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INTERIM REGIONAL REPORT FOR NATIONAL COAL UTILIZATION ASSESSMENT. IMPACTS OF FUTURE COAL USE IN CALIFORNIA

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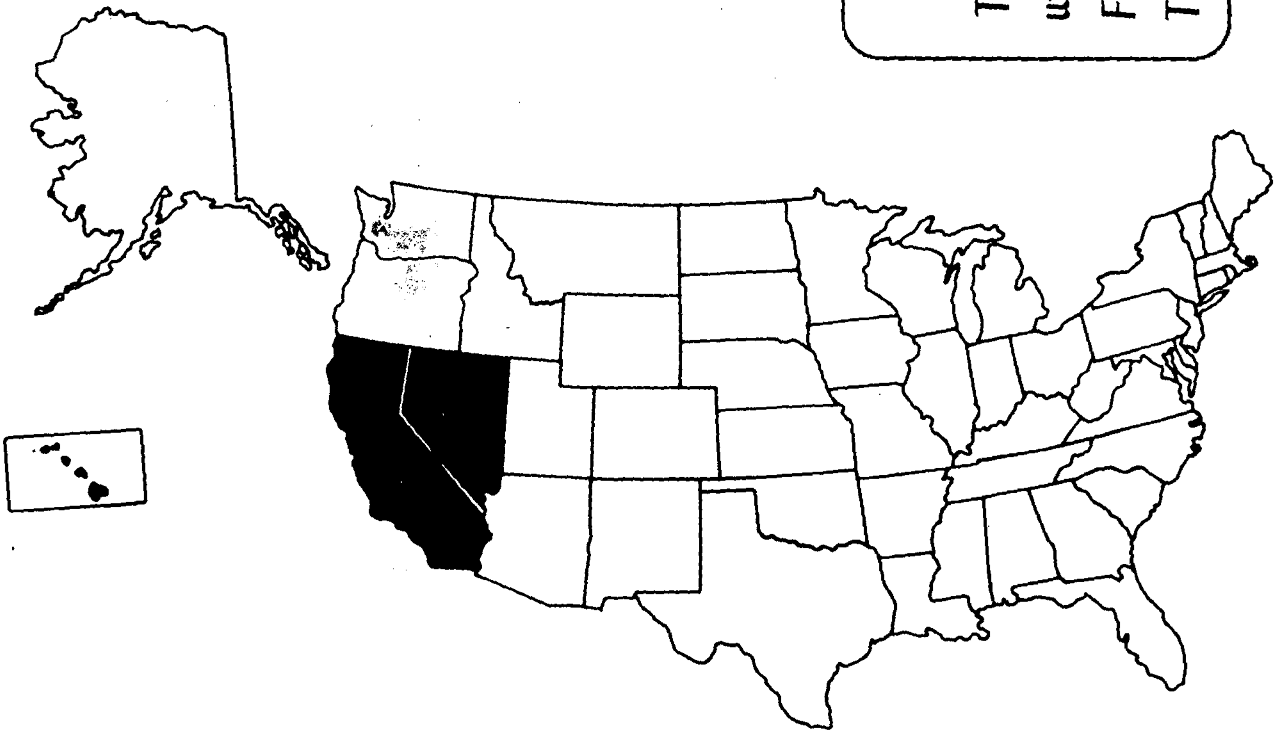

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INTERIM REGIONAL REPORT
FOR
NATIONAL COAL UTILIZATION ASSESSMENT

IMPACTS OF FUTURE COAL USE IN CALIFORNIA

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1. SUMMARY

This report details the preliminary methodology and results of an ongoing assessment of the impacts of future (to 2000) coal use in California. The assessment forms an integral part of the National Coal Utilization Assessment (NCUA) being conducted cooperatively by six of the ERDA national laboratories for the Division of Technology Overview, Office of Environment and Safety. Each laboratory is conducting a parallel investigation for its study region. Assessments for the six study regions will be integrated by Argonne National Laboratory to provide a comprehensive assessment of the impacts and constraints associated with increased utilization of coal in the United States.

A common basis for these assessments has been adopted. An initial set of four national coal utilization scenarios was constructed that features alternative coal technologies for comparative assessments. Each scenario, disaggregated to the regional level, specifies the type and number of facilities, and fuels for each region for the time span from 1976 to 2000. Lawrence Berkeley Laboratory is responsible for the integrated assessment of the scenarios for the State of California. In conducting the assessments, candidate sites for facilities are selected, on the basis of which analyses are performed to evaluate the impacts on air quality, water and other resources, local and state economy, and health and safety.

The organization of sections in this report follows the logic in the above assessment. Sections 2 and 3 provide historical data that characterize the region and its energy supply and use for the past 15 to 20 years, and describe the set of four alternative scenarios for future energy supply to California. Section 4 discusses the characteristics of the coal-fired power plants that will be operating in California and the properties of the coal that will be burned in them. Sections 5 and 6 present the economic and environmental impacts for the Recent Trends scenario (scenario 1). These impacts are statewide and are not site specific. Section 7 includes a description of the regulatory agencies and their interaction in the siting process for power plants. Section 8 describes the procedure used in this study for identifying locations suitable for siting of power plants. Water requirements for power plants included in each of the four scenarios were estimated for each aggregated subarea for 1985 and 2000 and are presented in Section 9. Air quality and health and safety impacts, discussed in Sections 10 and 11, were estimated for one coal-fired power plant to be located in Northern California. Details of the models for estimating the statewide economic impacts and the site specific air pollutant emissions are described in the appendices. A summary description of each section is presented below.

Energy supply scenarios for California were disaggregated from the four Pacific Region scenarios developed by Brookhaven National Laboratory. These scenarios specify in detail the quantities of major energy supply sources for 1975, 1985, and 2000. Major sources include coal, petroleum, natural gas, solar and geothermal, and electricity supply by type of generation. Scenarios for 2020 will be forthcoming at a later date. Each of these four scenarios emphasizes different amounts and type of coal use. The first scenario, or the Recent Trends scenario, extrapolates current low quantities of coal use in California. The second and third scenarios call for increased coal use for conversion to synthetic fuels and for electricity generation respectively. The fourth scenario postulates increased coal use for both electricity generation and synthetic fuels production. In California, coal use is assumed only for electricity generation and for industrial production; scenarios 1 and 2 are therefore identical as are scenarios 3 and 4 except for minor differences in natural gas supply in the latter two scenarios.

Statewide economic impacts and pollutant residuals were calculated for the Recent Trends scenario (scenario 1). Economic impacts include estimates of direct capital and manpower requirement for construction and operation of all facilities required for energy supply and estimates of consequent changes in value added and indirect manpower requirements. These impacts were estimated with the models described in Appendix A. In-state capital outlays and manpower requirements generally decrease over time, although these show an irregular behavior since many of the energy facilities are built in large discrete units. The construction of coal related facilities to generate power from the single coal-fired power plant assumed in this scenario requires roughly $400 million (1974 constant dollars), a small outlay compared to a total capital requirement of $11 billion for all the energy facilities. The manpower requirements are also a relatively small fraction of the total. The direct and indirect value added both decrease, although irregularly, through to 2000. However, over the twenty-five year period, 1975-2000, the direct economic impacts constitute an increasing fraction of the total economic impacts. This indicates a shift away from capital intensive to more labor intensive energy facilities.

Of the statewide pollutant residuals, air pollutants from coal-related facilities are of significance to this study. In California these coal facilities include coal trains and a coal power plant. Quantities of the three major pollutants emitted by these facilities--particulates, oxides of nitrogen and sulfur oxides--were estimated. These amount to less than ten per cent of the statewide emissions of these pollutants by energy and transportation facilities during the 1975-2000 period.

The siting of power plants in California is governed by a complex set of rules and regulations. The primary regulatory responsibility for power plant siting rests with the California Energy Resource Conservation and Development Commission (CERCDC), established by the passage of the Warren-Alquist Energy Act of 1974. Although this Act has gone far to bring together the process of power plant siting under a single agency, it has not resulted in a one-step permit process. For example the authority of federal agencies to issue separate permits according to their responsibilities is recognized.

The siting procedure administered by the Commission is a three-year, two-stage process. The first stage begins with the utility's submission of a Notice of Intent (NOI). The 18-month NOI process allows for public notice and participation and ascertains the need for a generic-type plant and its environmental impacts for several alternative sites. If the NOI is approved, the utility can file an Application of Certification (AFC), which ascertains how well a specific plant design situated on a particular site will conform to the appropriate standards.

The approval of the AFC authorizes plant construction and operation.

During this three-year procedure the Commission will consider the rules and regulations of other state agencies such as the Coastal Commission, the Air Resources Board, the Water Resources Control Board, the State Lands Commission and local agencies. To what extent the Commission can or will abide by the regulations promulgated by these agencies is still unclear since no power plant has yet been sited under the new Act. However, the Act has effectively consolidated the siting procedure and greatly reduced the discretionary authority of the many state and local agencies that formerly held independent site approval authority.

To permit detailed analysis of impacts on water resources, air quality and health and safety aspects, site regions were selected to accommodate the power plants specified in the four NCUA scenarios for California. The area of the regions was determined by the type of impacts analyzed. For example, since water resources impacts were analyzed at the aggregated subarea (ASA) level, locations of all power plants were specified by ASA regions. Each ASA region is an aggregation of counties. On the other hand, for air quality and health impacts analysis the coal-fired power plant sites were designated at a more specific (sub county) level.

The siting analysis for this assessment utilized an exclusionary siting methodology in which areas of California were eliminated from consideration as potential power plant sites on the basis of selected criteria. The exclusionary criteria were:

1) air quality maintenance areas (AOMA's)
2) zone III earthquake intensity areas
3) areas with significant biological resources
4) urbanized areas as defined in the 1970 census and projected urbanized areas of 1990
5) prime agricultural lands and agricultural preserves
6) coastal areas
7) special state and federal lands

These exclusionary criteria eliminated substantial portions of California; secondary criteria were then applied to evaluate the remaining areas. These secondary criteria are of two types. The first, called avoidance criteria, took into account those features or alternatives which would not necessarily prevent power plant construction but which nevertheless represent some additional constraint or added costs. For example, flood-prone areas were avoided although power plants can be designed to withstand floods. Second, certain opportunities exist which make some areas more desirable than others for power plant sites, such as proximity to rail transportation or transmission lines. These are referred to as opportunity criteria. These criteria, both exclusionary and secondary, are listed in Section 8. The majority of the exclusionary criteria were mapped on transparent overlays, which resulted in a map of permissible areas for coal power plant locations within which site areas could be selected by application of secondary criteria.

Based on these criteria an 800 MWe coal power plant stipulated in all four 1985 California scenarios was sited in ASA 1802 in Tehama County (North Central California). For the year 2000 an additional 800 MWe unit was added at the same site along with six other 800 MWe units, two at each of three sites in Southeastern California. For the water resource impact analysis all water-consuming power plants were sited by ASA regions.

Fresh water requirements for power plants in 1975 were small, (32,000 acre-ft), since most of the power plants were located near the coast and used sea water for cooling. By 2000, however, the fresh water requirements for the new, inland power plants specified in the California scenarios will be as high as 400,000 acre-ft per year. Comparisons of projected water demands with developed supplies have indicated that fresh water shortages will occur in many areas by 2000. The 400,000 acre-ft per year demand for power plants will then pose an additional burden on developed supplies.

By the year 2000 statewide water requirements for scenarios 1 and 2, the Recent Trends and Accelerated Synfuels scenarios, are 25 percent larger than requirements for scenarios 3 and 4, the High Coal Electric and High Coal Electric and Accelerated Synfuels scenarios. This difference is due to the expanded use of less efficient nuclear capacity in scenarios 1 and 2, and the out-of-state siting of some of the coal capacity in scenarios 3 and 4.

The inland siting of most of these nuclear power plants in Central California (ASA 1802), a water-deficient region with groundwater overdraft, poses a serious freshwater availability problem. Supplies of cooling water will therefore have to come from agricultural waste waters or from water transfers from other users. Similarly, water for coal power plants in the southeastern desert region (ASA 1806) will have to come from uncertain groundwater sources or from agricultural waste waters or from transfer of water from other users.

Air quality impacts due to coal combustion in the 800 MWe coal power plant in North Central California were investigated. Coal used in the power plant was assumed to have a heat content of 12,000 Btu per lb, a sulfur content of one percent, and an ash content of ten percent. The power plant was assumed to have scrubbers and precipitators as pollution control equipment. The pollutant concentrations were estimated using a short-range (50-60 Km) Gaussian Plume Model with first order chemistry and a flat surface with choice of surface cover types for deposition. Due to data limitations, climatological data for Sacramento, California was assumed to approximate the weather conditions at the Southern Tehama County site.

The model indicates that the levels of major pollutants, particulates (TSP), SO_2, NO_x produced solely by the power plant are lower than the annual average federal or state Ambient Air Quality Standards for all three pollutants. These pollutants also fall below the short term 1-hour, 3-hour, and 24-hour standards, with the only exception being the 24-hour TSP standard. The plant emissions exceed this standard by 50 percent. Moreover, TSP and NO_x concentrations have been fairly high in the surrounding communities with TSP levels having exceeded the primary TSP standard by a factor of 2. Power plant emissions will add to this ambient background pollutants, thus further aggravating the TSP pollutant problem.

Health and safety impacts resulting from this air pollution and from the mining, processing and transportation of coal were estimated from data and information contained in the Brookhaven National Laboratory's "Handbook for the Quantitation of Health Effects". Sulfates and TSP are the only two major pollutants for which we have adequate quantitative data on health impacts. For this preliminary assessment we estimated the effects of sulfates on mortality rates. It was assumed that the power plant will be sited so that the population within ten kilometers from the plant will be small and hence the effects of the high concentrations of TSP close to the source can be neglected.

The areal distribution of annual average sulfate concentration levels at ground level was estimated by using the air pollution model. This was superimposed on a map of the region to estimate the population distribution exposed to each sulfate concentration level. The product (mean sulfate concentration x population at risk) coupled with a linear dose response relationship provided an estimate of the mortality rate associated with sulfate pollutants. For the 800 MWe coal-fired power plant sited in Tehama County, the rate was estimated as 0.3 fatalities per year. It should be emphasized that this figure has large uncertainties associated with it, and at this stage should not be used for drawing quantitative conclusions.

The mining health effects and accidents were assumed to be proportional to the amount of coal mined, whereas transportation accidents were assumed to be proportional to the trip-miles incurred. The expected annual fatalities for mining range from 1 to 4.8, while for transportation the estimate is three fatalities per year. Most of the transportation fatalities result from accidents between trains and motor vehicles occurring at rail-highway crossings.

2. REGIONAL ENERGY TRENDS

The State of California consumes more energy than is produced indigenously. Historically, most of this energy has been provided by fossil fuels--namely oil and natural gas. In-state supplies of these resources are diminishing; in fact, California has not been 'self-sufficient' in terms of energy supply-demand balances of these two fuels since the late 1940's or early 1950's.

The supply-demand balance for the major energy types is presented in Tables 2-1 through 2-5. Data for the years 1960, 1965, 1970, and 1975 are shown to illustrate the regional trends and shifts in fuel use.

Crude oil supplies and product sales are shown in Table 2-1. In-state crude oil production peaked about 1969[5], and California is presently experiencing declining on-shore production. In contrast, demand for oil has continued to increase, although the growth rate has slowed in the last five years. The growth in consumption has occurred in two main categories, transportation fuels (which in 1975 accounted for more than 25 percent of the total energy use in this state) and in the past five years, residual fuel oil. The use of residual fuel oil has increased due mainly to the decline in availability of natural gas for utility boiler fuel. Most utilities in the state expect that natural gas will be completely unavailable for electricity generation after 1980.

Natural gas supply and end use consumption trends are shown in Table 2-2. The in-state production trend is similar to that of oil; production peaked in 1968[5], and has declined since, to a level almost 50 percent lower. Canadian supplies have taken up part of this decrease, with the remainder supplied by sources in the southwestern United States. The total supply available to California dropped between 1970 and 1975. As a consequence, industrial and electric utility consumption dropped in 1975. Electric utilities are lowest on the prioity list for gas and have begun to use residual fuel oil.

In 1960, the two major sources for electrical energy for California were natural gas-fired generation and hydroelectric generation, as shown in Table 2-3. Hydroelectricity increased over the fifteen-year period

Table 2-1

California Petroleum Supply and Sales[a]

	1960[b]	1965[b]	1970[b]	1975[c]
Crude Oil Sources—in 10^6 barrels/yr, (10^{12} Btu/yr)				
California	300 (1740)	313 (1814)	379 (2197)	296 (1717)
Other States	17 (97)	25 (144)	74 (432)	60 (348)
Foreign Imports	64 (373)	74 (428)	55 (322)	189 (1096)
Total	381 (2210)	412 (2386)	508 (2951)	545 (3161)
Oil Sales—in 10^{12} Btu/yr				
Gasoline	752	934	1153	1244
Jet Fuel	137	275	411	351
Distillate	163	214	236	292
Residual	500	431	421	809
Other	411	459	560	336
Total	1963	2313	2781	3032

[a]The difference between the supply and sales is mainly due to refinery and transport losses, and miscellaneous product imports and sales.

[b]Ref. 1.

[c]Ref. 2.

Table 2-2

California Natural Gas Supply[a] and Sales[b]

	1960	1965	1970	1975
Source—Marketed Production—in $10^9 ft^3$ (10^{12} Btu)				
California	515	644	642	368[c]
Imports				
Canadian	0	151	294	365[d]
Southwestern U.S.	838	1004	1262	1159[d]
Total	1353 (1454)	1799 (1934)	2198 (2363)	1892 (1987)
End Use—in 10^{12} Btu				
Residential	394	526	594	664
Commercial	117	176	226	205
Industrial	342	412	615	557
Electrical Generation	348	530	684	295
Miscellaneous	264	278	230	235
Total	1465	1922	2349	1956

[a]Supply figures are from Ref. 3 for 1960, 1965, and 1970 periods and are converted to energy content using 1075 Btu/ft^3 (Ref. 1).

[b]End-use data are from Ref. 1 for 1960, 1965 and 1970 and from Ref. 2 and Ref. 4 for 1975.

[c]Ref. 5; includes production from federal OCS land off California.

[d]Ref. 2. The conversion to Btu assumes 1050 Btu/ft^3 (also from Ref. 2).

[e]This category includes production and processing use, transportation, chemical feedstocks and other miscellaneous uses.

[f]The slight mismatch of total supply and demand is due to rounding errors, and to different data sources.

Table 2-3

Electrical Energy Generation and Sales for California (10^9 kWh)

	1960[a]	1965[a]	1970[a]	1975[b]
Generation				
Hydroelectric	17.4	30.5	37.9	40.7
Natural Gas	31.7	51.6	67.4	27.3
Fuel Oil	14.6	10.4	13.0	48.3
Geothermal	0	0.3	0.6	3.2
Nuclear	0	0.3	3.1	6.1
Total (in-state)	63.7	93.1	122.0	125.6
Transfers	—	1.9	9.3	23.8
Coal (out-of-state)	—	—	3.7	10.7
Total Generation	63.7	95.0	135.0	160.1
Sales (end use)				
Residential	19.8	23.0	34.6	43.5
Commercial	14.0	30.0	48.3	40.9
Industrial	22.1	29.7	39.1	44.8
Other	0.3	0.4	1.1	16.2
Total Sales[c]	56.2	83.1	123.1	145.4

[a] Data from Ref. 1.

[b] Data from Ref. 2.

[c] The difference between generation and sales is predominantly due to transmi-sion losses.

1960 through 1975, while natural gas use peaked in 1970, then declined by nearly 60 percent in the last five years. As we noted earlier, this decline has been made up primarily by residual fuel oil. During this period both geothermal and nuclear power plants were constructed and placed in operation in California. However, by 1962 it was necessary for California to import electrical energy and power from out-of-state sources, primarily from the Bonneville Power Administration in the Pacific Northwest. By 1970, imported electrical energy accounted for 10 percent of the supply, most of which came from Bonneville Power Administration, (shown as 'Transfers' in Table 2-3) and the remainder from coal-fired facilities partially owned by two Southern California utilities. In 1975, the fraction of imported electrical energy was 22 percent of the total supply.

Electricity consumption increased about 7.5 to 8 percent per year from 1960 to 1970, and at a growth rate about half that between 1970 and 1975. The largest growth in consumption occurred in the commercial sector. These end-use data are also shown in Table 2-3.

Two other fuels contribute to California energy supply, Liquified Petroleum Gas (LPG) and Coal, as shown in Table 2-4. LPG production and consumption has grown about 3 percent per year, although for 1975 the supply level shown may be an underestimate, since refinery production of LPG apparently has not been included. Coal supply has been nearly constant for the past 15 years. The coal imported into California has been mainly high Btu, low sulfur metallurgical grade coal for coking use in steel making.[6] More recently, there has been some coal used as fuel for cement making. Another source, not shown in the tables is wood, which between 1960 and 1970 (the last year for which we have data) produced between 15 and 18 x 10^{12} Btu per year.[1]

Total primary energy supply to California is summarized in Table 2-5. Petroleum and natural gas predominate during the past fifteen years. Electrical energy conversion has increased its consumption of fossil fuels during this time period. California has grown increasingly reliant upon imported energy. In 1960 63 percent of the total energy supply came from in-state resources. By 1975 this had dropped to 42 percent.

The historical data on energy supply and demand for California

Table 2-4

Miscellaneous Energy Sources and Uses

	1960	1965	1970	1975
LPG—Supply[a]	42	49	66	69[b]
LPG—Uses[a]				
Residential, Commercial	18	24	25	c
Industrial	5	1	7	c
Transportation	4	3	3	c
Miscellaneous	15	21	31	c
Coal—Supply[d]	52	57	56	55[e]
Coal—Uses	The predominant use is coking coal for steel production.[a,d] Since 1970, a small amount has been used for fuel in cement plants.			

[a]Ref. 1 for 1960, 1965, 1970.

[b]Ref. 2.

[c]Data incomplete.

[d]Ref. 6.

[e]Lawrence Berkeley Laboratory estimate based on past trend and an evaluation of end-uses.

Table 2-5
Primary Energy Supply to California (10^{12} Btu)

	1960	1965	1970	1975
Petroleum	2210	2386	2951	3161
Natural Gas	1454	1934	2363	1987
Hydroelectric[a]				
In-state	174	305	379	407
Transfers	0	19	93	238
Geothermal[a]	0	3	6	32
Nuclear[a]	0	3	31	61
LPG	42	49	66	69
Coal				
Non-electric	52	57	56	55
Electric Gen.	0	0	37	107
Total	3932	4756	5982	6117
Resource Use:				
Total In-state	2468	2814	3272	2542
Percent In-state	63	59	55	42
Percent Natural Gas	37	41	40	32
Percent Petroleum	56	50	49	52

[a]Converted to primary energy equivalent using 10,000 Btu/kWh.

rely upon two main sources.[1,2] However, one should note that other sources we have consulted do not agree precisely in some of the details. We have attempted to resolve some of these differences, as shown by the values in our tables. For 1975, there are also differences between values listed here and those that appear in the section on scenarios. Again, part of the disagreement is due to different accounting assumptions in the various data sources. In this section we have converted non-fossil fuel sources of electrical energy into fossil-fuel equivalent energy inputs, using 10,000 Btu per kWh. Arguably, this conversion may be misleading, since it understates the thermal requirements for geothermal production of electrical energy (15 percent efficient) and overstates the thermal equivalent of stored water (90 percent efficient). We point these problems out as caveats to the reader.

We have not endeavored here to show projections of future energy supply and demand. Reference 3 contains a synopsis of oil, natural gas, uranium and thorium reserves and expected depletions. Neither oil nor gas supplies in California are expected to show major production increases, hence continued dependence on imports of these fuels is likely for the near future. Large quantities of Alaskan oil are expected to be available on the West Coast by 1978. Although the ultimate transportation route and disposition of this oil are unclear, part of this oil may be used to offset the in-state supply deficit.

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3. SCENARIOS

Scenarios for California were disaggregated from the four Pacific Region scenarios developed by Brookhaven National Laboratory. The Pacific Region includes the states of Alaska, Hawaii, Washington, Oregon and California. These scenarios form a part of the scenarios developed by BNL for each census region in the U.S. Each scenario includes detailed demand and supply figures for 1975, 1985, 2000 and 2020 for five major sources of energy: 1) coal; 2) natural gas; 3) petroleum; 4) electricity and 5) solar and geothermal. The supply scenarios for the Pacific Region were designed to meet the demand projected by detailed categories in the demand scenarios. A second set of scenarios based in part on the results in this report will be formulated at a later date.

Since the main objective of the NCUA is to analyze impacts due to implementation of the various supply options, especially coal, only the supply scenarios for the Pacific Region have been disaggregated to California. Analysis of scenarios for Alaska, Oregon, Hawaii and Washington was conducted at Pacific Northwest Laboratory, Richland, Washington.

Four California Energy Supply Scenarios were constructed to reflect a set of alternative fuel mixes for energy supply to California. The total energy supplied to California remains relatively unchanged among each of the four scenarios as does the quantity of energy available from electricity, petroleum, natural gas, solar and geothermal sources; however, each scenario emphasizes a different amount of coal use. The first scenario assumes that recent trends in energy development will continue to dominate over the foreseeable future (to 2000); that is, there will be very little in-state coal use for California. The second and third scenarios emphasize development of coal conversion to liquid and gaseous fuels and coal-fired electricity generation, respectively, both in and out of state. The highest use of coal occurs in the fourth scenario where both coal-fired electricity generation and coal conversion to synthetic fuels is emphasized.

Projections for these scenarios were developed for each of the three years 1975, 1985 and 2000. A similar set of figures for 2020 will be forthcoming at a later date. In all four scenarios coal use in California is restricted to electricity generation and for process and industrial heating. Conversion of coal to synthetic fuels is not assumed to occur in California.

Our choice of growth rates or of energy supply projections for each of the three years was constrained by the energy projections made by Brookhaven National Laboratory in their Pacific Region Scenarios and by the projections made by PNL for the Pacific Northwest. Within these constraints and lacking a sophisticated model for projecting growth rates and fuel mixes, we resorted to a judgmental projection of the electricity supply growth rate. Growth rates for other forms of energy supply were determined by subtracting the PNL projections from the BNL Pacific Scenario projections.

Electricity supply until 1985 in each scenario grows at 3.6 percent per annum. This rate may be compared with the 3.4 percent per annum growth in electricity demand forecasted until 1995 by the CERCDC. Electricity growth rate figures between 1985 and 2000 are far more uncertain. It is generally expected that California's population growth rate will continue to decline over the next few decades. Electricity supply growth would therefore be expected to decrease between 1985 and 2000 unless electricity were used to substitute for other forms of energy or the per capita consumption were to increase for other reasons. We assumed that electricity supply between 1985 and 2000 would grow at 2.2 percent per annum.

The electricity supply fuel mix and the consequent power plant schedules generally follow the utility siting proposals as submitted to the CERCDC,[1] but at our assumed slower growth rates (see Tables 3.1 through 3.4). The major exception is the degree of coal utilization in each scenario. To enable a broad assessment of impacts due to coal utilization we assumed a relatively broad range for the coal-fired electric capacity to be located in California. By the year 2000 this ranges from one power plant in the 1) recent trends and 2) accelerated synfuels scenario, to eight power plants in the 3) high coal-electric and 4) high coal-electric

Table 3.1

Electricity Supply
(10^{15} Btu)

	Scenarios		
	1) Recent Trends	2) Accelerated Synfuels	
	1975[b]	1985	2000
Coal	.036[a]	.036[a]+.018	.055[a]+.018
Oil: Conventional Turbines	.165	.315 .004	.306 .011
Gas	.093	0.0	0.0
Nuclear	.021	.143	.347
Geothermal	.014	.030	.062
Solar	0	.003	.025
Hydro[c] Pumped Storage	.219	.211 .009	.225 .012
Subtotal	.548	.769	1.061
Less Pump Losses	---	-.003	-.005
Electricity Generated	.548	.766	1.056
Distribution Losses	-.052	-.055	-.078
TOTAL SUPPLY/DEMAND	.496	.711	.978

[a]Designates out-of-state coal capacity located in the mountain states (Los Alamos Scientific Laboratory study region).

[b]Quarterly Fuel and Energy Summary, Vol. 1, No. 4, Fourth Quarter 1975, California Energy Resources Conservation and Development Commission.

[c]Includes interstate transfers from the Pacific Northwest.

Table 3.2

Electric Capacity
(MWe)

Type of Plant	Capacity Factor	Scenarios: (1) Recent Trends 1975[b]	(2) Accelerated Synfuels 1985	2000
Coal	.75	2276[a]	2276[a]+800	3120[a]+800
Oil: Conventional	.6	13635	21694	19194
Turbines	.1	1083	1416	3750
Combined Cycle	.6	24	1500	3500
Gas	.6	7726	0	0
Nuclear	.6	1379	8245	19545
Geothermal	.7	502	1502	2978
Solar	.4	0	250	2000
Hydroelectric	.5	7385	8518	9385
Pumped Storage	.1	1055	3000	4000
In-state Total		32789	46925	65152
Out-of-state Total		+ 2276[a]	+ 2276[a]	+ 3267[a]
TOTAL		35065	49201	68419

NOTE: Load factors were used to calculate capacity additions to existing 1975 capacity.

Capacity totals do not include hydroelectric capacity in Pacific Northwest which supplies some electricity to California.

[a]Designates out-of-state coal capacity located in the mountain states (Los Alamos Scientific Laboratory study region).

[b]Figures for 1975 are from Table 10, "Analysis of California Energy Industry," J.A. Sathaye, et al., LBL 5928, January 1977.

Table 3.3

Electricity Supply[a]
(10^{15} BTU)

SCENARIOS:	(3) Hi Coal Electric	(4) Hi Coal Electric and Accelerated SynFuels	
	1975	1985	2000
Coal	.036[b]	.036[b]+.018	.144[b] + .095
Nuclear	.021	.143	.158

[a]The fuel mix for these scenarios is identical to that for the Recent Trends scenario except for changes in the coal and nuclear capacity projections.

[b]Designates out-of-state coal capacity located in the mountain states (Los Alamos Scientific Laboratory study region).

Table 3.4

Electric Capacity
(MWe)

SCENARIOS:[a]	(3) Hi Coal Electric	(4) Hi Coal Electric and Accelerated SynFuels		
Type of Plant	Capacity Factor	1975	1985	2000
Coal	.75	2276[b]	2276[b]+800	4243[b]+6400
Nuclear	.6	1379	8245	9045

NOTE: Load factors were used to calculate capacity additions to 1975 capacity.

[a]The fuel mix for these scenarios is the same as that in the Recent Trends scenario except for changes in coal and nuclear capacity projections.

[b]Designates out-of-state coal capacity located in mountain states (Los Alamos Scientific Laboratory study region).

and accelerated synfuel scenarios. The increase in coal plants in scenarios 3 and 4 is balanced by a decrease in nuclear plants in these scenarios. The following paragraphs briefly describe the considerations used in developing the fuel mix.

Over the past few decades California has mainly relied on hydroelectric and oil- and gas-fired power plants for electricity supply. Most of the economical hydroelectric sites have already been developed while development of some of the major remaining sites is precluded by the California Wild and Scenic Rivers Act. Potential for future development at most of these sites is therefore small. As a result hydroelectric capacity in the scenarios increases by only 2000 MWe. Construction of new conventional oil-fired power plants is not likely due to the uncertain nature of both fuel oil and natural gas supplies. Use of natural gas is already restricted and will be phased out by 1980. However, to a limited extent utilities do plan to construct combustion turbines and combined cycle power plants. These would use distillate oil as fuel. Combustion turbines would serve as peaking units while the more efficient combined cycle units would serve to meet intermediate base loads. The scenarios reflect these changes in scheduling of oil-fired units.

Vapor-dominated geothermal resources are currently utilized to generate electricity to a limited extent (500 MWe). Future development of this resource along with hot water-dominated geothermal resources is under active investigation. Extensive development of hot water-dominated sources in the Imperial Valley and the eastern Sierra could provide up to 15,000 MWe[2] of power by 2020. Our scenarios include 3,000 MWe by the year 2000.

Nuclear energy, a potential major source of energy, still has all the well-known problems of nuclear waste disposal, accident risk, safety hazards, etc. The high side estimate for this resource in two of the scenarios assumes that these problems can be surmounted and that nuclear power can serve as an alternative to coal-fired generation.

The last resource category in the scenarios includes solar power plants. A demonstration plant is presently authorized for development in California by ERDA and several in-state utilities. Further development of this resource is likely. The projections used in the scenarios are the BNL figures for the Pacific Region.

Energy supply projections other than electricity, in the scenarios include projections of petroleum, natural gas, coal, and geothermal and solar heating (see Tables 3.5 through 3.8). Figures for California fuel supply for all of these scenarios were obtained by subtracting the projections made by PNL for the rest of the Pacific states from the BNL Pacific Region fuel supply figures. Petroleum supplies include the expected supplies from Alaska. These scenarios also assume that part of the Alaskan crude oil coming into California will be exported to other states while refined petroleum from other states would be imported into California. The scenarios assume increased supplies of gas from Alaska, and from foreign countries, while phasing out Canadian supplies. Accelerated synfuels scenarios also assume increased SNG supplies to California. Coal use for industrial and process heating is also assumed to increase more than two-fold by the year 2000. Solar and geothermal heating is assumed to share an increasing fraction of space, water and process heating.

Total natural gas supply figures for 1985 and 2000 in the California scenarios fall between the low-production and the medium-production scenarios in Energy Alternatives for California: Paths for the Future by the Rand Corporation,[3] whereas the refined oil figures fall between the medium and high-use scenarios in the same report (pp. 36-38).

Table 3.5

Total Petroleum Supply to California
(10^{15} Btu)

	All Scenarios		
	1975[a]	1985	2000
Crude Oil Supply			
California Production	1.778	3.269	2.100
Alaska	0.255	4.319	4.970
Imports - Foreign	1.109	.294	.379
Exports - Regional	0	-3.674	-3.093
Imports - Regional	0.435	0	0
Refinery Inputs	3.577	4.208	4.356
Less Processing Energy Use	-0.158	- .412	- .392
Refined Products	3.419	3.796	3.964
Exports - Regional	0.533	0	0
Imports - Regional	0	.414	1.422
Imports - Foreign	0	0	0
TOTAL SUPPLY/DEMAND	2.886	4.210	5.386

[a]Figures based on refinery data from Quarterly Fuel and Energy Summary, Vol. 1, No. 4, Fourth Quarter 1975, Tables, M,N,O and P.

Table 3.6

Geothermal and Solar Energy Supply (Non-electric)
(10^{15} Btu)

	All Scenarios		
	1975	1985	2000
Geothermal Industrial Process Heat	0	.018	.099
Solar Residential			
Space Heat	0	.007	.099
Water Heat	0	0	.045
Solar Commercial			
Space Heat	0	0	.049
Solar Industrial Process Heat	0	0	.120
TOTAL	0	.025	.412

Table 3.7

Natural Gas Supply
(10^{15} Btu)

	1975[a]	1985		2000		
		(1)Recent Trends (3)Hi Coal Elec.	(2)Acc. Syn (4)Acc. Syn + Hi Coal Elec.	(1)Recent Trends (3)Hi Coal Elec.	(2)Acc.Syn	(4)Acc.Syn + Hi Coal Elec.
Alaska	0	.833	.835	1.112	1.114	1.114
California Production	.378	.209	.209	.157	.146	.152
Biomass	0	0	0	0	0	0
Canadian Imports	.376	.328	.328	0	0	0
LNG Imports	0	.260	.150	.865	.150	.156
Total Gas-Unprocessed	.754	1.630	1.522	2.134	1.410	1.422
Less Processing Energy Use	-.165	-.150	-.142	-.191	-.127	-.128
Total Gas Processed	.689	1.480	1.380	1.943	1.283	1.294
Total Gas Available	.689	1.480	1.380	1.943	1.283	1.294
Regional Exports				.106		
Regional Imports	1.196	.452	.552		.554	.543
Total	1.885	1.932	1.932	1.837	1.837	1.837
Demand	1.885	1.872	1.872	1.778	1.778	1.778
Pipeline Usage		.060	.060	.059	.059	.059

[a]Figures are from Table 8, Analysis of California Energy Industry, J.A. Sathaye et al., LBL-5928, January, 1977.

Table 3.8

Coal Demand[a] (Non-Electric)
(10^{15} Btu)

Coal Demand	1975	1985 Recent Trends/ Hi Coal Electric	1985 Accel. Synfuels/ Accel. Synfuels & Hi Coal Electric	2000 Recent Trends/ Hi Coal Electric/ Accel. Synfuels	2000 Accel. Synfuels Hi Coal Electric
Residential	0	0	0	0	0
Commercial	0	0	0	0	0
Industrial					
Iron	.043	.070	.070	.107	.107
Process Heat	.008	.011	.011	.019	.017
TOTAL	.051	.081	.081	.126	.124

[a] Coal supply to meet the total demand for each year is assumed to come from other NCUA regions.

REFERENCES

1. Supply Forecast by Utility Service Area, submitted to the California Energy Resources Conservation and Development Commission, Docket No. 75-FOR-3, 1976.

2. U.S. Geological Survey, Assessment of Geothermal Resources of the United States - 1975, Circular 726, 1975.

3. William Ahern et al., Energy Alternatives for California: Paths to the Future, Rand Corporation, Report No. R-1793- CSA/RF, December 1975.

4. COAL TECHNOLOGY CHARACTERIZATION

In this section we discuss the characteristics of the coal-fired power plants that may be operating in California and the properties of the coal that may be burned in them. This work is based, in part, on data developed by the NCUA Technology Characterization work group. Construction and operation requirements were taken from the Energy Supply Planning Model (ESPM) developed by the Bechtel Corporation.[1] Data on residuals from facilities which do not utilize coal are derived from the MERES data base[2] and from reports by Teknekron, Inc.[3,4] These were augmented by data on specific facilities and residuals from a variety of sources.

COAL CHARACTERISTICS

The coal to be burned in California to generate electricity is expected to come primarily from deep mines in Utah. At least one California utility has already acquired the rights to coal reserves near Price, Utah. A second source is coal from New Mexico. Although this coal is of lower quality than Utah coal, it may be cheaper to transport it to power plants in the southern California desert. A third possibility is coal from southern Alaska. This would require constructing a coal handling facility in the California Coastal Zone. Regulatory constraints and transshipment costs make this possibility less likely.

Coal from Utah can be shipped into northern California along the main line of the Western Pacific and Southern Pacific Railroads and into southern California along the Union Pacific and Santa Fe Railroads. The distances involved are 500-600 miles. Since little else is shipped between these origins and destinations, the coal will be transported on unit trains. The volume of coal involved does not appear to be large enough to make a coal slurry pipeline economically feasible. Another factor that argues against the use of a pipeline is the scarcity of water in the mountain states.

Utah coal is typically medium to high volatile bituminous, whereas New Mexico coal is primarily sub-bituminous. An assessment of the coal reserve base for the southern Rocky Mountain region,[5] weighted by the mean heat content of each type of coal, gives an average heat content of 12,500 Btu/lb. This analysis also yields an average value of 9.1 percent for the ash content and 0.7 percent for the sulfur content for coal in this region. These data are corroborated by a recent U.S. Geological Survey study of remaining identified coal resources from which one obtains an average heat content of 12,000 Btu/lb where both reserves and inferred resources have been included.[6] For this preliminary analysis we have chosen "typical" coal as having a heat content of 12,000 Btu/lb with 10 percent ash and one percent sulfur content.

COAL-FIRED POWER PLANTS

The first coal-fired power plants to operate in California will use conventional combustion technology. The boiler will be of dry bottom design using pulverized coal. Atmospheric fluidized bed (AFB) combustion plants will come on-line in the 1990's. The conventional plants are expected to be equipped with flue gas desulfurization (scrubbers) to meet the strict California air quality standards. We have assumed that both types of plants will use wet cooling towers.

Our calculations of residuals and construction and operations requirements are based on an 800 MWe nominal facility operating at a capacity factor of 75 percent. SO_2 emissions are calculated assuming 100 percent of the sulfur passes into the scrubber, which operates at 90 percent removal efficiency. (For the AFB plants, we assume that 90 percent of the sulfur will remain in the limestone bed.) A 99 percent efficiency for particulate removal in conventional plants is used. This efficiency is not known for AFB plants, so the recommended emission estimate of 0.1 $lb/10^6$ Btu is used. Since NO_x reduction technology is not commercially available, we have assumed the conventional plants meet the EPA New Source Performance Standards of 0.70 $lb/10^6$ Btu. NO_x emissions from fluidized bed power plants are expected to be lower than from conventional plants because they operate at lower temperatures. We used a NO_x emissions coefficient of 0.48 $lb/10^6$ Btu for AFB power plants. Solid wastes from both types of plants will be comprised of bottom ash, spent limestone and water treatment sludge. Out estimates of residuals from these nominal facilities are presented in Table 4.1.

To obtain data on costs, manpower and materials required for construction and operation of conventional coal-fired power plants, we combined the data for two ESPM facilities: Coal-Fired Power Plant Low-Btu and Sulfur Oxide Removal. No similar breakdown of requirements is available for fluidized bed combustion. In fact, we were unable to obtain overall cost estimates for an AFB power plant. To be economically competitive, this cost should not differ substantially from the cost of a conventional plant; however, a detailed cost breakdown would show significant differences. Because of the lack of data, for this preliminary analysis we used the same data for both types of power plants. The construction and operation requirements are summarized in Table 4.2.

Table 4.1

Characteristics of Coal-Fired Power Plants

	Conventional Combustion	Atmospheric Fluidized Bed
Capacity (MWe)	800	800
Capacity Factor (percent)	75	75
Heat Rate (Btu/kWh)	9500	9550
Efficiency	0.359	0.357
Energy Input (10^{12} Btu/yr)	50.0	50.2
Coal Input (10^{6} tons/yr)	2.08	2.09
Heat Rejected (10^{12} Btu/yr)	32	32.3
Water Evaporated (ac-ft/yr)	9650	9730
Make-up Water (ac-ft/yr)	10859	10930
SO_2 Emission (10^{3} tons/yr)	4.14	4.18
NO_x Emission (10^{3} tons/yr)	17.5[a]	12.0
Particulates (10^{3} tons/yr)	1.76	2.5
Solid Waste (10^{3} tons/yr)	600	450[b]

[a] Based on EPA New Source Performance Standards

[b] Assuming no sorbent regeneration

Table 4.2

Construction and Operating Requirements for Coal-Fired Power Plants

Construction Manpower (man-years)	
Technical	708
Non-Technical (non-manual)	292
Craftsmen	2662
Teamsters and Laborers	348
TOTAL	4010
Construction Materials (10^3 tons)	
Cement and Concrete	171.6
Iron and Steel	12.8
Pipe and Tubing	4.0
Petroleum Products	22.5
Construction Costs (10^6 dollars)	
Materials	36.0
Equipment	133.0
Labor and Other	171.0
TOTAL	340.0
Operating Manpower (man-years)	
Technical	35.0
Non-Technical (non-manual)	16.0
Craftsmen	112.0
Teamsters and Laborers	32.0
TOTAL	195.0
Operating Costs* (10^6 dollars)	
Materials and Supplies	2.83
Equipment	1.44
Utilities	3.19

* Does not include fuel and labor costs.

REFERENCES

1. Bechtel Corporation, San Francisco, CA, The Energy Supply Planning Model, Vols. I and II, report submitted to NSF under contract no. NSF-C867 , August 1975.

2. U.S. Council on Environmental Quality, MERES and the Evaluation of Energy Alternatives, May 1975.

3. Teknekron, Inc., Berkeley, CA, Comprehensive Standards: The Power Generation Case, EPA No. 68-01-0561, March 1975.

4. ________, Polutant Releases, Resource Requirements, Costs and Efficiencies of Selected New Energy Technologies, December 1975.

5. U.S. Federal Energy Administration, Coal, Final Task Force Report Project Independence Blueprint, p. 111, November 1974.

6. Averitt, Paul, Coal Resources of the United States, January 1, 1974, USGS Bulletin 1412, 1975.

5. ECONOMIC IMPACTS

INTRODUCTION

An analysis of the statewide economic impacts of increased coal use in California based on the NCUA Recent Trends scenario has been performed for the years 1976 to 2000. We have examined both the direct and indirect impacts on employment and income due to construction and operation of power plants and other energy and transportation facilities. Direct impacts include all impacts arising directly out of the construction and operation of any facility. Indirect impacts include impacts due to other activities required for the construction and operation of that facility. For example, the manpower required to construct a power plant would be a direct requirement, whereas the manpower required to make steel used in constructing the power plant would be an indirect requirement.

The impacts were calculated using two models developed at LBL. The direct impacts come from the California Energy Supply Model (CESM) which was derived from the Bechtel-NSF Energy Supply Planning Model.[1] The output of the CESM includes annual estimates of the manpower and materials needed to construct and operate each of the energy facilities called for by the scenario. The direct materials requirements for construction are converted into an incremental final demand vector for an interindustry transactions model of the California economy. This input-output model is used to estimate indirect changes in income in the state. Based on these income changes, the employment impacts are estimated using employment coefficients developed at LBL.[2] The operating schedule for energy facilities produced by the CESM is used to calculate the residuals associated with their operation. These models are described in more detail in Appendix A.

RESULTS

In this section we examine the resource requirements called for by the Recent Trends scenario. The results have been calculated on a yearly basis and then aggregated to five-year intervals. They are presented for the five-year periods running from 1976 through 2000 in Tables 5-1 to 5-4. Requirements for the period after 2000 have not been calculated because the scenario has not been specified past this date. Capital and operating costs are expressed in constant 1974 dollars.*

Construction Requirements

Our results on capital requirements represent capital outlays within California for constructing new facilities. The scenario assumes that although California's need for energy will continue to grow, albeit at a diminishing rate of growth, a decreasing fraction of the energy will come from in-state sources. In-state capital requirements will therefore decrease over time. Furthermore, these requirements show an irregular behavior since many of the energy facilities are constructed in large, discrete units and are typically built several years in anticipation of demand.

In this scenario construction of offshore oil wells requires major capital outlays over the first two five-year periods. There are also expenditures during this time for importing oil and gas, including LNG tankers, and expenditures for refineries and for a coal-fired power plant. These facilities, plus the solar and nuclear power plants that will be added at a constant rate, will satisfy

* It should be noted that the construction data include resources required for engineering, design, procurement, construction and start-up for each energy facility. There are other costs, mainly "owners' costs" which are highly variable and difficult to estimate. These are not included in our results. Owners' costs typically include project feasibility studies, site evaluation, studies required for site and project approval by government agencies, interest during construction, and land costs. Owners' costs average 25 to 30 percent of construction costs incurred by the builders for many major energy facilities. They are higher for energy extraction facilities, on the order of 40 to 60 percent.

Table 5-1

Construction Costs
(millions of 1974 dollars)

ENERGY FACILITIES	1976-80	1981-85	1986-90	1991-95	1996-2000
Offshore oil production	3612	2426	0	0	0
Low gasoline refinery	430	396	0	0	0
Onshore oil import	37	95	0	0	0
LNG import	59	693	88	0	59
LWR fuel fabrication	37	11	0	0	0
Oil-fired power plant	142	0	0	0	0
Coal-fired power plant	7	333	0	0	0
Combined cycle power plant	156	273	57	0	24
Light water reactor	1633	1624	1523	1592	1628
Solar power plant	0	520	624	624	598
Dam+hydroelectric power plant	269	271	22	239	252
Pumped storage	287	189	72	414	189
Geothermal power complex	455	157	174	666	0
Total Energy Facilities	7124	6987	2559	3534	2750
TRANSPORTATION FACILITIES					
Oil tanker	256	256	64	64	288
Oil tank truck	35	36	23	38	38
Products pipeline	28	31	16	0	0
Hot oil pipeline	28	23	13	0	0
Refined products bulk station	38	34	18	7	2
Railroad	11	39	15	20	47
Coal train	5	28	9	9	32
Gas distribution facilities	25	5	0	0	0
LNG tanker	0	1400	200	300	200
230 KVAC transmission line	0	149	222	0	190
345 KVAC transmission line	0	0	0	0	0
500 KVAC tranmission line	0	0	188	0	188
Electricity distribution	2040	2456	2111	2282	2139
Conventional rail	9	9	5	9	9
Total Transportation	2475	4466	2884	2730	3124
TOTAL	9599	11454	5443	6264	5884

Table 5-2

Construction Manpower
(man-years)

ENERGY FACILITIES	1976-80	1981-85	1986-90	1991-95	1996-2000
Offshore oil production	16870	11303	0	0	0
Low gasoline refinery	6849	6388	0	0	0
Onshore oil import	359	984	0	0	0
LNG import	645	8505	1215	0	645
LWR fuel fabrication	543	167	0	0	0
Oil-fired power plant	1877	0	0	0	0
Coal-fired power plant	50	3960	0	0	0
Combined cycle power plant	1690	2791	646	0	211
Light water reactor	21208	22427	20536	21704	22046
Solar power plant	0	2786	3344	3344	3204
Dam + hydroelectric power plant	4326	4054	381	3682	4157
Pumped storage	4272	2845	1008	6194	2845
Geothermal power complex	1944	635	777	2840	0
Total Energy Facilities	60633	66848	27907	37764	33108
TRANSPORTATION FACILITIES					
Oil tanker	0	0	0	0	0
Oil tank truck	0	0	0	0	0
Products pipeline	286	329	165	0	0
Hot oil pipeline	251	191	110	0	0
Refined products bulk station	348	312	161	63	27
Railroad	133	474	189	239	580
Coal train	0	0	0	0	0
Gas distribution facilities	305	91	0	0	0
LNG tanker	0	0	0	0	0
230 KVAC transmission line	0	2073	2876	0	2531
345 KVAC transmission line	0	0	0	0	0
500 KVAC transmission line	0	0	2372	0	2372
Electricity distribution	28355	34432	29333	32007	29830
Conventional rail	0	0	0	0	0
Total Transportation	29677	37903	35206	32308	35340
TOTAL	90311	104751	63113	70072	68447

Table 5-3

Operating Costs*
(millions of 1974 dollars)

ENERGY FACILITIES	1976-80	1981-85	1986-90	1991-95	1996-2000
Onshore oil production	772	698	631	572	556
Offshore oil production	145	344	388	327	245
Low gasoline refinery	3418	3819	4026	4073	4116
Onshore oil import	23	35	42	44	46
Onshore gas production	48	36	29	27	24
LNG import	0	11	55	69	82
LWR fuel fabrication	0	35	48	48	48
Oil-fired power plant	260	262	253	238	231
Coal-fired power plant	0	9	45	45	45
Combined cycle power plant	11	22	48	51	51
Gas turbine power plant	11	11	11	11	11
Light water reactor	87	159	275	373	471
Solar power plant	0	28	334	661	990
Dam+hydroelectric power plant	50	55	58	59	63
Pumped storage	4	8	9	11	17
Geothermal power complex	14	27	30	40	55
Total Energy Facilities	4843	5557	6282	6648	7051
TRANSPORTATION FACILITIES					
Crude oil pipeline	22	20	17	16	16
Oil tanker	137	250	302	318	338
Oil tank truck	99	113	121	126	129
Products pipeline	5	6	6	7	7
Hot oil pipeline	21	21	20	19	19
Refined products bulk station	6	7	7	8	8
Rail line	1	2	4	5	5
Coal train	10	20	37	42	46
Gas pipeline	106	94	83	78	78
Gas distribution facilities	305	273	240	227	227
LNG tanker	0	82	348	407	466
230 KVAC transmission line	1	1	1	2	2
500 KVAC tranmission line	1	1	1	1	1
Electricity distribution	392	464	539	611	693
Conventional rail	23	23	23	23	23
Total Transportation	1128	1376	1750	1889	2048
TOTAL	5971	6933	8032	8537	9098

*Excludes labor and power plant fuel costs.

Table 5-4

Operating Manpower
(man-years)

ENERGY FACILITIES	1976-80	1981-85	1986-90	1991-95	1996-2000
Onshore oil production	88960	80399	72707	65873	64017
Offshore oil production	6596	15687	17701	14935	11185
Low gasoline refinery	18930	21151	22295	22555	22795
Onshore oil import	1140	1746	2075	2182	2289
Onshore gas production	14387	10672	8730	7968	7206
LNG import	0	117	605	766	908
LWR fuel fabrication	0	508	705	705	705
Oil-fired power plant	11339	11428	11056	10400	10077
Coal-fired power plant	0	195	975	975	975
Combined cycle power plant	238	476	1059	1133	1129
Gas turbine power plant	277	277	277	277	277
Light water reactor	1700	3090	5353	7258	9175
Solar power plant	0	0	0	0	0
Dam+hydroelectric power plant	2249	2476	2632	2680	2841
Pumped storage	192	372	417	477	740
Geothermal power complex	1601	3028	3366	4435	6179
Total Energy Facilities	147608	151622	149951	142617	140498
TRANSPORTATION FACILITIES					
Crude oil pipeline	124	111	97	91	91
Oil tanker	3557	6489	7846	8273	8770
Oil tank truck	12358	14160	15226	15770	16167
Products pipeline	622	697	756	814	814
Hot oil pipeline	1536	1545	1487	1453	1453
Refined products bulk station	1543	1762	1903	1980	2018
Rail line	69	183	423	492	562
Coal train	367	683	1292	1469	1618
Gas pipeline	996	886	775	731	731
Gas distribution facilities	42544	38192	33593	31720	31720
LNG tanker	0	1634	6899	8079	9259
230 KVAC transmission line	126	131	188	209	217
500 KVAC transmission line	94	94	113	141	141
Electricity distribution	34538	40885	47489	53789	60089
Conventional rail	802	797	800	797	797
Total Transportation	99277	108247	118884	125807	134447
TOTAL	246885	259869	268835	268424	274945

California's energy needs up to 2000. Thus this scenario shows large capital requirements up to 1985 followed by a sharp drop between 1985 and 2000. We expect that delays in offshore oil production and improved specification of facilities coming on-line after 2000 will smooth out this distribution

The major construction of coal-fired power plant and related facilities occurs during 1981-85 (see Table 5-1). The capital cost for these facilities is relatively small, amounting to roughly $400 million out of a total cost of $11 billion for all facilities. If these costs are compared with the estimated $75 billion in Gross Private Capital formation in California in 1974, we see that constructing coal facilities will have only a small direct effect on the State's economy.

The construction manpower requirements are also at a high level during the first 10 years and then drop in the subsequent periods. At first about 20,000 man-years per year will be needed to construct the energy and transportation facilities, of which less than 900 man-years are coal-related. Since employment in the construction sector has been averaging just over 300,000 during the past decade, the impact of constructing a coal-fired power plant on construction employment in the state will be small.

Operation Requirements

The operating costs (excluding fuel and labor costs) for energy and transportation facilities show a steady increase with time as the energy demands increase. Major increases occur for operating nuclear and solar power plants and their associated transmission lines and for operating oil and LNG tankers. Offshore oil production peaks in the 1976-90 time period, whereas onshore production shows a steady decrease. The operating costs for the coal-fired power plant are less than one percent of the statewide total for energy facilities.

The operating manpower shows a somewhat different behavior. For energy facilities the requirement stays constant at about 30,000 man-years per year until 1990 and then drops off as oil production declines.

For transportation facilities, on the other hand, there is a steady increase in manpower required mainly due to increases in manpower for electricity distribution. The net effect is a slight increase of 10 percent from less than 50,000 man-years per year during the 1976-80 period to 55,000 man-years per year during 1995-2000. Over this period the manpower required for transporting and burning coal also increases from about 75 to over 500 man-years per year.

Indirect Impacts

To provide a more complete assessment of the effects of constructing new energy facilities on the California economy, we have used the direct construction capital requirements calculated with the Energy Supply Planning Model in an interindustry transactions model for the state. By doing this we are able to estimate the indirect impacts of construction expenditures on the various industrial sectors which make up the California economy. We present the results for employment and Gross State Product (GSP) aggregated to five-year intervals in Table 5-5. The value-added figures shown in this table represent payments to the various factors of production (wages, rents, interest and profits). As such they provide a measure of the economic services rendered by all factors of production in the economy of the state during that period. The total value-added figure is thus a way of quantifying the overall impact on economic activity in the state.

The indirect impacts generally show the same behavior as the direct impacts. During the 1981-85 period, the total contribution to GSP is about $1.7 billion per year and to employment is about 7,000 man-years per year. These represent about one percent of the GSP and non-agricultural employment in California during 1974. Over the twenty-five-year period up to 2000, the direct impacts become an increasing fraction of the total impacts. The increase in the ratio of direct to indirect impacts is a consequence of the fact that a larger fraction of the construction costs will be spend for direct labor rather than for materials which incorporate indirect labor. This indicates a shift away from capital-intensive to more labor-intensive energy facilities.

Table 5-5

Direct and Indirect Impacts on Employment and Value Added

	Value Added (10^6 1974 $)				
	1976-80	1981-85	1986-90	1991-95	1996-2000
Direct	2444	3840	2072	2323	2305
Indirect	4523	4729	2044	2403	2169
TOTAL	6964	8569	4116	4726	4474
Percent Direct	35%	45%	50%	49%	52%
	Employment (man-years)				
	1976-80	1981-85	1986-90	1991-95	1996-2000
Direct	90,000	105,000	63,000	70,000	68,000
Indirect	239,000	250,000	109,000	127,000	116,000
TOTAL	329,000	355,000	172,000	197,000	184,000
Percent Direct	27%	30%	37%	36%	37%

REFERENCES

1. Bechtel Corporation, San Francisco, CA, The Energy Supply Planning Model, Vols. I and II, report submitted to NSF under contract no. NSF-C867, August 1975.

2. Deane Merrill, U.S. Employment for 368 Input-Output Sectors for 1963, 1967, and 1977, Lawrence Berkeley Laboratory, UCID-3757, July 1975.

6. RESIDUALS

In this section we present and discuss the pollutant emissions (residuals) that will be discharged to the environment for the Recent Trends scenario. Included in these results are land requirements for energy facilities. The health and safety impacts are discussed in a separate section. While we estimate the emissions from plants in California needed to produce and distribute fuel and electricity, we do not estimate the emissions associated with the end uses of this energy.

The calculation of residuals starts with the operating schedule of facilities produced by the California Energy Supply Model. The operation of this model is described in Appendix A. This schedule contains the numbers of each type of facility that are operating annually in California for the period 1975 to 2000. These are multiplied by a set of residual coefficients for each type of facility to give the residuals emitted. The residual coefficients for the coal-fired power plants are discussed in the section of technology characterization. For other facilities the coefficients are derived primarily from the Matrix of Environmental Residuals for Energy Systems[1] and from reports by Teknekron.[2,3] A more complete discussion of the methodology for residuals calculation may be found in Ref. 4.

The residuals generated by the coal-fired power plant in our scenario are shown in Table 6-1 . The plant will be equipped with limestone scrubbers for flue gas desulfurization and with wet towers for cooling. It is assumed to operate at a constant capacity factor of 75 percent so these residuals stay constant from 1985 to 2020. The water pollutants are mainly due to boiler blowdown, whereas the solid waste is comprised of bottom ash and spent limestone from the scrubbers.

Although the amount of coal burned for generating electricity stays constant, there will be an increase in the use of coal for other industrial purposes. This results in an increase in residuals due to the transportation of coal by unit or conventional train.

The residuals for all energy and transportation facilities within the state are shown in Table 6-2. In Table 6-3 we compare the amounts of air pollutants emitted by the coal-fired power plant and the trains used

Table 6-1

Residuals from Coal-Fired Power Plants

NATIONAL COAL UTILIZATION ASSESSMENT
ENERGY FACILITY 49 COAL-FIRED POWER PLANT - LOW-BTU

SCENARIO 1 - RECENT TRENDS
REGION 11 CALIFORNIA

ANNUAL SUMMARY OF RESIDUALS		1975	1980	1985	1990	1995	2000
WATER POLLUTION							
ACIDS	TONS	0.	0.	4.37E+01	4.37E+01	4.37E+01	4.37E+01
BASES	TONS	0.	0.	5.52E+00	5.52E+00	5.52E+00	5.52E+00
PHOSPHATES	TONS	0.	0.	2.21E+01	2.21E+01	2.21E+01	2.21E+01
NITRATES	TONS	IIIII	IIIII	IIIII	IIIII	IIIII	IIIII
OTHER DISSOLVED SOLIDS	TONS	0.	0.	7.55E+02	7.55E+02	7.55E+02	7.55E+02
TOTAL DISSOLVED SOLIDS	TONS	0.	0.	7.55E+02	7.55E+02	7.55E+02	7.55E+02
SUSPENDED SOLIDS	TONS	0.	0.	2.64E+02	2.64E+02	2.64E+02	2.64E+02
NON-DEGRADABLE ORGANICS	TONS	0.	0.	3.50E+01	3.50E+01	3.50E+01	3.50E+01
BIOLOGICAL OXYGEN DEMAND	TONS	0.	0.	1.25E+00	1.25E+00	1.25E+00	1.25E+00
CHEMICAL OXYGEN DEMAND	TONS	IIIII	IIIII	IIIII	IIIII	IIIII	IIIII
THERMAL	BTUS	0.	0.	0.	0.	0.	0.
TOTAL SOLIDS+ORGANICS	TONS	0.	0.	7.55E+02	7.55E+02	7.55E+02	7.55E+02
AQUEOUS AMMONIA	TONS	0.	0.	0.	0.	0.	0.
AIR POLLUTION							
PARTICULATES	TONS	0.	0.	1.76E+03	1.76E+03	1.76E+03	1.76E+03
OXIDES OF NITROGEN	TONS	0.	0.	1.75E+04	1.75E+04	1.75E+04	1.75E+04
SULFUR OXIDES	TONS	0.	0.	4.14E+03	4.14E+03	4.14E+03	4.14E+03
HYDROCARBONS	TONS	0.	0.	3.00E+02	3.00E+02	3.00E+02	3.00E+02
CARBON MONOXIDE	TONS	0.	0.	7.92E+02	7.92E+02	7.92E+02	7.92E+02
CARBON DIOXIDE	TONS	0.	0.	3.89E+06	3.89E+06	3.89E+06	3.89E+06
ALDEHYDES, ETC.	TONS	0.	0.	4.99E+00	4.99E+00	4.99E+00	4.99E+00
TOTAL AIR POLLUTANTS	TONS	0.	0.	2.56E+04	2.56E+04	2.56E+04	2.56E+04
HYDROGEN SULFIDE	TONS	0.	0.	0.	0.	0.	0.
AMMONIA	TONS	0.	0.	0.	0.	0.	0.
BORON	TONS	0.	0.	1.75E+02	1.75E+02	1.75E+02	1.75E+02
PHOSPHOROUS PENTOXIDE	TONS	0.	0.	0.	0.	0.	0.
FLUORIDES	TONS	0.	0.	0.	0.	0.	0.
LAND AND SOLID WASTE							
SOLID WASTE	TONS	0.	0.	6.00E+05	6.00E+05	6.00E+05	6.00E+05
LAND	ACRES	0.	0.	5.28E+02	5.28E+02	5.28E+02	5.28E+02

Table 6-2

Residuals from All Energy and Energy Transportation Facilities

NATIONAL COAL UTILIZATION ASSESSMENT
ENERGY FACILITY 96 TOTAL OF ALL FACILITIES

SCENARIO 1 - RECENT TRENDS
REGION 11 CALIFORNIA

ANNUAL SUMMARY OF RESIDUALS

		1975	1980	1985	1990	1995	2000
WATER POLLUTION							
ACIDS	TONS	1.17E+03	1.23E+03	1.27E+03	1.28E+03	1.24E+03	1.27E+03
BASES	TONS	0.	0.	7.12E+00	1.09E+01	1.45E+01	1.83E+01
PHOSPHATES	TONS	6.02E+02	6.33E+02	6.58E+02	6.64E+02	6.41E+02	6.57E+02
NITRATES	TONS	0.	0.	3.55E+01	3.55E+01	3.55E+01	3.55E+01
OTHER DISSOLVED SOLIDS	TONS	5.00E+03	5.27E+03	6.13E+03	5.95E+03	5.72E+03	5.74E+03
TOTAL DISSOLVED SOLIDS	TONS	1.27E+05	1.55E+05	1.96E+05	2.21E+05	2.41E+05	2.62E+05
SUSPENDED SOLIDS	TONS	9.41E+03	1.01E+04	1.06E+04	1.07E+04	1.05E+04	1.07E+04
NON-DEGRADABLE ORGANICS	TONS	2.26E+03	4.45E+03	6.62E+03	6.42E+03	6.14E+03	5.73E+03
BIOLOGICAL OXYGEN DEMAND	TONS	2.39E+03	2.70E+03	3.00E+03	3.04E+03	3.07E+03	3.10E+03
CHEMICAL OXYGEN DEMAND	TONS	1.44E+04	1.63E+04	1.81E+04	1.83E+04	1.86E+04	1.87E+04
THERMAL	BTUS	5.55E+13	1.39E+14	3.16E+14	4.59E+14	5.99E+14	7.46E+14
TOTAL SOLIDS+ORGANICS	TONS	1.21E+05	1.38E+05	1.57E+05	1.58E+05	1.59E+05	1.60E+05
AQUEOUS AMMONIA	TONS	2.09E+03	2.36E+03	2.63E+03	2.66E+03	2.70E+03	2.72E+03
AIR POLLUTION							
PARTICULATES	TONS	4.24E+04	4.63E+04	5.26E+04	5.49E+04	5.36E+04	5.45E+04
OXIDES OF NITROGEN	TONS	2.94E+05	3.07E+05	3.28E+05	3.23E+05	3.14E+05	3.15E+05
SULFUR OXIDES	TONS	4.27E+05	4.48E+05	4.56E+05	4.39E+05	4.18E+05	4.19E+05
HYDROCARBONS	TONS	4.59E+05	4.18E+05	3.65E+05	3.58E+05	3.91E+05	3.76E+05
CARBON MONOXIDE	TONS	8.34E+03	9.12E+03	1.05E+04	1.15E+04	1.18E+04	1.20E+04
CARBON DIOXIDE	TONS	2.52E+05	5.91E+05	4.64E+06	4.74E+06	5.38E+06	5.38E+06
ALDEHYDES, ETC.	TONS	1.67E+04	1.84E+04	2.01E+04	2.01E+04	2.01E+04	2.03E+04
TOTAL AIR POLLUTANTS	TONS	1.46E+06	1.43E+06	1.40E+06	1.34E+06	1.28E+06	1.27E+06
HYDROGEN SULFIDE	TONS	1.84E+04	4.32E+04	5.51E+04	6.24E+04	1.09E+05	1.09E+05
AMMONIA	TONS	3.31E+04	6.83E+04	8.57E+04	9.59E+04	1.60E+05	1.61E+05
BORON	TONS	4.70E+03	4.93E+03	5.12E+03	5.15E+03	4.97E+03	5.09E+03
PHOSPHOROUS PENTOXIDE	TONS	0.	0.	0.	0.	0.	0.
FLUORIDES	TONS	0.	0.	2.09E+00	2.09E+00	2.09E+00	2.09E+00
LAND AND SOLID WASTE							
SOLID WASTE	TONS	2.59E+05	2.81E+05	8.99E+05	8.95E+05	8.90E+05	8.92E+05
LAND	ACRES	7.75E+06	8.99E+06	1.10E+07	1.22E+07	1.40E+07	1.53E+07

Table 6-2

Residuals from All Energy and Energy Transportation Facilities (cont.)

NATIONAL COAL UTILIZATION ASSESSMENT
ENERGY FACILITY 96 TOTAL OF ALL FACILITIES

SCENARIO 1 - RECENT TRENDS
REGION 11 CALIFORNIA

ANNUAL SUMMARY OF RESIDUALS

		1975	1980	1985	1990	1995	2000
RADIOLOGICAL							
RADIATION POPULATION EXPOSURE	MAN-REM	0.	0.	0.	0.	0.	0.
SOLID HIGH LEVEL WASTE	CUBIC FEET	0.	0.	0.	0.	0.	0.
TRITIUM EMISSION	CURIES	2.48E+01	6.44E+01	1.48E+02	2.16E+02	2.82E+02	3.52E+02
KRYPTON EMISSION	CURIES	5.79E+03	1.50E+04	3.46E+04	5.04E+04	6.59E+04	8.21E+04
RADON-222	CURIES	0.	0.	0.	0.	0.	0.
THORIUM-230 AIRBORNE	CURIES	0.	0.	0.	0.	0.	0.
TRANSURANIC ELEMENTS	CURIES	0.	0.	0.	0.	0.	0.
RADIUM-226 AIRBORNE	CURIES	0.	0.	0.	0.	0.	0.
URANIUM AND DAUGHTERS AIRBORNE	CURIES	0.	0.	9.24E-04	9.24E-04	9.24E-04	9.24E-04
IODINE-131	CURIES	1.32E-02	3.44E-02	7.92E-02	1.15E-01	1.51E-01	1.88E-01
MISC AIRBORNE FISSION PRODUCTS	CURIES	0.	0.	0.	0.	0.	0.
NOBLE GASES	CURIES	0.	0.	0.	0.	0.	0.
RADIUM-226 IN LIQUIDS	CURIES	0.	0.	0.	0.	0.	0.
URANIUM AND DAUGHTERS LIQUIDS	CURIES	0.	0.	9.54E-02	9.54E-02	9.54E-02	9.54E-02
RUTHENIUM-106	CURIES	0.	0.	0.	0.	0.	0.
THORIUM-234	CURIES	0.	0.	0.	0.	0.	0.
MISC FISSION PRODUCTS LIQUIDS	CURIES	4.14E+00	1.07E+01	2.47E+01	3.60E+01	4.70E+01	5.86E+01
SOLID LOW LEVEL WASTE	CUBIC FEET	0.	0.	4.77E-02	4.77E-02	4.77E-02	4.77E-02
SOLID HIGH LEVEL WASTE	CURIES	0.	0.	0.	0.	0.	0.
SOLID LOW LEVEL WASTE	CURIES	0.	0.	0.	0.	0.	0.
THORIUM 230 IN SOLIDS	CURIES	0.	0.	0.	0.	0.	0.
THORIUM IN SOLIDS	CURIES	0.	0.	0.	0.	0.	0.
URANIUM AND DAUGHTERS SOLIDS	CURIES	0.	0.	4.04E-01	4.04E-01	4.04E-01	4.04E-01
PLUTONIUM IN SOLIDS	CURIES	0.	0.	0.	0.	0.	0.
RADIUM 226 IN SOLIDS	CURIES	0.	0.	0.	0.	0.	0.
PLUTONIUM IN LIQUIDS	CURIES	0.	0.	0.	0.	0.	0.
THORIUM 230 IN LIQUIDS	CURIES	0.	0.	0.	0.	0.	0.
TRITIUM IN LIQUIDS	CURIES	3.72E+02	9.66E+02	2.23E+03	3.24E+03	4.23E+03	5.28E+03
PLUTONIUM - AIRBORNE	CURIES	0.	0.	0.	0.	0.	0.
CARBON 14 - AIRBORNE	CURIES	4.96E+00	1.29E+01	2.97E+01	4.32E+01	5.64E+01	7.04E+01
ACTINIDES IN SOLIDS	CURIES	0.	0.	0.	0.	0.	0.
ACTINIDES IN LIQUIDS	CURIES	0.	0.	0.	0.	0.	0.
ACTINIDES - AIRBORNE	CURIES	0.	0.	0.	0.	0.	0.
LIQUID MEDIUM LEVEL WASTES	GALLONS	0.	0.	0.	0.	0.	0.
LIQUID LOW LEVEL WASTES	GALLONS	0.	0.	0.	0.	0.	0.
MISC FISSION PRODUCTS IN SOLID	CURIES	0.	0.	0.	0.	0.	0.
KRYPTON 85 STORED	CURIES	0.	0.	0.	0.	0.	0.
FISSION PRODUCTS IN FUEL RODS	CURIES	1.12E+08	2.90E+08	6.68E+08	9.73E+08	1.27E+09	1.58E+09

Table 6-3

Air Pollutants from Coal-Related Facilities
Recent Trends Scenario
(in tons per year)

	1985		
	Particulates	Oxides of Nitrogen	Oxides of Sulfur
Coal-fired power plant	1,760	17,500	4,140
Coal unit train	1,470	110	100
Conventional train	500	40	30
Total coal-related	3,730	17,650	4,270
Total statewide energy and energy transportation facilities	52,600	328,000	456,000
Percent coal-related*	7%	5%	1%
	2000		
Coal-fired power plant	1,760	17,500	4,140
Coal unit train	1,990	155	130
Conventional train	780	60	50
Total coal-related	4,530	17,700	4,320
Total statewide energy and energy transportation facilities	54,500	315,000	419,000
Percent coal-related*	8%	6%	1%

* This represents the fractions of statewide air pollutants from energy-related facilities that are attributable to coal.

to transport coal with the statewide emissions from energy and transportation facilities. We see that the coal-related emissions amount to about seven per cent of the total particulates from these facilities, five per cent of the NO_x and one per cent of the SO_2 during the period 1985 to 2000.

REFERENCES

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2. U.S. Council on Environmental Quality, MERES and the Evaluation of Energy Alternatives, May 1975.

3. Teknekron, Inc., Berkeley, CA, Comprehensive Standards: The Power Generation Case, EPA No. 68-01-0561, March 1975.

4. Siri, W.E. et al., Impacts of Alternative Electricity Supply Systems for California, Western Interstate Nuclear Board, May 1976.

7. REGULATORY ASPECTS OF SITING

INTRODUCTION

By most accounts California will need additional electric generating power plants for the foreseeable future. Traditionally the utilities in California have relied upon natural gas and hydroelectricity to meet the increased electricity demand. While these will continue to play a role in electric generation, large future additions of these plants are not likely. As one of the alternatives California utilities are planning to build coal-fired power plants. Presently coal's advantage to the utilities is its abundance in nearby states. It is also consistent with national security because it is invulnerable to foreign interruption and control.

These benefits are not without costs. While all fuels produce wastes that are harmful to the environment, coal's major end-use impact is air pollution. In addition it shares the problems of land use and water requirement which are inherent in steam-electric generation.

At present, California has no coal-fired plants, and their use may pose additional problems for the regulatory agencies in California. Although the regulation of power plants involves both state and federal agencies this discussion is limited to the state agencies which will shape the utilization of coal in California to the extent permitted by federal regulation.

The principal state agencies are the Energy Resource Conservation and Development Commission (ERCDC), the Coastal Commission, the State Air Resources Board (ARB) and local air pollution control districts (APCD), the State Water Resources Control Board (SWRCB), the California Public Utilities Commission (CPUC) and the State Lands Commission (SLC).

THE ENERGY RESOURCE CONSERVATION AND DEVELOPMENT COMMISSION

The key to power plant siting in California rests with the Energy Resource Conservation and Development Commission (ERCDC), hereafter referred to as the Commission.

The passage of the Warren-Alquist Energy Act in 1974 established the Commission and charged it with a wide range of responsibilities such as forecasting electricity demands, approving sites for thermal power plants, research and development of alternative energy sources, developing conservation measures and developing an emergency allocation program. The Commission has the "exclusive power to certify all sites" and such a certificate is "in lieu of any permit, certificate or similar document required by any state, local or regional agency or federal agency to the extent permitted by law."[1]

This contrasts with the former practice in which a multitude of local and state agencies held hearings and each issued permits according to its own objectives. The issuance of the Commission's certificate involves a two-stage, three-year procedure.

The first stage begins with the utility's submission of a Notice of Intent (NOI). The 18-month NOI process allows for public notice and participation and ascertains the need for a generic-type plant and its environmental impacts for several alternative sites. If the NOI is approved, the utility can file an Application for Certification (AFC), which ascertains how well a specific plant design situated on a particular site will conform to the appropriate standards. Only the approval of the AFC authorizes plant construction and operation.

The Notice of Intent (NOI) Process

The purpose of the NOI is "primarily to determine the suitability of the proposed site" and to determine "the general conformity" of the proposal to the standards and forecast of the electricity demand of the Commission. The Commission will follow a detailed procedure in order to gather evidence necessary to determine suitability and general conformity.[2] A series of public hearings are conducted on the proposal which must include three alternative sites, at least one of which is not on the coast. Various local, regional, state and federal agencies and the general public are invited to comment on all aspects of the proposal. The maximum time allowed by law for each of these activities is shown in Table 7.1.

The Commission's decision to approve the NOI will be based on a

Table 7.1

Notice of Intent (NOI) Timetable

Maximum Length for Event (days)	Event	Total Elapsed Time (days)
0	NOI submitted; includes design, economic, environmental features and need	
30	Adequacy test; Commission judges completeness of the NOI	30
90	Time before public hearing on NOI	120
90	Length of public hearings on NOI	210
90	Time before Preliminary Report is issued; includes conformity with forecast, applicable laws, relative merit of each site, safety and reliability	300
60	Time for comments on Preliminary Report	360
60	Time before Final Report issued; includes conformity with forecast, existing laws, Coastal Commission findings, acceptability and relative merit of each site, any modifications ordered by Commission	420
60	End of hearings on Final Report (to commence within 30 days of the report and last no longer than 30 days - total of 60 days)	480
60	Time to decide NOI; based on Final Report and all the above proceedings	540

Final Report, which is the culmination of hearings, comments, reports and independent Commission investigations. It must include a determination of the conformity of the proposed sites with the Commission's 10-year forecast of electrical energy demand, existing local and state laws and regulations, the standards of the Commission, and the "acceptability and relative merit" of each proposed site.[3]

The Warren-Alquist Act gives the Commission considerable discretion in approving the NOI. The threshold level of "general conformity" is undefined and left to the Commission to determine (case by case). At one extreme there may be proposals that conform to all existing laws and regulations of each government agency. In this case the Commission would function merely as a medium to consolidate the approval process without the need for controversial policy choices. At the other extreme, a proposal could violate most of the existing laws and regulations. Such obvious non-conformity would probably result in its disapproval.

However, most proposals will lie between the two extremes and the Commission will decide controversial public policy questions under criteria of general conformity. The criteria have not been explicitly defined and will probably evolve on a case-by-case basis.

While the criteria for general conformity are unclear, the proposal must be measured against the following conditions: the 10-year forecast, current laws and regulations, and the Commission's standards. An additional condition for siting in the coastal zone is the finding of the Coastal Commission. (The Coastal zone is generally anything within 1000 yards inland of the mean high tide line.) These are the minimum indexes that a proposal must comply with; the Commission may develop additional criteria.

The 10-year forecast refers to the planning and forecasting role of the Commission. Beginning on January 1, 1977, the Commission will publish a "comprehensive" report every two years containing a 10-year forecast of electrical energy demand. This forecast is "the basis for planning and certification of facilities ..." In the Commission's judgment the forecast will balance the needs for growth, the public health and safety, the preservation of the environment, maintaining a sound economy and conserving energy. This balancing requirement is subject to considerable discretion since it is based on many uncertainties.[4]

While the forecast has been adopted, it is not clear how it will be used to judge the need for a plant. Some say that the need for a plant is demonstrated so long as the latest 10-year forecast shows that additional supply capability is needed. The forecast, it is argued, is the result of conservation measures that will reduce the demand. Others argue that the 10-year forecast is only a rough guide and that conservation techniques should be evaluated as a substitute for part of the supply. Since a plant has not yet been sited under the Warren-Alquist Act, the manner in which the 10-year forecast will be used is unclear.

The next condition is the degree of conformity with existing local, regional, state and federal laws and regulations, the Commission's standards, and the report of the Coastal Commission. The legislative intent is to incorporate the existing objectives and concerns of governmental agencies in a single process and leave the judgment of sufficient "conformance" to the Commission. While the concept of a tradeoff between the need for plant and conflicting public agency objectives seems implicit in the decision of conformity, the legislation has offered only vague guidelines. The degree of non-conformance with existing laws and the relative importance of different kinds of laws are undefined.

Besides conformity with regulations promulgated by other agencies, the proposal must be measured against the "standards adopted by the Commission." These standards are designed to safeguard the public health and safety. Except for water and air quality, they may be different from the existing standards to the extent permitted by federal law.[5] Thus the Commission must measure the proposal against the existing air and water quality regulations but may adopt different land use, safety and environmental regulations. To date the Commission has not adopted its own standards but is using existing ones. The staff counsel indicated that if different standards were adopted it would be done on a case-by-case basis.[6] While the Commission is precluded from independently setting air quality standards, the existing air quality regulations are in a state of flux.

The final criteria are the acceptability and the relative merit of each site. The law requires utilities to submit three alternative sites as a backup to the primary site.[7] If certification of the primary site is denied, the other sites would be evaluated as possible substitutes.[8]

While the relative merit will be based on site-specific characteristics such as health and safety, a finding of "acceptability" is a matter of the Commission's judgment. While the findings will be based in part on how well the plant conforms to existing laws and regulations and the Commission's standards, it is possible that an "acceptable" site may not be in strict conformity with the provisions of state law or local ordinances or plans. The Commission can order any modifications in design, location and construction that will meet its standards and policies as a condition of approval.

If the Commission determines that the proposal adequately meets the above conditions, it may approve the NOI as long as two alternative sites are acceptable. The Commission may certify only one site if it finds the applicant made a good faith effort. Further, if none of the proposed sites are acceptable and the applicant made a good faith effort, then the Commission will designate a "feasible site" if the utility so requests.[9] Finally, no coastal site may be approved unless it has greater merit than the alternative sites.

The Application for Certification (AFC) Process

The purpose of the AFC is to authorize construction and operation of power plants. But it is difficult to draw a sharp distinction between the NOI and the AFC. It seems that the NOI and the AFC stages will be eventually be considered as one process; thus, the utility proposals will be measured against the same criteria in the AFC process as in the NOI. The AFC will merely take a second look at the whole project; however, this interpretation is controversial. The utilities believe the NOI's purpose is to determine site suitability and the AFC's purpose is to determine the plant type suitability. The Commission will probably look closely at all the details of the plant during both the NOI and AFC stages.

In contrast to the NOI procedure, the AFC process is less clear; yet the approval of the AFC is necessary to build and operate the plant.

By the law the AFC starts with a utility proposal for a plant based on one of the sites approved in the NOI proceedings. The utility is required to submit detailed plans concerning all aspects of the plant. The law requires an Environmental Impact Report (EIR) to be completed within one year from the date of the applicant's submission. The Commission is the lead agency for preparing the EIR and plans call for drafts to be circulated to interested agencies.[10]

The Commission is required to reconsider the approval of the NOI in light of "current conditions and other reasonable and feasible alternates" to the proposal. Within 180 days it will decide the "acceptability" of a site which it has previously approved. Thus the Commission can stop the plant within the first six months of the AFC if conditions have changed.[11] If the site is reconsidered and found acceptable, the process continues. The Commission holds further hearings and issues a decision within 18 months from the start of the AFC or at a later time if both the Commission and the utility agree. The tentative timetable is shown in Table 7.2.

The decision is based on the same NOI criteria: the conformity to the 10-year forecast, conformity to existing laws, "applicable" air and water standards, the Commission standards, and the provisions that will meet the Coastal Commission's report for coastal sites.

But strict conformity is not required. For some coastal sites the Commission may waive the recommendations of the Coastal Commission if they would "result in greater adverse effect on the environment" or "would not be feasible." Generally, if a proposal is in non-conformance with any laws or regulations, the Commission will meet with the appropriate agency to correct or eliminate the non-conformance. If the non-conformance cannot be corrected, then the proposed facility cannot be built unless the Commission finds that the facility is needed for the "public interest and necessity" and that there are "no more prudent and feasible means" of achieving the public convenience. This is the so-called overrule clause, PRC 25525. Thus the Commission can approve a site which is in non-conformance with existing laws if it makes a determination pursuant to 25525. The conditions for which 25525 would apply have not been determined.

Table 7.2

Application for Certification (AFC) Timetable

Maximum Length for Event (days)	Event	Total Elapsed Time (days)
0	Utility submits AFC based on an approved NOI	0
30	Commission judges adequacy of data submitted with AFC	30
variable	Hearings	180
180	Reconsideration of the NOI on which application is based. Application can be terminated in light of "current conditions" and "feasible alternatives."	180
365	Environmental Impact Report	365
	Decision on AFC; if approved, construction may begin	540 max. from day of submission; may be extended if Commission and utility agree.

The authority to overrule existing laws does not apply to federal laws and regulations. While this point seems unambiguous, it is unclear if other state and local air pollution control agencies are endowed with federal power. This uncertainty affects the relationship between the Commission and the Air Resources Board and local Air Pollution Control District (APCD). Since there has not yet been a complete siting under the Warren-Alquist Act, it is unclear if the existing regulatory agencies will insist on issuing their permits or will be satisfied to merely participate in the Commission's proceedings.

On the city and county level, it seems clear that traditional land use concerns will be evaluated in a statewide energy context. The local governments can no longer regulate or prohibit power plant construction. According to the Attorney General:[12] "There can be little doubt that the specific statement of legislative interest to establish exclusive Energy Commission jurisdiction over the thermal power plant-approval process, accompanied by such an extensive scheme of evaluation and regulation, amounts to complete state occupation of the entire field of thermal power plant site and facility approval ..." Further, "... the Legislature intends the Energy Commission to give great weight to the comments, opinions, ordinances and standards of local governments ..." and "... are not to be ignored or to be given secondary consideration ..." Indeed, if there is a conflict between a proposed plant and local regulation, the plant cannot be built unless the Commission determines that there are no more "prudent and feasible means" and that the public convenience and necessity require the plant.

But according to the Attorney General, "... Once the Energy Commission determines that the public convenience and necessity require the facility be constructed as determined by the Commission and on the site selected by the Commission, the certificate issued by the Commission overrides the objections of the County government ..." and "... shall supersede any applicable statute, ordinance or regulation of any state, local or regional agency in conflict therewith."*

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*Local and state agencies which own or control parks, wilderness, scenic, natural and wildlife reserves, or recreation or historic preservation areas retain veto power over siting in these areas.

Assuming local governments abide by this opinion, the degree to which their concerns are complied with in the siting of power plants will depend upon the Commission's willingness to invoke the "no more prudent and feasible test." If the Commission is unwilling to invoke the overrule clause, except for the most extraordinary circumstances, local agencies will retain a large measure of de facto regulatory power. However, the Commission retains the authority to overrule them based on its own determination, subject only to limited judicial review.

In contrast to local governments, several state agencies either retain limited concurrent authority with the Commission or have an unclear and potentially conflicting basis of authority. These include the Coastal Commission, local and state air pollution control authorities, the State Water Resources Control Board (SWRCB), the State Lands Commission (SLC) and the California Public Utility Commission (CPUC). Although this list is not exhaustive, it contains the state agencies which have the potential for jurisdictional conflicts with the Energy Commission.

THE COASTAL COMMISSION

The people of California have determined that the coast is a "distinct and valuable resource of vital and enduring interest to all the people and exists as a delicately balanced ecosystem." Such a sentiment is the rationale for the California Coastal Act of 1976. While the Act states that the permanent protection of the coast is of paramount concern to all Americans and that it is necessary to protect it from destruction, the Act also states that power plants may have to be sited on the coast.[13]

The intent of legislature was to establish a mechanism, the Coastal Commission, that would evaluate the tradeoff between the needs of industry for abundant ocean waters with the needs of people for recreation. The Coastal Commission is charged with preserving the coast as well as with accounting for the social and economic needs of the people regarding coastal resource utilization. To this end the Coastal Commission has the authority to retain its permit authority in designated areas of the coastal zone. A designation of such areas will be made by

January 1, 1978, and updated every two years. Within these areas the Energy Commission may not authorize a site unless:

1. The Coastal Commission finds that such use is not inconsistent with the primary uses of the land;
2. There will be no substantial adverse environmental effects; and
3. Approval of the public agency having ownership is obtained.

Thus the Coastal Commission could allow or disallow siting in the designated areas based on its judgment of the compatibility of the land use.[14]

For proposed sites that are not so designated but are in the coastal zone, the Coastal Commission will comment extensively during the NOI proceedings and their comments will become part of the basis for the Commission's decision. But the Commission's approval for the NOI is not strictly bound by the concerns of the Coastal Commission. In contrast, the decision on the AFC must be based on the degree to which the proposal meets the Coastal Commission's detailed recommendations on the design and operation of the plant which help to reduce harmful or undesirable aspects. Thus it has substantial power to shape the specific characteristics of the plant—which could incidentally result in greater operation or construction costs. However, the Energy Commission need not follow these recommendations if (they) "would result in greater adverse effect on the environment" or "would not be feasible."[15]

The word "feasible" itself is not defined in the Energy Act; it is thus subject to differing interpretations and subsequently a potential source of controversy and litigation. Subject to judicial review, the determination of feasibility rests with the Energy Commission and inherent in that determination is the power to authorize coastal sites that have not been designated by the Coastal Commission. However, the Coastal Commission may designate and reserve more coastal area through its two-year updates. If aggressively pursued, this policy would progressively erode the Energy Commission's exclusive authority to site plants on the coast.

The issue is important because utilities need water for cooling and ocean water is more efficient than inland water due to its lower temperature. Also, the availability of fresh inland water is severely limited, which adds to the pressure to site on the coast. If the Coastal Commission pursues an aggressive policy and determines that many or most of the ocean sites are unsuitable, the Energy Commission will face an added constraint in certifying plants for coastal sites.

THE AIR RESOURCES BOARD AND THE AIR POLLUTION CONTROL DISTRICT

The air quality control regulations are a serious limitation on the location of power plants. The setting of standards and their enforcement are exercised by a mix of federal, state and local agencies. The primary agency for the setting of standards and their enforcement under state law is the local Air Pollution Control District (APCD). There are 47 APCD's in California which roughly follow county boundaries.

The APCD's are overseen by the State Air Resources Board (ARB) in Sacramento. The ARB has the power to intervene in local APCD's if state or federal laws are being violated. The Environmental Protection Agency (EPA) sets federal standards and promulgates regulations that the states must follow and enforces these rules until states submit a suitable plan.

The utility enters this triad by applying to the local APCD for two permits. The authority to construct (A/C) ensures that the utility's plant is designed to conform to the APCD's air rules, and the permit to operate (P/O) is designed to ensure compliance with those rules after the plant is built.

The power of the APCD to prohibit plants that did not meet its rules was upheld in 1972. The California Supreme Court held that under California law the APCD had concurrent authority with the Public Utility Commission, which was the agency responsible for regulating power plants.[16]

Since then the responsibilities of the APCD and especially the ARB have been broadened by amendments to the Clean Air Act and EPA regulations. The Act has been interpreted by the Supreme Court and EPA to mandate a two-front attack on air pollution. The first is to improve areas that do not meet federal ambient air quality standards, and the second is to prevent the cleaner areas from getting dirtier. Under federal law the states can adopt more stringent regulations than the federal regulations. The ARB is pushing for tougher emission standards by requiring a reduction in the amount of allowable pollutants and by including more emissions as pollutants. The result of state and federal legislation and litigation has been the establishment of several separate programs. There are state emission rules adopted and enforced by the APCD's. When these rules are stricter than the federal emission rules, called New Source Performance Standards (NSPS), the EPA allows the local regulations to supplant the federal rules. The New Source Review program is intended to prevent the construction of plants whose operation would result in the violation of ambient air quality standards or their continued violation. In some areas the EPA is enforcing this regulation while in other areas APCD's are. The Prevention of Significant Deterioration program is being administered by the EPA.[17]

The ARB-proposed Air Conservation Plan incorporates the separate programs into an integrated one. The Plan would not only meet federal minimums but go substantially beyond them.[18]

The effect of this complex state of regulations is to constrain greatly the siting of coal-fired plants. If the Commission must adopt ARB rules, then there may be few, if any, coal plants in California. This would place a burden on other fuels which have safety and environmental liabilities of their own.

The Commission does not concede that the ARB rules must apply. In the 1977 Biennial Report, the Commission said:[19]

> Facilities subject to the Commission's certification authority may have to comply with standards promulgated by state and local air pollution agencies; whether they must is a complex question of law which is currently unresolved.

This conclusion rests on the uncertainty over whether the ARB and the APCD are carrying out federal regulations. If they are, then the Energy Commission must abide by them; if not, the Commission has more flexibility.

It is clear that the standards that the Commission must adopt are those of the ARB/APCD. Section 25216.3(a) explicitly states that the Commission may adopt different public health and safety standards except for air and water quality. Yet facilities may not have to comply with these standards if the Commission "determines that such facility is needed for the public convenience and necessity and that there are not more prudent and feasible means of achieving such public convenience and necessity" (PRC 25525). Thus if the ARB rules are not federal regulations and the two conditions specified in 25525 are met, the Commission could overrule existing air quality standards.

The crucial question then is whether the ARB/APCD rules have the force of federal regulations. The difficulty of establishing a definitive answer stems from the nature of the Clean Air Act itself. The primary responsibility for air pollution control is up to the states; yet they must follow federal regulations. If they don't, the EPA will enforce its own rules. But states can set more stringent rules. Thus, when the ARB proposes standards for the APCD's that are more stringent than either federal minimums or current APCD rules, the EPA finds the proposals satisfactory from the Clean Air Act perspective.

The crux of the problem is whether such EPA approval gives the rules the force of federal regulations. According the the EPA regulations an approved plan is enforceable by either the EPA or state and local agencies and the approved plan becomes the plan mandated by the Clean Air Act. The inference is that if the EPA approves more stringent state rules, then they are endowed with federal authority. The counter arguments claim that the EPA will delegate its authority only to those agencies which have legally enforceable procedures for enforcement. If this means that the APCD must have authority under California statutes to enforce federal regulations, then the ARB/APCD's will not be able to accept responsibility for EPA regulations.

If the APCD cannot enforce the New Source Review, the EPA has indicated that it will make a distinction between administration and enforcement. The APCD will determine whether the plants conform to the rules. Enforcing these rules would be left to the EPA. Thus if the Energy Commission were to overrule the APCD decision, the EPA would intervene. "The Administrator of the EPA will carry out any required enforcement actions in cases where the State does not have adequate legal authority to initiate such actions." This provision raises two questions: when is inadequate legal authority established and what kind of actions will EPA take?[20]

A possible scenario would find the Energy Commission authorizing a plant over the objections of the APCD/ARB. The courts would find such action lawful if the Commission meets the "necessity" and "prudent and feasible" tests. Assuming the court was satisfied that these tests were met, the only remaining question is whether the rules have federal power. The EPA would claim that they did, thereby reaffirming the authority of the APCD's. This would place de facto power in the ARB/APCD's to prohibit plant construction.

However, things are further complicated because ARB/APCD rules are more stringent than the EPA's. The question is whether the EPA can and will enforce rules stricter than its own. At the minimum, it seems clear that the Energy Commission will have to abide by any regulations that are enforceable by the EPA. Since the Energy Act precludes the Commission from conflicting with federal law or regulation, the question turns on whether the EPA can endow the APCD's with federal authority in the absence of a state law allowing them to exercise federal regulations.

In the face of this uncertainty and complexity, both the Commission and the ARB are conducting discussions in an attempt to reach an understanding. If agreement is reached, it is not known whether it will be formal or informal. So far the Energy Commission has informally indicated it will accommodate the ARB's concerns, but this could change at any moment.

THE STATE WATER RESOURCES CONTROL BOARD

The jurisdictional conflict between the Energy Commission and the State Water Resources Control Board (SWRCB) could turn on the need for water. Electric generation produces waste heat, and water is used to cool the plant. All other things being equal, the utilities would prefer to use fresh water or ocean water for the once-through cooling method. This method takes water from natural sources to cool the plant and then discharges the heated water back to a natural source. While this technique is well known, great quantities of water are needed, and the heated discharge poses a threat to aquatic organisms.

The SWRCB's responsibility is to make the most beneficial use of water resources and to ensure water quality, including discharges of heated water. The Board's authority for making water available is based on state law while water quality regulations are based on both state and federal law:

The Board disfavors the use of freshwater for cooling purposes due to the present unavailability of water in some basins and the projection of general shortages by year 2000. It established a priority of sources for plant cooling:[21]

1. waste water being discharged into the ocean,
2. ocean water,
3. brackish water from natural or irrigation returns,
4. inland water with low Total Dissolved Solids (TDS), and
5. other inland water.

In addition, the Board will approve the use of fresh inland water only when use of other water sources would be environmentally unsound.

The heated water discharge requirements adopted by the Board in May, 1972, call for severe limits on the discharge of water of elevated temperature. This requirement precludes once-through cooling for inland sites.[22]

The Board favors the coastal siting of power plants because ocean water is abundant and the heated discharge is felt to cause less environmental damage. Yet there are constraints on coastal locations. Besides the earthquake hazards, the coast falls under the partial control of the Coastal Commission. The Coastal Commission's mandate is to preserve the coast and added specific criteria must be met in order to site on the coast. The Energy Commission is faced with contradictory policies. If it approves coastal locations because water is available, it may run into sites where the added concerns of the Coastal Commission cannot be met. If it approves inland locations, the utility may not be able to find enough water or to meet the discharge requirements.

The Commission will not be able to authorize a site where the discharge would not meet the thermal requirements. It is clear that the applicable water quality standards are those of the SWRCB. It is also clear that the ability to overrule those standards, under 25525, is precluded because these are in pursuance to the Federal Water Pollution Control Act of 1972. However, the availability of water and the most beneficial use are state issues.

The Commission could interpret the supremacy clause and the overrule clause 25525 as giving them the power to order SWRCB to find water for a utility. Whether the supremacy clause is meant to give the Commission such power has not been settled. At the minimum, it would be necessary for extraordinary conditions to exist for such a confrontation. There would have to be a pressing need for the plant, no other sites could be available and no alternative means could be found.

Thus far they have viewed the utility as responsible for finding water. The Commission will judge the reliability of water supply and how well it conforms to the existing laws and regulations. The Commission found the use of freshwater for a power plant "unacceptable and unreasonable" in light of the testimony of state and local agencies. The Commission called for further study of the costs of using waste water because "waste water from municipal treatment plants represents a presently available and technically feasible source of coolant."[23]

THE PUBLIC UTILITY COMMISSION

Prior to the Energy Act the Public Utility Commission (PUC) was the prime state agency which regulated power plants. A privately-owned utility needed a Certificate of Public Convenience and Necessity from the PUC before construction could commence. The PUC's authority and working relationship with the Energy Commission is uncertain. It is clear that the PUC's certificate cannot be issued before the Energy Commission has issued its permit (Sec. 25518). However, a utility may apply concurrently to the PUC and the Energy Commission. The question arises whether a PUC permit is needed at all.

The Energy Act suggests that the PUC permit may be necessary. Section 25505 states that the Energy Commission shall transmit a copy of the NOI to the PUC "for sites and related facilities requiring a Certificate of Public Convenience and Necessity ..." The Energy Act recognizes that some facilities may need a PUC permit. If so, when is a permit needed and what discretion does the PUC have to refuse issuance?

The California Public Utilities Code still requires privately-owned utilities to receive a certificate from the PUC. The Energy Act did not specifically amend the Public Utility Code. The legal opinion of the PUC is that a certificate is still required of utilities and that the

PUC could refuse such a certificate. If so, it is unclear on what basis the PUC could refuse issuance. The effect this would have on the Energy Commission's siting process could be important.

The issue may not be crucial since the PUC believes "such a refusal seems most unlikely assuming that the Energy Commission's approval ... is reasonable and in the public interest."[24]

THE STATE LANDS COMMISSION

The State Lands Commission (SLC), made up of the State Controller, the Lieutenant Governor and the Director of Finance, manages over four million acres of state-owned public land. Most of this is coastal, marsh or estuaries, but there are some scattered inland holdings. It has general authority to issue leases for the use of the state land. The SLC can specify conditions of the lease in order to meet the California Environmental Quality Act. A public hearing is held on the request and the process usually takes three months.

The Energy Act states that the Energy Commission has the exclusive authority to site and it may mean that a SLC permit is not needed. But according to a March 14, 1975 memorandum by Assistant Attorney General Jay Shavelson, which is still the current opinion, the SLC still must issue a permit.[25] However, their discretionary authority is limited to proprietary considerations such as rental fees. Presumably this means that SLC will merely accept the Energy Commission's EIR and issue the lease. Whether the SLC will abide by this interpretation remains to be seen. As long as the EIR is "reasonable" the SLC has indicated it would probably issue the lease.[26]

CONCLUSION

While the Energy Act has gone far to consolidate the process for siting power plants in one procedure, it has not resulted in a one-step permit process. One-step implies that a single agency will grant the one permit that is necessary and sufficient to construct and operate a power plant.

The Energy Act explicitly recognizes that federal agencies will issue permits according to their own procedures. The Energy Act requires the utilities to submit with the AFC a list of the federal agencies from which approval is needed and a time table for obtaining the authorization.[27] The attempt is to incorporate the procedures of the federal agencies into the three-year Energy procedure and to minimize delay. But the federal agencies will approve or disapprove according to their federal authority and responsibilities. The Commission has no formal power over such agencies.

Perhaps a more accurate formulation of the Commission's role is a consolidation of all state and local concerns in one procedure with the sole determination left to the Energy Commission. The local city and county governments fall under this formulation but significant exceptions exist. The Coastal Commission will reserve areas of the coast for concurrent permit authority with the Energy Commission. The ARB/APCD's may still have authority to withhold or issue their permits to construct and permits to operate. The SWRCB will grant water appropriations rights according to its own priorities. The State Lands Commission may still be required to issue a permit for the use of state lands, and the PUC will still issue its permit.

However, the Energy Act has given a clear focus to the siting procedure and greatly reduces or eliminates the discretionary authority of the state and local actors. The relationship between the Energy Commission and the other state agencies will rest mainly upon the attitudes of the individual Commissioners. The Commission could assume a passive role and allow the existing laws and regulations of local and state agencies determine the location, type and number of power plants. As long as the Commission's forecast showed the need for more electric generation, the utilities would face the same regulatory actors after the Energy Act as they did before it. The only difference is that the actors would regulate in one procedure administered by the Commission. The Commission could interpret the overrule clause (25525) as requiring extraordinary and exceptional conditions before it would authorize a plant that did not conform to existing laws and regulations.

On the other hand, the Commission could become an advocate for the utilities. The Commission could interpret the words "prudent" and "necessary" in such a way that many utility proposals would meet the criteria. This could give the Commission and hence the utilities the power to ignore the objections and concerns of other state and local agencies.

It is doubtful that the Commission could move very far in either direction. The Energy Act mandates the Commission to certify enough sites to meet their demand forecast but at the same time the Commission must seek to reduce waste and to decrease demand.[28] Only time and circumstances will show how the Commission meets these complementary objectives.

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27. PRC 25519(j).

28 PRC 25500.5 and 25400 et seq.

8. FACILITY SITING

The siting analysis for the National Coal Utilization Assessment (NCUA) requires the selection of most probable locations for power plants for four scenarios for the years 1985 and 2000 for California. Siting energy facilities in California, especially coal-fired electricity-generating facilities, presents a complex problem due to a unique combination of environmental elements, political attitudes and institutional policies. For example, the siting process for "energy facilities"* is primarily governed by the Energy Resources Conservation and Development Commission (ERCDC) as instituted under the Warren-Alquist Act of 1974. The ERCDC administers the three-year, two-stage procedure of the Notice of Intent (NOI) and the Application for Certification (AFC).

In addition to ERCDC, the California Coastal Commission (Coastal Commission) has authority over coastal power plant siting. The problem of possible conflicting jurisdiction between these two agencies has not yet been fully resolved. As of now no single power plant has completed the three-year procedure and those proposed sites currently under consideration do not involve coastal sites. The Coastal Commission land use criteria may tend to favor inland siting of power plants and proposals for coastal power plant sites will be considered on a case-by-case basis. So the relationship of these two agencies has not yet been fully established. (See section 7 for a fuller discussion of this situation.) To further illustrate this, the physical environment of California which offers many scenic and recreation opportunities also constrains power plant siting (i.e., in severe earthquake zones and mountainous areas). The tradeoff between preservation of biological and environmental resources and power plant siting is particularly complex and one which has only been considered in a preliminary fashion in this siting analysis.

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*"Facility" means any electric transmission line or thermal power plant, or both electric transmission line and thermal power plant. "Thermal power plant" means any stationary or floating electrical generating facility using any source of thermal energy, with a generating capacity of 50 megawatts or more and any appurtenant facilities.

LOCATIONS OF EXISTING ELECTRICAL GENERATING PLANTS

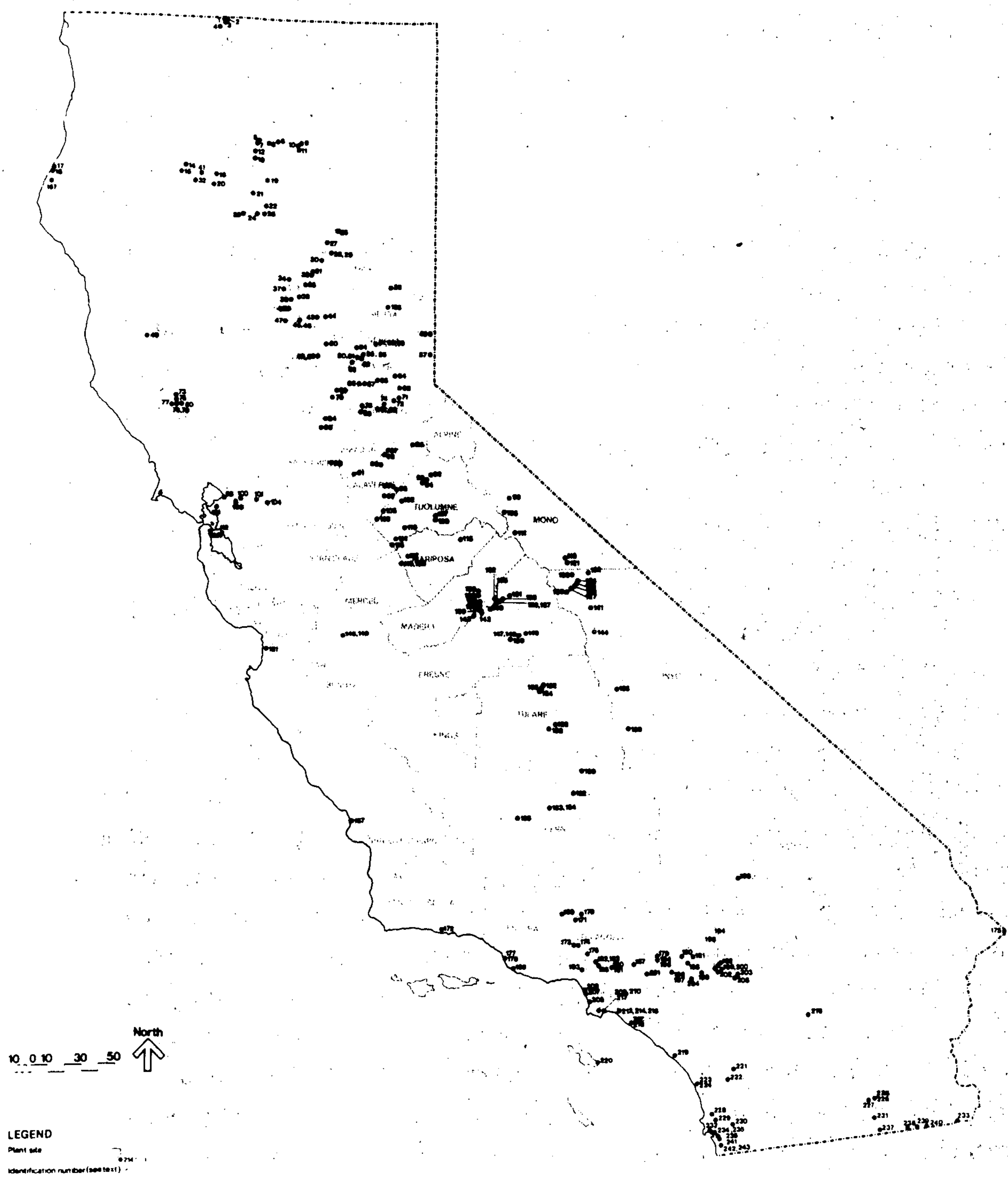
In California there are five investor-owned electrical utilities, eight publicly-owned utilities, and eleven public agencies that produce electricity which they consume and sell to other utilities. The location of the electricity-generating facilities in 1976, which totals 242 units, is shown in Figure 8-1. The breakdown among these plants is:

Type	Number of Units	Total Installed Capacity (in megawatts)
Hydroelectric	172	8438
Nuclear	3	1534
Fossil Fuel	61	24201
Geothermal	6	561
Total	242	34734

The pattern of location shows several distinct clusters. First, the hydroelectric plants are clustered in the Sierra Nevada mountain range in the eastern part of the state from Plumas County down to Tulare and Inyo counties. In addition, there is another cluster in Shasta County. The geothermal plants are necessarily constrained to the region where the geothermal source exists; they are clustered in northeastern Sonoma county. The major concentrations of fossil fuel energy facilities are in metropolitan areas, including the San Francisco Bay area, the Los Angeles area and the San Diego metropolitan area. Southern Imperial County has a cluster of small electricity-generating plants. Finally, the three sites with operating nuclear power plants are scattered throughout the state, with one each in Humboldt County, Sacramento County and San Diego County. A fourth site with nuclear units nearing completion is located on the coast in San Luis Obispo County.

The present pattern of energy facility siting is not likely to continue for several reasons. First, the concentration of power plants in metropolitan areas is not likely to increase due to air quality problems and health and safety effects from the proximity to population concentrations, especially for nuclear power plants. Second, the number of potential sites for additional hydroelectric development has decreased as most of the usable sites have already been developed. It is estimated, however, that hydroelectric output could be expanded by approximately 30 percent (DWR Bulletin 194), although the environmental impacts of doing so have yet to be considered. Third, the

Fig. 8.1 *Existing Generating Plants -- 3*



CALIFORNIA ELECTRIC UTILITIES

EXISTING ELECTRICAL GENERATING PLANTS 1976

Source: CERCEC, California Energy Trends and Choices, vol. 7, Power Plant Siting predominance of coastal siting is not likely to be reinforced due to the Coastal Commission policies designed to help conserve coastal resources. Thus a shift in the siting pattern of energy facilities is likely to occur over the next decade with the central portion of the state and the southeastern desert area receiving increased attention as power plant siting areas.

SITING METHODOLOGY

The siting analysis has been conducted utilizing an exclusionary siting methodology in which areas of California were eliminated from consideration as potential power plant sites on the basis of selected criteria. The exclusionary criteria are:

1) air quality maintenance areas (AQMAs)
2) zone III earthquake intensity areas
3) areas with significant biological resources
4) urbanized areas as defined in the 1970 census and projected urbanized areas of 1990
5) prime agricultural lands and agricultural preserves
6) coastal areas
7) special state and federal lands .

While the exclusionary criteria eliminated substantial portions of California, secondary criteria were necessary to evaluate the remaining areas. These secondary criteria were of two types. First, avoidance criteria refer to those features or alternatives which would not necessarily prevent power plant construction but which nevertheless represent some additional problem or added costs. For example, flood-prone areas were avoided although power plants can be designed to withstand floods. Second, certain opportunities exist which make some areas more desirable for power plant sites, such as proximity to rail transportation or transmission lines. These are referred to as opportunity criteria. These criteria, both exclusionary and secondary, are listed in Table 8-1.

These criteria were selected in consideration of the environmental constraints to power plant siting in California, in addition to feasibility

Table 8-1

Siting Criteria

	Primary Criteria: Exclusionary Criteria	Secondary Criteria: Avoidance	Secondary Criteria: Opportunity
I. Physical/Biological Factors			
A. Air Quality			
1. Air Quality Maintenance Areas (AQMA)	X		
2. Air Conservation Areas		X	
B. Geology/Seismology			
1. Active Quarternary Faults/Zone III Areas	X	X	
2. Landslide Areas		X	
3. Areas of High Liquefaction Potential		X	
4. Potential Volcanic Hazard Areas		X	
5. Subsidence Areas		X	
6. Areas of Geological Significance		X	
7. Seismicity Areas		X	
8. Ground Motion Areas		X	
9. Tsunami Hazard Areas*			
C. Hydrology/Water Resources			
1. Flood Prone Areas		X	
2. Overdrafted Water Basins		X	
3. Water Quality Limited Segments		X	
D. Significant Biological Resources			
1. Coastal Wetlands	X		
2. Inland Freshwater Marshes	X		
3. Anadromous Fish Spawning Areas	X		
4. Deer Winter Ranges	X		
5. Bighorn Sheep Winter Ranges	X		
6. Rare and Endangered Fish and Wildlife Habitats	X		
7. Kelp Beds	X		
8. Nature Conservancy Lands	X		

* Excluded because it is a coastal area.

Table 8-1

Siting Criteria (continued)

	Primary Criteria	Secondary Criteria	
	Exclusionary Criteria	Avoidance	Opportunity
II. Land Use and Transportation/ Transmission Factors			
A. Special Land Use			
1. Prime Agricultural Land	X		
2. Agricultural Preserves	X		
3. Urbanized Areas	X		
4. Coastal Areas	X		
B. Special State and Federal Lands			
1. National Parks and Monuments	X		
2. National Forests and Pt. Reyes National Seashore	X		
3. State Parks	X		
4. Wildlife Refuge Areas			
a) National Wildlife Refuge Areas	X		
b) State Wildlife Areas for Waterfowl	X		
c) State Waterfowl Refuge Area	X		
d) Marine Life Refuges and Reserves	X		
5. Wild, Scenic and Protected Waterways	X		
6. Wilderness, Natural and Primitive Areas	X		
7. Scenic Highways	X		
8. Indian Reservations	X		
9. Bomb Missile and Target Test Areas	X		
10. Military Bases	X		
C. Transportation and Transmission Lines			
1. Highways			X
2. Railroads			X
3. Navigable Waterways			X
4. Transmission Lines			X

considerations. In particular, although coastal sites would not necessarily be excluded due to physical constraints (with the exception of coastal zone III earthquake intensity areas), it was determined that the legal difficulties in obtaining approval for a coastal site made them less feasible than alternative inland sites.

Water presents such a complex problem in power plant siting in California that it is not possible to evaluate water availability on an area-wide basis. California has developed a large-scale system for transporting water since the areas of water supply are generally not coincident with areas of demand. Thus a given area may be able to obtain water from elsewhere in-state. We therefore analyzed each potential site for its water availability after the site had met the exclusionary siting criteria.

Most of the exclusionary criteria and two opportunity criteria were mapped on a series of transparent overlays at a scale of 1:2,000,000. These transparencies are reproduced here in black and white (Figures 8-2 through 8-12). Prime agricultural land was not mapped because a sufficiently generalized map of this information could not be obtained. Figure 8-12 depicts the areas which remained after the exclusionary criteria had been met. Since these feasible siting areas must be evaluated on an individual basis for water availability and for their proximity to prime agricultural land, many portions which appear in Figure 8-12 may upon closer evaluation be found unsuitable for power plant siting.

It should also be noted that many of the areas remaining as potential siting areas lie in mountainous regions which would increase the difficulty of constructing power plants or preclude them entirely. California has two main mountain ranges, the coastal range and the Sierra Nevada. The feasible siting areas in Humboldt, Mendocino, Sonoma, Monterey, San Luis Obispo and Santa Barbara Counties lie in the coastal ranges. The western portions of Nevada, Placer, El Dorado, Amador, Calaveras, Tuolumne, Mariposa and Madera Counties meet the exclusionary criteria, but they lie in the Sierra Nevada Mountain Range. The topography of the state is illustrated in Figure 8-13.

Figure 8-2


LEGEND
Air Basin Boundary
Air Quality Maintenance Area
1" = approx. 70 miles
DEL NORTE
SISKIYOU
MODOC
HUMBOLDT
TRINITY
SHASTA
LASSEN
TEHAMA
PLUMAS
MENDOCINO
GLENN
BUTTE
SIERRA
NEVADA
LAKE
COLUSA
SUTTER
YUBA
PLACER
YOLO
EL DORADO
SONOMA
NAPA
SACRA MENTO
ALPINE
AMADOR
SOLANO
MARIN
CALAVERAS
MONO
CONTRA COSTA
SAN JOAQUIN
TUOLUMNE
SAN FRANCISCO
ALAMEDA
SAN MATEO
STANISLAUS
MARIPOSA
SANTA CLARA
MERCED
MADERA
SANTA CRUZ
FRESNO
SAN BENITO
INYO
MONTEREY
TULARE
KINGS
SAN LUIS OBISPO
KERN
SAN BERNARDINO
SANTA BARBARA
VENTURA
LOS ANGELES
ORANGE
RIVERSIDE
SAN DIEGO
IMPERIAL

Figure 8-3

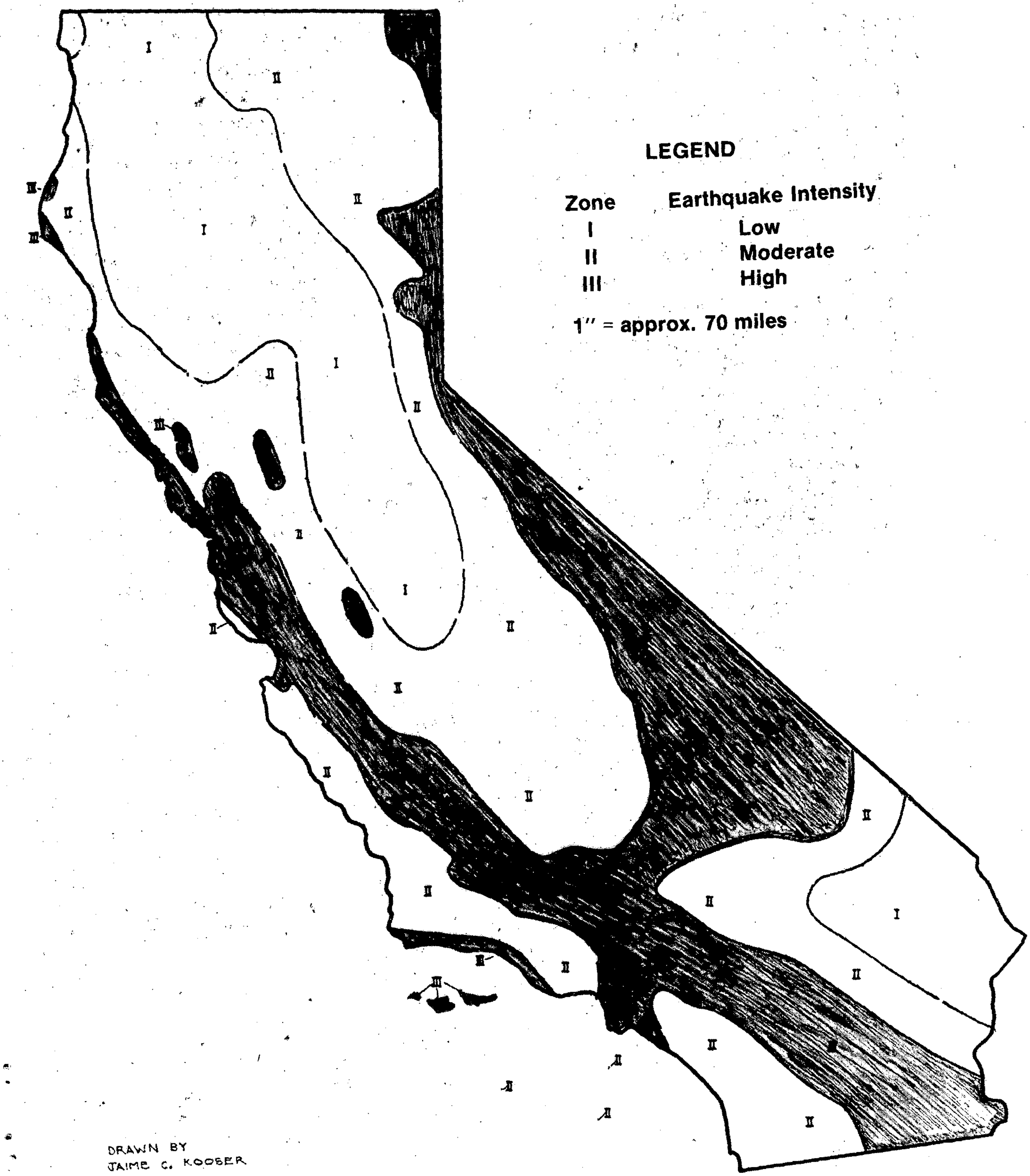


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Figure 8-4

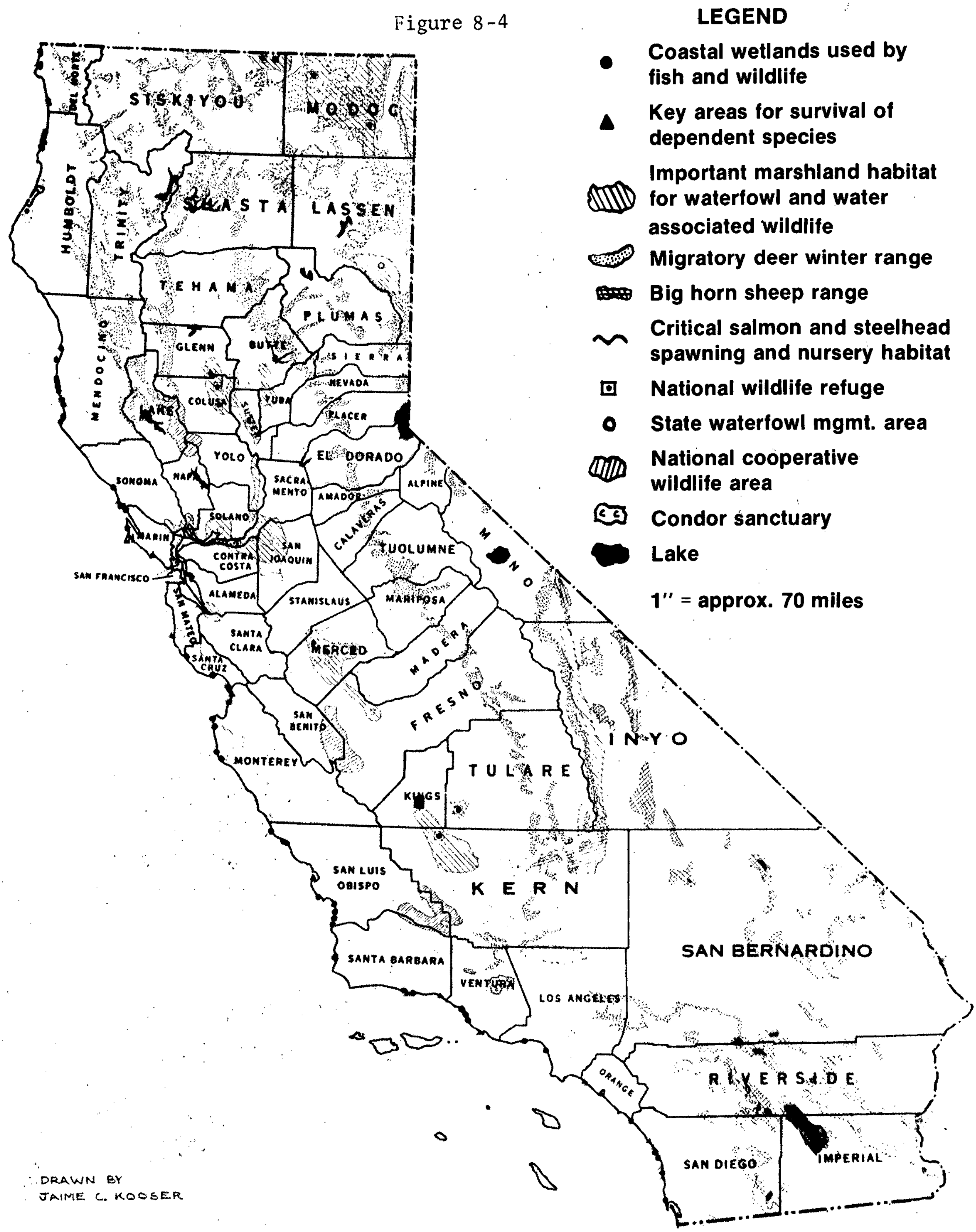

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Figure 8-5

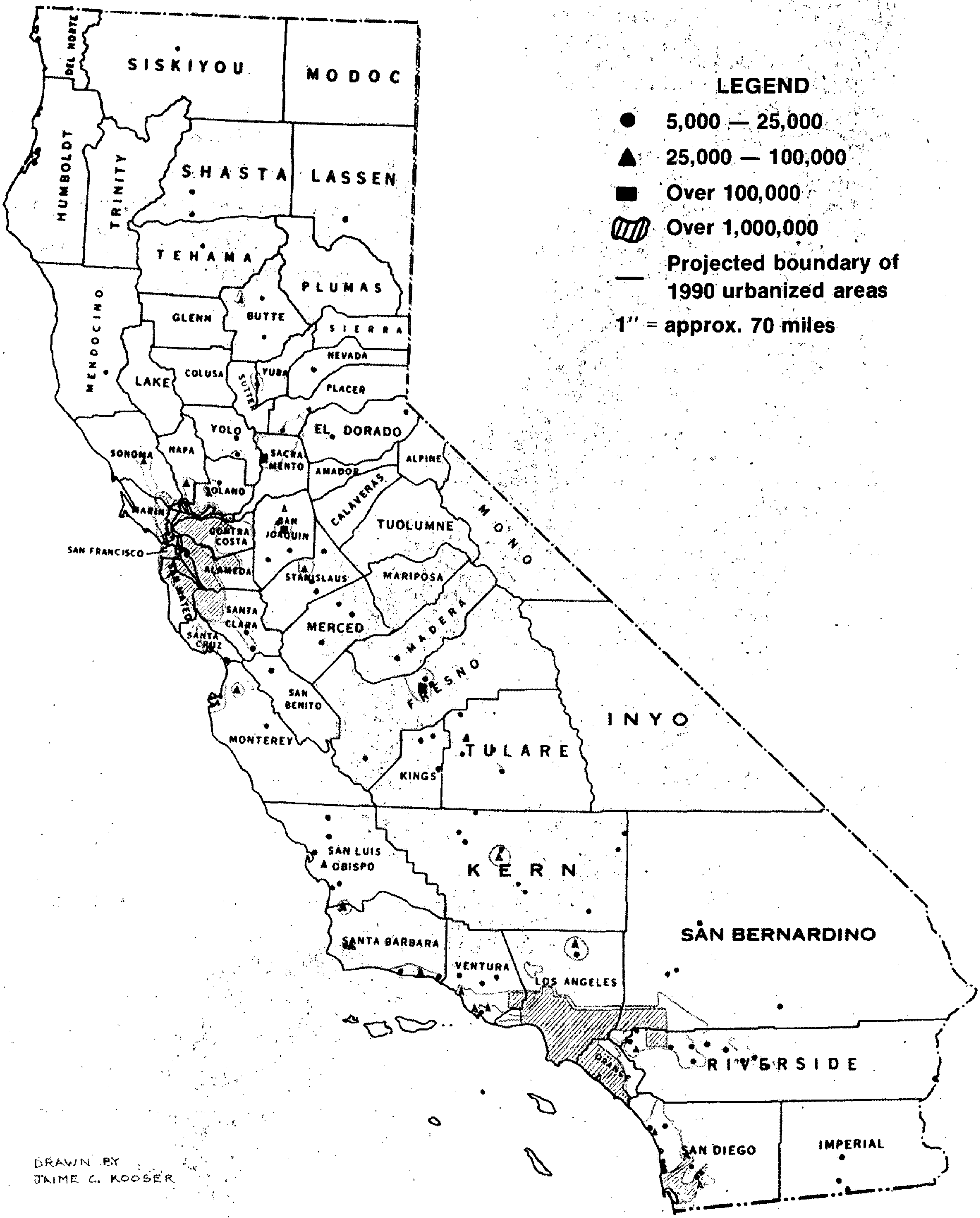

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Figure 8-6

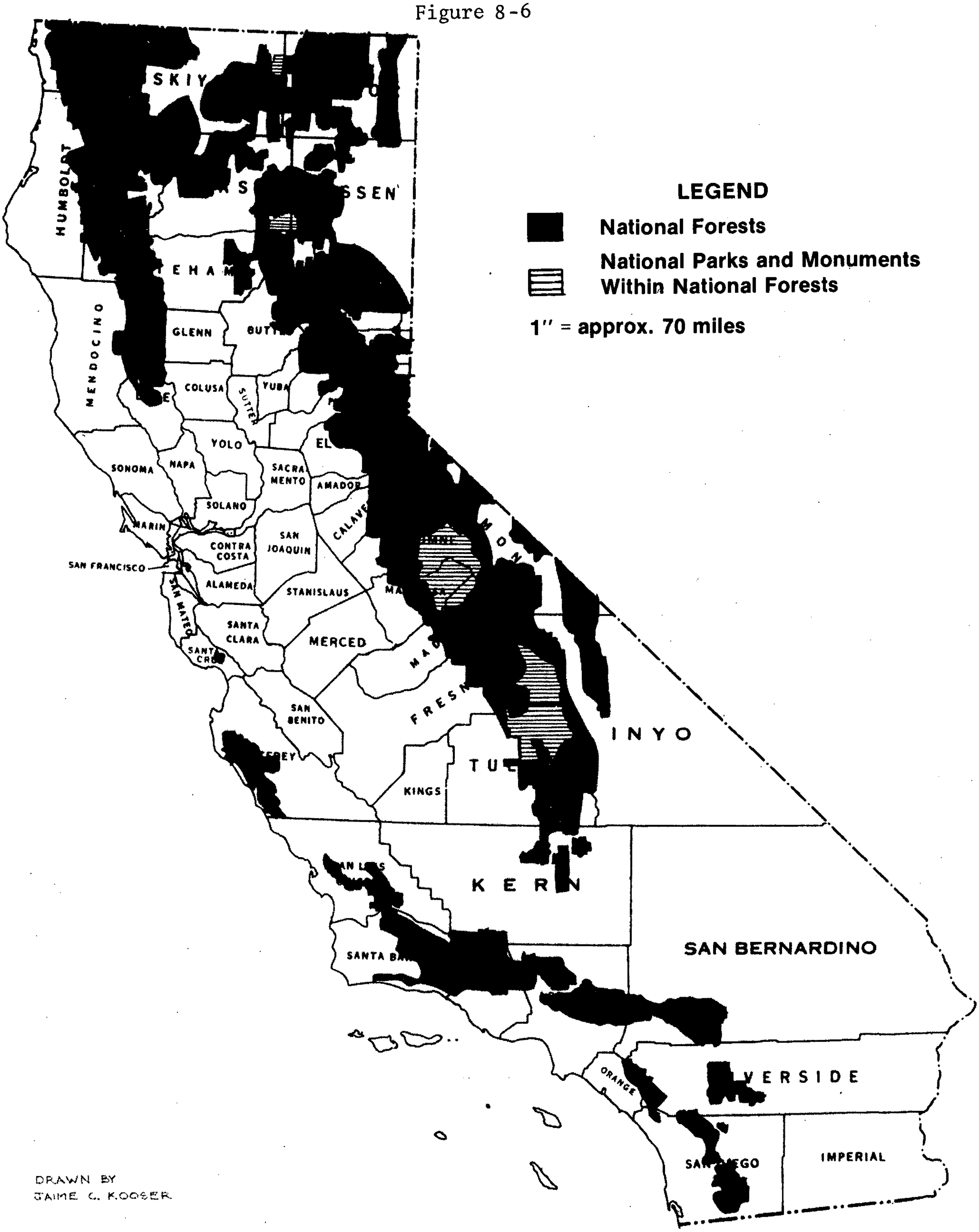

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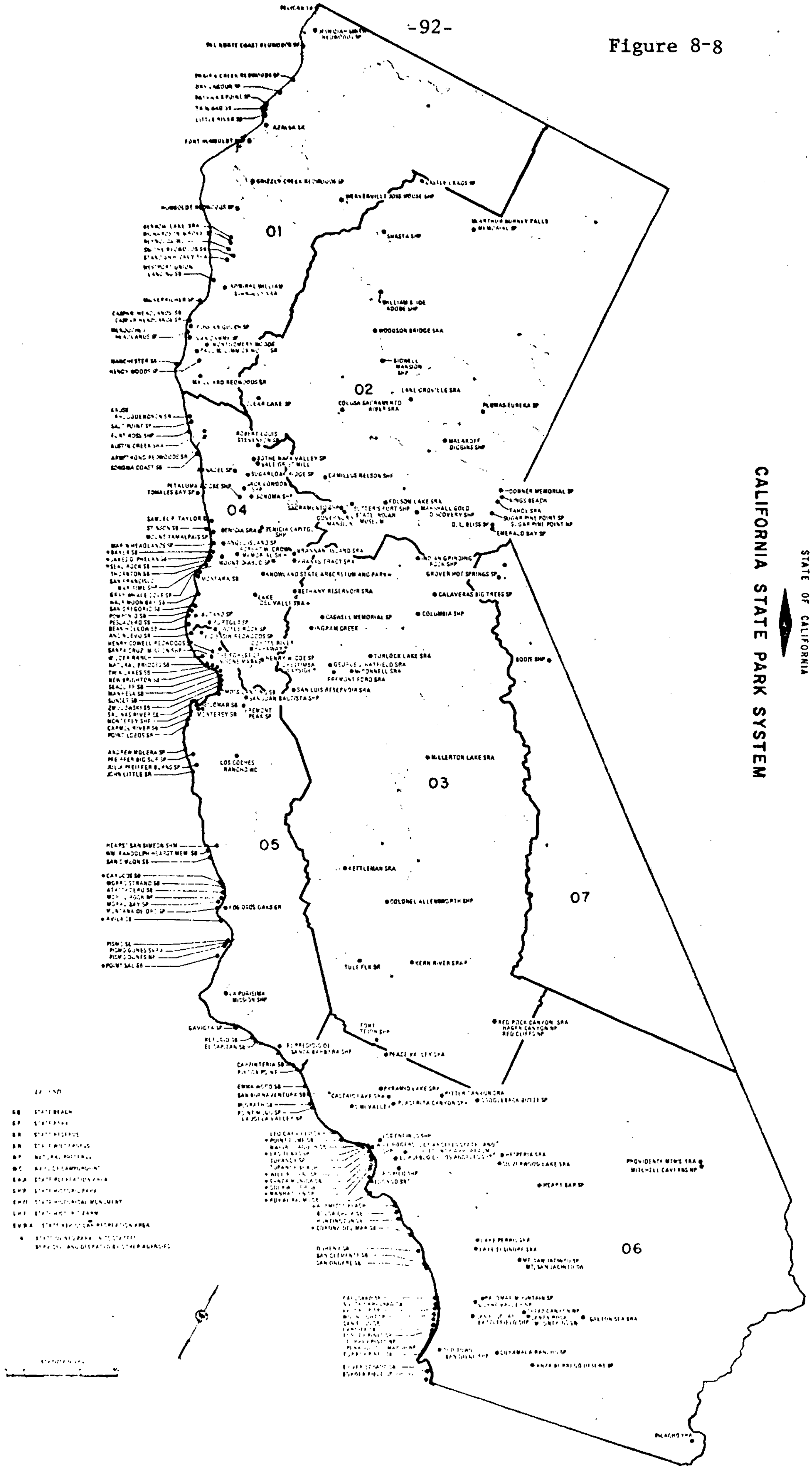
Figure 8-7

CBB 777-6971

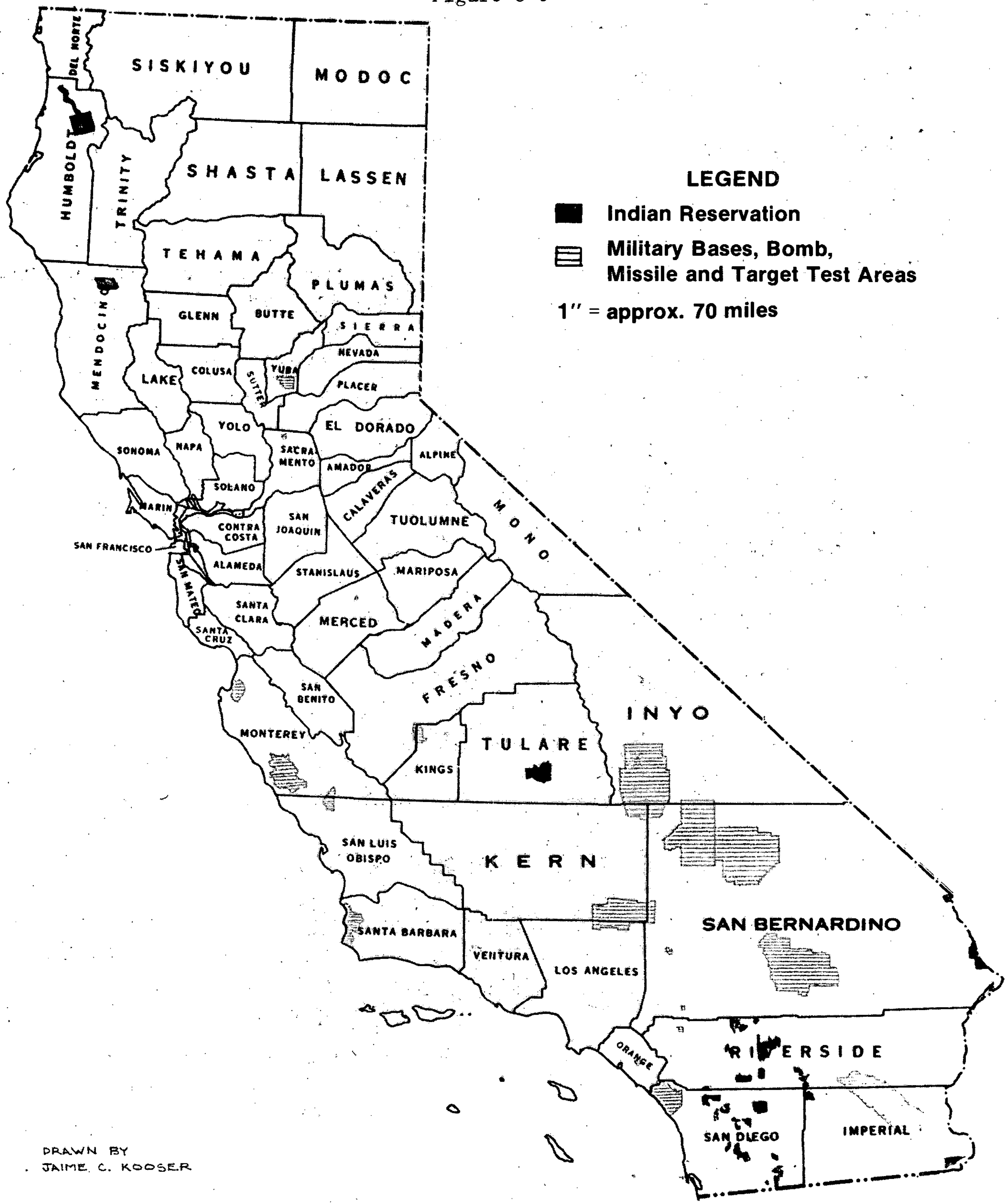
Figure 8-8



CALIFORNIA STATE PARK SYSTEM

Source: 1975 NATIONAL ASSESSMENT
REGION 18
STATE OF CALIFORNIA

Figure 8-9

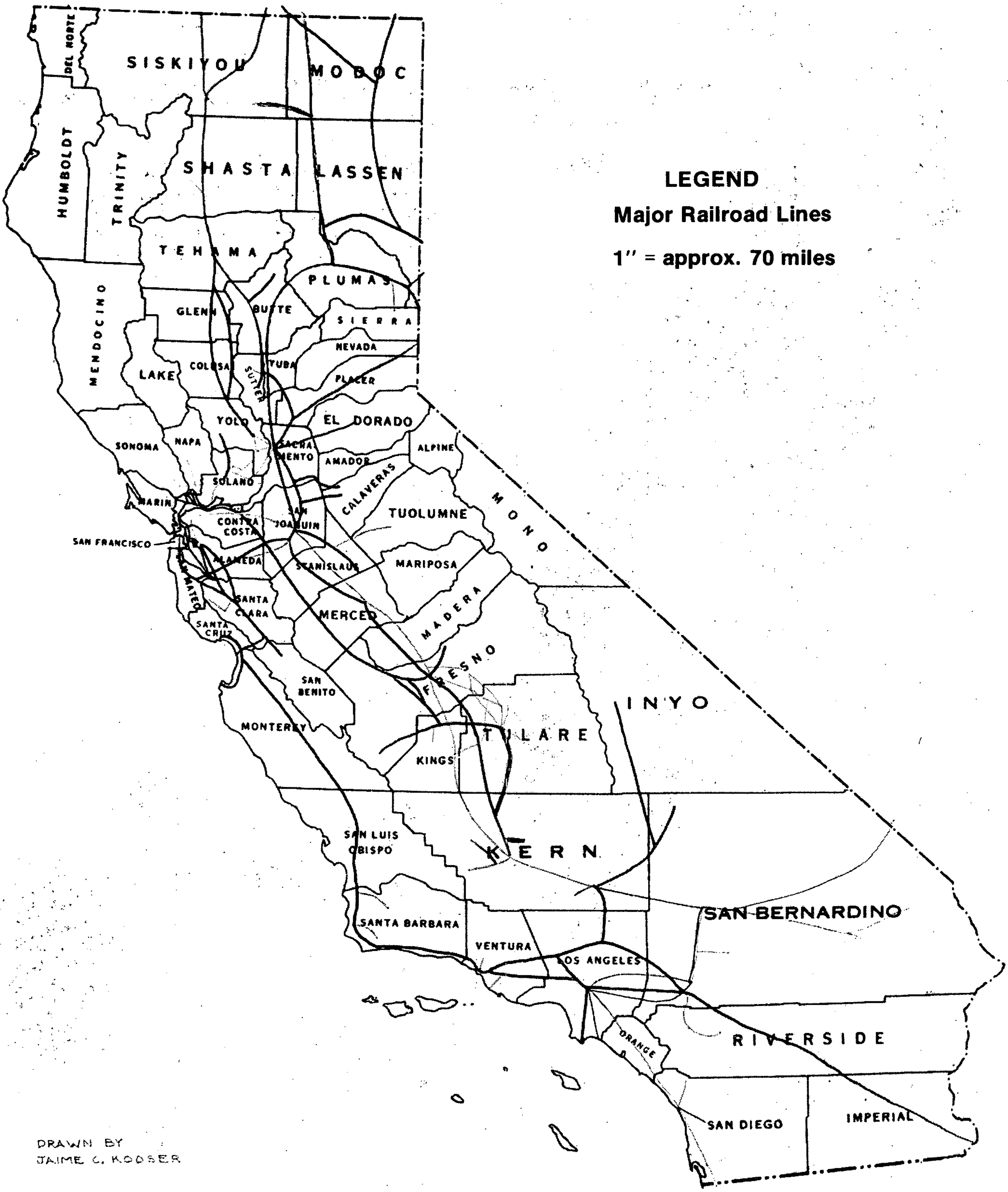


CBB 777-6979

Figure 8-10

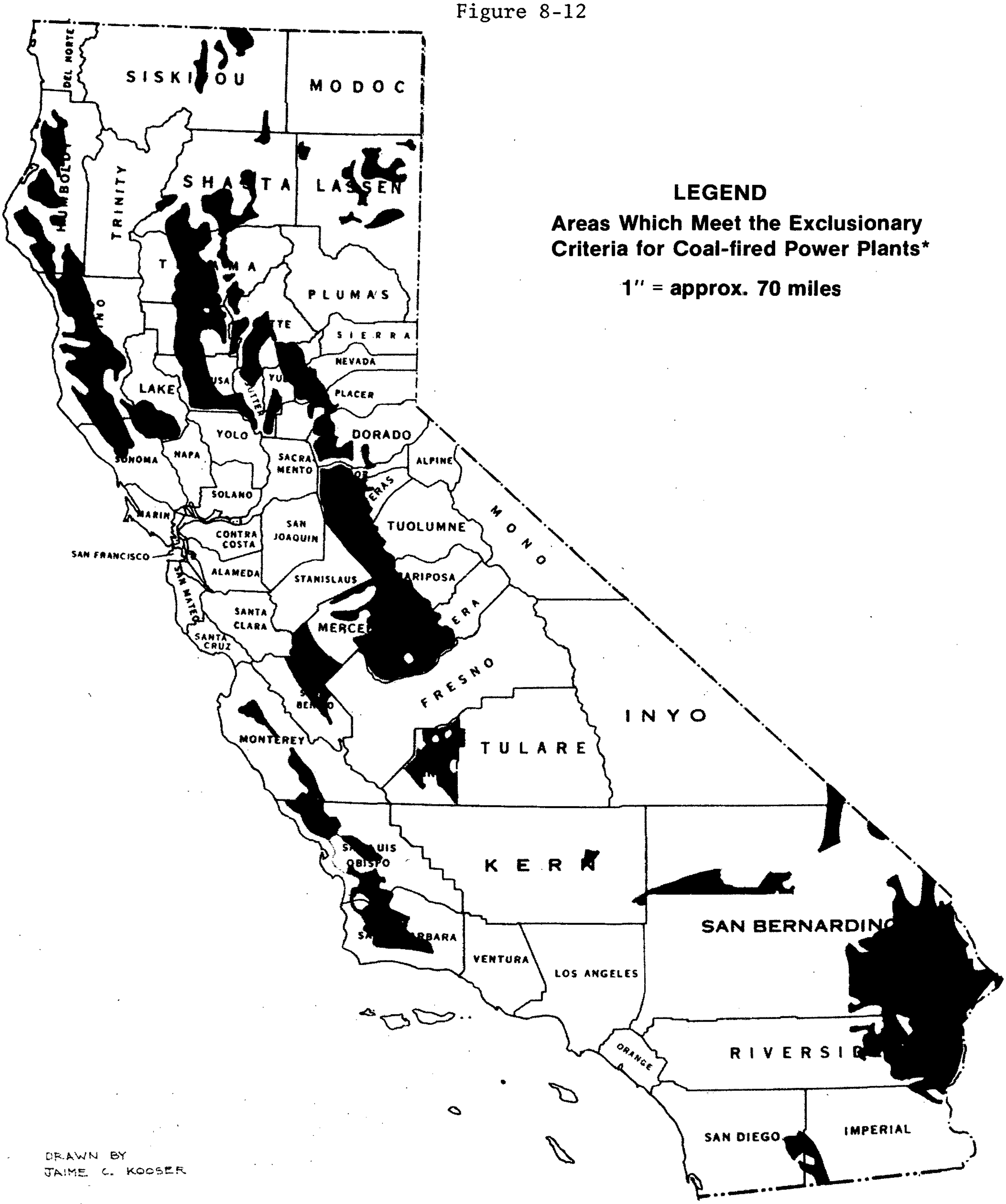
CBB 777-6977

Figure 8-11



CBB 777-6975

Figure 8-12



LEGEND
Areas Which Meet the Exclusionary Criteria for Coal-fired Power Plants*
1" = approx. 70 miles

***These areas may not meet the primary exclusionary criterion of prime agricultural land or the secondary avoidance criteria.**

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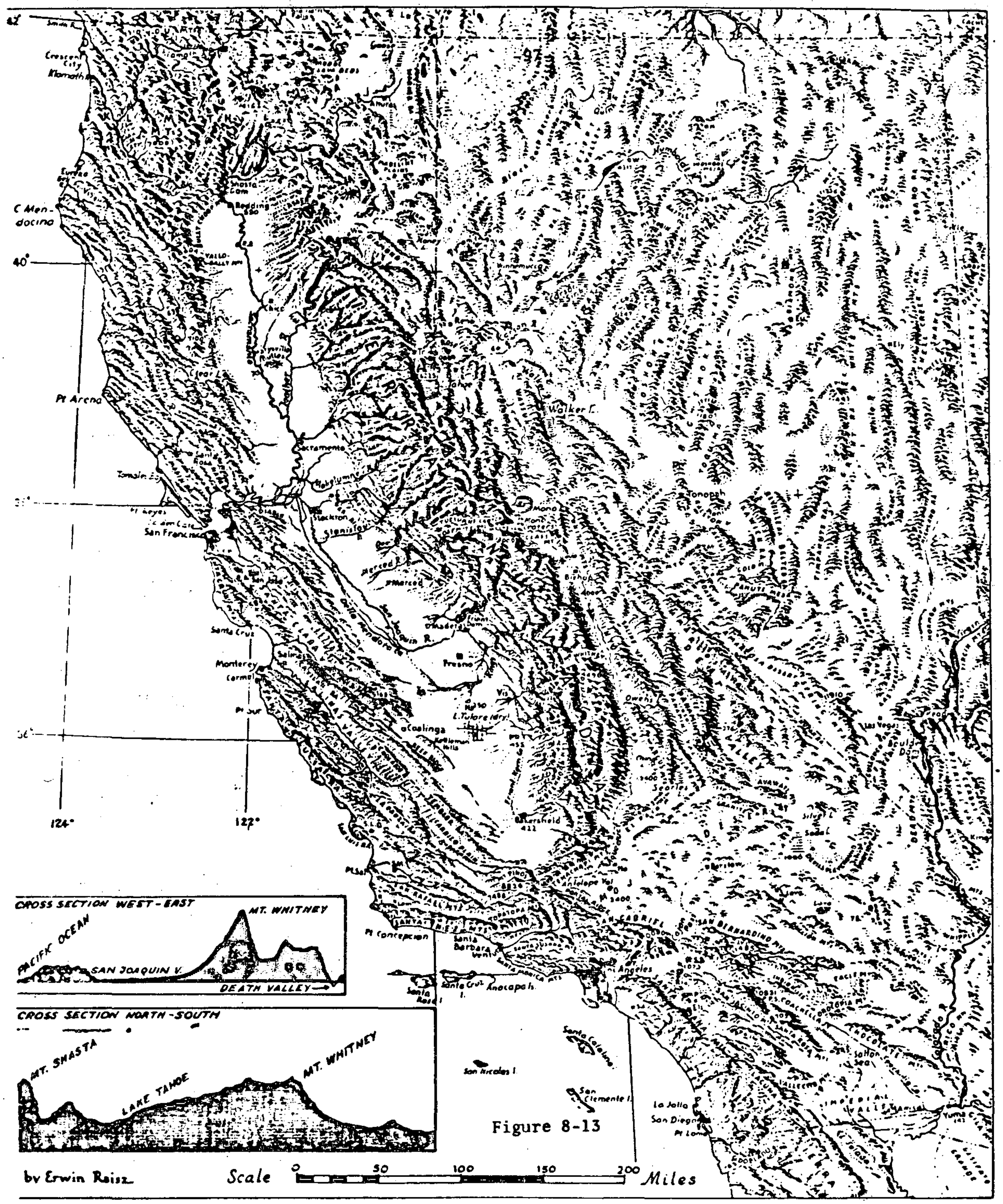
CROSS SECTION WEST - EAST
PACIFIC OCEAN
SAN JOAQUIN V.
MT. WHITNEY
DEATH VALLEY
CROSS SECTION NORTH - SOUTH
MT. SHASTA
LAKE TAHOE
MT. WHITNEY
by Erwin Raisz
Scale
0
50
100
150
200
Miles
40°
124°
122°
Pt Arena
Sacramento
San Francisco
Santa Cruz
Monterey
Carmel
Stockton
Merced
Fresno
Coalinga
Bakersfield
Pt Concepcion
Santa Barbara
Los Angeles
Santa Catalina
San Nicolas I.
San Clemente I.
La Jolla
San Diego
Tonopah
Walker L.
Bishop
Las Vegas
Salton Sea
Yuma

Figure 8-13

POWER PLANT SITING FOR THE NCUA SCENARIOS

The scenarios for California, disaggregated from the Pacific Region scenarios developed by Brookhaven National Laboratory, cover five major fuel types: 1) coal, 2) natural gas, 3) petroleum, 4) electricity and 5) solar and geothermal. There are four scenarios for 1975, 1985 and 2000: 1) Recent Trends, 2) Accelerated Synfuels, 3) High Coal-Electric, and 4) High Coal-Electric and Accelerated Synfuels. The fuel mix for scenarios 1) and 2) are identical, as are those for scenarios 3) and 4).

For the 1985 NCUA scenarios we sited on 800 MWe coal-fired power plant in Aggregated Subarea* (ASA) 1802 in southeastern Tehama County. The siting area is near Kirkwood which is approximately ten miles from Orland. The area is near a main line of the Southern Pacific Railroad and Interstate 5. In addition, it is near four 230 KV transmission lines. The area is within 25 miles of national forest areas to the west (Mendicino National Forest) and to the east (Lassen National Forest). Also, the Woodson Bridge State Recreation area is approximately 10 miles north of Kirkwood. The large areas of national forest land in northern California are difficult to avoid. Although the Kirkwood siting area is not presently in an air quality maintenance area, the degradation of the air quality may result in such a designation in the future. Certainly the air quality over the national forest areas can be expected to deteriorate, thus reducing the scenic and recreational value of these resource areas. It should be noted that the Kirkwood siting area is in a flood-prone hazard area (an avoidance criteria), but the siting area meets all the exclusionary criteria.

The possible sources of water in Tehama County include groundwater, reclaimed agricultural waste water and water made available by shifting current water use to power plant cooling. Presently, it is not possible to determine which source of water will be utilized for the coal-fired facility.

The High Coal-Electric and High Coal-Electric and Accelerated Synfuels scenarios for the year 2000 required the siting of seven additional units of coal-fired power plants. (Scenarios 1) and 2) did not require more coal-fired power plants.) We sited a second 800 MWe

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*For a discussion of Aggregated Subareas, see section 9.

unit at the first siting area near Kirkwood in Tehama County. A total of six units (two in each of three siting areas) was sited in the southeastern desert region in ASA 1806. Two of the units are sited near Cadiz in San Bernardino County. This siting area is near the junction of two main lines of the Atchison Topeka and Santa Fe Railroad and is close to a transmission corridor. Route 66 is several miles north of Cadiz. The siting area for two more units is near Goffs in eastern San Bernardino County. The Atchison Topeka and Santa Fe Railroad goes through Goffs and Route 66 lies to the south. The final two units are located in a siting area south of the town of Rice in Rice Valley in Riverside County. Again, the siting area is near an Atchison Topeka and Santa Fe rail line and Route 62 goes through Rice. The total coal-fired capacity in 2000 is 6400 MWe. These four coal siting areas are shown in Figure 8-14.

The eastern desert area of San Bernardino and Riverside Counties is not currently an air quality maintenance area, but the six units of coal-fired capacity are sited near significant biological resources (especially big horn sheep range areas) and are in recognized scenic desert areas. The air pollutants may result in adverse impacts on these resources. The sources of water available in the eastern desert area are discussed below in the section on nuclear power plant sites.

All four NCUA scenarios specify 8245 MWe of nuclear power plant capacity for 1985. For the nuclear siting analysis, we relied mainly on the nuclear sites already identified by various California utilities. More power plant sites than are needed to meet the NCUA scenario requirements have already been identified by the electric utilities. For 1985 these consist of those currently operating nuclear plants (Humboldt Bay, Rancho Seco and San Onofre) plus an additional two units at San Onofre (in San Diego County), two units under construction at Diablo Canyon in San Luis Obispo County, and one unit each at Sundesert in eastern Riverside County and San Joaquin in Kern County. This totals 8245 MWe of nuclear capacity for 1985.

For the year 2000 nuclear capacity increases to 19545 MWe in the Recent Trends and Accelerated Synfuel scenarios, requiring an additional

Figure 8-14

Coal-fired Power Plant Siting Areas

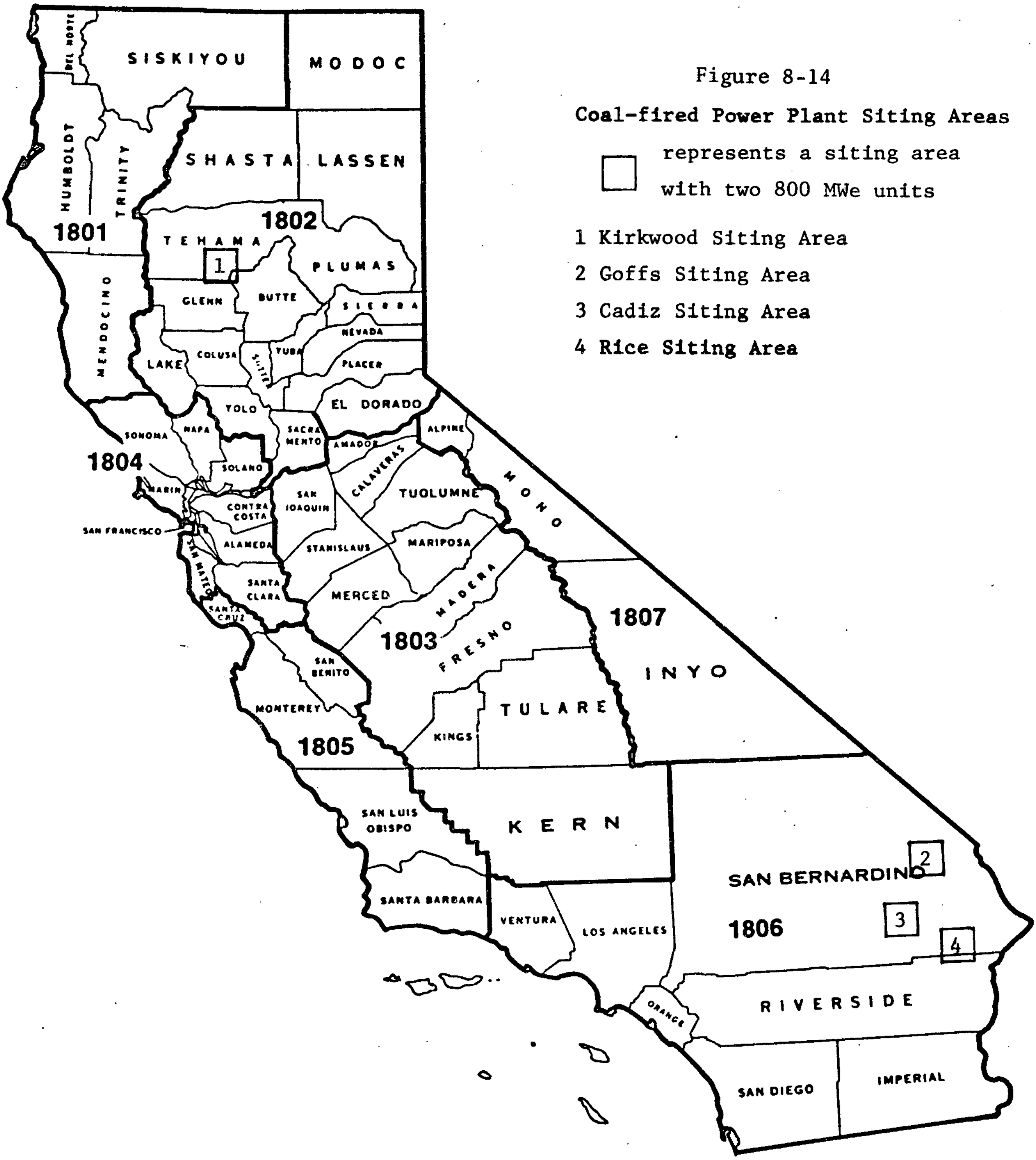
☐ represents a siting area with two 800 MWe units

1 Kirkwood Siting Area

2 Goffs Siting Area

3 Cadiz Siting Area

4 Rice Siting Area



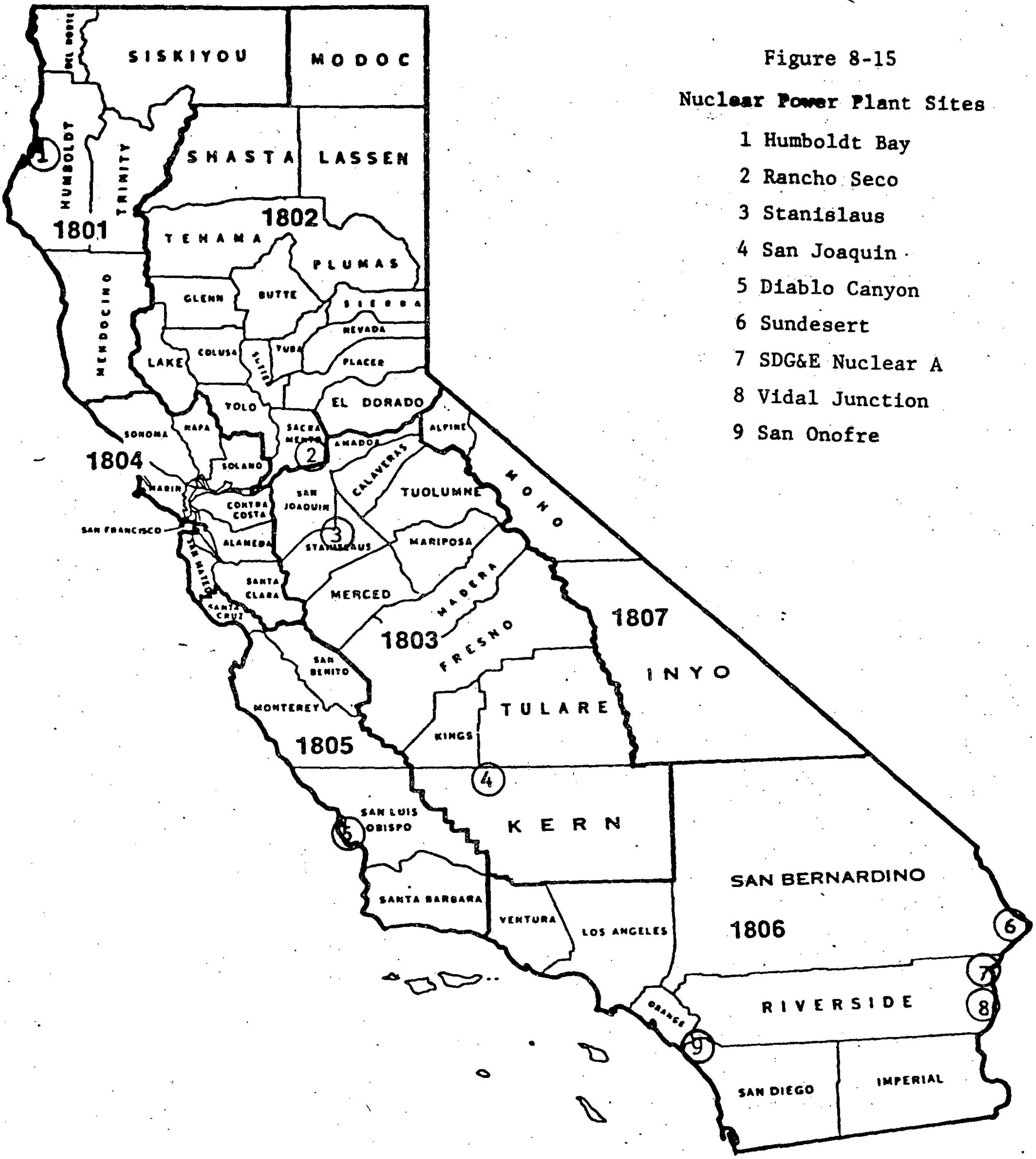
Aggregated Subareas of California

XBL 776-8970

Figure 8-15

Nuclear Power Plant Sites

1 Humboldt Bay
2 Rancho Seco
3 Stanislaus
4 San Joaquin
5 Diablo Canyon
6 Sundesert
7 SDG&E Nuclear A
8 Vidal Junction
9 San Onofre



Aggregated Subareas of California

XBL 776-8970

11300 MWe to be sited. Assuming that each power plant is approximately 1100 MWe, this necessitates ten additional units. They have been sited as follows: Rancho Seco 2 (ASA 1802), San Joaquin 2, 3, 4 (ASA 1803), Stanislaus 1, 2 (ASA 1803), Sundesert 2 (ASA 1806), SDG&E Nuclear A (ASA 1806) and Vidal Junction 1, 2 (ASA 1806). The siting pattern for nuclear plants thus emphasizes Central Valley sites (8 units by the year 2000) and eastern desert sites (5 units by the year 2000). All the nuclear sites are shown in Figure 8-15.

The nuclear power plants in the eastern desert have several available sources of water, including Colorado River water, potential deep groundwater and reclaimed agricultural waste water. The plans for unit one at Sundesert specify 17,000 acre-feet of reclaimed agricultural waste water for cooling purposes. In addition to these sources, San Diego Gas and Electric has obtained water by purchasing ranches, thereby obtaining the water rights. These types of transactions make it difficult to determine exactly how the water will be obtained, although it appears there is sufficient water available for the nuclear power plants sited in the eastern desert area.

Not all of the nuclear power plant sites meet all of the exclusionary siting criteria due to our utilization of utility proposed sites. Rancho Seco, Stanislaus, San Joaquin and San Onofre are in air quality maintenance areas. Siting nuclear power plants in air quality maintenance areas is not considered critical, however, since the air emission standards for the AQMAs generally affect fossil fuel use and are not based upon airborne radioactive emissions. Also, several plants are in areas of significant biological resources, particularly areas of important marshland habitat for waterfowl and water-associated wildlife. These power plant sites include Humboldt Bay, San Joaquin and San Onofre. Other than these exceptions, the nuclear sites meet our exclusionary siting criteria.

The remaining fuel types in the NCUA scenarios, namely, oil, gas, geothermal, solar and hydro, were not specifically considered in the siting analysis; geothermal, solar and hydro were sited by ASA regions. No new oil and gas facilities were considered and therefore no new sites were necessary. Geothermal development will necessarily be confined to the Imperial Valley Geothermal Resource Area in ASA 1806, and in 2000 there will be four sites (Salton Sea, Brawley, Heber and East Mesa).

Solar power plants of the central receiver type have been assigned to ASA 1806 in the southeastern desert. These 20 plants have not yet been sited more specifically. Any hydroelectric additions would most likely be sited in ASA 1802, but no specific additions of hydroelectric plants have been designated in our siting analysis.

CONCLUSIONS AND FURTHER SITING ISSUES

1) The siting of energy facilities in California is severely constrained by physical and political difficulties. In particular, air quality problems and water availability problems, which will be exaccerbated by the expected increase in population by 2000, will require special attention in order to meet the requirements of the 2000 scenarios.

2) The potential conflict among state agencies increases the difficulty of siting power plants in California. The potential problem between ERCDC and the Coastal Commission has already been mentioned. The Coastal Commission encourages inland sites which need fresh water for cooling while the State Water Resources Control Board (SWRCB) gives inland fresh water for power plant cooling the lowest priority. The Air Resources Board (ARB) is presently considering standards for air quality conservation that would preclude construction of fossil fuel plants over 100 megawatts anywhere in California. The conflicting mandates among state agencies are certain to complicate power plant siting, despite the exclusive authority for siting of the ERCDC.

3) The socio-cultural impact on rural areas, which are the most likely sites for power plants, could be severe. Usually local rural governments have few resources to spare for handling the problems inherent in the intense activity surrounding the construction of a power plant, such as demands on local services. Governments not prepared for the changes in the community structure will suffer more severe social impacts. Although this issue has not been addressed in this siting analysis, it deserves consideration in the second year of the study.

9. WATER RESOURCES ANALYSIS

REGIONAL WATER PROFILE

Geographic Distribution

Water availability in California varies widely over the state with about 75 percent of the State's runoff occurring north of the Sacramento-San Joaquin Delta area. However, about 75 percent of the water demand occurs south of the Delta, causing large geographic disproportionalities in the water supply and demand picture. Transport of water from supply to demand areas requires a massive, intricate system that is one of the world's larges water projects.

The California water system has two regulated points of diversion: the Sacramento-San Joaquin Delta and the Colorado River (Fig. 9-1) The State Water Project (SWP) and the Federal Central Valley Project (CVP) divert water from the Sacramento-San Joaquin Delta and transport it to the south. California has an annual entitlement of 4.4 million acre-feet; however, the State currently diverts over 5 million acre-feet/year from the Colorado River. Of this amount, about 4 million acre-feet/year are delivered to the Colorado Desert region primarily for agriculture.[2] The remaining million acre-feet are transported by the Metropolitan Water District of Southern California to the South Coastal Plain. California's entitlement to the Colorado River will be reduced by about 600,000 acre-feet when the Central Arizona Project is completed in the mid-1980's.

The SWP, which is operated by the California Department of Water Resources, delivered about 1.6 million acre-feet of water in 1976 through the California Aqueduct. The majority of this water is delivered to the San Joaquin Valley for agricultural irrigation, while some of it is pumped over the Tehachapi Mountains for use in Southern California. The CVP, which is operated by the Federal Bureau of Reclamation and the Corps of Engineers, delivers about 6 million acre-feet/year of water from

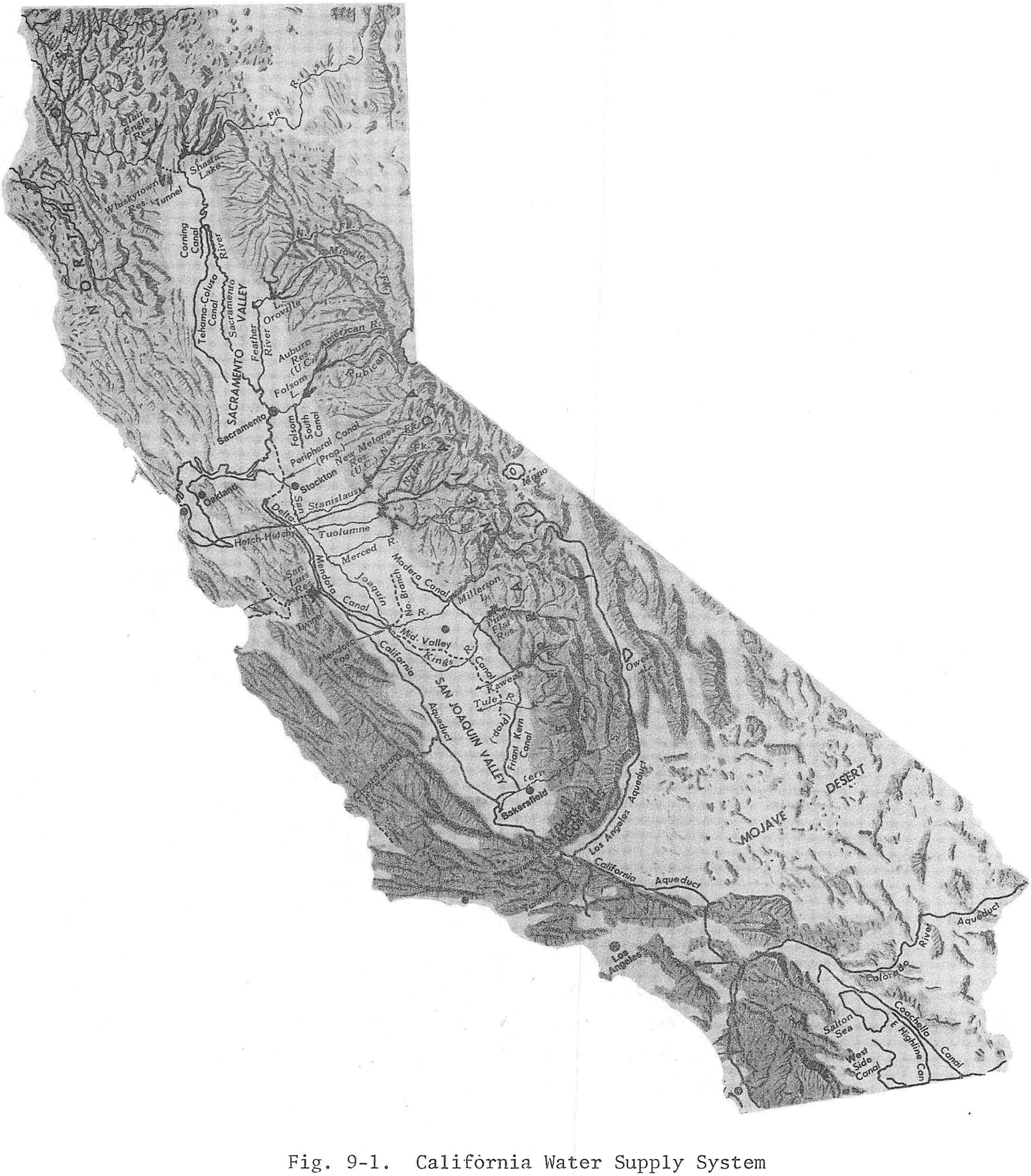


Fig. 9-1. California Water Supply System

XBB 777-7307

the Delta. The Bureau also sells the Colorado River water to California and therefore is responsible for about one-third of the State's water needs.

Figure 9-2 shows the aggregated subareas (ASA) in California as defined by the Federal Water Resources Council. Since the ASA is used throughout the report as the basic geographic unit, the following brief description of each ASA in California will help establish the regional water profile.

ASA 1801 (North Coastal) is situated in Northern California and includes Klamath County (about 3.2 million acres) in south central Oregon. California's portion of this ASA (about 14.5 million acres) is the most water-abundant area in the State producing 40 percent of the total surface water runoff annually.[1] However, the California Wild and Scenic Rivers Act of 1972 preserves and protects much of this area from future water development. The relationship of this Act to future water resource development will be discussed in a later section of the report. Generally water supplies in this ASA are adequate to meet needs, but there is a lack of carry-over storage of winter runoff.

ASA 1802 (Sacramento Basin) comprises 17 counties in Northeastern California with a total area of 20.8 million acres. The Sacramento Basin is the second largest water-producing area in the State with about 30 percent of the State's natural runoff originating in this subarea. Ninety percent of the water withdrawals are used for farming, but urban growth is expected to continue near present cities with a 65 percent increase from present water demand occurring by 2000.[2] Generally, this ASA has adequate surface water supplies; however, some areas have water shortages. Water quality of surface flows is reported to be generally good. There are some water quality problems caused by local concentrations of return water from irrigated agriculture and heavy metals from drainage through tailings of abandoned mines.

ASA 1803 (San Joaquin Valley) is an area which envelopes the southern two-thirds of the Central Valley. The subarea includes 12 counties with a total area of about 21 million acres. Although there is natural runoff within the area, ground water withdrawals in many basins exceed the estimated safe yields (i.e., the amount by which the supply is annually replenished usually by precipitation). At present

Aggregated Subareas of California

XBL 776-8970

Fig. 9-2

there is a ground water overdraft of about 1.5 million acre-feet per year in the San Joaquin Valley.[3] Over 95 percent of the water withdrawal is used to irrigate nearly 5 million acres of farmland. These agricultural withdrawals are projected to increase over the next 25 years.[1] The major problems include ground water overdraft, especially in the Tulare Basin and water quality degradation due to agricultural drain waters.

ASA 1804 (San Francisco Bay) comprises 4.7 million acres and 9 counties surrounding San Francisco, San Pablo and Suisun Bays. This subarea is second in total population for the State. San Francisco Bay area has sufficient water supplies through importation to meet its needs unto 2000.[1] The northwest portion of ASA 1804 is both agricultural and urban with irrigated agriculture accounting for about 60 percent of the total water demand. The southeastern part is highly urbanized and present irrigation is expected to be substantially reduced by urban encroachment by 2000.[1]

ASA 1805 (Central Coast) is a subregion which essentially spans the coastal interval between the metropolitan areas of San Francisco Bay and the south coastal area. It includes 5 counties and a total area of 7.2 million acres. Ground water is the main water source, which is presently overdrafted. This subarea is water-deficient and with expected increases in urban demands, there may develop a conflict between municipal needs and agriculture. However, water conservation practices and reclamation of waste water from the urban sector may offset the loss of prime agricultural water diverted to urban use.

ASA 1806 (South Coastal area and Colorado Desert) is composed of two distinct hydrologic systems. The California South Coastal Plain includes all basins draining directly to the Pacific Ocean from the Ventura River to the Mexican border. The Colorado Desert area includes the drainages of the Colorado River Basin portion in California. The total area encompasses 7 counties and about 27.5 million acres. ASA 1806 includes the most populous area in the State which is projected to increase in the future to about 12 million people.[1] Eighty-five percent of the total withdrawal is from imported water from the Colorado River diversion and the SWP. Since irrigated agriculture in the Colorado River is second only to the Central Valley, the competition between agriculture, municipal and industrial users could be severe in the future.

ASA 1807 (south Lahontan) includes 3 counties on the east side of the Sierra Nevada, an area which encompasses 8.9 million acres. The subarea is characterized by a large number of enclosed basins and sinks. Water supplies are generally adequate for demands estimated through 2000.[1] Since this region is the most sparsely populated in the State, there are no severe problems identified.

Water Resources Availability

The presently developed water supplies in California include the following:

1) water transported within California through the SWP and CVP;
2) interregional water transfer from the Colorado River diversion to the Los Angeles Basin and Colorado Desert; and
3) ground water used in agriculture and urban areas.

The average annual runoff potentially available to California is about 76.6 million acre-feet.[4] Runoff in individual years, however, has varied. In 1975-76, a dry year, runoff was estimated to be about 44 million acre-feet.* California meets about 60 percent of its annual demand through the diversion of natural runoff. The use of remaining natural runoff is limited by the ability to capture the resource.

California, through the Department of Finance, Department of Water Resources (DWR) and the State Water Resources Control Board (SWRCB) retains possession of the State's filings on surface water. There have been filings on most unappropriated surface water in the State. Development potential for additional firm surface water supplies is limited due to economic, environmental and institutional constraints.

The largest potential source of additional water supply is in the North Coastal Area (ASA 1801); however, its development is precluded by the California Wild and Scenic Rivers Act of 1972. In case of the

*It was forecasted that the statewide runoff in 1977 would be only 20 percent of an average year.[5]

Eel River, DWR is required to report to the legislature in 1985 as to whether segments of the river should be deleted from the Act.

Ground water forms another major source of water in California. About 40 percent (roughly 15 million acre-feet) of the applied water requirement is now pumped from underground basins.[4] DWR estimates that the State's total ground water storage capacity is about 143 million acre-feet.[3] The only major ground water basin that has the capability of a safe yield greater than its present use is in the Sacramento Valley. At present, there is an overdraft of about 2.2 million acre-feet/year of which the San Joaquin Valley (ASA 1803), especially the Tulare Basin, accounts for 1.5 million acre-feet/year.

A potential problem with the continued use of ground water involves the concept of ground water mining. Removal of ground water in excess of safe yield constitutes ground water mining. The approach of the California courts in recent years has been to consider ground water as a non-renewable resource and to discourage ground water mining. This trend, however, may be changed in the future as the need for new water sources becomes more urgent.

Due to the limited fresh water supplies and growing demands for water, waste water reclamation has become a potential water source. The two main sources are agricultural drainage water and municipal waste water. It is estimated that about 2 million acre-feet/year of municipal waste water now flows into the ocean and is lost as a fresh water source. Less than 8 percent of this water is reclaimed for further beneficial use.[6] The City of Burbank, for example, cools its municipal power plant with reclaimed water. Currently, the facilities for complete municipal waste water reclamation do not exist, nor do the conveyance systems which would transport the effluents from their source to the remote sites of utilization.

Agricultural drainage water is another potential source of water. After single or multiple use of irrigation water it is no longer suitable for agricultural purposes and is classified as waste water. In the Imperial Valley alone about one million acre-feet/year of agricultural drainage water is available for use by power plants.[7] Another area where agricultural waste water is being collected is the San Joaquin

Valley. There are various problems associated with the use of irrigation waste water including conveyance costs, costs of chemical pretreatment in some cases, and the seasonal nature of the irrigation drainage.

Table 9-1 summarizes the projected water supply picture in California by ASA. The information was interpolated from data presented in DWR Bulletin 160-74, using Alternative II.[2] Alternative future II includes a fertility rate of 2.5 and a net migration rate of 150,000 people. Since the information in the Bulletin is reported by hydrologic study areas (HSA) rather than ASA, certain area correlations are assumed. Table 9-2 contains the correlations that are used by DWR in relating hydrologic study areas to aggregated subareas.[1]

DWR's water supply projections for 1985 and 2000 assume the following conditions:[2]

1) construction will be completed as necessary to meet contractual deliveries of SWP;
2) ground water will be within safe yields by the year 2000;
3) Colorado River imports will be reduced from the present level of over 5 million acre-feet/year to California's allotment of 4.4 million acre-feet/year by 1990;
4) New Melones Reservoir yield would be maximum;
5) SWRCB's Decision 1379 ("Criteria for Sacramento-San Joaquin Delta") will be relaxed; and
6) Some trans-delta conveyance facility will be constructed to convey water across the Sacramento-San Joaquin Delta to the SWP and the CVP.

Water Demands

The projected net water demands in California are shown in Table 9-3. The values were derived from data in DWR Bulletin 160-74 using Alternative II.[2] The information was adjusted to aggregated subareas using the method described above. Agricultural irrigation accounts for about 85 percent of the total net water demand in California. The remaining water requirements are for the municipal and industrial sectors,

Table 9-1

Projected Water Supply in California*
(10^6 acre-feet)

ASA	1975	1985	2000
1801	.963	.974	.991
1802	7.726	8.304	8.744
1803	12.342	13.197	13.647
1804	2.042	2.309	2.529
1805	.850	.917	.950
1806	7.416	8.320	8.777
1807	.215	.280	.314
TOTAL	31.554	34.301	35.952

* Interpolated from data in DWR Bulletin 160-74, Table 27, pp. 146-47 and adjusted from hydrologic study areas to aggregated subareas.

Table 9-2

Correlations or Hydrologic Study Areas to Aggregated Subareas in California

ASA (Aggregated Subarea)	HSA (Hydrologic Study Area)	Planning Subareas
1801	North Coastal	All
1802	Sacramento	All
	North Lahontan	Lassen Group; Alpine Group-Tahoe and Truckee Basin
	Delta Central Sierra	30% Delta service area
1803	San Joaquin	All
	Tulare	All
	Delta Central Sierra	Foothill and uplands; Eastern Valley Floor; 50% of Delta service area
1804	San Francisco Bay	All
	Delta Central Sierra	Western uplands; 20% of Delta service area
1805	Central Coast	All
1806	South Coastal	All
	Colorado Desert	All
	South Lahontan	Mohave River, Antelope Valley
1807	South Lahontan	Mono-Owens area; Death Valley
	North Lahontan	Alpine Group; Canyon and Walker Basins

Source: California Department of Water Resources, 1975 National Assessment: State-Regional Future, Technical Memorandum No. 2, July 1976.

Table 9-3

Projected Net Water Demands in California*
(10^6 acre-feet)

ASA	1975			1985			2000		
	Agri-culture	Urban	Total	Agri-culture	Urban	Total	Agri-culture	Urban	Total
1801	.556	.392	.948	.549	.427	.976	.535	.468	1.003
1802	6.526	.529	7.055	7.281	.676	7.957	7.967	.866	8.833
1803	12.989	.416	13.405	14.380	.522	14.902	15.563	.716	16.279
1804	.860	.970	1.830	.976	1.207	2.183	1.105	1.527	2.632
1805	.889	.103	.992	.994	.137	1.131	1.098	.195	1.293
1806	5.406	2.009	7.415	5.364	2.467	7.831	5.266	3.173	8.439
1807	.236	.016	.252	.245	.024	.269	.273	.023	.296
TOTAL	27.462	4.435	31.897	29.789	5.460	35.249	31.807	6.968	38.775

* Interpolated from data in DWR Bulletin 160-74, Table 27, pp. 146-47 and adjusted from hydrologic study areas to aggregated subareas.

which includes power plant cooling. Power plants consume a very small fraction (32,000 acre-feet/year) of the total fresh water demands, since most of this demand at the present time is met by the use of sea water.

Water demands now exceed the available water supplies in some areas of the State. At present, the deficiency is supplied for the most part by ground water overdraft. Table 9-4 shows the deficiency in water supply required to meet agricultural and urban water needs.

Until the year 2000 the deficits are primarily in the San Joaquin Valley (ASA 1803) and the Central Coast (ASA 1805) areas. By 2000 nearly every ASA in California is expected to have a deficiency in water supply. This deficiency may be larger if power plants are restricted from being sited along the coast. Furthermore, in-stream water uses such as recreation, fish, wildlife, and water quality management have received increasing attention in recent years. These uses in the future may require higher minimum water levels in streams, thus affecting the firm water commitments for other uses. Additional water requirements for power plants and for in-stream uses may not be reflected in the DWR estimates.

WATER REQUIREMENTS FOR PROJECTED ENERGY DEVELOPMENT

The objective of this portion of the analysis is to calculate the water requirements for projected energy development in California using the NCUA scenarios. Cooling water requirements vary depending on the type of power plant (Table 9-5).[8] The proportion of different types of power plants in a fuel mix and the various methods for cooling will dictate the impact on water resources in California.

Table 9-6 illustrates the fresh water requirements for power plant cooling by ASA within California for 1975, 1985 and 2000. Since the fuel mix for the Recent Trends (1) and Accelerated Synfuels (2) scenarios are different from the High Coal-Electric (3) and High Coal-Electric and Accelerated Synfuels (4) scenarios, the data for 2000 is separated by scenarios.

Table 9-4

Projected Deficiency in Water Supply to Meet Agricultural and Urban Demand (10^6 acre-feet)

	1975			1985			2000		
ASA	Supply	Net Demand	Deficit	Supply	Net Demand	Deficit	Supply	Net Demand	Deficit
1801	.963	.948	--	.974	.976	--	.991	1.003	.012
1802	7.726	7.055	--	8.304	7.957	--	8.744	8.833	.089
1803*	12.342	13.405	1.063	13.197	14.902	1.705	13.647	16.279	2.632
1804	2.042	1.830	--	2.309	2.183	--	2.529	2.632	.103
1805*	.850	.992	.142	.917	1.131	.214	.950	1.293	.343
1806	7.416	7.415	--	8.320	7.831	--	8.777	8.439	--
1807	.215	.252	--	.280	.269	--	.314	.296	--
TOTAL	31.55	31.90		34.30	35.25		35.95	38.77	

Table 9-5

Unit Water Requirements

Type of Power Plant	Assumed Plant Factor	Wet Tower Water Requirements acre-ft/MWe-yr
Nuclear	.60	16.50
Oil	.60	11.25
Coal	.75	14.06
Combined Cycle	.60	13.80
Geothermal (hydrothermal)	.70	52.50
Solar Central Receiver	.40	12.60

Table 9-6

Freshwater Consumption for Electricity Generation
(acre-feet/year)

ASA	1975	1985	2000	
		(Scenarios 1,2,3,4)*	(Scenarios 1,2)*	(Scenarios 3,4)*
1801	--	--	--	--
1802	9,613	19,778	36,533	34,170
1803	--	18,151	122,101	16,501
1804	6,624	10,614	21,231	21,231
1805	--	--	--	--
1806	15,822	68,642	218,246	244,158
1807	--	--		--
TOTAL	32,059	117,185	398,111	316,060

* Scenarios:

(1) Recent Trends
(2) Accelerated Synfuels
(3) Hi Coal Electric
(4) Hi Coal Electric and Accelerated Synfuels

Nearly all the current electric generation capacity is located along the California coast and therefore power plants use sea water for once-through cooling. The few power plants that are located inland use wet cooling towers. Fresh water requirements for these plants in 1975 amounted to about 32,000 acre-feet/year.

Due to the California Coastal Commission's policy which requires examination of inland sites prior to coastal siting, the utilities may opt for inland siting of power plants. As a result most of the future water consumptive electrical capacity may be located inland. This is reflected in the water requirements for power plant cooling in 1985 which increase to 117,185 acre-feet/year. Much of the increase is accounted for by the following factors:

1) higher proportion of water consumptive electricity capacity, especially nuclear;
2) inland siting of most of the new power plants; and
3) use of wet cooling towers which consume large quantities of water.

The California scenarios for 2000 show significant differences between them, especially related to the generation capacity of coal and nuclear. The Recent Trends and Accelerated Synfuels scenarios consist of a large increase in nuclear capacity over 1985 (8245 MWe to 19,545 MWe) and no increase in the in-state coal combustion. On the other hand, the High Coal-Electric and High Coal-Electric and Accelerated Synfuels scenarios project large increases in in-state coal capacity (800 MWe to 6670 MWe), but only a slight increase in nuclear capacity (8245 MWe to 9045 MWe).

Because of the differences in fuel mix the calculated water requirements for the different scenarios also vary. The Recent Trends and Accelerated Synfuels scenarios, which include no growth of in-state coal facilities from previous years, show more fresh water consumption than the scenarios requiring a high level of in-state coal combustion. The variation in water requirements between the scenarios in 2000 is influenced for the most part by the level of nuclear generating capacity, since nuclear power plants consume more cooling water than coal-burning facilities.

Geothermal capacity from hydrothermal or hot water sources makes a contribution to the total fresh water cooling requirements by 2000. Water demands per unit of geothermal (hydrothermal) capacity are nearly five times those for fossil power plants.[9] In addition, geothermal resources are located inland which eliminates the possibility of once-through cooling technology using sea water and suggests that the water use impacts will be more localized. A more complete discussion of the projected water use by individual ASA will be presented in a later section.

WATER USE IMPACTS

Overall, the total fresh water required for cooling power plants ($\sim$398,000 acre-feet/year) represents a small fraction of the roughly 36 million acre-feet/year of water supplies expected to be available by 2000. However, as described previously, California is currently water deficient in som ASA's. This condition is expected to be more widespread by 2000 (see Table 9-4).

The water deficiency is largely confined to inland ASA regions some of which have a potential for siting power plants. Availability of fresh water supplies to these regions in the future is contingent upon construction of certain key water development projects such as a trans-delta facility and the New Melones and Auburn Reservoirs. The future of these projects is very uncertain at present. If power plants are sited in these water-deficient regions, there could be a further burden on available water resources.

The estimates of water requirements by individual types of power plants are reported by ASA. Table 9-7 contains the cooling water demands by power plant type and location (ASA) for 1975, 1985 and 2000. In addition, a summary is given of the total fresh water consumed in California by type of power plant.

Hydrological conditions in California vary considerably within individual ASA. As a result each ASA usually has several sources of supply including natural streams or rivers, developed surface water supplies, ground water, and waste water from agricultural or municipal

Table 9-7

Freshwater Cooling Requirements
(acre-feet/year)

ASA	Powerplant Type	1975	1985	2000 (1,2)*	2000 (3,4)*
1801	Nuclear	0	0	0	0
	Oil	0	0	0	0
1802	Nuclear	9,613	8,528	24,203	8,431
	Coal	--	11,250	12,330	25,739
	Geothermal	0	0	0	0
1803	Nuclear	0	18,150	122,100	16,500
	Oil	0	1	1	1
1804	Oil	6,624	6,750	7,569	7,569
	Combined Cycle	--	3,864	13,662	13,662
1805	Nuclear	0	0	0	0
	Oil	0	0	0	0
1806	Nuclear	0	15,675	82,500	31,350
	Oil	15,822	17,777	8,946	8,946
	Coal	--	--	--	77,062
	Combined Cycle	--	11,040	25,475	25,475
	Geothermal	--	21,000	76,125	76,125
	Solar	--	3,150	25,200	25,200
1807	--	--	--	--	--
California Summary					
	Nuclear	9,613	42,353	228,803	56,281
	Oil	22,446	24,528	16,516	16,516
	Coal	--	311,250	12,330	102,801
	Combined Cycle	--	14,904	34,137	39,137
	Geothermal	0	21,000	76,125	76,125
	Solar	--	3,150	25,200	25,200
	TOTAL	32,059	117,185	398,111	316,060

*Scenarios:

(1) Recent Trends (2) Accelerated Synfuels
(3) Hi Coal Electric (4) Hi Coal Electric and Accelerated Synfuels

users. Water requirements and their possible sources of supply are therefore analyzed for each type of energy facility within an ASA.

Since it is projected that water demands in most of the ASA will be met by existing and planned supplies in 1985, there will probably be few water use impacts.[1] According to the California scenarios for the NCUA only one coal-fired power plant (800 MWe) is projected for 1985. We have sited this facility in the Sacramento Basin (ASA 1802) on the western side of the Sierras. Generally this ASA has adequate surface water supplies, most of which are already committed. Since little or no agricultural waste water exists, arrangement for purchase of fresh water would be necessary. Currently, the Rancho Seco nuclear plant receives water from the Folsom South Canal (Bureau of Reclamation). Similar arrangements might be possible for other facilities. Potential ground water sources exist in the subarea, but the knowledge of their perennial yields is superficial.

ASA 1803, which includes a large portion of the Central Valley, already shows a significant deficit. Virtually all the existing supplies are committed and ground water overdraft is a serious problem. Agriculture is the major water user in the Central Valley and these withdrawals are expected to increase in the future. Reclaimed agricultural waste water therefore form a potential source of supply for cooling water.

ASA 1805 (Central Coast) is essentially a water-deficient region. There are potential water use impacts between agriculture and the growing urban sector, but not related to the development of energy facilities. The nuclear- and oil-fired plants in this subarea are located along the coast and use sea water for once-through cooling.

By 2000 the projected water supply and demand picture in California becomes more critical. There are expected to be deficiencies in water supply to meet agricultural and urban demand in nearly all of the aggregated subareas.

ASA's 1801 and 1805 will not be included in the discussion since the proposed power plants located in these regions use sea water for cooling. No energy facilities were located in ASA 1807 although there is some potential in the future for the development of geothermal resources in the Mono Lake area.

The Recent Trends and Accelerated Synfuels scenarios for California in 2000 emphasize a high utilization of nuclear capacity, while the other two scenarios stress the use of in and out-of-state coal-fired facilities. The fresh water cooling requirements therefore vary significantly.

In ASA 1802 nuclear and coal-fired scenarios will account for most of the generating capacity. The high nuclear scenarios will consume more fresh water for cooling purpose than those scenarios with high coal capacity (36,533 acre-feet/year and 34,170 acre-feet/year, respectively). Agriculture is the major economic activity in this subarea and the major user of water. Since little or no agricultural drainage water exists, the source of water to meet the projected cooling requirements will come either from ground water sources or through exchanges and purchases of fresh water from other users. The latter case could create a competitive situation between agriculture and municipal/ industrial users.

Virtually all the existing water supplies are committed in ASA 1803. The Recent Trends and Acclerated Synfuels scenarios for 2000 include about 7400 MWe of nuclear power generation and a subsequent requirement of over 120,000 acre-feet/year of cooling water. Portions of this subarea (e.g. Tulare Basin) already overdraft significant amounts of ground water. The degree to which this practice of ground water mining is extended in the future is uncertain at this time. Agricultural waste waters have been suggested for some of the proposed nuclear plants. It may be possible by 2000 to use water from the San Luis Drain, which is located in the upper third of the subarea. As much as 500,000 acre-feet/year of agriculture drainage water is believed to be available in this region.[7]

Combined cycle facilities located in ASA 1804 are projected to require over 13,000 acre-feet/year of fresh water. No nuclear or coal-fired facilities were located in this subregion due to siting restrictions related to air quality standards. If air quality standards are relaxed in the future, allowing nuclear or coal facilities to be sited in this region, there may develop serious competition between the various water users.

ASA 1806 is comprised of the south coastal and Colorado Desert regions. A large part of the nuclear and oil capacity in this subarea will use sea water for cooling. The rest of the capacity will require fresh water sources.

The Metropolitan Water District of Southern California (MWD) has made available up to 100,000 acre-feet/year of its allotment from the Colorado River for power plant use in desert sites. In 1974 the Lanterman Act (AB 3140) was enacted in order to allow this type of transaction. MWD has executed letters of intent for allocation of water with the following utilities:

1) San Diego Gas and Electric Company (SDGE) - 17,000 acre-feet/year;
2) Los Angeles Department of Water and Power (LADWP) - 33,000 acre-feet/year; and
3) Southern California Edison Company (SCE) - 50,000 acre-feet/year.

The high nuclear scenarios (Recent Trends and Accelerated Synfuels) require nearly 85,000 acre-feet/year of fresh water. A specific example of how utilities are addressing the water problem involves SDGE's proposed Sun Desert nuclear plant. The Sun Desert project will receive 17,000 acre-feet/year of water from the Palo Verde Drain for cooling unit one, while MWD will forebear from diverting an equivalent amount into the Colorado River aqueduct at Parker Dam. In order to provide fresh water for the second unit, SDGE has purchased three ranches within the Palo Verde Irrigation District for a total of 7,259 acres. By taking the land out of production, an additional 17,000 acre-feet/year will become available for use in the cooling system. It is uncertain at this time whether other proposed projects will use a similar strategy for acquiring fresh water. It is also unclear what long-term impacts might develop due to water tradeoffs between agriculture and energy development.

Agricultural drain water from the Imperial and Coachella Valleys in the east desert area represent additional available sources of cooling water if the salinity problems can be overcome. It is also necessary to devise a method to guarantee a long-term supply of drainage water. Ground water sources are well known and inventoried in this ASA and could provide some water as well.

Development of geothermal resources (hydrothermal) is scheduled for the Imperial Valley. This area is currently a major agricultural region in the state with agricultural waste water flows of one million acre-feet/year to the Salton Sea and 400,000 acre-feet/year to the Colorado River. The New and Alamo Rivers carry the one million acre-feet/year flow to the Salton Sea. The cooling water required for geothermal capacity (about 76,000 acre-feet/year) could be obtained from the New and Alamo Rivers.[9] The water supplies therefore appear adequate for geothermal development in this subarea without any impact on competing users.

Solar power plants will consume only a small fraction of the fresh water required for cooling. By 2000 it is estimated that about 25,000 acre-feet/year will be needed. Since solar central receivers will probably be sited in the east desert region, the cooling water could come from several potential sources including: ground water, agricultural drainage water, or transfer of surface water rights.

The high coal scenarios for 2000 include about 5000 MWe of coal-fired capacity in the east desert area. The fresh water required for cooling is calculated to be about 77,000 acre-feet/year. It is uncertain at this time which water source option would be utilized. The analysis of cooling water requirements presented in this report assumes the use of wet cooling towers for all inland sites. The utilities, however, may resort to wet/dry or dry cooling technologies as they become available. The wet/dry towers would reduce water demands to 25 percent of normal requirements for wet towers, while dry towers would reduce the demands to virtually nil.

SUMMARY

Since almost all the power plants in 1975 were located along the California coast, fresh water requirements for power plants were only 32,000 acre-feet. Coastal siting restrictions and development of resources located inland (e.g. geothermal and solar) will increase these cooling water demands for the NCUA scenarios to 398,000 acre-feet/year by 2000. This estimate is lower when compared to other forecasts of energy-related water use in California.[8,10] However, the other forecasts were based on a significantly different set of scenarios.

Future projected water demands when compared to developed supplies indicate that fresh water shortages will occur in many areas of the state by the year 2000. This situation could pose serious constraints on siting power plants in some ASA's.

It was assumed in this analysis that most new power plants will be located inland due to coastal siting restrictions. However, it should be noted that the SWRCB in a recent policy statement outlined the order of priority for cooling water sources.[11] The SWRCB resolution favored the use of sea water or waste water being discharged to the ocean and suggested the use of inland fresh water only as a last resort. SWRCB, among other functions, issues water rights permits. The utility companies in recent submittals to the California Energy Resources Conservation and Development Commission seem to favor inland sites over those along the coast. As a result we added very little new capacity in the coastal areas of ASA 1801, 1804 and 1805.

Capacity additions, especially of nuclear power plants in ASA 1803, which is already a water-deficient region, will require substantial quantities of fresh water. The Recent Trends and Accelerated Synfuels scenarios which include a high level of nuclear capacity in ASA 1803 have cooling water demands that are seven times greater than the other scenarios. Since portions of this subarea already have ground water overdraft problems, additional supplies of cooling water will have to come from "new" sources. Agricultural waste water has been suggested as a "new" source, but this will require improved collection and conveyance facilities. Furthermore, chemical pretreatment may be necessary depending on the quality of the drainage water. In some instances it may also prove more economical for the farmer to transfer water from agricultural uses to the utilities.

The expansion of electrical capacity in ASA 1806, which has a coastal zone, will occur mostly in the eastern desert region. The fresh water requirements needed to support this increase will be over 200,000 acre-feet/year. Currently, almost 85 percent of the water in this subarea is imported from the Colorado River and from Northern

California. Therefore the cooling water demands may have an adverse impact on competitive water users. In addition, by 1990 California is expected to relinquish the 600,000 acre-feet/year of Colorado River water that is currently above its entitlement. Potential water supplies include deep ground water sources, water in the MWD system or agricultural waste water. Utilities may resort to wet/dry or dry cooling towers to reduce water requirements.

The analysis of water use impacts related to coal utilization in California has identified many uncertainties. In addition to the electricity supply and demand picture, which involves the level of capacity and the fuel mix, there are various economic, environmental and institutional constraints to providing sufficient amounts of fresh water for cooling. The following list of uncertainties needs further attention during the second year of the study:

1) fate of pending or proposed major water projects;
2) transfer of water rights between agriculture and the municipal/industrial users;
3) effects of prevailing drought conditions, which limit natural runoff;
4) availability of waste water from agriculture and municipal basins;
5) potential ground water sources in some California basins;
6) future impacts of ground water mining;
7) use of cooling technologies which are less water-consumptive (wet/dry or dry towers);
8) institutional interactions between state agencies regarding coastal/inland siting policy; and
9) water quality problems associated with coal utilization.

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10. AIR QUALITY IMPACTS

In this section we discuss estimates of air quality impacts due to coal use for electricity generation in California. At this point only the one site required for 1985 by all NCUA scenarios for California has been investigated. In the following subsection a general characterization of existing background air quality and a brief description of air quality issues and constraints in California is presented. In the subsequent sections the results of a short-range air quality model are described, giving both annual average concentrations in the vicinity of the site and short-term concentration impacts. The model itself is briefly documented in Appendix B. The last section contains a discussion of future work on the remaining scenario projections and a more complete investigation of coal utilization constraints imposed by air quality issues in California.

STATE AND REGIONAL AIR QUALITY ISSUES

The location and operating conditions of any proposed coal-fired power plant for California will have to meet both state and federal air quality and emissions criteria before such a plant can be built. The relevant state and federal air quality standards are listed in Table 10-1. The Environmental Protection Agency has, in addition to these National Ambient Air Quality Standards (NAAQS), proposed regulations that would prevent significant air quality deterioration (PSD) These regulations, not yet adopted into law, would limit concentrations for two air pollutants, total suspended particulates (TSP) and sulfur dioxide (SO_2), depending upon the specific air quality class. These classifications range from Class I, where in general, pollutant concentrations are below the NAAQS, and no major new sources would be permitted, to Class III, where significant pollutant emissions already exist. These proposed standards are also shown in Table 10-1.

The State of California has proposed a four-level classification scheme for air conservation areas, with Class A approximately corresponding to Class I. Included in these areas would be national parks and monuments, and wilderness areas. California also proposes to include certain state park lands as well.

Table 10-1

State and Federal Air Quality Standards
(in μg/m^3)

	TSP		SO_2				NO_x		SO_4
	Annual[a]	24 hr	Annual	24 hr	3 hr	1 hr	Annual	1 hr	24 hr
California	60	100	--	105	--	1300	--	470	25
NAAQS (federal)									
Primary	75	260	80	365	--	--	100	--	--
Secondary	60	150	--	--	1300	--	100	--	--
PSD[b] (federal)									
Class I	5	10	2	5	25	--	--	--	--
Class II	10	30	15	100	700	--	--	--	--
Class III	75	150	80	365	1300	--	--	--	--

[a] annual geometric mean

[b] proposed Prevention of Significant Deterioration Regulations

Tehama County, which has been selected as a representative location for the 1985 power plant site, contains, and is close to, several National Park Recreation and Wilderness areas. Since a precise site within the county has not been selected, the exact distances to these areas cannot be specified. Sites in the southern part of the county would, for example, lie approximately 50 to 70 km from at least three such areas.

Data on present air quality for several counties in north-central California are sparse. We have listed in Tables 10-2 and 10-3 data available through the EPA's SAROAD data base for monitoring sites in or near Tehama County. The data for total suspended particulates indicate high levels of this pollutant, as are sometimes found in agricultural areas in California. Although no projections of future pollutant concentrations have been made, one notes that from the Bureau of Economic Analysis projections of economic activity to 1990[5] that agriculture and forestry would continue to dominate in BEA Region 169, which includes Tehama County.

Finally, emissions regulations have been established to aid in attaining the NAAQS goals. As such, these regulations limit source emissions based on local air quality criteria. The State Implementation Plan (SIP) for SO_2 in Tehama County limits emissions to the equivalent output of a plant burning $\leq$ 0.5 percent sulfur fuel. This level can be achieved through either the use of low-sulfur coal as fuel, or stack gas controls for SO_2, or a combination of both. As noted in the next section, we have assumed a scrubber efficiency of 90 percent, and one percent sulfur coal, which will reduce the emissions below the SIP regulations.

Annual Average Air Quality Impacts

Air quality impacts were estimated using a short-range, Gaussian plume model,[1] similar to the EPA's Climatological Dispersion Model, with modifications to include first-order chemistry and deposition. A more complete description of the model is presented in Appendix B.

Table 10-2

Total Suspended Particulates - Annual Data for 1975[a]
(in $\mu g/m^3$)

	Chico, Butte County	Red Bluff, Tehama County	Redding, Shasta County Station Designation 002F01	Redding, Shasta County Station Designation 004I01
Arithmetic Mean	78			55
Standard Deviation	35.1			27.8
Maximum Value	177	145	94	134
Second Highest Value	153	125	68	126
No. of Violations of Primary Standard	0	0	0	0
No. of Violations of Secondary Standard	2	0	0	0

[a] Air pollution data taken from EPA's SAROAD data base

Table 10-3

NO_2 Measurements - Annual Data for 1975[a]
(in $\mu g/m^3$)

	Chico, Butte County	Redding, Shasta County
Arithmetic Mean	35.3	
Standard Deviation	22.5	
Maximum Value	206.8	169.2
Second Highest Value	188	150.4
No. of Violations of Primary Standard	0	0
No. of Violations of Secondary Standard	0	0

[a] Air pollution data taken from EPA's SAROAD data base

This model is presently available at Lawrence Livermore Laboratory, where the modeling runs were done.

The NCUA scenarios for California all require an 800 MWe coal-fired power plant for 1985. As discussed in the previous section on siting, we have selected Tehama County as the possible location. Since the site selection protocol has been to use only county level detail, the air quality model should give the order of magnitude results necessary for this assessment. The model used for these estimates does not include terrain; rather it uses a flat surface with a choice of surface cover types for deposition. This model, like most short-range models, gives estimates reliable only for distance up to 50-60 km from the source.

Model Inputs

We have used annual average climatological data for Sacramento, California, which appears to typify Central Valley sites in north-central California. These were the only data readily available in joint frequency distribution form (wind speed, direction and Pasquill stability class) from the National Climatological Center. In the future, we may obtain more localized metrological data and convert them for use in the model as a comparison. The model also employs a perfectly reflective inversion layer "cap." Based upon Sacramento area radiosonde data,[2] we have used a constant inversion layer height of 305 meters (m).

The general power plant characteristics have laready been discussed in the technology characterization section. We have assumed that all coal-fired power plants built in California will have SO_2 scrubbers as well as precipitators for the control of particulates and that the coal will be pulverized before firing. A list of technical input parameters is given in Table 10-4.

Results and Discussion

The model results for Tehama County County are shown in Figures 10-1 through 10-7. The concentration isopleths are labelled in $\mu g/m^3$. The

Table 10-4

Power Plant and Emission Characteristics

Annual Electricity Generation:		5.26×10^9 kWh; 18×10^{12} Btu	
Coal:			
Heat Content		12,000 Btu/lb	
Sulfur content		1%, 20 lb S/Short Ton (ST) coal	
Ash Content		10%, 200 lb ash/ST coal	
Stack:			
Height		180 m	
Diameter		8 m	
Temperature at Exit		79°C	
Ambient Air		24°C	
Exit Velocity		13.7 m/s	
Control:			
		Into Control Devices	Removal Efficiency
SO_2		100%	90%
NO_x		100%	0%
Particulates[a]	Weight percent		
<5 μm	15	85%	72%
5-10 μm	17	85%	94.5%
10-20 μm	20	85%	97%
20-44 μm	23	85%	99.5%
>44 μm	25	85%	100%
Source Strength (after control):			
SO_2		121.6 g/s	
SO_4		0	
NO_x		511 g/s (New Source Performance Stds.)	
Particulate		(Σ = 302.2 g/s)	
<5 μm		217 g/s	
5-10 μm		48.3 g/s	
10-20 μm		31.0 g/s	
20-44 μm		5.9 g/s	
>44 μm		0	

Table 10-4 (continued)

Power Plant and Emission Characteristics

Reaction Rate:	
$SO_2 \rightarrow SO_4$	$1 \times 10^{-5} s^{-1}$
Deposition Rates:	
SO_2	1×10^{-2} m/s
SO_4	1×10^{-3} m/s
NO_x	0
Particulates	
<5 μm	2×10^{-2} m/s
5-10 μm	6.5×10^{-2} m/s
10-20 μm	1×10^{-1} m/s
20-44 μm	3.3×10^{-1} m/s

[a] The size distribution and removal effficiencies given here yield an overall removal fraction of 94.5%, instead of 99% as defined in the technology characterization section. In the future we will adjust these distribution or removal fractions to give a 99% overall removal efficiency. Results discussed elsewhere in this section are based upon the numbers in this table.

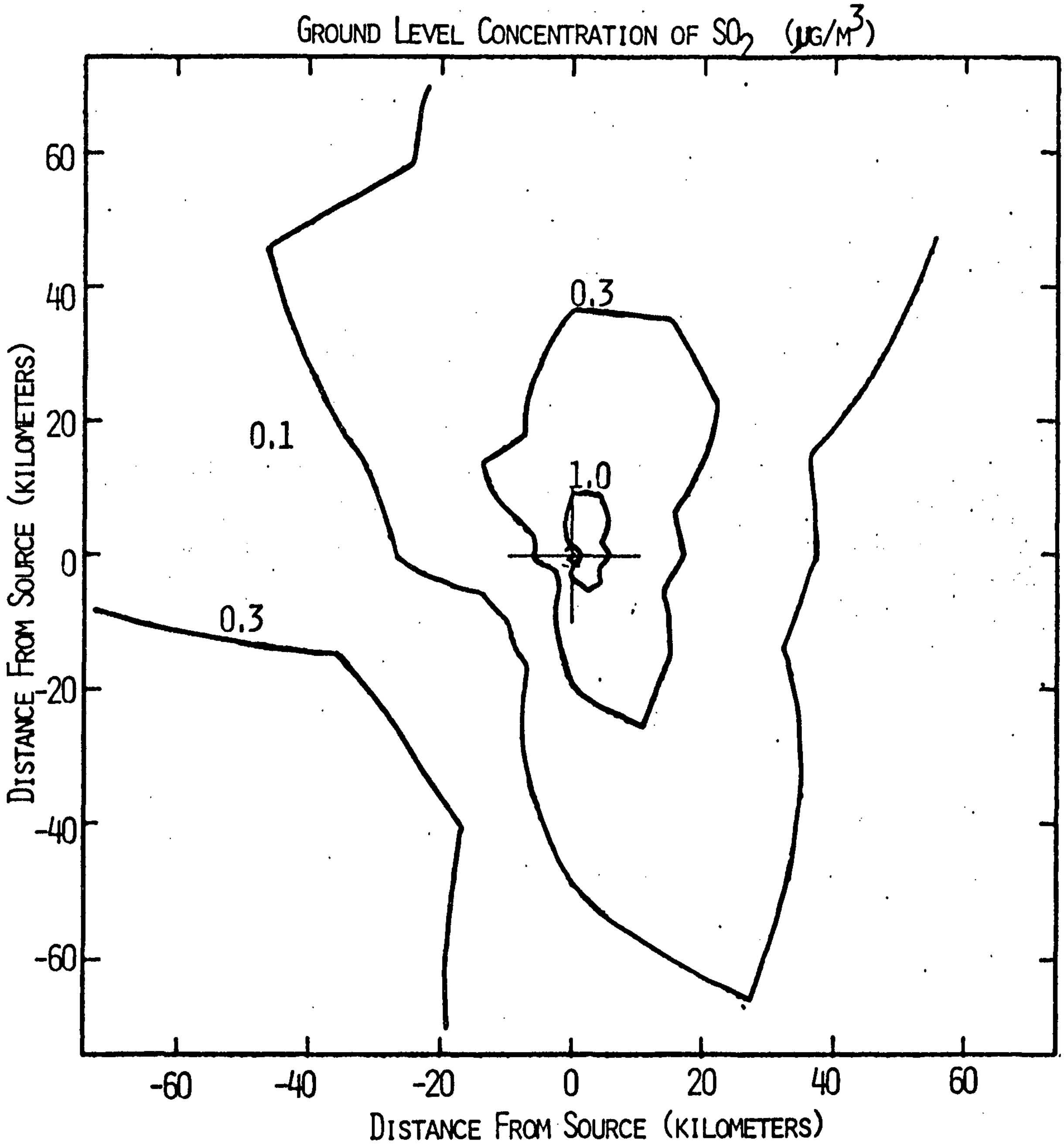

Fig. 10-1. Concentration Isopleths for SO_2.

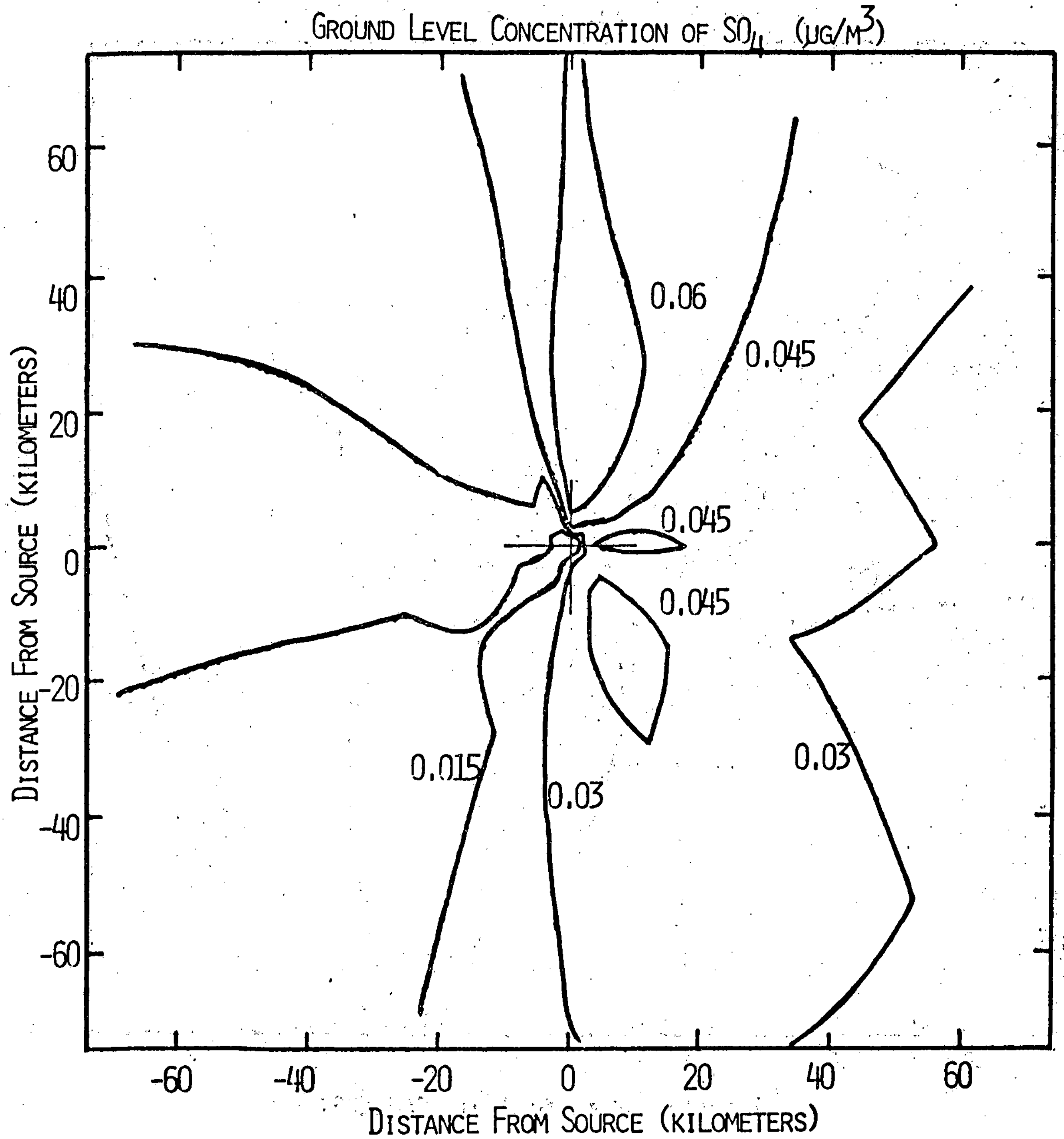

Fig. 10-2. Concentration Isopleths for SO_4.

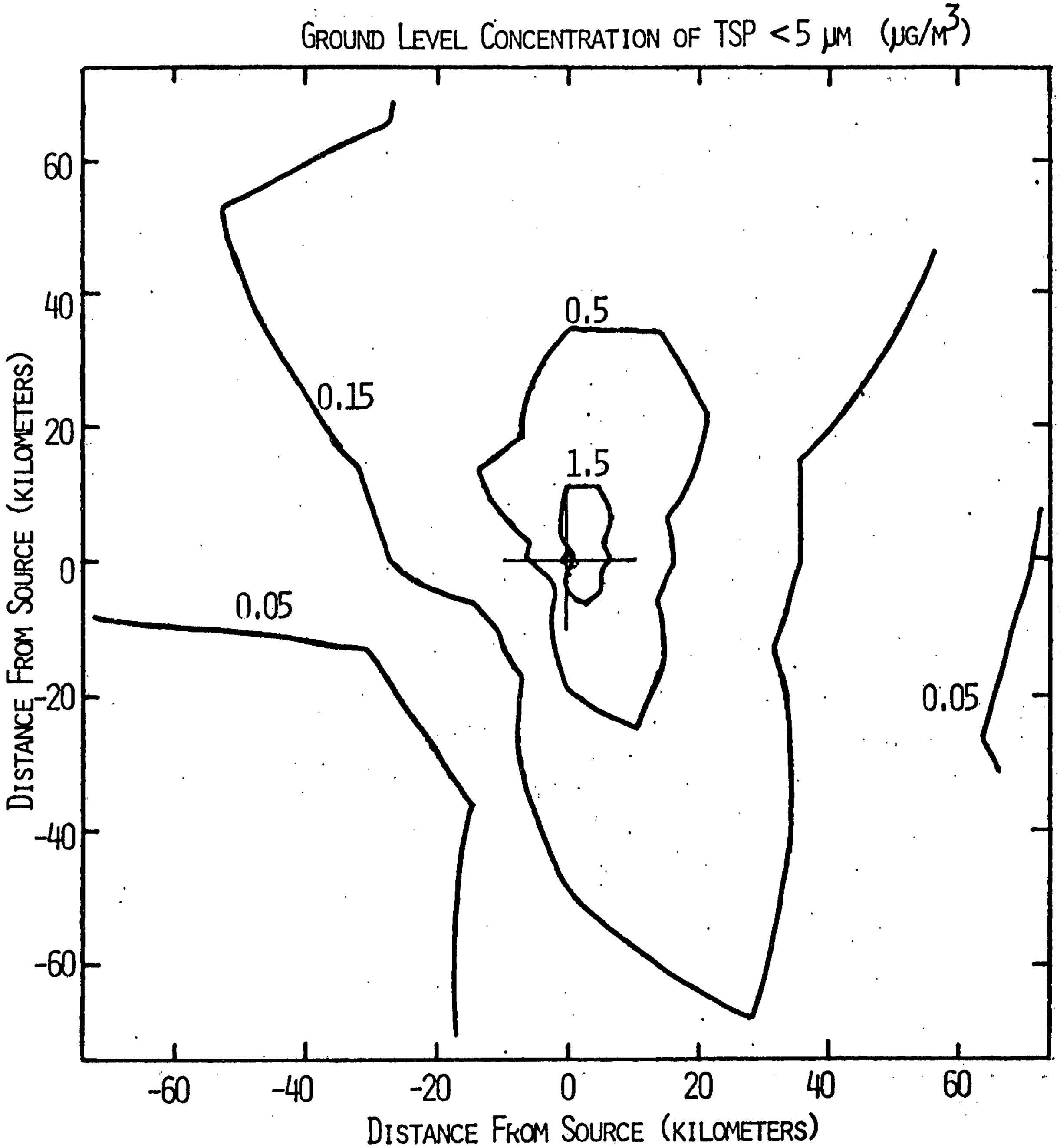

Fig. 10-3. Concentration Isopleths for TSP less than 5 μm in diameter.

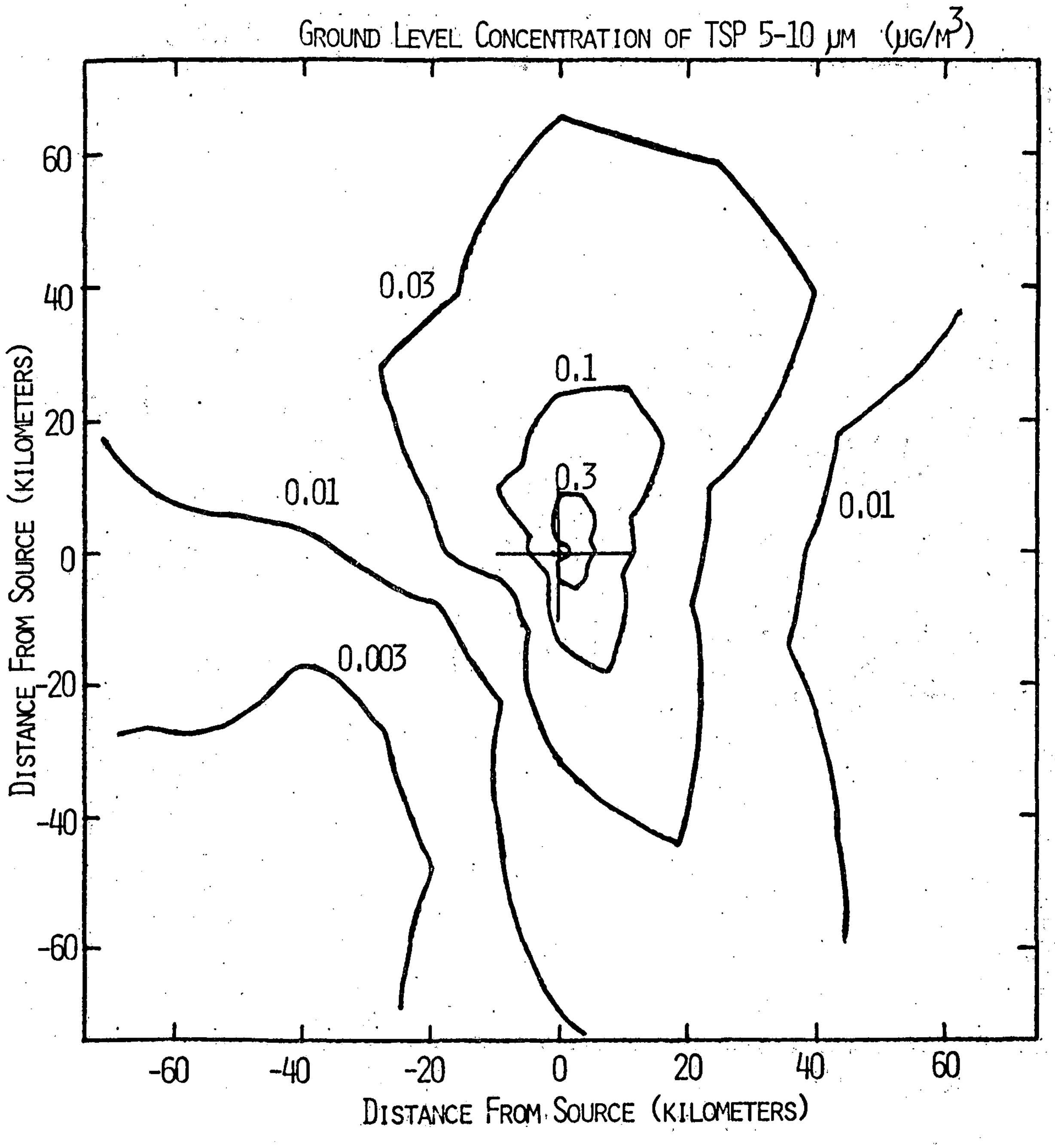

Fig. 10-4. Concentration Isopleths for TSP with diameters between 5-10 μm.

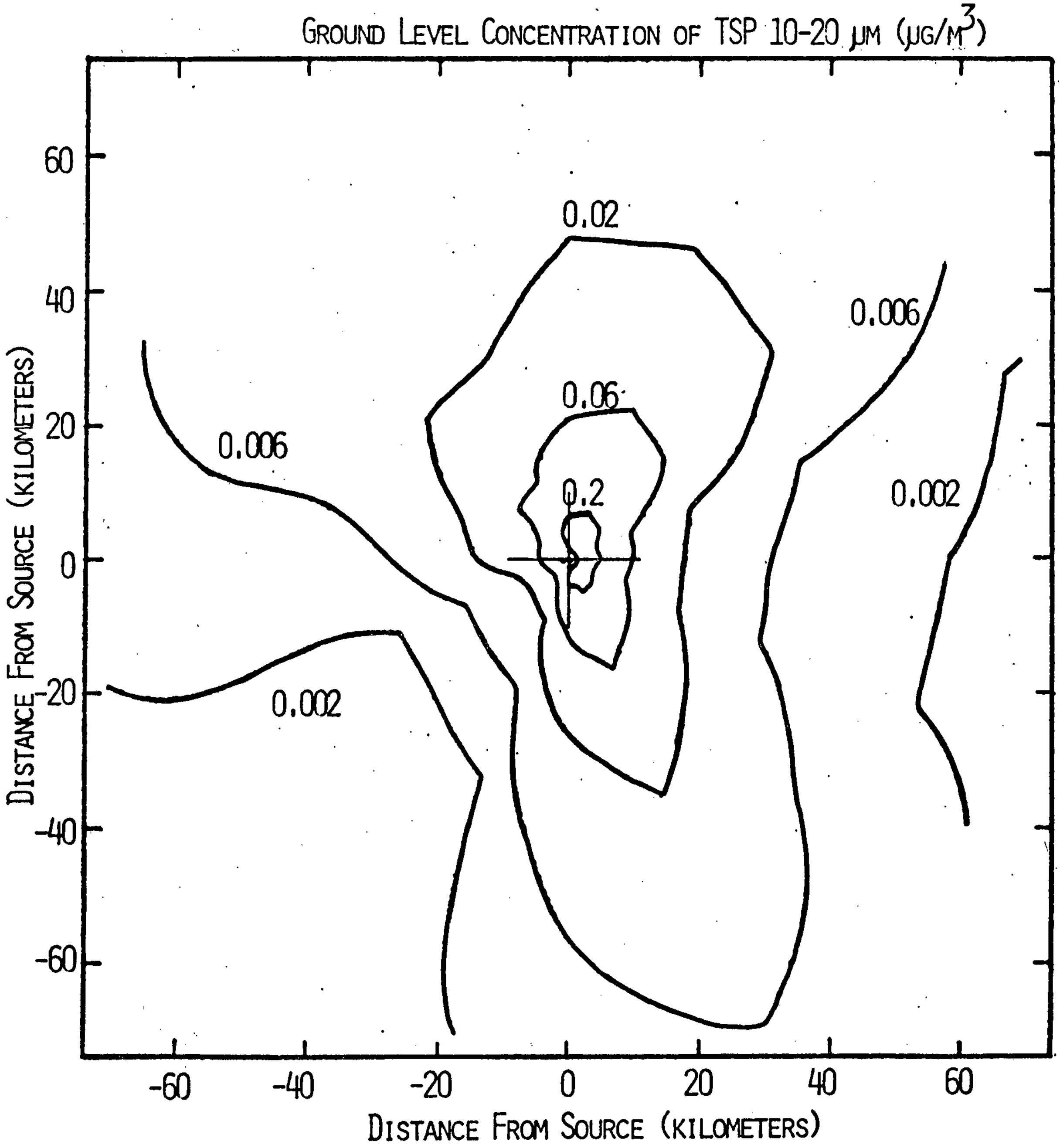

Fig. 10-5. Concentration Isopleths for TSP with diameters between 10-20 μm.

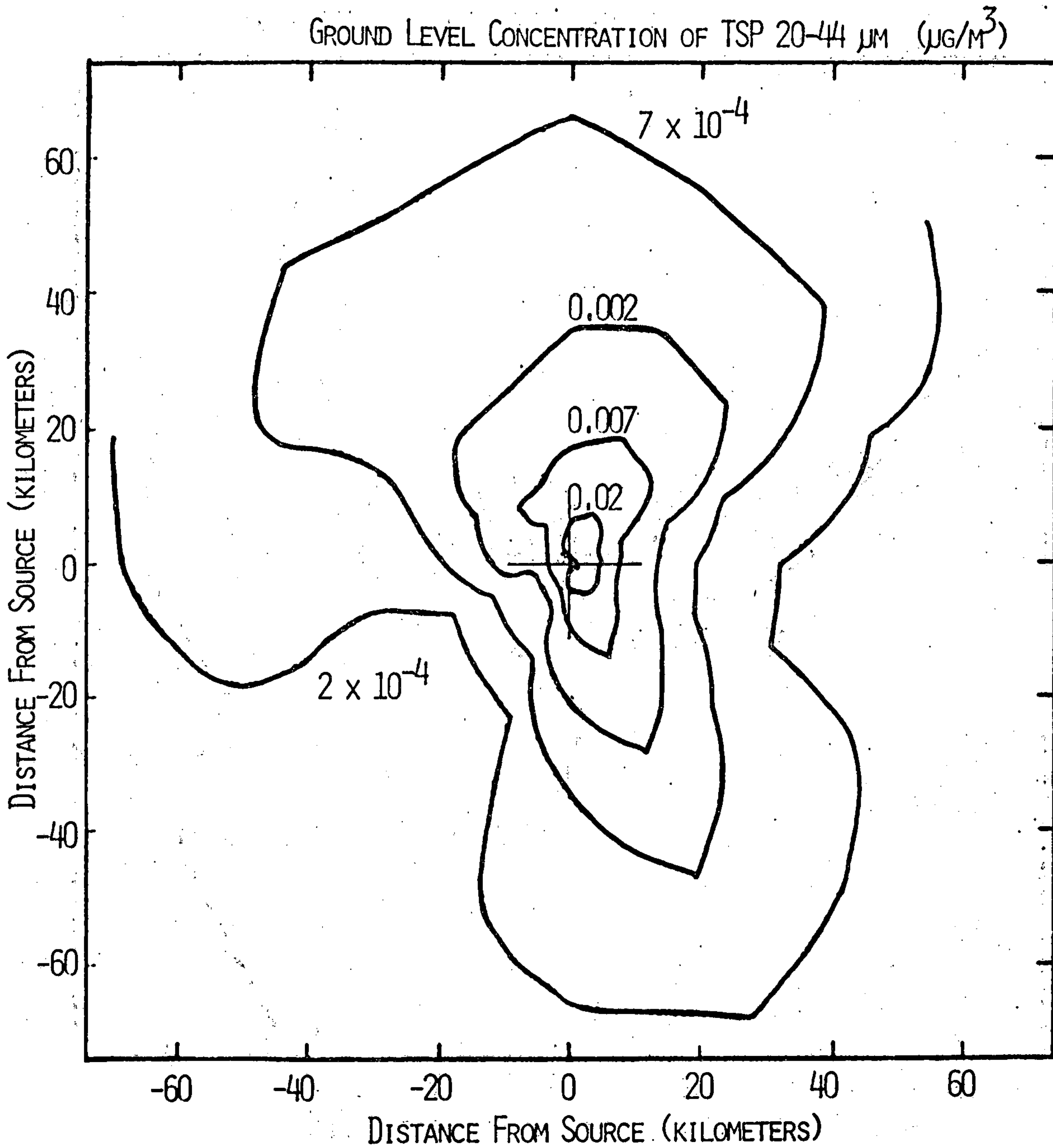

Fig. 10-6. Concentration Isopleths for TSP with diameters between 20-44 μm.

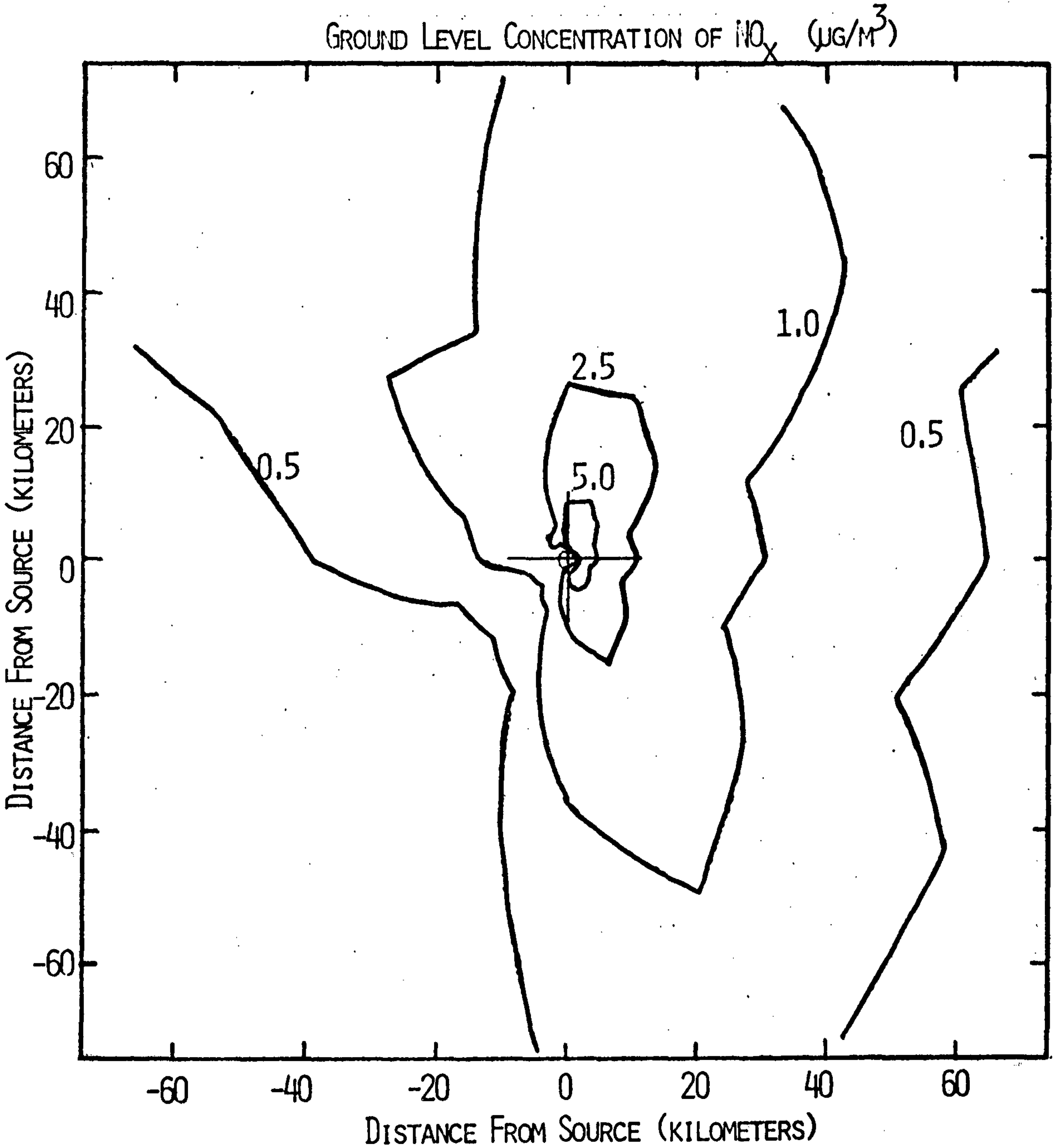

Fig. 10-7. Concentration Isopleths for NO_X

particulate results are shown for each particle size category. The area covered by each pollutant concentration contour map is 130 x 130 km. Figure 10-8 is a projection of ground level pollutant concentrations as a function of radial distance from the source in the north-northeast (NNE) direction. This is the direction of the maximum concentration of all pollutants, except SO_4, which has its concentration peak directly north of the source. Note that all pollutant concentrations except SO_4 fall off in nearly the same way as a function of distance. The peak value is generally between 2 and 3 km from the source. For SO_4, there is no source emission, rather a chemical conversion in the plume from SO_2. Hence the peak concentration (see Fig. 10-8) is broadly distributed, with the maximum value at 18 km from the source, and the distribution of concentration $\geq$ 90 percent of maximum running from 8 km out to 36 km.

The results, when compared with the annual average federal or state Ambient Air Quality Standards (shown in Table 10-1) are smaller than the standard for all three pollutants. If one were to assume <u>no</u> sulfur control, the SO_2 and SO_4 concentration profiles would increase by a factor of 10 (to first order). Even then, the output of SO_2 falls below the standard. However, if one assumes a linear relationship between maximum SO_2 concentration and energy output, the primary NAAQS standard will be reached if 3600 MWe of capacity with no sulfur control were co-located at this one site. With sulfur controls, the dominant criterion becomes either the concentration of suspended particular matter (TSP) or NO_x. In this case, the 60 $\mu g/m^3$ annual standard for TSP is reached assuming nearly 13 times the capacity modeled here, while the primary NO_x standard is equalled with 12.5 times the capacity.

This discussion has, so far, ignored the background concentration of pollutants. As noted in the previous section, the TSP concentration in many Central Valley counties is quite high, primarily due to agriculture and related activities. As indicated in Table 10-2, the primary TSP standard has been exceeded by almost a factor of 2 in Red Bluff, Tehama County. Similar results are found for both Chico and Redding in nearby counties. The NO_x concentration presents a similar picture for both Chico and Red Bluff, with the mean concentration in Chico about one-third that of the standard (see Table 10-3). Hence, any precise determination of air quality impacts in Tehama or surrounding counties

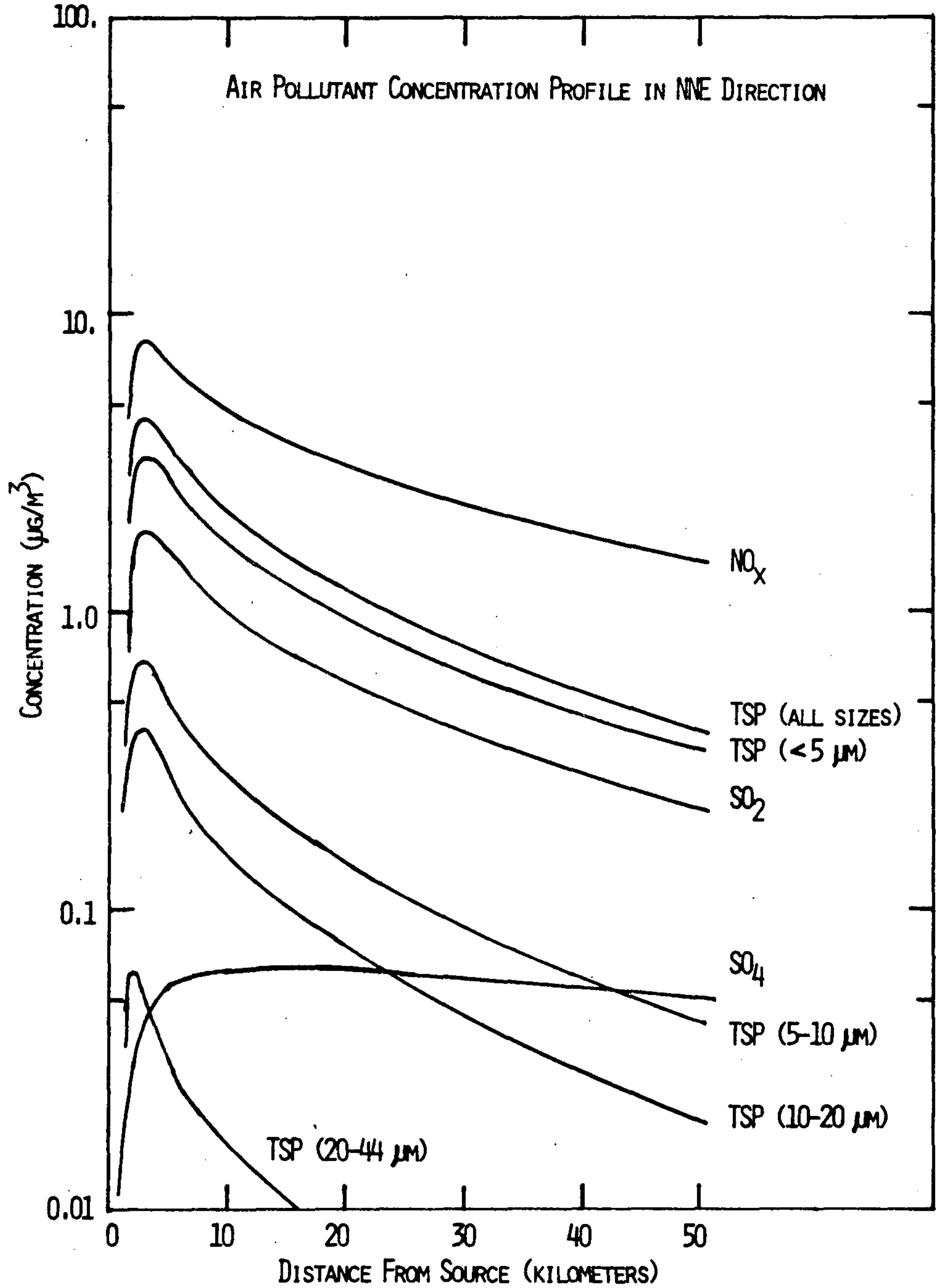

Figure 10-8. Concentration Profile in Direction of Maximum Annual Average

due to a coal-fired power plant would depend upon a more detailed examination of ambient air quality levels in the surrounding areas.

Short-Term Concentration Impacts

We have used the method developed by General Electric Company and described in a recent report by Argonne National Laboratory[4] to estimate short-term concentrations of pollutants. The emission rates were adjusted to reflect the smaller plant size and the pollution control systems used here. The results have also been scaled linearly to account for stack height and exit temperature differences, according to scaling parameters shown in Table 6A.9 of Ref. 4. For the one- and thre-hour averaging times, we have assumed the plant is operating at 100 percent capacity, a reasonable assumption considering that during times of peak load, many base load plants operate near full capacity. The duration of the peak loads typically are up to six hours.

For the 24-hour average, we assume the plant will operate at the average capacity factor of 75 percent. Our estimates of maximum concentration for each time period have been taken from the appropriate tables (6A.8) in Ref. 4 and adjusted for the factors described above. The results are shown in Table 10-5, along with a comparison with the most stringent federal or state standards. The one short-term violation that appears in this table is the 24-hour average for total suspended particulates. One should also note, however, that an increase in plant size by a little more than a factor of two would result in violation of the one-hour California NO_x standard.

Future Work

The data presented above resulted from a recent implementation of the climatological dispersion model at Lawrence Livermore Laboratory; hence, only the 1985 scenario results have been obtained. We will use this model to assess the 2000 and 2020 scenarios shortly. We also expect to obtain meteorological data more localized to the power plant site of interest which will be incorporated into these analyses.

Table 10-5

Concentration Maxima for an 800 MWe Plant[a]
Compared to the Most Stringent Standard[b]
(in $\mu g/m^3$)

Time Scale	TSP	(standard)	SO_2	(standard)	NO_X	(standard)
1 hour	126	(--)	50	(1310)[c]	207	(470)[c]
3 hours	101	(--)	40	(700)[d]	166	(--)
24 hours	46	(30)	20	(100)[d]	82	(--)

[a]Calculated for an 800 MWe plant with characteristics and emission summarized in Table 10-4, using the method described in Ref. 4.

[b]See Table 10-1.

[c]California standard.

[d]PSD Class II standards.

Air quality issues in California are complex, with both stationary and mobile sources contributing in varying proportion depending upon pollutant and area of interest. In addition, the local Air Pollution Control Districts and the California Air Resources Board have adopted and proposed several emission standards for pollutants of interest to the NCUA. We will assess these more fully in the future, especially with regard to the impacts upon our proposed siting locations for the scenarios.

We also expect to implement a short-term air quality model, using hourly meteorological data for some of the sites. The interaction between the proposed sites and possible Class I or Class A areas, as well as the short-term air quality standards will require further work for a more complete assessment.

We have recently forwarded to PNL data on our proposed sites and capacities for each scenario in order to complete the long-range air quality modeling. Further site or technology iteration might result from this analysis.

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5. Bureau of Economic Analysis, Area Economic Projections 1990, U.S. Department of Commerce, Social and Economic Statistics Administration, 1975.

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11. HEALTH AND SAFETY EFFECTS

In this section we discuss the health and safety impacts of the supply and use of coal in California. The analysis in this interim report is restricted to effects linked to the operation of the coal-fired electricity-generating plant required in the Recent Trends scenario. This plant, located in southern Tehama County, would generate air pollution in the surrounding area of the northern section of the Central Valley of California. Air quality calculations were carried out over an area within a range of sixty kilometers of the power plant location (see section 10). This region includes parts of Tehama County and three adjoining counties: Glenn (to the south), Butte (southeast) and Shasta (to the north). The area is largely rural and contains few towns. Some characteristics of the area are displayed in Table 11.1.[1,2]

At best, the available data and methodology permit estimates of only the order of magnitude of the various health effects discussed here. Our analysis is largely based on the data and information contained in the Brookhaven National Laboratory's handbook for the quantification of health effects.[3] This handbook presents a selective compilation of data derived from laboratory studies and U.S. national and international sources. For California it may be necessary to modify these data with information on local conditions in the western United States. For example, accident statistics from Utah coal mines and railroads in the western states should be used rather than the corresponding U.S. national average figures used in this study.

The coal supply chain starts with coal mining followed by coal processing, rail transport and combustion in a coal-fired electricity-generating plant. Although the mining, processing, and much of the rail transport occurs outside of California, we account for the health aspects of these processes in order to carry out a balanced assessment. For mining, processing and transportation, we estimate accidental deaths and injuries and occupational disease associated with coal supplies required for one electricity generating station.

Table 11-1

Population and Areas of Counties in Northern Section of California's Central Valley

County	Butte	Glen	Shasta	Tehama
Area (sq.miles)	1665	1319	3850	2976
Population[1] on 7/1/75 (thousands)	117	18.9	87.7	31.8
Population of cities[1] on 7/1/75 (thousands)	Biggs 1.3 Chico 22.3 Gridley 2.8 Oroville 7.9	Orland 3.1 Willows 4.5	Anderson 6.1 Redding 18.4	Corning 3.8 Red Bluff 8.2 Tehama .36
County population projections[2] for 7/1/85 (thousands)	143	20.3	108.1	37.1

The clinical effects of exposure to high concentrations of air pollutants have been investigated, established and documented over a long period. Acute and chronic respiratory disease, neoplastic diseases and aggravation of pre-existing respiratory and other diseases have been related to such pollutants. The following hazardous gases are generated by coal combustion: sulfur dioxide, nitrogen oxides, carbon monoxide and gaseous hydrocarbons. Chemical transformations of these substances in the atmosphere can lead to the formation of sulfates, nitrates and ozone. The particulate combustion products emitted from stacks contain aromatic hydrocarbons and trace amounts of various metals.

To permit an assessment of the magnitude of clinical effects on populations at moderate distances from power plants, data are required on the health effects of pollutants at low concentrations. Such data are not available and hence no assessments of these clinical effects is attempted here.

This preliminary analysis of air pollution health effects is limited to estimating the overall increase in mortality rate. Epidemiological analysis of air pollution data has established an association between increased mortality rate and concentrations in air of both total suspended particulates (TSP)[6,7] and sulfates, although the form of the dose-response relationship between these pollutants and increased mortality rate is not clear.[3,9,10]

The quantitative estimate made here of the increase in mortality rate due to air pollutants is to be regarded as a rough, order-of-magnitude calculation. For this purpose, the effects are linked solely to ground level sulfate concentration. Quantitative data on the effects of nitrogen dioxide are lacking; hence, no estimate of the effects of this pollutant were made. Except for particles of diameter less than five microns, the concentration of TSP decreases rapidly with distance from the source. It is here assumed that the power plant will be sited so that the population within ten kilometers from the plant will be small and hence the effects of the high concentrations of particulates close to the source can be neglected. The expected pollutant increase due to the coal-fired power plant is estimated using the air quality model described in the previous section. This model is used to compute the distribution at ground level, of annual average concentrations for TSP, sulfur dioxide, sulfate and nitrogen dioxide. The isopleths of sulfate concentration shown in Figure 10.2 of section 10 are superimposed on a map of the region in order to locate, for each county, the towns and areas exposed to each of the ranges of sulfate concentrations. Each range of exposures is approximated by its mean value. For example, for areas lying between the .015 and .03 isopleths, a value of .0225 micrograms sulfate per cubic meter is used. The population at risk is estimated as follows: for each city the population given for 1975 in Table 11.1 is multiplied by the projected fractional increase in county population for 1985. For the rural areas, county average rural population densities are used. These also are adjusted by multiplying the 1975 values by the fractional increase in population projected for 1985. The basic data for 1975 and 1985 for these four counties are displayed in Table 11.1.

The product (mean sulfate concentration x population at risk) is computed for each range of sulfate concentrations. Following the Brookhaven handbook,[3] a linear exposure-response relationship is assumed between concentration of sulfate in air at ground level and increase in total mortality rate. Using the values in Table 3 of the Brookhaven handbook, the increase in mortality rate is estimated as

$$3.3 \times 10^{-5} \times \sum \text{(mean sulfate concentration} \times \text{population at risk)} .$$

Uncertainties occur in many of the steps of this chain of calculations. These are propagated through the calculations to the final estimate. Quantities in the air pollution model which have appreciable uncertainties include meteorological data, differences between wind patterns at the power plant site and the point of meteorological measurement, frequency distribution of inversion layer heights, air pollutant chemical reactions, and the chemical reaction rate constants. Similarly, in the health effects calculation there are uncertainties regarding the distribution of population, future population estimates, assumed linear relationship between mortality increase and concentrations of a single pollutant, etc. A methodology for estimating the cumulative effect of these individual sources of uncertainty has been developed at Brookhaven National Laboratory[11] and will be applied in the final assessment of health effects.

DISCUSSION OF RESULTS

The average air pollution pattern extends mostly to the north and east of the power plant site. Appreciable amounts of sulfate are carried beyond the sixty-kilometer boundaries shown on our air pollutant maps. Since the air pollution transport model used in these simulations is not suitable for making estimates of the long-range transport of sulfates, we confine our health effects analysis to the portions of Tehama County and three adjacent counties which are covered by our air quality calculations. However, the areas beyond the 60-km limit that have significant sulfate concentration also have low population densities and would not contribute substantially to the overall health effects estimates.

The cancer mortality data displayed in Table 11.2 are shown to permit comparison between the effects of increased coal use and other mortality data, and to compare the rural area under discussion with some urban areas of California. For this purpose data are displayed for the four counties under study—Butte, Glenn, Shasta and Tehama—together with data on three urban California counties—Alameda, Los Angeles, and San Francisco.

For mining, the health effects and accidents are assumed to be proportional to the amount of coal mined. Table 11.3 contains the risk factors per million tons of coal and the total effects per year associated with the coal supply system for operation of an 800 MWe power plant. Transportation accidents are assumed to be proportional to the trip miles incurred and are expressed in units of accidents per 10^9 ton-miles. A hauling distance of 600 miles from Utah to California is assumed. Accidents on back hauls of empty freight cars are not accounted for. Most of the deaths from rail accidents result from collision between trains and motor vehicles occurring at rail-highway crossings. These estimates are based on a review of statistical data for recent years[3] and are applicable if future mining and transportation conditions are similar to the average of the recent past.

Table 11-2

Cancer Mortality Data for California Counties

California County	Non-white Female	White Female	Non-white male	White male
Total Cancer Mortality				
Alameda	128	133	175	179
Butte	140	115	140	170
Glenn	170	110	260	160
Los Angeles	132	132	186	175
San Francisco	119	150	176	212
Shasta	110	120	120	155
Tehama	60	120	180	180
Lung, Trachea, & Bronchus				
Alameda	8	8	39	41
Butte	9	6	14	41
Glenn	---	7	34	33
Los Angeles	7	8	40	41
San Francisco	10	8	39	47
Shasta	---	6	7	42
Tehama	---	6	70	40

Annual age-adjusted cancer mortality rates per 100,000 persons for 1950-1969 (20-year average). Taken from National Cancer Institute county mortality data.[4]

Table 11-3

Quantitative Aspects of Health Effects and Accidents Associated with Operation of an 800 MW Coal-Fired Power Plant Located in Southern Tehama County

	Incidents per Million Tons of Coal	Incidents per Year	Assumed Location of Occurrence
Air Pollution			
Estimated number of excess deaths		0.3	California
Electricity Generating Plant Operation			
Accidental deaths[5]	0.02	0.04	California
Accidental injuries[5]	2.0	4.0	California
Coal Transport			
Rail accidental deaths	2.5*	3.1	California
Rail accidental injuries	12.0*	15.0	& elsewhere
Coal Processing Plants			
Accidental deaths	0.02	0.04	Utah
Accidental injuries	1.3	2.7	Utah
Underground Coal Mining			
Occupational accidents - deaths	0.4	0.8	Utah
Occupational disease - deaths	0.1 - 2.0	0.2 - 4.0	Utah
Occupational disability - injuries	28.0	58.0	Utah

Amount of Coal: 2.06 million tons per year

Sulfur Content of Coal: 1 percent

Average Rail Haul: 600 miles per trip

*per 10^9 ton-miles

Table 11.3 shows that the expected number of fatalities per year associated with various stages of this fuel cycle are: mining, 1-4.8; coal transport, 3; and coal combustion, 0.3. Due to the large uncertainties associated with these estimates, caution should be exercised in the use of these numbers. However, these results suggest that the major risks of increased mortality associated with operating such a power plant occur in mining and coal transport. These risks are borne, to a large extent, by persons living outside of California.

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APPENDIX A

MODELS FOR ESTIMATING ECONOMIC IMPACTS

ESTIMATION OF DIRECT IMPACTS

A California Energy Supply Model has been developed to estimate the direct impacts* of construction and operation of energy and related transportation facilities. This model is based on the data developed for the Energy Supply Planning Model by the Bechtel Corporation.[1] Data for nonconventional facilities were acquired and developed at LBL. The indirect economic impacts were estimated using a California input-output table. This table has 334 sectors, reflecting the California interindustry structure for 1972.

The California Energy Supply Model consists of several submodels, shown as circles in Fig. A-1. These submodels allow the exploration of energy supply options to California. The model converts a future fuel and electricity supply mix into a yearly schedule of electric generation, fuel production, and transportation facilities. It also calculates the set of direct resources and pollutant emissions associated with the construction and operation of these facilities for each year. The sequence proceeds as follows:

Inputs:

- Annual schedules are specified for i) gas demand, ii) oil demand, iii) coal demand, iv) electrical generating capacity, and v) nonconventional energy supply facilities.
- Gas and oil supply constraints and characteristics are also specified.

Calculations Performed by Model

- The computer program then calculates the necessary energy facility construction schedules and the fuel flows required for these facilities.

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*Direct impacts include all impacts arising directly out of the construction and operation of any facility. Indirect impacts include impacts due to other activities related to the construction and operation of that facility. For example, the manpower required to construct a power plant would be a direct requirement whereas the manpower required to make steel used in constructing the power plant would be an indirect requirement.

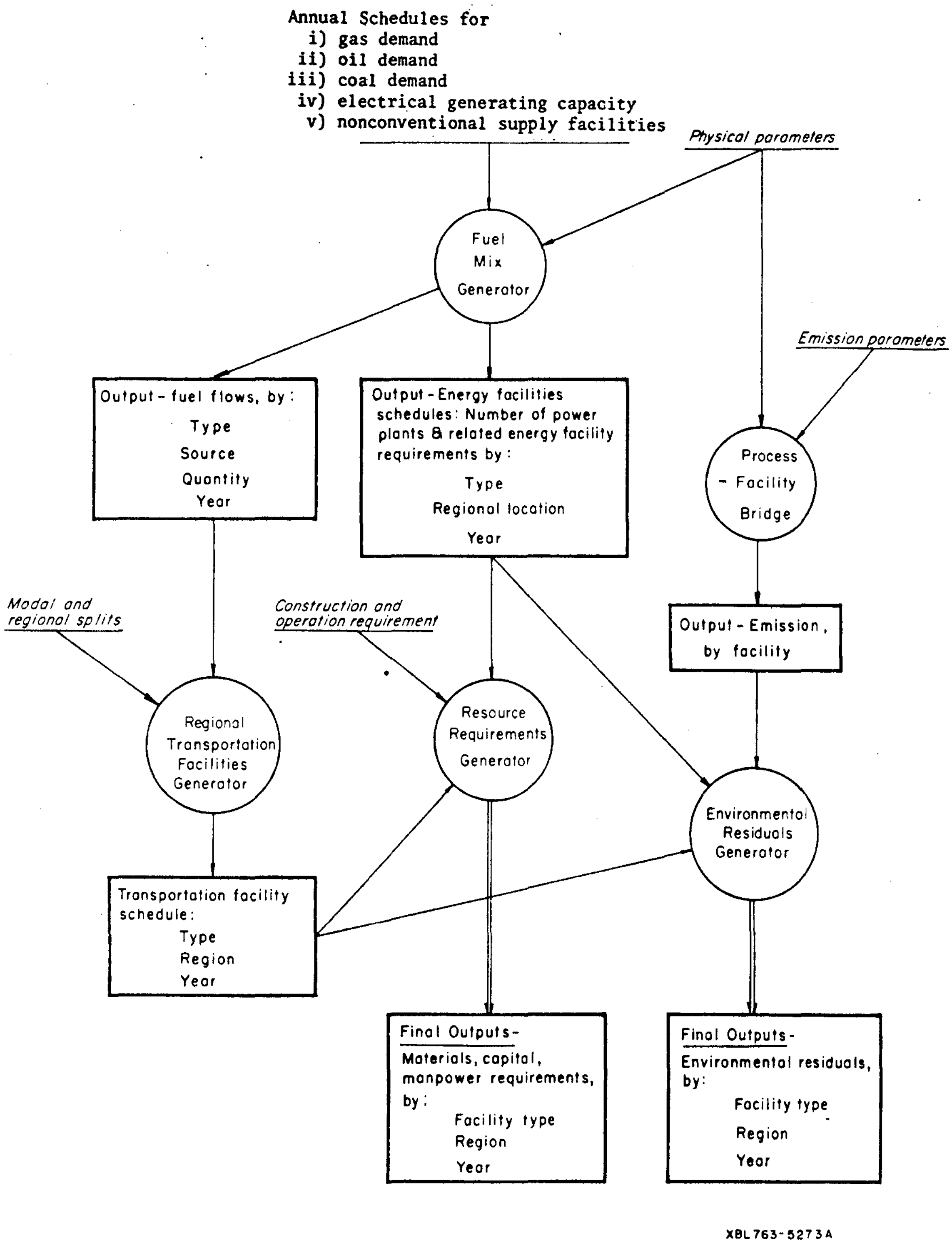

Fig. A-1 California Energy Supply Model

- These fuel flows are then converted into transportation facility schedules.

Model Outputs

- The program next calculates the capital, manpower and equipment required to construct and operate these facilities.
- A separate program calculates the environmental pollutants emitted by these facilities.

Output Format

- Finally the output from the two previous steps is reassembled and printed in a tabular and graphical format.

Fuel Chains and Input Data for the Model

Fuel and energy flows into California are shown schematically in Fig. A-2, with basic facilities and the interlinking flows indicated. These links represent both present and potential flows for meeting California energy requirements. Table A-1 lists these facilities and the resources and manpower required for their construction and operation.

Gas Supply

Crude oil and natural gas form the bulk of energy supplied to California. Natural gas for California at present comes from California, Texas, the Rocky Mountain states and Canada. As existing onshore sources are depleted, additional gas supplies are expected to come from Alaska, Indonesia and offshore wells. Table 3-7 shows a list of gas supply sources and their expected production for each scenario. Imported natural gas will be transported to California as liquefied natural gas (LNG) in tankers. Alaskan gas, either from the North Slope or Cook Inlet, will come to California either as LNG or by pipeline. Synthetic natural gas (SNG) expected from the Rocky Mountain states will be transported by pipeline.

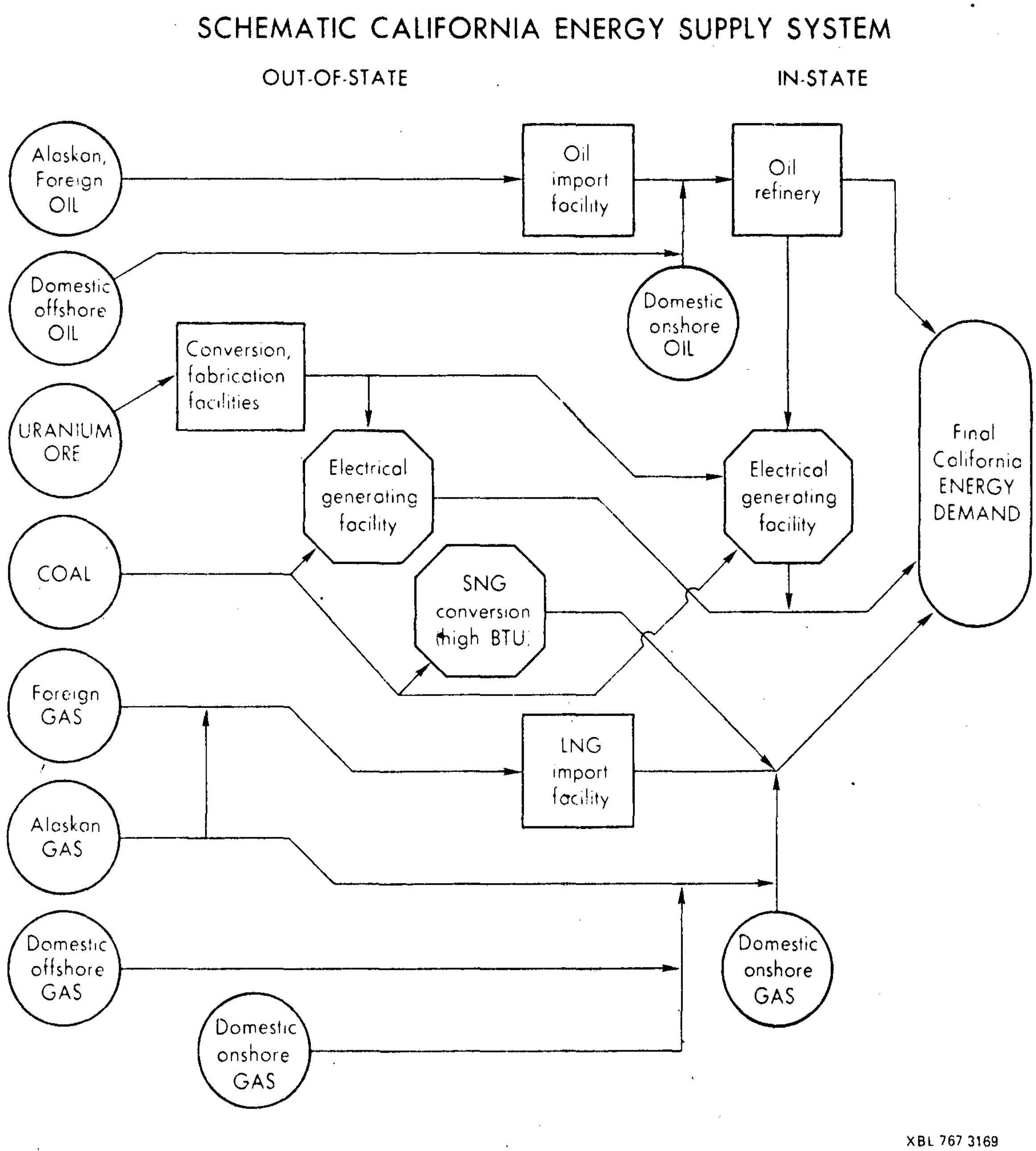
SCHEMATIC CALIFORNIA ENERGY SUPPLY SYSTEM
OUT-OF-STATE
IN-STATE
Alaskan, Foreign OIL
Oil import facility
Oil refinery
Domestic offshore OIL
Domestic onshore OIL
Conversion, fabrication facilities
URANIUM ORE
Final California ENERGY DEMAND
Electrical generating facility
Electrical generating facility
COAL
SNG conversion (high BTU)
Foreign GAS
LNG import facility
Alaskan GAS
Domestic offshore GAS
Domestic onshore GAS
Domestic onshore GAS
XBL 767 3169

Fig. A-2

Table A-1

Cost and Manpower Data for Nominal Facilities

Facilities	Nominal Size[a]	CONSTRUCTION REQUIREMENTS: Total Cost[b] in million (1974) dollars	CONSTRUCTION REQUIREMENTS: Manpower[c] in 10^3 man-hours	OPERATION REQUIREMENTS: Cost[d] in million (1974) dollars per year	OPERATION REQUIREMENTS: Manpower in man-years per year
I. ENERGY FACILITIES					
1. Onshore oil production	250 bbl/day	5	94	0.04	5
2. Offshore oil production	4000 bbl/day	32	287	0.35	16
3. Low-gasoline refiner	200,000 bbl/day	430	13,150	72.73	403
4. Onshore oil import	1 X 10^6 bbl/day	95	1,890	3.56	177
5. Onshore gas production	3 X 10^6 ft^3/day	5	94	0.032	10
6. Offshore gas production	50 X 10^6 ft^3/day	68	720	0.487	17
7. LNG import terminal	2.8 X 10^6 ft^3/day	420	9,950	8.712	96
8. Surface western coal mine	6 x 10^6 ST/year	44	794	5.65	276
9. Surface uranium mine	1200 ST/day	14	532	2.31	178
10. Uranium mill	1000 ST/day	7	217	1.68	111
11. LWR fuel fabrication (no PU recycle)	660 ST U/year	48	1,365	34.46	503
12. Oil-fired power plant	800 MWe	180	4,400	2.60	84
13. Coal-fired power plant (with SO_2 removal)	800 MWe	340	7,700	6.61	195
14. Coal-fired power plant (with fluidized bed combustion)	800 MWe	340	7,700	6.61	195
15. Combined cycle power plant	400 MWe	66	1,320	1.46	26
16. Gas turbine power plant	133 MWe	17	224	0.23	7
17. Light water reactor	1100 MWe	460	12,000	4.64	112
18. Dam and hydroelectric power plant	200 MWe	80	2,385	0.27	12
19. Pumped storage	1000 MWe	225	6,430	0.56	25
20. Geothermal power plant	200 MWe	120	992	0.74	83
21. Solar power plant	100 MWe	104	1,070	11.20	--
22. Waste-fired power plant	133 MWe	167	3,424	20.00	300
23. Active solar heating	2.1 X 10^{12} BTU/season	234	7,960	6.203	375
24. Wind turbine generator	4 MWe	2	17	0.06	--
25. Coal Gasification	250 X 10^6 ft^3/day	750	20,698	7.50	590

Table A-1 (Continued)

Cost and Manpower Data for Nominal Facilities

Facilities	Nominal Size[a]	CONSTRUCTION REQUIREMENTS: Total Cost[b] in million (1974) dollars	CONSTRUCTION REQUIREMENTS: Manpower[c] in 10^3 man-hours	OPERATION REQUIREMENTS: Cost[d] in million (1974) dollars per year	OPERATION REQUIREMENTS: Manpower in man-years per year
II. TRANSPORTATION FACILITIES					
1. Crude oil pipeline	800,000 bbl/day, 1000 miles	406	6,500	20.30	115
2. Oil tanker	90,000 DWT	32	--	3.19	83
3. Oil tank truck	9500 gallons	0.07	--	0.02	2
4. Products pipeline	70,000 bbl/day,100 mi.	16	316	0.13	16
5. Hot oil pipeline	40,000 bbl/day,50 mi.	13	212	0.18	13
6. Refined products bulk station	69,000 bbl/day	7	120	0.05	13
7. Gas pipeline	830 X 10^6 ft^3/day	430	6,500	14.811	139
8. LNG - tanker	2.6 X 10^6 ft^3/day	100	--	4.572	91
9. Gas distribution facility	50 X 10^6 ft^3/day	30	760	.589	82
10. Rail line	40 miles, single track	12	289	0.17	18
11. Coal train	10,500 ST	5	--	0.85	30
12. Coal truck	25 ST	0	--	0.02	1
13. 230 kV AC transmission line	480 MWe,500 miles	95	2,430	0.03	4
14. 345 kV AC transmission line	960 MWe,500 miles	120	3,255	0.05	7
15. 500 kV AC transmission line	2080 MWe,500 miles	188	4,555	0.07	9
16. Electricity distribution	131.6 MWe	41	1,100	0.27	23
17. Conventional rail	10,500 ST	5	--	0.85	30

a. Unit Abbreviations: MWe - megawatts, electric; ST - short ton; DWT - dead weight ton

b. Excluding owners' cost.

c. Manpower figures not included for non-stationary facilities.

d. Excluding labor and fuel costs.

The model simulates the flow of gas into and within California and identifies the facilities required to produce and transport the natural gas. For domestic flows the facilities included are onshore gas production wells, offshore gas production wells, and gas pipelines. For imported gas the facilities are LNG import terminals and LNG tankers. Based on the estimated annual supply of natural gas to California, the model calculates the nominal numbers of each of these facilities required to provide the gas.

Oil Supply

Crude oil is available from onshore and offshore wells and from imports. Onshore crude oil production in California is expected to decline over the next 20 years, whereas California offshore production is expected to peak in 1990. Additional oil requirements would be met by Alaskan oil and foreign imports. Crude oil supply sources and quantities for the scenarios are shown in Table 3-5. Crude oil is assumed to form the only major input to the refineries. These refineries are assumed to produce transportation fuels, power plant fuels, and feedstocks for industry. In the model, the fraction of different types of fuel produced can be varied to meet the necessary demand, i.e., it is implicitly assumed that refineries can change the product fraction to meet the changes in demand for each type of fuel.

Gas and Oil Demand

The California energy flow simulation process starts with the stipulation of gas flows to California and then proceeds to calculate the flow of petroleum products. If the demand for natural gas is in excess of the available supplies, highest priority users are satisfied first. The unsatisfied demand for natural gas is then met by oil supplies. This demand for fuel oil along with transportation, power plant and non-fuel demands determine the total crude oil requirements in a given year. Power plant fuel requirements are calculated based on the projected mix of power plants.

Supplies of natural gas, if less than total demand, are allocated to different types of demands in the following order of priority:

i) Firm Gas Demand

ii) Interruptible Gas Demand

iii) Residential and Commercial Oil Demand

iv) Industry Fuel Oil Demand

The first two categories include the demands projected by the California Public Utilities Commission for natural gas consumption in the state. Categories iii) and iv) are the projected demands for oil which can be met by gas supplies. It is not clear whether available projections for categories ii), iii) and iv) are entirely independent of each other. As a first cut they are assumed to be independent, subject to later revisions.

The combined annual demand for these four categories is expected to exceed the natural gas supply available in a given year. The unsatisfied gas demand is then met by residual fuel oil. Demands for oil supplies are categorized as follows:

i) Transportation

ii) Electricity Generation

(a) Low sulfur heavy fuel oil

(b) Distillate oil

iii) Industry Non-Fuel Demand

iv) Unsatisfied Gas Demand

Fuel requirements for power plants are based on the annual schedule of power plants coming on-line by 2020. Distillate oil is consumed by both gas turbine and combined cycle power plants. These power plants are located in California only. Table A-2 shows the power plant and fuel characteristics assumed in the model. Category iv), unsatisfied gas demand, is the excess demand for gas which is substituted for by oil supplies. These four demands are converted from physical units to a common unit of energy (BTU's) using conversion factors shown in Table A-3. Crude oil requirements (in barrels) are computed by converting the total BTU requirements determined above into barrels of oil required as input to the refineries.

Table A-2

Power Plant and Fuel Characteristics

Power Plant	Capacity Factor[a]	Thermal Efficiency	Fuel	Heat Content million BTU/Unit
Oil	0.6	0.38	Low sulfur Heavy fuel oil	6.287/bbl
Coal				
Conventional	0.75	0.359	Strip-mined Coal	24/ton
Fluidized Bed	0.75	0.357	Strip-mined Coal	24/ton
Nuclear (LWR)	0.6	0.32	Enriched uranium	2.5×10^6/ton of uranium .033 ^{235}U .0025 tails
Combined Cycle	0.6	0.40	Distillate oil	5.88/bbl
Gas Turbine	0.10	0.27	Distillate oil	5.88/bbl

a. Weighted averages of utility submissions to CERCDC. Annual capacity factors used in the model vary from year to year based on utility submissions.

Table A-3

Conversion Factors[a]

	Demand Types	Million BTU/barrel
(i)	Transportation Gasoline	5.253
(ii)	Electricity Generation	
	(a) Residual[b]	6.287
	(b) Distillate	5.880
(iii)	Industry Non-Fuel Demand	5.506
(iv)	Unsatisfied Gas Demand[b]	6.287
(v)	Crude Petroleum	5.800
(vi)	Natural Gas	1032 BTU/ft^3

a. Knecht, R. L., and C. W. Bullard, "Direct Energy Use in the U. S. Economy, 1971", Center for Advanced Computation, University of Illinois at Urbana-Champaign, Report no. CAC-43, April 1975.

b. CERCDC Quarterly Fuel and Energy Summary, Vol.1, No.4.

Coal

Coal-burning power plants may be located in California and the Southern Mountain Region (consisting of the states of Arizona, Colorado, Nevada, New Mexico and Utah). Power plants at both locations are assumed to burn the same type of strip-mined coal, all of which is mined in the Southern Mountain Region. Coal is transported via conventional or unit trains and coal trucks from the coal mines directly to the power plants. The fuel chain includes two categories of energy facilities: coal mines and coal-burning power plants; and four types of transportation facilities: unit trains, conventional trains, coal trucks and fixed railroad facilities.

The model calculates the amount of coal mined to meet the requirements of the coal-burning power plants in the two regions. We have used an average heat content of 12,000 BTU/lb for coal found in the Southern Mountain Region. This comes from an assessment of the coal reserve base for the Southern Mountain Region, weighted by the mean heat content of each coal type. Based on this analysis we assume an average value of ten percent for the ash content and 1.0 percent for the sulfur content for coal in this region. These data are corroborated by a recent U.S. Geological Survey study[2] of remaining identified coal resources in the U.S. from which one obtains a similar heat content.

Uranium

Light water reactors are the only facilities in the model that use uranium as a fuel. The reactors supplying electricity to California are located in California and the Southern Mountain Region. The fuel chain begins with uranium mining and milling activities, which are assumed to occur in the Southern Mountain Region only. Further processing of uranium ore, except for fuel fabrication, is assumed to occur in states other than California and the Southern Mountain Region and no resource requirements are calculated for these facilities. Fuel fabrication facilities are located in California only if the requirements exceed 20 percent of the nominal size of the fabrication facility; otherwise this facility is assumed to be located outside the two regions under consideration. Uranium transportation is not included as the quantities were deemed too small to make a significant change in the impacts under consideration.

The model calculates the amount of uranium mined in the Southern Mountain Region and the amount of uranium fuel required by the power plants. These fuel requirements are based upon 3.3 percent enrichment in ^{235}U; 0.25 percent ^{235}U in the enrichment tails; an average thermal specific power of 30 MW/metric ton of uranium fuel; and an uranium ore concentration of 0.15 percent.

No uranium or plutonium recycling is assumed, so that fuel requirements are based on flows through the reactor; therefore, our calculations set an upper limit on the amount of uranium needed. If uranium and plutonium are recycled, the amount of uranium to be mined could be less by as much as 30 percent. Since there is presently considerable uncertainty regarding fuel reprocessing and waste storage, these facilities are not specifically included in the model.

The operation of fuel chains is simulated in the fuel mix generator (see Fig. A-1). This program also accepts all the input data outlined earlier along with relevant data on each type of nominal facility. Based on this information, the program then calculates:

- Annual fuel flows by type, source and quantity, and
- the energy facilities' schedules, which specify the number of nominal power plants and related nominal energy facility requirements by type, regional location and year.

The fuel flows are then used to determine the types and sites of nominal transportation facilities required to meet the demand for fuels. Fuel flows include transmission of electricity.

Having determined the number of nominal energy and transportation facilities that need to be constructed, the program next calculates the manpower, capital and materials resources required to construct and operate these facilities. These resources are computed for each region and for each year until 2000. Tables A-4 and A-5 show the detailed list of resources included in the model. Data for these resources were acquired from the Energy Supply Planning Model.[1] The capital resources serve as a final demand vector which stimulates

Table A- 4

California Energy Supply Model

Construction Resource Requirements

Manpower in Thousands of Man hours

1	Chemical Engineers
2	Civil Engineers
3	Electrical Engineers
4	Mechanical Engineers
5	Mining Engineers
6	Nuclear Engineers
7	Geological Engineers
8	Petroleum Engineers
9	Other Engineers
10	Total Engineers
11	Total Designers & Draftsmen
12	Total Supervisors & Managers
13	Total Technical
14	Total Nontechnical (Nonmanual)
15	Pipefitters
16	Pipefitter/Welders
17	Electricians
18	Boilermakers
19	Boilermakers/Welders
20	Iron Workers
21	Carpenters
22	Operating Engineers
23	Other Major Skills
24	Total Major Skills
25	Other Craftsmen
26	Total Craftsmen
27	Total Teamsters & Laborers
28	Manpower Total

Table A-4 (Continued)

Materials

29	Refined Products (Tons)
30	Cement (Tons)
31	Ready Mixed Concrete (Tons)
32	Pipe & Tubing (Less than 24" D)(Tons)
33	Pipe & Tubing (24" D & Greater)(Tons)
34	Oil Country Tubular Goods (Tons)
35	Steel Forgings(Tons)
36	Iron & Steel Castings (Tons)
37	Structural Steel (Tons)
38	Rebar (Tons)
39	Valves (24" D & Greater)(Items)
40	Valves (24" D & Greater)(Tons)
41	Steam Turbogenerator Sets (1000 HP)
42	Steam Turbines W/O Generators (1000 HP)
43	Gas Turbogenerator Sets (1000 HP)
44	Gas Turbines W/O Generators (1000 HP)
45	Draglines (Cubic Yards)
46	Draglines (Tons)
47	Drill Rigs (Item-Years)
48	Pumps & Drives (100 HP)(Items)
49	Pumps & Drives (100 HP)(Tons)
50	Compressors & Drives (1000 HP)(Items)
51	Compressors & Drives (1000 HP)(Tons)
52	Heat Exchangers (1000 Sq Ft Surface)
53	Pressure Vessels (1½" Plate)(Tons)
54	Boilers (10^6 BTU/hr)
55	Nuclear Steam Supply Systems (GWe)

Table A-4 (Continued)

Construction Costs in Million (1974) Dollars

56	Wood Products (20)*
57	Chemicals & Allied Products (27,28,30,32)
58	Petroleum Products (31)
59	Stone & Clay Products (36)
60	Primary Iron & Steel Products (37)
61	Primary Nonferrous Metals (38)
62	Fabricated Structural Products (40)
63	Other Fabricated Products (42)
64	Materials Subtotal
65	HVAC Heating & Cooling Units (52)
66	HVAC Ductwork & Accessories (40)
67	Turbines (43)
68	Construction, Mining & Oil Field Eqp (45)
69	Gas Welding Sets & Metalworking Eqp (47)
70	Electric Welding Sets (53)
71	Materials Handling Equipment (46)
72	General Industry Equipment (49)
73	Instrumentation & Controls (62)
74	Electrical Equipment (53)
75	Fabricated Plate Products (40)
76	Miscellaneous (1-68, Except Above)
77	Equipment Subtotal
78	Construction Capital Cost Total

*Figures in parentheses are BEA input-output sector numbers.

Table A- 5

California Energy Supply Model

Operation Resource Requirements

Manpower in Man-years

1	Chemical Engineers
2	Civil Engineers
3	Electrical Engineers
4	Mechanical Engineers
5	Mining Engineers
6	Nuclear Engineers
7	Geological Engineers
8	Petroleum Engineers
9	Other Engineers
10	Total Engineers
11	Total Designers & Draftsmen
12	Total Supervisors & Managers
13	Total Other Technical
14	Total Technical
15	Total Nontechnical (Nonmanual)
16	Pipefitters
17	Pipefitter/Welders
18	Electricians
19	Boilermakers
20	Boilermakers/Welders
21	Iron Workers
22	Carpenters
23	Equipment Operators
24	Other Operators
25	Underground Miners
26	Welders, Unclassified
27	Other Major Skills
28	Total Major Skills
29	Other Craftsmen
30	Total Craftsmen
31	Total Teamsters & Laborers
32	Manpower Total

Coal

Coal-burning power plants may be located in California and the Southern Mountain Region (consisting of the states of Arizona, Colorado, Nevada, New Mexico and Utah). Power plants at both locations are assumed to burn the same type of strip-mined coal, all of which is mined in the Southern Mountain Region. Coal is transported via conventional or unit trains and coal trucks from the coal mines directly to the power plants. The fuel chain includes two categories of energy facilities: coal mines and coal-burning power plants; and four types of transportation facilities: unit trains, conventional trains, coal trucks and fixed railroad facilities.

The model calculates the amount of coal mined to meet the requirements of the coal-burning power plants in the two regions. We have used an average heat content of 12,000 BTU/lb for coal found in the Southern Mountain Region. This comes from an assessment of the coal reserve base for the Southern Mountain Region, weighted by the mean heat content of each coal type. Based on this analysis we assume an average value of ten percent for the ash content and 1.0 percent for the sulfur content for coal in this region. These data are corroborated by a recent U.S. Geological Survey study[2] of remaining identified coal resources in the U.S. from which one obtains a similar heat content.

Uranium

Light water reactors are the only facilities in the model that use uranium as a fuel. The reactors supplying electricity to California are located in California and the Southern Mountain Region. The fuel chain begins with uranium mining and milling activities, which are assumed to occur in the Southern Mountain Region only. Further processing of uranium ore, except for fuel fabrication, is assumed to occur in states other than California and the Southern Mountain Region and no resource requirements are calculated for these facilities. Fuel fabrication facilities are located in California only if the requirements exceed 20 percent of the nominal size of the fabrication facility; otherwise this facility is assumed to be located outside the two regions under consideration. Uranium transportation is not included as the quantities were deemed too small to make a significant change in the impacts under consideration.

The model calculates the amount of uranium mined in the Southern Mountain Region and the amount of uranium fuel required by the power plants. These fuel requirements are based upon 3.3 percent enrichment in ^{235}U; 0.25 percent ^{235}U in the enrichment tails; an average thermal specific power of 30 MW/metric ton of uranium fuel; and an uranium ore concentration of 0.15 percent.

No uranium or plutonium recycling is assumed, so that fuel requirements are based on flows through the reactor; therefore, our calculations set an upper limit on the amount of uranium needed. If uranium and plutonium are recycled, the amount of uranium to be mined could be less by as much as 30 percent. Since there is presently considerable uncertainty regarding fuel reprocessing and waste storage, these facilities are not specifically included in the model.

The operation of fuel chains is simulated in the fuel mix generator (see Fig. A-1). This program also accepts all the input data outlined earlier along with relevant data on each type of nominal facility. Based on this information, the program then calculates:

- Annual fuel flows by type, source and quantity, and
- the energy facilities' schedules, which specify the number of nominal power plants and related nominal energy facility requirements by type, regional location and year.

The fuel flows are then used to determine the types and sites of nominal transportation facilities required to meet the demand for fuels. Fuel flows include transmission of electricity.

Having determined the number of nominal energy and transportation facilities that need to be constructed, the program next calculates the manpower, capital and materials resources required to construct and operate these facilities. These resources are computed for each region and for each year until 2000. Tables A-4 and A-5 show the detailed list of resources included in the model. Data for these resources were acquired from the Energy Supply Planning Model.[1] The capital resources serve as a final demand vector which stimulates

Table A- 4

California Energy Supply Model

Construction Resource Requirements

Manpower in Thousands of Man hours

1	Chemical Engineers
2	Civil Engineers
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4	Mechanical Engineers
5	Mining Engineers
6	Nuclear Engineers
7	Geological Engineers
8	Petroleum Engineers
9	Other Engineers
10	Total Engineers
11	Total Designers & Draftsmen
12	Total Supervisors & Managers
13	Total Technical
14	Total Nontechnical (Nonmanual)
15	Pipefitters
16	Pipefitter/Welders
17	Electricians
18	Boilermakers
19	Boilermakers/Welders
20	Iron Workers
21	Carpenters
22	Operating Engineers
23	Other Major Skills
24	Total Major Skills
25	Other Craftsmen
26	Total Craftsmen
27	Total Teamsters & Laborers
28	Manpower Total

Table A-4 (Continued)

Materials

29	Refined Products (Tons)
30	Cement (Tons)
31	Ready Mixed Concrete (Tons)
32	Pipe & Tubing (Less than 24" D)(Tons)
33	Pipe & Tubing (24" D & Greater)(Tons)
34	Oil Country Tubular Goods (Tons)
35	Steel Forgings(Tons)
36	Iron & Steel Castings (Tons)
37	Structural Steel (Tons)
38	Rebar (Tons)
39	Valves (24" D & Greater)(Items)
40	Valves (24" D & Greater)(Tons)
41	Steam Turbogenerator Sets (1000 HP)
42	Steam Turbines W/O Generators (1000 HP)
43	Gas Turbogenerator Sets (1000 HP)
44	Gas Turbines W/O Generators (1000 HP)
45	Draglines (Cubic Yards)
46	Draglines (Tons)
47	Drill Rigs (Item-Years)
48	Pumps & Drives (100 HP)(Items)
49	Pumps & Drives (100 HP)(Tons)
50	Compressors & Drives (1000 HP)(Items)
51	Compressors & Drives (1000 HP)(Tons)
52	Heat Exchangers (1000 Sq Ft Surface)
53	Pressure Vessels (1½" Plate)(Tons)
54	Boilers (10^6 BTU/hr)
55	Nuclear Steam Supply Systems (GWe)

Table A-4 (Continued)

Construction Costs in Million (1974) Dollars

56	Wood Products (20)*
57	Chemicals & Allied Products (27,28,30,32)
58	Petroleum Products (31)
59	Stone & Clay Products (36)
60	Primary Iron & Steel Products (37)
61	Primary Nonferrous Metals (38)
62	Fabricated Structural Products (40)
63	Other Fabricated Products (42)
64	Materials Subtotal
65	HVAC Heating & Cooling Units (52)
66	HVAC Ductwork & Accessories (40)
67	Turbines (43)
68	Construction, Mining & Oil Field Eqp (45)
69	Gas Welding Sets & Metalworking Eqp (47)
70	Electric Welding Sets (53)
71	Materials Handling Equipment (46)
72	General Industry Equipment (49)
73	Instrumentation & Controls (62)
74	Electrical Equipment (53)
75	Fabricated Plate Products (40)
76	Miscellaneous (1-68, Except Above)
77	Equipment Subtotal
78	Construction Capital Cost Total

*Figures in parentheses are BEA input-output sector numbers.

Table A-5

California Energy Supply Model

Operation Resource Requirements

Manpower in Man-years

1	Chemical Engineers
2	Civil Engineers
3	Electrical Engineers
4	Mechanical Engineers
5	Mining Engineers
6	Nuclear Engineers
7	Geological Engineers
8	Petroleum Engineers
9	Other Engineers
10	Total Engineers
11	Total Designers & Draftsmen
12	Total Supervisors & Managers
13	Total Other Technical
14	Total Technical
15	Total Nontechnical (Nonmanual)
16	Pipefitters
17	Pipefitter/Welders
18	Electricians
19	Boilermakers
20	Boilermakers/Welders
21	Iron Workers
22	Carpenters
23	Equipment Operators
24	Other Operators
25	Underground Miners
26	Welders, Unclassified
27	Other Major Skills
28	Total Major Skills
29	Other Craftsmen
30	Total Craftsmen
31	Total Teamsters & Laborers
32	Manpower Total

Table A-5 (Continued)

Operating Costs in Million (1974) Dollars

33	Lumber & Wood Products (20,21)*
34	Paper & Paper Products (24-26)
35	Chemicals & Allied Materials (27-32)
36	Stone, Clay & Glass Products (35,36)
37	Nonferrous Metals (38)
38	Metal Products (39-42)
39	Miscellaneous
40	Total Materials & Supplies
41	Nonelectrical Machinery (43-50,52)
42	Electrical Equipment (53-58)
43	Transportation Equipment (59-61)
44	Instruments & Controls (62,63)
45	Miscellaneous (64)
46	Total Equipment
47	Fuel (Heat) (68)
48	Electricity (68)
49	Water (68)
50	Total Utilities

*Figures in parentheses are BEA input-output sector numbers.

indirect production in the California and U.S. economies. The estimations of these indirect impacts in California using an input-output table for state is described in the next section.

ESTIMATION OF INDIRECT ECONOMIC IMPACTS

The indirect economic impacts due to a change in final demand can be estimated using an input-output table. (Final Demand is the consumption by ultimate consumers such as households, government, exports, and capital formation.) In an input-output table the economy is broken up into sectors such as coal mining, automobile manufacturing, or retail trade. Each element in the table is the dollar purchases during one year by one sector of the output of another sector. Reading across the rows shows the sales of a given commodity to all sectors including final demand. Reading down a column shows all the inputs to a given sector including value added which represents payments to the factor of production (land, labor, capital, etc.). The sum of all the elements in a column is called the gross output of that sector. If each element in the column is divided by the gross output, the resulting vector of technical coefficients shows the inputs from each sector needed to produce one dollar's worth of output in that sector. Insofar as these technical coefficients do not change significantly over the time period of this study, an input-output table can be used to calculate the changes in gross output due to a change in final demand.

To do this, the table is first converted into the direct requirements matrix A by dividing each column by the gross output in that sector. The Leontief inverse $(I-A)^{-1}$ is computed and postmultiplied by the change in the final demand vector ΔY to give the change in gross output:

$$\Delta X = (I-A)^{-1} \cdot \Delta Y. \qquad \text{(A-1)}$$

The change in value added and employment in each sector is assumed to be proportional to the change in gross output in that sector.

$$\begin{aligned} \Delta V_i &= v_i \Delta X_i \\ \Delta E_i &= e_i \Delta X_i \end{aligned} \qquad \text{(A-2)}$$

INDIRECT ECONOMIC IMPACTS

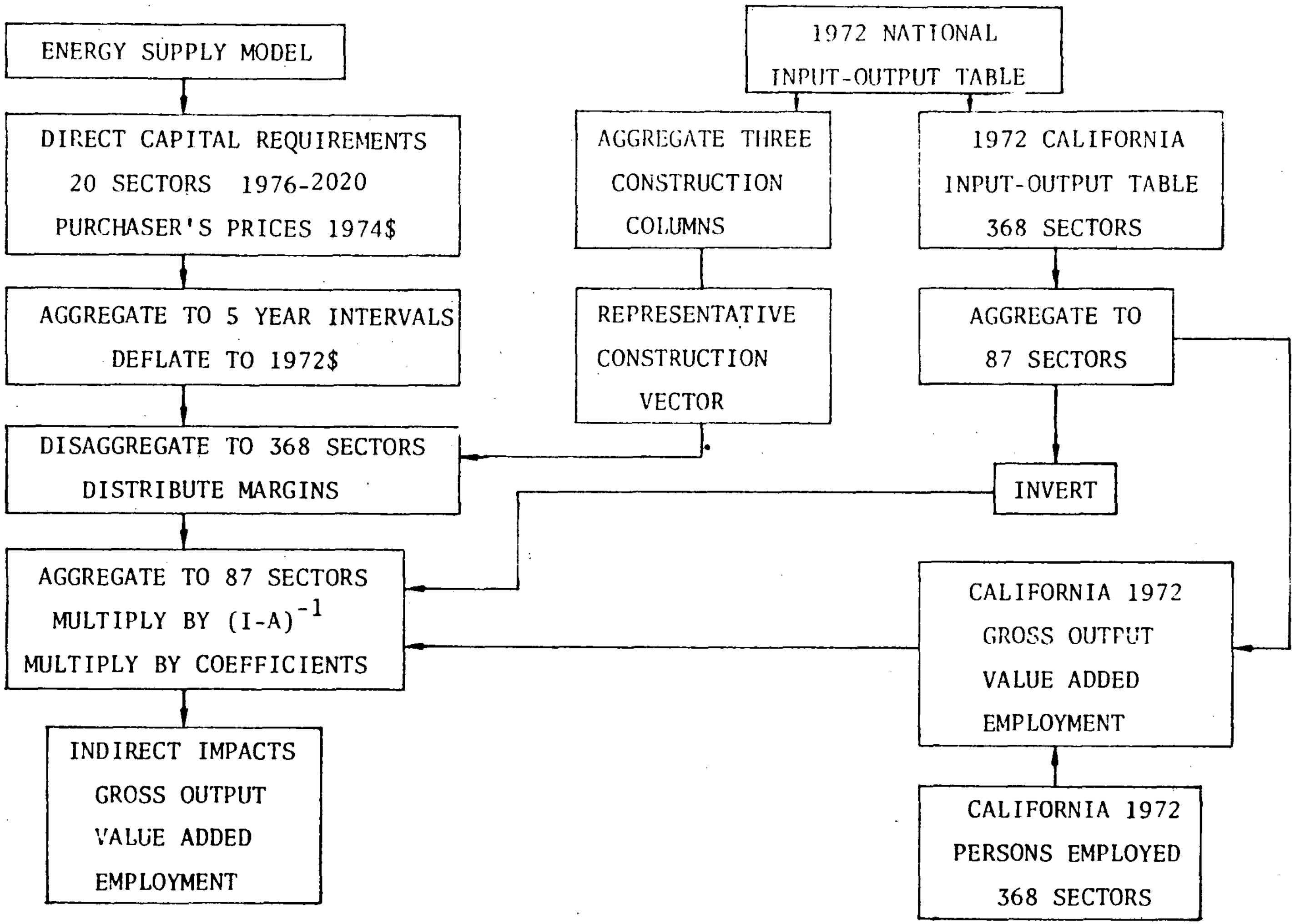

Figure A-3

The coefficients v_i and e_i are the value added and employment in sector i divided by the sectoral gross output from the I-O table.

To calculate the indirect impacts a preliminary version of the 368-Sector California Input-Output Table being developed by LBL for ERDA has been used. The California table is based on the technical coefficients derived by updating the 1967 national table to 1972.[3] For convenience we aggregated the California table to 87 sectors deleting those sectors which do not exist in the state at the 368-sector level. At the 87-sector level the missing sectors are Coal Mining and Tobacco Manufacturing. The table does not include the special industries that are used by BEA for accounting purposes. The Leontief inverse was calculated for the remaining 79 productive sectors. The calculation of indirect impacts is done in constant 1972 dollars, then inflated to 1974 dollars.

Construction of Final Demand Vectors

The steps in construction the final demand vectors from the direct requirements calculated by the Energy Supply Model are shown schematically in Fig. A-3. The model gives the construction requirements from 1974 to 2020 for the twenty categories of materials and equipment listed in Table A-4. A total capital cost is also given. All these data are expressed in purchaser's prices in third quarter 1974 dollars. The first step is to aggregate these requirements to five-year intervals starting with 1976 and to deflate the data to constant 1972 dollars. This was done using deflators obtained from CAC and the Survey of Current Business.[4,5]

Of the twenty requirements categories only six correspond to the BEA 368-sector classification; the rest correspond to two-digit or groups of two-digit codes. Because data were available at the 368-sector level on the transportation costs and trade margins needed to convert purchaser's prices to producer prices, we decided to disaggregate the requirements to 368 sectors. The proportions used to disaggregate the requirements were derived in the following manner. A representative final demand vector was constructed by adding the columns from the 1972 national I-O table for 1) new construction of non-residential buildings; 2) new construction of public utilities; and 3) gross private capital formation excluding the five new construction rows. This 368-order final demand vector is an approximation to the requirements for both structures and equipment needed in constructing energy facilities. The requirements calculated by the model were disaggregated according to these proportions. Transportation costs and trade margins[4,6] were subtracted from each producing sector and assigned to the appropriate transportation or trade sector. The remaining construction costs not included in the twenty requirements categories were allocated to the service and government sectors, imports and valued added, in proportion to the two construction sectors contained in the representative final demand vector.

Changes in Gross Output, Value Added and Employment

The interpretation of the indirect impacts depends on the method of constructing the California input-output table. The table we use is constructed as follows. Each column of the 368-sector national table is divided by the corresponding national gross output. This gives a set of national coefficients which are multiplied by the state gross outputs giving the columns of the state table. The resulting California table has 334 producing sectors. The final demand columns for personal consumption expenditures, capital formation and government purchases are appended. The rows of the table are permuted so that these 334 sectors are first. The remaining rows represent imports by each sector. The rows are then summed to get the total consumption by sector within the state. Finally, a sector-by-sector net trade balance is calculated by subtracting the consumption from the production. If the difference is positive, it is assumed to represent the value of the exports; if the difference is negative, it represents imports. For those sectors in which the production is less than consumption, each element of the row is multiplied by the production to consumption ratio. This assumes that all consuming sectors import this good in the same proportion. The resulting table is thus a domestic flow table for the state, i.e., each element represents the purchase by a consuming sector in the state of the output of a producing sector in the state.

The electric utilities were handled as a special case because the mix of generating capacity in California is substantially different from the national mix. The general procedure is to disaggregate the electric utilities sector into several columns which represent generation by each of the technologies. The columns are expressed as coefficients by dividing each element by the column sum. A new electric utilities column is constructed by combining these coefficient columns weighted by the proportion of electricity generated in California by each new technology. This column, which represents the inputs required for generating electricity in California, is used in place of the national electric utilities column in constructing the California table.

The first step in carrying out this procedure is to combine the private, federal, and state and local utilities sectors of the 1972 national table into one sector. Five new columns representing electricity generation from coal, oil, gas, hydro and nuclear power were constructed. All the coal purchased by the electric utilities plus the transportation costs and trade margins were assigned to the coal generating column. Similarly, petroleum products were assigned to oil generation and natural gas from utilities to gas generation. The purchases of inorganic chemicals, which includes nuclear fuels, by the nuclear generating sector had to be increased by $95 million to match the technical coefficients published by the Mitre Corporation.[7] It is reasonable to expect the amount of inorganic chemicals to be low in the 1972 national table because it is an update of the 1967 table when there was little nuclear power generated. There are no fuel inputs to the hydroelectric sector. The remaining inputs, except inter-utility sales, are disaggregated in proportion to the amount of electric energy produced by each of the five technologies. Additional columns for new generating technologies may be constructed in a similar manner using data from the Mitre Corporation.[7]

Before calculating the Leontief inverse, the 334 producing sectors were aggregated to the 87-sector level. The final demand vectors were aggregated to this level omitting those sectors which have no gross output in the state. To calculate the employment coefficients the 368-sector California persons employed data[8] were similarly aggregated and then divided by the corresponding gross outputs.

The change in gross output X was calculated using Eq. A-1. Using this gross output vector in Eq. A-2, we calculate the indirect changes in employment and value added. The output and value added results are inflated to 1974 dollars using output deflators obtained from BEA.[9]

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APPENDIX B

SHORT-RANGE AIR QUALITY MODEL

The model we have employed for estimating annual average concentrations of airborne pollutants at distances out to approximately 60 km from a coal facility is an existing code developed at Lawrence Livermore Laboratory by Ermak and Nyholm. The model, the major features of which have been described elsewhere (Ref. 1), is a climatological dispersion model, similar to the EPA model.[2] The essential features are the use of a Gaussian plume concept for the vertical dispersion of pollutants. The wind velocity is assumed to be constant in magnitude and direction and uniform vertically. The emission rates are assumed to be constant over a period of time greater than or equal to the travel time from the source to the receptor furthest away (i.e., 50-60 km).

The horizontal dispersion uses a narrow plume approximation, using 16 directional sectors. The pollutants are distributed into these sectors according to the relative frequency of wind direction. These climatological data—obtained as a joint frequency distribution of wind speed, direction and Pasquill stability class—are available from the National Climatological Center for many locations in California.

The Gaussian plume concept has been modified to account for chemical transformation, surface deposition and inversion layers. The first of these uses first-order chemical kinetics to allow for conversion from one chemical species to another (e.g. SO_2 to SO_4) in the plume. The formulae incorporating this change into the model are straightforward for transforming species 1, with mass concentration C_1 into species 2, with mass concentration C_2:

$$\frac{dC_1}{dt} = -k_1 C_1 \qquad \text{(B-1)}$$

where k_1 is the effective rate constant for the process. This is then used to modify the emission rate, Q_1, for species 1, resulting in Q_1 (effective):

$$Q_1(\text{eff}) = Q_1 \exp(k_1 \frac{x}{U}) \quad , \qquad \text{(B-2)}$$

and to give an effective emission rate for species 2:

$$Q_2(\text{eff}) = Q_1[1 - \exp(-k_1 \tfrac{x}{U})] \quad , \qquad \text{(B-3)}$$

where x is the downwind distance at which the concentration is to be evaluated, and U is the wind speed.

The second modification treats surface deposition of the pollutant using the source depletion approach. This approach essentially treats ground deposition as a perturbation to the Gaussian plume dispersion model. The shape of the vertical plume profile is assumed to be unaltered by the dispersion process and the constant source strength is replaced by a virtual source strength which decreases with downwind distance. The virtual source strength is derived from an integral form of the continuity equation and the assumption that the deposition rate is proportional to the pollutant air concentration at ground level. The resultant equation for the virtual source strength is

$$\frac{dQ(x)}{dx} = -\left(\frac{2}{\pi}\right)^{\frac{1}{2}} \frac{V_d}{U\sigma_z(x)} \exp\left[\frac{-Z_o^{\,2}}{2\sigma_z^{\,2}(x)}\right] Q(x) \quad , \qquad \text{(B-4)}$$

where

V_d = deposition velocity

$\sigma_z(x)$ = vertical Gaussian plume dispersion parameter

$Q(x)$ = virtual source strength as a function of downwind distance x

Z_o = plume height .

The solution is

$$Q(x) = Q(o) \exp\left\{ -\left(\frac{2}{\pi}\right)^{\frac{1}{2}} \frac{V_d}{U} \int_o^x \frac{dx}{\sigma_z(x)} \exp\left[\frac{-Z_o^{\,2}}{2\sigma_z^{\,2}(x)}\right] \right\}$$

The plume diminishes exponentially with downwind distance while retaining the original plume shape.

When there is also chemical transformation, the deposition equation for the second pollutant is slightly different. Assuming first-order chemical kinetics, the virtual source strength equation is

$$\frac{dQ_2(x)}{dx} = -\left(\frac{2}{\pi}\right)^{\frac{1}{2}} \frac{V_{d_2}}{U\sigma_z(x)} \exp\left[\frac{-Z_o^{\,2}}{2\sigma_z^{\,2}}\right] Q_2 - \frac{k_1}{U} \frac{e^{-k_1 x/u}}{[1 - e^{-k_1 x/u}]} [Q_2 - Q_1] \qquad \text{(B-6)}$$

where

V_{d_2} = deposition rate for species 2

Q_2 = virtual source strength for species 2

Q_1 = virtual source strength for species 1

The inversion layer is treated following a method described in Ref. 4. Essentially, the plume is "trapped" between a perfectly reflective inversion layer "cap" and the ground surface which is absorptive, as we have just described. The model uses a constant inversion layer height, which generally is selected to be the average annual height.

The model has several overall limitations that should be recognized. It assumes flat terrain; hence, care must be taken in areas where the surface features are not flat. Secondly, the model assumes no precipitation scavenging or gravitational interaction. The former could be important for chemical species such as SO_2, while the latter would affect total suspended particulate concentrations. Finally, we have used the model with annual average climatological data, which may tend to obscure important, shorter time-duration effects. Data for other time periods may be used with this model, such as monthly or quarterly average data, or even hour-by-hour simulations are possible.

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