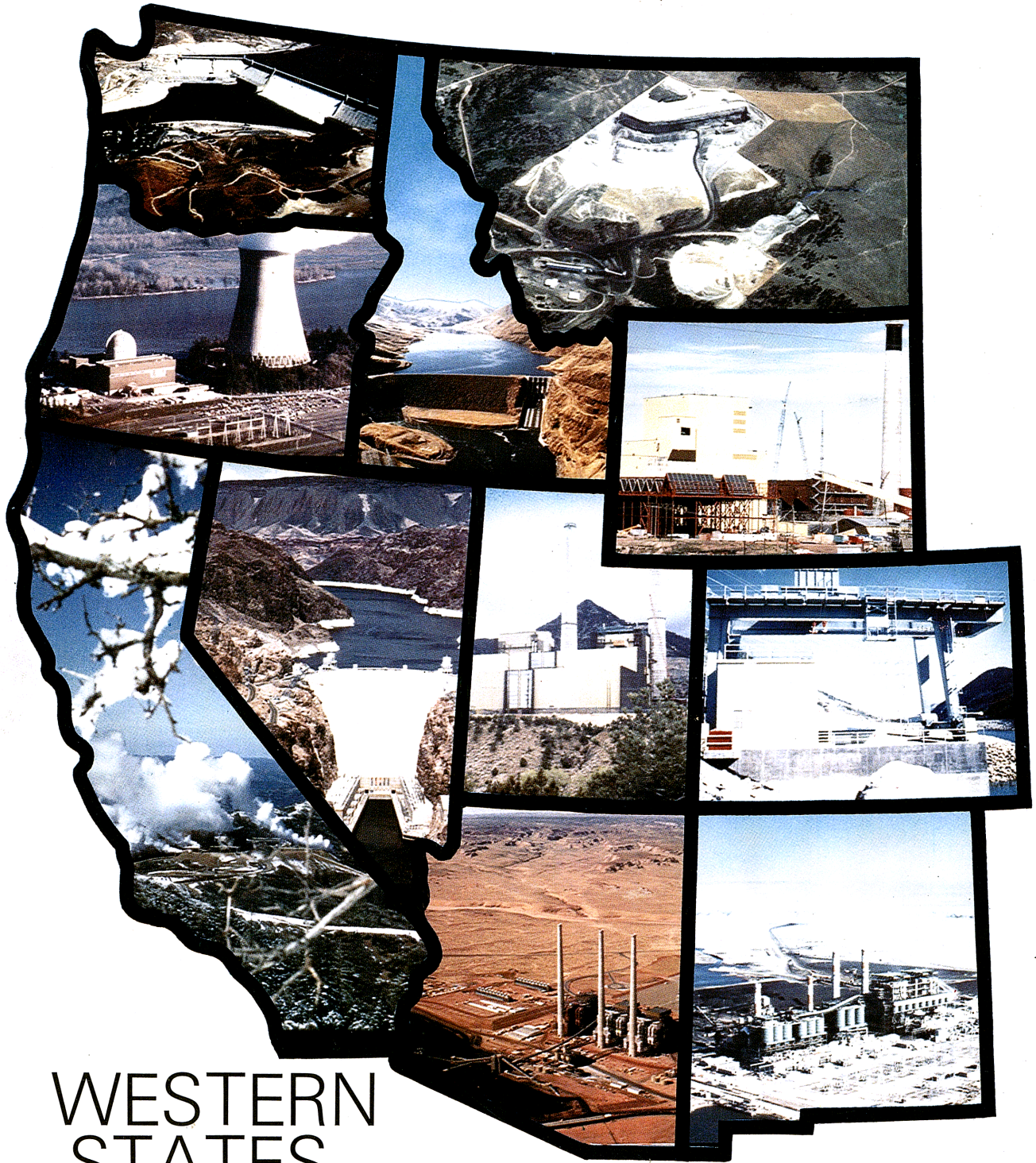


WATER FOR WESTERN ENERGY DEVELOPMENT UPDATE 1977



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STATES
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WATER FOR WESTERN ENERGY DEVELOPMENT UPDATE 1977

SEPTEMBER, 1977

**WESTERN STATES WATER COUNCIL
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Salt Lake City, Utah 84111**



Tucson Myers and Associates, Inc.
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PREFACE

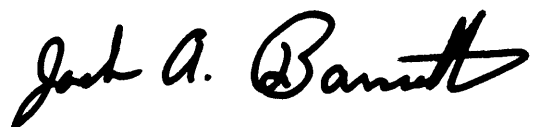
In 1974, the Western States Water Council issued its first report regarding water requirements for energy. Notable at that time were indications of significant future Western water demands for large oil shale processing and a number of coal gasification facilities, coupled with substantial water needs for steam-electric generation facilities planned to meet electrical demands, as electricity use was expanding at about seven percent per year.

Since 1974, the Council has observed a change in those indications and future water for energy needs now appear to be smaller. Oil shale and coal gasification industry plans are in essence indefinite, at least prior to 1990, and steam-electric generation development is now planned to occur at a slower rate, to meet a reduced electrical demand growth of now projected rates between three and five percent per year. These abrupt changes, resulting in part from inconsistent Federal energy policies, justify

review and presentation of current concepts of water needs for western energy development.

The Council felt also that a review and analysis of ways to conserve water in energy processes would be important and timely. Many independent studies have looked at water demands and potential water saving practices in isolated energy processes, but the impact Westwide of conservation practices was not known.

The council contracted with Tucson Myers and Associates, Inc., who in association with L. E. Wilkinson, prepared data and draft text. This document, then, is a product of the consultant's effort, review and comment by the Council's Water Resources Committee, and approval of the Western States Water Council.



Jack A. Barnett
Executive Director

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I. SUMMARY AND CONCLUSIONS

This report contains projections of steam-electric plants and other energy production developments in the West to 1990 and presents findings in regard to their estimated water requirements. Important institutional considerations and water conservation opportunities relating to western energy development also are examined.

National load growth is expected to be between 3 and 5 percent per year (p. 2) and is expected to reach a total demand of 170 quads by the year 2000 (p. 2). Western energy consumption will total about 25 quads over the same period (p. 2), about half of which will be electrical energy (p. 2).

By 1990, oil shale processing may be barely started, geothermal development will be small, and only two coal gasification facilities are planned (p. 6). Five coal slurry pipelines are planned with a total water requirement of 46,000 AcFt/yr to transport 59 million tons per year (p. 6).

Firm plans exist among Western utilities to construct 85 additional large steam-electric generating units in 46 locations, with an aggregate capacity of 46,189 MW (p. 6).

Total freshwater consumption for existing and planned steam-electric generation plants to 1986 will total 885,000 AcFt/yr, an increase of 588,000 AcFt/yr (p. 13). An estimated additional 15,000 MW installed between 1986 and 1990 will increase consumption by 240,000 AcFt/yr. Total increased consumption of 828,000 AcFt/yr over present levels compares to 1,337,000 AcFt/yr estimated for the same purpose in the Council's 1974 report (p. 13).

Use of once-through cooling, the least

expensive method of plant cooling with respect to both investment and water consumption, will not be predominant (p. 13). Evaporative cooling is becoming the most prevalent system, although it is the largest water user (p. 13). Both wet-dry and dry systems are being planned for a few installations, although higher in cost (p. 13).

Evaporative cooling systems are attractive until water costs exceed \$660 per Ac. Ft. Wet/Dry systems are feasible till water costs exceed \$4,200 (p. 17). Purchase of irrigated farm lands results in water costs of about \$90 to \$160 per Ac. Ft. (p. 17).

Western agriculture will not be able to compete in the open market place with the energy industry for water supplies, although agricultural interests could participate in cost sharing of joint use facilities (p. 17).

Two pilot projects are under way to determine feasibilities of use of treated return flows (p. 18).

State water institutions can accommodate future energy development. State water law provides for acquisition of water supplies for energy production (p. 18). Many Western states siting laws include provisions whereby opportunities exist for planning multiple purpose water developments in conjunction with needed new energy facilities (p. 20).

Up to 75,000 AcFt/yr could be conserved by 1990, if energy conservation measures result in a one percent reduction in electrical load growth (p. 21). If ten of the 85 additional plants scheduled by 1986 were to be converted to once-through cooling, instead of evaporative systems now planned for, up to 100,000 AcFt/yr would be conserved (p. 21). A possibility exists for use of once through cooling without significant environmental degradation (p. 21).

II. NEED FOR WATER

A. Update of 1974 Energy Production Projections

1. Projected Load Demands

Electrical load growth for the nation has been 7 percent per year for the period 1955 to 1973. The recession that was prompted by the OPEC oil embargo late in 1973 altered energy use patterns and contributed to a new round of price escalation which in turn affected energy consumption. Current estimates are that national electrical load growth will continue over the next 10 to 20 years but at a reduced rate of between 3 and 5 percent per year. Figure II-1 shows electrical energy demands over the past six years.

Numerous projections of electrical loads have been made. Using Bureau of Census predictions of a United States population of 263 million persons by the year 2000, with 96 percent employment, the Electric Power Research Institute (EPRI), the research arm of utilities in the United States, has projected an energy requirement of 170 quads.¹ The Bureau of Economic Analysis has projected a Gross National Product (GNP) of over \$2 trillion by the year 2000; and EPRI, noting the near linear relationship between energy consumption and GNP over a 90 year period, calculates the resulting energy need at 180 quads. Current predictions by the U.S. Bureau of Mines² show a national energy need of 163 quads by the year 2000. EPRI predicts the portion of U.S. energy consumed as electrical energy will range between 43 and 63 percent, depending on electrification of transportation.

The West, with 17 percent of the nation's

population, consumes 15 percent of the energy consumed nationwide, according to the Western Interstate Nuclear Board (WINB).³ WINB also has shown, using Federal Power Commission (FPC) data, that the West has been reasonably self-sufficient in electrical energy production. Table II-1 lists electrical energy production and consumption in 1972 for western states.

Based on three major assumptions, WINB recently has examined future energy needs in the West. The assumptions are:

1. National energy needs in the U.S. in the year 2000 will total 170 quads.
2. The relationship between national energy needs and Western energy consumption will remain at 15 percent and the West will continue to "export" energy at the same relative rate.
3. Half the total energy consumed in the West will, by 1990, be electrical energy.

Figure II-2 illustrates a summary of the foregoing discussion. The upper curve shows total energy use. Reading the right hand ordinate, which measures national energy demands, for the year 2000 shows 29 billion barrels (bbl) of oil. At 5.8 million BTU/Bbl, and 10^{15} BTU/quad, national energy demand is 170 quads. Using the left hand ordinate, which measures Western energy demands, values are 15 percent of those on the right hand, national, side, giving a value of about 4,400 million Bbl for the year 2000. Applying the same conversion factors results in a Western states energy demand of about 25 quads in the year 2000.

The curve labeled 'Total Electrical Demand - West Only' is a plot of historic electrical demands from 1950 to 1975. The period 1975 to 1985 is a forecast by Western Systems Coordinating Council (WSCC) and the period 1985 to 2000 is a projection by

¹Quad - 10^{15} BTU
- 175 million barrels of oil (Bbl)

²Bureau of Mines, "U.S. Energy Through the Year 2000," Dec. 1975.

³Western States Energy Resource Development Update, 1976, L.E. Wilkinson for Western Interstate Nuclear Board, Sept. 1976.

Figure II-1

Historic Electric Load Growth in U.S.

Source: Electric Power Statistics-1976

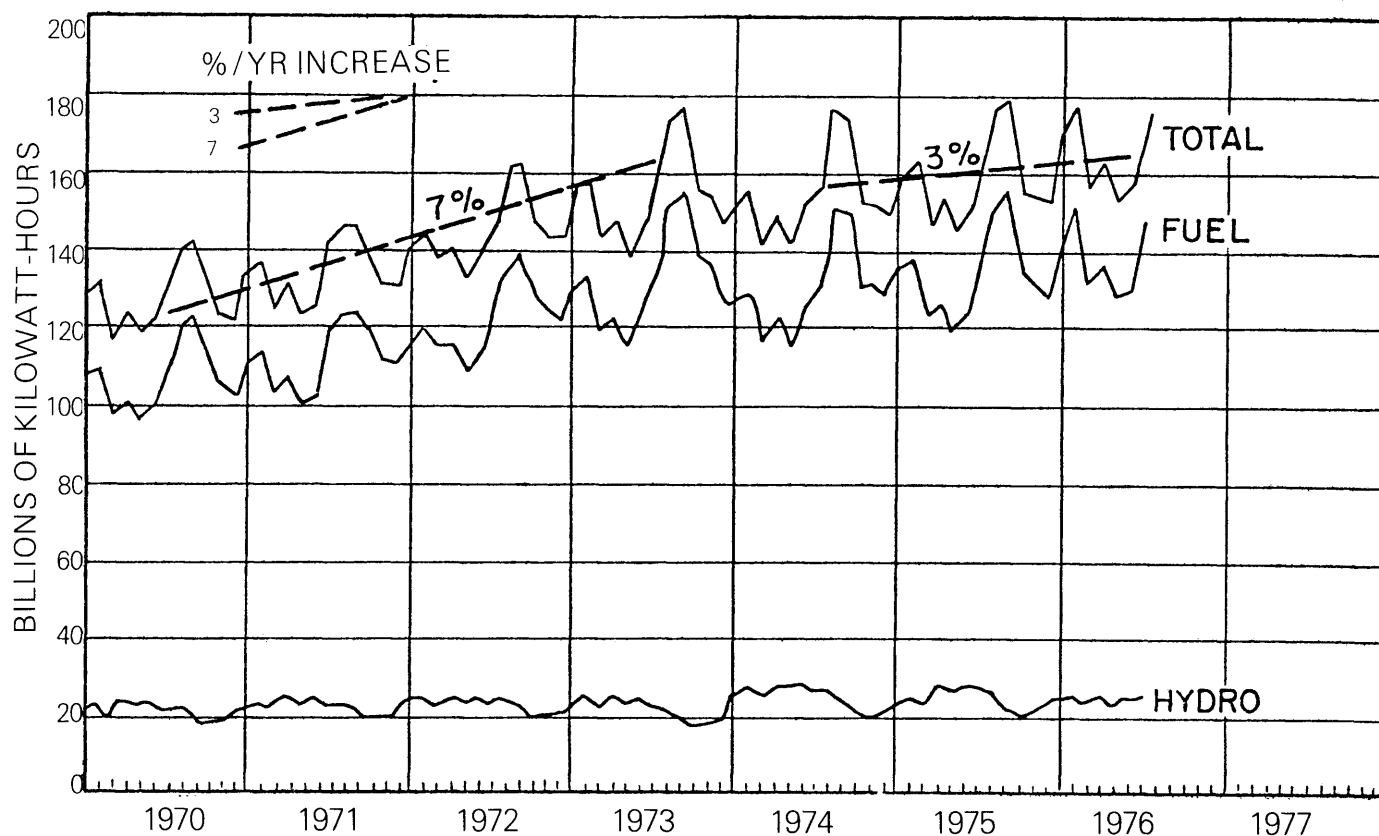


TABLE II-1

ELECTRICAL ENERGY PRODUCTION AND CONSUMPTION IN WESTERN STATES (1,000,000 KW - HR)

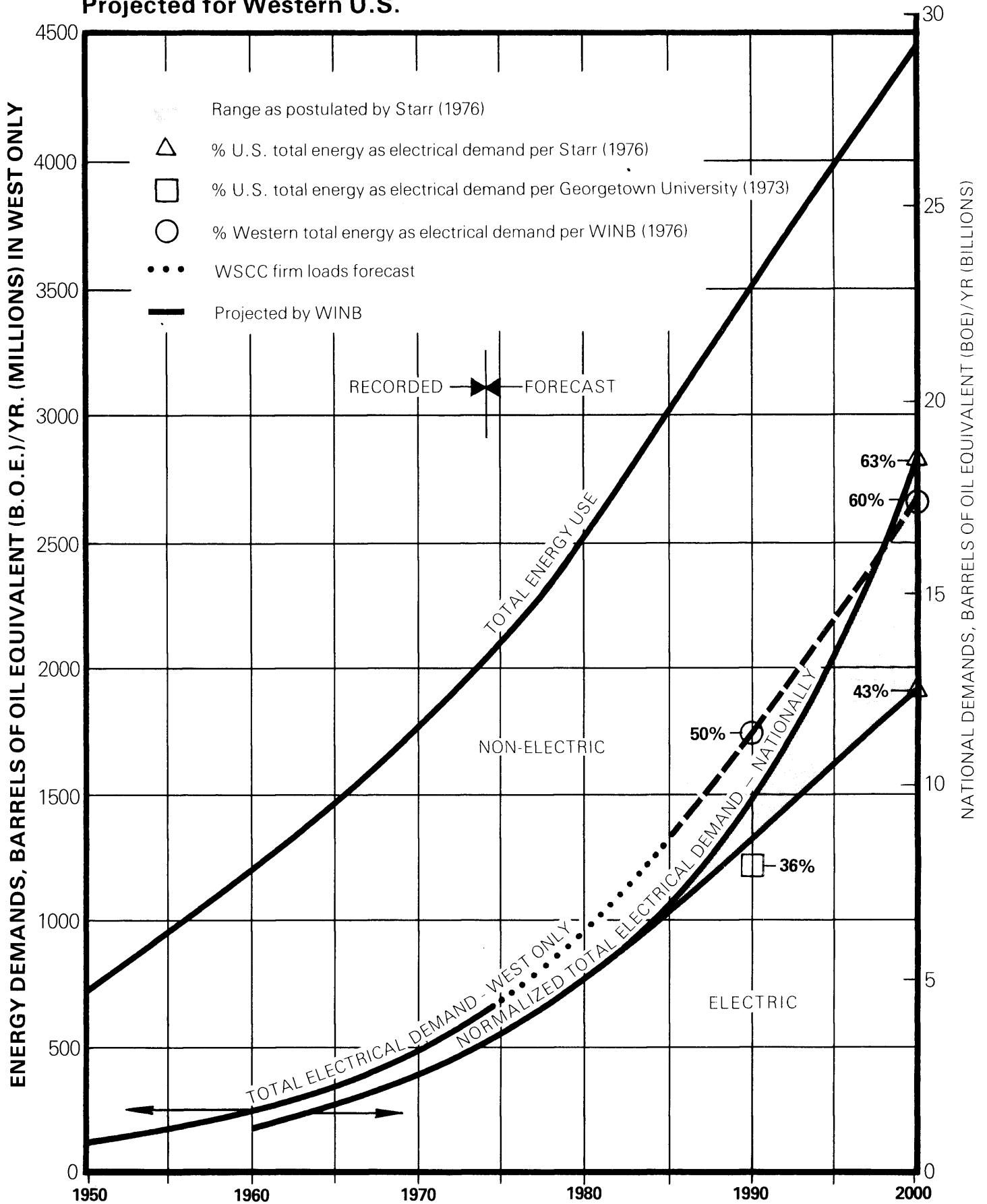
State	Elect. Consumption ^a	Gross Production ^a	Net Production ^b	Net Imports	Net Exports	% Consumpt. Imported	% Production Exported
Arizona	20,280	20,532	17,863	2,417		11.9	
Alaska	1,624	1,860	1,618	6		0.4	
California	133,283	122,094	106,222	27,061		20.3	
Colorado	14,949	15,650	13,616	1,333		8.9	
Idaho	12,922	9,694	8,434	4,448		34.7	
Montana	9,169	11,055	9,618		449		4.7
Nevada	7,724	13,838	12,039		4,315		35.8
New Mexico	7,070	20,113	17,498		10,428		59.6
Oregon	30,646	35,293	30,705		59		0.2
Utah	7,201	4,038	3,513	3,688		51.2	
Washington	59,134	89,379	77,760		18,626		24.0
Wyoming	4,200	10,803	9,397		5,197		55.3
Total	308,202	354,349	308,283	38,993	39,074		

a) "Electric Power Statistics" Federal Power Commission - 1974 (12 volumes)

b) Net production averaged 87% of gross production for Region. Equal losses assumed for each state.

Total Energy Use and Total Electrical Demand Projected for Western U.S.

Figure II-2



SOURCE: ADAPTED FROM WINB, SEPT. 1976 REPORT
 "WESTERN STATES ENERGY RESOURCE DEVELOPMENT - UPDATE 1976"

WINB. Values relating to this curve should be read from the left hand ordinate.

The lower curve, labeled 'Normalized Total Electrical Demand — Nationally' is a plot of historic and projected data by EPRI. The shaded area reflects the range of the electrical energy portion of total energy demands.

2. Facilities and Processes

a. General Considerations

The 1974 Report of the Western States Water Council, "Western States Water Requirements for Energy Development to 1990" was prepared just following the OPEC oil embargo. The need for energy independence became clear at that time but not the means for achieving such a goal. For the West, there were visions of a wide range of energy developments including several oil shale recovery plants, 7 geothermal developments, and 18 coal gasification plants, all of which were scheduled to commence before 1990. Current information indicates that by 1990 oil shale development may be barely started, a smaller number of geothermal developments are expected, and only two coal gasification plants are scheduled.

The delay in development of an oil shale industry is a result of the lack of a firm Federal price support policy for the product. It has not been clear to the sponsors of the first oil shale plant how they would be able to compete with oil prices resulting from controlled domestic production. The first plant was to be operational about 1979, but is now "tabled" until "a more favorable political and economic situation" prevails.

Oil shale activities that are continuing tend to be experimental rather than production oriented. The U.S. Bureau of Mines has a project scheduled for the

Piceance Basin region of Colorado for in situ retorting and recovery of vaporized oil. Tar sands processing also is proceeding on an experimental basis in Utah. However, full scale production of oil from shale and tar sands is not likely without currently absent federal incentives. Therefore, no reliable estimates of water requirements for oil shale and tar sands processing between now and 1990 can be prepared. Lead times are such however, that with establishment of a Federal energy policy, oil shale and tar sand processing would probably not commence prior to 1985 and attendant water requirements would still be quite small by 1990.

Geothermal development, likewise, is in too adolescent a position for reasonable predictions to be made of when, where, and how much water will be needed. Thus, geothermal water needs also have been omitted from this report.

The 1974 WSWC report qualified water needs for recovery of natural gas, crude oil, refineries, and strip mine revegetation. These needs are basically unchanged since the 1974 report and are relatively small. This report contains no new projections for these less significant needs and concentrates rather on the major water uses.

The energy processes to be further considered include:

- Coal Slurry Pipelines

- Coal Gasification and Liquefaction Plants

- Thermal Electric Generation Plants

- Coal-Fired

- Nuclear

- Oil and Gas-Fired

b. Coal Slurry Pipelines

Use of slurry pipelines for transportation of coal to plants near load centers has received increasing attention since 1974. Five such projects are now proposed, as

listed in Table II-2 and shown in Figure II-3, with a water requirement totaling 46,000 Ac. Ft./yr. for all five.

TABLE II-2
Potential Coal-Slurry
Pipelines Originating
In WSWC Member States

Sponsor	Routing	Capacity, millions tons/year
Energy Transportation Systems, Inc.	Wyoming to Arkansas	25
Houston Interstate Gas Co.	Colorado to Texas	9
Nevada Power Company	Utah to Nevada	10
Gulf Interstate Engineering Co.	Wyoming to Oregon	10
Southern California Edison	Arizona to Nevada	5
Total		59

Slurry pipelines can result in less environmental impact than electrical transmission lines along their respective rights of way. Additionally, the estimated water requirement is only about 18 percent of that required for evaporatively cooled plants burning a comparable amount of coal. However, local economies in areas where pipelines originate are affected to nearly the same extent as if a generation plant were also to be constructed without receiving the benefits of large assessed valuations resulting from plant construction. Thus lower water requirements should not be the only concern in the decision making process.

Plans are not definite regarding pipeline construction, however. Coal slurry pipeline proponents are pleading their case for eminent domain authority before congressional committees. Railroad companies strongly oppose federal approval of such authority. The outcome will greatly influence how many proposed pipeline projects actually materialize and their schedules of construction and operation.

c. Coal Gasification and Liquefaction Plants

Coal gasification and liquefaction plants eventually will be needed to supply natural gas and burnable liquids. Commercial feasibility depends heavily on natural gas pricing policies by FPC. A specific effort was made in the preparation of this report to locate firm plans for coal gasification and liquefaction plants calling for completion prior to 1990. Although many are being considered, none were found to be firmly scheduled. Two plants in the Four Corners area of New Mexico appear likely but plans are far less firm than those for thermal electric plants. Most probably the gas industry will be "tooling up" about 1990 and, as a result, on a regional basis, water needs before then are not likely to be large.

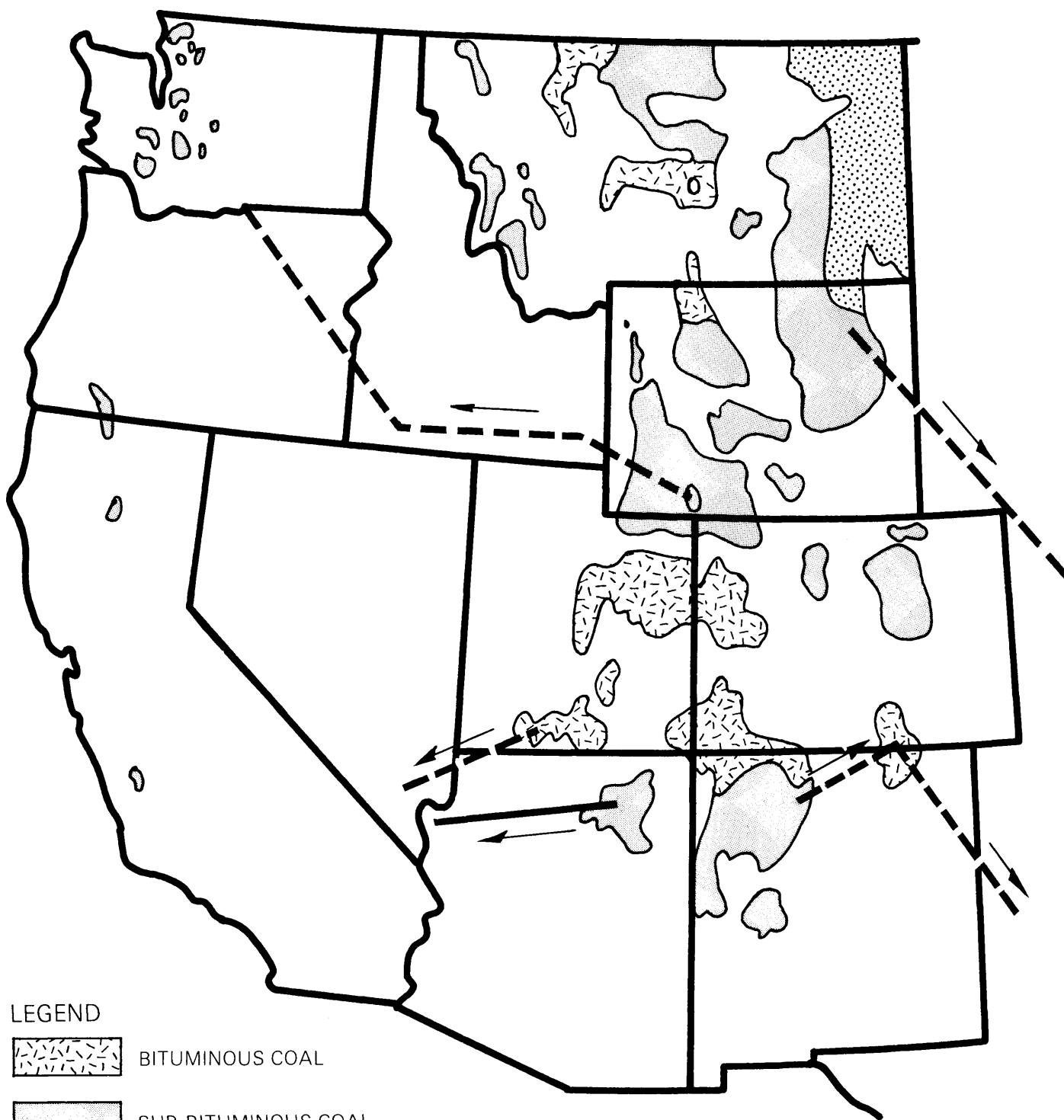
Processes employed for both coal gasification and liquifaction require high temperatures such that opportunities for utilization of air cooling appear greater than at steam-electric plants. A commercial plant (250 million standard cubic feet/day) relying on evaporative cooling could consume about 45,000 Ac. Ft./Yr. Recent estimates for plants which would utilize a dry cooling system amount to about 8,000 Ac.Ft./Yr. With such a large range, site specific data are important in preparation of regional water requirement estimates, a factor lacking at this time.

d. Steam-Electric Generation Plants

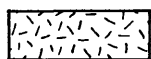
There are over 150 large thermal electric generating plants (those with generating units greater than 100 MW) in the West with an aggregate capacity of 40,039 MW. Numerous plants with smaller generating units comprise an additional aggregate capacity of 10,000 MW.

Firm plans exist to construct 85 additional large thermal electric generating units by

Figure II-3



LEGEND



BITUMINOUS COAL



SUB-BITUMINOUS COAL



LIGNITE COAL



POTENTIAL PIPELINE



EXISTING PIPELINE

Routing of Existing, Proposed and Planned Coal-Slurry Pipelines

1986 in 46 locations, many of which already have existing generating units. The 85 new units are projected to have an aggregate generating capacity of 46,189 MW.

The April 1977 assessment of the Western States Coordinating Council (WSCC) is the source of these data. Member utilities, to ensure meeting future increases in demand, declare through this organization their intended construction schedules ten years in advance of operation.

Existing and planned large thermal electric generation plants in WSWC member states are shown in Figure II-4. Existing large steam-electric plants are listed in Tables A-1 through A-3 in Appendix A. A similar listing for planned plants, Tables B-1 through B-3, is contained in Appendix B. These tables list plants by name and location, planned methods of cooling, and the typical water consumption based on plant size.

The majority of existing plants plotted are oil and gas fired (solid circles) and are located near load centers, with a significant grouping on the coast of Southern California. In general their construction occurred when oil and gas fuel supply availability was firm and opportunities for low cost cooling systems utilizing sea water were not, at the time of construction, faced with the complexities that now exist.

Plans for future plants, on the other hand, reflect an emerging dependence on Western coal resources as a result of the basic need for an assured fuel supply and licensing difficulties which have been encountered with proposed nuclear fueled facilities.

Plans for future energy facilities show a diminution in reliance on nuclear fuel, compared to plans made prior to 1974. Nuclear plant construction costs now exceed \$1 billion per 1,000 MW unit with

construction schedules extending over ten to twelve years. For a utility that is uncertain of its future demands ten years hence, it is difficult to make a decision to incur the billion dollar obligation.

Schedules for all of the coal-fired and nuclear plants have changed since 1974. Nuclear plant schedules have slipped and a number that were proposed have been cancelled. Figure II-5 compares 1974 total Western generation capacity plans with those now planned. Nuclear plant capacities in the predictable future in the West are no longer expected to equal those of coal-fired plants. The schedules, displayed in Figure II-5, are probably reasonably accurate to 1984. Relative stability of fuel prices beyond that date could be expected to maintain the same, or an even greater lead by the coal-fired plants.

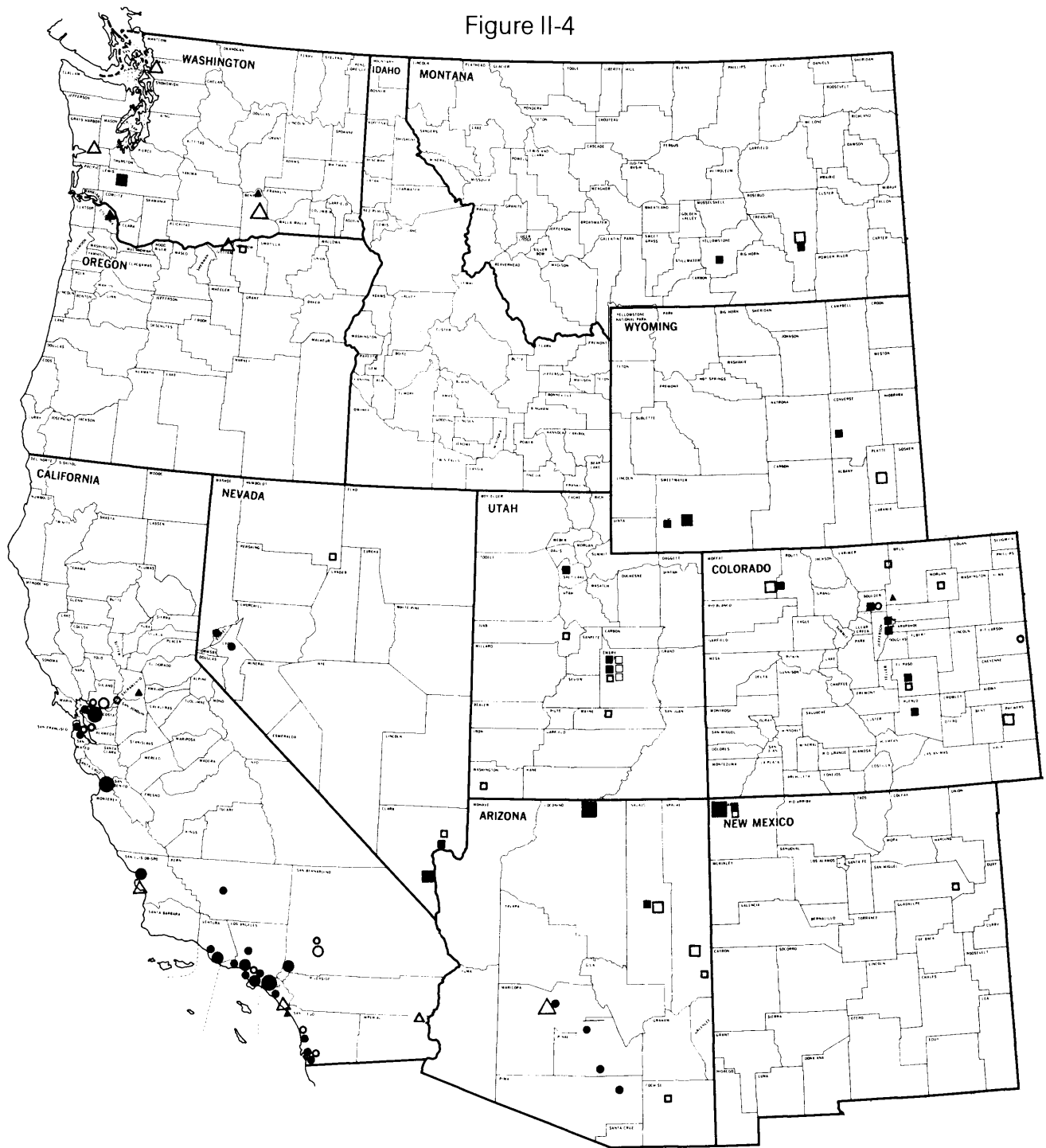
3. Steam-Electric Plant Cooling Water Consumption

Steam-electric plants rely on the Rankine cycle to produce electricity from heat energy. The efficiency with which the generated steam can be used is directly related to how well the low pressure side of the turbine can be cooled. Figure II-6 shows a schematic of essential components of steam-electric plants.

Condenser cooling can be accomplished by any of the following:

- (1) Once-through passage of large quantities of seawater or freshwater from a stream or large lake.
- (2) Passage of large quantities of water circulating through a cooling pond.
- (3) An evaporative cooling tower.
- (4) A "dry" system using air as the cooling medium, operating much like an automobile radiator.
- (5) A combination of (3) and (4) known as a

Figure II-4

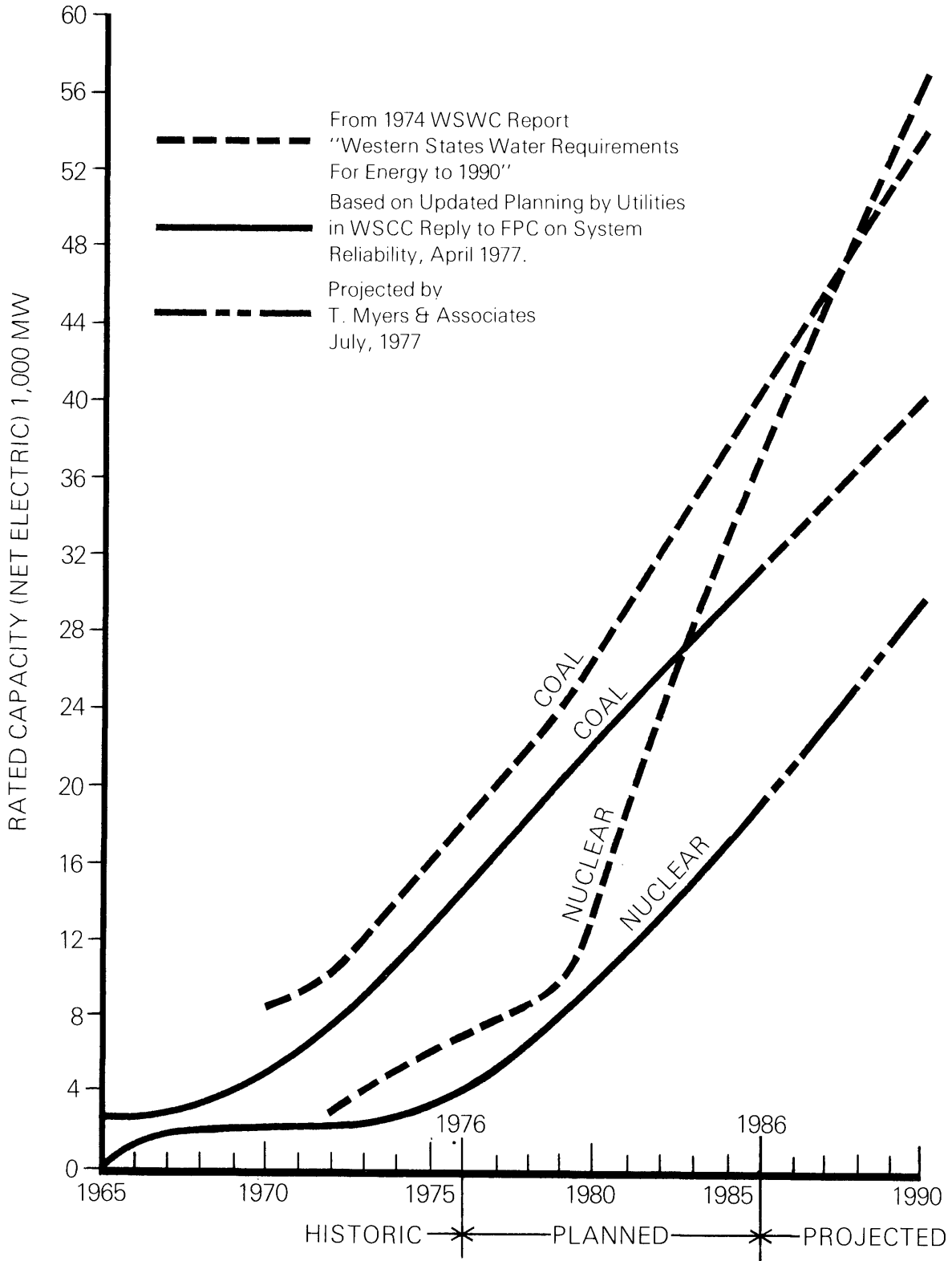


RATING MEGAWATTS	EXISTING			PLANNED		
	OIL/GAS	COAL	NUCLEAR	OIL/GAS	COAL	NUCLEAR
100-1000	•	■	▲	○	□	△
1000-2000	●	■	▲	○	□	△
2000-3000	●	■	▲	○	□	△
3000 PLUS	●	■	▲	○	□	△

**Location of Existing and Planned
Steam-Electric Power Plants**

Figure II-5

Shift from Nuclear Towards Coal-Fired Plants for Thermal Electric Generation



wet/dry cooling system.

The least expensive system, by far, is the once-through cooling system. Since utilities are obligated to produce electrical energy in the least expensive manner, the once-through system is the first to be considered. Water quality standards adopted under the Federal Water Pollution Act of 1972 have included stringent standards on thermal discharges to natural waters. Under these standards, utilities have encountered difficulties in acquiring permits for plant construction. To ensure meeting their obligations, utilities have directed their planning efforts toward more acceptable, although more expensive, cooling systems. Consumptive use of water in the once-through option occurs from evaporation of heated water, and is variable depending on plant site. Representative values, shown in Table II-3, are about 3600 to 4000 AcFt/yr per 1000 MW unit.

The second least expensive alternative is use of a cooling pond. The simplest form is

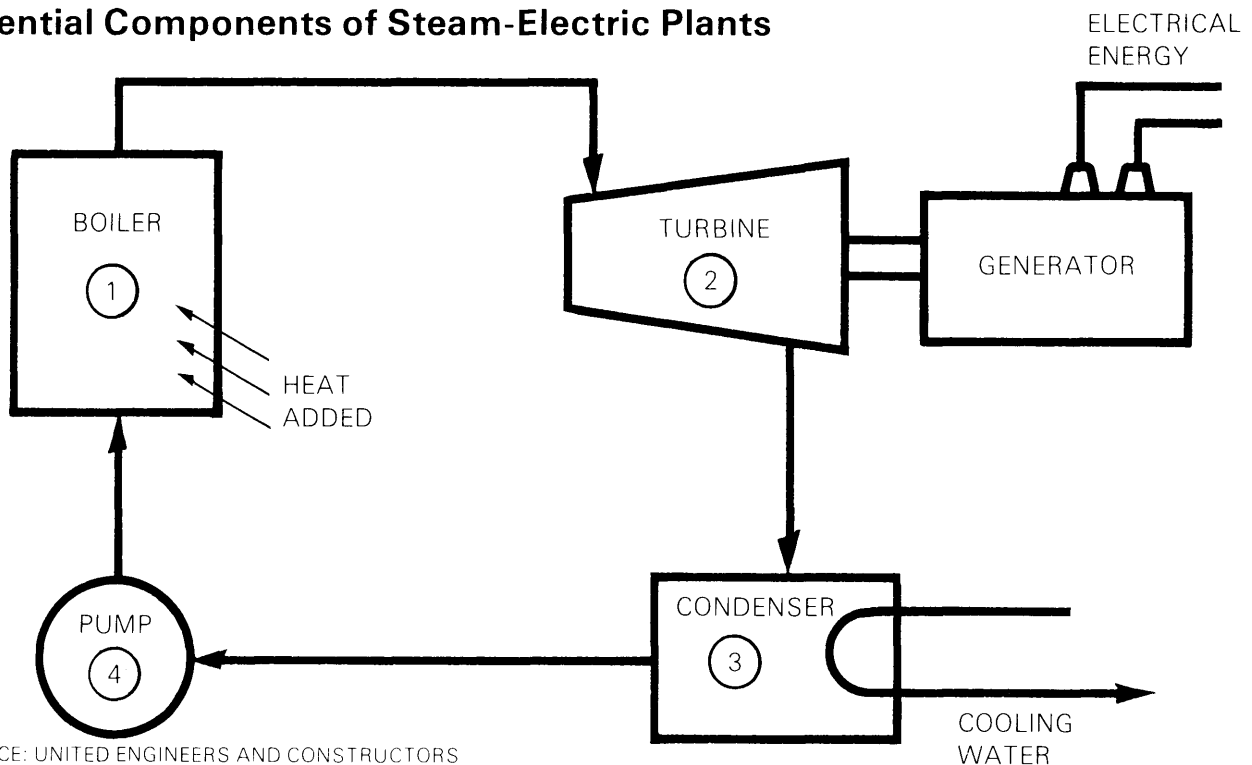
to construct a reservoir and to pass stored water through the plant's condenser in a manner similar to once-through cooling. Water consumption is a function of pond configuration and its attendant heat absorption characteristics. Representative consumptive use values are in the 10,000 to 12,000 AcFt/yr per 1000 MW range for cooling ponds.

Depending on the site, multiple use opportunities could be developed wherein diversion from a cooling pond could be made for other uses. The Boardman, Oregon, development is an example. Water will be pumped from the Columbia River to an off-stream pond for use in the coal-fired plant's once-through cooling system. Water also will be used from the pond for irrigation on adjacent lands. Cost sharing agreements have been developed whereby both the utility and the irrigators will achieve economies over other alternatives.

A more expensive alternative, and the choice which consumes the most water, is

Figure II-6

Essential Components of Steam-Electric Plants



SOURCE: UNITED ENGINEERS AND CONSTRUCTORS REPORT "ENGINEERING AND ECONOMIC EVALUATION OF WET/DRY COOLING TOWERS FOR WATER CONSERVATION" UE&C-ERDA-761130, NOVEMBER 1976.

TABLE II-3

WATER CONSUMPTION RATES FOR VARIOUS ENERGY PROCESSES

Energy System	Water Needs
Steam-Electric Nuclear	
Evaporative Cooling	17,000 acre-ft/yr/1000mw unit
Pond	12,000 acre ft/yr/1000mw unit
River	4,000 acre-ft/yr/1000mw unit
Wet-Dry Radiator	2,000 acre-ft/yr/1000mw unit
Steam-Electric Coal	
Evaporative Cooling	15,000 acre-ft/yr/1000mw unit
Pond	10,000 acre-ft/yr/1000mw unit
River	3,600 acre-ft/yr/1000mw unit
Dry Radiator	2,000 acre-ft/yr/1000mw unit
Geothermal	48,000 acre-ft/yr/1000mw unit
Natural Gas	50,000 acre-ft/yr throughout the West
Crude Oil	50,000 acre-ft/yr throughout the West
Refineries	39 gal/Bbl/crude
Oil Shale	7,600 to 18,900 acre-ft/yr/1000,000 BPD plant
Coal Gasification	8,000 to 45,000 acre-ft/yr/250 million SCF/day plant
Coal Liquefaction	20,000 to 130,000 acre-ft/yr/100,000 BPD plant
Coal Slurry Pipeline	20,000 acre-ft/25 million tons coal (1 cfs will transport about 1,000,000 tons per year)
Coal Mining	
Vegetation reestablishment	.5 to 4 acre-ft/acre/yr (some areas may require two years)

the evaporating cooling tower. For a 1,000 MW coal-fired or nuclear plant, an evaporative cooling tower will normally evaporate 15,000 to 17,000 AcFt/yr which is considered representative for estimates in this report. There is an additional requirement for "blowdown" to allow water to evaporate without excessive mineral deposits being formed in the tower which occurs when water is high in total dissolved solids (TDS). If the incoming water is low in TDS, the blowdown need be no more than 3,000 AcFt/yr for a 1,000 MW plant. If the incoming water is high in TDS, the blowdown may exceed 8,000 AcFt/yr. Each plant site has its own particular requirement for additional water such as for ash sluicing, revegetation, etc. Thus, water consumption for a 1,000 MW plant could total 20,000 to 25,000 AcFt/yr; however because these values are dependent on site characteristics, these additional requirements are not included in regional water use estimates in this report.

Dry cooling systems, while placing very small demands on water supply are difficult to justify economically because they entail the largest capital costs along with increased operating costs attendant with lower efficiencies.

Some makeup water is necessary and a representative value has been found to be 2,000 AcFt/yr per 1000 MW unit.

The only totally dry cooling system planned in the West is the Wyodak coal-fired plant in Wyoming, rated at 330 MW which is expected to become operational about mid-1978. The plant will utilize a high back-pressure turbine designed to match the cooling system, but overall plant efficiencies still will be less than those of more "conventional" plants. Because of the lower efficiency and attendant high costs,

the plant probably is not an example of the plant of the future, although valuable operating experience will be gained.

More typical of what might be expected in the future in the West is the San Juan -3 plant under construction in the Four Corners area which will utilize parallel path (wet/dry) mechanically induced draft cooling towers.

Current plans for future thermal electric generation facilities reveal an increasing tendency to rely on evaporative cooling towers as illustrated by Figure II-7. The small increment shown for air cooling results from installation of the Wyodak plant, San Juan -3 and combustion turbines, all of which are expected to contribute a small portion of future generation capacity. The trend toward evaporative cooling towers will result in maximum water consumption compared with other systems.

Summary Tables II-4 and II-5 show steam-electric plant consumptive use by existing and planned generation facilities in each of the WSWC member states. Total freshwater consumption by steam-electric plants throughout the West is expected to reach about 888,000 AcFt/yr by 1986, an increase of 588,000 AcFt/yr over present levels.

Extrapolating thermal electric power production needs from 1986 to 1990 reveals the likely addition of another 15,000 MW of thermal generation capacity which, using values for evaporative cooling systems, results in a possible additional consumption of 240,000 AcFt/yr. Therefore, the total increase in steam-electric cooling water needs to 1990 is expected to be about 828,000 AcFt/yr. This compares with a previously forecast increase in need of 1,337,000 AcFt in the 1974 WSWC Water for Energy Report.

Figure II-7

Trends in Cooling System Selections for Thermal Electric Power Plants in WSWC Region

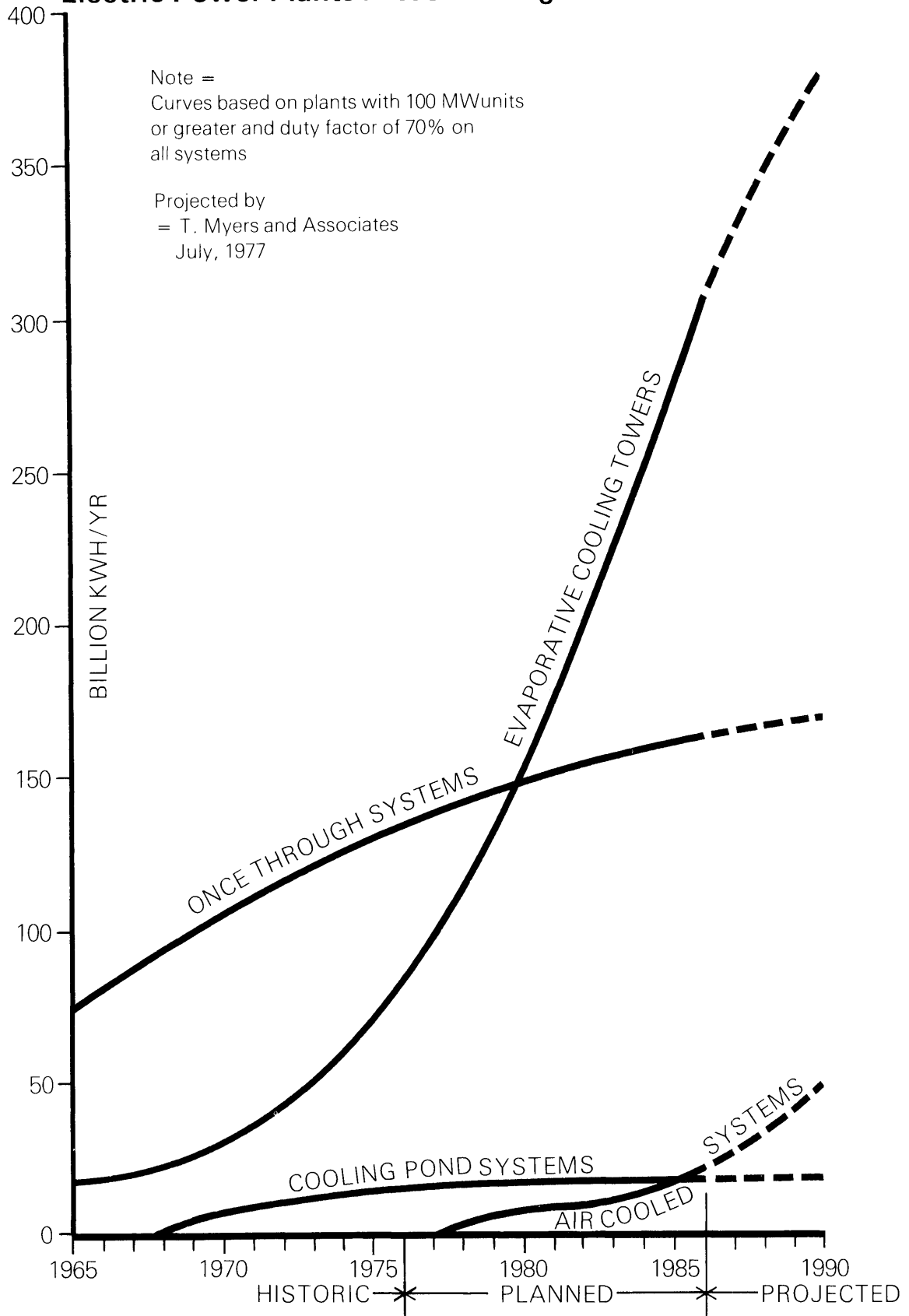


TABLE II-4

**STATE SUMMARY
CONSUMPTIVE USE BY EXISTING STEAM-ELECTRIC
GENERATION AS OF 1976**

STATE	EXISTING OIL & GAS-FIRED	CONSUMPTIVE USE Thous. AcFt/Yr
Arizona		15
California		25
Nevada		3
		<hr/> 43
	EXISTING COAL-FIRED	
Arizona		35
Colorado		33
Montana		10
Nevada		29
New Mexico		42
Utah		9
Washington		20
Wyoming		41
		<hr/> 219
	EXISTING NUCLEAR	
California		16
Colorado		3
Oregon		19
		<hr/> 38
	STATE TOTALS	
	TOTAL	300
Arizona		50
California		41
Colorado		36
Idaho		--
Montana		10
Nevada		32
New Mexico		42
Oregon		19
Utah		9
Washington		20
Wyoming		41
		<hr/> 300
	TOTAL	300

TABLE II-5

STATE SUMMARY
CONSUMPTIVE USE BY PLANNED STEAM-ELECTRIC
GENERATION 1977 to 1986

STATE		CONSUMPTIVE USE Thous. AcFt/Yr
	OIL & GAS-FIRED	
California		29
Colorado		8
		<hr/> 37
	COAL-FIRED	
Arizona		38
California		24
Colorado		54
Montana		21
Nevada		15
New Mexico		16
Oregon		8
Utah		56
Wyoming		27
		<hr/> 259
	NUCLEAR	
Arizona		63
California		33
Colorado		6
Oregon		43
Washington		147
		<hr/> 292
		TOTAL 588
	STATE TOTALS	
Arizona		101
California		86
Colorado		68
Idaho		--
Montana		21
Nevada		15
New Mexico		16
Oregon		51
Utah		56
Washington		147
Wyoming		27
		<hr/> TOTAL 588
1987-1990 Increase over Region		240
Total 1990 Use by Generation Facilities		828

III. Water Use Considerations in Energy Development

A. Economic Considerations in Plant Cooling

As discussed previously, in terms of capital costs, dry cooling systems rank highest among alternatives, followed by wet-dry systems, and then evaporative or all wet systems at the lower end. Examination of alternatives in regard to operating costs results in the same rank order.

The cost of water is a factor in cooling system selection analysis. A recent study⁴ reviewing all cost data for three nuclear plant sites at various locations concludes that "for the range of reference sites it would require water costs in excess of \$1 to \$2 per thousand gallons (\$330 to \$660 per acre foot) before wet cooling towers would not be the economic choice" and that "water costs would have to approach the \$13 to \$50 per thousand gallon (\$4200 to \$16,300 per acre foot) range for air cooling to become competitive." A current overview study⁵ summarizing other economic analyses conclude that the breakeven range for wet/dry cooling is \$1.60 to \$2.50 per thousand gallons. (\$520 to \$815 per acre foot) Thus, plant designers will be motivated to select evaporative cooling systems until water costs exceed

about \$660 per AcFt. Above that value wet/dry systems would be attractive until water costs reach \$4,200 per AcFt, at which level an all dry system becomes feasible. The same overview study includes a tabulation of relative costs of alternative cooling systems for a nuclear plant. Based on 1969 data, total unit costs in mills/KWH for selected cooling systems are:

COOLING SYSTEM	TOTAL UNIT COSTS Mills/KWH
Once through-River	0.168
Cooling Pond	0.219
Mechanical Draft Wet Tower	0.480
Mechanical Draft Dry Tower	0.618
Air Cooled Condenser	0.506

Most irrigation occurs in the West based upon an economy which includes water costs of \$20 per AcFt and less, although recent large scale private developments are paying more than twice that amount. Agricultural interests generally will not be able to compete for water supplies with thermal plant development. However, costs being paid by recent irrigation developments indicate that opportunities for cost sharing of joint facilities are probable. The previously cited overview study includes a brief examination of the approximate cost of acquiring a water supply by purchase of irrigated lands. The table below reproduces the results:

COST OF WATER ACQUIRED BY PURCHASING IRRIGATED FARMS

Case	Land Cost \$/Acre	Ft. of Water Per Acre	Irrigation Efficiency	Capitalized Cost \$/Ac. Ft.	\$/1000 gal
A	2000	4	60%	88	0.27
B	4000	4	70%	151	0.46
C	1500	3	40%	132	0.41
D	3000	4	50%	159	0.49

⁴ Future Needs for Dry or Peak Shaved Dry/Wet Cooling and Significance to Nuclear Power Plants, NP-150, Gen. Electric Co. for EPRI, February, 1976.

⁵ An Overview of Economic Legal and Water Availability Factors Affecting the Demand for Dry and Wet/DRY Cooling for Thermal Power Plants, Paul L. Hendrickson, Baltelle Northwest, June, 1977.

B. Alternative Water Supplies

Water supplies from other than conventional surface or ground water sources have been and are being investigated. Two projects are underway in the West to evaluate use of return flows of two types as cooling water supplies.

A developmental project started in mid-1975 with the objectives of determining costs of treating large quantities of water no longer suitable for agricultural use to a level usable in cooling towers and to assess the effect of those costs on utility rates. Data will be obtained from construction and operational field testing of a 5000 gpd capacity plant using ion exchange softening and evaporative techniques. The state-utility sponsored project located near Firebaugh, California is scheduled over a three year period and is funded for \$600,000.

In a similar kind of effort the Arizona Nuclear Power Project will treat 60,000 gpm of sewage effluent for cooling the Palo Verde nuclear plant near Phoenix. The project will utilize a two-stage lime clarification process and will pipe the effluent 40 miles to the plant.

Such projects are noteworthy and can assist in achieving less reliance on conventional supplies, but economic justification may be difficult in other locations. In addition, the seasonal availability of agricultural return flows creates a need either for storage facilities, or seasonal use of another water supply, further increasing costs. Not only are costs a consideration, but in some areas water users depend upon and have valid rights to return flows from other users. Serious consideration must be given these alternatives because of their water conservation potentials.

An alternative source of water that has attracted more attention in the past than now is desalinization of seawater. In 1968 it was estimated that desalinization of seawater would cost 22¢/1,000 gallons. More recent estimates for less saline water are closer to 80¢/1,000 gallons (\$260/AcFt).⁶ Desalted seawater also would be available on demand, although delivery to an inland site would add substantially to costs.

C. Institutional Considerations

1. State Water Law

Water laws and associated institutions have been developed in each of the Western States. The existing institutions can be modified; as has been done in the past to meet new demands when it appeared appropriate and necessary.

Much of the water available for appropriation in the arid and semi-arid West has already been appropriated, and therefore supplies for new energy production will be obtained, to a certain extent, through sales and transfers of water rights from existing uses, principally agricultural.

Under the appropriation doctrine, which predominates in the western states, water rights may generally be sold and transferred, either with the sale of the land upon which the water is used, or separately. If the purchaser continues the same use at the same place of use, there is no problem beyond registering or filing a record of the transaction. However, state water codes generally require that any change in the point of diversion, place or purpose of use, either on a permanent or temporary basis, receive the approval of the state administering agency.

The considerations of the state engineer in making this determination differ from

⁶ Estimated costs for Bureau of Reclamation desalinization plant near Yuma, Arizona, using water with 3200 ppm of dissolved solids in and 386 ppm out and employing the

membrane process. The 22¢/1,000 gallons quoted in 1968 was a distillation process using vertical tube evaporators.

state to state, but the rule applied in all western states is that other water rights, including those which depend on return flow, must be protected.

The sometimes substantial legal and engineering costs associated with a transfer are not seen as a significant impediment in acquiring water for the production of energy. In the first place, the dollar return for water use for energy production is much higher than it is in many other uses, such as in irrigation agriculture where water is often priced at less than \$20 per AcFt. Moreover, even if the price of water increased substantially, the percentage that water costs bear to all costs associated with energy production would remain low. When this is coupled with a policy which permits these costs to be incorporated in the price and passed along to the consumer, the price of water, even if increased substantially, would not have significant effects on the amount of water used for energy production.

Legal considerations will play an important role in determining the water available for energy production. As already noted, a major consideration will be the effect of the proposed transfer on existing rights. In addition, state policies and priorities relating to the utilization and management of the waters of the state may be determinative.

Such priorities may range from a simple declaration that in times of shortage domestic uses shall prevail over agricultural uses, to a very lengthy agenda of policies which emphasizes the affording of protection to the environment as part of a water resources management program. Thus, factors other than the impact on other water rights, to be considered by a state water rights administrator in determining an application to transfer water rights for

energy production, could include the following: (1) water conservation measures implemented in the area to be served by the transfer; (2) availability of alternative sources of water supply, including reclaimed water; (3) specific steps to be taken to assure that water will be diverted and used in the most efficient manner to minimize possible waste and compatibility of the proposed use of water with water quality laws for the basin involved; (4) whether the proposed change is in the public interest; and (5) effects the proposed transfer will have on the environment.

Some states forbid the transfer of water rights apart from the land to which the right is appurtenant. Others forbid an irrigation district to transfer its water right to a use outside the district. In one case, changes from agricultural to industrial use of more than 15 cubic feet per second are prohibited.

Thus, in some states the constraints of water laws involving water transfers are formidable with respect to obtaining water for proposed energy development.

Decisions on issues regarding water allocations are properly the responsibility of the states. As noted in the WSWC's earlier report, "it would be poor economics and poor social policy to attempt to modify basic institutions for water allocation or seek a blanket solution of any kind. There appears to be no substitute for a careful consideration of problems arising from individual situations. State and local officials are often prepared to make decisions on individual situations. By such procedure, it is possible to balance economic, ecological, and national interest objectives in a context of a particular problem."

In some areas of the west, new water rights will be established within the frame-

work of existing state institutions. These rights can be established: (1) in areas where the natural flow of surface streams has not yet been fully appropriated; (2) in areas where additional storage can be constructed so that during periods of high runoff water can be stored for later use; or (3) in areas where more expensive sources of water, such as deeper ground waters, waters that will require desalinization, or water that can be imported from some significant distance or lifted to higher elevations is available. In all of the Western states there are procedures available to the energy industry to rapidly and efficiently establish new water rights to the use of these unappropriated waters.

2. State Siting Practices

Seven of the member states of the Western States Water Council have agencies established for review and regulation of the construction and operation of energy facilities. Each state's legislation includes statements of policy which reflect the individual requirements and unique characteristics of the state.

Facilities requiring permits include plants designed for production of electricity, gas, liquid hydrocarbon products, oil and gas refineries, uranium enrichment, and others. Some states include facilities for nuclear storage or waste disposal facilities, underground reservoirs for natural gas, or any industry whose cost is at least 50 million dollars. Transmission lines and pipelines also are included. In short, states have responded where needs exist for regulation of energy production facilities.

Many states require utilities to submit long range plans, identifying facilities to be constructed within the subsequent ten years. This provision creates an opportunity

for states to not only review proposals, but to integrate identified future needs into their water resource planning efforts. Opportunities for joint use may be explored through cooperative state-utility planning and considering water costs utilities are able to pay, water development projects which have been judged to be economically infeasible in the past should be re-evaluated.

3. Environmental Considerations

Water quality standards developed pursuant to the Federal Water Pollution Control Act Amendments of 1972 affect power plant siting in the WSWC member states. Standards involving the discharge of heated cooling water have been interpreted to generally preclude the use of once-through cooling facilities on all water bodies except the ocean. Consequently, the majority of facilities constructed since 1972 have resorted to evaporative cooling towers.

On a site specific basis, however, it may be possible for once-through cooling techniques to be utilized during times of the year when stream flows are at their greatest, thus allowing for dissipation of much of the annual waste heat load without harmful environmental impact. Appreciable water savings would result where once-through cooling could be used seasonally, and evaporative cooling towers used during the warmer months.

Waste water management plans are being developed by states under Section 208 of the Federal Water Pollution Control Act Amendments of 1972. The major emphasis of these planning activities has been on management of municipal wastes and planning for waste water treatment facilities. As data are acquired on the assimilation capacities of streams it may

become possible to identify locations where discharge of waste heat could be accomplished without exceeding standards.

The Coastal Zone Management Act of 1972 has fostered natural resource inventory and planning activities in the three coastal states that are members of WSWC. State programs have been developed for coastal zone management which are integrated into the energy facility siting agency's programs. Energy production facility siting opportunities have been narrowed as many coastal areas have been identified as possessing fragile environments or other values such that preservation has been selected as the most appropriate use.

D. Water Conservation Opportunities

Energy conservation can result in significant delay in the need for additional energy production facilities and attendant water demands. If the accepted growth rate in total energy demands were to be reduced by one percent, the 1990 demand for electrical energy would be reduced by about 5,000 MW. Assuming this capacity to be cooled by evaporative systems, up to 75,000 AcFt/yr would then not be required. Water savings resulting from energy conservation can be significant in the West.

Major amounts of water would not be required if once-through cooling could be utilized by western energy developments. When typical rates shown in Table II-3 are applied in the case of a 1,000 MW coal-fired unit 5000 AcFt/yr would be conserved by the use of ponds versus an evaporative system and if once-through cooling from a river or large reservoir were possible, over 11,000 AcFt/yr could be saved. If 10 plants of the 85 now scheduled for installation by 1986 could be converted to these less

consumptive cooling systems, 50,000 to 100,000 AcFt would then be available for other uses.

Pursuit of these opportunities appears justified, based on conclusions presented by staff members of the Iowa Institute of Hydraulic Research, summarized in the following: "The experience amassed to date at numerous power plants indicates that thermal pollution of water at the levels permitted by significantly relaxed standards, produces only minimal impact on the nearby aquatic communities. The price that the nation is paying, in terms of dollars, resource utilization, and water consumption, to take its waste-heat load off major water bodies is a very great one indeed, and in many instances appears not to be justified by the generally insignificant resulting environmental enhancement. Indeed, there are many instances in which the closed-cycle cooling systems likely impact the environment more adversely than would a well designed open-cycle system." Western streams wherein a cold water fishery exists should be given thorough study in a site specific basis, however, as existing temperature conditions may approach maximum tolerable levels.

As energy developments occur in the West, water requirements for the existing hydro-power system must continue to be a consideration. Consumptive uses upstream from a hydro-power installation reduce amounts of water available for generation. If, on the other hand, a hydro-facility is being operated under water rights senior to those of upstream users, state water administrators could be required to reduce junior diversions or to stop them altogether. These conditions become of increasing importance in low flow seasons, or in drought

⁷ Precis of remarks by John F. Kennedy, University of Iowa, at the National Conference on Water, 23 May 1977.

conditions such as those being experienced in 1977.

Additionally, in a multi-purpose facility, releases for other purposes during low water situations can reduce the amount of energy potentially available from the then existing storage or flows. Releases required for downstream flows may be necessary on a schedule which does not coincide with hydro-generation requirements. Use of other facilities such as fish ladders may become of primary importance thereby

reducing amounts of water available for passing through generators.

Water use by steam-electric generation facilities can be an asset in terms of conjunctive operation with hydro stations, but water supplies for steam-electric facilities must be supplied on no less a firm basis than for a hydro-facility. Additionally, if water is not conserved at steam-electric plants it will have an adverse impact on Western hydro-power production.

APPENDIX A

TABLE A-1

WSWC REGION EXISTING OIL AND GAS-FIRED ELECTRICAL GENERATION PLANTS

Plant Name	Start Date	Rating MW (Net Elect)	Cooling System	Water Nged 10 ³ a-ft	Location	Plant Name	Start Date	Rating MW (Net Elect)	Cooling System	Water Nged 10 ³ a-ft	Location
ARIZONA											
Saguaro Steam -1	1954	115	ECT	1.73	Red Rock, AZ	Encina -1	1954	100	OT	negl.	Carlsbad, CA
Ocotillo Steam -1	1960	115	ECT	1.73	Tempe, AZ	-2	1956	102	OT	negl.	Carlsbad, CA
-2	1960	115	ECT	1.73	Tempe, AZ	-3	1958	102	OT	negl.	Carlsbad, CA
Agua Fria -1	1958	109	ECT	1.64	Glendale, AZ	-4	1973	287	OT	negl.	Carlsbad, CA
-2	1957	109	ECT	1.64	Glendale, AZ	South Bay -1	1960	140	OT	negl.	Chula Vista, CA
-3	1961	182	ECT	2.73	Glendale, AZ	-2	1962	142	OT	negl.	Chula Vista, CA
Irvington Steam -3	1962	104	ECT	1.56	Tucson, AZ	-3	1964	198	OT	negl.	Chula Vista, CA
-4	1962	156	ECT	2.34	Tucson, AZ	-4	1971	220	OT	negl.	Chula Vista, CA
CALIFORNIA											
Contra Costa -1	1951	116	OT	negl.	Antioch, CA	Kearny GT 1-3	1972	183	Air	none	San Diego, CA
-2	1951	116	OT	negl.	Antioch, CA	Valley -1	1954	101	ECT	1.52	Sun Valley, CA
-3	1951	116	OT	negl.	Antioch, CA	-2	1954	101	ECT	1.52	Sun Valley, CA
-4	1953	117	OT	negl.	Antioch, CA	-3	1955	171	ECT	2.57	Sun Valley, CA
-5	1953	115	OT	negl.	Antioch, CA	-4	1956	160	ECT	2.40	Sun Valley, CA
-6	1964	340	OT	negl.	Antioch, CA	Scattergood -1	1958	179	OT	negl.	Playa Del Rey, CA
-7	1964	340	OT	negl.	Antioch, CA	-2	1959	179	OT	negl.	Playa Del Rey, CA
Haynes -1	1962	222	OT	negl.	Long Beach, CA	-3	1974	309	OT	negl.	Playa Del Rey, CA
-2	1961	232	OT	negl.	Long Beach, CA	Hunters Point -2	1948	107	OT	negl.	San Francisco, CA
-3	1964	220	OT	negl.	Long Beach, CA	-3	1949	107	OT	negl.	San Francisco, CA
-4	1964	227	OT	negl.	Long Beach, CA	-4	1958	163	OT	negl.	San Francisco, CA
-5	1966	344	OT	negl.	Long Beach, CA	Kern -2	1950	106	ECT	1.59	Bakersfield, CA
-6	1967	344	OT	negl.	Long Beach, CA	Morro Bay -1	1956	163	OT	negl.	Morro Bay, CA
Redondo Beach -5	1954	175	OT	negl.	Redondo Beach, CA	-2	1955	163	OT	negl.	Morro Bay, CA
-6	1957	175	OT	negl.	Redondo Beach, CA	-3	1962	338	OT	negl.	Morro Bay, CA
-7	1967	480	OT	negl.	Redondo Beach, CA	-4	1963	338	OT	negl.	Morro Bay, CA
-8	1967	480	OT	negl.	Redondo Beach, CA	Moss Landing -1	1950	116	OT	negl.	Moss Landing, CA
Long Beach -8	1976	252	OT	negl.	Long Beach, CA	-2	1950	115	OT	negl.	Moss Landing, CA
Etiwanda -1	1953	132	ECT	1.98	Etiwanda, CA	-3	1951	117	OT	negl.	Moss Landing, CA
-2	1953	132	ECT	1.98	Etiwanda, CA	-4	1952	117	OT	negl.	Moss Landing, CA
-3	1963	320	ECT	4.80	Etiwanda, CA	-5	1952	117	OT	negl.	Moss Landing, CA
-4	1963	320	ECT	4.80	Etiwanda, CA	-6	1967	739	OT	negl.	Moss Landing, CA
-5	1969	121	ECT	1.82	Etiwanda, CA	-7	1968	739	OT	negl.	Moss Landing, CA
El Segundo -1	1955	175	OT	negl.	El Segundo, CA	Pittsburg -1	1954	153	OT	negl.	Pittsburg, CA
-2	1956	175	OT	negl.	El Segundo, CA	-2	1954	163	OT	negl.	Pittsburg, CA
-3	1964	335	OT	negl.	El Segundo, CA	-3	1954	153	OT	negl.	Pittsburg, CA
-4	1965	335	OT	negl.	El Segundo, CA	-4	1954	163	OT	negl.	Pittsburg, CA
Alamitos -1	1956	175	OT	negl.	Long Beach, CA	-5	1960	325	OT	negl.	Pittsburg, CA
-2	1957	175	OT	negl.	Long Beach, CA	-6	1961	325	OT	negl.	Pittsburg, CA
-3	1961	320	OT	negl.	Long Beach, CA	-7	1972	720	OT	negl.	Pittsburg, CA
-4	1962	320	OT	negl.	Long Beach, CA	Potrero -3	1965	207	OT	negl.	San Francisco, CA
-5	1966	480	OT	negl.	Long Beach, CA	NEVADA					
-6	1966	480	OT	negl.	Long Beach, CA	Tracy -3	1974	110	CP	1.10	Reno, NV
-7	1969	121	OT	negl.	Long Beach, CA	Ft. Churchill -1	1968	110	CP	1.10	Yerington, NV
Huntington Beach -1	1958	215	OT	negl.	Huntington Beach, C	-2	1971	110	CP	1.10	Yerington, NV
-2	1958	215	OT	negl.	Huntington Beach, C	ECT - Evaporative Cooling Tower					
-3	1961	215	OT	negl.	Huntington Beach, C	OT - Once Through					
-4	1961	225	OT	negl.	Huntington Beach, C	CP - Cooling Pond					
-5	1969	121	OT	negl.	Huntington Beach, C	Air - Dry Cooling System					
Mandalay -1	1959	215	OT	negl.	Oxnard, CA	W/D - Wet/Dry System					
-2	1959	215	OT	negl.	Oxnard, CA	negl. - Negligible					
-3	1970	121	OT	negl.	Oxnard, CA						
Ormond Beach -1	1971	750	OT	negl.	Oxnard, CA						
-2	1973	750	OT	negl.	Oxnard, CA						

NOTE: Plants Limited To Those With Units Greater Than 100 MW

TABLE A-2

WSWC REGION EXISTING COAL-FIRED ELECTRICAL GENERATION PLANTS

Plant Name	Start	Rating	Water		Location
	Start Date	Rating MW (Net Elect)	Cooling System	Water Need 10 ³ a-ft	
ARIZONA					
Cholla -1	1962	116	CP	1.16	Joseph City, AZ
Navajo -1	1974	750	ECT	11.25	Page, AZ
-2	1975	750	ECT	11.25	Page, AZ
-3	1976	750	ECT	11.25	Page, AZ
COLORADO					
Arapahoe -4	1955	101	ECT	1.52	Denver, CO
Cherokee -1	1957	104	ECT	1.56	Denver, CO
-2	1959	107	ECT	1.61	Denver, CO
-3	1962	156	ECT	2.34	Denver, CO
-4	1968	330	ECT	5.09	Denver, CO
Comanche -1	1973	350	ECT	5.25	Pueblo, CO
-2	1975	350	ECT	5.25	Pueblo, CO
Valmont -5	1964	175	CP	1.75	Boulder, CO
Hayden -1	1965	175	ECT	2.63	Hayden, CO
-2	1976	261	ECT	3.92	Hayden, CO
Martin Drake -7		138	ECT	2.07	Colorado Springs, CO
MONTANA					
Corette	1968	180	OT	negl.	Billings, MT
Colstrip -1	1975	330	ECT	4.95	Colstrip, MT
-2	1976	330	ECT	4.95	Colstrip, MT
NEVADA					
Mohave -1	1971	790	ECT	11.85	Laufin, NV
-2	1971	790	ECT	11.85	Laufin, NV
R. Gardner -1	1965	110	ECT	1.65	Moapa, NV
-2	1968	110	ECT	1.65	Moapa, NV
-3	1976	110	ECT	1.65	Moapa, NV
NEW MEXICO					
Four Corners -1	1963	175	CP	2.63	Farmington, NM
-2	1963	177	CP	2.66	Farmington, NM
-3	1964	220	CP	3.30	Farmington, NM
-4	1969	795	CP	11.93	Farmington, NM
-5	1976	800	CP	12.00	Farmington, NM
San Juan -1	1976	330	ECT	4.95	San Juan, NM
-2	1973	330	ECT	4.95	San Juan, NM
UTAH					
Gadsby -3	1955	105	ECT	1.58	Salt Lake City, UT
Carbon -2	1955	105	ECT	1.58	Castle Gate, UT
Huntington -2	1974	415	ECT	6.23	Huntington, UT
WASHINGTON					
Centralia -1	1972	650	ECT	9.75	Centralia, WN
-2	1972	650	ECT	9.75	Centralia, WN
WYOMING					
SD. Johnson -1	1959	100	OT	negl.	Glenrock, WY
-2	1961	100	OT	negl.	Glenrock, WY
-3	1964	220	ECT	3.30	Glenrock, WY
-4	1972	330	ECT	4.95	Glenrock, WY
J. Bridger -1	1974	500	ECT	7.50	Rock Springs, WY
-2	1975	500	ECT	7.50	Rock Springs, WY
-2	1975	500	ECT	7.50	Rock Springs, WY
-3	1976	500	ECT	7.50	Rock Springs, WY
Naughton -1	1963	160	ECT	2.40	Kemmerer, WY
-2	1968	220	ECT	3.30	Kemmerer, WY
-3	1971	330	ECT	4.95	Kemmerer, WY

ECT - Evaporation Cooling Tower
 OT - Once Through
 CP - Cooling Pond

Air - Dry Cooling System
 W/D - Wet/Dry System

NOTE: Plants Limited To Those With Units Greater Than 100 MW

TABLE A-3

WSWC REGION EXISTING NUCLEAR ELECTRICAL GENERATION PLANTS

Plant Name	Start Date	Rating MW/Net Elect	Cooling System	Water Need 10³ a-ft	Location
CALIFORNIA					
San Onofre -1	1967	438	OT	negl.	San Clemente, CA
Rancho Seco -1	1975	913	ECT	15.52	Sacramento, CA
COLORADO					
St. Vain	1976	330	ECT	5.00	Platteville, Colo.
OREGON					
Trojan	1976	1130	ECT	19.21	Rainier, OR
WASHINGTON					
Hanford Gen. Plant	1966	850	OT	negl.	Hanford, WN

ECT - Evaporative Cooling Tower
 OT - Once Through

NOTE: Plants Limited To Those With Units Greater Than 100 MW

APPENDIX B

TABLE B-1

WSWC REGION PLANNED OIL AND GAS-FIRED ELECTRICAL GENERATION PLANTS

Plant Name	Start Date	Rating MW (Net Elect)	Cooling System	Water Need 10 ³ a-ft	Location
CALIFORNIA					
Long Beach -9	1977	238	OT	negl.	Long Beach, CA
Cool Water -3	1978	236	ECT	3.54	Dagget, CA
Oakland 1-3	1978	192	OT	negl.	Oakland, CA
Cool Water -4	1978	138	ECT	2.07	Dagget, CA
Long Beach 10-11	1979	112	OT	negl.	Long Beach, CA
Encina -5	1979	292	OT	negl.	Carlsbad, CA
Comb. Turb. -1	1979	150	W/D	1.35	Sacramento, CA
Silver Gate -2	1979	100	ECT	1.50	San Diego, CA
Portero -7	1980	292	Air	none	San Francisco, CA
Thermal A 1-3	1980	225	Air	none	Bay Area, CA
Thermal B 1-3	1980	225	Air	none	Bay Area, CA
Lucerne Valley	1981	120	Air	none.	Lucerne Valley, CA
Portero -7	1981	120	OT	negl.	San Francisco, CA
Thermal A 1-8	1982	600	ECT	9.00	Bay Area, CA
Thermal A 9-10	1982	200	ECT	3.00	Bay Area, CA
Thermal B 1-10	1983	600	ECT	9.00	Bay Area, CA
Lucerne Valley	1984	180	Air	none	Lucerne Valley, CA
Lucerne Valley	1985	915	Air	none	Lucerne Valley, CA
Gas Turbines	1986	385	Air	none	Undetermined, CA
COLORADO					
Burlington 1-2	1977	102	ECT	1.53	Burlington, CO
Valmont 2-4	1979	171	ECT	2.57	Boulder, CO
Valmont 1-4	1981	228	ECT	3.42	Boulder, CO

ECT - Evaporative Cooling Tower

OT - Once Through

CP - Cooling Pond

Air - Dry Cooling System

W/D - Wet/Dry System

negl. - Negligible

NOTE: Plants Limited To Those With Units Greater Than 100 MW

TABLE B-2

WSWC REGION PLANNED COAL-FIRED ELECTRICAL GENERATION PLANTS

Plant Name	Start Date	Rating MW (Net Elect)	Cooling System	Water Need ap ³ a-ft	Location
ARIZONA					
Apache -2	1978	175	ECT	2.63	Cochise, AZ
Cholla -2	1978	235	CP	2.35	Joseph City, AZ
Coronado -1	1979	350	ECT	5.25	St. Johns, AZ
Apache -3	1979	175	ECT	2.63	Cochise, AZ
Cholla -3	1979	242	ECT	3.63	Joseph City, AZ
Coronado -2	1980	350	ECT	5.25	St. Johns, AZ
Cholla -4	1980	347	ECT	5.21	Joseph City, AZ
Cholla -5	1983	347	ECT	5.21	Joseph City, AZ
Springerville -1	1985	312	ECT	4.68	Springerville, AZ
CALIFORNIA					
Fossil -1	1984	800	ECT	12.00	CA
Fossil -2	1985	800	ECT	12.00	CA
COLORADO					
Craig -1	1979	380	ECT	5.70	Craig, CO
Craig -2	1979	380	ECT	5.70	Craig, CO
Ray D. Nixon -1	1980	200	ECT	3.00	Fountain, CO
Craig -3	1982	380	ECT	5.70	Craig, CO
Craig -4	1983	380	ECT	5.70	Craig, CO
Pawnee -1	1980	500	ECT	7.50	Ft. Morgan, CO
Southeastern -1	1984	500	ECT	7.50	Southeastern, CO
Rawhide -1	1984	200	ECT	3.00	Wellington, CO
Ray D. Nixon -2	1985	200	ECT	3.00	Fountain, CO
Southeastern -2	1986	500	ECT	7.50	Southeastern, CO
MONTANA					
Colstrip -3	1980	700	ECT	10.50	Colstrip, MT
Colstrip -4	1981	700	ECT	10.50	Colstrip, MT
NEVADA					
Valmy -1	1981	250	ECT	3.75	Valmy, NV
Valmy -2	1984	250	ECT	3.75	Valmy, NV
H. Allen -1	1986	500	ECT	7.50	Las Vegas, NV
NEW MEXICO					
San Juan -3	1979	486	W/D	3.25	Waterflow, NM
San Juan -4	1981	468	ECT	7.50	Waterflow, NM
Plains -1	1982	330	ECT	4.95	NM
OREGON					
Boardman -1	1985	550	CP	8.25	Boardman, OR
UTAH					
Huntington -1	1977	400	ECT	6.00	Huntington, UT
Emery -1	1978	400	ECT	6.00	Emery County, UT
Emery -2	1980	400	ECT	6.00	Emery County, UT
Emery-3	1983	400	ECT	6.00	Emery County, UT
Emery-4	1985	400	ECT	6.00	Emery County, UT
Warner -1	1984	250	ECT	3.75	St. George, UT
Warner -2	1985	250	ECT	3.75	St. George, UT
Intermountain -1	1986	750	ECT	11.25	Wayne County, UT
Nephi -1	1986	500	ECT	7.50	Nephi, UT
WYOMING					
Wyodak -1	1978	330	Air	none	Gillette, WY
Jim Bridger -4	1979	500	ECT	7.50	Rock Springs, WY
Laramie -1	1980	500	ECT	7.50	Wheatland, WY
Laramie -3	1983	500	ECT	7.50	Wheatland, WY
Wyodak -2	1983	330	ECT	4.95	Gillette, WY

ECT - Evaporative Cooling System

OT - Once Through

CP - Cooling Pond

Air - Dry Cooling System

W/D - Wet/Dry System

negl. - Negligible

NOTE: Plants Limited To Those With Units Greater Than 100 MW

TABLE B-3

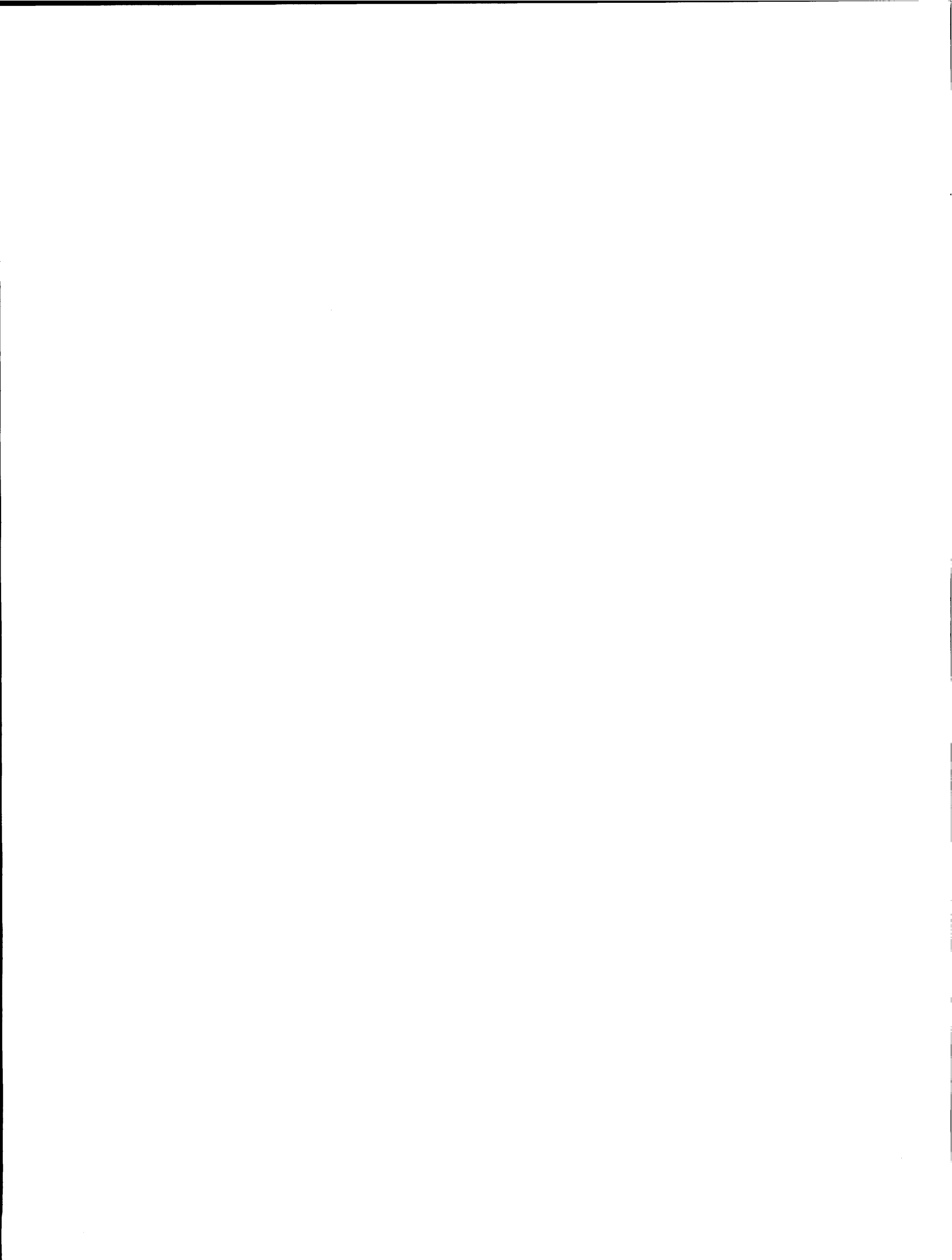
WSWC REGION PLANNED NUCLEAR ELECTRICAL GENERATION PLANTS

Plant Name	Start Date	Rating MW (Net Elect)	Cooling System	Water Need 10 ³ a-ft	Location
ARIZONA					
Palo Verde -1	1982	1235	ECT	21.00	Wintersburg, AZ
-2	1984	1235	ECT	21.00	Wintersburg, AZ
-3	1986	1235	ECT	21.00	Wintersburg, AZ
CALIFORNIA					
Diablo Canyon -1	1977	1060	OT	negl.	San Luis Obispo, CA
-2	1977	1060	OT	negl.	San Luis Obispo, CA
San Onofre -2	1981	1100	OT	negl.	San Clemente, CA
-3	1983	1100	OT	negl.	San Clemente, CA
Sundesert -1	1984	974	ECT	16.56	Blyth, CA
-2	1986	974	ECT	16.56	Blyth, CA
COLORADO					
Fort St. Vrain	1977	330	ECT	5.61	Platteville, CO
OREGON					
Pebble Springs -1	1985	1260	ECT	21.42	Arlington, OR
-2	1988	1260	ECT	21.42	Arlington, OR
WASHINGTON					
WNP -1	1981	1250	ECT	21.25	Hanford, WN
-2	1980	1100	ECT	18.70	Hanford, WN
-4	1983	1250	ECT	21.25	Hanford, WN
Skagit -1	1983	1288	ECT	21.89	Sedro Wooley, WN
-2	1986	1288	ECT	21.89	Sedro Wooley, WN
Satsop -3	1983	1240	ECT	21.08	Aberdeen, WN
-5	1985	1240	ECT	21.08	Aberdeen, WN
Hanford -1	1983	(850)	OT		Hanford, WN

ECT - Evaporative Cooling System
 OT - Once Through
 CP - Cooling Pond
 () - Planned Retirement
 Au - Dry Cooling System
 W/D - Wet/Dry System
 negl. - Negligible

NOTE: Plants Limited To Those With Units Greater Than 100 MW







on the Cover . . .

1. ARIZONA The Navajo Generating Station near Page, Arizona. With a rating of 2,250 MW, the coal fired units are cooled by evaporative cooling towers.
U.S. Bureau of Reclamation photo
2. CALIFORNIA The world's largest, and the United States only geothermal plant. The Geysers geothermal electric generating facility, located north of San Francisco and owned and operated by Pacific Gas and Electric Company currently produces 502 MW with 11 units. An additional 4 units are under construction with another 2 units in the permit stage. With the six additional units, planned to be on line in mid 1981, capacity will total 1,128 MW.
Pacific Gas and Electric Co. photo
3. COLORADO Cabin Creek pumped storage hydro-electric facilities located near Georgetown, Colorado, 35 miles west of Denver. Utilizing off-peak power from its steam plants, Public Service Co. of Colorado uses the plants' 2 pump/turbines to lift water nearly 1200 ft. The units are used as generators during peaking hours. The units are rated at 150 MW each.
Public Service Co. of Colorado photo
4. IDAHO Brownlee Dam located on the Snake River near Weiser, Idaho. The facility is operated for flood control purposes in addition to generation of power for Idaho Power Company customers. Brownlee Pool provides recreation opportunities for many of the area's residents.
Idaho Power Co. photo
5. MONTANA Coal from Westmoreland Mine near Colstrip, Montana is hauled by unit-train to customers in the Midwest.
Montana Department of State Lands Photo
6. NEVADA Aerial view of Hoover Dam and Lake Mead. The world-famous dam, completed in 1935, spans the Colorado between Nevada and Arizona, providing multipurpose benefits; flood protection, river control, water storage, and conservation for irrigation and low-cost hydroelectric energy.
Bureau of Reclamation photo by E. E. Hertzog
7. NEW MEXICO The Four Corners complex near Farmington, New Mexico. With five coal-fired units total capacity exceeds 2100 MW. Cooling is accomplished by use of water from a cooling pond.
Bureau of Reclamation photo
8. OREGON The Trojan Nuclear Plant near Rainier, Oregon. This 1130 MW facility uses water from the Columbia River for its evaporative cooling tower.
Portland General Electric photo
9. UTAH The Huntington Plant near Huntington, Utah consists of two units with a total capacity of 800 MW. The Massachusetts Institute of Technology has praised the Huntington Plant as the most aesthetically pleasing, both in site and appearance, of any fossil fuel burning plant in the United States. The "mine mouth" plant uses evaporative cooling.
Utah Power & Light Co. photo
10. WASHINGTON Multi purpose Grand Coulee Dam on the Columbia River has been supplying energy since 1941. Including the third power house, total capacity is nearly 6,300 MW.
Bonneville Power Administration photo
11. WYOMING The Wyodak plant near Gillette, Wyoming is scheduled for operation in 1978. The 330 MW plant will be "the world's largest air cooled power plant." Water sources, used for boiler blow-down, include effluent from the City of Gillette's sewage treatment facility.
Pacific Power and Light Co. photo

