the risks and hazards of nuclear power would be present to a significant degree and must be dealt with on a regional as well as individual basis. In this range the problems would be much the same regardless of the number of plants. If there are more than 20 plants, the actual and potential impacts would again rise as the technology spreads. Under Scenario II, the nuclear power situation in the three-State region falls into the intermediate category; under Scenario I, it falls just above the intermediate category.

Biomass

Biomass contributes air residuals characteristic of wood fuels. In appendix III, the tons of residuals produced in this way are compared to end-use residuals for Scenario I.

Wood wastes generate air residuals in amounts less than 1 percent of those produced by end-use applications in California. The solid wastes produced in combustion of wood require disposal methods similar to those involved in ash disposal for other fuels.

Solar and wind energy

The principal impacts of solar and wind units appear to be commitments of land. Land occupied by central-station solar power is 1 to 2 square miles per 100 MW. For wind, the commitment is 0.4 to 0.8 square miles per 100 MW. Using these numbers, we computed the land area committed to these renewables in the region for Scenario II in the year 2000, as follows:

Table 5-8

Resource	Land commitment (square miles) 1985	2000
Solar	0	18 - 36
Wind	0	2 - 4

Each of these is a larger land commitment than required by thermal plants but is comparable to the land commitments involved in transmitting the power from the generating stations to the power markets.

The visual impact of these units might be quite different from the visual impact of thermal powerplants because the technologies involved represent a very different approach to energy supply. The disruption of television service in the vicinity of large wind turbines would be objectionable to nearby residents. However, the effect would be local and should be correctable through use of cable reception.

The impacts described here are limited to those associated with central station powerplants; distributed (i.e., decentralized) systems are not included because the acquisition of such units is voluntary to the user and the impacts appear to be small and widely dispersed.

Geothermal generation

Geothermal sources of energy cover a wide range of pollution potential. The fluids from hydrothermal reservoirs sometimes contain large amounts of salt that can be quite polluting if they are released into surface waters. For this reason, present trends are to reinject them into the reservoirs from which they are withdrawn. If the brines are reinjected, the amounts of salt released will be minimal and will occur during initial well test procedures, well clean-out operations, or accidents. Under these conditions, salt releases from geothermal powerplants are smaller than the corresponding releases from coal-fired plants of the same size.

The principal gaseous emissions from hydrothermal sources are carbon dioxide, hydrogen sulfide, and ammonia. Carbon dioxide releases are generally much smaller per unit of electricity produced than are the releases from conventional plants. Sulfur and ammonia releases are somewhat larger than sulfur dioxide and nitrogen oxide emissions from coal plants.

So far, there is not much experience with land subsidence or seismic activity from geothermal development in this country, but land subsidence can be expected whenever large amounts of material are withdrawn from underground. There is ample evidence of impacts of land subsidence from coal mining and oil production. Reinjection of brines raises the risk of seismic effects.

The noise at geothermal plants is intermittent and is produced during the testing and cleaning of wells. Sound levels in the vicinity of such operations can reach 90 decibels, about the level of a passing freight train and above levels that are likely to be adopted as noise standards.

Oil and gas fuel cycles

Oil and gas fueled steam plants, gas turbine plants, and combined cycle plants contribute to air pollution just as coal plants do. The amounts of residuals that can be expected for Scenario I are computed in Appendix III. In California emissions of particulates resulting from the use of oil and gas in powerplants are small compared to the corresponding emissions during end-use, but nitrogen oxide and sulfur oxide emissions are more nearly comparable for the two classes of use. Sulfur oxide emissions for powerplants increase sharply from 1975 to 1985, partly because of the expected shift away from natural gas to oil.

The process emissions from oil refineries also can be partially attributed to production of fuels for electricity generation. However, only the sulfur dioxide emissions from California refineries are very significant.

Of course, all emissions are important in those parts of California where ambient standards are exceeded. The 24-hour particulate standard is often exceeded in almost all parts of the State. The only exceptions are the mountain counties (El Dorado, Placer, Plumas, Tuolumme). The sulfur dioxide standards are exceeded around Fontana, Whittier, Los Angeles, and San Francisco. In Arizona, the 24-hour and annual particulate standards are exceeded in many parts of the State, and the sulfur dioxide standards are violated at sites near the copper smelters. The situation is similar in Nevada.

Impact of shortfall or surplus capacity

Comparison of risks and impacts of shortfalls and surpluses does not show any clear-cut advantages of one scenario over the other.

The supply of electricity may occasionally be less than or greater than long-term equilibrium would dictate, which in either case leads to adverse impacts. Short-term shortfalls, such as blackouts, can produce severe impacts that command immediate attention from the public and from industry. Longer term shortfalls that develop gradually call forth a range of responses such as appeals for voluntary reductions in use. These are often followed by increasingly restrictive curtailment actions.

Some recent studies judge the economic impacts of such shortfalls to be very large. This is based on the expectation that the unavailability of electric power would partially shut down industry and commercial activities. However, the extent to which a regional economy can respond to such a situation has not been tested in practice or even thoroughly evaluated through impact studies. Adjustments through market and non-market mechanisms should be able to mitigate much of the immediate impact. For example, consider what would happen if electricity were offered in the three States at 25 cents/kWh or even 5 cents/kWh. If conservers and producers received such prices for the electrical energy that they made available, large amounts of new conservation savings or extra generation from existing resources could be expected.

The risks of shortfalls or surpluses depend on factors that affect either supply or demand. On the demand side, the uncertainties of forecasts probably contribute most to the risks. In the scenarios examined in this study, Scenario I runs the greater risk of surplus and Scenario II the greater risk of shortfall.

On the supply side, the comparison of Scenarios I and II is less clear. The risk that the supply system will fail to perform as expected, or to expand as expected, depends on the reliability of the components of the supply system, on the reliability of construction schedules, on warnings of impending failures, and on the possibility of responding to warning signals. In these respects, the two scenarios do show some quantitative differences, but qualitatively they are similar.

Reliability of generating plants and conservation

The generating plants in Scenarios I and II are very similar. Most of the generation is supplied by conventional fossil fuel steam plants, nuclear plants, and hydroelectric facilities. There is considerable experience with the reliability of these kinds of plants, and the reserve margins established by utilities are adjusted to provide the necessary backup. Scenario II has contributions from solar and wind units. These supply elements rely on resources subject to considerable fluctuations; however, the peak capabilities have been adjusted to account for these fluctuations. Another relevant consideration is the fact that solar and wind units are smaller so that failure of one unit is less serious than failure of conventional plants.

Comparing the reliability of the supply systems in Scenarios I and II means weighing the reliability of conservation measures versus the reliability of the generating units that conservation replaces. Because conservation measures already in place are more reliable, this comparison favors Scenario II.

Reliability of construction schedules

Recent experience of the electric utility industry in adhering to construction schedules for conventional power-plants has been poor. Delays have arisen because of labor shortages, financing and licensing problems, and other difficulties. In some respects, we can expect that these problems will not be as severe for construction of conservation and renewable resource "plants" as they have been for conventional plants. Labor requirements are more dispersed geographically, and the labor required is less skilled. Individual units are less costly and licensing requirements are reduced. Also opposition by environment and consumer groups will probably be less. For these reasons, it appears that Scenario II is more reliable so far as meeting construction schedules is concerned, once the renewable technologies are established, and assuming that conservation is regulated as it is in California.

Warnings of impending failure and ability to respond

The available experience with conventional powerplants and the close attention to their performance usually provides warning signals of impending failure. The long lead times for building new plants of this type lead to inability to respond in timely fashion to the signals of future shortfalls.

By contrast, there is at present no regular monitoring of conservation, nor is there a history of performance of modern renewable supply components. Thus, in this respect, Scenario II ranks low compared to Scenario I. However, the response time to a developing shortfall or surplus, once it is recognized, is short compared to the lead times for powerplant construction. In this regard, Scenario II is superior.

These considerations do not show any clear advantage of one scenario over the other so far as warnings and responses are concerned.

HOW SCENARIO I WOULD BE FINANCED

Under this Scenario, the supply sources would be financed through the existing financial utility structure. The financial outlays would be recouped through the rate base for electrical power.

HOW SCENARIO II COULD BE FINANCED

Although Scenario II is more in line with the National Energy Principles as outlined in table 1.1, it goes against several established institutions, especially those of utility expansion and return on investment. Under this scenario, the utilities would operate in an environment where demand would be met by relying on conservation instead of new powerplants.

Utilities, under their current charters, have little incentive to devote large sums of money to promote conservation programs or to develop unproven technologies. As explained earlier, not all conservation measures require Government subsidies or will result in increased utility rates. For example, building and appliance standards, when implemented, could be paid for by the consumer at the time of purchase, or in some cases like housing, in the form of long-term mortgages. Others such as retrofit and solar assist can be spurred by subsidizing portions of the cost. As discussed earlier, we estimate it would take subsidies of 25 to 50 percent.

To meet the cost of conservation and development of renewable resources outlined in Scenario II, we evaluated the following funding alternatives:

- --Using current marketing structure, i.e., using existing utility financing structure.
- --Using WAPA to finance Scenario II through bonding authority and power revenues.
- --Using WAPA to finance Scenario II through Federal appropriations.

Using current marketplace

The objective of this option is to use the existing utility structure to finance and implement the goals of

Scenario II. The financing outlays could be recouped through the rate base for electrical power, i.e., power revenues would be used to pay for conventional as well as renewable resources development and for conservation.

This option would utilize an existing institutional structure and minimize Federal Government involvement. Also it would spread the cost of the program over all the consumers of the region.

This option may be difficult to achieve since it does not provide a focal point to implement the scenario. Instead, it would require approval by the State Utility Commissions and acceptance of a new role by the utility industry. Also, the utilities may not be anxious to implement Scenario II since, as noted earlier, it would reduce their projected growth. Utilities would probably be hesitant to invest in new technologies such as solar energy and wind. They might require some generated rate of return on such investments. Additionally, if the power rates are applied to all customers equally, those customers who had already achieved conservation would be penalized.

<u>WAPA could finance Scenario II through bonding authority and power revenues</u>

Another option is that WAPA could finance the subsidies that are required to get adoption of conservation measures, and could finance and assume responsibility of three-fourths of the solar and wind programs. In this option we do not assume that WAPA would need to be given a role with respect to the geothermal program. Rather, we feel that the utilities will carry out this program on their own after the technology has been developed. Our reasons for this assumption are two-fold: (1) geothermal power, when developed, lends itself to baseload operation, and (2) geothermal power cost estimates are shown to be potentially favorable compared to either coal or nuclear. Both of these aspects make geothermal a prime candidate for utility involvement.

Conversely, utilities would not appear to be as anxious to develop solar and wind power because they are not considered reliable as supplies for peak demand, intermittent in nature, and not conducive to base load operations without an energy storage backup system. Since the power that WAPA markets comes from hydroelectric projects that have large storage capability, WAPA has excellent potential for firming up the energy contributions from solar and wind plants.

The table below shows the total annualized cost and average payment per kWh sold, which would be needed to finance such a program. Under this option, we also assumed that WAPA would be given bonding authority to obtain capital necessary to implement this option.

Table 5-9

Year	Annualized cost of proposed program ($ millions)	Billions of kWh sold	Required average payment mills/kWh sold
1985	$ 148.0	11.7	12.7
1990	245.6	11.9	20.7
1995	506.9	16.7	30.4
2000	1303.3	35.0	37.3

Assuming that WAPA customers would pay for such a program, the average rate would increase from about 6.7 mills per kWh in fiscal year 1977 to 37.3 mills per kWh in the year 2000. This is a substantial increase, but it would occur gradually. Comparatively, the average wholesale cost of power in the three States under Scenario II would be 35.6 mills per kWh by 1985 and stay at that level to the end of the century. Therefore, WAPA power would continue to be a bargain through 1995 and still be competitive through 2000 if it were to undertake the program outlined above. The adjustment of WAPA rates to match those paid by other utility customers would resolve the equity considerations discussed in chapter 4.

We recognize that increases in rates have to be applied judiciously so they do not result in economic disruption for customers. For example, it would need to be determined if agricultural customers who depend upon WAPA power for irrigation pumping would be harmed. Such analysis, as discussed earlier in this chapter and in appendix II, may likely show that with improved irrigation efficiencies, rate increases may in fact be absorbed. Should a study show that increases could not be absorbed, continuation of Federal subsidies for that industry might have to be considered.

Under this approach, WAPA would be used as a showcase to demonstrate the Federal Government's commitment to conservation and renewable resources and a focal point for funding such programs. This would avoid some of the problems associated with obtaining a consensus among State and Federal Governments and utility companies.

A disadvantage of using WAPA as the source of funding is that WAPA power rates would increase. Such rates would become as high as those charged by utility companies. As a result, if WAPA funds conservation and renewable resources under Scenario II, and significant unanticipated increases in program costs occurred, then a reduction of the scope of these programs would occur to keep power rates competitive.

Federal appropriations through WAPA

Under this alternative, WAPA would carry out the programs outlined in Scenario II through annual appropriations from the Congress. This alternative would spread the cost of conservation and renewable resources development programs to all taxpayers in the Nation. The benefits would accrue primarily to those States located within the WAPA area of operations.

This alternative recognizes the political reality that the consumer as well as political and business institutions may resist the move toward conservation and development of new technologies. It also recognizes that WAPA customers currently benefiting from low-cost Federal power would resist an increase in rates to a level competitive with other utility customers.

Since appropriation of Federal funds would be within the Federal sector, this alternative would provide for better focusing of efforts to meet Scenario II objectives. The Congress, however, would have to be reassured that national benefits can be derived from such funding.

There are disadvantages and problems to the Federal appropriations approach. The appropriation process offers no assurance of providing the needed money because of changing priorities, national pressures, and the need for annual approval. In addition, any actions to perpetuate low prices for Federal hydropower at the expense of the national public or to pledge Federal assistance could be viewed as regional energy subsidies. As such, they could be sought--on the basis of equity--by all regions.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

Fast-rising economies in Arizona, California and Nevada have been matched by ever-increasing power development. Utility companies have had to rely heavily on conventional resources, such as oil and coal, to provide electrical power to meet needs, and will continue to rely on them and nuclear energy to provide additional power through the 1990s. Whether growth plans will be met is becoming more uncertain because of (1) the unreliability of oil imports, (2) escalating fuel and plant construction costs, (3) environmental concerns, and (4) long delays in obtaining approval for and the construction of new powerplants--especially nuclear plants.

Increasingly, conservation and the development of renewable resources are being considered as supply options. Conservation efforts have achieved some success, but much more can be done. Utilities do not consider renewable resources as a major supply option.

WAPA, the only Federal power agency in the area, does not have a program to foster conservation or to develop renewable resources. Also, the current practice of marketing Federal power at the lowest possible rate for the widest possible use is not consistent with the principles of the National Energy Plan.

CONCLUSIONS

Three States within the WAPA marketing area--Arizona, California, and Nevada--have implemented conservation programs and, primarily through DOE, are undertaking research projects to develop renewable resources. They recognize in their energy planning the need to enhance the use of vast solar, wind, and geothermal power potential.

The utility companies are willing to shift to new technologies, if and when they are proven to be reliable and commercially feasible. The companies we contacted do not believe major progress in commercializing new technologies will be made in this century.

An analysis of energy policy ranging from today's way of conducting business (Scenario I) to more aggressive conservation and more intensive development of new resources (Scenario II) demonstrates the benefits of the latter from the standpoint of environment, equity, economy, and risk. The analysis also notes that these benefits could be obtained at a lower cost to the consumer than under Scenario I and without traumatic changes in current policies at the local, State, Federal and utility levels, and would demand little change in lifestyle for the general public. The analysis also discloses that the utility companies and/or the Federal Government can generate the moneys necessary to conceive and develop new sources of power.

Conversely, the analysis shows that, should today's way of conducting business continue, traumatic changes may be forthcoming because of the difficulties associated with building new powerplants, increasing costs, and environmental impacts. In fact the Department of Energy, in commenting on this report, agrees that the utilities are having and will continue to have difficulty in meeting the demands forecast in Scenario I.

The utility companies in the Southwest, and to varying degrees, the States, reflect primarily the supply and electrical management policies of Scenario I. As a result, if we are to look to these organizations to implement Scenario II and to effectively pursue the principles of the administration's National Energy Plan, significant changes may be required. WAPA markets power to a broad spectrum of customers in many States. Thus, it seems that it should be a focus of the administration's attempt to implement the goals of the National Energy Act as the Act relates to conservation and electricity management and development. If DOE is to be credible in its attempts to implement the act, it would seem that entities under it, such as WAPA, should exemplify the goals of the act.

WAPA, if rechartered, could provide the leadership to foster the conservation and development of solar and wind programs outlined in Scenario II. WAPA could generate the funds necessary to subsidize the conservation measures and solar and wind programs outlined in Scenario II through bonding authority and power revenues. Under this program, WAPA's rates by the turn of the century would still be competitive with utility companies and would approach the incremental cost of power from coal and nuclear powerplants in the three States. This would be consistent with the principle in the National Energy Plan that energy prices should generally reflect the true replacement cost of energy.

Based upon these conclusions, we have listed below recommendations of what the Federal Government and, particularly, WAPA's role should be in these States. These recommendations are based upon our belief that aggressive conservation and development of renewable resources need to be spurred by the Federal Government and the States, if significant and timely progress is to be achieved.

Our work was limited to 3 of the 15 States served by WAPA. These States represent about 50 percent of WAPA's market. We believe that an evaluation similar to ours in the 12 remaining States would disclose, in varying degrees, problems of a nature and magnitude similar to those noted in Arizona, California, and Nevada. Our report "Region at the Crossroads--The Pacific Northwest Searches for New Sources of Electric Energy" (EMD 78-76) supports this contention since problems similar to those discussed in this report were noted in the States of Idaho, Montana, Oregon, and Washington.

We believe that WAPA should evaluate electricity devellopment and management in these other States in order to better delineate WAPA's role and to coordinate the implementation of the recommendations made below.

RECOMMENDATIONS

The many constraints to further development of conventional resources make conservation and development of renewable resources attractive (Scenario II). By cooperating with State governments and the utilities, and providing, through WAPA, an example of good electricity management, the Federal Government can help the Southwest and other WAPA marketing areas to meet their energy needs. To accomplish this, WAPA will have to be given a broad charter by the Congress. Therefore, we are recommending that the Congress:

--Relieve WAPA of its charter responsibility for encouraging the widest possible use of electricity at the lowest possible cost and direct it to undertake programs to examine the most appropriate structure of its rates to encourage conservation, consistent with the Public Utility Regulatory Policy Act, and to implement those rates.

--Provide WAPA with bonding authority and direct it to act as a lead agency to give priority with such funds to conservation, consistent with the intent of the National Energy Conservation Policy Act, and to the application and development of renewable resources; and allow these funds to be repaid through power revenues. DOE has proposed legislation (H.R. 3506) to give WAPA limited bonding authority. This authority could be broadened to cover funding of conservation and renewable resources.

--Provide WAPA with authority to exercise flexibility in power charges. Implementation of programs recommended would result in a gradual rate increase leading to parity with average utility rates prevailing in the WAPA marketing area by year 2000.

--Direct WAPA to report annually to the Congress and the executive branch on its progress toward implementing these recommendations.

In implementing these recommendations we would expect DOE to coordinate new WAPA programs within the Department and with other Federal agencies, State governments, and the utility companies. WAPA should also insure that the public is aware of any efforts it initiates under the recommended programs.

Adoption of these recommendations will likely require restaffing or additional staffing of WAPA. Before requesting such staff changes, we believe WAPA should first look to DOE's existing resources for maximum technical support.

AGENCY COMMENTS

Copies of the draft of this report were furnished to the Department of Energy and Western Area Power Administration and the Governors of the States of Arizona, California, and Nevada. The States did not reply to the report. Comments were received from the Department of Energy which were to include comments from the Western Area Power Administration (see appendix VI). The report was revised in several sections to reflect technical comments received informally. The recommendations remain basically the same. The following section summarizes the overall comments and presents our views on these matters.

The Department of Energy believes the report accurately points out that WAPA is not fostering conservation or development of new resources, but believes other elements of the Department are doing so and duplication could occur if WAPA were given the responsibilities recommended in this report. They further point out that WAPA is a relatively new organization and not prepared to actively foster conservation or develop new renewable sources of power.

Chapter 4 covers existing conservation and development of renewable resources efforts of Government and industry. We found these programs were fragmented and their benefits could not be readily assessed. Generally, most programs, especially development of renewable resources, were of a research nature or pilot projects. The commercial application role we support for WAPA goes far beyond what is being achieved under these programs. Therefore, DOE's fear of duplication and lack of coordination is not totally warranted. As we recommended, we would expect DOE to consider using existing resources and in-house expertise before deciding on additional staffing. As recommended, DOE should coordinate the new WAPA mission with other Federal agencies, the States, and the utility companies. Specifically, DOE could look to the Bureau of Reclamation, the U.S. Army Corps of Engineers, and the State Energy Commissions.

While we agree that WAPA is a new organization, by name, transferred from the Bureau of Reclamation to DOE with its organization in 1977, the responsibilities and functions performed by WAPA have been in effect for nearly 50 years. We recognize, as DOE points out, that the proper role for WAPA and the other power marketing agencies is being considered and that changes could occur through an evolutionary process. While we know the range of WAPA's role could vary, we also believe that the analysis in this report and the recommendations should weigh heavily in considerations in developing a coordinated effort and role for WAPA. This would be timely since no alternative roles for WAPA have been identified by DOE at this time.

DOE disagrees with the conclusions that WAPA programs and goals are inconsistent or opposite to the National energy policy and DOE goals. DOE observes that the goal of encouraging widespread use of power does not mean that people should be encouraged to use more power but that the benefits of Federal power should be dispersed as broadly as possible. Our conclusions are based upon two factors: (1) WAPA does not foster conservation and renewable resources as DOE also points out, and (2) WAPA sells power among the lowest priced in the United States.

Conversely, the principles of the National Energy Plan made conservation the cornerstone principle, called for development of renewable resources, and said energy should be priced to reflect its true replacement cost. Therefore, we feel WAPA's practices and the overall goals of DOE are not consistent.

DOE implies that the report recommends rate increases for Federal power to encourage conservation and that rate increases could make Federal power noncompetitive and unwanted. Our report does not recommend higher power rates to encourage conservation although our previous reports demonstrate that low rates discourage conservation investments. The report suggests WAPA use bonding authority to raise the money needed to make investments in conservation measures and the development of solar and wind resources. Such investments would then be included in WAPA's rate base and through the rates repay the costs of such programs. Our analysis showed that Federal power rates would remain competitive through the period of our study. Our study also considered alternative funding proposals for these programs, and they are discussed in chapter 5.

With regards to the marketability of WAPA power, we believe the ever-increasing problems experienced by utilities to meet customer loads should continue to make competitively priced Federal power attractive. We are aware that, in the past, finding a market for Federal hydropower may have been difficult in an environment where there was a glut of power. In the future, when power resources are expected to be drastically limited, we doubt, in spite of DOE's concern, that WAPA would have problems marketing its power, especially as shown in our scenario, when such power would be sold at competitive rates.

DOE feels our analysis does not equally evaluate the options for meeting electricity demand. We believe our analysis represents a sound blueprint for initiating actions in the areas dealt with. In doing the study, we used what were believed to be the best and most recent data available at the time from DOE, State energy studies, and other pertinent studies relating to the economics, technology, and environmental aspects of each. We do recognize that the unknown impacts of alternative resources are more difficult to identify than those of existing resources. For this reason, we developed the two scenarios in order to analyze a conventional approach to meeting demand as opposed to a scenario which follows a heavy emphasis on conservation and renewable resources.

DOE indicates that minor modifications to WAPA's charter could result in implementation of some of our recommendations. While we agree that the WAPA charter could be modified, we believe that in view of the far-reaching recommendation for WAPA's future role, a new charter should be drafted. This would provide WAPA with a clear statement of its future role and WAPA personnel with a new sense of mission.

We are strengthened in our convictions that an expanded WAPA mission be directed through new legislation when considering DOE's comment that WAPA changes should occur as "a part of the normal evolutionary process." In an era when the Nation is facing grave and immediate energy problems, and when our recommendations for the Southwest deal with the reduced use of liquid fuels dependency, "normal evolution" is certainly not what we visualize as an optimum course of action. Further, we feel the "evolutionary process" shows the time is at hand for a change in WAPA's mission.

In summary, DOE believes our recommendations are based on misconceptions of WAPA's current role and, if our recommendations are adopted by the Congress, would bring about a major mission change in the Western Area Power Administration. However, WAPA states it would welcome a mission change to lead development of renewable resources.

We believe that a mission change is needed if DOE wants to bring WAPA in-line with the principles of the National Energy Plan.

We would further point out that our analysis did not consider the full range of roles for WAPA. If the Congress and DOE decide a mission change, as we recommended, for WAPA, is not appropriate, then further analysis should be done to consider whether WAPA's current functions and operations warrant Federal involvement and whether certain functions could be and should be transferred to the private sector or local entities.

DEMAND FOR ELECTRICITY:

SCENARIOS I AND II

In order to determine what kind of energy supply could be considered for Arizona, California and Nevada through year 2000, we had to establish how much energy these States would require. This is usually referred to as "demand" for electrical energy and is expressed in terms of kilowatt hours (kWh) for energy used by the consumer and megawatts (MW) for power used at peak periods.

Demand for electrical energy was categorized by type of consumer in Arizona, California, and Nevada and was projected to the year 2000. Estimates were based on available information about present consumption, and on official or semiofficial load forecasts. For Scenario II, a set of "end-use" projections was prepared and conservation savings were estimated. Tables I-1 and I-2 reflect the results of these estimates by consumer category and at peak demand. The assumptions and procedures used to derive the estimates are explained in further details in the sections which follow.

PROJECTED ENERGY AND PEAK LOADS

Projected demands for electric energy are presented in table I-1. The demands are estimated separately by state and consuming sector at 5-year intervals to the year 2000. Estimates for Scenarios I and II indicate the potential for reduced demand with conservation measures. Peak demands that correspond to the Scenario I and II energy demands are presented in table I-2.

The Scenario I energy and peak demand levels agree with the adopted forecasts that have been discussed above. Energy demand is projected to grow at the average annual rate of 3.7 percent per year. Arizona has the highest rate of growth among the States. Rapid population growth, immigration, and a widespread switch to electricity in several applications is responsible for this high growth rate. This conversion is reflected in particularly high projected rates of growth in the Arizona commercial and residential sectors. For the entire three-State area, energy demand is projected to grow to 425.7 billion kWh by the year 2000 as compared to 169.5 billion kWh demand in 1975.

APPENDIX I

Table I-1

Energy Used by Final Consumers
(in billion kWh)

	1975			1985			2000		
	AR	CA	NV	AR	CA	NV	AR	CA	NV
Scenario I:									
Residential	7.3	44	2.8	14.3	61	4.8	24.8	86	7.2
Commercial	5.8	42	2.9	12.5	70	4.9	25.1	125	7.9
Industrial	5.7	36	1.9	10.2	58	2.7	13.6	99	3.4
Agricultural	2.3	7	.2	2.7	7	.2	3.3	7	.2
Other	.6	11	-	.8	16	-	1.2	22	-
Total	21.7	140	7.8	40.5	212	12.6	68.0	339	18.7
Scenario II:									
Residential	7.3	44	2.8	12.0	58	4.1	18.5	76	5.4
Commercial	5.8	42	2.9	7.8	48	3.6	12.4	57	4.7
Industrial	5.7	36	1.9	9.9	42	2.4	13.0	45	3.1
Agricultural	2.3	7	.2	2.4	7	.2	3.0	7	.2
Other	.6	11	-	.7	16	-	1.1	22	-
Total	21.7	140	7.8	32.8	171	10.3	48.0	207	13.4

APPENDIX I

Table I-2

Power Used at Peak Periods
(Coincident Peaks at Load)
(in 1,000 MW)

	1975			1985			2000		
	AR	CA	NV	AR	CA	NV	AR	CA	NV
Scenario I:									
Residential	2.1	9.5	.7	3.8	13.4	1.2	6.2	18.8	1.8
Commercial	1.3	8.7	.6	2.4	15.4	.9	5.1	26.7	1.5
Industrial	.8	6.6	.3	1.8	10.6	.3	2.6	18.0	.5
Agricultural	.6	1.8	.06	.8	1.8	.06	1.0	1.8	.06
Other	.2	-	-	-	-	-	.3	-	-
Total	5.0	26.6	1.66	9.0	41.3	2.46	15.2	65.3	3.86
Scenario II:									
Residential	2.1	9.5	.7	3.3	11.7	1.0	4.8	14.8	1.4
Commercial	1.3	8.7	.6	1.3	10.2	.7	1.7	10.8	.9
Industrial	.8	6.6	.3	1.5	7.8	.3	2.0	9.4	.4
Agricultural	.6	1.8	.06	.7	1.6	.05	.9	1.6	.05
Other	.2	-	-	.2	-	-	.3	-	-
Other Load Management	-	-	-	-.2	-	-	-.4	-	-
Total	5.0	26.6	1.66	6.8	31.3	2.05	9.3	36.6	2.75

Peak loads are projected to grow under Scenario I at about the same rate as total energy consumption. By 2000, the three-State peak load is projected under Scenario I to be 84,400 MW, which is 51,200 MW over the 1975 level. If this rate of growth in demand is realized the equivalent of 59,800 MW in additional capacity would be required by the end of the century.

In Scenario II, the growth of demand is significantly lower. The principal bases for the reduction are the assumptions that the intensity of electricity use in commercial buildings or manufacturing processes will not increase and that reductions in the rate of electricity use will be achieved through specific conservation programs, especially by residential and commercial customers. By 2000, energy consumption in Scenario II is projected to be 268.5 billion kWh, which is 58 percent above the 1975 level, but 37 percent below the Scenario I projection for 2000. The average annual rate of growth is 1.9 percent per year in Scenario II. The growth rate is somewhat higher for Arizona, as it was in Scenario I. Among sectors, the greatest reduction is for the commercial sector.

The Scenario II peak is 46 percent above the 1975, three-State peak load. This is a slightly smaller growth than for energy due to some shifting away from high-peak loads, and a small saving by load management. The average annual rate of growth in peak is only 1.5 percent per year under Scenario II. Scenario II projections indicate that 25,700 MW of capacity will be added between 1975 and 2000. This is 34,100 MW less than the capacity needs indicated under Scenario I.

Approximately two-thirds of the decrease in Scenario II can be accounted for with an assumption that commercial and industrial projections in Scenario II are based on constant rather than increasing energy use per unit of end use activity. The difference due to end-use projections alone is shown on tables I-3 and I-4. This indicates that a critical element to consider in the electrical future of the three-State area is whether energy prices, policies, and businessmen's attitudes, will be such as to forestall further intensification in electricity use.

1975 ELECTRICAL ENERGY AND PEAK REQUIREMENTS

The forecasts of energy and peak demand were estimated by end-use category in 1975 from State agency, utility sources and the technical literature.

In the residential sector the energy use coefficients and applicance numbers for California came from the 1977 Biennial Report of the Energy Commission. 1/ In Arizona the corresponding energy use coefficients came primarily from a report of Arizona Public Service Company. 2/ The applicance saturations came from the company's report, "Inside Phoenix" 3/ and from the U.S. Census of Housing. 4/ In Nevada the appliance saturations were derived from a survey conducted by Sierra Pacific Power Company, conversations with utilities, and people in Las Vegas. Energy use coefficients in Las Vegas were based on the values used in Phoenix; the coefficients in the Reno area were adjusted to take account of the different climate. Residential peak values were derived from the numbers of appliances and from peak to average power ratios estimated on the basis of normal applicance operation and the date and time of the system peaks.

In the commercial sector the forecast methodology is based on square footage and energy used per square foot of commercial floor space for seven building types. The figures for floor space in 1975 in California were drawn from the current Energy Commission natural gas forecast 5/ as were the energy use coefficients for air conditioning. The other use coefficient, i.e., lighting and other appliances, were drawn from the technical literature. 6/ The square feet of floor space in 1975 for the building types in Arizona and Nevada were taken from the General Electric Energy Systems Report. 7/ The energy use coefficients for lighting and other appliances were the same as those used in California, but the values for air conditioning in Arizona were increased by 20 percent because of the hotter climate. In 1975 commercial buildings in the three States were heated almost entirely by natural gas. The procedure for calculating commercial peak values were, in principle, the same as in the residential sector.

In the industrial sector the breakdown was not by end-use but industry two digit Standards Industrial Classification (SIC). The data for dividing energy use among sectors in California came from the U.S. Annual Survey of Manufacturers 8/. In Arizona the census figures were supplemented with consumption data for mining operations available in reports of the three major utilities in the state 9/ because mining (SIC 10) is not included in the Annual Survey of Manufacturers. In Nevada the survey data included only a few sectors. Additional information was obtained from the State Department of Energy, Division of Colorado River Resources on the electricity used by the Basic Magnesium Complex at Henderson. Peak demand in the manufacturing sector was estimated to have between .85 and .95 coincident peak demands for mining loads and for the magnesium complex. The load factors used for the general manufacturing sectors ranged from 0.45 to 0.55.

For the agricultural sector the 1975 consumption figures were derived from a state power survey in Arizona 10/, a special study in California 11/, and in estimates of the amounts of ground water and sprinkler irrigation in Nevada. In most cases the coincident load factor was taken in 0.4.

The "other" category was treated as a residual amount in California and Arizona, but it includes Government uses such as street lights. There is no such category in the Nevada breakdown. The "other" category was not included in the peak.

PROJECTING ENERGY DEMAND FOR SCENARIO I

The projected energy demands for Scenario I were developed following as closely as possible forecasts that have been "officially adopted" for use in electricity planning in each of the three States.

In California, an adopted forecast has been developed by the Energy Resources Conservation and Development Commission 12/ and coordinated with the major utilities' forecasts. The California forecasts extend to 1995 and are extrapolated to 2000 by assuming that demand growth from 1995 to 2000 would equal the growth projected from 1990 to 1995. The projections were categorized by residential, commercial, industrial, and other customers for each utilities' service area.

In Arizona there is no official state forecast of energy demands. The major electric utilities' forecasts 13/ were used for projections in Scenario I. Arizona Public

Service and the Salt River Project have detailed forecasts of sales and peak load to year 2000. The forecast available from Tucson Gas and Electric Company included only a total peak load for the next ten years; the later peak loads were extrapolated and the energy forecast was based on growth rates similar to those of Arizona Public Service Company and Salt River Project. A survey of electrical power used in Arizona in 1975 14/ provided an indication of sales and peak load components that were not included in the three major utility forecasts.

For Scenario I in Nevada, we used a statewide projection prepared for the Nevada Public Service Commission. 15/ These projections were prepared by sector to the year 2000.

ESTIMATING ENERGY DEMAND FOR SCENARIO II

The calculations of energy demand for Scenario II were carried out in two steps. First, projections were prepared based on the assumption of constant intensity of "end-use" of electricity. Specifically, the initial "end-use" projections made here assume constant electricity consumption (1) per electrical appliance in residences (some exceptions were made), (2) per square foot of commercial floor space, or (3) per unit of industrial output. As a second step, specific conservation opportunities were identified and the further reduction in demand arising from their adoption was estimated for each end-use category.

The end-use projections of demand made in this report apply specific rates of energy use to end-use categories. The resulting projections turn out to be considerably lower than the projections described in Scenario I. Since both projection methods rely on the same or equivalent forecasts of economic activity, the difference lies in the fact that the Scenario I models imply increasing energy intensity, i.e., an increasing amount of energy used per electrical appliance, per unit of building space or per unit of industrial output. These increases in intensity in the Scenario I forecasts are often not based on explicit simulation of the end-use but on a fitting of past behavior to an assumed functional dependence of energy use on certain explanatory variables. The assumption made in the "end-use" forecast is that a combination of changed future conditions and new energy policies can alter the dependence of rate of consumption on the usual variables so that it is constant or even decreasing in the future. There may be valid cause for questioning whether the next 25 years will see intensity of lighting, space conditioning, labor-saving equipment, etc., continuing to increase at rates comparable to those that occurred in the past 25 years even though traditional forecasting equations would predict such increases. This is especially true now when Government energy policies are becoming so much stronger than they used to be. Hence, it is reasonable to look at constant intensity end-use projecions that hold energy use rates at 1975 levels. In fact, DOE and the State of California are beginning to use these techniques in their forecasting.

Tables I-3 and I-4 reflect the impact of end-use projections on the forecasts obtained in each State under Scenario I.

For the residential sector, most utility or State forecasts are composites of forecasts for each major electricity-using appliance. They are, in effect, end-use forecasts. In California, there are statewide and utility area projections to 1995 17/ of saturation rates, energy use coefficients, and total electricity use by every major residential appliance. These projections include space heating, air conditioning, water heating, as well as refrigerators, lights, etc. These projections were adopted for use in this study without any revision. The resulting end-use projections assume increases in saturation rates of certain appliances such as electric space heating, air conditioners, dishwashers, and reductions in energy use per appliance due to the effects of existing conservation programs.

Residential load growth forecasts by the Arizona utilities 18/ assumed that all residential energy uses in new residences would be supplied by electricity rather than natural gas due to a moratorium on natural gas service to new residential customers. This assumption was accepted in the end-use forecast.

For the commercial sector, end-use forecasts were calculated by multiplying projections of floor space in various types of commercial buildings times coefficients of average electricity use per square foot of floor space in 1975. This implies no further intensification in electricity use in these buildings, i.e., no net increase in lighting, air conditioning, electric space heating, etc., per square foot. For California, projections of commercial floor space that have been prepared for the Energy Commission 19/ were adopted for use in this study.

Table I-3

End-Use Projections Forecast Compared
to Scenario I Forecasts
by Final Consumer
(in billion kWh)

	1975			1985			2000		
	AR	CA	NV	AR	CA	NV	AR	CA	NV
Scenario I:									
Residential	7.3	44	2.8	14.3	61	4.8	24.8	86	7.2
Commercial	5.8	42	2.9	12.5	70	4.9	25.1	125	7.9
Industrial	5.7	36	1.9	10.2	58	2.7	13.6	99	3.4
Agricultural	2.3	7	.2	2.7	7	.2	3.3	7	.2
Other	.6	11	-	.8	16	-	1.2	22	-
Total	21.7	140	7.8	37.4	183	11.6	63.2	249	17.8

Note: Columns may not add to total because of rounding.

Table I-4

End-Use Projections Forecast Compared
to Scenario I Forecasts
for Power Used at Peak Periods (coincidental peaks at load)
(in 1,000 MW)

	1975			1985			2000		
	AR	CA	NV	AR	CA	NV	AR	CA	NV
Scenario I:									
Residential	2.1	9.5	.7	3.8	13.4	1.2	6.2	18.8	1.8
Commercial	1.3	8.7	.6	2.4	15.5	.9	5.1	26.7	1.5
Industrial	.8	6.6	.3	1.8	10.6	.3	2.6	18.0	.5
Agricultural	.6	1.8	.06	.8	1.8	.06	1.0	1.8	.06
Other	.2	-	-	.2	-	-	.3	-	-
Total	4.9	26.7	1.6	9.0	41.2	2.6	15.2	65.3	3.9
Constant Intensity End-Use Projections:									
Residential	2.1	9.5	.7	3.8	12.8	1.2	6.2	16.9	1.8
Commercial	1.3	8.7	.6	1.6	12.1	.8	3.0	16.6	1.4
Industrial	.8	6.6	.3	1.5	8.4	.3	2.3	10.8	.5
Agricultural	.6	1.8	.06	.8	1.8	.06	1.0	1.8	.06
Other	.2	-	-	-	-	-	.3	-	-
Total	4.9	26.7	1.6	8.0	35.1	2.4	12.9	46.1	3.8

Note: Columns may not add to total because of rounding.

Projections of floor space in Arizona and Nevada were based on growth in related economic activity for each building type. Economic growth, compared to 1975, was measured by the ratio of personal earnings in a later year to 1975 earnings for an appropriate sector as they have been forecast in the OBERS, Series E Projections of the Water Resources Council. 20/

Electricity use per square foot of commercial floor space was calculated separately for each State on the basis of 1975 use rates as estimated for this study. These coefficients were already discussed in an earlier section on 1975 Electrical Energy and Peak Requirements.

Projections for the industrial sector were prepared by multiplying projected future industrial production, industry-by-industry, times electricity use coefficients set at the State average rate of use by each industry in 1976. Earnings were used to approximate industrial production because forecasts are generally available only in terms of earnings. Projections 21/ for all industrial sectors in California have been prepared for use in energy demand forecasting. We adopted those without change, noting that they generally agreed well with the widely used OBERS projections. 22/ For Arizona and Nevada, OBERS Series E projections were used.

Electricity use per unit of earnings was calculated, industry-by-industry, for each state using data reported in the 1976 Annual Survey of Manufacturers. 23/ These coefficients were held constant to 2000, which presumed neither net improvement in energy efficiency nor electrical intensification.

Agricultural pumping demands were assumed to remain constant at their 1975 level. In Arizona, California, and Nevada decreases in area irrigated from groundwater are more than offset by increases in energy use per acre-foot of water pumped due to increased pumping lifts from declining groundwater aquifers and new surface water delivery systems. Overall, we believe a forecast of little change in total demand for pumping energy is a reasonable assumption.

Utilities' forecasts of agricultural electricity demand vary from a projected slow decrease by a major California utility to a projected doubling in 10 years for irrigation sales by one of the major Arizona utilities. The Central

Valley Project anticipates an increase of 1,000 million kWh in irrigation pumping by 1980 and then no change until after 2000. The California State Water Project's pumping energy requirements are projected to grow from 3,866 million kWh in 1976 to 7,261 million kWh in 1985 and 11,300 million kWh in 2000. However, most of the increase is for moving water that will be used for purposes other than irrigation.

ESTIMATING CONSERVATION SAVINGS

Energy conservation savings were estimated for specific conservation measures or techniques. Conservation measures for the residential sector have been evaluated in detail, especially in California. 24/ Our estimates rely heavily on the work in California and generally our estimates of residential savings in Arizona and Nevada were derived by adopting the California conservation measures.

The energy conservation savings are estimated to be those achievable by cost-effective conservation measures that can be brought into use by feasible conservation programs. Cost effectiveness was estimated by comparing the annualized cost of the conservation measure to the benefit which is realized through saving of energy supply costs. Energy supply costs, in these calculations, are the costs of providing additional electricity to meet increasing customer demand.

Projected adoption of conservation measures is based on our assumption that the following set of programs or conditions will become effective by 1980 and remain in effect throughout 2000.

1. Mandatory energy efficiency standards for new appliances would achieve an average of 25-percent reduction in electricity use in appliances.

2. All new appliances would be labeled for energy efficiency, which would assist customers in selecting the more efficient types and makes.

3. Integrated utility and State information programs including media and school programs, energy audits, specific advice on building and equipment selection and management, etc., would reach all classes of customers.

4. Residential retrofit and solar system financing programs would provide the initial capital for adopters of the measure and also reduce the cost to the adopter by approximately 25 percent.

5. The price of new electricity to all customers would reflect at least 90 percent of the cost of the new electricity being supplied.

ELECTRICITY CONSERVATION IN THE RESIDENTIAL SECTOR

In the residential sector, electricity conservation is achievable mostly by improving the thermal efficiency of housing units that are heated or cooled with electricity and by improving the operating efficiency of electrical appliances in all residences.

Several policies are in effect to encourage energy conservation or appear likely to be adopted in the near future. The potential for savings is strongly affected by the future numbers of housing units (table I-5), and by the number of new units which are easily equipped for energy conservation. The fraction of residences equipped with various electrical appliances, especially the fraction of electrically heated and cooled units, is also important in estimating the potential for conservation. As the chart reflects, the three States are expected to increase new housing from 1,115,000 in Arizona to 7,495,000 for California and by 313,000 for Nevada by year 2000. This is almost a doubling of existing housing units in these States.

NOTES:

Arizona

Households are the sum of residential customer projections by Arizona Public Service, Salt River Project, and Tucson Gas and Electric, extended to 2000. Vacancy is assumed to be 6 percent and removal is 1.2 percent per year.

California

1975 and projected population and households are taken from Center for Continuing Study of the California Economy,

APPENDIX I

Table I-5

Housing Stock

	1975	1980	1985	1990	1995	2000
	(1976)	(thousands)				
Arizona:						
Population						
Population/HH						
HH (customers)	653	790	989	1,155	1,322	1,497
Housing units	692	837	1,049	1,224	1,401	1,596
Carryover	-	651	787	986	1,151	1,317
Net new	-	186	262	238	250	179
Cumulative new	-	-	448	686	936	1,115
California:						
Population	21,198	22,841	24,472	26,037	27,402	28,797
Population/HH	2.83	-	-	-	-	2.46
HH	7,486	8,471	9,586	10,564	11,082	11,726
Housing units	7,935	8,979	10,161	11,179	11,747	12,430
Carryover	-	7,459	8,440	9,551	10,508	11,042
Net new	-	1,520	1,721	1,628	1,239	1,388
Cumulative new	-	-	3,241	4,868	6,107	7,495
Nevada:						
Population	610	731	829	937	1,014	1,094
Population/HH	3.1	2.95	2.79	2.5	2.72	2.69
HH	197	248	297	341	373	407
Housing units	209	263	315	361	395	431
Carryover	-	196	247	298	340	371
Net new	-	67	68	63	55	60
Cumulative new	-	-	135	198	253	313

*HH - Households

Economic and Demographic Variables for CFMII, Report to Forecasting Office, ERCDC, Dec. 15, 1977. These population projections are derived from economic and employment projects in a procedure similar to OBERS. They agree quite closely with the series D-100 projections (California Department of Finance, Population Projections for California Counties, 1975-2000, Report 74, P-2, June 1974 that have been used in CERCDC and Distributed Energy studies.

Housing units are 1.06 times the households due to vacancies. Carryover of housing units is based on a gross removal rate of 1.2 percent per year which is taken from U.S. Census, "Components of Inventory Change," 1970 as reported and used in Weisenmiller and Caesar, Appendix Al, Residential Building Stock.

Nevada

Population is taken from Energy in Nevada, Nevada Public Service Commission, Sept. 1976, p. 8.

Mandatory energy efficiency standards for new major appliances have been adopted in California. 25/ Federal standards also appear likely to be adopted, perhaps before the end of 1978. In addition, California has proposed a "utility outreach and appliance labeling" program which it is estimated could save 1,200 million kWh by 1985 26/ simply by increasing consumer's awareness of opportunities for selecting more energy-efficient appliances. Arizona and Nevada utilities are also conducting information programs, and appliance labeling is also being considered at the Federal level.

Mandatory energy efficiency standards for new buildings have been in effect since 1976 in California 27/ and since July 1978 in Nevada. Arizona is considering enacting similar standards. In addition, there are Federal Housing Administration mortgage loans. Design standards that are following in most new construction of commercial and public buildings have also recently been revised to significantly improve energy efficiency. 28/

A tax credit for solar systems equaling 55 percent of the cost incurred, up to $3,000 is provided in California. 29/ A 15-percent Federal tax credit is available in any State. Installers of solar systems in California are presumably eligible for credits from both sources.

Several utilities in the three State area have some kind of conservation program for residents who use electricity (or natural gas) for home heating or cooling. The most common elements are information and energy audit programs for customers. In addition, several utilities are planning or considering programs to assist customers in retrofitting existing residences by selling conservation materials and by providing or arranging for installation or financing.

To estimate the conservation savings in Scenario II, we first identified measures that might be adopted in addition to those already in effect. Next, potential savings, if adopted, were estimated and projections were made of potential and likely rates of adoption. We relied heavily on several reports of energy conservation potential in California 30/ for estimates of likely levels and factors. Similar studies for the Pacific Northwest also helped to identify plausible savings.

The specific conservation measures considered were:

1. Retrofit existing residences with ceiling insulation to approximately R-19. The potential savings are 25 percent of heating requirements and 15 percent of cooling for uninsulated units, and 5 percent of heating and 3 percent of cooling for retrofit of under-insulated units. Uninsulated units are estimatd to be 12 percent of electrically heated and 25 percent of electrically cooled residences. The estimates for under-insulated units and 25 percent of electrically heated residences and 12 percent of electrically cooled residences. In future years, potential adopters decrease due to assumed 1 percent per year removal rate from the 1977 existing housing stock.

This measure is extremely profitable for the adopter. Therefore, we estimated that adoption would be 80 percent of potential by 1985 and 90 percent of potential in 2000 if there is a strong consumer information program plus added financial incentives equal to approximately 5 percent of cost to the adopter.

2. Retrofit walls, floors, doors and windows. The potential savings from this measure are estimated to be 30 percent of heating and cooling for uninsulated units and 0-15 percent for partially insulated units. Fifty percent of all electrically heated or cooled residential units are not now insulated and, therefore, could adopt

this measure. However, payback is less favorable as for ceiling insulation so adoption is expected to be only 20 percent of potential by 1985 and 40 percent by 2000 if there is a strong information program plus financial incentives equal to approximately 25 percent of installed cost.

3. Improved insulation and thermal efficiency standards for all future residential construction. This program already exists in California and has recently been adopted in Nevada. All new residential units must meet the standards. Expected savings have already been included in the adopted California forecasts. However, there is potential for added savings in Arizona and Nevada since typical construction practices fall below recommended standards. Potential savings are 20 percent of heating and cooling requirements on all new electrically heated or cooled residences. Effective adoption is 90 percent if mandatory standards are enforced.

4. Super insulation and energy-efficiency design of new residences involves more insulation (R-38 ceilings, R-19 walls and floors), double pane, tightly sealed windows, careful orientation to capture passive sollar in winter and avoid thermal gain in summer, etc. Potential savings are approximately 25 percent of heating and cooling requirements for a unit that just meets the required efficiency standards. Potential adopters are all new residences with electric heating or cooling. There is some hesitancy about adopting these practices. We think that an information and demonstration program, combined with a 25 percent subsidy could increase adoption to 10 percent of new construction from 1980-85. After that, improved understanding of the potential will encourage more widespread adoption. We thought that at least one-fourth of all new residential construction would meet these standards by 2000.

5. Substituting heat pumps for resistance type electric space heating can save 30 percent or more of electricity used for space heating; however, heat pumps are quite expensive unless some of the cost is assignable to air conditioning. Thus, potential adopters are assumed to be only those new residences expected to have both electric space heat and air conditioning. This is about 18 percent of all new residences in California. Arizona already has a high rate of heat pumps saturation and an

even higher rate projected for new residential customers so there is very little opportunity for further adoption of this measure. Expected adoption in California is expected to gradually increase from 10 percent of potential adopters in 1980 to 50 percent in 2000.

6. Solar assistance for space heating can save up to 70 percent of space heat requirements. The amount saved is less if the dwelling unit is already highly energy efficient and thus has a low heating requirement. Potential adopters are all new residences, but electricity savings will be realized only in electrically heated units. Very high costs, probably exceeding $10,000 per unit, discourage adoption. We estimated that about 5 percent of new construction would install these units in 1985, rising to 10 percent in 1995 and 2000. This presumes a strong information program plus financial incentives equalling one-fourth of the costs of an installed unit.

7. An energy conservation program for water heating, including retrofit insulation of water heaters, thermostat set back of 10 degrees and reduced volume of hot water use could save 20 percent of energy use for water heating. This measure could be adopted for all existing water heaters. The potential savings declines as existing units are replaced by new units meeting improved standards. Expected adoption is 80 percent in 1985 under a strong consumer information program plus 25 percent subsidy for retrofit material.

8. Solar assistance for water heating can save up to 70 percent of water heating energy requirements. For electricity conservation, potential adopters are all new residences with electric water heaters.

The economics of solar assisted water heating is favorable, but only marginally, so we expected that adoption will be only about one percent of potential in 1980. As experience grows, so will adoption, to an estimated 20 percent in 2000.

9. Improved energy efficiency in appliances can save large amounts in residential electricity use. California has mandatory energy efficiency standards that apply to several appliances. These have already been incorporated into adopted forecasts. Arizona forecasts assume a small efficiency improvement perhaps due to anticipated Federal

APPENDIX I

Table I-6

Estimates of Energy Conservation Savings for the Residential Sector (in billion kWh)

	1985			2000		
	AR	CA	NV (note a)	AR	CA	NV (note a)
Space heat						
Retrofit existing residences	.155	.184	.047	.177	.240	.051
New construction standards	.360	*	.110	.270	*	.206
Super insulation and design	.040	.130	.012	.240	1.006	.069
Heat pumps	.123	.161	.037	.576	.866	.165
Solar assisted heating	.050	.071	.015	.225	.350	.064
Air conditioning						
Retrofit existing residences	.867	.135	.264	1.717	.128	.491
Super insulation		.026			.204	
Appliance efficiency standards		*			*	
Water heater						
Retrofit and management	.178	.590	.054	0	.059	0
Solar assist	.033	.023	.010	.225	.084	.064
Appliance efficiency standards	.210	*	.064	.924	*	.264
Other appliances	.263	1.680	.080	1.453	6.000	.415

*Already in force and accounted in projections.

a/Conservation savings in Nevada are calculated by multiplying conservation savings in Arizona by the ratio of residential consumption in Nevada to residential consumption in Arizona.

standards. Additional savings are possible by extending California standards to other appliances and lights, adoption of similar standards in Arizona and Nevada, and convincing the public to buy better than minimum standard models and use them carefully. The potential savings from this measure are estimated at 10 percent of projected use in California and 20 percent in Arizona and Nevada by the year 2000. All households could adopt the improved appliances and practices, but it will take time to extend awareness of the potential and make the changeover. We estimated that adoption will rise from 0 in 1978 to the full potential in 2000 as existing appliances are replaced with new energy efficient units.

ELECTRICITY CONSERVATION IN THE COMMERCIAL SECTOR

Several of the conservation measures evaluated for the commercial sector are closely modeled on the new title 20 and title 24 standards in the California Administration Code. The first conservation measure proposed in this study, however, is to maintain electricity use per square foot of floor space at current average levels and not to continue past trends of increasing use per square foot. The other measures are presented in the groupings that occur in the new building (title 24) and appliance (title 20) standards. Measures proposed are:

1. Maintain constant electricity use per square foot of commercial floor space. The measure consists of using building design parameters for new buildings that maintain electricity use per square foot of floor space equal to the average in existing buildings. This restriction is much less severe than the title 24 standards, but it would nevertheless save a large fraction of the commercial energy use that is forecast in Scenario I for the year 2000 (30 percent in California, 24 percent in Arizona, 14 percent in Nevada). The potential adopters of this measure are the builders of commercial buildings. In Scenario II full adoption of this measure (100 percent of new floor space) is assumed as a partial step in the implementation of new building standards similar to those in title 24.

2. Adopt standards for new buildings similar to those in title 24 and title 20 of the California Administrative Code. Title 24 sets forth standards for building insulation, heating, ventilating and air conditioning

systems and equipment, service water heating, electrical distribution systems, and lighting levels in nonresidential buildings. The standards do not apply at present to hospitals or hotels and motels. Title 20 standards apply energy efficiency requirements to sales of refrigerators, freezers, and air conditioners in California. Full adoption of the title 20 and title 24 standards in the three States would reduce the net consumption in the year 2000 below the values achieved through the adoption of measure one above by significant amounts (35 percent in Arizona, 30 percent in Nevada, 25 percent in California). Potential adopters of this measure are builders of new commercial buildings to which title 20 and title 24 standards do, or would, apply. The assumption is made in Scenario II that these standards are adopted in each State.

3. Initiate a retrofit program to reduce lighting levels and air conditioning requirements in existing buildings. Delamping is a relatively simple process, but making other changes to reduce electricity used for air conditioning will be difficult in many buildings. This program is assumed to achieve electricity savings per square foot of floor space in existing buildings equal to 15 percent by 1985 and 50 percent by 2000 of the lighting, air conditioning, and heating (for Arizona) savings expected to result from the adoption of title 20 and title 24 standards in new buildings. New policies that could be used to encourage adoption of this measure include: (a) information programs (e.g., on cost savings) to encourage volunteer action to reduce lighting levels and to change to new temperature settings; (b) loan guarantees and subsidies for the installation of new temperature control systems and other new building features that would improve energy efficiency; and (c) tax relief for investment required for new temperature systems; and (d) modification of building codes to permit or require lower air flows and illumination levels in existing buildings.

4. Extend the coverage of title 24 standards to hotels, motels, and hospitals and encourage further savings in electricity use for air conditioning in auto repair shops, warehouses, and schools. The last three categories, although currently covered by title 24, are not expected to save much electricity as a result. Coverage of hotels and motels by title 24 is already included in the Energy Commission regulations, but they are not yet in effect (summer 1978).

This conservation measure is expected to produce additional electricity savings by 1985 equal to 10 percent of the air conditioning and lighting savings achieved from measure two. The corresponding savings in 2000 are expected to be 50 percent of those achieved in measure two.

ELECTRICITY SAVINGS IN THE INDUSTRIAL SECTOR

Evaluation of conservation measures in the industrial sector is based on the CONAES study and the application of that study in California. 31/ In the CONAES project the total industrial sector was divided into subsectors according to two digit SIC designations. The expected energy savings in 2010 for each two-digit industry were estimated by a panel of knowledgeable people for each of four possible future sets of energy prices. Savings were evaluated in comparison to consumption that would be expected if the industries maintained constant energy intensity, i.e., constant use of energy per unit of production, from 1975 to 2010. In the present work the improvements in energy intensity in CONAES Scenario II were utilized except that a modification used in the California work 32/ was adopted. In California the savings were reduced to three-fourths of the national figures, and this change was made for all three States in the present work. An additional assumption made was that the fractional electricity savings equal the fractional energy savings. A similar assumption was made in the California report.

Mining (SIC 10) was not included among the industries for which savings were evaluated. A separate estimate was made for this sector based on conversations with Department of Energy personnel and based on the technical literature.

The reductions in energy intensity adopted for the two-digit industries are shown in table I-8.

ENERGY CONSERVATION IN IRRIGATION PUMPING

There is a definite possibility of some reduction in demand for pumping energy due to reasons other than response to higher electricity prices. One factor could be water conservation to increase efficiency and reduce water usage that will have the incidental effect of reducing the amount of water to be lifted for delivery to the land. Generally, increasing demands for water in the arid Southwest have elevated water conservation to a high priority level.

APPENDIX I

Table I-7

Estimates of Energy Conservation Savings for the Commercial Sector
(in billion kWh)

	1985			2000		
	AR	CA	NV	AR	CA	NV
Maintain constant electricity use per square foot of commercial floor space	3.1	16	.8	6	49	1.1
Adopt standards for new buildings similar to those in California Administrative Code	1.2	4	.4	5	11	1.3
Immediate retrofit program to reduce lighting levels and air conditioning requirements in existing buildings	.24	1.2	.12	.8	4	.4
Extend coverage of new building standards	.16	.8	.08	.8	4	.4

APPENDIX I

Table I-8

Improvements in Electricity Intensity in Industrial Sectors

Standard industrial classification		Reduction from 1975 base level	
		1985 Improvement (percent)	2000 Improvement (percent)
10	Mining	1	5
20	Food and kindred products	4	18
26	Paper	7	27
28	Chemicals	4	17
32	Stone, Clay, and Glass	6	25
33	Primary Metals	4	18
	All Others	5	19

Opportunities for water savings by agriculture in California have been estimated at 1.1 million acre-feet in basin-wide consumption. 33/ Other States in the area probably also have opportunities for savings. Reductions in water applied could be increased if some on-farm waste could be eliminated to save energy even though the water that is wasted could be recovered for later use within the basin. A reduction of 1.1 million acre-feet would be about 4 percent of the quantity of water applied to agricultural lands. The savings in pumping energy would be considerably less because unused potentials for water savings are generally highest on the lands that receive gravity flow water.

One commonly used approach to saving irrigation water use is to convert from surface to sprinkler application in order to gain more precision in application and reduce run-off and deep percolation. Sprinklers require about 200 kWh for pressurizing each acre-foot applied. The added power required for pressurizing sprinklers generally exceeds the pump energy savings unless the lift is high and the water savings due to sprinklers is great. For example, with a 300-foot lift, sprinkling must reduce water use by 40 percent in order to reduce energy demand for pump lift by enough to offset the energy required for operating the sprinklers.

There are also opportunities for conserving energy by improvements in the energy efficiency of irrigation systems. Pumping plants on irrigation wells in southern California required an average of 1.8 kWh per acre-foot per foot of lift whereas the Nebraska test standards performance was 1.55 kWh per acre-foot per foot of lift. 34/ Energy efficiency can also be increased by changing to lower pressure sprinklers, drip irrigation or precision systems for surface irrigation. Pacific Gas and Electric Company projected that an information and advisory program for irrigators would lead gradually up to a savings of 8 percent in 1998. 35/ This appears to be based mostly on expected improvements in efficiency of water application and pumping plant operation.

PROJECTING PEAK LOADS FOR SCENARIO I

The information that is available from State agencies and utilities for projecting peak loads is in most cases rather limited. For California the 1977 Commission Biennial report 36/ lists the total system peak, which occurs in summer, for the five major utilities at 5-year intervals through 1995. These numbers were accepted as the Scenario I totals except for minor adjustments for consistency with totals of the contributions from the major sectors estimated from sales and constant load factors. The system peak values obtained in this way matched closely with those in the 1977 Commission report.

In Arizona the two largest utilities, Arizona Public Service and Salt River Project, showed the major sector components of the summer peak in their own forecasts. These numbers and the associated load factors were used as guidelines to establish the state totals. The technique used was to divide the forecast kWh used in each sector by 8,760 hours per year and then divide the results by a load factor to find the peak numbers.

This same procedure was used in Nevada except that only the system total loads from Nevada Power Company and Sierra Pacific Power Company were available for comparison. In the case of Sierra Pacific, the highest peak occurs in the winter. However, the summer peak was used in developing a State total because the summer peak in Las Vegas dominates the winter peak in Reno.

PROJECTING PEAK LOADS FOR SCENARIO II

The procedure that was used to project peak loads under Scenario II assumptions was to use end-use energy requirements and coincident load factors for the end-use applications in the residential and commercial sectors. In the industrial sector, a composite load factor was used except for mining, for which coincident load factors between 0.85 and 0.95 were used. There is very little information available on the values of most of these load factors. They depend on the daily and seasonal operation of the appliances and processes that supply the end uses and on the date and time of the yearly peak. The values selected in this analysis were based on estimated on-off times during the day and season and on coincidence of operation with the peak. For example, residential heating and lighting were assumed not to contribute to the coincident residential peak in any of the States because these appliances were not expected to be used during the summer afternoons when the yearly peak occurs. For residential appliances like freezers the load factor was taken to be one because the operation is assumed to be uniform during the day and season. For air conditioners the load factors were very high because the peak coincides with, and is in fact largely produced by, these appliances.

REDUCING PEAK LOAD REQUIREMENTS BY CONSERVATION AND LOAD MANAGEMENT

The savings in peak load that are included in Scenario II come partially from the peak reductions that accompany the energy conservation measures described earlier in this appendix, and partially from load management programs that shift electricity use away from the peak time but do not save much, if any, electrical energy.

The peak savings that accompany energy conservation are calculated using the same peak to average ratios (load factors) that were described earlier in this report in the projections of peak requirements for each State under Scenario I.

The load management program envisions additional peak savings beyond the amounts expected as a result of energy conservation. These savings can be achieved through such practices as cycling of air conditioners, restrictions on time of use of water heaters, and time of use pricing of electricity. The savings for California are based on the load management savings in the 1977 Biennial Report of the Energy Commission; however, there were some modifications based on the Scenario II forecast of energy consumption and a reduced expectation of savings in air conditioning loads. For example, in the year 2000, residential savings from the water heater program were kept at 500 MW to 490 MW. The commercial load management savings were not included, and the industrial program was decreased in the year 2000 from 2,470 MW to 1,190 MW.

In Arizona the load management programs included were the Arizona Public Service program and an industrial load management program in the Tucson Gas and Electric service area. No load management was included in the Nevada peak savings estimates.

The conservative incorporation of load management savings reflects a somewhat skeptical attitude on the part of the consultants towards the effectiveness of such means of reducing peak loads unless the program is based on high peak load prices to which industry can be expected to respond.

APPENDIX I

Table I-9

Estimates of Energy Conservation Savings for the Industrial Sector
(in billion kWh)

	1985			2000		
	AR	CA	NV	AR	CA	NV
Maintain constant electricity use per unit of output from industries	0	13	.3	-1.2	16	-.2
Reduce electricity use per unit of output (see table I-8)						
Mining	.06		.01	.37		.08
Food and kindred products	.01	.18		.07	.97	.02
Paper		.17			.83	
Chemicals	.01	.17	.04	.10	.92	.20
Stone, clay, and glass	.02	.24	.01	.13	1.25	.09
Primary metals	.01	.15	.01	.06	.76	.06
All others		1.31			6.61	.01
Cogeneration		.67		1.06	1.83	
Total	.11	2.89	.07	1.79	13.17	.46

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SUPPLY MIX, INCLUDING THE COST

OF GENERATING AND CONSERVING ELECTRICITY

Twelve supply technologies are included as candidates to supply peak and energy demands to the three States in 1975, 1985, and 2000. The actual supply mix in 1975 is established using a number of sources. 1,2,3,4/ It includes in the overall peak capability for each State the capabilities of the plants that are owned by the utilities of that State plus in some cases imported peak capability. The energy supplied by these plants is similarly included as state domestic supply even though some plants actually may be outside the borders of the State involved. Imports of peak and energy refer to amounts supplied from sources that are outside the State boundaries and not owned by the utilities of the State.

The supplies of electricity in 1985 and 2000 are increased over the 1975 values so as to meet the calculated peak and energy demands in Scenarios I and II plus 10-percent losses, plus a 15-percent reserve margin over summer peak capability. The mix of supply technologies that is used to meet the added demand is established in a sequence of steps. First, the plants actually under construction or planned for construction are brought into the supply according to the announced schedule 5/. If, as a result of these additions, the peak capability exceeds peak requirements, including the reserve margin and firm imports, the difference is shown as an excess. If, on the other hand, peak requirements exceed peak capability, more plants are added to the supply. The additions are calculated in various ways depending on the technology involved. For "new" technologies the additions are made as follows:

--Geothermal and fuel cell components in California are added using utility plans for guidance. Geothermal additions in Arizona and Nevada are based on comparisions with California.

--Central solar and central wind additions to supply are calculated from the regional supply forecasts in the recent Mitre study. 6/ The regional results in this study are further disaggregated to determine the supplies for the three States. The disaggregation is based on qualitative evaluations of the amounts of resource (solar and wind) in the States compared to the regions in which they are located.

--Hydro additions are based on a recent special study. 7/

Other additions are made to provide a balance among peak, intermediate, and baseload plants. No new oil/gas steam plants are added, but plants of this type are retired from service according to utility plans. No other plants are decommissioned during the planning period. The allocation of additional baseload capacity between coal and nuclear is generally made to bring the amounts closer together except in Nevada where no nuclear plants appear likely to be built by 2000. The new intermediate load capability required is supplied by combined cycle plants and short-term peak by gas turbines.

The operation of existing plants to supply electrical energy demands is specified so as to minimize variable costs. Thus, high variable cost units are used as little as possible while low cost ones are operated close to their maximum plant capacity factors. The imports and exports are gradually phased out in most cases.

The supply mixes that have been calculated using the procedures described above are tabulated in tables II-2 to II-13. It is interesting to notice that oil/gas steam plants will be phased out as time goes on not only because of Federal policy, but also it is much cheaper to operate plants that use coal, nuclear, or other resources. A further observation is that the fraction of total electrical peak power and energy that will be supplied by renewables other under than hydroelectric power is rather modest, even under Scenario II conditions.

COSTS OF GENERATION

The total costs of supplying power are calculated using the data in table II-1. Transmission costs are included at two mills/ kWh (with losses) and distribution costs at eight mills/kWh for residential, commercial, and other sales (without losses). Energy transfers are evaluated at 20 mills/kWh in 1985 and 29 mills/kWh in 2000. Peak transfers are evaluated at gas turbine cost. The results of the cost calculations are shown in tables II-14 to II-19. The footnotes for this table detail the unit cost assumptions.

Costs of industrial conservation

The calculation of the costs of industrial energy conservation is based on the principle that industry will adopt those conservation measures that are less costly than the energy that they save. There is not enough information available to apply this principle accurately to this study. However, some estimates are made, and these are shown in table II-20.

There are two levels of conservation savings whose costs must be evaluated. The first consists of the savings expected if industries maintain constant electric energy intensity (energy use per unit of output) rather than the increasing intensity implied by the industrial electricity consumption figures in Scenario I. The cost of this much conservation in 1985 and 2000 is very uncertain, but it is definitely less than the energy savings times the present cost of energy. Such a value represents an upper limit because (1) a constant energy intensity projection corresponds to falling real energy prices 8/ and (2) Scenario I corresponds to energy prices which are greater than zero. Actually a better approximation is probably zero cost for these savings, but the upper bound is adopted, in view of the uncertainty, in order to avoid a heavy bias toward the conservation scenario in California. Only California has a clearcut difference between Scenario I and the end-use calculation, and only for this State is a cost calculated.

The second conservation measure presents extra energy savings beyond those expected with constant energy intensity. The extra savings are expected to arise from a doubling of real energy prices by the year 2000. The cost of these extra savings in 1985 is calculated at the present electricity price. The cost in 2000 is calculated partly at the present price and partly at 1.5 times the present price. The proportion of savings calculated at each price varies from State to State and is determined by the rate at which savings are expected to be achieved.

Costs of commercial conservation

The costs to commercial consumers of the four conservation measures proposed in each State are shown in table II-21. The first measure, which restricts the consumption of electricity per square foot in new buildings to the 1975 average, is not projected to have any direct costs attributable to the measure itself. However, the trend toward increasing electric intensity is stopped; as a result there may be indirect costs that arise because the competitive positions of new commercial enterprises involved suffer from the constraints on electricity use. These indirect costs are not included.

The costs for the second measure, which reduces energy intensities in new buildings according to provisions in the California code, are also taken to be zero. The zero costs in this case are based on the conclusions of the Arthur D. Little analysis of the ASHRAE 90-75 standards and on similar studies of energy saving appliance costs. 9/

Measure three extends the conservation program for new buildings to retrofitting existing buildings. Some of the retrofitting, such as delamping and replacing worn out equipment with more energy efficient models, costs almost nothing beyond normal expenses. However, weatherizing buildings to title 24 standards is estimated to cost about $1 per square foot (1977 dollars). This cost, and an annual charge for capital of 15 percent are used to calculate the numbers for measure three in table II-21. Fifty percent of 1975 floor space at wholesale and retail buildings, office buildings, and miscellaneous buildings is assumed to be retrofitted by 2000, and 15 percent is assumed to be retrofitted by 1985.

Energy savings from measure four arise partially from new building activity and partially (50 percent) from retrofitting. The new building savings are assumed to involve no extra costs, and the retrofitting is assumed to have costs per square foot comparable to those in measure three. The costs for this measure, under these assumptions, are one-third of the costs in 1985 for measure three and one-half of the costs for measure three in 2000.

Costs of residential conservation

The costs of conservation measures in the residential sector were evaluated using, primarily, unit costs developed by the State of California 10/ and the amounts of conservation shown in appendix I. Tables II-22 to II-24 show the results of these calculations.

Summary

The costs in Scenario II by the year 2000 are much lower than those in Scenario I because of the low unit costs of conservation. Renewable resources in our Scenario II have not had much of an impact by the end of this century. The high cost of oil has the effect of phasing out the use of this fuel over the course of time in line with Federal policy.

APPENDIX II

Table II-1

Generating Technologies Data

Description	Capital cost ('77 $/kw)	Annual capital cost factor	Maximum plant capacity factor	Summer peak availability
Oil/gas-fired steam	$ 270(7)	.155(5)	.8 (1)	.95
Coal-fired steam	784(9),(20)	.154(2)	.7 (1)	.9
Gas turbine	193(2),(20)	.153(2)	.75(1)	.98
Combined cycle	289(2),(20)	.155(2)	.8 (1)	.95
Fuel cell/central-fossil fuel	676(1)	.155(5)	.7 (1)	.98
Nuclear-steam (LWR)	981(9),(20)	.159(2)	.7 (1)	.9
Geothermal/central (hydrothermal)	500(3),(1)	.15 (2)	.7 (1)	.9
Hydroelectric	247(15),(1)	.14 (6)	(8)	.95
Hydroelectric/pumped storage	237(16),(1)	.14 (6)	.5 (8)	.98
Biomass (mostly co-generation)	1190(12)	.155(5)	.8 (4)	.9
Solar-central (photo-voltaic or thermal)	762(14)	.155(5)	.36(11)	.25
Wind-central	780(13)	.155(5)	.48(10)	.15

O&M fixed ('77/yr/kw)	Total fixed(17) costs ($/yr/kw)	O&M var. (mills/kWh)	Total var. costs (mills/kWh)(18) 1975	1985	2000	Total gen. costs at MPCF (mills/kWh) 1975	1985	2000
1(19)	$ 43	1.0(19)	21	35	48	27	41	54
6(2)	127	.5(2)	7	12	16	27	32	36
1(2)	31	1.6(2)	26	44	60	31	49	65
5(2)	50	.4(2)	19	32	44	25	39	50
5(19)	110	1.0(19)	22	38	52	40	55	69
3(2)	159	0.0(2)	5	6	14	30	32	39
3(2)	78	.1(2)	9	7	5	20	18	16
1(19)	36	.1(19)	.1	.1	.1	4	4	4
1(10)	34	.1(19)	.1	.1	.1	4	4	4
6(19)	190	1.0(19)	12	13	14	38	39	40
6(19)	124	.1(19)	.1	.1	.1	38	38	38
6(19)	127	.1(19)	.1	.1	.1	29	29	29

Table II-2

Arizona Electricity Scenario I
Estimated Loads and Resources: Peak

	1975 (actual)	1985 (projected)	2000 (projected)
	(thousand MW)		
Loads:			
Load at customer	4.9	9.0	15.2
Losses	.5	.9	1.5
Total loads	5.4	9.9	16.7
Resources:			
Oil/gas-fired steam	1.6	1.6	1.6
Coal-fired steam	2.6	5.8	5.8
Gas turbine/diesel	1.3	1.3	4.3
Combined cycle	.4	.6	3.0
Fuel cell			
Nuclear-steam		1.2	3.7
Geothermal			
Hydroelectric	.8	.8	.8
Hydro-pumped storage	.1	.1	.1
Biomass/cogeneration			
Solar-central			
Wind-central			
Net firm transfers	(-1.0)	(1.0)	
Other transfers			
Total resources	5.8	10.4	19.3
Surplus (resources-loads)	.4	.5	2.6
Desired margin	.8	1.5	2.5
Net above margin	(-.4)	-1.0	.1

Table II-3

Arizona Electricity Scenario I
Estimated Loads and Resources: Energy
Scenario I

	1975 (actual)	1985 (projected)	2000 (projected)
	(billion kWh)		
Loads:			
Load at customer	21.7	40.5	68.0
Losses	2.2	4.0	6.8
Total loads	23.9	44.5	74.8
Resources:			
Oil/gas-fired steam	6.4	3.2	1.7
Coal-fired steam	13.3	28.5	39.6
Gas turbine/diesel	.7	.7	2.1
Combined cycle	.9	1.3	3.5
Fuel cell	-	-	-
Nuclear-steam	0	8.2	25.3
Geothermal	-	-	-
Hydroelectric	2.6	2.6	2.6
Hydro-pumped storage	*	*	*
Biomass/cogeneration	-	-	-
Solar-central	-	-	-
Wind-central	-	-	-
Net firm transfers	-	-	-
Other transfers	-	-	-
Total resources	23.9	44.5	74.8

*Negligible.

Table II-4

Arizona Electricity Scenario II
Estimated Loads and Resources: Peak

	1975 (actual)	1985 (projected)	2000 (projected)
	(thousand MW)		
Loads:			
Load at customer	4.9	6.8	9.2
Losses	.5	.7	.9
Total loads	5.4	7.5	10.1
Resources:			
Oil/gas-fired steam	1.6	1.6	1.6
Coal-fired steam	2.6	5.5	5.5
Gas turbine/diesel	1.3	1.3	1.3
Combined cycle	.4	.6	.6
Fuel cell	-	-	-
Nuclear-steam	-	1.2	1.8
Geothermal	-	-	.1
Hydroelectric	.8	.8	.9
Hydro-pumped storage	.1	.1	.1
Biomass/cogeneration	-	-	-
Solar-central	-	-	.1
Wind-central	-	-	-
Net firm transfers	(-1.0)	(-1.0)	-
Other transfers	-	-	-
Total resources	5.8	10.1	12.0
Surplus (resources-loads)	.4	2.6	1.9
Desired margin	.8	1.1	1.5
Net above margin	(-.4)	1.5	.4

Table II-5

Arizona Electricity Scenario II
Estimated Loads and Resources: Energy

	1975 (actual)	1985 (projected)	2000 (projected)
	(billion kWh)		
Loads:			
Load at customer	21.7	32.9	48.0
Losses	2.2	3.3	4.8
Total loads	23.9	36.2	52.8
Resources:			
Oil/gas-fired steam	6.4	3.2	2.5
Coal-fired steam	13.3	20.2	31.0
Gas turbine/diesel	.7	.7	.7
Combined cycle	.9	1.3	1.3
Fuel cell	-	-	-
Nuclear-steam	0	8.2	12.3
Geothermal	-	-	-
Hydroelectric	2.6	2.6	3.0
Hydro-pumped storage	*	*	*
Biomass/cogeneration	-	-	-
Solar-central	-	-	1.3
Wind-central	-	-	-
Net firm transfers	-	-	-
Other transfers	-	-	-
Total resources	23.9	36.2	52.8

*Negligible.

Table II-6

California Electricity Scenario I
Estimated Loads and Resources: Peak

	1975 (actual)	1985 (projected)	2000 (projected)
	(thousand MW)		
Loads:			
Load at customer	26.7	41.2	65.3
Losses	2.7	4.1	6.5
Total loads	29.4	45.3	71.8
Resources:			
Oil/gas-fired steam	20.8	20.8	17.9
Coal-fired steam	2.2	2.5	16.0
Gas turbine/diesel	1.2	1.6	2.6
Combined cycle	*	3.6	4.4
Fuel cell	-	*	.4
Nuclear-steam	1.3	5.9	21.8
Geothermal	.5	1.7	3.5
Hydroelectric	8.1	8.8	9.2
Hydro-pumped storage	1.1	3.0	3.0
Biomass/cogeneration	.2	.4	.5
Solar-central	-	-	.1
Wind-central	-	-	*
Net firm transfers	3.5	2.9	2.7
Other transfers	-	-	-
Total resources	38.9	51.2	82.6
Surplus (resources-loads)	9.5	5.9	10.8
Desired margin	4.5	6.8	71.8
Net above margin	5.0	(.9)	(.5)

*Negligible.

Table II-7

California Electricity Scenario I
Estimated Loads and Resources: Energy

	1975 (actual)	1985 (projected)	2000 (projected)
	(billion kWh)		
Loads:			
Load at customer	140.0	213.0	339.0
Losses	12.4	21.3	33.9
Total loads	152.4	234.3	372.9
Resources:			
Oil/gas-fired steam	75.2	101.2	16.5
Coal-fired steam	10.6	17.1	109.3
Gas turbine/diesel	.5	.8	1.4
Combined cycle	-	215.0	26.4
Fuel cell	-	-	.5
Nuclear-steam	5.9	40.3	148.9
Geothermal	3.2	11.6	23.9
Hydroelectric	37.4	32.7	34.5
Hydro-pumped storage	*	(.3)	(.5)
Biomass/cogeneration	.7	1.8	3.0
Solar-central	-	-	1.1
Wind-central	-	-	.1
Net firm transfers	5.1	.3	.5
Other transfers	13.8	7.3	7.3
Total resources	152.4	234.3	372.9

*Negligible.

Table II-8

California Electricity Scenario II
Estimated Loads and Resources: Peak

	1975 (actual)	1985 (projected)	2000 (projected)
	(thousand MW)		
Loads:			
Load at customer	26.7	31.3	36.6
Losses	2.7	3.1	3.7
Total loads	29.4	34.4	40.3
Resources:			
Oil/gas-fired steam	20.8	20.8	17.9
Coal-fired steam	2.2	2.5	4.1
Gas turbine/diesel	1.2	1.6	1.6
Combined cycle	*	1.6	1.6
Fuel cell	-	-	.4
Nuclear-steam	1.3	5.9	6.2
Geothermal	.5	1.0	7.0
Hydroelectric	8.1	8.8	10.2
Hydro-pumped storage	1.1	3.0	3.0
Biomass/cogeneration	.2	.4	.5
Solar-central	-	-	1.6
Wind-central	-	-	.4
Net firm transfers	3.5	2.9	2.7
Other transfers	-	-	-
Total resources	38.9	48.2	57.2
Surplus (resources-loads)	9.5	12.8	16.6
Desired margin	4.5	5.2	6.0
Net above margin	5.0	7.6	10.6

*Negligible.

Table II-9

California Electricity Scenario II
Estimated Loads and Resources: Energy

	1975 (actual)	1985 (projected)	2000 (projected)
	(billion kWh)		
Loads:			
Load at customer	140.0	171.0	207.0
Losses	12.4	17.1	20.7
Total loads	152.4	188.1	227.7
Resources:			
Oil/gas-fired steam	75.2	71.7	19.2
Coal-fired steam	10.6	17.1	28.0
Gas turbine/diesel	.5	.8	.8
Combined cycle	-	9.6	9.6
Fuel cell	-	-	.2
Nuclear-steam	5.9	40.3	42.4
Geothermal	3.2	6.8	47.8
Hydroelectric	37.4	32.7	39.3
Hydro-pumped storage	-	(.3)	(1.0)
Biomass/cogeneration	.7	1.8	3.0
Solar-central	-	-	20.5
Wind-central	-	-	10.1
Net firm transfers	5.1	.3	.5
Other transfers	13.8	7.3	7.3
Total resources	152.4	188.1	227.7

Table II-10

Nevada Electricity Scenario I
Estimated Loads and Resources: Peak

	1975 (actual)	1985 (projected)	2000 (projected)
	($, millions)		
Loads:			
Load at customer	1.6	2.6	3.9
Losses	.2	.3	.4
Total loads	1.8	2.9	4.3
Resources:			
Oil/gas-fired steam	.7	.7	.7
Coal-fired steam	.6	1.3	3.0
Gas turbine/diesel	.3	.6	1.0
Combined cycle	-	-	-
Fuel cell	-	-	-
Nuclear-steam	-	-	-
Geothermal	-	-	-
Hydroelectric	.3	.3	.3
Hydro-pumped storage	-	-	-
Biomass/cogeneration	-	-	-
Solar-central	-	-	-
Wind-central	-	-	-
Net firm transfers	a/.5	b/.9	-
Other transfers	-	-	-
Total resources	2.4	3.8	5.0
Surplus (resources-loads)	.6	.9	.7
Desired margin	.3	.4	.6
Net above margin	.3	.5	.1

a/1.5 x Ave. Annual MW of energy imports.

b/Increased from 1975 by 1985 load - 1975 load.

Table II-11

Nevada Electricity Scenario I
Estimated Loads and Resources: Energy

	1975 (actual)	1985 (projected)	2000 (projected)
	(billion kWh)		
Loads:			
Load at customer	7.8	12.6	18.7
Losses	.8	1.3	1.9
Total loads	8.6	13.9	20.6
Supply:			
Oil/gas-fired steam	3.2	3.2	.4
Coal-fired steam	3.7	8.9	20.5
Gas turbine/diesel	.1	.2	.4
Combined cycle	-	-	-
Fuel cell	-	-	-
Nuclear-steam	-	-	-
Geothermal	-	-	-
Hydroelectric	1.2	1.2	1.2
Hydro-pumped storage	-	-	-
Biomass/cogeneration	-	-	-
Solar-central	-	-	-
Wind-central	-	-	-
Net firm transfers	.4	.4	(1.9)
Other transfers	-	-	-
Total supply	8.6	13.9	20.6

Table II-12

Nevada Electricity Scenario II
Estimated Loads and Resources: Peak

	1975 (actual)	1985 (projected)	2000 (projected)
	(thousand MW)		
Loads:			
Load at customer	1.6	2.1	2.8
Losses	.2	.2	.3
Total loads	1.8	2.3	3.1
Resources:			
Oil/gas-fired steam	.7	.7	.7
Coal-fired steam	.6	1.0	1.0
Gas turbine/diesel	.3	.6	.8
Combined cycle	-	-	-
Fuel cell	-	-	-
Nuclear-steam	-	-	-
Geothermal	-	-	.6
Hydroelectric	.3	.3	.4
Hydro-pumped storage	-	-	-
Biomass/cogeneration	-	-	-
Solar-central	-	-	.1
Wind-central	-	-	-
Net firm transfers	.5	.7	-
Other transfers	-	-	-
Total resources	2.4	3.3	3.6
Surplus (resources-loads)	.6	1.0	.5
Desired margin	.3	.4	.5
Net above margin	.3	.6	0

Table II-13

Nevada Electricity Scenario II
Estimated Loads and Resources: Energy

	1975 (actual)	1985 (projected)	2000 (projected)
	(billion kWh)		
Loads:			
Load at customer	7.8	10.2	13.5
Losses	.8	1.0	1.3
Total loads	8.6	11.2	14.8
Resources:			
Oil/gas-fired steam	3.2	3.2	.8
Coal-fired steam	3.7	6.2	6.8
Gas turbine/diesel	.1	.2	.3
Combined cycle	-	-	-
Fuel cell	-	-	-
Nuclear-steam	-	-	-
Geothermal	-	-	4.1
Hydroelectric	1.2	1.2	1.5
Hydro-pumped storage	-	-	-
Biomass/cogeneration	-	-	-
Solar-central	-	-	1.3
Wind-central	-	-	-
Net firm transfers	.4	.4	-
Other transfers	-	-	-
Total resources	8.6	11.2	14.8

APPENDIX II

Table II-14

Cost Summary - Arizona, Scenario I
(millions of 1977 dollars)

	1975			1985			2000		
	F	V	T	F	V	T	F	V	T
Oil/Gas fired	$ 40	$132	$172	$ 40	$112	$152	$ 40	$ 82	$ 122
Coal fired	121	93	214	572	339	911	572	638	1,210
Gas turbine/diesel	21	18	39	21	31	52	116	126	242
Comb. cycle	11	17	28	22	42	64	148	154	302
Fuel cell									
Nuclear				212	53	265	654	342	996
Geothermal									
Hydroelectric	30	.3	30	30	.3	30	30	.3	30
Hydro-ps	3	*	3	3	*	3	3	*	3
Biomass/cogeneration	—	—	—	—	—	—	—	—	—
Solar-central	—	—	—	—	—	—	—	—	—
Wind-central	—	—	—	—	—	—	—	—	—
Transfers	(32)		(32)	(3)		(3)			
Transmission			48			89			150
Distribtuion			110			221			409
			$ 612			$ 1,726			$ 3,464

Note: F--fixed; V--variable; T--total.

*Negligible.

APPENDIX II

Table II-15

Cost Summary - Arizona, Scenario II
(millions of 1977 dollars)

	1975			1985			2000		
	F	V	T	F	V	T	F	V	T
Oil/Gas fired	$ 40	$132	$172	$ 40	$112	$152	$ 40	$120	$ 160
Coal-fired	121	93	214	530	240	770	530	499	1,029
Gas turbine/diesel	21	18	39	21	31	52	21	42	63
Comb. cycle	11	17	28	22	42	64	22	57	79
Fuel cell	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	212	53	265	318	172	490
Geothermal	-	-	-	-	-	-	9	4	13
Hydroelectric	30	.3	30	30	.3	30	34	.3	34
Hydro-ps	3	*	3	3	*	3	3	*	3
Biomass/cogeneration	-	-	-	-	-	-	-	-	-
Solar-central	-	-	-	-	-	-	50	.1	50
Wind-central	-	-	-	-	-	-	-	-	-
Transfers	(32)		(32)	(32)		(32)			
Transmission			48			72			106
Distribution			110			164			256
Conservation:									
Residential			-			87			303
Commercial			-			4			15
Industrial			-			10			23
			$ 612			$ 1,641			$ 2,624

Note: F--Fixed; V--variable; T--total.

*Negligible.

APPENDIX II

Table II-16

Cost Summary - California Scenario I
(millions of 1977 dollars)

	1975			1985			2000		
	F	V	T	F	V	T	F	V	T
Oil/gas-fired	$527	$1579	$2106	$527	$3542	$4069	$ 396	$ 792	$1188
Coal-fired	102	74	176	145	205	350	2050	1749	3799
Gas turbine/diesel	19	13	32	31	35	66	63	84	147
Comb. cycle	*	*	*	189	688	877	237	1162	1399
Fuel cell	-	-	-	-	-	-	45	26	71
Nuclear	85	30	115	887	242	1129	3707	2085	5792
Geothermal	43	29	72	147	81	228	303	120	423
Hydroelectric	307	4	311	333	3	336	348	3	351
Hydro-ps	38	*	38	104	*	104	104	*	104
Biomass/ cogeneration	42	8	50	84	23	107	106	42	148
Solar-central	-	-	-	-	-	-	49	-	49
Wind-central	-	-	-	-	-	-	-	-	-
Transfers (firm)	(133)	(51)	(184)	(110)	(6)	(116)	(102)	(13)	(115)
(non-firm)		(97)	(97)		(88)	(88)		(117)	(117)
Transmission			305			469			746
Distribution			688			1048			1688
			$3,612			$8,589			$15,673

Note: F--fixed; V--variable; T--total.

*Negligible.

Table II-17

Cost Summary - California Scenario II
(millions of 1977 dollars)

	1975			1985			2000		
	F	V	T	F	V	T	F	V	T
Oil/gas-fired	$527	$1579	$2106	$527	$2510	$3037	$396	$923	$1319
Coal-fired	102	74	176	145	205	350	370	448	818
Gas turbine/diesel	19	13	32	31	35	66	31	48	79
Comb. cycle	*	*	*	190	307	497	84	422	506
Fuel cell	-	-	-	-	-	-	45	10	55
Nuclear	85	30	115	887	242	1129	950	594	1544
Geothermal	43	29	72	87	48	135	607	239	846
Hydroelectric	307	4	311	333	3	336	386	4	390
Hydro-ps	38	*	38	104	*	104	104	*	104
Biomass/cogneration	42	8	50	84	23	107	106	42	148
Solar-central	-	-	-	-	-	-	794	2	796
Wind-central	-	-	-	-	-	-	339	1	340
Transfers (firm)	(133)	(51)	(184)	(110)	(6)	(116)	(102)	(13)	(115)
(non-firm)		(97)	(97)						
Transmission			305			376			455
Distribution			688			848			1064
Conservation:									
Residential						306			839
Commercial						57			220
Industrial						410			1280
			$ 3,612			$ 7,642			$ 10,688

Note: F--fixed; V--variable; T--total.

*Negligible.

APPENDIX II

Table II-18

Cost Summary - Nevada, Scenario I
(millions of 1977 dollars)

	1975			1985			2000		
	F	V	T	F	V	T	F	V	T
Oil/gas-fired	$18	$89	$107	$ 18	$112	$130	$ 18	$ 19	$ 37
Coal-fired	28	26	54	126	106	232	366	330	696
Gas turbine/diesel	5	3	8	14	9	23	27	24	51
Comb. cycle	-	-	-	-	-	-	-	-	-
Fuel cell	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-
Hydroelectric	11	.1	11	11	.1	11	11	.1	11
Hydro-ps	-	-	-	-	-	-	-	-	-
Biomass/cogeneration	-	-	-	-	-	-	-	-	-
Solar-central	-	-	-	-	-	-	-	-	-
Wind-central	-	-	-	-	-	-	-	-	-
Transfers	(16)	(8)	(24)	(29)	(8)	(37)		(55)	(55)
Transmission			16			25			37
Distribution			46			78			121
			$218			$462			$898

Note: F--fixed; V--variable; T--total.

APPENDIX II

Table II-19

Cost Summary - Nevada, Scenario II
(millions of 1977 dollars)

	1975			1985			2000		
	F	V	T	F	V	T	F	V	T
Oil/gas-fired	$18	$89	$107	$ 18	$112	$130	$18	$ 38	$ 56
Coal-fired	28	26	54	84	74	158	84	109	193
Gas turbine/disesel	5	3	8	15	9	24	21	18	39
Comb. cycle	-	-	-	-	-	-	-	-	-
Fuel cell	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	52	20	72
Hydroelectric	11	.1	11	11	.1	11	15	.1	15
Hydro-ps	-	-	-	-	-	-	-	-	-
Biomass/cogeneration	-	-	-	-	-	-	-	-	-
Solar-central	-	-	-	-	-	-	50	.1	50
Wind-central	-	-	-	-	-	-	-	-	-
Transfers	(16)	(8)	(24)	(22)	(8)	(30)			
Transmission			16			20			27
Distribution			46			62			81
Conservation:									
Residential			-			27			85
Commercial			-			2			8
Industrial			-			9			9
			$218			$413			$635

Note: F--fixed; V--variable; T--total.

Table II-20

Costs of Industrial Energy Conservation
(annual cost in millions of 1977 dollars)

Measure	1985 AZ	1985 CA	1985 NV	2000 AZ	2000 CA	2000 NV
Savings with constant energy intensity	$0	$360	$0	$0	$980	$0
Additional savings with doubling of real prices	10	51	9	23	300	9
Total	$10	$410	$9	$23	$1280	$9

Note: Electricity prices based on current rate schedules for utilities in each State.

Table II-21

Summary of Commercial Sector Conservation Costs
(annual cost in millions of 1977 dollars)

Measure	1985 AZ	1985 CA	1985 NV	2000 AZ	2000 CA	2000 NV
Maintain constant energy use per square foot	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Savings from regulations corresponding to Title 20 and 24 of the Calif. Adm. Code.	0	0	0	0	0	0
Retrofit program (note a)	2.9	43	1.5	9.7	143	5.0
Extension of new building savings and retrofitting (note a)	1.0	14	.5	4.9	72	2.5
Total	$ 3.9	$ 57	$ 2.0	$ 14.6	$ 215	$ 7.5

a/Values calculated at 0.15 dollars per square foot per year.

APPENDIX II

Table II-22

Conservation Costs, Residential Sector (Ariz.)

Measure	Cost/unit	Projected adoption 1978-1985	Projected adoption 1986-2000	Total annual adopter cost 1978-1985 installations	Total annual adopter cost 1978-2000 installations
		(thousands)		($, millions)	
Retrofit:					
Ceiling	$ 250*	67	13	$ 2.2	$ 2.6
Other	1,300*	29	50	6.1	16.5
New Construction Standards:	600	448	667	29.6	73.6
Heat Pumps:					
Substitute for radiant	1,000	40	90	6.4	20.8
Improved efficiency	50	200	800	1.6	8.0
Solar Assist:					
Space heat	12,000	13	55	20.3	106.2
Water heat	1,500	14	98	2.7	21.8
Appliances:					
Water heater retrofit	20	200	10	.8	0.8
Water heater standards	20	435	1,165	1.2	4.2
Other appliances (new residence)	200	336	667	10.7	32.0
(replace)	200	180	350	5.8	17.0
Total				$ 87.4	$ 303.5

*Assume 30 percent multi-unit.

Table II-23

Conservation Costs, Residential Sector, (Calif.)

Measure	Cost/unit	Projected adoption 1978-1985	Projected adoption 1986-2000	Total annual adopter cost 1978-1985 installations	Total annual adopter cost 1978-2000 installations
		($, thousands)		($, millions)	
Ceiling Retrofit:					
Uninsulated single-family	$ 300	384	48	15.0	16.8
Uninsulated multi-family	150	214	27	4.2	4.7
Underinsulated single-family	225	171	14	4.9	6.1
Underinsulated multi-family	100	125	10	1.6	1.7
Other retrofit:					
Uninsulated single-family	1,500	96	96	23.0	46.0
Uninsulated multi-family	800	54	54	6.9	13.8
Super insulation & design:					
New single-family	1,500	42	288	6.9	54.4
New multi-family	750	47	314	3.9	29.9
Heat Pumps:					
Avg. cost/AC unit	1,000	89	393	14.2	77.1
Solar:					
Space heat	12,000	25	91	39.0	181.0
Water heat	1,000	10	69	1.3	10.3
Appliances:					
Water heater insulation	20	600	50		
Mandated standards					
(new residence)	100	2,500	4,000	40.0	104.0
(replace)	100	2,000	4,000	32.0	96.0
Other general residential	100	7,100	5,200	113.6	196.8
Total				306.5	838.6

Table II-24

Conservation costs, Residential Section (Nevada)

Conservation measure	Total annual adopter cost 1978-1985 installations	1978-2000 installations
	($, millions)	
Retrofit residences	$ 2.4	$ 5.3
New construction	9.0	20.9
Heat pumps	2.4	8.1
Solar	7.0	35.4
Water heaters	0.6	1.6
Other appliances	5.0	13.8
Total	$ 26.4	$ 85.1

Subsidy required for conservation

The energy conservation that is estimated to be achieved in Scenario II presumes that specific programs will be required for at least some of the measures. Many of the programs are regulatory. For example, thermal efficiency standards for new construction and energy efficiency standards for new appliances are programs which, if enacted, will require that the conservation measures be adopted, whether an individual wishes to do so or not. Other measures, such as retrofitting existing buildings, are not well suited to regulation and hence will most likely be achieved by voluntary programs. In that case, it will be necessary to gain the cooperation of the building or company owner. We included only conservation measures that are cost effective, so there are economic gains to be achieved by adoption of these measures. However, the financial situation of individual customers, idiosyncrasies of specific applications, tenure arrangements, differences in knowledge about conservation, etc., all may intervene to cause individuals to choose not to conserve, even though, it is generally of economic benefit to do so. Subsidies can be used to overcome various deterrents to conservation by making conservation less expensive and more attractive to those who adopt the subsidized measures. Some subsidies are already available. The Federal Government has just enacted a program providing 15-percent rebate on homeowner insulation and weatherization costs. Subsidies could also take the forms of loans at low or zero interest or of subsidies to provide cheap, below-cost supplies of conservation inputs.

In Scenario II if one assumes the continuance of average cost pricing, subsidies would be required to encourage retrofitting residential buildings and installing solar assist measures, retrofitting commercial buildings and adopting industrial conservation measures. (Under incremental cost pricing of power such subsidies would not be required.) In the residential sector it is assumed that a 25-percent subsidy on the costs of the retrofit and solar assist measures would gain the estimated adoption. In the commercial sector, a 50-percent subsidy on retrofit costs would be required to bring the payback period for most retrofit measures down from 10 to 20 years, which is comparable to powerplant criteria, to the 3- to 5-year payback period that commercial firms are generally seeking. In the industrial sector, a 25-percent cost subsidy would bring the benefit/cost ratio up to the level that would be attained with full incremental cost pricing.

The total conservation subsidy required with these criteria is:

Required annual outlay for finance subsidies

($, millions/year)

State	Residential 1985	Residential 2000	Commercial 1985	Commercial 2000	Industrial 1985	Industrial 2000	Total 1985	Total 2000
Arizona	$ 4	$ 12	$ 2	$ 8	$ 2	$ 6	$ 8	$ 26
California	24	70	28	110	13	75	65	255
Nevada	1	3	1	4	2	2	4	9
Total	$29	$85	$31	$122	$17	$83	$77	$290

The above costs are stated in terms of average annual outlay that would be required for interest and principal repayment over the life of a loan or bond sufficient to finance the subsidized portion of the initial investment in conservation devices.

NOTES

1/Pacific Gas and Electric Company, Southern California Edison Company, Los Angeles Department of Water and Power, Sacramento Municipal Utility Districts, "Supply Plans for Common Forecasting Methodology", submitted to California Energy Resources Conservation and Development Commission, March 1978.

2/Form 1 submissions by utilities to Federal Power Commission for 1977.

3/Helmut, Frank, Arizona Energy Inventory: 1977. University of Arizona, 1977.

4/David Mendive, Energy in Nevada, Nevada Public Service Commission, 1976.

5/Western Systems Coordinating Council Staff, Summary of Estimated Loads and Resources, Western Systems Coordinating Council, 1978.

6/G. Bennington et al. Solar Energy: A Comparative Analysis of the Year 2020. MITRE Corp. Report MTR-7579, 1978.

7/Richard J. McDonald, Estimate of National Hydroelectric Power Potential at Existing Dams, U.S. Army Corps of Engineers, Institute of Water Resources, 1977.

8/John Gibbons et al. "U.S. Energy Demand: Some Low Energy Futures" Science, v. 200, 142-152 (1978).

9/Walter Butcher et al. "Energy Conservation Policy, Final Report on Module I-A. Technical Appendix," Northwest Energy Policy Project, 1978.

10/Helmich, James and Hugh Montgomery, Conservation, (Supporting Document No. 16 to Staff Summary Report for AB 1852 Proceeding (77-NL-1), California Energy Resources, Conservation, and Development Commission, Sacramento, Jan. 1978.

GENERATING TECHNOLOGIES DATA REFERENCES

(1) Source: "Summary of electric utility data submittals under the California Energy Commission's June 1977 order securing information (77-622-14)," dated December 30, 1977 (table 27, p. 21). Unless otherwise noted the data are those supplied by Pacific Gas and Electric Company and include the Sacramento Municipal Utility District figures as well.

(2) Source: "Nuclear Notice of Intention (NOI): alternative sites" (77-NOI-3, Aug., 1977). Unless otherwise noted the data are from table IIIF-2. Nuclear refers to a twin 1200-megawatts complex; coal refers to a twin 800-megawatt complex employing scrubbers.

(3) This figure represents a judgmental average of liquid dominated and vapor dominated geothermal resources. The data basically were collected from the reference stated in footnote 1.

(4) Source: The Mitre Corporation METREK Division, "Solar Energy: A Comparative Analysis to the Year 2020" Mitre Technical Report MTR-7579, March 1978. (Page 15)

(5) Assumed based on the spread of annual fixed charge ratios submitted by Pacific Gas and Electric.

(6) Based on the assumption that much of the hydro- and hydro-pump storage capacity is built by Federal and State agencies thus justifying a somewhat lower annual fixed charge ration compared to the primarily private utility constructed capacity.

(7) The 150 dollars per KW is 28 percent of the PG&E value shown for new oil or gas fired steamplants. The justification for this lower cost is that there will be essentially no new oil or gas fired steamplants and that the average age of the existing plants is such that much of the initial cost has been amortized.

(8) The plant capacity factor for hydro varies with the year and with the State in which the facility is located. For California, annual hydroelectric generation data were obtained from utility submittals (see supply reference #1). For Arizona and Nevada, generation estimates were based on EAPA and Salt River Project data for major hydroelectric facilities. Generation additions for Scenario #2 were based on special study (see supply reference #7).

(9) The figures used in the Mitre Corporation study referenced in footnote 4. The figures for coal and light water reactor nuclear were updated to 1977 dollars using a five percent inflation rate. The Mitre data were provided by Grant Miller of the Mitre Corporation.

(10) Source: The Mitre Corporation Report referenced in 4, above, page 15.

(11) A composite figure made up of solar thermal central receiver, used both directly in the fuel-saver mode and in the combined cycle hybrid intermediate mode, together with photovoltaic central suing thin film cells for semi-peak and fuel-saver modes. Reference the Mitre Corporation Report cited in 4 above, pages 14 and 15 (Ultimate System).

(12) Source: The Mitre Corporation Report, page 15.

(13) Composite of the two WECS Wind Generators and central station use, one in the fuel-saver mode, Mitre Corporation Report, page 15 ("Ultimate System").

(14) Composite of four solar central technologies, the same four used in the maximum plant capacity factor determination discussed in footnote 11.

(15) One half the estimated total capital cost cited in the reference of footnote 1. The justification for this is that very few new hydro facilities will be built and

a good portion of the existing capital cost imbedded in hydro facilities has already been amortized. The estimate was provided by Southern California Edison in the footnote 1 citation.

(16) The estimate provided by Los Angeles Department of Water and Power in the reference of footnote 1.

(17) Total annual fixed costs equal annual generation capital cost plus O&M annual fixed costs. The annual generation capital cost expressed in 1977 dollars per year per installed kilowatt is a simple product of the capital cost in 1977 cost per KW times the annual fixed charge rate.

(18) Total variable costs equal fuel cost plus O&M variable costs.

The fuel costs used in this table were derived from those in the Mitre report cited above as follows: distillates used for combustion turbine (gas turbine) and for combined cycle turbines are assumed to be 10 percent more expensive than the main price of oil and gas in that year. Fuel cell application is assumed to involve hydrogen-rich hydrocarbon which is 20 percent more expensive than the mean of oil and gas for the same year. Coal in the Pacific Southwest is assumed to be 10 percent less expensive than the national average shown in the Mitre Corporation tables. Biomass fuel is assumed to be priced at the arithmetic mean of logging residues, mill residues and silvicultural fuels. It is further assumed for biomass that no more than half the available supply of residues is ever used. Thus, the penalty in cost increases mentioned by Mitre Corporation is never incurred.

Fuel costs for oil and gas were based on an average of 40 oil or gas fired steam electric plants owned by Southern California Edison supplied in their submission to the California Energy Commission dated March 1978 entitled "Supply Plans for Common Forecasting Methodology I."

(19) Assumed, based on judgement concerning similar technologies for which the fixed O&M costs are well-known.

(20) The capital costs for four technologies were adjusted in 1975 to account for lower costs of plants constructed before 1975. Data on older plant costs were taken from Form-1 submissions to the Federal Power Commission. The ratio of capital costs for plants existing in 1975 to capital costs for plants constructed after that date are:

Coal-firm steam	.33
Turbine	.50
Combined cycle	.50
Nuclear	.37

EVALUATION OF IMPACT OF VARIOUS POLICIES

ECONOMIC IMPACTS OF ELECTRICITY SCENARIOS

There is considerable concern that electricity policies aimed at reducing the rate of growth in electricity use will depress economic growth and cause unemployment. The concern probably arises from the observation that economic activity and electricity use tend to be correlated. Rich nations use more electricity as they become richer and the rate of growth in use of electricity speeds and lags more or less in step with the booms and recessions of the economy.

The correlation between electricity use and economic activity is commonly used as a basis for forecasting future electricity demand. It is generally accepted that economic growth does cause demand for electricity to increase. However, the more important issue where questions of economic impact are concerned is whether energy policy actions that decrease electricity consumption will necessarily retard economic growth.

The effect of energy availability and energy policy on the economy has not been studied until recently. In the last few years there have been several energy/economic analyses, using structural economic models to predict the consequences of increased costs of energy. None of these studies is directly applicable to the economic impacts of electricity demand management in the California, Arizona, and Nevada area. However, they do indicate the relatively small effects on the overall level of economic activity that could be expected from even more widespread policies. For example, in Hudson and Jorgensen's 1974 article, they estimated that an energy tax of $1.35 per million Btus would achieve independence from energy imports by reducing 1985 energy consumption by 16.2 percent from a base case level. The total effect on GNP was estimated to be only a one-percent reduction from base case 1985 levels. Actually, the decline may have been even less or turned into a GNP increase if full account were taken of uses that could be made of the taxes collected or of indirect benefits realized from redirected investments, etc.

These predictions of small economic impacts from relatively large changes in the energy supply situation are borne out by the course of events since 1973. The price of oil and natural gas suddenly increased to twice or more for most customers, and supplies sometimes were not available. Since then, energy use has grown much more slowly than in the 1960's. Nevertheless, it would be difficult to attribute any more than a brief lag in economic activity to the effects of and the price increases and lower energy growth rates that have applied ever since.

The ability of the economy to withstand large adverse changes in energy prices and supplies is due principally to: (1) the relatively small portion of total costs of production and living that are due to energy, which means that a large energy cost increase does not mean a large total cost increase and (2) the flexibility and adaptability of the economy, which makes it possible to shift to less energy intensive modes of production or to the goals that can be produced with less energy.

Assessment of the economic impacts of electricity scenarios in this study will have to be very approximate. There is no economic impact model available for use for tracing initial changes through successive chains of economic repercussions, and there is not enough time to build such a model especially for this study. However, some useful observations can be made by noting how electricity supplies and users would be affected by each of the scenarios, and then indicating the further implications for the economy of the most probable response by the suppliers and users. In this exercise we assume that the economy has considerable ability to adjust to various shocks. Adjustability is especially good in the long run when it is quite safe to assume that any immediate dislocations will have been worked out, and the only enduring impact is the effect on overall economic efficiency.

In the short run, a sharp economic shift, such as to more conservation and less electricity production, will require adjustments. Some workers, equipment and plants will need to be employed for different purposes such as producing insulation, heat pumps, etc., rather than powerplants, electric furnaces, etc. These shifts cannot all occur immediately so some workers and facilities may be stranded--committed to producing products in greater amounts than are needed after directions change.

Impact of projected growth: Scenario I

Scenario I is characterized by a continuation of past policies and an extension into the future of only slightly reduced rates of growth in electricity use. Electricity use is projected to grow between now and the year 2000 by 4.7 percent per year in Arizona, and 3.6 percent per year in California and Nevada. That growth is only slightly above projected rates of growth in total State output, so electricity use is expected to grow about in proportion to industrial production and personal income. But, more expensive means will have to be used to generate the additional electricity so the costs of electricity supply will rise about 50-percent faster than will the quantity supplied. Total electricity supply costs in the three States are projected to rise by four-fold from $5 billion in 1975 to $20.5 billion in the year 2000 (measured in 1977 dollars).

The economic impact of the projected growth in electricity supply will be determined more by the rapidly growing expenditures of the industry than by the more slowly growing quantity of electricity supplies. Electric utilities will be a growth industry if Scenario I is realized. Their hiring of workers and purchase of goods and services from other sectors will grow more rapidly than in the economy in general. In the short run, rapid growth by a sector can be beneficial for resolving problems of unemployment and idle capacity. However, in the case of electric utility growth envisioned in Scenario I, there are some offsetting negative aspects to the growth.

One negative aspect of the projected growth of the utilites is the tendency to import a large share of the inputs that make up their rapid growth production expenditures. This would be particularly true for Arizona and Nevada, which do not produce within their own State, many of the components that are required for large, modern electricity generating plants. Even in California, many components would be imported from other regions or even from out of the country. Virtually all the fuel inputs will be imported for all the States (except from some in-State coal in Arizona). When this kind of leakage occurs, the expanded utility business helps stimulate economies of areas other than the one that is paying the higher costs for the new supplies.

To the electricity customers, the increased costs and revenues of the utilities will appear as higher costs of doing business or higher cost of living. Electricity rates will have to average about 4.8 cents/kWh in 2000 to cover all of the costs of supplying the expanded loads. This would require a rate increase of more than 40 percent, in real terms, over and above any increase due to inflation. Since the growth in electricity use is at about the same pace as economic output and personal income it follows that about a 40 percent larger share of business costs and consumer incomes will have to be allocated to paying for electricity at the anticipated higher rates.

Ultimately, consumers will have to absorb all of the rate, and cost increase directly through the higher cost of electricity used in their own home and indirectly through the higher costs of goods and services purchased from industries who are passing their own increased electricity costs on to their customers. On balance, about 1 percent of total personal income will have to be shifted over to the electricity suppliers in order to pay for the anticipated increased costs of electricity generation.

In the long run, the shift of income to pay for the higher costs of electricity has the same effect on consumers as would a one-percent decrease (or lack of growth) in their incomes. In order to pay the added costs of electricity they will be forced to curtail their purchase of other goods and services by enough to rebalance their budget, including the more expensive electricity. Those curtailments will be spread over many items and will be quite small for each. However, they will be felt as small reductions in sales by various industries whose products are given up by consumers because of the necessity of paying for that expensive electricity.

The total decline for these "other" industries should be about equal to the 1 percent of income that will have to go to cover the higher costs per unit of electricity. Thus their production, employment and purchases from input suppliers will be reduced by about the same amount as the electricity industry's cost expansion. Employment will be about the same, but total output will be less since other industries reduce their output to free up the added resources needed to produce the more expensive electricity.

The size of the ultimate impact on the local economies could differ if the expanding and contracting sectors differ significantly in their linkages to the rest of the local economy. For example, a large portion of the increased expenditures for power supply may "leak" out of the State to pay for imported high technology components, and nuclear or fossil fuels. In contrast, the industries that lose out, because of the burden of paying the power costs, may be more likely to typically hire local workers and buy inputs that are supplied by other local industries. If so, the local economy will lose out by more than just the 1-percent income decrease mentioned above. The increased flow of funds out for the State will create an imbalance that will tend to force either some out-migration from the State, following the money to the jobs, or some off-setting growth of the States' export industries. Unfortunately, it is hard to expand exports to other States or abroad without doing something to improve the competitive position of the State's export industries. One can only hope that it is not necessary to accept the lower wages and incomes in order to gain that competitive edge in export markets.

Under Scenario II, the electric utilities will represent a slightly smaller share of the total economy in 2000 than they do at present. Their revenues, and costs, are projected to be 2.2 times the 1975 level as compared to an overall economic growth of about 2.5 times. The gross value of power sales is projected to be $11.4 billion, which is only 55 percent as much as the value of sales expected under Scenario I. The difference is growth not realized, rather than a decline, so there would be no economic disruption as a result of the slower growth in the electricity supply business.

Impact of conservation emphasis: Scenario II

Scenario II is characterized by (1) much less electricity use, only 63 percent as much as Scenario I in 2000; (2) real costs of electricity supply that are less per kWh, in 2000 than in Scenario I; and (3) costs of $2.8 billion per year for additional conservation (over and above the conservation included in Scenario I). As a result of these differences, the economic impacts of Scenario II would differ significantly from those of Scenario I.

Under Scenario II, the electric utilities will represent a smaller share of the total economy in 2000 than they do at present. Their revenues and costs, are projected to be 2.2 times the 1975 level as compared to a general economic growth to 2.5 times the 1975 level. The total costs of meeting electricity needs in 2000 is estimated at $14.2 billion, for the three States, including $11.4 billion in supply system costs and $2.8 billion for additional conservation measures not yet included in Scenario I. In contrast, total electricity supply system costs in Scenario I were estimated to be $20.4 billion.

The slower growth of electricity supply and of the value of utilities' sales (which must equal costs) means that the electricity sector will be less of a factor in the States' economies. Utilities will employ fewer workers and do less business with other sectors than they would if a Scenario I type of energy future were realized. However, this does not mean that there would be a sudden gap in employment and business activity. Electricity supply and conservation costs together are very close to the same share of total regional production and income as in 1975. Thus, meeting electricity needs under this scenario will require very little adjustment of the economy as it was in 1975. Furthermore, electricity system growth in Scenarios I and II is much more similar until 1985 than it is after that time. So the differences will mostly appear after 1985.

One of the major concerns about economic impacts is that policies designed to direct the "States'" energy future toward Scenario II will hinder industrial production and retard economic growth. For example, rationing energy to industrial users could cause economic harm if some firms receive less than the minimum needed to run their businesses. "Brown-outs" and interruptions may occur if reserve capacity is inadequate. This situation may also damage business far more than the value of the power involved. In view of the seriousness of these impacts, Scenario II is designed to avoid these problems by concentrating on reducing demand, but providing for adequate supply to meet the demand.

Another policy that arouses concern is an "OPEC-style" price increase. Electricity prices could be increased to encourage conservation and discourage consumption. The effect of higher electricity prices has already been discussed above. Even though the increase amounts to a relatively small share of total production or living costs, it is safe to presume that there will be economic contractions, or reduced growth, as an ultimate response. In an earlier discussion, we referred to an increase that is necessitated by higher costs of electricity supply. However, the ultimate impact on the economy can be quite different if the added revenue from the price increase is not required to cover higher costs but instead is "recycled" back to the economy. The recycling could take the form of subsidies for the adopters of cost-effective conservation measures or investors in desired renewable energy resources. Alternatively, funds obtained through charging a price that is above average cost may be used for general tax relief, for a "dividend." (As long as it is not distributed in proportion to electricity use.) The "recycled" revenues either decrease someone's costs or increase someone's income. That will set in motion economic expansion that will tend to offset the contractionary effects of the electricity rate increase. The expansion may take place in different sectors than the contraction. (For example, a general rate increase might lead to contraction in the electric utilites, electro-process industries and generating equipment manufacturers and to expansion for insulation, construction and electrical equipment manufacturing.) However, the overall impact on the economy should about balance out as long as the excess revenues collected through a designed price increase are refunded back into the same economy that they came from.

From the total State or regional economy's point of view, the price increases to be feared are those where the added revenues are not refunded in any form. This would happen if rates are forced up by cost increases or if the extra revenue collected with the higher rates is lost to the economy that is paying the higher rates. Cost increases might come about by the system being pushed into higher cost generating modes, as in Scenario I, or by unwise allocation of the revenues to very costly and/or useless programs. Transfer of funds out of the region seems unlikely, unless perhaps excess revenues from "conservation" pricing of Federal power could be lost from the project area to other regions or the Federal treasury.

EQUITY AND DISTRIBUTION OF IMPACTS

Whenever major changes occur, such as those anticipated in electricity supply and use, questions naturally arise about whether the impacts of the changes are equitably distributed among all of the parties that are involved. In the case of electricity, the feelings about equity of impacts are especially strong because government is very much involved in determining policies and rates that directly impact electricity supplies and customers of all types.

It is very likely that the costs of supplying electricity will average much higher during the next 20 years than they have in the past. Policies that facilitate less expensive supply options could help reduce the size of the cost increase, but it is very unlikely that it could be completely avoided. Those added costs must be paid, somehow, by the electricity customers. So, on balance, customers are going to be adversely impacted. Rate or pricing policies will determine the distribution of that added cost among various classes and types of customers. The only way to avoid an adverse impact for some groups is to have others shoulder a larger share of the added costs through higher utility rates, increased taxes, or more do-it-yourself costs.

Judgments about the "equity" or "fairness" of an impact are very difficult to make because fairness is a many-faceted term. Some specific aspects of equity are:

--Should every individual bear a fare share of the costs caused by his or her activities (i.e., no freeloaders or special favors).

--Should individuals and industries be protected from sudden, unexpected financial disasters (i.e., no wipeouts).

--Should poor people, lagging regions, and struggling industries be helped whenever possible and at least protected from the pressure of further increases in their costs.

IMPACTS OF SCENARIO I

Scenario I is characterized by an electricity system that is a continuation and extension of the present system. The added costs of future supplies are assumed to be paid directly by customers in the form of higher rates. However, there is no rate reform except as required to cover the added costs. So, differences that now exist among customers will tend to be carried forward. Specifically, customers with contracts for low-cost WAPA power will be able to continue to get that power at the costs of hydrogeneration.

Arguments over equity in Scenario I are likely to center around (1) the impact of power cost increases on individuals and businesses who are unable either to avoid or to bear the increase and (2) growing disparity between rates of average customers and the few customers who are in a position to get very cheap power from WAPA.

In Scenario I, the average cost of electricity supply increases from 29.7 mills/kWh in 1975, to 48.2 mills/kWh in

2000. Two-thirds of the increase occurs by 1985 as more expensive generating systems are rapidly expanded to form a large fraction of the 1985 rate base. A few electricity customers will be hit hard by these rate increases. Irrigators that do not have access to guaranteed low cost power will find electricity too expensive to continue high-lift pumping except for high-value fruit and vegetable crops. The cost increase will be enough to drive a few irrigators out of business. More often, irrigators will switch to alternate fuels, if available, or make increased effort to conserve both water and energy in their farming operations. There would be very little new high lift irrigation developments at these rates.

Most industries and commercial businesses would not be seriously impacted by rate increases that are implied by these costs. They would certainly prefer not to have the increase, but it is not likely to be large enough to drive many out of business. It may, however, be large enough to cause businesses to seriously seek ways to avoid the substantial increases in electricity use per unit of production that are projected in official demand forecasts.

The average residential customer's electric bills would more than double by the end of the century under Scenario I. The increase would come from projected higher rates plus increased usage per household. An expected movement toward electric space and water heating is a factor, especially in Arizona where all new residences are expected to be forced to use electricity due to a moratorium on new gas hook-ups.

In Scenario I, there could be serious adverse impacts on individuals or industries that are already having economic difficulties. Some irrigated land owners fall in this category. Most industries do not. Some low-income households that are already in financial difficulty might be hurt if they had to shoulder the anticipated rate increase. Still, average electric bills will be about $35 per month (in 1977 dollars) in California. Even a low-income family, in the year 2000, would not find this to be a large portion of their monthly budget. But there is always the possibility that public opinion would prefer to use electricity rates as a means of helping the needy by shifting some of the costs of their needs over to others through special rates or through a tax/subsidy program.

IMPACTS OF SCENARIO II

Under Scenario II, the average cost of supplying a kWh of electricity rises rapidly to 1985 but then stays almost constant to the end of the century. Therefore, the rates that must be charged to cover the average costs of supplying electricity need not rise as much as they would under Scenario I. Furthermore, demand for electricity grows much less rapidly, due to conservation, so that total electric bills need to be only about 60 percent as large as in Scenario I to cover all supply system costs. There are conservation costs as well, but they are quite small compared to electricity supply costs. So, overall costs of meeting energy needs with a combination of electricity supply and conservation will average much less under Scenario II than under Scenario I. In fact, costs of electricity supply and conservation per kwh of Scenario II-type base demand are only slightly above the average 1975 cost/kWh.

Lower costs under Scenario II mean less general impact and less likelihood that needy individuals or weak industries will be put in jeopardy by rising power costs. Therefore, impacts of that sort will be considerably less than under Scenario I. However, Scenario II involves more costs outside the electricity supply system for specific conservation measures, and for a general shift to hold down the increase in electricity use. Scenario II also includes more explicit intervention in prices and policies to channel the electricity future of the region toward what is felt to be more consistent with national energy objectives. These differences could impact some customers in ways that could be questioned on equity grounds.

One of the changes anticipated in Scenario II is more involvement of WAPA in the furtherance of conservation and alternative energy sources. This would cause WAPA's rates to rise in order to cover the added costs. If WAPA financed the cost subsidies that are required to get adoption of conservation by users and built a substantial fraction of the solar and windpowered generating plants scheduled in Scenario II, WAPA rates would have to rise to about the same level as other utilities in the area. This would eliminate disparities and reduce the conflict that would arise if WAPA rates came to be only about one-fourth as high as those of other suppliers. But, an increase of two or three cents/kWh in the price of electricity to a long time WAPA customer would be quite a "disappointment."

The most noticeable impact of a substantial WAPA rate increase would fall on irrigators, who use about one-fourth of all WAPA power. Irrigators are hard hit by a rate increase because the amount of electricity used can be quite large relative to the value of production. For example, an irrigator who is lifting water 500 feet and applying four acre-feet per acre will use about 5,000 kWh of electricity per year to produce crops that average, in 1976, $700 gross value per acre. Electricity use is about seven kWh per dollar of output, which is above the use rates of even the electricity intensive industries. Each one-cent per kWh rate increase, in this case, would represent a cost increase equal to seven percent of gross returns. If the farmer happens to be producing low-value grain and forage crops, value might be $300 per acre per year, and electricity consumption becomes 17 kWh per dollar of output. Costs would increase by 17 percent of gross value for each one-cent per kWh increase in power rates. An increase of three cents per kWh, which is not inconceivable, would increase power costs by an amount equal to 50 percent of gross value.

Many irrigators in all three States are much less affected by power rate increases than this example indicates because they do little or no pumping or they are producing crops with high values that completely overshadow the effect of rate increases. Several California basins, parts of Arizona and most of Nevada obtain irrigation water with less than 100 feet of pump lift. Pumping energy requirements in these areas are less than 1,000 kWh/acre/year and a one-cent per kWh rate increase will cause only a $10 per acre per year cost increase. In other areas, fruit and vegetable producers have crop values ranging from $1,000 to $4,000 per acre. Even if power costs double, the cost of electricity is only a small fraction of total costs and gross returns.

Analyses by Knutsen, et al., 1/ include estimates of pumping energy requirement for different crops, water sources and application methods in each of California's hydrologic basins. The areas under most pressure to respond will be those where large amounts of electricity are used to produce low-value crops.

The resources were not available for an indepth study of irrigator's most profitable and probable response to higher power rates. However, results of a study in the Bonneville Power service area 2/ indicated that irrigators will first take actions that reduce energy use without affecting production patterns. Measures that improve water and energy efficiency are profitable for everyone as long as the conservation measures cost less than it would to keep on buying the power at new, higher rates. A 10-percent average savings is reasonable to expect by this means if a moderate rate increase is combined with information and demonstration programs. Beyond that, further energy savings may entail expensive facilities, such as drip systems, crop changes or even land abandonment.

The next line of response will generally concentrate on shifting crop acreages and making permanent changes that improve pumping efficiencies. Low pressure systems and improvements to pumping plants become more attractive as power costs rise. Farms will reduce production of grains and forages, partly by substituting other crops and partly by reducing land irrigated in the high cost areas that have a limited range of cropping alternatives. A rate increase in the range of one and one-half to three cents per kWh would put considerable pressure on southern California, the Colorado River, and the Arizona areas that are lifting water 300 to 500 feet out of rapidly declining groundwater aquifers.

The most dramatic response and obvious impact will be where there is a reduction in land irrigated due to a water and energy cost crunch. In southern California and parts of Arizona that impact could be softened by the fact that land and water are already being converted from agriculture to urban use at a substantial rate. If high value crops can be concentrated on the land that remains in agriculture, the specter of dried up farms may be avoided. In that case, the main thing that will be lost will be expansions of irrigation hoped for, in part, as an offset to lands being lost to urbanization.

In actuality, by far the largest economic impact would be the effect of higher power rates on the irrigators who find that their best option is to continue to operate, with only some adjustments that help avoid part of the higher power costs. These irrigators will find that their costs increase, perhaps by more than $200 per acre per year, and hence their net returns are reduced. This decline will soon be reflected in the value of land, at a capitalized rate that is several times as large as the change in annual income. This impact on land values will affect all power users, although it will be proportionately less for those farmers that use only small amounts of power. If a rate increase of one-cent per kWh were applied to the entire 10 billion kWh used for irrigation pumping in the three-State area, irrigator's costs would be increased by $1 billion. Actually, some of the cost increase could be avoided by measures that were discussed above. In some cases the threatened cost increase is larger than the total profit now realized from farming the land. Still, even if the impact only amounts to $500 million less land value than would have otherwise been enjoyed, it is a substantial loss to owners of the area's 10 million acres of irrigated land. And, the impact is very unevenly distributed, so it will fall hard on some land owners. On the other hand, it can be argued that land values have been rising rapidly due to general inflation and other factors. Therefore an adverse impact at this time will only involve giving up recent gains. Furthermore, there is the possibility of gradually phasing in rate increases so that their impacts are offset by the general increase in land prices.

ENVIRONMENTAL QUALITY AND THE ELECTRICITY SUPPLY SYSTEM

The generation of electricity in the Southwest will produce environmental effects which will depend on the number and types of power plants being used. These effects will range from the direct, such as lung irritation produced by air pollutants, to the indirect, such as the exercise of police power to prevent theft of nuclear materials. A summary of environmental impacts asociated with the major sources of electric power in the Southwest is presented below.

Hydroelectric generation

The adverse environmental impacts of new hydroelectric power are generally related to the welfare of fish and wildlife, the loss of the use of land that is inundated, the loss of free-flowing stream and other aesthetic changes and recreational problems. New energy capability that comes about as a result of installing more generators in existing dams can expected to be, on the average, less disruptive than energy produced by raising existing dams or by constructing new dams. Past experience indicates that residents in the Southwest place a high value on the preservation of natural conditions in the vicinities of most of the undammed sections of streams and rivers in the region. Therefore, in most cases the environmental impacts of raising existing dams or building new dams on flowing streams will be negative, but the addition of generating capacity at existing dams may or may not be, depending on circumstances.

Coal fuel cycle

Coal-fired plants will add particulates, sulfur dioxide, nitrogen oxides, hydrocarbons, and trace amounts of other toxic elements to the air in their vicinities, and the plumes can be expected to produce effects on health, aesthetics, and property. Some indication of the impacts is provided by comparing coal air emissions with emissions resulting from the end-uses (home heating, automobile operation, etc.) of fuels in the region. See the entries in table III-1. Scenario I conditions were assumed for purposes of calculating the table entries. The summer peak MW of coal-fired generation used for the three-State region were 9,600 MW in 1985 and 24,800 MW in 2000.

Beyond the indication of relative impacts of air pollutants provided by residuals, there are other measures of relative magnitudes, namely the concentration of pollutants normally found at ground level. Table III-2 shows annual average concentrations of particulates and sulfur dioxide at several points in the three States along with approximate values to be expected from a coal-fired powerplant.

The entires in table III-1 show that emissions from coal plants serving California are rather small compared to emissions associated with end-uses. Damage to health and property produced by coal plant emissions is even less significant relative to damage from end-use emissions because of the generally remote locations of the powerplants and the great height above ground at which the plant stacks release effluents. These same conclusions do not hold for plants serving Arizona or Nevada. The emissions of sulfur dioxide and nitrogen oxide from power plants in these two States are comparable to those from end-uses except for sulfur dioxide in Arizona. The high sulfur dioxide emissions in Arizona come largely from the copper smelters in the State. It should be noted that in Nevada, the emissions from plants located within the State are greater than the emissions from plants serving Nevada. The reason is that part of the output from the Mohave plant in southern Nevada serves Southern California utilities.

In addition to the plans themselves, other components of the coal supply system produce some air pollution. In particular the rail transport of coal from mine to plant site is accompanied by particulate emissions. However, the plants themselves are the principal polluting sources.

Considering coal's reputation as a highly polluting fuel, it may be surprising that coal plants do not contribute an even larger fraction of the air pollution in the three States. The reason for the relatively small impact is that emissions from new plants are now controlled by Federal performance standards which were not in effect until recently.

The numbers in table III-2 indicate that the annual average concentrations of particulates and sulfur dioxide produced by coal-fired powerplants in its vicinity are small compared with levels in typical locations in Arizona, California, and Nevada. However, it should be noted that the maximum short-term concentrations from a powerplant will be higher than the annual average values, and furthermore the size distribution and composition of the coal plant particulates may lead to greater damage per ton emitted than is the case for other particulates, such as wind-raised dirt. Also, the sulfur dioxide concentrations in rural areas away from industrial and automobile sources will be lower than the values in the tables, probably in the range one to three micrograms per cubic meter. Existing air quality regulations will preclude the possibility of building large new coal fired powerplants in parts of California and Arizona. Emission regulations in several air quality districts of California limit NOx emissions to 140 lbs/hr. This is approximate the emission rate expected from a 25-MW(e) powerplant operating at capacity at the NOx limit imposed by proposed Federal New Source Performance Standards. A 25-MW(e) plant would supply power for a small town but is not the size plant that a utility would consider building. Some California air quality districts also have very low emission limitations on SO_2 and particulates. There is no possibility of building large plants in districts where these emission limitations are in effect. In addition to these excluded areas, there are several other locations in Arizona and California where present high pollution levels would prevent the construction of new plants.

Land disturbances associated with coal plants come about as a result of coal mining and solid waste disposal. Except for the Black Mesa area of Arizona, the coal mining will take place outside the three States being considered, but solid waste disposal (ashes, sludge, and chemicals) will presumably be inside the region. Treatment and disposal methods for the solid wastes are at present still in the development stage so that a full evaluation of their effectiveness cannot be given at the present time. However, recent Environmental Protection Agency estimates of total sludge fixation and disposal costs range from $7.30 to $11.40 per ton of dry waste. Such costs would add only slightly to the total generating cost of electricity (1 mill/kWh). However, disposal problems will be very site specific and careful attention must be given to the disposal site.

Restoration of strip-mined lands is a somewhat uncertain matter but appears to be feasible in much of the area in the Rocky Mountain States from which coal for the powerplants would come. A closely related effect is the interruption of aquifers during mining. The changes in ground water quality and availability can be serious depending on local circumstances. A recent GAO report summarizes these environmental effects of the coal fuel cycle. They are less serious for Western strip coal mining than for eastern underground mining.

Nuclear fuel cycle

The principal environmental effects of nuclear power arise from uncertainty about the ability of Government to cope with the consequences of malfunctions and misapplications of the technology. A derivative concern is that covert investigations, invasions of privacy, and massive exercise of police power in an emergency may be necessary to prevent the diversion of nuclear weapons grade material in a nuclear economy employing spent fuel processing and plutonium separation. There will also be some effects on health that arise from routine plant operation, but they will be small.

The determination of nuclear environmental effects is an exercise in evaluating the significance of catastrophies of low probability. Events leading to enormous disasters can be conceived, but the likelihood of their occurrence is estimated by most (but not all) analysts to be infinitesimally small. The average is not the quantity that establishes most people's reactions to nuclear side effects. One faction focuses on the major consequences of a reactor core meltdown, nuclear blackmail of a major city, or contamination of a regional water supply by a leaking radioactive waste disposal site. The opposite faction emphasizes redundant safety features, elaborate security measures, and stable geologic formations. The first side fears the complex nuclear technology and mistrusts the Government security that surrounds it. The second side sees few problems with either.

In view of this broad range of uncertainty, the impact of nuclear power in the two scenarios is simply described in terms of the level of potential effects as it is determined by the number of nuclear reactors in the region. In a somewhat arbitrary way, a qualitative distinction is made between having fewer than five nuclear reactors, five to 20, or more than 20 in the three-State region. Fewer than five are regarded as manageable on an individual basis. If there are from 5 to 20, all the risks and hazards of nuclear power would be present to a significant degree and must be dealt with on a regional, as well as, an individual basis. In this range the problems would be much the same regardless of number of plants. If there are more than 20 plants, the actual and potential impacts would again rise as the technology spreads. On this basis, the nuclear power situation in the three-State region falls into the intermediate category for Scenario II and just above the intermediate category in Scenario I.

Biomass

Biomass generation contributes air residuals characteristic of wood fuels. In table III-1, the tons of residuals produced in this way are compared to end-use residuals for Scenario II.

The schedule shows that wood wastes generate air residuals in amounts less than one percent of those produced by end-use applications in California. The effects of the wood plant emissions will be relatively even less because of the remote locations of the plants and the height above ground of the emissions.

The solid wastes produced in combustion of wood require disposal methods similar to those involved in ash disposal for other fuels.

Solar and wind energy

The principal impacts of solar and wind units appear to be commitments of land. Land occupied by central station solar power is 1-2 square miles per 100 MW. For wind the commitment is 0.4-0.8 square miles per 100 MW. Using these numbers we computed the land area commited to these renewable resources in the region for Scenario II in the year 2000 as follows:

Resources	Land commitment (square miles) 1985	2000
Solar	0	18-36
Wind	0	2- 4

These are larger land commitments than are required by thermal plants, but are rather comparable to the land commitments involved in transmitting the power from the generating stations to the power markets.

The visual impact of these units is uncertain, but it might be quite different from the visual impact of thermal powerplants because the technologies involved represent a very different approach to energy supply. The disruption of television service in the vicinity of large wind turbines would be objectionable to nearby residents. However, the effect would be local and should be correctable through use of cable reception.

The impacts described here are limited to those associated with central station powerplants; distributed (i.e., decentralized) systems are not included because the acquisition of such units is voluntary to the user and the impacts appear to be small and widely dispersed.

Geothermal

Geothermal sources of energy cover a wide range of pollution potential. The fluids from hydrothermal reservoirs sometimes contain large amounts of salt that can be quite polluting if they are released into surface waters. For this reason, present trends are to reinject them back into the reservoirs from which they are withdraw. If the brines are reinjected, the amounts of salt released will be minimal and will occur during initial well test procedures, well clean-out operations or accidents. Under these conditions, salt releases from geothermal powerplants are smaller than the corresponding releases from coal-fired plants of the same size.

The principal gaseous emissions from hydrothermal sources are carbon dioxide, hydrogen sulfide, and ammonia. Carbon dioxide releases are generally much smaller per unit of electricity produced than are the releases from conventional plants Sulfur and ammonia releases are somewhat larger than sulfur dioxide and nitrogen oxide emissions from coal plants.

So far, there is not much experience with land subsidence from geothermal development in this country, but land subsidence can be expected whenever large amounts of material are withdrawn from underground. There is ample evidence of impacts of land subsidence from coal mining and oil production. There is little experience with seismic effects induced by extraction and/or reinjection of geothermal fluids; but hydrothermal reservoirs do tend to occur in active seismic regions, and the Rocky Flats Colorado experience with injecting fluids underground does show that seismic effects can be induced.

The noise at geothermal plants is intermittent and is produced during the testing and cleanout of wells. Sound levels in the vicinity of such operations can reach 90 decibels, about the level of a passing freight train and above levels that are likely to be adopted as noise standards. The comparison with a passing freight train is perhaps appropriate because the coal supply system often does include rail transport of the coal.

Oil and gas fuel cycles

Oil and gas fueled steamplants, gas turbine plants, and combined cycle plants contribute to air pollution just as coal plants do. The amounts of residuals that can be expected for Scenario I are shown in table III-1. The table entries show that in California emissions of particulates resulting from the use of oil and gas in powerplants are small compared to the corresponding emissions during end-uses, but nitrogen oxide and sulfur oxide emissions are more nearly comparable for the two classes of use. Sulfur oxide emissions increase sharply from 1975 to 1985 partly because of the expected shift away from natural gas to oil by powerplants. In Arizona and Nevada, powerplant emissions are in all cases, small compared to emissions associated with end uses.

The process emissions from oil refineries also can be partially attributed to production of fuels for electricity generation. However, only the sulfur dioxide emissions from California refineries are very significant.

Of course all emissions are important in those parts of California where ambient standards are exceeded. The 24-hour particulate standards is often exceeded (1976) in almost all parts of the State. The only exceptions are the mountain counties (El Dorado, Placer, Plumas, Tuolumme). The sulfur dioxide standards are exceeded around Fontana, Whittier, Los Angeles and San Francisco. In Arizona the 24-hour and annual particulate standards are exceeded in many parts of the State, and the sulfur dioxide standards are violated at sites near the copper smelters. The situation is similar in Nevada.

SUMMARY

The severity of the impacts for each scenario is summarized in table III-3. A distinction is made between local impacts (subscript L) near the plant, regional impacts (R) extending over the Northwest, and global impacts (G).

As the table shows there is qualitatively no difference between Scenario's I and II. However, quantitatively Scenario II is superior because it replaces generating units with conservation which has very low environmental impacts.

Table III-1

Emissions from Powerplants and End Uses

1000 Tons/Year Emitted

	1975			1985			2000		
	TSP	SO_2 (H_2S) (note a)	NO_x (NH_2) (note a)	TSP	SO_2 (H_2S) (note a)	NO_x (NH_2) (note a)	TSP	SO_2 (H_2S) (note a)	NO_x (NH_2) (note a)
California:									
Oil/gas (note c)	10	58	200	16	104	157	2.5	17	25
Coal (note d)	5.5	66	38	6.5	73	55	21	168	294
Gas turbine	-	-	-	-	-	-	-	-	-
Comb. cycle (note e)	-	-	-	-	-	-	-	-	-
Geothermal (note f)	-	15	4	-	54	15	-	112	31
Biomass (note f)	4.5	.4	3	4.7	1.1	6	4.9	2	9
Total	20	139	245	27	232	233	32	326	427
End-uses (note g)	520	437	1147						
Arizona:									
Oil/gas (note c)	.6	2	25	.5	3	5	.3	2	2
Coal (note d)	6.8	83	48	9.2	98	87	11	110	116
Gas turbine	-	-	-	-	-	-	-	-	-
Comb. cycle (note e)	-	-	-	-	-	-	.5	4	-
Geothermal	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-
Total	7	85	73	10	101	92	12	116	127
End-uses (note g)	116	2047	141						
Nevada:									
Oil/gas (note c)	.2	.6	11	.5	3	5	.06	.4	.6
Coal (note d)	1.9	23	13	2.7	28	27	4.5	40	57
Gas turbine	-	-	-	-	-	-	-	-	-
Comb. cycle (note e)	-	-	-	-	-	-	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-
Biomass	-	-	-	-	-	-	-	-	-
Total	2	24	24	3	31	32	5	40	58
End-uses (note g)	112	281	41						

TSP--total suspended particulates.
SO_2--sulfur dioxide.
H_2S--hydrogen sulfide.

NO_x--nitrogen oxide.
NH_2--ammonia.

a/Amounts of H_2S and NH_2 are shown for geothermal only.

b/Based on Geysers emissions as reported in table 8-11, Energy Alternatives, University of Oklahoma, 1975.

c/1975 TSP, SO_2 and NO_x based on 1973 EPA inventory. Later years based on TSP emission rate .03 lb./106 Btu, SO_2 emission rate .2 lb./106 Btu, NO_x emission rate .3 lb./106 Btu.

d/SO_2 based on 1.2 lb.106 Btu for 1975 and .2 lb./106 Btu for additions. TSP based on .1 lb.106 Btu for additions. NO_x based on .7 lb.106 Btu for 1975 and .5 lb./106 Btu for additions.

e/No residuals are included in 1975 and 1985 because it is assumed that the combined cycle will use natural gas and clean petroleum fuels. Residuals in 2000 are based on values used for additions in * based on coal fuel.

f/1975 values based on: TSP 1.25 lb./106 Btu; SO_2 .12 lb./106 Btu; NO_x .83 lb/106 Btu. 1985 and 2000 additions based on: TSP .03 lb./106 Btus; SO_2 .12 lb./106 Btu; NO_x .5 lb./106 Btu.

g/Amounts shown are for 1973 taken from 1973 National Emissions Report, Environmental Protection Agency, Report, EPA -450/2-76-0007, May 1976.

Table III-2

Air Pollutant Concentrations

Location	Time	Total suspended particulates: Annual average	Total suspended particulates: 24-hour high	Sulfur dioxide: Annual average	Sulfur dioxide: 24-hour high
		(micrograms/cubic meter)			
California:					
Contra Costa	1976	52	265	5.2	86
Santa Barbara	1976	66	170	8	39
Anaheim	1976	102	252	18	91
Los Angeles (downtown)	1976	102	206	49	186
Fontana	1976	117	338	62	260
Escondido	1976	82	159	0	0
Fresno	1976	94	414	21	52
El Centro	1976	126	393	8	36
Portola		3	4		
Standard (CA)		60	100	80	131
Arizona:					
Ajo (Dot Wells Rd.)	1976	92	1107	21	356
Grand Canyon (Village)	1976	14	69	6	17
Joseph City (3.5 mi. south)	1976	46	260	6	19
Morenci (Cadillac Pt.)	1976	41	150	105	2131
Phoenix (241 N. Central)	1976	71	448	8	50
Tucson (U. of Arizona)	1976	73	163	6	18
Standard (AZ)		75	150	80	365
Nevada:					
Boulder City	1976	43	194		
E. Charleston	1976	118	312	9	
Sahara Casino (Las Vegas)	1976	125	594		
Baker	1976	8	32		
McGill	1976	50	182	3.4	
Tonapah	1976	15	107		
Winnemucca	1976	79	346		
Carson City	1976	49	150		
Reno Airport	1976	74	212		
Standard (NV)		60	150	60	260
Effect of adding one powerplant in any of the three States:					
500-MW coal-fired powerplant located in flat country with scrubbers and electrostatic precipitators, burning low-sulfur coal and using best available Control technology (equivalent to proposed New Source Performance Standards)		a/0.1-0.5		a/0.2-1.0	

a/Maximum concentration, generally occurring about 5 miles from plant.

APPENDIX III

Table III-3

Summary of Environmental Impacts

Technology and impacts	Degree and location of impacts in 2000 for each Scenario: Scenario I	Scenario II
Coal-fired powerplants:		
Air pollution	M L	M L
Land disruption	M R	M R
Ecosystem threats	U R	U R
Water pollution	L R	L R
Occupational hazards	M R	M R
Heat balance	U G	U G
Esthetic	M L	M L
Land use	L L	L L
Solid waste disposal	M L	M L
Nuclear powerplants:		
Routine radiation exposure	L L	L L
Radiation exposure of workers	L L	L L
Accidents--primarily reactors	U L	U L
Sabotage--primarily reactor	M L	M L
Diverson impacts:		
Terrorism	U G	U G
Extortion	U G	U G
Repressive and obtrusive police power	U G	U G
Water disposal problems	U R	U R
Land use	L L	L L

APPENDIX III

Table III-3 (cont.)

Summary of Environmental Impacts

Technology and impacts	Degree and location of impacts in 2000 for each scenario: Scenario I	Scenario II
Hydroelectric (operations and extensions:		
Loss of fish and wildlife	M_R	M_R
Esthetic	M_R	M_R
Recreation	M_R	M_R
Solar:		
Land use	L_L	L_L
Visual impact	L_L	M_L
Wind:		
Land use	L_L	L_L
Visual impact	L_L	L_L
Electromagnetic	L_L	L_L
Transmission lines:		
Esthetic	M_R	M_R
Land use	L_R	L_R

Degrees of adverse impact

H--High adverse impact; objectionable to most people.
M--Medium adverse impact; objectionable to some people.
L--Low adverse impact; objectionable to a few people.
U--Uncertain but possible damaging impact; of concern to many people.
V--Uncertain but possible damaging impact; of concern to only a few people.

Subscripts
L--Refers to local area around plant.
R--Refers to regional impacts extending beyond local area.
G--Refers to global impacts.

Table III-3 (cont.)

Summary of Environmental Impacts

Technology and impacts	Degree and location of impacts in 2000 for each scenario: Scenario I	Scenario II
Oil and gas fuel cycles		
air pollution	M L	M L
Water pollution		
at refinery	M R	M R
during oil transport	M G	M G
Land disruptions	M R	M R
Heat balance	U G	U G
Biomass (wood burning)		
air pollution	L L	L L
Solid waste disposal	L L	L L
Water pollution	L L	L L
Geothermal		
air pollution	M L	M L
Water pollution from geothermal brines	M R	M R
Land subsidence and seismic effects	L R	L R
Noise	M L	M L

RISK AND IMPACT OF SHORTFALL OR SURPLUS CAPACITY

Shortfall or surplus capacity refers to situations where the supply of electricity is less than or greater than long-term equilibrium would dictate. Both situations lead to adverse impacts. Short-term shortfalls, such as blackouts, can produce severe impacts that command immediate attention from the public and industry. Longer term shortfalls that develop gradually call forth a range of responses, generally appeals for voluntary reductions in use, followed by increasingly restrictive curtailment actions. In some recent studies economic impacts of such shortfalls have been judged to be very large based on the expectation that the unavailability of electric power would partially shut down industry and commercial activities. However, the extent to which a regional economy can respond to such a situation has not been tested thoroughly in practice or even evaluated through impact studies. Adjustments through market and nonmarket mechanisms should be able to mitigate much of the impact expected on a first round basis. For example, consider the potential responses that could be expected in the three States to offers of 25 cents/kWh for electrical energy, or even 5 cents/ kWh. Large amounts of new conservation savings or extra generation from existing facilities could be expected under circumstances where the conservers and producers would receive such prices for the electrical energy that they make available.

Surplus capacity has impacts that are more easily determined and readily accepted by the public than shortfalls. Surpluses raise the price of power somewhat, but price increases do not produce the strong public reactions that blackouts and curtailments do. In terms of economic impact, per kWh, however, surpluses may not be very different in magnitude from shortfalls.

The risks of shortfalls or surpluses depend on factors that affect either supply or demand. On the demand side the uncertainties of forecasts probably contribute most to the risks. In the scenarios examined in this study, Scenario I runs the greater risk of surplus and Scenario II the greater risk of shortfall.

On the supply side the comparison of Scenarios I and II, is less clear, the risk that the supply system will fail to perform or expand as expected depends on (1) the reliability and diversity of the components of the supply system (2) reliability of construction schedules, (3) warnings of impending failures, and (4) the possibility of responding to warning signals. In these respects the two scenarios do show some quantitative differences, but qualitatively they are similar.

Reliability of generating plants and conservation

The generating plants in Scenarios I and II are very similar. Most of the generation is supplied by conventional fossil fuel steamplants, nuclear plants, and hydroelectric facilities. These supply elements rely on resources subject to considerable fluctuations; however, the peak capabilities have been adjusted to account for these fluctuations. Another relevant consideration is the fact that solar and wind units are smaller than conventional plants so that failure of one unit is less serious.

The principal difference in reliability between the supply systems in Scenarios I and II lies in the difference between reliability of conservation and reliability of the generating units that conservation replaces. Of these two, conservation measures already in place are more reliable. Thus, Scenario II is favored.

Reliability of construction schedules

Recent experience of the electric utility industry in adhering to construction schedules for conventional power plants has been poor. Delays have arisen because of labor shortages, financing and licensing problems, and other difficulties. In a number of respects, we can expect that these problems will not be as severe for construction of conservation and renewable resource "plants" as they have been for conventional ones. Labor requirements are more dispersed geographically, and the labor required is less skilled. Individual units are less costly and licensing requirements are reduced. Also opposition by environmentalist and consumer groups will probably be less. For these reasons it appears that Scenario II is more reliable so far as meeting construction schedules is concerned once the renewable technologies are established and assuming that conservation is controlled by regulation as it is in California.

Warnings of impending failures and ability to respond

The available experience with conventional powerplants and the close attention to their performance usually but not always provide warning signals of impending failure. On the other hand, the long leadtimes for building new plants of this type lead to an inability to respond in timely fashion to the signals of future shortfalls.

By contrast there is at present no regular monitoring of conservation nor is there a history of performance of modern renewable supply components. Thus, Scenario II ranks low compared to Scenario I. However, the response time to a developing shortfall or surplus, once it is recognized, is short compared to the leadtimes for power plant construction, and in this regard, Scenario II is superior.

These considerations do not show any clear advantage of one scenario over the other so far as warnings and responses are concerned.

Summary

The overall comparions of risks and impacts of shortfalls and surpluses do not show any clearcut advantages of one scenario over another.

NOTES

1/Knutsen, G. D., R. G. Curley, E. B. Roberts, R. M. Hagan, and V. Cervinlca, Pumping Energy Requirements for Irrigation in California, U. of Calif., Div. of Agric. Sci., Spec. Pub. 3215, Revised, Feb. 1978.

2/Departments of Agricultural Economics, University of Idaho, Oregon State University, and Washington State University, Demand for Electricity by Pacific Northwest Agriculture, Report for Bonneville Power Administration, EIS, on Rate Increase, Portland, June 1978.

ORGANIZATIONS CONTACTED DURING REVIEW

Utility companies:

Arizona Public Service Comapny
Los Angeles Department of Water and Power
Nevada Power Company
Pacific Gas and Electric Company
San Diego Gas and Electric Comapny
Southern California Edison Company
Sacramento Municipal Unility District
Salt River Project
Sierra Pacific Power Company
Tucson Gas and Electric Company

State agencies:

Arizona Office of Economic Planning and Development
  Office of the Governor
Arizona Power Authority
Arizona Solar Energy Commission
Arizona Corporation Commission
California Department of Water Resources
California Energy Resources Conservation and
  Development Commission
California Public Utility Commission
Nevada Energy Commission
Nevada Bureau of Mines and Geology
Nevada Public Service Commission
Colorado River Resources Division

Federal agencies:

Department of Energy
  Western Area Power Administration
  Solar Energy Research Institute
Bureau of Reclamation

Other organizations:

Arizona State University
Desert Research Institute, University of Nevada
Electric Power Research Institute
University of Arizona
University of California, Berkeley
Western Interstate Nuclear Board
Western Systems Coordinating Council
Arizona Irrigation Districts 1, 2, 3
Basic Magnesium Complex, Henderson, Nevada

GAO ENERGY CONSULTANTS

Walter R. Butcher, Professor of Agricultural Economics, Washington State University; participated in Northwest Energy Policy Project conservation study and in Pacific Northwest Regional Commission energy study; member of steering committee, Washington Energy Research Center and Washington Water Research Center; participated in studies dealing with water resource development and use; participated in our review entitled "Region at the Crossroads--The Pacific Northwest Searches for New Sources of Electric Energy."

George W. Hinman, Director, Environmental Research Center, Washington State University; participated in NEPP conservation study and in Pacific Northwest Regional Commission energy study; participant in energy impact assessment for U.S. Department of Energy; member of several Washington State energy advisory committees; participant in our review entitled "Region at the Crossroads--The Pacific Northwest Searches for New Sources of Electric Energy."

Robert Murray, private consultant; participated in developing the NRDC alternative scenario; also contributed to the Skidmore, Owings, and Merrill conservation, Oregon transition, and Seattle-Energy 1990 studies; participated in our review entitled "Region at the Crossroads--The Pacific Northwest Searches for New Sources of Electric Energy."

Department of Energy
Washington, D.C. 20545

June 22, 1979

Mr. J. Dexter Peach, Director
Energy and Minerals Division
U.S. General Accounting Office
Washington, D.C. 20548

Dear Mr. Peach:

We appreciate the opportunity to review and comment on the GAO draft report entitled "Electric Energy Development In The Pacific Southwest." Our views with respect to the text of the report and recommendations contained therein are discussed below.

The draft report accurately points out that the Western Area Power Administration (WAPA) is not fostering conservation or development of new resources of power in Arizona, California, and Nevada. However, other elements of the Department are doing so. Some duplication of staff and lack of coordination could result from designating WAPA as the lead organization for the application and commercialization of renewable resource technology in 15 States while other segments of the Department would have these same responsibilities for other States. The Department, in cooperation with WAPA, will evaluate how WAPA can best assist with these programs.

WAPA is a relatively new organization and is in the process of developing a functioning, coordinated organization. The continued reliable operation of extensive power systems and the transaction of the power marketing business must have priority. Under these circumstances, WAPA is not yet prepared to actively foster conservation or develop new renewable sources of power.

The Department fully agrees with the report conclusion that bonding authority is needed for WAPA. The Department's proposed bill to provide limited bonding authority was transmitted to the Congress in February of this year. The bill does not include authority to use WAPA revenues to develop renewable resources. Traditionally, the Corps of Engineers and the Bureau of Reclamation have been the construction agencies for hydroelectric facilities. It is possible that if these two agencies are not given authority to construct other renewable resources, such as geothermal, wind, and solar plants, then the Department will seek such construction authority for the power marketing administrations. It would be premature to seek that authority now for WAPA.

The conclusion that WAPA's program is inconsistent with the national energy policy is not correct. Neither do we agree that the Department of Energy and WAPA have "opposite goals." The WAPA goals in question may not be clearly understood. For example, WAPA's goal of encouraging widespread use of Federal power has been understood for some time to mean that the dispersement of the benefits of Federal power should be as broad as possible and is not now understood to mean that people should be encouraged to use more power.

It is true that WAPA encourages the use of hydropower during peak hours in order to conserve oil or other nonrenewable resources that would otherwise be used. For this purpose, a favorable price differential between renewable and nonrenewable resources is desirable whenever it can be maintained. As long as hydropower is less expensive than fossil fuel generation, wholesale purchasers of Federal power have an economic inducement to replace their highest cost generation, usually oil or gas, with hydropower whenever it is available.

A great deal of study must be given to the matter of ratesetting for Federal power between now and the year 2000. However, it would be premature to act on the basis suggested in the draft report. To promote conservation effectively, distinctions must be made between the effects of wholesale rates as opposed to retail rates. Higher prices at the retail level may induce some conservation, but the validity of that relationship at the wholesale level is questionable.

The Department expects to explore further opportunities to promote conservation while retaining cost-based rates at the wholesale level that will serve as a yardstick in the industry and will mitigate inflation. Most Federal power contractors are wholesale power purchasers and are expected to pass on the economic benefits received from obtaining relatively low-cost Federal power to their ultimate consumers. It may be possible to develop a reasonable method of requiring that some of the benefits of receiving Federal power be transferred to ultimate consumers in the form of the contractors' conservation programs or their participation in the development of renewable resources.

The draft report description of WAPA's objective to provide power at the lowest possible cost is incomplete. The Flood Control Act of 1944 provides that power and energy will be disposed of ". . . in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles. . . ." (underlining added). As circumstances change, the exercise of sound business principles can be expected to render results that differ over time.

The draft report then concludes that coal may not be a practical means of meeting forecasted future electricity needs and lists numerous reasons why nuclear power cannot be relied upon for this objective. As presented, the report text does not clearly convey the treatment of these evaluations in those scenarios reflecting aggressive conservation; nor does it address possible options in the coal/nuclear area. The treatment of the uncertainties and problems of the coal and nuclear programs and the treatment of the uncertainties of programs advocated in the alternatives do not appear to be evaluated with the same degree of objectivity. Similarly, in the utilization of renewable resources additional consideration could be given to the development of hydroelectric power since this renewable resource is well known and could be developed with present technology.

Consideration might also be given to some additional treatment of the national impact of the recommendation concerning the Western Area Power Administration (WAPA) funding of the recommended program, of the legislative implications involved, and of possible options regarding WAPA funding, such as modifying the first article of the WAPA charter instead of deleting it, e.g., ". . . the development of an adequate amount of electricity at the lowest possible cost consistent with sound economic, environmental and social practices, and in the national interest."

With the exception of the rate policies proposed, the "new" role that is suggested for WAPA would not necessarily have to be a dramatic departure from the past. Instead, the activities of WAPA will be changing as a part of the normal, evolutionary process that can take place with the continued understanding and consent of Congress and will include participation in conservation programs and renewable resource programs. The Assistant Secretary for Resource Applications recently sent a letter to Congress regarding aggressive conservation and renewable energy programs that might be undertaken by the power marketing administrations, including WAPA. We will be pleased to furnish you a copy of this letter upon request.

In conclusion, we believe that some of the recommendations in the draft report appear to be based on misconceptions about the Western Area Power Administration. If the Congress adopts these recommendations as provided in the subject draft report and passes them into law, it would bring about a major mission change in the Department, especially in the Western Area Power Administration. We do not believe that such changes are warranted.

We appreciate your consideration of these comments in the preparation of the final report and will be pleased to provide any additional information you may desire. Comments of an editorial nature have been provided to members of your staff.

Sincerely,

Don C. Gestiehr

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Director
Office of GAO Liaison

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