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DEPARTMENT OF ENERGY

PHASE I. INTEGRATED COMMUNITY ENERGY PLAN FOR RIVERSIDE, CALIFORNIA

Volume 3. Final Report

January 1979

Work Performed Under Contract No. W-7405-ENG-92-100

Battelle Columbus Laboratories
Columbus, Ohio

U. S. DEPARTMENT OF ENERGY

Division of Buildings and Community Systems

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PHASE I. INTEGRATED COMMUNITY ENERGY PLAN FOR RIVERSIDE, CALIFORNIA

Contract W-7405-ENG-92, Task 100

Volume 3

to

U.S. Department of Energy
Office of Assistant Secretary for Environment
Office of Technology Impacts
Division of Regional Assessments
Office of Assistant Secretary for Conservation and Solar Applications
Division of Buildings and Community Systems

January 1979

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APPENDIX D

ALTERNATIVE ENERGY SUPPLY

APPENDIX D

ALTERNATIVE ENERGY SUPPLY

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D1. COAL

D1. COAL

It is a well known fact that coal is one of this nation's most abundant energy resources. Varying estimates of reserves indicate that the U.S. has at least several hundred years supply at projected use rates. President Carter has made increased use of domestic coal an integral part of his proposed energy legislation. Therefore, it seems certain that attempts to use coal as a substitute for scarce petroleum and natural gas in this country will intensify in the future.

Sources and Current Use in California

California itself has no significant indigenous coal supplies and no working mines.(1) The most likely source of coal for use in Southern California is Utah. Two industries near Riverside - Riverside Cement in Rubidoux and Kaiser Steel in Fontana - currently use coal from Utah as an energy source.

The Utah coal resource is substantial with mapped reserves of 39.3 billion tons, of which, 24.3 billion tons are measured, indicated, or inferred.(2) This estimate is a minimum and is expected to increase by 20 to 30 percent as further exploration takes place. In 1980 coal production is expected to reach 17 million tons. Utah ranks behind only Wyoming and Montana in rate of increased coal production in the U.S.

In general Utah coal is higher in heating value and moderately low in sulfur compared to other western coals. The two most important fields are the Kaiparowitz Plateau and the Wasatch Plateau. Table D1-1 gives a typical range of coal analysis for the Wasatch Plateau, which is currently one of the best developed fields in Utah.(2)

The 1977 price of Utah coal delivered in Riverside is estimated at $\$1.40/10^6$ Btu (see Appendix (D8). This cost, in constant 1977 dollars, is expected to increase at a rate of approximately 3.2 percent per year through 1990 and 1.7 percent per year from 1990 through the year 2000.

TABLE D1-1. RANGE OF COAL ANALYSES FOR WASATCH PLATEAU IN UTAH (As Received)[2]

Constituent	Composition Range (percent)	Average
Moisture	5.4 - 8.0	7
Volatiles	38.2 - 42.4	40
Fixed Carbon	45.3 - 47.1	46
Ash	6.1 - 6.7	6.4
Sulfur	0.56 - 0.64	0.6
Heat Value (Btu/lb)	11,727 - 12,744	12,200

Constraints to Utilization

Coal has several drawbacks that inhibit its use. The two main drawbacks are (1) the environmental impact associated with its use as a fuel and (2) the high cost of coal-using systems which is closely related to the necessity for strict environmental controls.

The environmental impact of using coal can broadly be separated into two areas: (1) its extraction from the ground, which is a localized impact near the area of mining, and (2) its conversion to energy which can have wide-ranging effects on the atmosphere.

Extraction of coal from the ground is either by surface mining or deep mining. Both of these methods have deleterious effects on the immediate area surrounding the mine. In the future, varying degrees of land reclamation will be required to minimize the environmental impact of mining. These reclamation activities, while not being able to return the land stone for stone to its premined status, can restore it to useful service and minimize the impact of mining as it relates to the health of people or wildlife. If coal is to become an increasingly important energy resource in our future, some compromises must be reached concerning the degree of reclamation required and the added cost per unit of coal.

Of more immediate concern to the use of coal in Southern California is the environmental impact associated with its conversion to energy. Coal contains several contaminants that add nothing to its value as a fuel. Those currently receiving most concern are sulfur, nitrogen, and ash.* When coal is converted to useful energy all three of these contaminants can end up as atmospheric emissions in the form of sulfur oxides, nitrogen oxides, and particulate matter respectively. Once in the atmosphere they can have wide ranging impact and are beyond man's ability to alter or control. Therefore, to minimize their impact, efforts are concentrated on removing these contaminants from the coal before or during its use as a fuel. They are then ultimately either buried in the ground or, in some cases, converted to usable substances.

* Ash represents the mineral content of coal consisting of silicon, aluminum, iron, calcium oxides and almost every other element in the periodic table.

A variety of methods exist for controlling atmospheric emissions from the use of coal. The choice of methods depends on how the coal is converted to useful heat or work. The following section discusses coal utilization options and their environmental characteristics.

General Coal Utilization Options

Figure D1-1 schematically illustrates a wide range of options for utilizing coal to satisfy a community's energy end-use requirements. All options begin with a primary conversion step that converts coal to a more usable form such as a combustible gas or liquid, or a high-temperature fluid such as steam or hot water.

In a community it is desirable for the primary conversion process to be concentrated in as few areas as possible, with the conversion products (gases, liquids, etc.) being distributed to points of end use. There are three main reasons for this:

(1) It restricts the handling of coal to a few locations where maximum efforts can be made to control dust emissions and liquid runoff from coal piles and coal handling operations.

(2) Most of the efforts to remove contaminants (primarily sulfur, nitrogen, and ash) are concentrated in the primary conversion step. Restricting this process to a few locations helps to minimize the impact of contaminant removal and disposal on the community environment.

(3) The primary conversion step involves expensive, complex equipment. Centralization of these facilities results in maximum economy of scale.

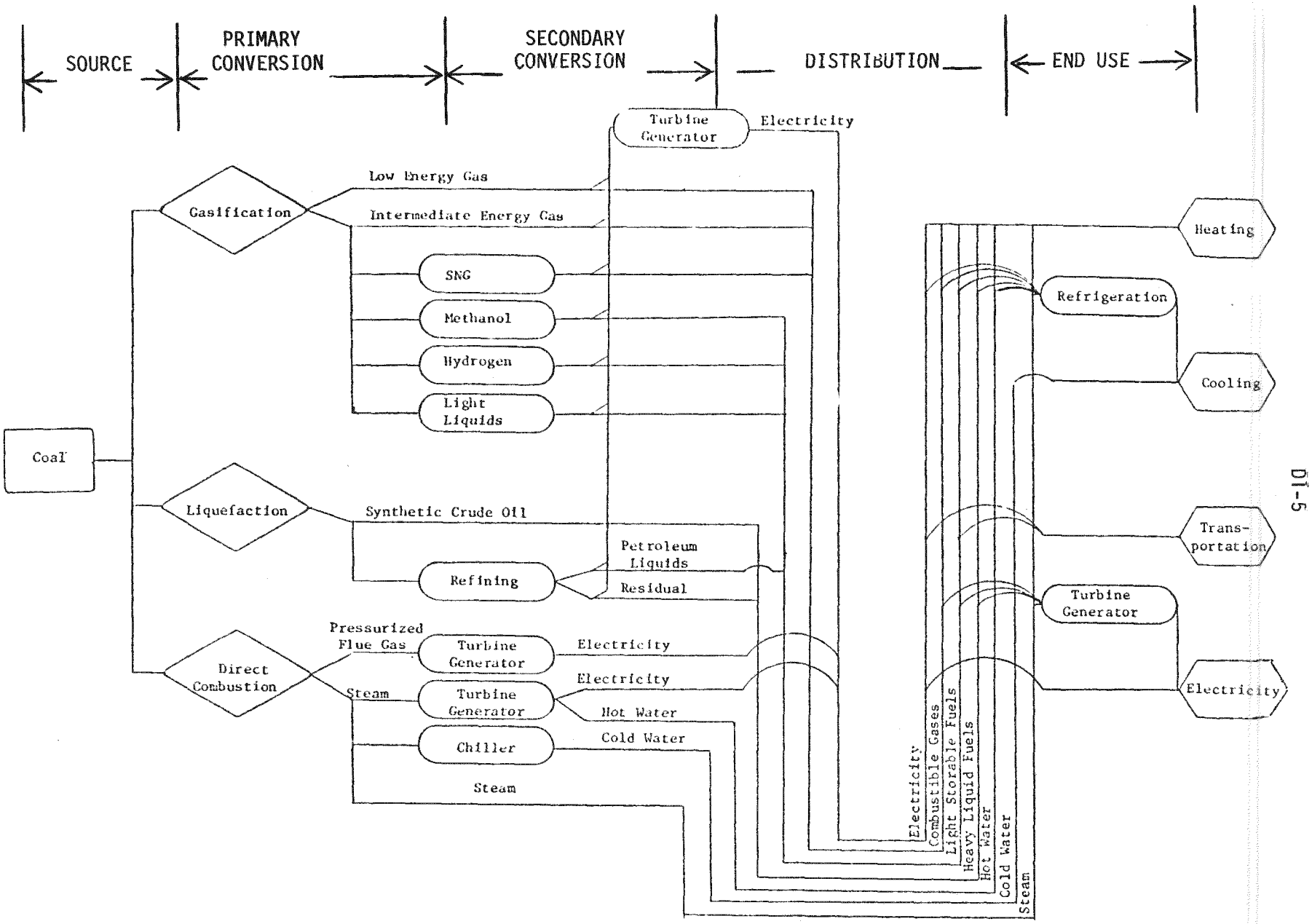

FIGURE D1-1. REFERENCE ENERGY SYSTEM FOR COAL CONVERSION

Coal Conversion Technology

Figure D1-1 shows three primary conversion technologies - direct combustion, gasification, and liquefaction. The secondary conversion processes involve conversion of primary conversion products to potentially more usable energy forms such as electricity or refined gases and liquids such as methane (SNG), hydrogen, and methanol. All secondary conversion processes involve an incremental cost and some energy loss or lowering of efficiency, but may still be desirable because of enhanced energy usability, easier transmission, greater storage capability, or reduced potential for environmental impact at the point of end use.

The following is a general discussion of the status of conversion technologies based on the three primary conversion processes of direct combustion, gasification, and liquefaction.

Direct Combustion. The oldest and most basic form of energy recovery from coal is direct combustion in a furnace or other heat recovery device. This method remains today the only significant means by which energy is recovered from coal.

The methods for burning solid fuels in steam-raising equipment or boilers have undergone steady evolution and improvements over the years. The oldest method, which is still used today in smaller equipment (up to 100,000 lb of steam per hour), involves combusting the fuel in lump form on various types of moving grates. This method is used extensively for mass burning of refuse and is also used for coal although it is restricted to the burning of coals with relatively low caking characteristics.

The spreader stoker is an improvement or addition to simple grate firing. This method involves flipping or blowing the fuel into the combustion zone of a grate-fired furnace where about 50 percent of the burning takes place in suspension above the grate. The remainder of the combustion process is then completed on the grate. This method is advantageous in that it allows for increased capacity per unit size (largest sizes in the 250,000 lb/hr range) and it allows for burning of coal with higher caking characteristics.

The technique of firing pulverized coal in suspension, which was first developed in the cement industry, was adapted to boiler use by the electric utilities as the need for larger unit sizes increased. This method allows for the complete combustion of coal in suspension without the need for a grate. The mechanical limitations of building and operating large grates was a serious obstacle to larger units. Pulverized coal-fired boilers of well over 1,000,000 lb/hr capacity are commonly used today in the utility industry. Refuse has been successfully fired with coal in suspension-fired boilers at the Union Electric Meramec facility in St. Louis, Missouri. First, however, the refuse must be reduced to about 1 inch in size and also classified to remove many of the solid noncombustible particles.

Fluidized-bed combustion also involves the suspension burning of the fuel without a grate. However, unlike pulverized-coal firing, the coal is larger in size and the gas velocities are such that the coal is maintained in a suspended, turbulent, fluidized state for longer periods of time. Usually an inert material, such as sand, and a sulfur sorbent, such as lime are added to the combustion zone along with the coal. Heat Transfer tubes are also placed in the bed in order to lower combustion temperatures such that efficient capture of SO_2 by the sulfur sorbent is possible. NO_x emissions are also lower than with conventional firing methods because of the lower combustion temperatures. Fluidized-bed technology is not yet considered fully commercial although a few commercial units are, at present, being offered.* The first of a series of ERDA/DOE fluidized bed demonstration units is currently undergoing tests in Rivesville, West Virginia. After nearly 1 year of testing the Rivesville unit has not yet achieved operations representative of commercial status. Other ERDA/DOE demonstrations are planned over the next few years including demonstrations at Georgetown University in Washington, D.C., Exxon Research in Linden, N.J., and Battelle in Columbus, Ohio.(3) Exxon(4) estimates that, when commercialized, the fluidized bed will have about 85 percent of the capital and annual operating costs of conventional coal-fired boilers that use scrubbers for SO_2 control. It seems likely, however,

* For example, Fluidyne Engineering in Medicine Lake, Minnesota, see Air Conditioning, Heating, and Refrigeration News, January 30, 1978

that full commercialization of fluidized-bed technology will not be achieved much before 1985.

Controlling emissions from coal combustion processes has been a subject of concern for many years. Until recently, most attention has focused on visible emissions consisting of fly ash (entrained mineral matter) and smoke (unburned carbon). Electrostatic precipitators have been used extensively in the utility industry and are capable of removing over 99 percent of the particulate matter from stack gases, thus preventing it from being emitted to the atmosphere. Baghouses are among the most efficient-particulate collection devices and are gaining favor as particulate emission regulations get tighter. They are capable of particulate removal efficiencies of up to 99.9 percent. Although baghouses have not been tested as extensively on coal burning equipment as electrostatic precipitators, they appear to be successful, though possibly somewhat more expensive to operate.

In recent years emphasis on coal combustion emissions has shifted from particulates to SO_2 and NO_x. In fact, the development of fluidized-bed combustion is primarily stimulated by the ability to control SO_2 and NO_x emissions within the combustion process. However, techniques have also been developed for controlling both forms of emissions from conventional coal-burning equipment.

Table D1-2 summarizes estimated emission rates for various types of control techniques as applied to particulates, SO_2, and NO_x emissions. Note that the best available control technology (BACT) consists of using a baghouse filter for particulate removal, followed by combination SO_2/NO_x scrubbing. By using this technology, emissions can be reduced well below the existing New Source Performance Standards as shown, although the costs will be high.

SO_2 scrubbing has been under development and demonstration in this country at a number of utility and industrial coal-fired power plants over about the past 10 years. These systems are still undergoing testing and development and still have operational problems that affect their dependability.[5] Nevertheless, scrubbers are capable of high SO_2 removal

TABLE D1-2. EMISSION CONTROL DATA FOR COAL COMBUSTION BOILERS

Pollutant	Control Technique	Emission Rate lb/10^6 Btu	Percent Control	Comments
Particulate	None	4.72[b]	0	Assumes Wasatch coal in Table D1-1 with 90% of ash as fly ash
	ESP[a]	0.0472	99[8]	Well established technology
	Baghouse	0.0047	99.9[8]	Relatively unproven on coal but existing commercial status
	NSPS[f]	0.1		
SO_2	None	0.98[c]	0	Assumes Wasatch coal in Table D1-1 with all sulfur as SO_2
	Scrubber	0.049	95[6]	Currently being installed and operating on a number of utility and industrial boilers
	Fluid Bed[e]	0.098	90[3]	Depends on Ca/S ratio; taken at Ca/S of 3.5
	NSPS Std	1.2		
NO_x	None	0.74 [d]	0	Conventional pulverized firing
	Combustion Modification	0.40	50[7]	Low NO_x burners
	Catalytic	0.04	95	Hitachi-Zosen NH_3 injection unproven in U.S.
	Fluid Bed[e]	0.45	40[3]	Atmospheric fluid bed - average of data
	NSPS Std	0.7		

(a) Electrostatic Precipitator.
(b) Assumes Wasatch coal in Table D1-1 with 90 percent of ash as fly ash.
(c) Assumes Wasatch coal in Table D1-1 with 100 percent of sulfur as SO_2.
(d) Assumes 18 lb/ton of coal (9) AP42.
(e) Fluidized bed combustor.
(f) Current New Source Performance Standard.

efficiencies even on low-sulfur coal such as that used at the Mohave power plant in Arizona.[6]

Control of NO_x emissions in this country has primarily been restricted to combustion modification techniques. These seek to control peak combustion temperature in order to minimize thermal conversion of elemental nitrogen to NO_x and oxidation conditions that affect the conversion of fuel-bound nitrogen to NO_x. The effectiveness of this technique varies considerably, from about 20 to 70 percent reduction in NO_x emissions. New, low-NO_x burners for gas- and oil-fired units are capable of 40 to 65 percent reduction in NO_x and low-NO_x coal burners have promise of being slightly more efficient.[7] In Table D1-2 an efficiency of 50 percent was assumed

NO_x removal from coal-fired power plant stack gases has not been tested in this country to any great extent. The Los Angeles Department of Water and Power has conducted tests of ammonia injection at its oil-fired Valley Steam Plant.[10] Also, Southern California Edision has tested combined SO_2/NO_x scrubbing at its Mohave station.[11] Commercial availability of NO_x stack gas controls is projected for the early 1980's in the U.S.[7]

Gasification. An alternative to direct combustion of coal is to convert it first to a combustible gas. The combustible gas can be more easily distributed and used in a wider variety of applications than a solid fuel or steam produced by direct combustion. Also, potential pollutants such as sulfur and nitrogen compounds can be removed from the fuel gas prior to combustion more easily than from the gases resulting after combustion.

The simplest gasification process involves incomplete combustion or partial oxidation of the solid fuel with air and steam. This process, which was used extensively in the U.S. in the 1920's with coal, produces a low-energy gas containing primarily CO, H_2, and N_2 with a heat content about one-sixth that of natural gas (150 Btu/scf). If oxygen is used, instead of air, as the gasifying medium, then the inert nitrogen can be nearly eliminated and the heat content of the gas doubled to about one-third that of natural gas (300 Btu/scf). Another process, called pyrolysis, involves heating the fuel in an inert atmosphere producing a higher grade gas with about half the heat content of natural gas (500 Btu/scf) and also by-product liquid

fuels in the form of tars. Coking of coal used in steel making is a common example of pyrolysis. An extensive review of the status of gasification technology is presented in References 12 and 13.

The gas resulting from gasification of coal can also be a source of other fuels. Hydrogen, a key constituent of the gas can be stripped and used directly. Hydrogen can be a fuel with low pollution potential for use in transportation and fuel cells. Through a process called methanation, the CO and H_2 can be combined to form methane or synthetic natural gas (SNG). Major attractive features of SNG are that it is directly substitutable for natural gas and is nontoxic.

The CO and H_2 in the gas can also be combined to form light liquid fuels. Methanol, having about half the heat content of gasoline, can be made through a process similar to methanation. Fischer-Tropsch, a complex process developed by the Germans during World War II, can be used to synthesize a variety of liquid fuels from gaseous CO and H_2, including gasoline and diesel fuel. The Fischer-Tropsch process with lurgi gasification is currently employed in the world's largest gasification plant in Sasolburg, South Africa, for making a variety of liquid and gaseous fuels from lignite.

Pollutant concentrations in the product gases of coal gasification processes can be reduced to very low levels by a variety of cleaning systems. An attractive feature of gasification processes is that nitrogen and sulfur compounds appear in a reduced form as ammonia (NH_3) and hydrogen sulfide (H_2S). This makes their removal substantially easier than the oxidized forms of NO_x and SO_2 found in combustion gases and also allows for recovery of elemental sulfur from H_2S. Table D1-3 shows estimates of pollutant removal efficiencies and final pollutant concentration levels for representative cleaning processes.

Liquefaction. Technology is currently under development at a number of locations in the U.S. to develop processes for making liquid fuels from solid fuels directly, without the need for an intermediary gasification step. These processes, commonly called direct liquefaction, involve hydrogenation of the solid fuel under high pressure and temperature, yielding a heavy liquid fuel similar to crude oil. These processes have never been applied commercially, but they show promise of being conceptually less

TABLE D1-3. POLLUTANT CONCENTRATION LEVELS IN GASIFIER PRODUCT GASES

Cleaning Process	Sulfur[12] Compounds H_2S, COS, CS_2	Nitrogen[14] (NH_3)	CO_2[12]
Rectisol	< 1 ppmv	300-500 ppmv[a]	< 1 ppmv
Sulfinol	< 1 ppmv	300-500 ppmv	<50 ppmv
Amisol	0.4 ppmv	300-500 ppmv	10 ppmv
Benfield	76 ppmv	300-500 ppmv	7.2%[b]

(a) Ammonia removal accomplished in water scrubber which almost always precedes desulfurization process. Estimated concentration from Reference 12, Appendix E.

(b) Process is selective for H_2S and does not remove CO_2. Can result in lower costs in situations where CO_2 is not undesirable.

complex than existing liquefaction processes, such as Fischer-Tropsch, and hence, perhaps less expensive, although this must still be commercially demonstrated. Representative processes are H-Coal (Hydrocarbon Research, Inc.), Berstus (ERDA), SRC (Gulf/ERDA), Costeam (USBM), and Donor Solvent (EXXON).[15]

Because these processes produce a heavy crude-oil-type liquid, further refining is required to upgrade the liquid before it can be used for applications other than as a boiler fuel. As such, the use of direct liquefaction products for community use is restricted unless further refining operations are included.

Options for Riverside

Examination of Figure D1-1 shows that there are a wide variety of ways in which coal can be utilized in a community. Selection of the optimum mix of technologies over a 20-year period under the constraints of technology availability, coal use efficiency, environmental impact, cost and others is not possible. Also, the optimum mix would depend on other fuels, such as solar, wind, biomass, refuse, etc. Therefore, some practical judgments must be made as to which coal conversion technologies are most appropriate for consideration.

Of the three primary conversion technologies, direct liquefaction appears least attractive for application at the community level. The technology has never been commercially proven and the fuel produced (a crude-oil-type liquid) would require refining before more usable products could be obtained. It is unlikely that the product of these combined processes would be more economical than gaseous products from a coal gasification plant.

Both direct combustion and gasification processes have been commercially demonstrated in the past. Direct combustion is the more straightforward approach although gasification offers the potential for lower atmospheric emissions by achieving greater removal of the three primary pollutants (particulates, sulfur, and nitrogen) as discussed earlier.

The direct combustion process is best applied in a district heating approach such as that shown conceptually in Figure D1-2 where handling of coal can be restricted to a limited area. This also allows for utilizing

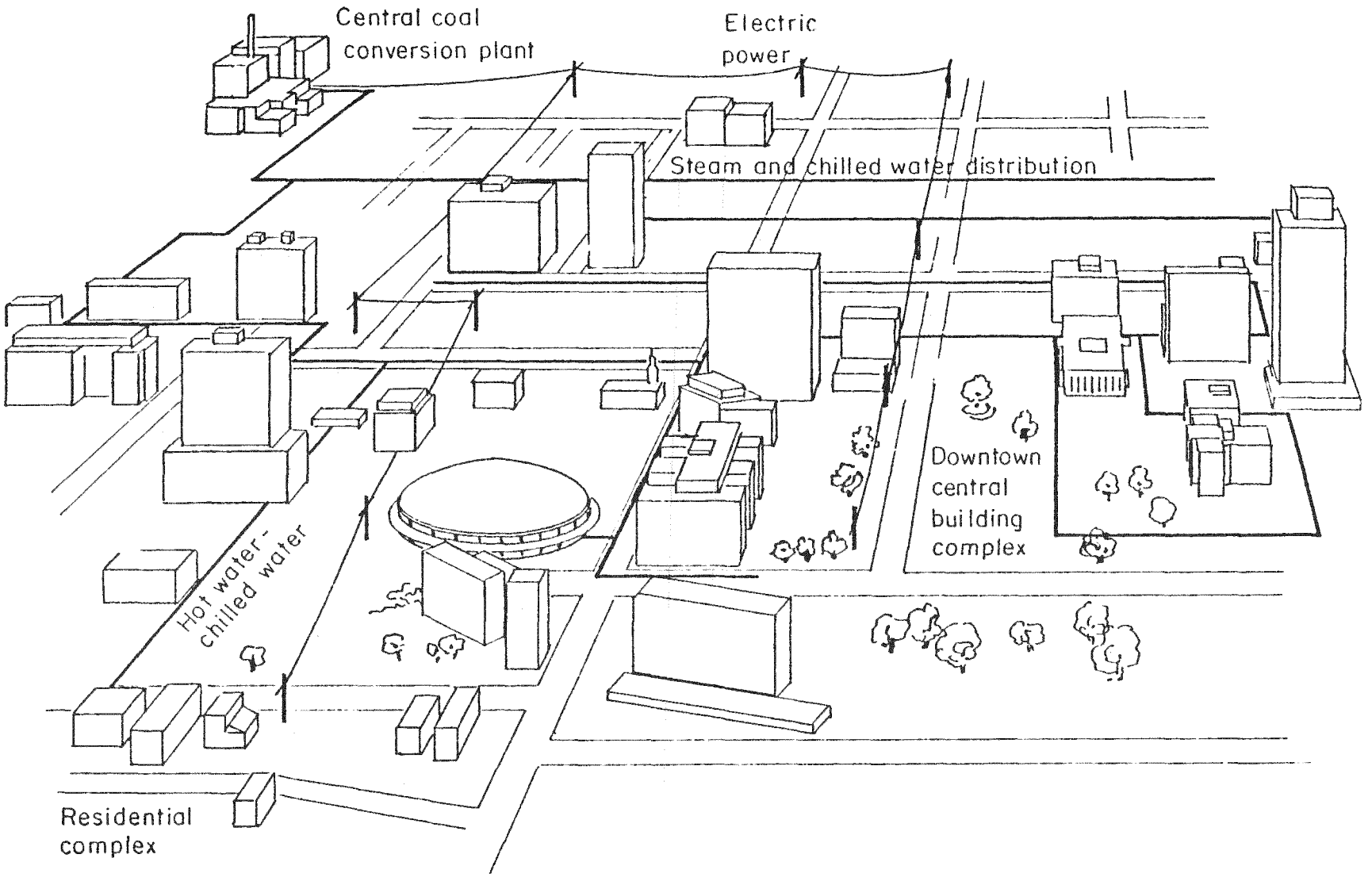

FIGURE D1-2. CONCEPTUAL DISTRICT HEATING COMMUNITY SYSTEM

the principle of cogeneration - using the waste heat from production of electricity to satisfy thermal and cooling requirements.

Gasification can also be applied in a district heating plant through the combined cycle process where the gas is first combusted in a gas turbine to generate electricity, and steam raised from the heat in the turbine exhaust is used to generate additional electricity and to satisfy thermal and cooling requirements.

Low- or medium-Btu gas from gasification can also be used in industrial applications in place of natural gas. Medium-Btu gas from an oxygen blown gasifier would be preferred because of greater ease of substitution for oil and natural gas. Low- or medium-Btu gas is not recommended for residential use. Unlike natural gas it is toxic (contains carbon monoxide) and could not be used in existing distribution systems or with existing appliances. Upgrading medium-Btu gas to SNG would allow its use in existing residential natural gas systems. Large mine-mouth plants for SNG production are currently planned where they could feed into natural gas distribution systems such as at Burnham, New Mexico. However, SNG processes are complex and would be expensive if used on a small scale at the community level. SNG produced at the local level is not judged cost-effective when compared to solar energy with electric backup for residential use.

The production of hydrogen from medium-Btu gas is somewhat less complex than SNG production (contains most of the same steps except for the critical methanation step). On a small scale, however, electrolysis of water using off-peak electricity may be more economical than coal-based systems.* Hydrogen production demonstrations using coal are planned by both DOE and the Billings Corporation of Provo, Utah.[16] A major attribute of hydrogen is that it can be used as a fuel with essentially no hydrocarbon or carbonaceous (CO and CO_2) emissions. This makes it especially attractive for the Southern California area. It can be used as a transportation fuel when stored either cryogenically as a liquid, or in metal hydrides, and is also the only fuel form that can be used directly in fuel cells, which offer potentially high electric conversion efficiencies.

*See Appendix D7 for more detail on hydrogen economics.

Based on the preceding analysis, the following coal utilization technologies were selected for consideration.

- Combustion of coal in a boiler with best available pollution control technology for production of steam and electricity through cogeneration to feed a district heating system. The district heating system would start by serving the densest energy use areas (primarily industrial) in the low impact scenario and progressively be extended to less dense areas in the high impact scenarios.
- Gasification of coal with use of a combined cycle power and steam generating plant to serve the district heating system described above.
- Production of hydrogen from medium-Btu gas for use in transportation and residential fuel cell applications.

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D2. SOLAR

Introduction

The purpose of this study was to evaluate the potential contribution that solar energy can make to the energy needs of the Riverside community. Specific applications of solar energy were identified and the cost and energy savings of those applications were estimated. Primary emphasis was given to the near term (15 to 20 years), and to those technologies that can be expected to make a significant contribution within this time. Emerging technologies that are expected to become viable options beyond the near-term period are discussed.

Presented in Table D2-1 is the percent of the total gas and electric energy used in Riverside, broken down into the various end uses for residential, commercial and industrial users. Over half of this energy is used for hot water and space heating, with over 1/3 consumed by residential users. A relatively small percentage of the total is consumed for space cooling, used primarily by residential and commercial users. Process heat consumed 22 percent of the total, while electric power consumed 20 percent.

TABLE D2-1. RIVERSIDE ENERGY END-USE BREAKDOWN, PERCENT OF TOTAL ENERGY USED

	Total	Residential	Commercial	Industrial
Hot Water	25	17	5	3
Space Heat	28	19	6	3
Space Cool[(a)]	4	2	2	0.3
Process Heat	22	5	7	10
Electric Power	20	6	11	3

(a) Expressed in terms of electricity consumed using a conversion factor of 3413 Btu/kWhr. In terms of actual energy demand at the point of end-use, the ratio of space heating to space cooling for the total column is estimated at 1.12 (see Table D9-1).

Solar Applications

Solar Heating. Solar energy applications that supply hot water (including pool heating) and space heating are technically well developed and appear to be economically viable in Riverside. These systems have the potential of replacing a significant fraction of the total gas and electric usage and therefore should be promoted on a community-wide basis. These systems have been evaluated in detail in this study to determine the economic potential of solar heating for new houses as well as retrofitting for existing structures, when compared with gas or electric heating. The influence of various tax incentives, including the California State Income Tax Credit, has been examined. A comparison between increasing insulation and adding solar energy has been made. The methodology and a discussion of the results of these studies are presented in succeeding sections of this report.

Solar Cooling. Solar space cooling does not appear to be economically competitive with electric-driven compression cooling. A recent study[1] of the system installed on the Santa Clara Community Recreation Center concluded that solar-driven absorption cooling is not now economically viable and probably would not become viable in the near term, even considering the improvements expected for absorption cooling units. Furthermore, since the space cooling load is relatively small, and can perhaps be reduced through passive design techniques (better insulated structures, nighttime cool down with internal storage), it would be inappropriate to promote solar absorption cooling.

Solar Industrial Process Heat, Solar Thermal Power. Solar industrial process heat and solar thermal power also do not appear to be attractive economic alternatives in the near term because of the high availability and low cost of gas to commercial and industrial users. The sophisticated concentrating tracking collector systems needed to deliver the high temperatures have not been developed to the same level of reliability as flat-plate collectors. These systems are at least as expensive as flat-plate systems and therefore cannot compete with low-cost gas. The effective cost of gas to commercial and industrial users is much less than that to residential customers because it is a tax deductible business expense.

Solar Photovoltaic. Photovoltaic power generation is expected to become competitive with commercial electric generation toward the end of the near term. A detailed discussion of this energy alternative is presented in a later section.

Systems Analysis of Solar Hot Water and Space Heating

Calculations on Performance

Performance Calculations for New Construction. Economic factors dominate any consideration of the ultimate use of solar energy and also play an important role in the sizing of specific components of a solar system. In this section, calculations are presented that indicate the optimum collector size needed to obtain maximum solar energy savings for a new single-family dwelling in Riverside, California. Collector efficiency parameters, income tax incentives, and alternative fuel costs are included in the analyses.

Computations were performed using a simplified analysis procedure called the "F-CHART".[2] This technique utilizes correlations obtained from many long-term, highly complex, hour-by-hour performance calculations. In the simplified method, only monthly average meteorological data and "steady-state" collector efficiency characteristics are used. However, results obtained using the F-CHART procedure compare very favorably to the more costly and time consuming calculations so this simplified method was considered adequate for the present analysis. Further, in this particular study, the calculations were performed quite rapidly using an interactive computer program version of the calculation procedure F-CHART.[2]

The calculation scheme utilizes what is known as the degree-day concept to model space heating loads for each month. Water heating loads are given in terms of per capita hot water usage which is taken as 100 liters per person per day. The economic calculations are given in terms of the present worth of various options in order to account for the time value of money.

Details of the calculation procedure are beyond the scope of this report but some insight into the computation can be obtained by examining

the input variables given in Table D2-2. The variables that change with collector type are marked with an asterisk in Table D2-2. These variables refer to the particular type of solar system (i.e., water or air), the collector performance properties (i.e., Items 3, 4, and 5), and the area-dependent collector cost (i.e., Item 21). Three standard collector types were chosen from various manufacturers' data to represent a range of performances and costs. The particular collector types and resulting data are presented in Table D2-3.

Collector orientation is given in Items 6 and 7 of Table D2-2. The collector was assumed to be pointed due south at an angle of 43 degrees to the horizon. Building properties are given in Items 9 and 10. No internal heat generation was considered and the effective building loss coefficient was taken to be 350 W/C (660 Btu/hr/F). This latter parameter indicates the amount of heat which must be supplied by the space heating system to offset heat losses through the exterior surface of the building.

A poorly insulated dwelling would have a building loss coefficient of 550 W/C (1040 Btu/hr/F). This value corresponds to most existing homes in Riverside. A very well insulated home can have a value of 250 W/C (470 Btu/hr/F) for the loss coefficient. The value 350 W/C (660/hr/F) was chosen for the present analysis because it represented an easily attainable value for new construction in Riverside assuming a modest insulation package. The daily hot water usage was computed assuming a family of four (i.e., Item 12). Meterological data for Riverside were utilized as supplied by the F-CHART program.

The economic analysis performed in F-CHART utilizes a life-cycle cost method. The required payments for solar heating are calculated for each future year by estimating various present costs and inflation factors. The life-cycle cost is then determined by discounting each annual payment to its present value and finally summing each of these discounted payments. The reason that all cash flows must be discounted to their present value is to account for the "time value of money". This discounting results in a $463 present worth for an item that costs $1000 in 10 years from today at a discount rate of 8 percent. The same procedure is followed for a chosen

TABLE D2-2. F-CHART INPUT VARIABLES

ITEM	VARIABLE DESCRIPTION	VALUE	UNITS	
1	AIR SYSTEM=1,LIQUID SYSTEM=2,,,,,,,,,,,,,,,,	1,00		*
2	COLLECTOR AREA,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	5,00	M2	
3	FRPRIME-TAU-ALPHA PRODUCT(NORMAL INCIDENCE),,	,49		*
4	FRPRIME-UL PRODUCT,,,,,,,,,,,,,,,,,,,,,,,,,,,	2,84	W/C=M2	*
5	NUMBER OF TRANSPARENT COVERS,,,,,,,,,,,,,,,,,	1,00		*
6	COLLECTOR SLOPE,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	43,00	DEGREES	
7	AZIMUTH ANGLE (E,G, SOUTH=0, WEST=90),,,,,,,,	,00	DEGREES	
8	STORAGE CAPACITY,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	315,00	KJ/C=M2	
9	EFFECTIVE BUILDING UA,,,,,,,,,,,,,,,,,,,,,,,,	350,00	W/C	
10	CONSTANT DAILY BLDG HEAT GENERATION,,,,,,,,,,	0,00	KJ/DAY	
11	(EPSILON)(CMIN)/(EFFECTIVE BUILDING UA),,,,,,	2,00		
12	HOT WATER USAGE,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	400,00	L/DAY	
13	WATER SET TEMPERATURE,,,,,,,,,,,,,,,,,,,,,,,,	60,00	C	
14	WATER MAIN TEMPERATURE,,,,,,,,,,,,,,,,,,,,,,,	11,00	C	
15	CITY CALL NUMBER,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	129,00		
16	THERMAL PRINT OUT BY MONTH=1, BY YEAR=2,,,,,,	2,00		
17	ECONOMIC ANALYSIS ? YES=1, NO=2,,,,,,,,,,,,,,	1,00		
18	USE OPTMZD, COLLECTOR AREA=1, SPECFD, AREA=2,	2,00		
19	SOLAR SYSTEM THERMAL PERFORMANCE DEGRADATION,	0,00	%/YR	
20	PERIOD OF THE ECONOMIC ANALYSIS,,,,,,,,,,,,,,	20,00	YEARS	
21	COLLECTOR AREA DEPENDENT SYSTEM COSTS,,,,,,,,	210,00	$/M2 COLL,	*
22	CONSTANT SOLAR COSTS,,,,,,,,,,,,,,,,,,,,,,,,,	1000,00	$	
23	DOWN PAYMENT(% OF ORIGINAL INVESTMENT),,,,,,,	10,00	%	
24	ANNUAL INTEREST RATE ON MORTGAGE,,,,,,,,,,,,,	9,00	%	
25	TERM OF MORTGAGE,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	20,00	YEARS	
26	ANNUAL NOMINAL(MARKET) DISCOUNT RATE,,,,,,,,,	8,00	%	
27	EXTRA INSUR,,MAINT, IN YEAR 1(% OF ORIG,INV,)	1,00	%	
28	ANNUAL % INCREASE IN ABOVE EXPENSES,,,,,,,,,,	6,00	%	
29	PRESENT COST OF SOLAR BACKUP FUEL (BF),,,,,,,	4,00	$/GJ	
30	BF RISE: %/YR=1,SEQUENCE OF VALUES=2,,,,,,,,,	1,00		
31	IF 1, WHAT IS THE ANNUAL RATE OF BF RISE,,,,,	10,00	%	
32	PRESENT COST OF CONVENTIONAL FUEL (CF),,,,,,,	4,00	$/GJ	
33	CF RISE: %/YR=1,SEQUENCE OF VALUES=2,,,,,,,,,	1,00		
34	IF 1, WHAT IS THE ANNUAL RATE OF CF RISE,,,,,	10,00	%	
35	ECONOMIC PRINT OUT BY YEAR=1, CUMULATIVE=2,,,	2,00		
36	EFFECTIVE FEDERAL-STATE INCOME TAX RATE,,,,,,	24,00	%	
37	TRUE PROP, TAX RATE PER $ OF ORIGINAL INVEST,	2,80	%	
38	ANNUAL % INCREASE IN PROPERTY TAX RATE,,,,,,,	6,00	%	
39	CALC,RT, OF RETURN ON SOLAR INVTMT?YES=1,NO=2	2,00		
40	SALVAGE VALUE (% OF ORIGINAL INVESTMENT),,,,,	0,00	%	
41	INCOME PRODUCING BUILDING? YES=1,NO=2,,,,,,,,	2.00		

* Items that vary with solar collector type.

TABLE D2-3. COLLECTOR DATA

Collector	Manufacturer	Type	Covers	$F_R\tau\alpha$	F_RU_L, W/C/m^2 (Btu/hr/F/ft^2)	Cost, \$/m^2 (\$/ft^2)
A	Solar Energy Prod.[a]	Water	1	0.76	7.08 (1.25)	170 (16)
B	Lennox	Water	1	0.84	4.54 (0.80)	229 (21)
C	Solaron	Air	2	0.49	2.84 (0.50)	210 (19.5)
Table D2-1 - Item Number		1	5	3	4	21

(a) Similar in construction and performance to the collector manufactured and sold by Solar Energy, Inc., of Riverside, California.

alternative method of heating. The latter calculation requires that each future year's fuel costs also be estimated. The solar savings are then determined by subtracting the discounted solar life-cycle cost from the corresponding alternative heating method costs. In simple terms, solar savings will be realized if the sum of fuel savings and tax credits is greater than the mortgage payments required to buy and install the solar equipment. The most serious drawback to the life-cycle costing method is that is must be possible to predict all costs and the discount rate far into the future.

Input for the present economic analysis is given in Table D2-4. A life-cycle analysis period of 20 years was chosen to coincide with the term of the new home mortgage. A value of $1000 was taken for the purchase and installation cost of noncollector-related solar equipment associated with plumbing, heat storage, and controls (fixed cost). The manufacturer-quoted cost per square meter of collector was increased by $50 to account for installation of collectors and extra storage capacity. The initial solar system cost was then calculated by the code using the following:

$$\text{Initial cost} = \$1000 + (\text{collector cost} + \$50) \times A_c \qquad [1]$$

where A_c is the collector area in m^2 specified by Item 2 in Table D2-2.

The home mortgage terms are given as the Down Payment, Annual Interest Rate, and Term of Loan. A 10 percent down payment was used with an annual interest rate of 9 percent, which represents the cost of borrowing money. The market discount rate was taken to be 8 percent.

The initial cost of the solar system is not the only cost involved. Insurance, maintenance, and the cost of fuel for the solar backup heater must also be included. The first year's extra insurance and maintenance is taken to be 1 percent of the original solar investment given by Equation [1]. These annual insurance and maintenance costs were assumed to increase from this initial value at a rate of 6 percent. The backup heater is required because it is never economically sound to size the solar system to take care of peak heating loads (i.e., 100 percent solar). The system should be sized for maximum economic benefit, so some backup fuel is required and this cost must be added to the solar system life-cycle cost. The effective cost of

TABLE D2-4. ECONOMIC INPUT PARAMETERS

Collector Cost	\$120 per m^2 (\$11 per ft^2)
Installation Cost	\$ 50 per m^2 (\$4.6 per ft^2)
Fixed Cost (Water Heat)	\$600
Fixed Cost (Space Heat)	\$1000
Down Payment	10%
Annual Interest Rate	9%
Term of Loan	20 years
Annual Discount Rate	8%
Insurance Cost	1/2%
Maintenance Cost	1/2%
Cost of Gas	\$4/GJ (\$4/MBtu)
Cost of Electric	\$10/GJ (\$10/MBtu)
Annual Rise in Fuel Cost	10%
Income Tax Rate	24%
Property Tax	2.8%

natural gas was assumed to be \$4/GJ (\$4/MBtu),assuming a gas cost of \$2/GJ (\$2/MBtu) and a 50 percent furnace efficiency. The cost of electric heating was assumed to be \$10/GJ (\$10/MBtu),corresponding to 3.5¢/kwhr. The rate of inflation of the fuel cost was assumed to be 10 percent.

The alternate heating cost was calculated using input from Items 32 to 34. Natural gas was picked as fuel for the alternative heating system for the case shown in Table D2-2. The same 10 percent fuel inflation rate as above was assumed for the alternative fuel.

Still another cost remains to be accounted for in the life-cycle analysis. This cash flow is the increased property tax that a homeowner would incur due to any increased property value caused by the installation of a solar system. An effective property tax rate value of 2.8 percent (i.e., Item 37 in Table D2-2) was used in the present analysis for Riverside This value was arrived at from information provided by the tax assessors office for the County of Riverside.

Some of the above costs can be partially recovered using the benefits of the income tax structure. Interest on the solar loan as well as property tax payments are deductible from gross earnings when Federal and California State taxes are determined. This cost recovery mechanism is provided for in the code through the effective Federal-State income tax rate (i.e., Item 36). Here, the effective rate is taken as 24 percent. It was computed using the formula

$$\text{Effective rate} = \%\ \text{Federal} + \%\ \text{State} - \frac{\%\ \text{Federal} \times \%\ \text{State}}{100} \qquad [2]$$

The Federal rate was taken to be 22.5 percent and 2 percent was the assumed value for the State income (i.e., gross income = \$20,000, taxable income = \$13,000 State and \$10,000 Federal). Equation [2] is not a simple sum because of the interaction between State and Federal taxes.

Besides these cost recovery items, there is an additional tax incentive for solar usage which is now provided by the State of California. According to this recently signed legislation, a 55 percent State income tax credit can be claimed up to a maximum of \$3000 on the total initial cost of a solar heating system. The benefits of this tax credit can be applied

year after year until the total credit is exhausted. The computer code does not presently provide for a method of handling this credit so it was applied to the results of the noncredit calculations. The method of applying this credit consisted of assuming a $250 first year California State income tax liability ($20,000 gross income, $13,000 taxable income). This amount was inflated at a rate of 6 percent per year and then each year's portion of the tax that was recoverable due to the credit was discounted back to the present value using a discount rate of 8 percent. The present value of the tax credit was then added to the present value of the solar savings to arrive at an effective solar savings due to the State tax credit. No Federal tax credit was included in this analysis because the details are unsure at this time, plus the fact that State and Federal credits will probably not be directly additive.

Given all the above input, the computer code was first used to evaluate the performance and solar savings for the three collectors listed in Table D2-3 as a function of collector area. A computer printout of the results for a calculation of the thermal and economic performance of Collector C is given in Table D2-5. This result is for a collector area of 5 m^2 (54 ft^2). The printout shows that for this particular collector area only 25 percent of the total heating load is provided by the solar system. The remaining 75 percent must come from the backup heating source. The economic results show that the cumulative solar savings never exceeds the mortgage principal, resulting in a net loss whose present worth is -$1525. Even with the 55 percent income tax credit, the present worth of cumulative solar savings is still negative at -$601 for this collector type and surface area. In Figure D2-1, the results for thermal and economic analyses are given for all three collectors as a function of collector area. For these calculocations, natural gas was assumed as the alternative heat source and both noncredit and tax credited results are shown in the economic plot.

The upper graph presents the results of the thermal analysis, and gives the solar fraction, or percent solar heating, as a function of collector area. As the collector area is increased, the solar fraction approaches 100 corresponding to 100 percent solar heating. However, the first 20 m^2 of collectors supplies approximately 80 percent of the heating load, whereas increasing the number of collectors to 40 m^2 contributes only an additional

TABLE D2-5. COMPUTER PRINTOUT FOR INPUT DATA IN TABLE D2-2 (Riverside, CA., 33.57° Latitude)

		Thermal Analysis				
Time	Percent Solar	Incident Solar GJ	Heating Load GJ	Water Load GJ	Degree Days C-Day	Ambient Temp, C
Year	24.7	40.47	32.24	29.98	1066	

Economic Analysis

Specified Collector Area =	5, M2
Initial Cost of Solar System =	$2050.00
The Annual Mortgage Payment for 20 years =	$202.00
The Solar System does not pay back within the term of the mortgage	
Cumulative savings never exceeded the Mortgage Principal	
Present Worth of Yearly Total Costs with Solar =	$7042.00
Present Worth of Yearly Total Costs W/O Solar =	$5517.00
Present Worth of Cumulative Solar Savings =	$1525.00
Tax Credit =	$1128.00
Present Worth of Tax Credit =	$924.00
Effective Present Worth of Cumulative Solar Savings =	-$601.00

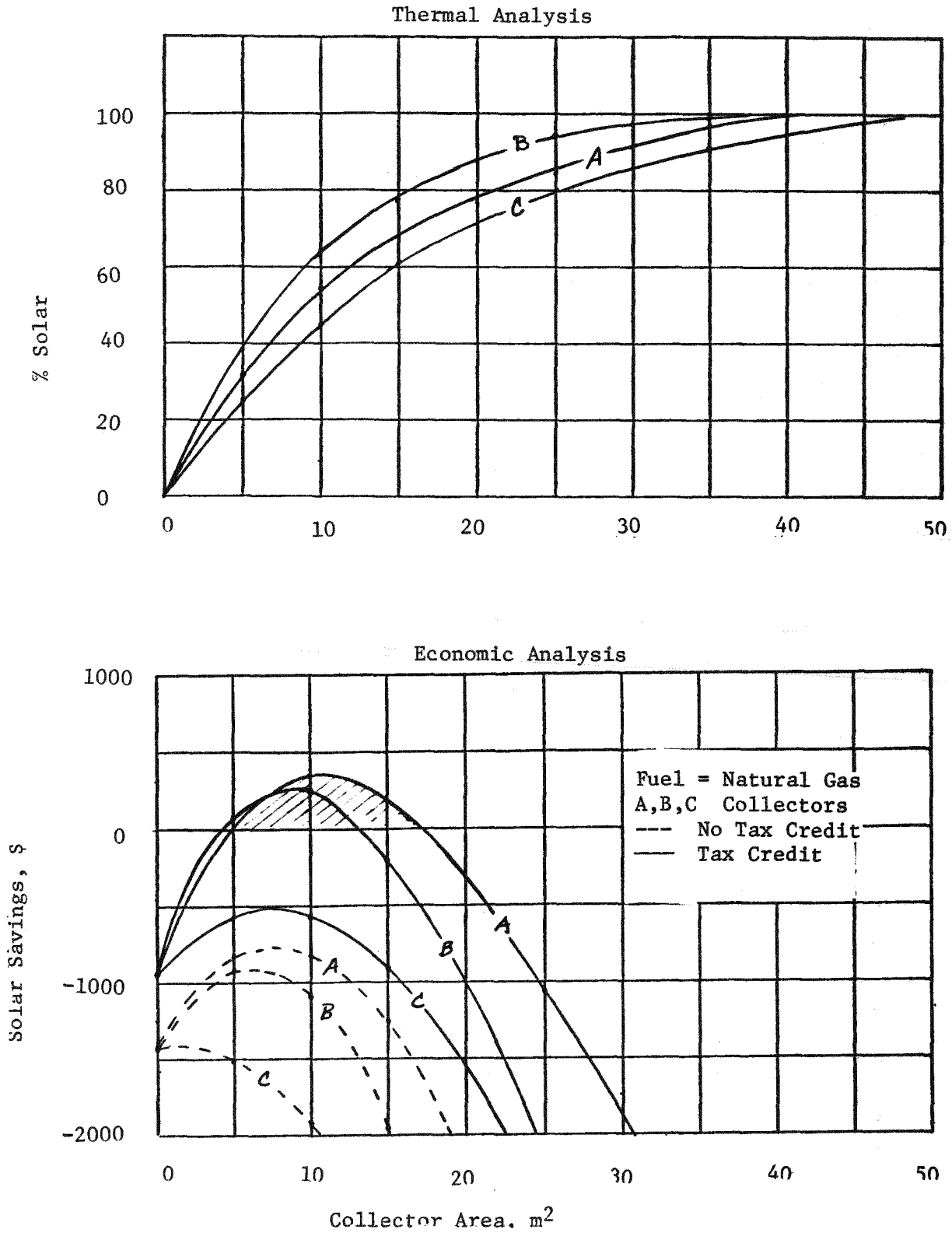

FIGURE D2-1 THERMAL AND ECONOMIC ANALYSIS FOR VARIOUS COLLECTOR TYPES ASSUMING NATURAL GAS AS THE ALTERNATIVE FUEL

20% of the load. Due to this principle of diminishing returns, there exists an intermediate collector size which represents the most cost effective system. The most cost effective system is determined by the economic analysis and the results are presented in the lower graph in Figure D2-1.

Note that the maximum solar savings occurs for Collector A using an area of approximately 12 square meters. This area results in approximately 60 percent of the space heat and hot water load being provided by the solar system. It is interesting to see that the most efficient collector was not the most cost effective since the improved efficiency of Collector B was offset by its increased cost. Also note that the use of Collector C will never result in a solar savings even including the tax credit, due primarily to its high cost. Therefore, this particular air collector always results in a net loss of money. The initial cost of a system which produced maximum solar savings would be $3040 or $25.83/month for 20 years.

Further calculations were performed only for Collector A, assuming that electricity was the alternative fuel source. For this case, a cost of $10/GJ (i.e., 3.5¢/kwhr and 100 percent efficiency) was utilized for the computer code fuel input (i.e., Items 29 and 32). Results of these analyses for various collector areas as shown in Figure D2-2. Note that much greater positive solar savings are realized both with and without the tax credit for electricity instead of natural gas as an alternative fuel source. Also note that the peak savings occur for a larger collector area (i.e., 20 to 25 m^2) in contrast to 12 m^2 for natural gas fuel (see Figure D2-1). This larger collector area results in a solar efficiency of 80 to 85 percent as indicated by the thermal analysis plot in Figure D2-2. This increased collector area also results in an increased initial cost to a value of $4400 or $37.35/month for 20 years.

Calculations were also performed for a solar system to supply hot water only (i.e., no space heating) for the same residence as mentioned above. These computations were performed only for Collector A and for both natural gas and electricity as the alternative fuel. Due to the fact that simpler controls are needed and the load water-to-air heat exchanger was not

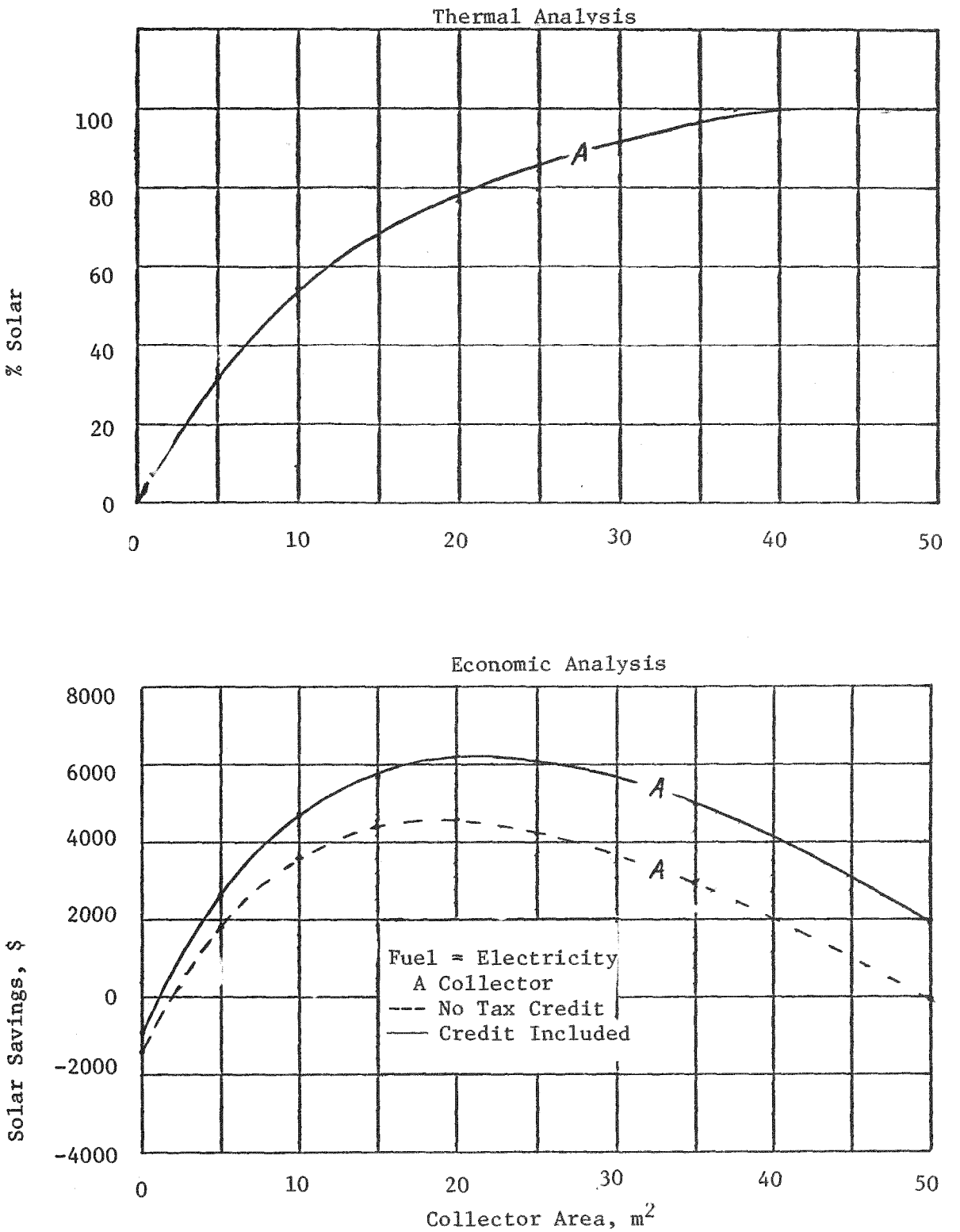

FIGURE D2-2. THERMAL AND ECONOMIC ANALYSIS FOR VARIOUS COLLECTOR TYPE ASSUMING ELECTRICITY OR THE ALTERNATIVE FUEL

necessary, the constant solar costs (i.e., Item 22 in Table D2-2) were reduced to $600. This value agrees with the costs of a similar system given in Reference 3.

These results, and the results of the Hot Water plus Space Heating, are summarized in Table D2-6. As before, the analysis included cases with and without tax credits. Note that losses are again incurred for a solar system with natural gas as the alternative fuel unless the California income tax credit is included. The required collector area is also reduced (i.e., approximately 6 m^2) for a system requiring only a hot water supply compared to hot water plus space heating. This fact lowers the initial investment cost to $1620. The annual mortgage payment is therefore only $160 or $13.33/month.

For the case where electricity was assumed to be the alternative fuel, substantial savings of $2600 and $3700 were realized with and without a tax credit. For the peak savings case of 10 m^2 collector area, the initial cost of the solar system was $2300 (i.e., $18.92/month). The discounted payback period was 6 years and it took just 10 years for the cumulative solar savings to equal the mortgage principal.

Performance Calculations for Retrofit Applications. The previous results were for the application of a solar energy collector system on a newly constructed home in Riverside, California. In addition, results, an analysis was made for retrofitting a solar system to an existing home. The optimum collector type (Type A) from the previous analysis was utilized in these calculations and home improvement loan conditions were assumed in the economic analysis.

For the retrofit analysis, the majority of input parameters did not change from the values given in Table D2-2. The period of economic analysis was held at 20 years, but the term of the mortgage was reduced to 10 years to coincide with present home improvement loan conditions. Other economic variables that reflect home improvement loan values are the annual interest rate (i.e., Item 10 - 10.2 percent) and the fact that no downpayment was required. The only other variables that changed from the new construction case were the initial constant solar cost and the building loss coefficient. The

TABLE D2-6. SOLAR SAVINGS OVER 20-YEAR SYSTEM LIFE IN 1978 DOLLARS FOR NEW CONSTRUCTION

System	Backup Fuel	Collector Area, m^2 (ft^2)	% of Total Heating Load by Solar	$ Savings	
				No Tax Credit	Tax Credit (a)
Domestic Hot Water	Gas	6 (64)	32	(950)	290
Domestic Hot Water	Electric	10 (107)	47	2600	3700
Domestic Hot Water & Space Heating	Gas	11 (118)	58	(775)	350
Domestic Hot Water & Space Heating	Electric	21 (226)	80	4400	6200

Note: Quantity in parentheses represents a net loss.

(a) California State Income Tax Credit, 55% Tax Credit on capital cost of solar heating system to a maximum system cost of $3000. Credit is also given on Federal Income Tax for the amount of State Income Tax that would have been paid without the tax credit.

initial costs were taken to be $400 more for the retrofit case. This extra cost is associated with installation of plumbing and storage tanks which may be hindered by present construction. In addition, the code requirements for older construction were such that most of the older homes are poorly insulated. Therefore, a nominal building loss coefficient of 550 W/C was assumed for the retrofit analysis.

The results are presented in Table D2-7. The dollar solar savings are very similar to the new construction case. The savings with the tax credit are approximately $100 less when the backup fuel is gas, and from $200 to $300 less for electric. A net positive savings is realized in every case with the tax credit.

In summary, calculations showed that solar savings could be realized for single-family dwellings in Riverside, California, for all cases of alternative fuels when the California solar income tax credit is included in the economic calculations, whether new construction or retrofit. The choice of collector type was shown to be important since an improper choice could result in economic losses for solar utilization.

Sensitivity Analysis. The results presented in the previous section were obtained by making many assumptions above the solar system parameters, and the economic conditions which apply to the installation. Since conditions can vary considerably from case to case, it is important to examine the sensitivity of the system performance to variations of the important parameters and conditions.

One of the most important parameters is the backup fuel cost. The sensitivity of solar economics to heating fuel costs is shown in Figure D2-3. In this figure, the peak solar savings is shown plotted as a function of effective fuel costs for both tax credit and no credit cases. The present effective costs of natural gas, oil, and electricity are also indicated in this figure. Note that positive solar savings are attained for the tax credit case for a fuel cost of $3/GJ ($3/MBtu). For no tax credit, a solar system becomes economically sound at a fuel cost of $5/GJ ($5/MBtu).

TABLE D2-7. SOLAR SAVINGS OVER 20-YEAR SYSTEM LIFE IN 1978 DOLLARS FOR RETROFIT APPLICATIONS

System	Backup Fuel	Collector Area, m^2 (ft^2)	% of Total Heating Load by Solar	$ Savings	
				No Tax Credit	Tax Credit (a)
Domestic Hot Water	Gas	6 (64)	25	(580)	180
Domestic Hot Water	Electric	10 (107)	33	2000	3500
Domestic Hot Water & Space Heating	Gas	10 (107)	54	(1000)	150
Domestic Hot Water & Space Heating	Electric	20 (215)	77	4200	5900

Note: Quantity in parentheses represents a net loss.

(a) California State Income Tax Credit, 55% Tax Credit on capital cost of solar heating system to a maximum system cost of $3000. Credit is also given on Federal Income Tax for the amount of State Income Tax that would have been paid without the tax credit.

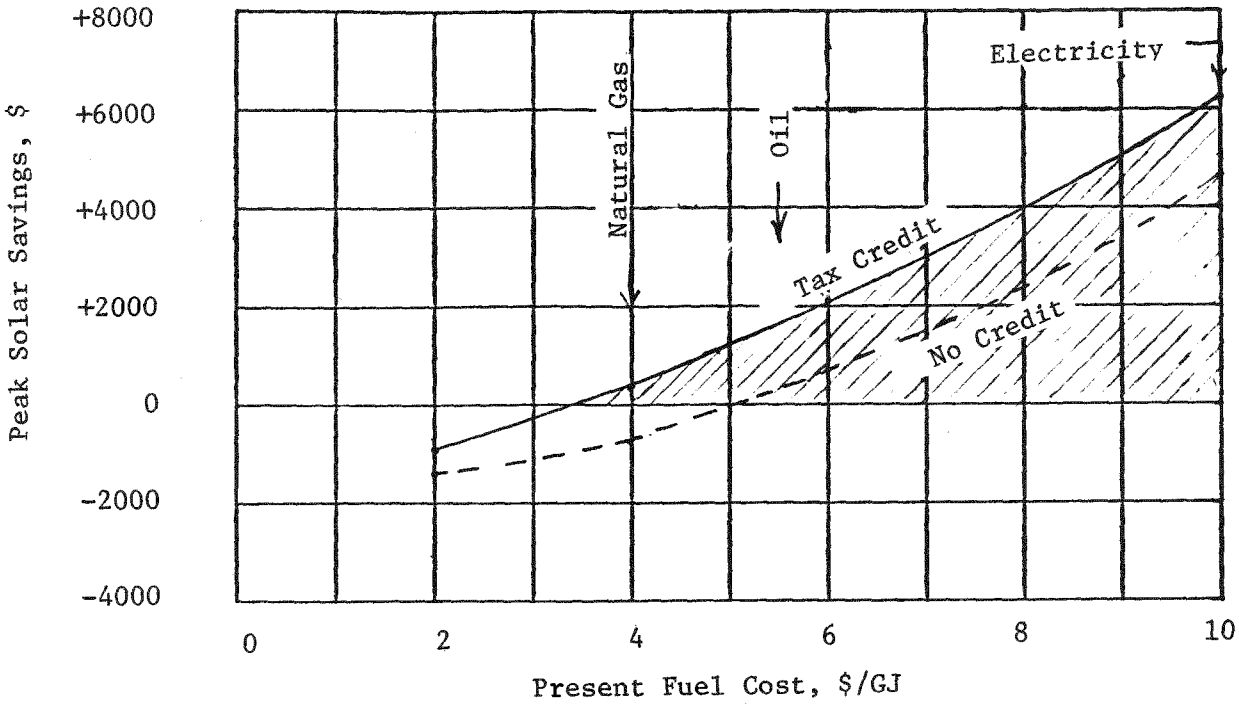

FIGURE D2-3. SOLAR SAVINGS AS A FUNCTION OF FUEL COST WITH AND WITHOUT AN INCOME TAX CREDIT (First Years Credit = $250)

In general, an increase in the alternative fuel costs by $1/GJ was found to increase 20-year solar life-cycle savings by approximately $1000 (present worth).

Another important economic parameter is the tax credit and the method by which the tax credit is applied. The California state tax credit has been included in the results presented earlier; however, it was assumed that the tax rebate was made in such a way as to allow the owner to claim the state tax as a deduction on his federal income tax form. If the owner cannot claim his state tax on his federal tax form, it will reduce the effect of the state tax credit by 20 or 30%. It will also mean that the state is effectively contributing this amount of money to the federal treasury.

In Table D2-8 the solar savings and fuel savings are presented for various tax incentives. The results are for solar hot water and space heating using gas as the backup fuel. The No Credit and the State Tax Credit cases have been presented previously and are given here for reference. If the State Tax Credit cannot be claimed on the federal tax form, resulting in a Federal Tax Loss, the dollar solar savings drop from $350 to $80. If a Property Tax Credit is given in addition to the State Tax Credit, the solar savings jump by $1000, to $1350. It is important to note that the optimum system is much larger for this case, and results in a fuel savings of 70%. However, if the Federal Tax Loss is included, the dollar savings drop to $800 and the fuel savings to 64%.

These results indicate that the addition of property tax credit to the State tax credit could significantly improve the economic viability of solar heating, and encourage the installation of larger systems with higher percentage fuel savings. The Federal Tax Loss, on the other hand, could seriously reduce the impact of these tax credits.

In order to explore the relative importance of a large number of parameters on the economic performance of a solar heating system, the following sensitivity analysis was conducted for solar hot water and space heating on new construction. The chosen parameters were varied by 10% and the net change in the solar savings was computed. Presented in Figure D2-4 is the resultant change in solar savings for a 10% increase in the indicated

TABLE D2-8. SUMMARY OF OPTIMUM SOLAR SAVINGS FOR VARIOUS TAX INCENTIVE CASES

Tax Incentive	$ Savings	% Fuel Savings
No Credit	(780)	36
State Tax Credit	350	58
State Tax Credit Federal Tax Loss	80	54
State Tax Credit Property Tax Credit	1350	70
State Tax Credit Property Tax Credit Federal Tax Loss	800	64

Note: Quantity in parentheses represents a net loss.

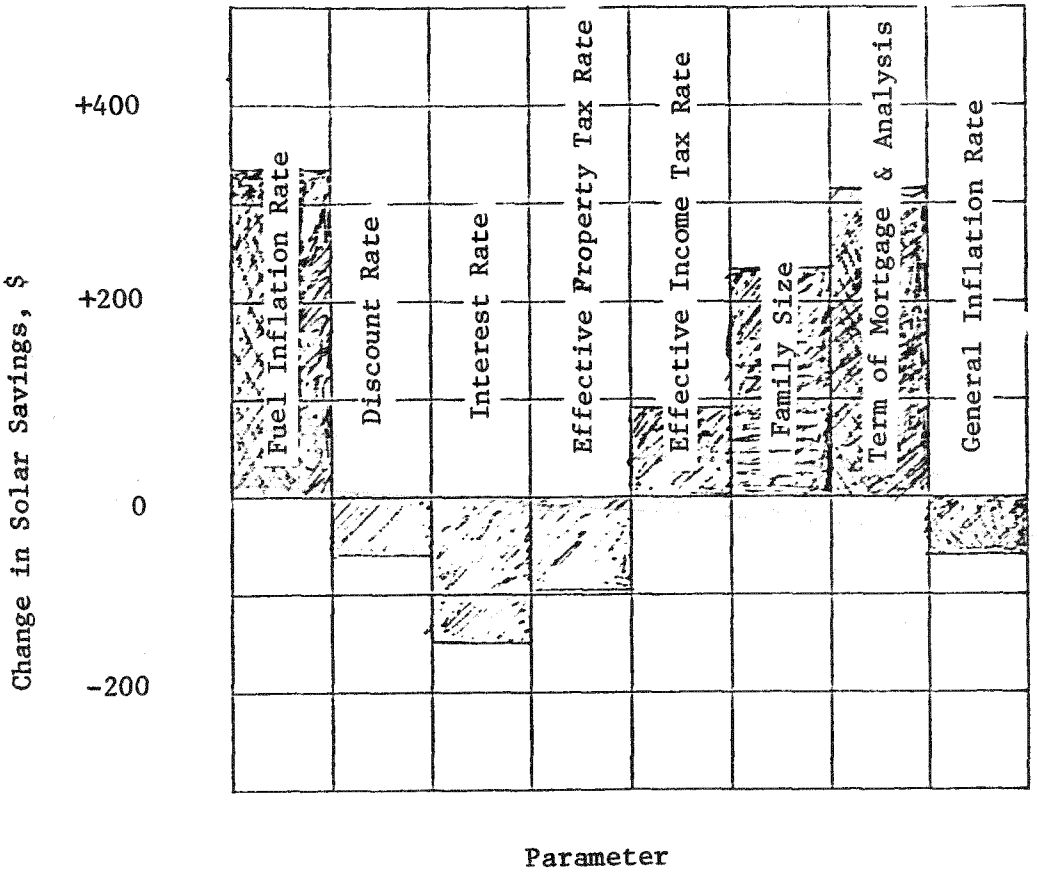

FIGURE D2-4. CHANGE IN PRESENT VALUE OF SOLAR SAVINGS FROM THE BASELINE AMOUNT FOR A 10% INCREASE IN VARIOUS PARAMETERS

parameter. The most important parameters are the fuel inflation rate and the terms of the mortgage and analysis. A 10% increase in the assumed fuel inflation rate (from 10% to 11%) increases the solar savings over $300. Likewise, increasing the term of the mortgage and the life of the system from 20 years to 22 years increases the solar savings by $300. The next most important parameters are the system size (family size) and the interest rate. Of least importance are the discount and inflation rate, and the effective property tax and income tax rates.

Finally, the sensitivity of the level of insulation was examined. In order to properly account for added insulation, however, it becomes necessary to estimate the cost of the insulation and include the cost into the economic analysis. The analysis was performed assuming that new construction in Riverside would have an insulation package that gave a building loss coefficient of 350 W/C (660 Btu/hr/F)*.

The added cost of insulating this new home during the construction period was calculated in order to decrease the loss coefficient to 250 W/C ($470 Btu/hr/F). A 150-$m^2$ (1600-ft^2) house was assumed for the cost calculations and values for building materials were obtained from the 1978 Building Cost File.[4] Labor costs were obtained assuming nonunion rates and large-volume work scheduling. The resulting costs for extra insulation are:

- 4" blow-in insulation in ceiling - $416
- 1" Styrofoam insulation on outside walls - $269
- Insulated windows (14 @ $30 extra each) - $420
- Insulated doors (2 @ $50 extra for each) - $100.

This totals up to $1205 for extra insulation on newly constructed homes. For the case of a retrofit, it was assumed that little insulation exists in the present structures such that the average building loss coefficient for a 150-m^2 (1600-ft^2) dwelling is 550 W/C (1040 Btu/hr/F). The costs were then

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* Code to be applied after March 23, 1978, includes R20 in ceiling, R13 in walls with no double pane windows or insulated doors.

estimated[4] to bring the loss coefficient of this older dwelling down to the present code of 350 W/C (660 Btu/hr/F). The resulting costs of insulating materials and labor are:

- 6" blow-in insulation in ceiling - $624
- 3-1/2" blow-in foam insulation in walls - $640.

The total price of this insulation package is therefore equal to $1264.

Various cases were then considered whereby an ordinary solar economic analysis was performed for each applicable value of building loss coefficient. Fuel costs from the program printouts were monitored and insulation savings noted. The costs of borrowing the capital required to provide the above insulation were also calculated including the cost reduction effects of claiming the extra mortage interest on federal and state tax forms.

Another cost reduction effect can be derived when the extra insulation is claimed as part of the solar energy package. This qualifies the extra insulation costs for inclusion in the State tax credit*. Such inclusion increases the State tax rebate and thus increases the effective savings of the entire combined system.

The results of the solar/insulation analysis for new construction in Riverside are presented in Table D2-9. Given is the dollar savings and the fuel savings for either gas or electric as backup fuel. Cases considered are:

1. Baseline case, no solar or extra insulation
2. Upgrade the insulation to reduce the heating load by 30%, with no solar heating and no tax credit
3. Add solar hot water and space heating with standard insulation; apply State income tax credit
4. Add solar hot water and space heating and upgrade the insulation; apply State income tax credit to both
5. Add solar hot water only and upgrade the insulation; apply State income tax credit to both.

* Page 9 of California Income Tax Form 540 concerned with the solar tax credit.

TABLE D2-9. SOLAR/INSULATION ANALYSIS - NEW CONSTRUCTION, RIVERSIDE, CALIFORNIA

Option	$ Savings		% Fuel Savings	
	Gas	Electric	Gas	Electric
1. No Solar or Extra Insulation (U_A = 350 Watts/C)	--	--	--	--
2. Extra Insulation, No Tax Credit (U_A = 250)	(-399)	932	15	15
3. Solar Heating, Tax Credit Baseline Insulation (U_A = 350)	350	6200	54	77
4. Solar Heating Plus Extra Insulation, Tax Credit (U_A = 250)	310	6600	67	87
5. Solar Hot Water only, Plus Extra Insulation, Tax Credit (U_A = 250)	440	6100	51	57

Note: Quantity in parentheses represents a net loss.

For gas heated homes, upgrading the insulation (Case 2) is not cost effective. The results indicate a $300 loss. For electric heated homes, on the other hand, nearly $1000 can be saved by upgrading the insulation. No tax credit has been applied in this case.

Adding solar hot water and space heating with baseline insulation (Case 3) shows a net savings for either gas or electric backup. These results have been discussed previously. When extra insulation is added to the solar system (Case 4) a slight decrease in the dollar savings is indicated for gas heating. For electric heating, a slight increase in dollar savings is realized. Overall, the results indicate that added insulation is not economically beneficial for gas heated homes but is beneficial for electric heated homes. In either case, the fuel savings for added insulation is 10 to 15%, compared to the fuel savings for solar heating of from 54 to 77%.

The most interesting results are for Case 5, solar hot water heating only with added insulation. This case shows the largest economic benefit for gas heated homes, and a near optimum benefit for electric heated homes. This case offers a simple, low cost system with a small collector area. It does not, however, save as much fuel as Cases 3 and 4.

The results for retrofit to existing structures are presented in Table D2-10. The major difference from the new construction case is an increase in the benefit of added insulation. For Case 2, added insulation with no tax credit, there is a positive dollar savings for both gas and electric. In fact, for gas heated homes, it is economically more effective to upgrade the insulation, even with no tax credit, than to add solar hot water plus space heating only. It is much more cost effective to add both solar heating and insulation, as shown by Cases 4 and 5, with a slight economic benefit again going with Case 5.

For the electric heated homes, the results for retrofit are similar to the new construction results, with a larger dollar savings indicated for upgrading the insulation.

It should be noted in Tables D2-9 and D2-10 that the maximum fuel savings do not coincide with the maximum dollar savings. In order to encourage.

TABLE D2-10. SOLAR/INSULATION ANALYSIS - RETROFIT, RIVERSIDE, CALIFORNIA

Option	$ Savings		% Fuel Savings	
	Gas	Electric	Gas	Electric
1. No Solar or Extra Insulation (U_A = 550	--	--	--	--
2. Extra Insulation, No Tax Credit (U_A = 350)	560	3000	23	23
3. Solar Heating, Tax Credit Baseline Insulation (U_A = 550)	120	7000	50	73
4. Solar Heating, Plus Extra Insulation, Tax Credit (U_A = 350)	940	8960	65	82
5. Solar Hot Water Only, Plus Extra Insulation, Tax Credit (U_A = 350)	1200	7000	56	66

maximum fuel savings for the community, it may be necessary to revise the tax credit to encourage the implementation of larger solar systems and more insulation.

Advantages and Disadvantages of Solar-Photovoltaic Systems

Photovoltaic devices (solar cells) convert photon energy (light) directly to electrical energy. The use of photovoltaic devices to convert solar insolation (sunlight) to electrical energy is considered by the U.S. Department of Energy (DOE) and by scientists and engineers working in the field, to be a viable means of supplying a significant percentage of the nations energy budget in future years. The major obstacle to the current use of these systems is cost, primarily that of the photovoltaic devices themselves. The Government ha smounted a massive program to reduce the cost of manufacturing solar cells and to promote an increase in production levels. These Government activities also include an effort to identify and stimulate a market for solar cell applications. The primary focus of this work is on silicon solar cells because they are the most technologically advanced and because their reliability and long lifetime have been proven in the space program. Other solar cell types of interest include gallium arsenide (GaAs) and thin film materials of various types of which cadmium sulfide/copper sulfide cells are the leading candidate.

The important attributes which make solar-photovoltaic systems attractive as an energy source are essentially the same as those which make solar-thermal systems attractive -- they are nonpolluting; they can operate in a distributed (i.e., at the point of usage) mode; the energy source is nondepletable. On the debit side, the energy is low in density, requiring dedication of significant areas to collection, and is discontinuous (e.g., at night and in the presence of interceding atmospheric/weather phenomena), thereby requiring a backup power source and/or energy storage to service loads requiring uninterruptable power or power during nondaylight hours. The efficiency range for silicon cells (Air Mass 1 conditions) is of the order of 12 to 15 percent for commercially available cells, while slightly higher efficiencies have been achieved in isolated (generally laboratory) instances. Efficiencies of the order of 20 to 22 percent are felt to be achievable by some researchers in the field.

There are two basic types of photovoltaic arrays of importance in terrestrial applications -- the flat-plate array and the concentrator or focusing array. The flat-plate array consists of strings of interconnected solar cells deployed over a large flat surface to collect the incident solar energy (insolation). These types of arrays are generally fixed (i.e., nontracking) and are oriented at an angle which optimizes collection during specific seasons or during the year. In some cases the orientation may be changed on a seasonal basis to further increase the total yearly energy collected. In concentrator arrays, optical focusing elements such as Fresnel lenses or parabolic mirrors are used to concentrate the solar energy onto smaller areas, thereby reducing the number of solar cells required to collect the energy. Concentrator arrays are generally (with a few exceptions) made to track the sun on a continuous one- or two-axis basis.

Since the efficiency of the devices is generally less than 20 percent, a significant portion of the energy is converted to heat. In some applications this low temperature heat can be used, thereby yielding a system (photovoltaic-thermal) with a significantly higher (up to 60 percent in some areas) overall efficiency. Effective use of the heat energy will, however, require operating the array at temperatures higher than the normal design values (i.e., for a photovoltaic-only system). This will result in a drop in the efficiency of the photovoltaic devices and an increase in the size of the photovoltaic array required to service a given load.

Photovoltaic and photovoltaic-thermal systems can have various configurations depending on whether the load is ac or dc (or a mix thereof), whether on-site storage is required or economically desirable, whether excess power generated by the photovoltaic system can be fed into the utility grid, etc. These and many other factors must be considered in assessing the desirability and feasibility of specific applications for these types of systems.

Cell/Array Types and Costs

Current Status. Currently, single-crystal silicon solar cells and flat-plate modules are commercially available from approximately 10 manufacturers in the United States at costs in the range of $12 to $30 per peak watt, depending on the quantity purchased.[5] Total world production is estimated at about 750 peak kilowatts for the year 1977. There are at least two manufacturers of cadmium sulfide modules in the U.S., although their cells are reported to be not available on the open market at present.[6] At the present price level only remotely located and isolated applications can approach being cost competitive. Thus, the major present applications for photovoltaic systems are on military or civilian remote sites or are subsidized test and demonstration sites.

Extensive use of concentrator photovoltaic systems in practical applications has not yet been realized, although one such system is presently under construction to provide power for the Mississippi County Community College in Arkansas. The cost for the concentrator arrays for this system was recently quoted as $6/We (array designed for 362 kilowatts output).[7]

Near-Term (1980-1982) Goals. The near-term goal of the DOE photovoltaic program is to achieve flat-plate module or concentrator array prices of $2/peak test watt (1975 dollars) at an annual production rate of 20 peak megawatts in 1982.[5] Energy costs at this price level are projected to be in the range of 100 to 200 mills/kwhr. It is anticipated that in the price range of $1 to $2 per peak watt a major intermediate market will exist. Concentrator arrays are expected to be highly cost competitive with flat-plate single-crystal silicon arrays in both near- and mid-term applications, and these two photovoltaic technologies will be dominant during these periods. The majority of the photovoltaic community seems confident that the near-term cost goals can be met, although there is some concern about the difference in the technologies needed to achieve near-term versus mid-term goals.

Mid-Term (1986) Goals. DOE's mid-term goals are to achieve flat-plate module or concentrator array prices of $0.50 per peak watt (1975

dollars), and an annual production rate of 500 peak megawatts in 1986. Energy costs at this price level are projected to be in the range of 50 to 80 mills/kwhr. DOE supported studies indicate that at this price, significant markets for large-scale photovoltaic systems will open up, with photovoltaics beginning to compete for both distributed applications and larger load-center type applications. There is reasonable confidence within the photovoltaic community that the mid-term goals will be achieved (or at least will come to within an acceptable factor of being achieved).

Far-Term (1990-2000) Goals. In this time frame the goals are to achieve a flat-plate module or concentrator array price of $0.10 to $0.30 per peak watt in 1990 (1975 dollars) and an annual production rate of 10 to 20 kilawatts in the year 2000. The corresponding energy cost range is 40 to 60 mills/kwhr. In this cost range, photovoltaic systems will be cost effective for utility (central station) applications and the projected annual photovoltaic capacity installation would ensure that photovoltaic systems are a significant contribution to the nation's energy supply.

Advanced materials (e.g., amorphous silicon) and thin-film solar cells are expected to play a large role in the achievement of the far-term goals for flat-plate configurations. Concentrator arrays may still be competitive in this time frame, through the use of higher cost but significantly higher efficiency cells than those used in low-priced flat-plate arrays. Any assessment of the level of confidence in achieving the far-term goals would be highly speculative at this time. There are a number of competing technologies involved, and the ultimate technology or technologies for achieving these goals cannot be identified at present because of the early stage of development of many of the candidates. The remoteness of the time period also makes it difficult to rationally evaluate what might or might not be accomplished in that period. Let it suffice to state that at present there are no basic reasons for concluding that these goals cannot be achieved, although it is clear that considerable developmental work will be required for their realization.

Systems and Systems Costs. The capital investment required to establish various types of photovoltaic power systems has been addressed by Wolf and Noel.[8] The basic cost elements associated with such systems include:

Array

Electric Energy Storage

Power Conditioning Subsystem (dc to ac conversion, regulation, etc.)

Thermal Energy Storage (applicable to photovoltaic-thermal systems)

Array Installation

Tracking Subsystems (applicable primarily to concentrator arrays)

Plant Structures and Equipment (primarily for central power stations)

Piping (photovoltaic-thermal systems only)

Operating and Maintenance

Land (primarily central station and load center systems)

Estimates of the present average annual electric power consumption in a single-family residence in the U.S. vary from about 5800 to 12,800 kwhr/yr with the more widely accepted values in the 6000 to 8000 kwhr/yr range as given in Reference 9. Peak demand is estimated at 3 to 5 kw in this study. Projections of the national average in the time period 1980-2000 have been given as 16,000-18,000 kwh/yr, with higher values (up to 30,000 kwhr/yr) projected for the southwestern states. These projections are felt to be high but serve to illustrate the uncertainty in the general magnitude of future demand.

In general, an array size of 30-100 m^2 (5 to 10 kw peak) will satisfy a major portion of the estimated demand range for the single-family residence. An array of this size could be incorporated into the structure of a house. The question of what portion of the load might be supplied by such an array is difficult to answer with any certainty without a detailed analysis based on hourly load and insolation data. In some cases it has been shown that reasonable sized arrays (in the range cited above) in favorable geographic areas (i.e., southwestern U.S.A.) could collect energy

equivalent to more than that used by a typical house over significant periods. How much of the load could actually be supplied under such circumstances would depend on the amount of electrical storage required and its impact on the cost effectiveness of the system.

Wolf and Noel[8] assumed an array size of 50 m^2 for a residential system and developed the following estimate (Table D2-11) of systems cost range using published projections of the cost range (mid-term) for the appropriate major cost elements listed above.

TABLE D2-11. CAPITAL COSTS FOR RESIDENTIAL SYSTEM--FLAT-PLATE ARRAY, AC ONLY, NO THERMAL OUTPUT

Cost Element	Size	Estimated Unit Cost	Estimated Cost (1977 dollars)
Array	50 m^2 (540 ft^2)	\$50/m^2 (\$4.6/ft^2)	\$2500
Array Installation	50 m^2 (540 ft^2)	\$30/m^2 (\$2.8/ft^2)	\$1500
Electric Storage	20 kwhr	\$45/ kwhr	\$ 900
Power Conditioning	5 kw	\$70/ kw	\$ 350
Operation & Maintenance (present value)	5 kw	\$15/ kw	\$ 75
Total			\$5325

A similar analysis for a residential photovoltaic-thermal system yielded a cost range of \$4140 to \$11,730.

Potential Impact of Solar Photovoltaic Energy on the Riverside Community

The potential impact of solar photovoltaic systems on a community in the time frame beyond the year 1990 is impossible to assess quantitatively without a detailed analysis, the magnitude of which is beyond the scope of the present effort. Estimates of the impact on the national energy budget in this time frame have ranged from about 2 percent up to the 20 percent range. The potential magnitude of the usage of photovoltaic

systems will depend on local energy costs (projected for the time period of interest), energy consumption patterns (hourly and seasonal), solar insolation patterns (hourly and seasonal), the rate of growth of the community (photovoltaics are expected to impact new construction heavily in the mid- and far-term periods), the types of industries present and their energy requirements (can they withstand some variability in their power source, are they primarily single shift, etc.), and many other factors. The seasonal insolation data and the annual electrical energy consumption data for Riverside indicate a qualitatively favorable match in this respect. The fact that oil-fired generators are used for electric power generation would tend to indicate that photovoltaic systems might become cost competitive earlier in Riverside than in communities where lower cost sources, such as coal-fired generators, are used. Perhaps the most significant indicator of the potential impact of photovoltaics on Riverside is its location. As the national solar insolation maps show, the south-western corner of the United States (New Mexico, Arizona, Southern California) receives significantly more solar radiation than other parts of the country. It is recognized as the most favorable area of the country for solar energy utilization. If photovoltaics systems are to play a significant role in the national energy budget, they must have a major impact in this most favorably disposed region. One must conclude that the potential impact of photovoltaic systems on Riverside, California, is significant and that some attention to and planning for this eventuality is warranted. There is a need to provide quantitative evaluations of the possible penetration of such systems; to identify the most suitable types of arrays and systems; to assess the legal, social and environmental impacts of such systems, and to identify optimal strategies for handling the integration of photovoltaic systems with the general mix of electrical energy sources.

Summary and Recommendations

Summary

Hot Water and Space Heat. The results of this study indicate that solar heating of residential hot water and space are cost competitive

with all other forms of heating available to residents in the Riverside community. Compared to electric resistance heating, a solar energy system could save the average homeowner over $6000 (1978 dollars) on water and space heating based on life-cycle costs over a 20-year period. Compared to gas heating, a solar energy system could save $100 to $200 (1978 dollars) on water and space heating for the same period. The solar energy system offers a significant cost savings to the owner of an electric heated home, whereas the savings to the owner of a gas heated home are marginal (uncertainties in the economic analysis could be greater than $\pm$\$200). The results were found to apply to both new construction and to retrofit to existing homes. The outstanding performance of solar energy systems in Riverside is the result of the favorable solar climate characteristic of the Southwest United States, coupled with the economic advantage offered by the California State Income Tax Credit for solar heating.

If solar hot water systems were installed on every home in Riverside, 50 to 75 percent of the energy used for hot water heating could be saved. This represents 0.28×10^9 to 0.41×10^9 kwh or 9 to 13 percent of the total gas and electric energy consumption of the Riverside community.

If solar hot water plus space heating systems were installed on every home in Riverside, 50 to 80 percent of the total residential hot water and space heating energy could be saved. This represents 0.6×10^9 to 1.0×10^9 kwh, or 18 to 30 percent of the total gas and electric consumption of the Riverside community.

Space Cooling. Solar space cooling, using absorption cooling machines, is not likely to become cost effective in the next 10-15 years. More effective means could be applied to reduce the space cooling load. Through passive design, structures can be built which require far less active cooling than existing structures.

Industrial Process Heat and Solar Thermal Power. Solar applications which supply industrial process heat and/or electrical power through solar thermal power do not appear to be cost effective at the present time. The

combined effect of abundant, low price gas to industrial users, and the high cost of advanced technology required for concentrating, tracking collectors produce an unfavorable market for solar systems. Solar energy technology may advance significantly in the next few years, however, as a result of numerous government research programs. A reevaluation of this conclusion should be made at that time.

Photovoltaic Power Generation. The U.S. Department of Energy estimate of the impact of photovoltaics on the national energy budget ranges from 2 to 20 percent. Riverside data on seasonal insolation and annual electrical consumption indicate that photovoltaic systems should become cost competitive earlier here than in other communities. The potential demonstration and application of photovoltaic systems in Riverside could be significant by the year 2000.

Riverside Solar Energy Industry. An emerging solar energy industry exists in Riverside and in nearby communities. At least one solar collector factory is located in Riverside which produces a collector similar to the collector found in this study to be optimum for Riverside. Several building contractors and heating and cooling contractors install solar equipment. Several large home builders in and around Riverside offer solar homes for sale. Given the favorable economic position of solar energy in this area, the solar energy industry should grow significantly in the next few years.

Recommendations

- Conduct a solar energy awareness program to make Riverside residents aware of the potential of solar energy and the cost savings possible, and to encourage the installation of systems on every home
- Create legislation which would exempt solar energy equipment from property tax, and would guarantee the sun rights of home owners
- Support a detailed study to verify the results of the present work and to extend the analysis to other areas such as passive solar design and photovoltaics.

Impact Calculations for Implementation of Solar Water and Space Heat Options

Table D2-12 gives calculations of the natural gas savings and emissions savings from implementation of solar energy for 3 impact levels. Implementation in all cases applies only to single-family and duplex residential.

Low - Application of water heating only on 70 percent of new units and 30 percent of existing units.

Mod - Water heating only on 100 percent of new units and 50 percent of existing units.

High - Water and space heat in 100 percent of new units and 70 percent of existing units.

TABLE D2-12. IMPACTS OF SOLAR IMPLEMENTATION

	Impact Level								
	Low			Mod			High		
	Population			Population			Population		
	Low	Mod	High	Low	Mod	High	Low	Mod	High
12. Impact of Solar Implementation									
a. Existing Housing									
1. No. of SF & Duplex units	23561	→	→	35342	→	→	47122	→	→
2. Natural gas consumption in SF & Duplex units									
Space heat E9 Btu/yr	733.3	→	→	1100	→	→	1466.8	→	→
Process heat E9 Btu/yr	949.5	→	→	1424.3	→	→	1899.1	→	→
3. Percent solar implementation	30	30	30	50	50	50	70	70	70
4. Savings-conservation	148.5	→	→	225.1	→	→	300.4	→	→
5. Percent Savings--solar	25	25	25	25	25	25	54	54	54
6. Natural gas savings E9 Btu	569.2	→	→	856.2	→	→	1692.6	→	→
7. Estimated Cost, $/unit	2020	2020	2020	2020	2020	2020	3100	3100	3100
8. Total Cost, $ E6	14.3	→	→	35.7	→	→	102.3	→	→
9. 20 year life savings, $E6	1.3	→	→	3.2	→	→	4.9	→	→
b. New Housing (Natural Gas)									
1. No. of SF & duplex units	10471	29136	29320	9145	16301	25608	7608	13561	21303
2. No. of Passive Design	2002	3567	5605	3313	5906	9279	3873	6904	10845
3. Difference (1-2)	8469	25569	23715	5832	10395	16329	3735	6657	10458
4. Projected Natural Gas Reqmt.									
Space heat E9 Btu/yr	258.7	461.5	724.7	170.8	307.3	478.3	102.7	183.0	287.5
Process heat E9 Btu/yr	341.3	608.5	955.7	235.0	423.6	658.1	150.5	268.2	421.4
5. Percent solar implementation	70	70	70	100	100	100	100	100	100
6. Percent savings-conservation	55.6	99.2	155.8	44.0	73.7	114.8	28.3	51.1	80.3
7. Percent Savings-solar	32	32	32	32	32	32	58	58	58
8. Natural Gas Savings, E9 Btu	247.6	441.6	693.5	170.9	307.6	478.5	175.7	312.8	491.5
9. Estimated Cost, $/unit	1620	1620	1620	1620	1620	1620	2700	2700	2700
10. Total cost, $E6	9.6	29.0	26.9	9.5	16.8	26.5	10.1	18.0	28.2
11. 20-year life savings, $E6	2.5	7.4	6.9	1.7	3.0	4.7	1.3	2.3	3.7
c. Total Natural Gas Savings (E9 Btu/yr)	816.8	1010.8	1262.7	1027.1	1163.8	1334.7	1868.3	2005.4	2184.1
d. Reduction in Emissions (lb/yr)									
1. Particulates	15519	19205	23991	19515	22112	25359	35498	38103	41498
2. SO_x	490	606	758	616	698	801	1121	1203	1310
3. NO_x	40840	50540	63135	51335	58190	66735	93415	100270	109205
4. Hydrocarbons	6534	8086	10102	8217	9310	10678	14946	16043	17473

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SURVEY AND PRELIMINARY EVALUATION OF POTENTIAL GEOTHERMAL ENERGY APPLICATIONS FOR RIVERSIDE, CALIFORNIA*

Introduction

Geothermal energy has the potential to meet many of Riverside's energy needs. In this report we will examine the technical, economic, legal, and environmental considerations involved in using geothermal energy to supply electricity, space heating and cooling, and process heat to Riverside. We will also examine the availability of nearby geothermal resources and the dependence of the various potential end uses on the characteristics and locations of the geothermal resources. We will formulate a plan for further evaluation or development of the most promising geothermal energy applications. The plan will propose actions designed to resolve existing constraints, risks, and uncertainties in a timely manner.

Geothermal energy, today, is a technically viable energy source for many American communities. Economics, the cost of production and distribution, is the main deterrent to its widespread use. Worldwide, geothermal energy already is used for electricity generation, space heating, domestic hot water, industrial process heat, greenhouse heating, refrigeration, by-product chemicals, fish rearing and balneology. Over 1000 MWe of geothermal electricity are generated in the U.S., El Salvador, Italy, New Zealand, Mexico, Japan, Iceland, and the U.S.S.R. New installations are planned in many of these and other countries. In Iceland, municipal district heating systems use geothermal energy to heat the homes of more than 100,000 people. Less extensive geothermal district heating systems are located in France, Hungary, Japan, and the U.S.S.R. In the U.S., geothermal energy currently heats less than 1000 dwellings in Klamath Falls, Oregon and Boise, Idaho. Many countries have geothermal process heat installations, but combined the total energy currently supplied is small.

Rising energy prices and potential shortages of fossil fuels have spawned increased interest in geothermal energy for both electrical and non-electrical uses. In the past, both were severely limited in development by competition from low-priced alternatives. Now, with low-priced alternatives in short supply geothermal energy may become economically competitive in many locations.

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* This part of Appendix D consists of a complete DOE report: Bloomster, C. H., Fassbender, L. L., Schilling, A. H., and Lippek, H. E., "Survey and Preliminary Evaluation of Potential Energy Applications for Riverside, California", PNL-2597, March 1978. Only the page numbers have been changed.

Survey of Geothermal Resources

We conducted a literature survey of the geothermal resources near Riverside and found eight resources within 200 miles that could be utilized to generate electricity. These eight resources contain an estimated electrical potential of 2749 MWe centuries (Table D3-1), which is enough to supply Riverside's electrical demands for over 2000 years. We also found over 20 hot springs within 50 miles of Riverside which might be suitable for non-electrical applications. However, of these resources, only Arrowhead Hot Springs has significant known potential; too little is known about the others.

TABLE D3-1. ELECTRICAL POTENTIAL OF GEOTHERMAL RESOURCES WITHIN 200 MILES OF RIVERSIDE, CALIFORNIA[a]

Name	Subsurface Temperature, °C	Electrical Potential, MWe Centuries
Coso	220	1360
Salton Sea	340	836
Heber	190	292
East Mesa	180	146
Brawley	200	100
Arrowhead	150	5
Border	160	5
Sespe	155	5
TOTAL		2749

(a) From USGS Circular 726

For potential electrical applications we included resources up to 200 miles away, although this is an arbitrary limit. Figure D3-1 shows the locations of all geothermal resources within 200 miles of Riverside with reservoir temperatures of 150°C or higher. These resources, which are described below, are considered promising for electrical generation. They include

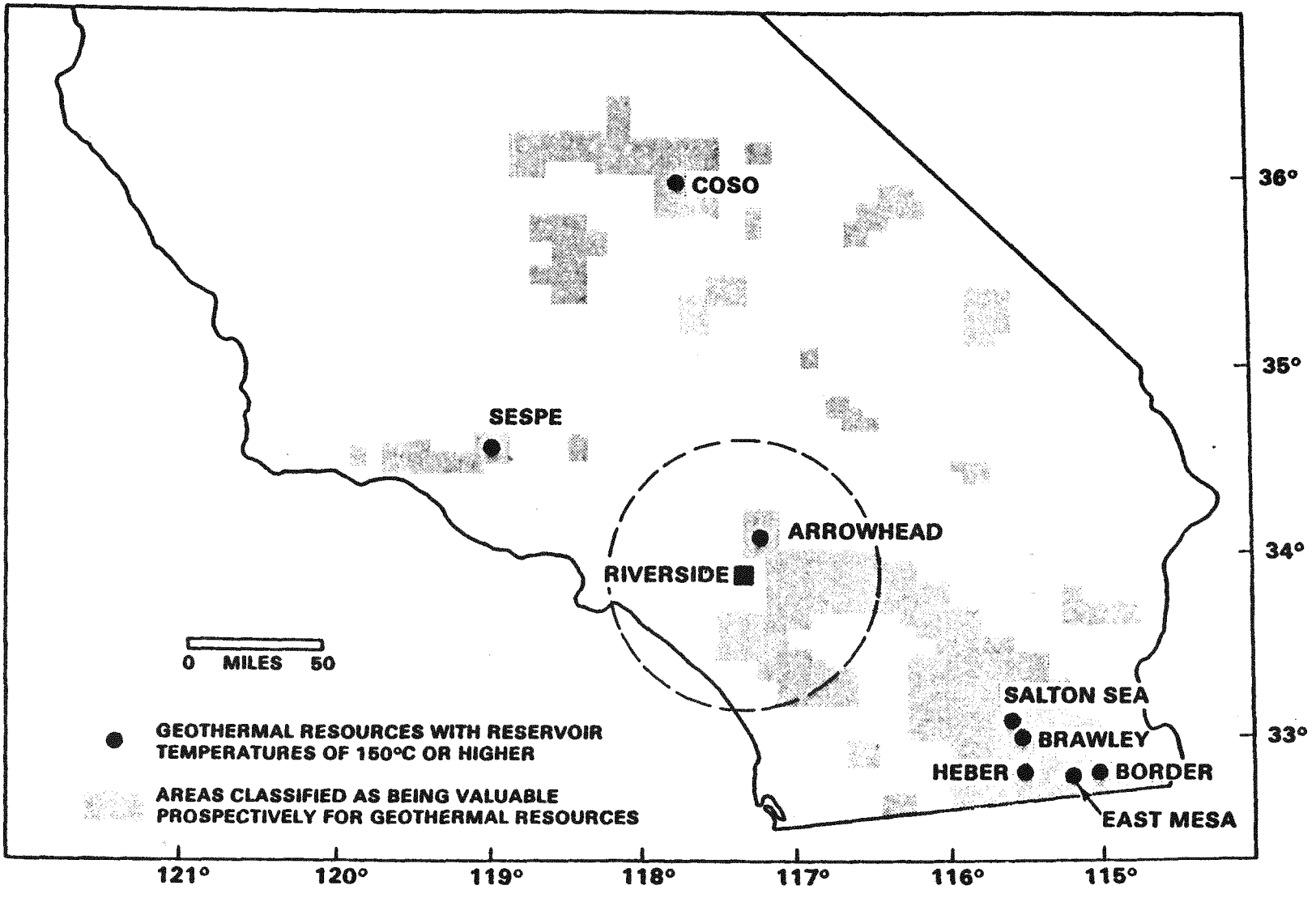


FIGURE D3-1. GEOTHERMAL RESOURCES WITHIN 200 MILES OF RIVERSIDE, CALIFORNIA

Coso Hot Springs in Inyo County, Sespe Hot Springs in Ventura County, Arrowhead Hot Springs in San Bernardino County, and Brawley, Border, East Mesa, Heber and the Salton Sea KGRAs (Known Geothermal Resource Areas) in Imperial County. The characteristics of these eight resources are summarized in Table D3-2. In addition to these identified resources, the shaded areas on Figure D3-1 are "areas classified as being valuable prospectively for geothermal steam and associated geothermal resources."[1] These areas are shown on a new map prepared by the National Geophysical and Solar-Terrestrial Data Center in cooperation with the ERDA Division of Geothermal Energy and the USGS.

If the 200 mile limit is relaxed, many additional geothermal resources could be considered. For instance, it might be possible to obtain electric power from The Geysers, the large commercial geothermal resource 450 miles north of Riverside. Regional tie-lines for bulk power transfer already exist between Northern and Southern California.

For potential non-electrical applications we included resources up to 50 miles away. Geothermal energy is competitive for space and process heating out to distances of 50 miles from the wellhead when employed on a large scale to serve concentrated markets.[2] The resources we considered for non-electrical uses include Arrowhead Hot Springs, Desert Hot Springs, and numerous thermal springs in the vicinity.

Potential Resources for Electricity Generation

Coso

Coso Hot Springs is located in the Mojave Desert in east-central California, about 150 miles north of Riverside. About 80% of the 51,760-acre KGRA lies within the U.S. Naval Weapons Center at China Lake, which is closed to the general public.[3] The Navy has announced plans to build a materials test facility and a 20-MWe power plant to utilize the geothermal energy.[4] The Coso Hot Springs KGRA is estimated to contain an electrical potential of 1360 MWe centuries.[5]

TABLE D3-2. GEOTHERMAL RESOURCES WITHIN 200 MILES OF RIVERSIDE, CALIFORNIA[a]

Name	Location			Subsurface Temperature, °C	Reservoir Assumptions		Total Dissolved Solids, PPM
	Latitude °N	Longitude °W	Miles From Riverside		Depth, km	Heat Content, 10^{18} Calories	
Coso	36° 03'	117° 47'	150	220	1.0	41	5,800
Salton Sea	33° 12'	115° 36'	115	340	1.0	21	120,000-250,000
Heber	32° 43'	115° 31.7'	130	190	1.0	11	14,000
East Mesa	32° 47'	115° 15'	145	180	1.0	5.5	2,400-25,000
Brawley	33° 01'	115° 31'	120	200	1.5	3	54,000
Arrowhead	34° 08.6'	117° 15.2'	15	150	1.5	0.2	*
Border	32° 44'	115° 07.6'	155	160	2.4	0.2	*
Sespe	34° 35.7'	118° 59.9'	105	155	1.5	0.2	*
TOTAL						82.1	

(a) From USGS Circular 726.

* No data available.

Salton Sea

The Salton Sea KGRA is located at the southeastern end of the Salton Sea in the Imperial Valley. It contains 95,824 acres, 50% of which is underwater. More than 95% of the onshore land and about half of the offshore land is privately controlled.(3) All of the ongoing geothermal activities in the Salton Sea KGRA, such as the San Diego Gas and Electric Company's geothermal loop experimental facility at Niland, are onshore on private land. The electrical potential of the Salton Sea KGRA is estimated to be 836 MWe centuries.(5)

Heber

The Heber KGRA is in the southern part of the Imperial Valley between El Centro, California and Mexicali, Mexico. The 58,568-acre KGRA is being developed by Chevron Oil Company, Magma Power Company, and New Albion Resources Company (a subsidiary of San Diego Gas and Electric Company).(6) The Heber KGRA is estimated to contain 292 MWe centuries of electrical potential.(5)

East Mesa

The 38,365-acre East Mesa KGRA is located in the southeastern part of the Imperial Valley very near the Mexican border. The area is being developed by the U.S. Bureau of Reclamation, Republic Geothermal, Inc., and Magma Energy.(3) The electrical potential of the East Mesa KGRA is estimated to be 146 MWe centuries.(5)

Brawley

The Brawley KGRA, which contains 28,885 acres, is in the southern part of the Imperial Valley about 20 miles north of Mexico. Several successful wells have been drilled in the area by Union Oil Company of California.(3) The Brawley KGRA is estimated to have an electrical potential of 100 MWe centuries.(5)

Arrowhead, Border, and Sespe

Little data is available on these three geothermal resources. The assumed heat content of each of these reservoirs is 0.2×10^{18} calories.(5)

The USGS estimated this heat content for systems with minimal surface evidence by assuming a subsurface area of 1.5 km^2, a depth of 1.5 km, and a specific heat of 0.6 cal/cm^3 - °C. Under these assumptions, the estimated electrical potential is 5 MWe centuries for each of the three geothermal resources. As further geological, geochemical, and geophysical data become available, these resources may prove to hold a much greater potential.

Ford Dry Lake

The 7,696-acre Ford Dry Lake KGRA is located 18 miles west of Blythe in Riverside County, about 140 miles from the City of Riverside. Ford Dry Lake is one of four dry lakes in the Chuckwalla Valley. The area was designated a KGRA only because overlapping geothermal lease applications were filed in the vicinity in 1974.[3] According to the USGS, there is no evidence of the existence of any geothermal resource in the Ford Dry Lake KGRA.[a]

Potential Resources for Nonelectrical Applications

The geothermal resources with reservoir temperatures below 150°C are not suitable for economic electric power generation, but some of them have potential for space and process heating. According to USGS Circular 726,[5] there is only one geothermal resource above 90°C within 50 miles of Riverside. This resource, Arrowhead Hot Springs, is shown inside the 50-mile radius circle surrounding Riverside in Figure D3-1. However, a previous USGS paper[7] shows about 20 lower-temperature thermal springs in the area; this paper lists only the surface temperature of the water. In order to assess the potential of these springs, more data are required on the subsurface temperature and the heat content of the reservoir. We tried to obtain additional information by telephone conversations with the USGS, the California Division of Oil and Gas, the Riverside County Planning Office, the University of California at Riverside, the California Energy Resources Conservation and Development Commission, and the California Institute of Technology's Jet Propulsion Laboratory. However, it appears that good resource assessment data on these lower-temperature nearby springs is not available. Figure D3-2 shows the locations of these springs.

(a) Discussion with Marshall Reed, USGS, Conservation Division, Menlo Park, CA, 9-14-77.

NUMBER	NAME OR LOCATION
1	TYLERS BATH SPRINGS
2	ARROWHEAD HOT SPRINGS
3	IN DEEP CREEK CANYON, 16 MILES S.E. OF VICTORVILLE
4	IN DEEP CREEK CANYON, 15 MILES S.E. OF VICTORVILLE
5	NEAR BALDWIN LAKE, 40 MILES S.E. OF VICTORVILLE
6	HARLEM HOT SPRING
7	WATERMAN HOT SPRINGS
8	IN SANTA ANA CANYON, 12 MILES E.-N.E. OF SAN BERNARDINO
9	HIGHLAND SPRINGS
10	DESERT HOT SPRINGS
11	EDEN HOT SPRINGS
12	PILARES HOT SPRING
13	GILMAN HOT SPRINGS
14	SOBOBA HOT SPRINGS
15	WRENDEN HOT SPRINGS
16	ELSINORE HOT SPRINGS
17	MURRIETA HOT SPRINGS
18	DELUZ WARM SPRINGS
19	SAN JUAN CAPISTRANO HOT SPRINGS
20	GLEN IVY HOT SPRING
21	FAIRVIEW HOT SPRING

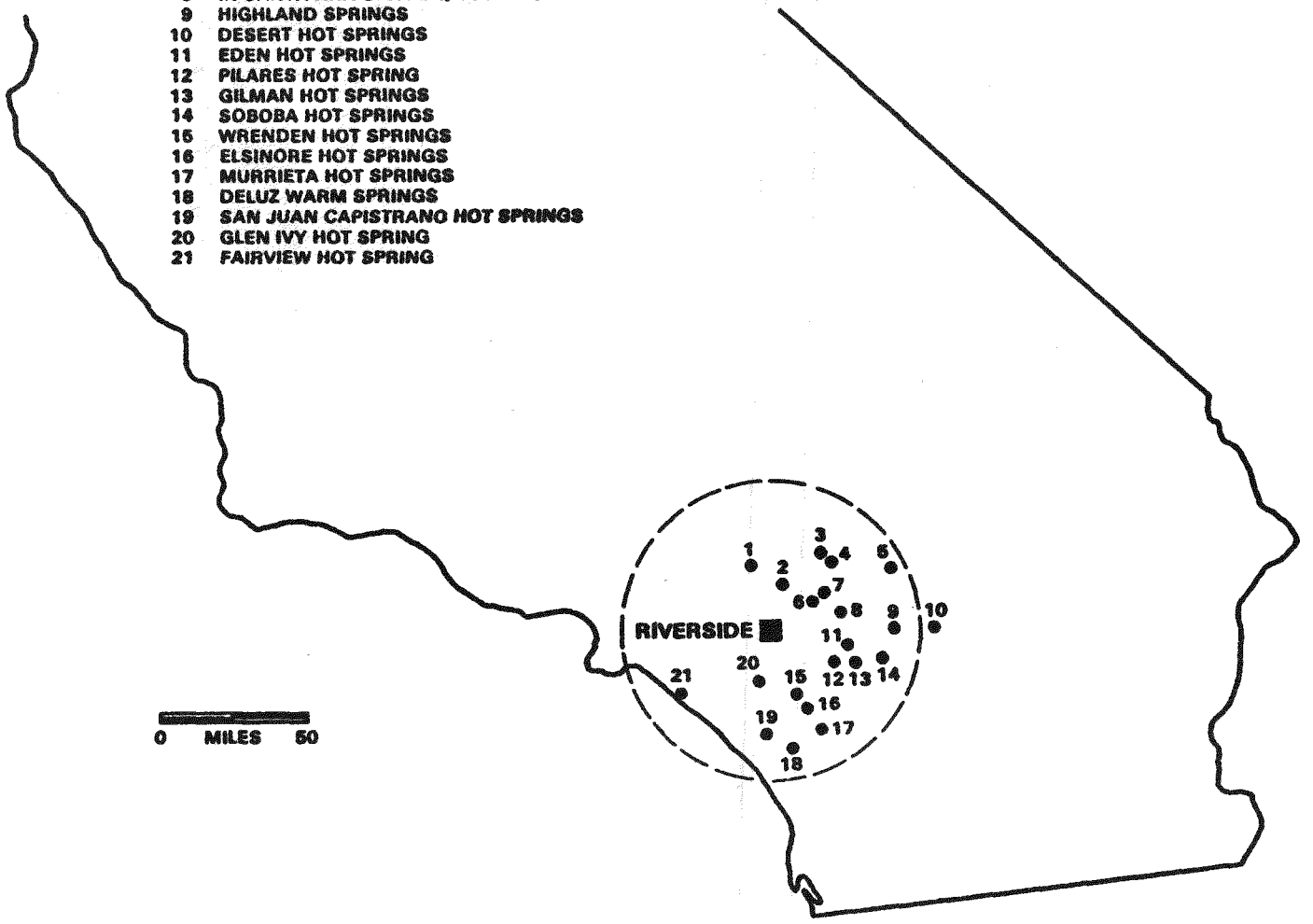


FIGURE D3-2. THERMAL SPRINGS WITHIN 50 MILES OF RIVERSIDE, CALIFORNIA

Arrowhead

The geothermal resource nearest to Riverside is Arrowhead Hot Springs, about 15 miles north. The estimated temperature of this resource is 150°C, which makes it potentially useful for either electrical or non-electrical applications. As mentioned previously, the USGS assumed a heat content of 0.2×10^{18} calories for Arrowhead Hot Springs. This amount of heat is equivalent to about 100 years of natural gas consumption in Riverside.

Desert Hot Springs

The town of Desert Hot Springs is located at the northern end of the Coachella Valley in Riverside County, about 55 miles east of Riverside. Researchers at the California Institute of Technology's Jet Propulsion Laboratory are working on a project involving the utilization of nearby geothermal resources for non-electric purposes in Desert Hot Springs. The data they have collected is for shallow wells (less than 500 feet deep) and shows temperatures ranging from 88°F (31°C) to 212°F (100°C). (No deeper wells have been drilled in the Coachella Valley because the geothermal resource lies directly above the potable water aquifer, separated by non-permeable rock.(a)

Although these temperatures are low, practical experience in several countries has shown them to be satisfactory for district heating, provided that the resource is very near the site of use. The Reykjavik municipal district heating system in Iceland uses 80°C water, the French use 70°C water, the Japanese use 40°C to 70°C water, and the Boise, Idaho district heating system uses 77°C water.(8) However, in all these applications the geothermal resources are within 10 miles of the point of use. Thus if further resource assessment work identifies similar low temperature geothermal resources very near Riverside, there are distinct possibilities for utilization of the heat.

Technical Feasibility of Electricity Generation from Geothermal Resources

The technical feasibility of generating electricity from dry-steam geothermal resources is well established. About 1000 MWe are currently

(a) Discussion with Yukio Nakamura, JPL, Energy Systems Section, 9-22-77.

produced worldwide from these resources. Unfortunately, there are no known dry-steam systems within 200 miles of Riverside. The nearest one is The Geysers in Northern California, about 450 miles away. The operating power plant capacity at The Geysers is 502 MWe with plans for expansion to 1500 MWe by 1985. The electrical potential of The Geysers is estimated at 477 MWe centuries, or 1590 MWe for 30 years.[5] Thus except for distance, The Geysers has potential to supply Riverside's electricity needs.

All of the known geothermal resources within 200 miles of Riverside are liquid-dominated systems. Worldwide, about 300 MWe are produced currently from liquid-dominated systems. The two most promising methods of geothermal power generation from liquid-dominated systems are the flashed steam cycle and the binary cycle.[9,10] In the flashed steam cycle the geothermal water is transported through an insulated pipeline to the power plant where it is flashed to produced steam. The steam is then expanded through a turbine as in conventional steam power plants. In the binary cycle heat is transferred from the geothermal water to the working fluid; the working fluid is then expanded through a turbine to produce electric power.

Flashed Steam Plants

In 1968 the Mexican Government started construction of a geothermal power plant at Cerro Prieto, about 19 miles south of Mexicali. Commercial operation of the 75-MWe flashed steam plant began in 1973. According to the Comision Federal de Electricidad, "Problems encountered have not been insurmountable. The operation of the plant is a great success."[11]

As shown in Table D3-3, Mexico is not the only country with a flashed steam plant. Geothermal power production from liquid-dominated reservoirs began at Wairakei, New Zealand in 1958; at Otake, Japan in 1967; at Namafjall, Iceland in 1970; at Pauzhetka, USSR in 1967; and at Ahuachapan, El Salvador in 1975. Thus, flashed steam power plant technology has proven successful for high-temperature liquid-dominated geothermal resources.

TABLE D3-3. FLASHED STEAM GEOTHERMAL POWER PLANTS OF THE WORLD

Name	1975 Capacity, MWe	Year Operation Began
Wairakei, New Zealand	193	1958
Kawerau, New Zealand		
Broadlands, New Zealand		
Hatchobaru, Japan	50	U.C.*
Onuma, Japan	10	1973
Otake, Japan	13	1967
Cerro Prieto, Mexico	75	1973
Pathe, Mexico	3.5	1958
Namufjall, Iceland	3	1970
Pauzhetka, USSR	5	1967
Makhachkala, USSR	12	U.C.*
Ahuachapan, El Salvador	30	1975

* U.C. = under construction.

Binary Plants

The only existing geothermal power plant using the binary cycle is the Paratunka power station (1 MWe) on the Kamchatka Peninsula in Russia. Evidently, the plant has been operating successfully since 1964, and the Russians have plans to build a similar 25-MWe plant nearby.[12] Two new binary cycle plants are scheduled to start up in the Imperial Valley in the near future. San Diego Gas and Electric Company has a 45-MWe project underway at Heber and Republic Geothermal has a 10-MWe project at East Mesa. Also, the Japanese have a 1-MWe plant under construction at Otake. Thus, experience with the binary cycle has not yet been demonstrated on a large scale.

Hybrid Plants

A hybrid combination of the flashed steam cycle and the binary cycle is potentially most promising for electric power generation from the Salton Sea resource. The Salton Sea resource is a high-temperature, hypersaline liquid-dominated system with a high noncondensable gas content. Removing large volumes of noncondensable gases from the turbine exhaust condenser leads to low efficiency in the steam cycle. Excessive scaling rates are expected if the geothermal brine is sent directly through a heat exchanger in the binary cycle. Consequently, a hybrid flashed steam/binary cycle has been proposed to overcome these problems. No hybrid plants currently exist.

In 1976 the Bechtel Corporation completed a conceptual design for a 50-MWe geothermal power plant to be built at Niland, 4.5 miles east of the Salton Sea. The Bechtel design is a "multistage flash/binary process" using isopentane as the working fluid and requires the use of "current or in-sight state-of-the-art technology". The estimated total capital cost for the plant is $37.1 million or $742 per net kilowatt, in December 1975 dollars.[13]

Economics of Electricity Generation from Geothermal Resources

There are sufficient geothermal resources within 200 miles to supply the electrical requirements of Riverside for thousands of years. The technology for producing electricity from these resources is either in-hand or in-sight. Depending on the particular reservoir involved, this electricity can probably be generated at costs ranging from 1 to 3 times the cost of conventional electric power generation. Over this distance, the additional unit cost for energy transmission should be comparatively small.

Electricity is currently produced from only high quality geothermal resources throughout the world. High quality usually means dry steam or high-temperature liquid-dominated resources located near the surface. In the past, high quality also meant high productivity (at least 3 MWe electrical capacity) from each geothermal well. However, rapid escalation in energy costs plus advances in geothermal energy recovery technology make

lower quality geothermal resources more economically feasible. Thus, geothermal energy should become a much more important and widespread energy source for electricity production.

The most important factors affecting the economics of geothermal electricity production are the wellhead temperature, the well flow rate, and the cost of the wells.[14] The capital cost of the power plant is significant, but not highly sensitive to these resource characteristics. The optimum geothermal plant size will be in the 50-100 MWe range; opportunities for achieving significant cost reductions in large plants through "economies of scale" are small. From this standpoint, geothermal power plants are ideal for integrated community energy systems.

Geothermal electricity production is capital intensive; over 75% of the generation costs are fixed costs related to capital investment. The steam and binary power cycles are closely competitive; the binary cycle appears better when the geothermal fluid temperature is below 200°C, and the flashed steam cycle appears better above this temperature.[14] The breakeven temperature and comparative advantage of either cycle could vary over a wide range depending on the relative costs of the energy supply and power plant, the noncondensable gas content, scaling rates, and other factors.

However, because of the lack of experience with binary cycle power plants, there is considerable uncertainty in their capital and operating costs and in their performance. Improvements might be more rapid in the new binary cycle technology relative to the well-developed steam technology, and thus the binary cycle capital costs might become more competitive with time.

Technological advances are needed to reduce costs from marginal geothermal resources and thus stimulate geothermal energy development. Significant reduction in power costs would be achieved by reducing well drilling costs, stimulating well flow rates, reducing power plant capital costs, increasing power plant efficiency and utilization, and developing more effective exploration techniques for locating and assessing high quality resources. Programs for geothermal energy development in the Department of Energy are directed at these technology advances.

Cost of Electricity from Geothermal Energy

We estimated the cost of generating electric power from geothermal resources near Riverside using the GEOCOST model.[15] The GEOCOST model is a techno-economic model which can simulate the production of electricity from any geothermal resource. Based on the subsurface temperature of the geothermal resources, we simulated a flashed steam cycle plant at Coso and binary cycle plants at Heber, East Mesa, Brawley, Arrowhead, Border, and Sespe. The steam cycle was modeled as a two-stage flash at the plant and the binary cycle was modeled with isobutane as the working fluid. For the Salton Sea resource we escalated the Bechtel cost estimate for the hybrid plant, discussed previously, by 7% to January 1977 dollars for purposes of comparison with the GEOCOST cost estimates for the other resources (Table D3-4). With the exception of the Salton Sea, the decrease in resource temperature results in an increase in the power plant capital cost. The binary plants become more expensive because the isobutane flow rate, and therefore the equipment sizes, must be greater with lower temperature geothermal fluids.

TABLE D3-4. POWER PLANT CAPITAL COSTS
(January 1977 Dollars)

Name	Subsurface Temperature, °C	55 MWe Power Plant Total Capital Cost, ($ Millions)	Capital Cost $/kWe (Net)
Salton Sea	340	39.7	794
Coso	220	20.4	389
Brawley	200	22.4	505
Heber	190	22.8	525
East Mesa	180	25.7	564
Border	160	30.4	669
Sespe	155	32.4	714
Arrowhead	150	33.4	740

Although the Salton Sea resource has the highest temperature of the eight resources, it also has the highest cost estimate. There are several reasons for this. The other seven resources are assumed to have non-corrosive, low-salinity fluids. The Bechtel cost estimate for the Salton

Sea resource is based on highly-corrosive, high-salinity brine. In addition, Bechtel's cost estimate includes safety factors and contingencies representative of a first-of-a-kind plant. A GEOCOST estimate is intended to be representative of an average plant cost for a standardized design rather than a safe cost for a first-of-a-kind plant. Placed on the same estimating basis, the Salton Sea plant would probably cost $500-$600/kWe (net).

The expected distribution of electricity generation costs is shown in Table D3-5. The total cost of geothermal power can be distributed into three categories: power plant capital costs, power plant operating costs, and energy supply costs. Nearly all the power plant costs are associated with the initial capital required to build it. Only a small percentage of the total is required to operate the plant, so uncertainties in operating costs would not have a significant impact on power costs. The energy supply cost is a significant part of the total and its significance grows as resource quality decreases.

Based on the cost of electricity generation (Table D3-5), the most promising geothermal resource for electricity generation for the City of Riverside is Coso Hot Springs. As stated previously, Coso is located about 150 miles north of Riverside on land owned by the U.S. Navy. The

TABLE D3-5. DISTRIBUTION OF ELECTRICITY GENERATION COSTS
(Mills/kwhr, January 1977 Dollars)

Name	Temperature, °C	Power Plant		Cost of Energy Supply	Total Cost
		Capital Costs	Operating Expenses		
Coso	220	10	0.4	18	28
Brawley	200	12	0.5	19	32
Heber	190	13	0.5	22	36
East Mesa	180	14	0.5	30	45
Border	160	16	0.6	35	52
Sespe	155	17	0.6	39	57
Arrowhead	150	18	0.6	44	63
Salton Sea*	340	13	1.0	20	34

* Estimate assumes standardized plant design and favorable resolution of scaling and corrosion problems.

Coso KGRA is estimated to have an electrical potential of 1360 MWe centuries, or about 4500 MWe for 30 years. The annual electricity consumption in Riverside during 1976 was 840,000,000 kwhr. The Coso KGRA could potentially satisfy Riverside's electrical demands at this level for over 1000 years.

Over the long term, the Salton Sea resource may be the most promising. If the severe scaling and corrosion problems can be overcome at a reasonable cost, then power generation from this highest-temperature resource might become the lowest in cost. Several research programs are underway to reduce geothermal scaling and corrosion problems.

The power cost for Brawley (32 mills/kwhr) is only 14% higher than the power cost for Coso (28 mills/kwhr); and the power cost for Heber (36 mills/kwhr) is only 29% higher than the power cost for Coso. These differences are not significant in comparison with the uncertainties in the characteristics of the resources. The Brawley and Heber resources are also promising sources for electric power generation for Riverside. In fact, Heber might even be considered more promising, since it is scheduled to be in production by 1980.

For purposes of comparison, Table D3-6 shows electricity generation costs from other conventional sources of power. These costs are based on FEA estimates[16] which we escalated by 11% (7% per year for 1.5 years) from July 1975 dollars to January 1977 dollars. Based on these data, geothermal electric power is expected to be 1 to 3 times as expensive as conventional power sources, depending on the particular reservoir involved.

TABLE D3-6. BASELOAD ELECTRICITY GENERATION COSTS*
(Mills/kwhr, January 1977 Dollars)

	Nuclear	Coal	Oil Steam
Capital	15	10	8
Fuel	2	11	23
Other	3	2	2
Total	20	23	33

* Assumes a delivered price of $1.10 per million Btu for low sulfur coal and $2.25 per million Btu for residual oil. Capital costs in 1975 dollars are $550 per kW for nuclear, $380 per kW for coal and $310 per kW for oil. A fixed charge rate of 15 percent and a capacity factor of 0.7 were assumed.

Electricity Transmission Costs

Cost ranges published by the Federal Power Commission[17] for the cost of energy transmission vary from 0.3 to 0.9 mills/kWh/100 miles for voltages which vary from 700 kV to 200 kV. Thus, transmission costs from nearby geothermal resources to Riverside are expected to be minor.

Methodology

The GEOCOST computer program was developed to provide rapid and systematic calculations of the variation in geothermal power costs with important resource, power recovery, and economic factors. The computer program simulates the geothermal power production processes. Cost functions developed for GEOCOST calculate the capital costs and operating expenses for commercial power plants using the resource characteristics and power conversion technology specified for each simulation. These cost functions generate the cash flow requirements over the economic life specified for the simulation. Using discounted cash flow analyses, GEOCOST calculates the unit cost of energy for the specified input conditions. The unit cost of energy is the most appropriate common unit for comparing energy costs from alternative sources, either geothermal or nongeothermal. The GEOCOST computer program is described in more detail elsewhere.[9,10,15,18,19]

Besides the unit cost of energy, the output from GEOCOST consists of the distribution of the components of the energy cost, including power plant and reservoir equipment costs and operating expenses. GEOCOST also calculates many other factors related to the design, performance, and operation of the power plant and reservoir, such as the number of wells required, fluid flow rates, thermodynamic conditions, internal electrical consumption and net plant output. Power costs are expressed as the "bus bar" generating cost of electricity and do not include electrical transmission and distribution costs. Costs are expressed in constant January 1977 dollars. Comparisons between GEOCOST estimates and other independently-developed estimates have shown consistent agreement.

Assumptions

We selected the assumptions shown in Table D3-7 for our cost estimates. These economic and financial assumptions would be typical of a large oil company operating the reservoir and an investor-owned utility operating the power plant. The taxes are a composite, typical of the western states.

TABLE D3-7. FINANCING AND TAX ASSUMPTIONS

Parameter	Reservoir (%)	Powerplant (%)
Capitalization		
Debt	42	59
Equity	58	41
Bond Interest Rate	8	8
Return on Equity	15	12
Federal Income Tax Rate	48	48
State Income Tax Rate	7	7
Property Tax Rate	2.5	2.5
Royalty Payment	10	--
Revenue Tax Rate	--	4

All cases assume mechanical draft cooling towers and injection of the geothermal fluid. In all cases exploration costs were assumed to be constant and contribute the equivalent of 0.8 mills/kwhr to the cost of power. Injection wells were assumed to be capable of handling twice the flow of the producing wells. All cases assume that dry wells will equal 20% of the producing wells, and will cost three-fourths of the cost of producing wells. All cases assume that 20% excess producing wells are required. Royalty payments are assumed to be 10% of the revenues of the reservoir. The assumed values for other important parameters are shown in Table D3-8.

TABLE D3-8. ASSUMED VALUES FOR OTHER IMPORTANT PARAMETERS

Parameter	Value
Power Plant Size, MWe	55
Drilling Cost per Producing Well, $	400,000
Drilling Cost per Dry Well, $	300,000
Drilling Cost per Injection Well, $	350,000
Average Depth of Wells, Meters	2,000
Geothermal Fluid Flow Rate, lb/hr/well	400,000
Average Production Life of Wells, yrs	10
Power Plant Operating Life, yrs	30
Reservoir Well Spacing, acres	20

Technical Feasibility of Nonelectrical Applications of Geothermal Energy

Although current non-electric usage of geothermal energy in the U.S. is miniscule, a large potential demand exists. Geothermal energy could be used for space heating and cooling, industrial process heating, greenhouse heating, balneology, soil warming, and fish-rearing. However, we will consider only space heating and cooling and process heating applications for the City of Riverside.

Space Heating

Residential and commercial space heating can be provided by using geothermal energy as the heat source in a district heating system. Geothermal space heating is technically feasible and thermodynamically efficient. Low quality geothermal energy is an excellent replacement for high quality fossil fuels or electricity for space heating purposes.

In district heating systems a network of insulated pipes distributes heat, using either hot water or steam, to commercial and residential customers from a central distribution point. European systems use hot water almost exclusively, while existing U.S. systems primarily use steam. In single-pipe, once-through distribution systems, fluid disposal is through a sewer system. In two-pipe systems, the fluid is recirculated, conserving the fluid and residual heat.

Geothermal district heating systems use hot water. Besides the distribution system, the geothermal system includes wells for hot water production and insulated pipes for fluid transmission between the wells and the central distribution point. Supplemental heating capacity is usually provided to handle peak demands, and storage tanks absorb flow fluctuations and provide limited reserve capacity. If the geothermal water is contaminated, heat exchangers may be used. If surface disposal of the water is not feasible, injection wells will be required.

A single-pipe distribution system is generally preferred when the geothermal energy is abundant and (1) the water is pure enough to be circulated through the distribution system and disposed of through a sewer system, or (2) the geothermal fluid is contaminated but sufficient fresh water is available for heat transfer, circulation, and disposal. Two-pipe, recirculating systems are preferred when the supplies of energy or potable water are the limiting factors of production.

The geothermal district heating systems in Iceland are mostly single-pipe systems, since the geothermal water is potable. The French geothermal district heating systems are mostly two-pipe systems; heat exchangers are used and the brine is injected. Future U.S. systems will probably be predominately two-pipe systems in the interest of both energy and water conservation.

Space Cooling

Residential and commercial space cooling (air conditioning) can be provided by using geothermal energy to power an absorption refrigeration system. In compression refrigeration machines, which are most common today, electricity is required to drive the compressor. An absorption refrigeration machine makes direct use of heat and does not consume electricity. This is accomplished by substituting a heat engine for the compressor.(20)

Absorption cooling is not a new idea. Cooling by absorption of vapors was achieved by Faraday in 1824. Portable absorption-desorption units operated with kerosene fuel or natural gas have been on the market for over 40 years.(21) With modifications, these units could be operated with geothermal energy.

In absorption cooling machines, cooling is accomplished through the vaporization of the refrigerant fluid; in the process heat is absorbed from the surroundings, thus cooling the room. Refrigerants are fluids which boil at low temperatures while at atmospheric pressure. The best fluids are fluorocarbons, lithium bromide/water solutions, and ammonia/water solutions.(22)

According to Edward Wehlage,[22] consulting electrical and mechanical engineer for geothermal heat, "These (absorption refrigeration) units are all eminently practical. The requirements of a proposed design for installation made by the author in 1964 remain unchanged and the installation could begin today."

There is one absorption unit operating today at the Rotorua International Hotel in Rotorua, New Zealand. It is the only system designed for both space heating and cooling using geothermal resources. The system uses geothermal water at 150°C in a heat exchanger to heat fresh water to about 120°C. The 120°C water is used in radiators, tap water heaters, and to drive the absorption unit.[8]

Industrial Process Heat

Under favorable economic conditions, geothermal energy could supply process heat to many industries. The substitution of geothermal energy for conventional energy in process heating involves replacing the conventional fuel supply and the plant furnace and boiler units with a delivery system for geothermal energy. The geothermal delivery system includes production wells, fluid transmission pipes, and heat exchangers, if required. The production wells and fluid transmission systems are similar to their counterparts for district heating applications.

If the mineral content of the geothermal fluid is high, heat will be transferred from the brine to purer process water. Depending on the location of the fresh water source, the heat exchanger can be located at the wellhead, at the plant site, at the disposal site, or at some other more favorably located site. If the geothermal fluid is sufficiently pure, it can be circulated through the plant, eliminating the need for the heat exchanger. Also, if pure enough, the geothermal fluid can be disposed of through the existing sewer system or perhaps used consumptively in the process, reducing or eliminating the need for fresh process water.

In applications in which the process heat is normally supplied by hot water, the in-plant circulation systems should be readily adaptable to geothermal energy and the incremental retrofitting cost for the geothermal system would be minimal.

Process heating applications differ from space heating in that (1) the fluid reject temperature is higher, and (2) climate has little or no direct impact on energy demand. However, the impact of seasonal variations in the production cycle may be significant. In some respects, process heating applications would tend to have economic advantages over district heating because the heat demand tends to be more concentrated and the average load factor tends to be higher. On the other hand, process heating would tend to have an economic disadvantage because the minimum temperature of utilization is higher and less of the potentially available energy is consumed. For district heating applications, the geothermal fluid in this study is rejected at 38°C. For process heating applications, the reject temperature in this study is 100°C. Actual reject temperatures may vary from these typical values depending on the characteristics of the specific application.

Economics of Nonelectrical Applications of Geothermal Energy

The use of Arrowhead Hot Springs for geothermal district heating and cooling for the City of Riverside looks economically attractive for high-density urban areas. Based on the USGS estimate of the heat content at Arrowhead Hot Springs, this resource could potentially supply both Riverside's residential space heating and residential space cooling demands for over 100 years. The most promising area in which such a system could be instituted is the northeast section of the city, including the campus of the University of Riverside, the commercial "downtown" area to the west of the campus, and the industrial area to the north of the campus. According to the City of Riverside General Plan Map, there are also medium-high density residential areas in this section of the city. Space heating and cooling of residential and commercial buildings (including the campus) appears to be both technically and economically feasible in Riverside. Supplying industrial process heat in combination with space heating and cooling also appears attractive.

Geothermal energy is competitive for space and process heating applications over significant distances when employed on a large scale to serve concentrated markets. Under these conditions geothermal energy

from 90°C to 150°C hydrothermal resources should be economically competitive with conventional fuels for high-density urban district heating out to distances of 50 miles from the wellhead. From these same resources geothermal energy should be competitive for district heating in low-density urban and suburban areas out to 50 miles from most resources when conventional residential heating costs exceed $8/million Btu. Resources in the 130°C to 150°C range should be competitive for process heating out to 30 miles from the wellhead.[2]

Production and distribution costs are particularly sensitive to well costs, well flow rate, resource temperature, distance separating demand and supply, population density, size of demand, and the system load factor. The supply of geothermal energy for district or process heating is capital intensive; over 75% of the production costs are fixed costs related to the initial capital investment.

Although no technology breakthroughs are required in the utilization of geothermal energy for these nonelectric applications, technological advances are needed to reduce costs and increase the distances over which geothermal energy can be competitive. Significant cost reductions would be achieved by reducing well drilling costs, stimulating well flow rates, increasing productivity in pipeline construction, developing low cost pipeline materials, reducing fluid disposal costs and developing low cost energy storage capacity. Current research in these areas may lead to these cost reductions.

A wide variation can be expected in geothermal energy costs for district heating and process heating applications. The costs vary according to the characteristics of the resource, the characteristics of the demand and the distance separating the resource and the demand.

Cost of Geothermal Space Heating

Our estimates of the cost of space heating for Riverside will be obtained using the GEOCITY[23] model. This model simulates geothermal district heating systems, including fluid production at the wellhead and its transmission to the district heating distribution center. GEOCITY designs and estimates the current costs of these systems. Process heating applications are also simulated with the GEOCITY model as large point-source

users. The economics of district heating and process heating applications are affected by many factors. With the GEOCITY model the impact of these factors on space heating costs can be analyzed rapidly in a systematic framework. Space heating costs are comprised of three components: energy production, fluid transmission, and distribution. These are analyzed separately below.

Production Costs. Energy production costs at the wellhead are sensitive to wellhead temperature, well flow rate, and well cost (Figure D3-3). The horizontal axis in Figure D3-3 is a derived unit reflecting the ratio of well cost to well flow rate; energy production costs vary directly with this ratio. Well flow and well cost are interrelated and to some extent are controllable by the developer; i.e., economic tradeoffs exist between increasing production and increasing cost which the developer will seek to optimize. Costs decrease with increasing temperature as shown.

As stated previously, the geothermal resource nearest to Riverside is Arrowhead Hot Springs. Because of its proximity and its relatively high temperature, Arrowhead Hot Springs is the most promising geothermal resource for non-electrical applications in Riverside. The USGS has estimated the subsurface temperature at Arrowhead Hot Springs to be 150°C. They also estimated the depth to the top of the reservoir to be 1.5 km. Based on this depth and assuming the rock is of medium hardness, we estimate a cost of $280,000 per well. Based on geothermal well flow rate data from the U.S., Mexico, and New Zealand, the average well flow rate from 8-inch bores in liquid-dominated reservoirs is 440,000 lb/hr (200,000 kg/hr). The ratio of well cost to this well flow rate is 1.4 and the energy production cost from Figure 3 is about 55¢ per million Btu. However, we should also include the cost of injection wells. If we assume each injection well has sufficient capacity to absorb the flow from 1.8 production wells, the appropriate well cost to use is ($280,000)(1 + 1/1.8) = $436,000. The ratio of this well cost to average well flow rate is now 2.2. Therefore, the estimated wellhead energy production cost for Arrowhead (from Figure D3-3) is about 75¢ per million Btu.

The system load factor has an enormous impact on the average cost of energy. The attainment of high system load factors will be important to the economic viability of geothermal energy in most applications. Energy production costs are inversely related to the load factor. The costs of production are predominately fixed costs. The principal variable cost will be the cost of energy consumption for pumping.

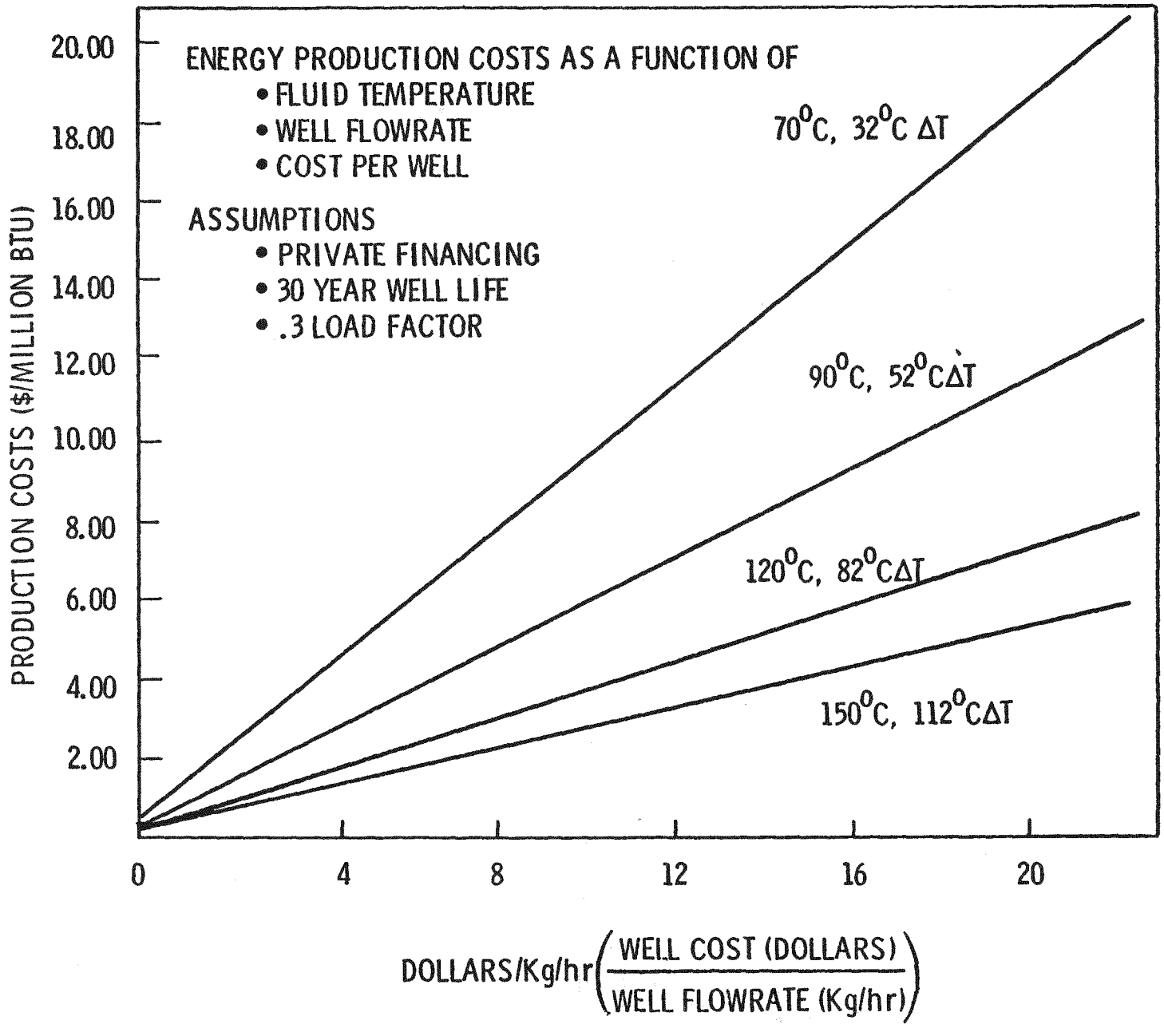


FIGURE D3-3. EFFECT OF FLUID TEMPERATURE, WELL FLOW RATE AND WELL COST ON PRODUCTION COSTS

The load factor is determined by the climate and is not directly controllable by the geothermal energy supplier. For district heating applications in Riverside, the load factor on the distribution system will be about 30%. However, opportunities exist to increase the load factor on the geothermal production and transmission systems through the use of storage capacity and supplemental heat to meet peak demands.

If land subsidence appears to be a problem at Arrowhead, it might be necessary to inject the geothermal water into the reservoir after transferring the heat to a fresh water stream. There are a number of fresh water wells near the City of San Bernardino which provide the fresh water supply for the City of Riverside.(a) The geothermal heat could be transferred to the water from these wells and then the hot fresh water could be transported to the distribution site in Riverside. After passing through the district heating system and giving up its heat, excess water could be disposed of in the existing sewer systems or used consumptively.

Transmission Costs. Flow rate and temperature have significant impacts on the cost of energy transmission (Figure D3-4). The flow rate refers to the peak demand, which is determined by the coincident end-use demands. Since pipe costs increase roughly lineraly with diameter while capacity increases with the square of the diameter, economies of scale are achieved with increasing peak demand. Thus, a large market would tend to be served more economically than a small one.

The distance of fluid transmission will be a limiting factor for non-electric applications of geothermal energy. Transmission distances for existing geothermal applications are short, rarely exceeding 10 miles. The impact of distance on transmission costs is illustrated in Figure D3-5 for three fluid temperatures and pipeline capacities.

Based on the City of Riverside General Plan Map, Riverside will have a population of 362,000 by the year 1990. We estimate that about two-thirds of this population will be in low-density suburban areas and one-third will be in high-density urban areas. The peak fluid demand for this population will be about 21 million lb/hr for suburban areas. For high-density urban areas the peak demand will be about 4.3 million lb/hr. The total demand, 25.3 million lb/hr, is high enough to justify

(a) Discussion with David Sparks, Energy Information Coordinator, Riverside Public Utilities Department, 12/9/77.

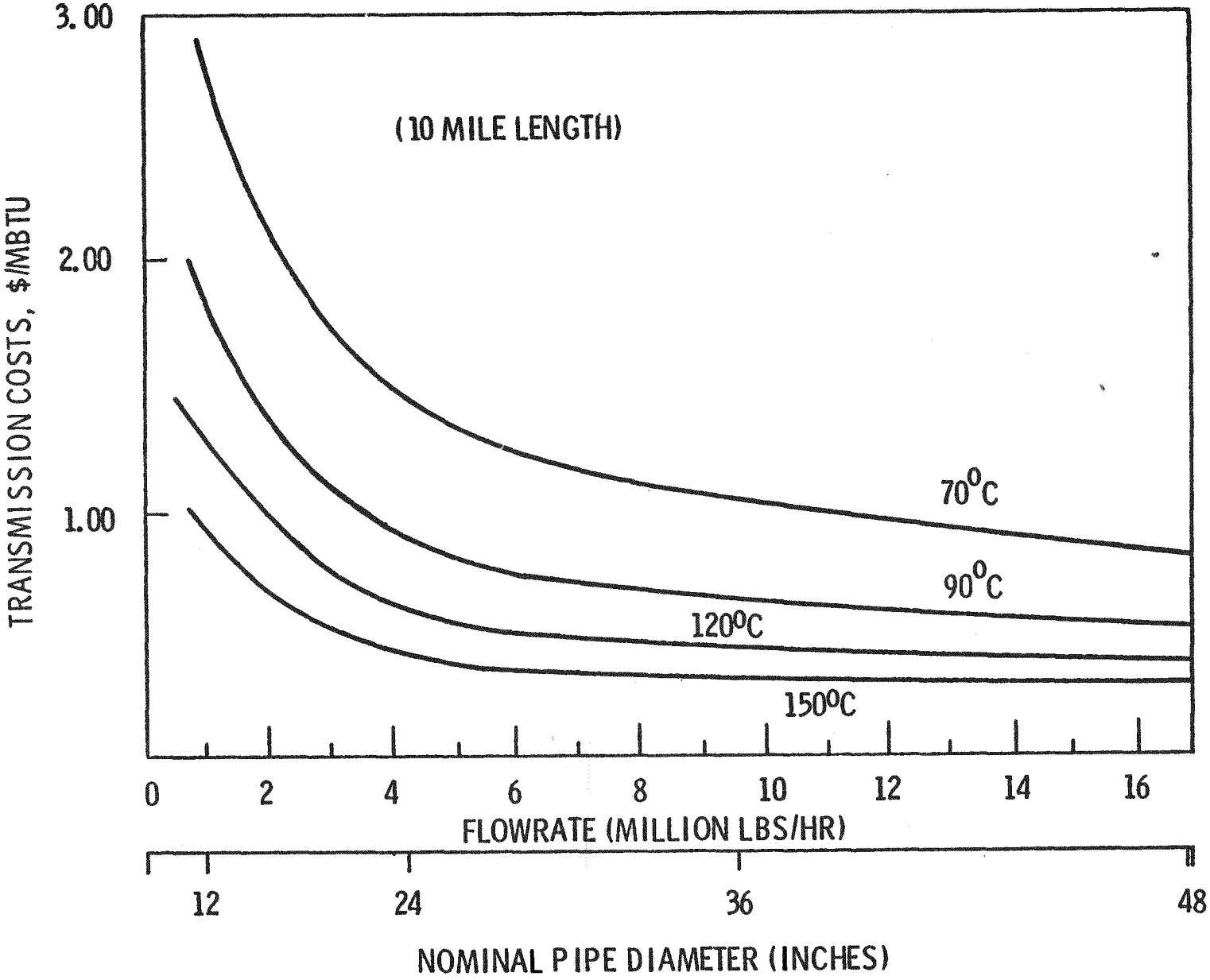


FIGURE D3-4. ENERGY TRANSMISSION COSTS

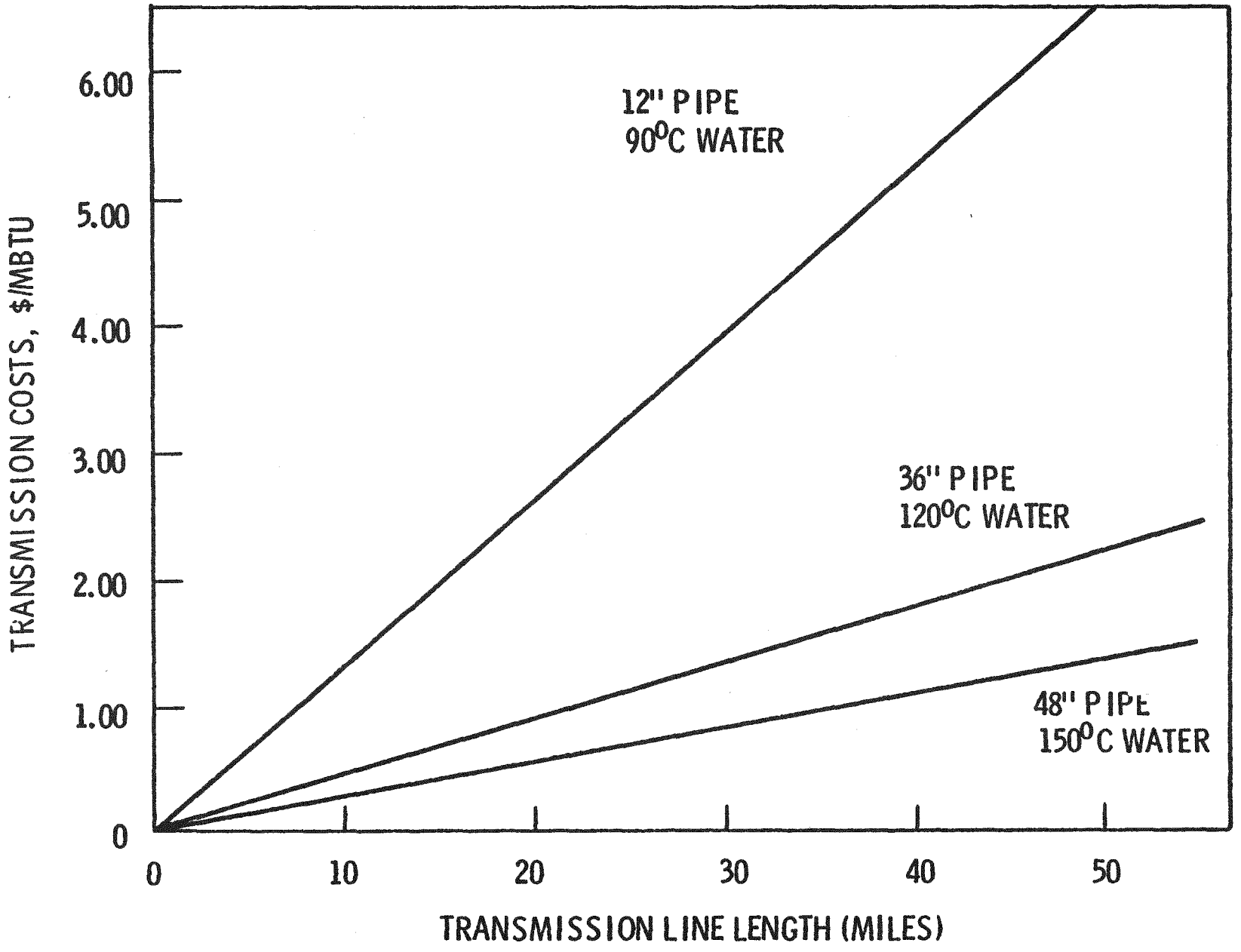


FIGURE D3-5. ENERGY TRANSMISSION COSTS

at least a 48-inch transmission pipeline. From Figure D3-5, the energy transmission cost is about 45¢ per million Btu to pipe 150°C water from Arrowhead Hot Springs to Riverside, a distance of about 15 miles. The cost is only slightly higher if a 24 to 30-inch pipe is used to meet the urban demand only. Since Arrowhead is located in the San Bernardino Mountains, the geothermal fluid can be piped down the mountain under gravity flow; no pumping power will be necessary.

Distribution Costs. The costs of district heating are dependent on many factors related to climate, community charateristics, resource conditions, financing, system design, and construction. The district heating costs in this study refer to new construction unless otherwise stated; i.e., retrofitting costs and the added costs of construction in established areas are not included. The cost of the heating system within the building is not included.

Climate affects district heating costs through two factors—the minimum exterior temperature and the heating degree days. The minimum temperature establishes the peak-load heating requirements and thus determines the size and cost of the pipes. Lower exterior temperatures require more flow and larger pipes. Larger pipes increase the capital cost of the system. For economic reasons, district heating systems are usually designed to meet less than the peak demand. The peak heating requirements are then met with supplemental heat.

For this study we have assumed a municipal district heating system in which geothermal energy supplies 92% of the annual heat load demand. The remaining 8% of the demand is assumed to be met with supplemental heat costing $6/million Btu. We have not included any geothermal energy storage capacity.

The number of heating degree days establishes the annual energy usage. In cold maritime climates, such as Iceland, the annual energy usage is high and relatively constant throughout the year. The average load factor on the Icelandic systems is about 50% of system capacity. In temperate climates, the average annual energy usage is less and the systems would

operate at lower capacity factors. Since district heating systems are very capital intensive, reductions in system capacity utilization, as reflected by degree days, lead directly to higher energy costs.

The total population of the district influences district heating costs in three ways. First, with increasing population, economies of scale are realized in the piping for the distribution network. Second, increasing population reduces costs associated with the investment in wells up to the point at which the maximum well flow is fully utilized. Third, with increasing population, economies of scale are realized in the transmission piping as discussed previously.

Population density is one of the most important factors affecting district heating costs. Increasing population density reduces district heating costs through reducing the average length of pipe run. With very high population densities, as in large multi-story apartment buildings, economies of scale are realized in the distribution system through the use of larger-diameter pipe. This cost advantage might be partially offset, however, by higher costs for heat distribution within the apartment building. Our cost estimates do not include costs of the heating systems within the buildings.

Researchers at Brookhaven National Laboratory have determined from case studies that $8/square meter of floor area is the approximate cost of retrofitting a house for district heating.[24] We estimate 1,620 square feet of floor area for a typical single-family residence. Using these figures, the typical residence could be retrofitted for about $1,200.

The City of Riverside has about 1100 heating °C days per year. For this climate, and assuming a 90°C fluid distribution temperature, the distribution costs for space heating are shown on Figure D3-6 as a function of population density. For suburban areas, the distribution cost ranges from $4.50 to $10 per million Btu. For high-density urban areas, the distribution cost ranges from $2.30 to $3 per million Btu. For construction in established areas, we estimate that the distribution costs would be 15 to 30% higher.

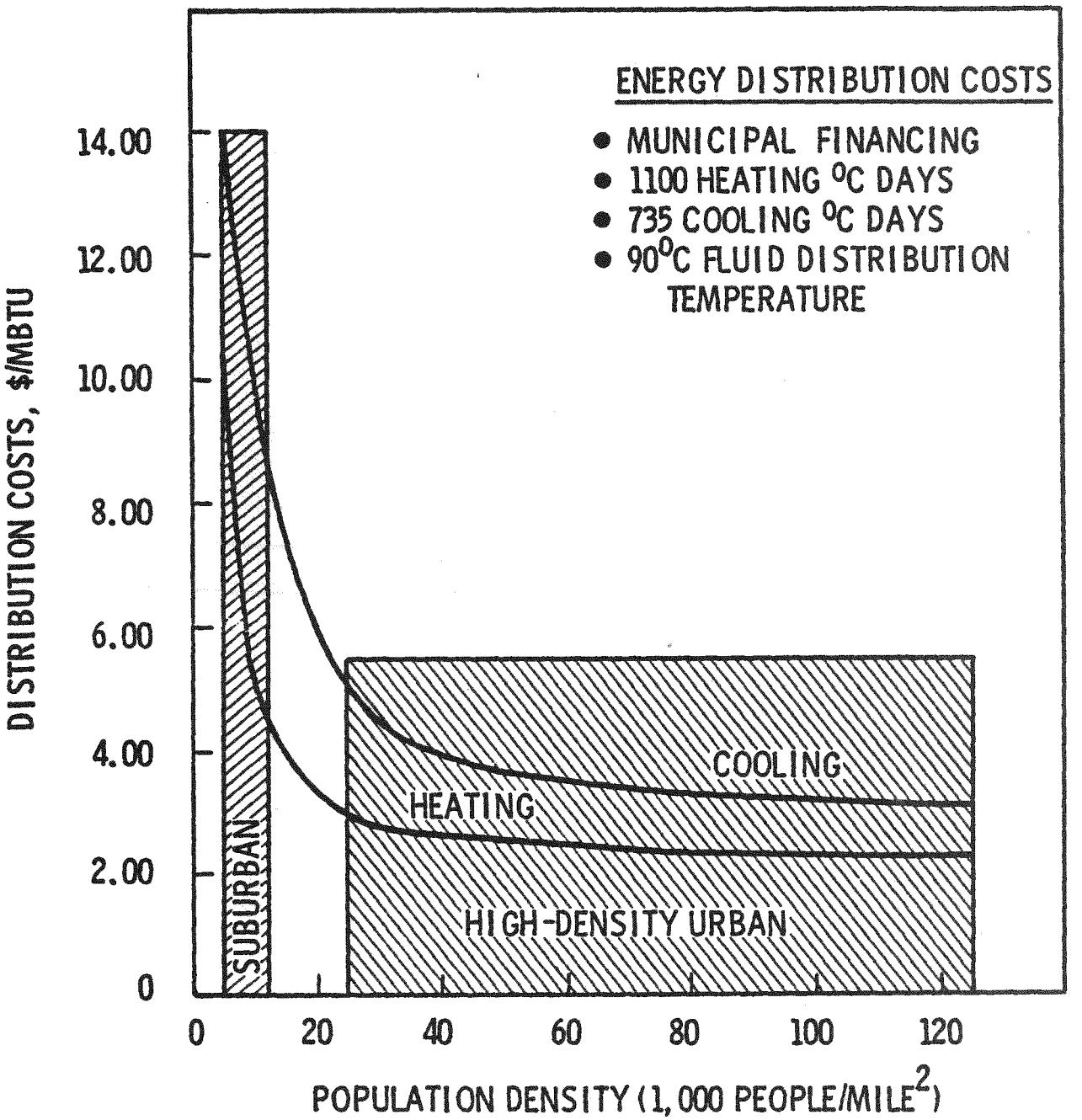


FIGURE D3-6. ENERGY DISTRIBUTION COSTS FOR RIVERSIDE

The total district heating costs, including production, transmission, and distribution, are summarized in Table D3-9. The total cost in urban areas ranges from $3.50 to $4.20 per million Btu, and the total cost in suburban areas ranges from $5.70 to $11.20 per million Btu. In the next section we will discuss comparative costs of conventional energy sources used for residential heating.

Opportunities exist for lowering the district heating costs by increasing the system load factor. This can be done by utilizing the district heating system for district cooling during the summer. It can also be done by supplying process heat for industrial demands. Both of these possibilities will be discussed later.

TABLE D3-9. DISTRICT HEATING COSTS, $/Million Btu

	Urban Areas	Suburban Areas
Production	0.75	0.75
Transmission	0.45	0.45
Distribution	2.30 - 3.00	4.50 - 10.00
TOTAL	3.50 - 4.20	5.70 - 11.20

Arrowhead Hot Springs is not the only geothermal resource with potential for space heating applications in Riverside. For instance, one of the nearby lower-temperature thermal springs identified by Waring[7] might be suitable. The French have a number of geothermal heating projects, mostly near Paris, which use heat pumps in conjunction with nearby low-temperature (50 to 80°C) geothermal resources.[25] These projects have demonstrated that it is definitely possible to utilize low temperature heat in district heating systems as long as the resource is very near the site of usage.

If a 90°C resource were found only one mile from Riverside, it would have space heating potential. The production costs would probably be higher than those quoted in Table D3-9 for Arrowhead (150°C resource) because the effective temperature range (ΔT) of utilization would be 60°C smaller (see Figures D3-3 and D3-4). However, if the transmission distance

were decreased from 15 miles to 1 mile, then the transmission costs would probably be lower even though the resource temperature was lower (see Figure D3-5). The distribution costs would be the same as shown in Table D3-9, because the fluid distribution temperature is 90°C in each case.

Comparative Costs of Conventional Energy Supplies. Space heating is commonly provided by natural gas, fuel oil, or electricity. Energy costs for residential heating are projected to increase in real dollars (Table D3-10), which will provide opportunities with time for the economic substitution of geothermal district heating. The energy costs include the energy utilization efficiency. The average energy utilization efficiencies for residential heating are: gas furnace, 69%; oil furnace, 66%; and electric furnace, 95%.[26] The residential electric heating costs reflect average prices in Riverside.

Comparison between Tables D3-9 and D3-10 shows that geothermal district heating is competitive now with heating oil and electricity in high-density urban areas. By 1985 geothermal should also be competitive with natural gas in urban areas. In suburban areas geothermal may be competitive by the year 2000.

Table D3-10. Energy Costs for Residential Heating (In 1977 Dollars) ($/MBtu of Space Heat Delivered in Riverside)[27]

	1977	1985	2000
Natural Gas	2.90	4.00	6.10
Heating Oil	4.15	4.55	6.05
Electric Furnace	10.25	13.40	17.90

(a) Includes utilization efficiency of fuel in the furnace.

Cost of Geothermal Space Cooling

The City of Riverside has about 735 cooling °C days per year. For this climate, and assuming a 90°C fluid distribution temperature, the distribution costs for space cooling are shown on Figure D3-6 as a function of population density. For suburban areas, the distribution cost ranges from $9 to $14 per million Btu. For high-density urban areas, the distribution cost ranges from $3.10 to $5 per million Btu.

The total district cooling costs are shown in Table D3-11. These costs should be compared with the costs of mechanical compression air conditioning, which uses electricity as the power source. Assuming an average coefficient of performance (Btu cooling/Btu input) of 2.0 for the compression cycle, the conventional energy costs for residential cooling are shown in Table D3-12. Comparison between Tables D3-11 and D3-12 shows that geothermal district cooling may be competitive by the year 2000 in urban areas, but it is far too expensive in suburban areas.

Table D3-11. District Cooling Costs, $/Million Btu

	Urban Areas	Suburban Areas
Production	2.25	2.25
Transmission	1.35	1.35
Distribution	3.10 - 5.00	9.00 - 14.00
TOTAL	6.70 - 8.60	12.60 - 17.60

Table D3-12. Energy Costs for Mechanical Compression Air Conditioning (In 1977 Dollars)($/MBtu of Space Cooling Delivered in Riverside)

1977	1985	2000
4.85	6.40	8.50

We have assumed that 50,000 Btu/hr of geothermal energy is required to deliver 3 tons (36,000 Btu/hr) of air conditioning using 90°C water,[28] which means that the absorption unit we modeled has a coefficient of performance of 0.72. We have also assumed that 1 ton of air conditioning is needed for every 600 ft^2 of floor area.

The production and transmission costs for district cooling (Table D3-11) are higher than the production and transmission costs for district heating (Table D3-9). There are several reasons for this difference in costs. First, the load factor on the cooling system is only 0.24 and the load factor on the heating system is 0.3. Production and transmission costs vary with the inverse of the load factor. Second, the ΔT of utilization for heating is about 30°C greater than the ΔT of utilization for cooling. Thus the geothermal fluid is used more efficiently for heating than for cooling, resulting in lower costs for the heating mode of operation. Third, the 0.72 coefficient of performance for the absorption cooling cycle means that each Btu of heat input results in only 0.72 Btu of cooling. This means that the cost per Btu utilized for cooling is greater than the cost per Btu supplied to the house by a factor of 1/0.72. The coefficient of performance for geothermal heating is assumed to be 1.

Distribution costs are strongly affected by climate; they vary inversely with the number of degree days. Since Riverside has 50% more heating degree days than cooling degree days, the heating distribution costs are lower than the cooling distribution costs.

We have specified a 90°C fluid distribution temperature for this study because Arkla data[28] is available on the coefficient of performance of units operating at this temperature. As discussed previously, there is an absorption cooling unit in New Zealand that utilizes 120°C water. The higher temperature would probably make the system more efficient; however, we do not know the C.O.P. at 120°C, so we cannot model the New Zealand unit accurately.

The Arkla absorption chiller, which operates with a 90°C hot water inlet temperature and an 85°C outlet temperature, was designed for solar use. Nevertheless, it is technically feasible to use geothermal energy instead of solar as the heat source. By using a closed-loop system (between 85°C and 90°C) and exchanging this water with the 150°C geothermal fluid, the geothermal ΔT of utilization is increased from 5°C (i.e., 90°C - 85°C) up to 65°C (i.e., 150°C - 85°C). Also, the required geothermal flowrate is lower by an order of magnitude if this closed-loop heat exchange scheme is used.

Combined District Heating and Cooling Costs

The total costs for the combination of district heating and district cooling are lower than either the heating costs alone (Table D3-9) or the cooling costs alone (Table D3-11). This is because the system load factor is increased to 0.54 when the system is used for both heating and cooling. Since the heating demand is greater than the cooling demand, the system should be sized for the heating mode. However, the year-around use of the system, once it has been designed, will effectively spread the total capital cost over a larger quantity of geothermal energy, resulting in a lower cost per Btu.

The total costs for space heating and space cooling are shown in Table D3-13. For suburban areas, the total cost ranges from about $4.80 to $7.30/MBtu. For high-density urban areas, the total cost ranges from $2.20 to $2.70/MBtu. The conventional energy costs for the combination of space heating and cooling are shown in Table D3-14. We have assumed here that conventional heating is done with natural gas and conventional cooling is done with electricity. We used weighted averages of the costs based on the annual energy consumption for heating and cooling. The combination of geothermal space heating and space cooling in Riverside is competitive now with conventional fuels in high-density urban areas and may be competitive in suburban areas by the year 2000.

Table D3-13. Total Costs for Geothermal Space Heating and Cooling in Riverside ($/Million Btu Utilized)

	Urban Areas	Suburban Areas
Production	0.50	0.50
Transmission	0.30	0.30
Distribution	1.40 - 1.90	4.00 - 6.50
TOTAL	2.20 - 2.70	4.80 - 7.30

Table D3-14. Conventional Energy Costs for Space Heating and Space Cooling in Riverside ($/Million Btu Utilized)

1977	1985	2000
3.60	4.85	6.95

Cost of Geothermal Process Heating

In addition to the costs for production, transmission, and disposal for geothermal process heating applications, some retrofitting costs may be incurred. These might include heat exchangers and other equipment for converting the conventional system to geothermal energy. For processes in which water is normally used to carry heat, few or no retrofitting costs are anticipated. For other processes, such as drying with hot air, the use of geothermal energy may require adding water-to-air heat exchangers. The economic incentive for converting to geothermal energy will depend on both the cost of the energy supply and the in-plant retrofitting costs.

The process itself will have a significant impact on the costs of the geothermal energy supply through the size of the energy demand, the maximum temperature of utilization, the effective temperature range (ΔT) of utilization, and the impacts of seasonal factors and plant operating schedule on the load factor. These factors have already been treated for the production, transmission, and disposal costs.

For district heating applications, the geothermal fluid is rejected at 38°C. For process heating applications, the reject temperature is 100°C. The production and transmission costs increase as the minimum temperature of utilization increases because less of the available energy in the fluid is being utilized.

At this time, we don't have any data on industrial process heat demands or process water temperatures for the Riverside area. However, we can estimate the cost of geothermal process heating from previous general analyses.(2)

The minimum cost of using geothermal energy from Arrowhead Hot Springs to supply process heat to industries in Riverside is estimated to be between $1.50 and $2.00/MBtu. Thus, under favorable conditions, geothermal energy has the potential to be competitive with conventional fuels for process heating. These estimates include only the cost of delivering the geothermal energy to the plant site. They assume a load factor of 100% (i.e., a constant demand throughout the year) and a large demand in a concentrated area.

Process heating is currently provided by natural gas and fuel oil. However, the availability of these fuels, particularly natural gas, for industrial process heat is subject to curtailment. In the future, coal should provide the marginal cost competition for process heating. Combining the capital cost of a furnace and boiler with the mining and transportation costs and the combustion efficiency, process heat from coal should cost $2 to $3/MBtu in 1985 (in 1977 dollars).(2) These costs are based on extrapolation of the current costs of coal production, transportation, and utilization. The underlying assumption is that coal supplies are abundant and, therefore, coal prices will be relatively insensitive to other energy prices and will be determined primarily by the costs of production.

Methodology and Assumptions

The basis for our geothermal energy cost analysis is the unit cost of energy which will recover all the costs of production - capital investment, operating expenses, taxes, and the specified rates of return on capital. This unit cost of energy can be directly compared with the costs for conventional energy sources. Our focus is on the economics of substituting geothermal energy, based on production costs, for conventional energy sources.

The calculation of the unit cost of energy is based on life-cycle costing and discounted-cash-flow analysis. The GEOCITY model is used for these calculations. The unit cost of energy is derived from the following expression:

$$C = \frac{\sum_{n=1,ny} PW_n \cdot (CAP_n + EXP_n + TAX_n)}{\sum_{n=1,ny} PW_n \cdot ENERGY_n}$$

where

C = unit cost of energy

ny = useful life, years

CAP = capital cost

EXP = annual operating expenses

TAX = annual taxes

PW = present worth factor

ENERGY = annual energy production

n = year

The geothermal energy is assumed to be provided by firms having the capitalization and financial characteristics shown in Table D3-15. The firms would typically be a large oil company operating the reservoir and a municipal utility operating the transmission and distribution system. Assumptions affecting taxes include expensing intangible drilling costs and accelerated (sum-of-the-years' digits) depreciation. All cost estimates are in 1977 dollars unless otherwise stated.

Table D3-15. Financing and Tax Assumptions

	Reservoir (%)	Transmission and Distribution System (%)
Capitalization		
Debt	42	100
Equity	58	0
Bond Interest Rate	8	6
Return on Equity	15	-
Federal Income Tax Rate	48	0
State Income Tax Rate	7	0
Property Tax Rate	2.5	0
Royalty Payment	10	-
Revenue Tax Rate	--	4

Combined Applications of Geothermal Resources with Other Energy Resources

Although it would be technically feasible to combine geothermal energy with other energy resources, both for electricity generation and non-electric uses, combined applications, in general, appear to result in higher costs and, in some instances, less energy-efficient uses of the resources. Under some conditions, as explained later, a slight economic incentive might be achieved with a combined plant but, in general, each energy source would be most efficiently used in facilities designed for that resource. That is, for a specific application, if geothermal energy is the economic choice, then supplementing with an alternative energy source will probably lead to a more costly system. If the alternative energy source is the economic choice, supplementing with geothermal energy will probably lead to a more costly system. Further, the use of high-Btu fuels to supplement a geothermal system will generally be less efficient thermodynamically than their use separately in a more efficient, high-temperature plant. In principle, combined applications would require additional separate facilities to handle each energy source without increasing capacity; therefore, the utilization of capital tends to be inefficient. As shown previously, the initial capital investment costs are the major costs in geothermal energy utilization.

There might be a role for combined plants based on energy-supply reliability and lower-risk geothermal development criteria. An important constraint to geothermal energy development is the time required to drill wells and prove the energy supply. Currently, this requires prolonged well testing periods and methodical reservoir development prior to construction of the power plant. However, if the first plant at a geothermal reservoir was based on a combined energy supply, a larger plant, not entirely dependent on the geothermal energy, could be built sooner. This might accelerate initial and subsequent reservoir development and power plant construction. As the geothermal reservoir capacity was expanded, the supplemental energy source could be phased out and held in reserve to begin another cycle of power plant

expansion. An economic penalty would derive from the low utilization rate of the supplemental energy capacity.

The potential uses of geothermal energy in combined applications are similar for both electrical and nonelectric uses: (1) geothermal could provide a reserve or backup capacity, (2) geothermal could provide supplemental energy, or (3) geothermal could provide the base energy source and be supplemented by the other energy source.

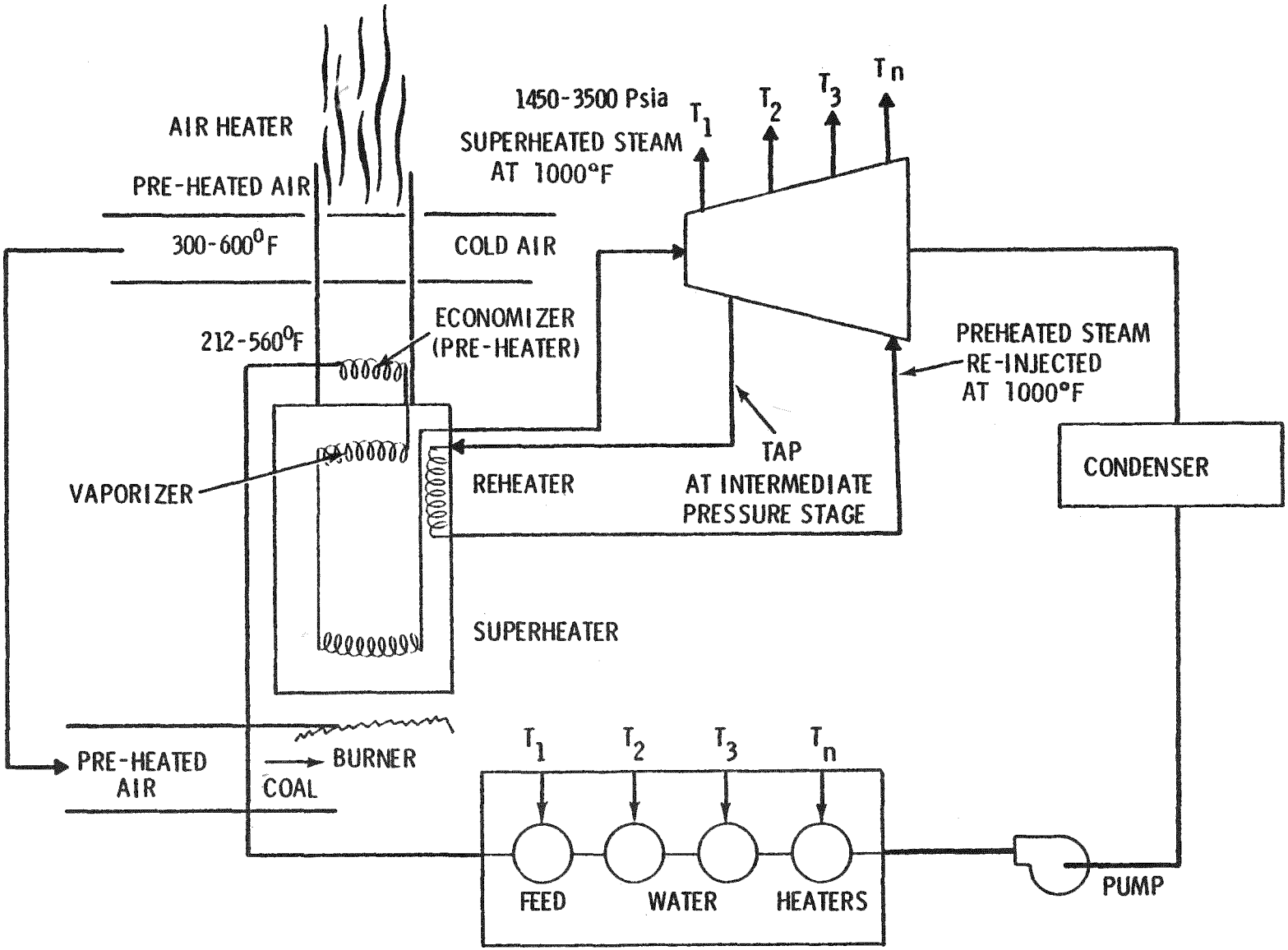
Combined Systems for Electrical Applications

Reserve or Backup Systems. Geothermal energy is capable of supplying reserve or backup capacity. The technical, economic, and resource potential for generating electricity for Riverside from geothermal energy was shown in preceding sections to be promising. However, the nature of geothermal power generation is that the preponderance of costs are incurred with initial investment. Thus, once the capacity is in place, continuing costs are low, and there would be little incentive to allow the plant to be idle. Therefore, a stiff economic penalty, in the form of low productivity of capital, would be associated with installing a geothermal backup system.

Combined Plants. For purposes of discussion, we will assume combined geothermal-coal plants. The coal will serve as a surrogate fuel for other alternative energy sources such as methane generated from solid wastes, garbage incineration, a high-temperature solar furnace, etc.

We will consider two applications of combined coal-geothermal plants: (1) supplementing a modern coal plant with geothermal energy and (2) supplementing a geothermal power plant with coal (or other high-Btu fuel).

Modern Coal Plant. A schematic diagram of a modern coal plant is shown in Figure D3-7. These plants operate at a high heat rate of about 9,000 Btu/kw-hr, or about 38% thermal-to-electric conversion efficiency. The thermal energy



T_n = TURBINE EXTRACTION POINTS WHERE STEAM/CONDENSATE (OFF-BLADES) IS TAKEN TO HEAT FEED WATER

FIGURE D3-7. POWER CYCLE FOR COAL PLANT

in geothermal fluids could provide energy to the feedwater heaters and could provide part or all of the energy to the economizers (preheaters).

In this plant, the enthalpy of the working fluid increases from 90 Btu/lb at the condenser outlet to 1,450 Btu/lb at the turbine inlets, an increase of 1,360 Btu/lb. If this increase is supplied entirely by coal, at a cost of $1.00/million Btu, then the cost of the energy supply is 9 mills/kwhr The capital cost of the power plant and other operating costs would add about 10 mills/kwhr (at 1977 prices), making the total cost of power about 19 mills/kwhr.

If a high-enthalpy geothermal fluid, say 590 Btu/lb, is used for preheating, then about 500 Btu/lb (590 to 90) will be available for preheating. Thus geothermal could supply, in this instance, 37% of the thermal energy. If the plant could be redesigned to achieve the same heat rate, the coal consumption could be reduced by the same 37%. When geothermal energy costs less than coal, then the cost of energy would be reduced. If the total plant capital costs and operating costs were not increased by using geothermal, then the total power cost would be decreased. For instance, if the geothermal fluid were free, the maximum savings (again assuming coal at $1/million Btu) would be 3.2 mills/kwhr or about 15% of the total power cost. If the fluid cost the same as the coal, there would be no savings. If the fluid cost $0.50/million Btu, a reasonable estimate, then the savings would be 1.6 mills/kwhr or about 8%.

There are a lot of favorable "if" assumptions in the foregoing analysis which, if resolved unfavorably, could easily turn this small economic advantage into a disadvantage. Besides, a 590 Btu/lb geothermal fluid, which would have a temperature of about 600°F, would be economically competitive with coal in a geothermal plant by itself. Fluids of this temperature have high silica concentrations; this might lead to excessive scaling and inhibit their use in heat exchangers in a coal-fired plant.

The situation is less attractive for a low-enthalpy geothermal fluid. For a fluid with an enthalpy of 290 Btu/lb, only 200 Btu/lb would be available for preheating. Under the same assumptions as above, this

fluid could replace only 15% of the coal. The savings (assuming $0.50/million Btu for the fluid) would be 0.7 mills/kwhr or about 4% of the total power cost. This savings could be easily offset by increases in plant capital cost for the fluid-handling system or decreases in the efficiency of coal utilization.

In a study[a] for the Energy Research and Development Administration, the City of Burbank reached similar conclusions. For three California sites, East Mesa, Coso, and Long Valley, a hybrid coal-geothermal plant would produce higher-cost electric power delivered in California than a coal-only plant located at Roosevelt Hot Springs, Utah. According to the study, a hybrid plant at Roosevelt, a high-enthalpy geothermal resource, would produce power at about a 10% savings over a coal-only plant located there. Whether there would be any savings over a coal-only plant located at a site more favorable for coal or a geothermal-only plant located at Roosevelt was not reported.

In summary, using geothermal fluid to supplement coal (or other high-Btu fuels) in a modern power plant could achieve up to a 35% reduction in coal consumption. On paper, a small economic advantage looks possible. However, this advantage, which is based on favorable assumptions, would diminish and probably disappear under actual conditions. Geothermal-only power plants, based on low-salinity and high-enthalpy fluids, would probably result in lower power costs than coal-only plants in most situations.

Geothermal Plants. If geothermal fluids are superheated with coal, then the coal would be used less efficiently than in a coal plant. (If the fluids are not heated to the same temperature and pressure as a modern coal plant, then the heat rates would be higher—the thermal conversion efficiency would be lower—than in a coal-only plant.) For example, at The Geysers, a geothermal steam plant, the heat rate is 21,000 Btu/kwhr. Even heating the geothermal fluid to duplicate the conditions of a modern coal plant results in less efficiency because the heat in the return condensate is

(a) City of Burbank, Site Specific Analysis of Hybrid Geothermal-Fossil Power Plants, June 1977.

lost in a once-through plant. In addition, noncondensible gases and dissolved solids in the fluid could lead to other inefficiencies and higher costs.

Supplementing an expensive geothermal energy supply with energy from lower cost coal could decrease the cost of geothermal power, but probably not to the point of being competitive with the coal-only plant. In most instances, the greatest power production and lowest average cost would probably result from two separate plants—one coal and one geothermal. This same conclusion would probably apply, generically, to other combined applications.

Combined Nonelectrical Applications

Systems

Combined systems for nonelectric applications also do not appear promising from an economic standpoint, principally because of the capital-intensive nature of geothermal developments and capital-related economies of scale.

Reserve or Backup Systems. Geothermal energy is capable of supplying reserve energy or a backup system for nonelectric applications. However, as with electrical uses, the preponderance of costs are incurred with the initial investment and the continuing costs are low. Thus, there would be no economic incentive to install and not use a geothermal backup system for nonelectric applications.

Combined Systems. Combined systems for nonelectrical uses would require separate facilities for the production and transmission of both energy forms. Two types of inefficiency might result from the combined application. First, if excess capacity is required in either system, the use of capital will be inefficient. Second, if the capacity for each energy source is decreased proportionately in size to avoid the foregoing problem, then diseconomies of scale will be encountered in both systems, again resulting in an inefficient use of capital. To illustrate the economies of scale in fluid transmission, the cost of a water transmission pipe varies approximately with the diameter to the first power, while the energy carrying capacity varies with

the square of the diameter. The economies of scale in developing the geothermal energy supply, although not large compared to those in transmission, also occur in well drilling and in maximizing the utilization of individual wells. Similar economies of scale also apply to the production and transmission of the nongeothermal energy source.

The Environment

For remote electric generation sites, and for hot-water sites in general, it would appear that the primary environmental concerns are (1) land use, (2) disposal of geothermal fluids, (3) other water pollution problems, and (4) subsidence of seismic activities.[32]

Air quality concerns may not be as important an issue with the use of hot-water resources as they are for geothermal steam at The Geysers, since many hot-water systems are apt to be closed loops from extraction through reinjection of the geothermal fluids. Some systems may, however, involve air emissions problems, particularly with hydrogen sulfide (H_2S) gas. Land use activity problems are quite site specific. In general, there are no prohibitive barriers for using land for drilling geothermal wells or constructing electric power plants or related facilities using geothermal energy, although there may be compelling environmental reasons to deny such use at a given site.

Disposal of geothermal wastes, on the other hand, is apt to be a major problem anywhere in Southern California. The region is generally short of water, with a strong demand for water for agricultural purposes as well as for human use. It is very likely, therefore, that proposals to dispose of geothermal fluids will receive intense scrutiny from the appropriate regional Water Resources Control Board, which grants permits for activities which do or might affect the quality of surface water. Moreover, there is apt to be conflict over the provision of groundwater for power plant cooling and other purposes, should it be needed. There does not appear to be much unallocated water available in Southern California as a whole and, therefore, a power plant developer is likely to be faced with the prospect of either buying an existing allocation or developing an alternative source of water.

Depending upon the geological characteristics of a given geothermal resource, there may be subsidence of the surface as geothermal fluids are pumped out. In Imperial County, where both the Brawley and Heber resources are located, surface subsidence could be a major problem because of disruption of irrigation networks and other facilities. The current preferred solution to subsidence problems from geothermal development in that area is to reinject the geothermal fluids into the reservoirs from which they came. This solution combines solutions to both the geothermal waste disposal and subsidence problems, while avoiding the need to use more valuable fluids (e.g., surface water) for the purpose of preventing subsidence.

It is too early to say with any confidence whether reinjection will prove successful generally, or in the geothermal resources most likely to be of interest to Riverside. There have been mixed results from reinjection tests at various hot-water geothermal sites: few problems at Heber, but some substantial ones at Brawley and other sites as the minerals in the fluid solidify and clog piping. To date, there is no firm evidence of subsidence in the Imperial Valley as a result of geothermal development, although it must be noted that activity there has been quite limited.

There may also be water allocation problems. Water may be necessary for power plant cooling or as an injection fluid to prevent subsidence. There is not much, if any, unallocated water in Southern California, therefore, it will be necessary to either purchase water or develop new wells to meet such needs. There is some possibility that unpotable well water in the Imperial Valley might be readily available for geothermal uses. However, it is likely that in any water-scarce area, concerns of other water users will lead to close regulatory scrutiny throughout the development process.

In the most probable case, that a geothermal developer would contract to supply hot water to a power plant which Riverside would construct and operate, many of these environmental problems would be for the developer to resolve. It is also likely that by the time any Riverside plant were constructed, enough would be known about the characteristics of the specific resources that any environmental problems would have been resolved. There is already substantial activity at both Brawley and Heber and considerable interest in the Coso resource.

There are also environmental issues involved for nonelectric geothermal applications. The development of Arrowhead Hot Springs for space heating and cooling would require the drilling of wells, installation of pipes connecting those wells, and construction of a pipeline leading some 15 miles through national forest land to Riverside itself. Once in Riverside, a distribution system to take the hot water to the ultimate users would need to be constructed.

There are land use questions involved in siting both the wells and the transmission facilities, although it is difficult to speculate on the environmental problems involved in these land use questions at this time. As a general matter, it would not appear that a transmission system through a national forest would be so obnoxious from an environmental point of view as to be a serious constraint on the resource development. It may, of course, be the case that a particular plan for such a transmission facility could be unacceptable, but such a judgment is impossible to make in advance of specific plans.

As with electrical application of geothermal energy, there are two potential environmental problems that can be identified now: waste disposal and subsidence. A solution to these problems, as with electricity production, may be to reinject into the geothermal formation. Since it would appear to be uneconomic to pipe the fluid back up the mountain, reinjection of the fluid at the reservoir would require a nearby potable water supply for heat transfer. If subsidence is not a problem, then it should be possible to reinject the fluid, if necessary, at a site near Riverside. It is not possible to say at this time that fluid reinjection would be necessary for the particular resource at Arrowhead Hot Springs.

The alternatives to reinjection are either to do notning or to find some other fluid to pump into the formation. It is too soon to say whether doing nothing would be acceptable at Arrowhead, although alternative disposal of the geothermal fluid, unless it is potable, is very likely to create problems. It would appear that alternative injection fluids would be hard to come by. Surface appropriations are already over-allocated,[(a)] and, therefore, finding water for injection purposes is apt to be difficult. In any event, it seems likely that a proposal to use groundwater to prevent subsidence is apt to be strongly resisted in any water-short area, particularly Southern California.

(a) Discussion with Dave Anderson, California Energy Resources Conservation and Development Commission, November, 1977.

Plans for Developing Geothermal Energy

Plan for Development of Low-Cost Electrical Generating Capacity

If cost is the most important criterion, Riverside should await further information on the characteristics and prospects for the Salton Sea, Brawley, and Coso resources. These resources have the potential to generate electricity at costs which are competitive with nuclear or coal plants. Over the next five years, definitive information about these resources should become available which will resolve current uncertainties surrounding their technical and economic viability. In addition, technical developments during this period, may improve the competitiveness of the Heber and East Mesa resources. Under this plan, the earliest geothermal capacity would be on line in 8 to 10 years with about 15 years required to construct sufficient capacity to meet all of Riverside's needs.

This longer schedule allows more time to resolve the same institutional constraints which were discussed under the near-term development plan. This longer timeframe would also provide Riverside a realistic opportunity to assume the role of the geothermal developer. If the developer role is selected, Riverside should seek to acquire leases or lease options as soon as possible, since the prices and availability of such leases should be strongly affected by the expected favorable determination of commercial viability of the higher-temperature resources.

Plan for Nonelectric Applications

Arrowhead Hot Springs is the most promising resource for nonelectric applications, but, again, too little is known of the resource to proceed with development. This resource, however, is much more promising for non-electric uses than for electricity generation. Little technical innovation will be required to utilize the resource for nonelectric uses, and further, it is expected that geothermal energy will be competitive with conventional energy sources for district heating and cooling and perhaps process heat. Riverside, under this plan, should begin exploration and assessment work at Arrowhead or undertake systematic exploration and/or wildcatting for other

geothermal resources nearby. The chances of successful wildcatting are much greater for nonelectric uses than for electric because lower temperature resources can be used efficiently and because of the greater sensitivity of fluid transmission costs to distance.

Since work under this plan would begin with resource exploration and assessment, at least 10 years would be required before widespread non-electric uses of geothermal energy in Riverside would be feasible. Nonelectric uses face similar institutional and environmental constraints as electrical uses; resolution of these institutional issues should be undertaken concurrently with the resource exploration and assessment program.

The constraints on nonelectric applications may be considerably less severe. While Southern California Gas (SCG) may feel the same concern with loss of market as SCE, the probability of opposition to Riverside's developing its own resources to replace natural gas may be lower. Loss of the Riverside market may, for example, not particularly bother SCG if natural gas is in short supply. On the other hand, loss of market and provisions to amoritize the existing gas distribution system may be major issues. Gas could be plentiful but expensive as, for instance, with imported LNG or coal gasification; this could result in strong opposition to Riverside's quest for independence. Such opposition is, however, less likely to be effective, since Riverside is not itself in the gas business and is, therefore, not dependent upon gas company cooperation in order to serve its own customers, as contrasted with the case with SCE.

Before proceeding to construct a geothermal municipal heating system, Riverside should establish the adequacy of the geothermal resource for this purpose and confirm the economic feasibility of space heating or cooling with that resource. Economic feasibility of a municipal geothermal system will depend upon a large concentrated market and high levels of participation by all potential customers. Several means are available for constructing and operating such a geothermal system. Two possibilities include the establishment of a municipal department to provide this service and the creation of a special district for this purpose.

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D4. NUCLEAR ENERGY

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D4. NUCLEAR ENERGY

Introduction

A substantial effort has been expended in this country and other parts of the world to develop nuclear energy as a viable energy source. Almost all this effort has been directed to its use as a fuel source in central steam electric power plants for generating electricity. Despite the massive effort to develop nuclear technology over a number of years, nuclear energy only recently surpassed wood in net contribution to U.S. energy needs. In 1975, nuclear energy accounted for only about 2.4 percent of net U.S. energy supply.(1)

The only nuclear technology in commercial use today is based on fission of a relatively rare uranium isotope (U^{235}) which accounts for less than 1 percent of natural uranium ore. Efforts have been under way for some time to develop the so-called breeder reactor which uses more plentiful U^{238} and produces fissionable Pu^{239}. The breeder considerably expands available nuclear fuel resources and greatly enhances the future of nuclear energy as an energy source for the U.S.

Both the conventional water-moderated fission reactor and the breeder reactor have faced substantial technological and environmental problems in their implementation. Most of the problems center around uncertainty regarding the safety and environmental impact of the nuclear plant itself and the environmental considerations associated with disposal of radiological waste. The recent California decision to cancel plans for the controversial Sundesert Nuclear Power Plant near Blythe, California, is indicative of the uncertainty associated with nuclear technology and its use. This decision is symbolic of the problems facing implementation of nuclear technology in California in the near future, given the existing political climate.

Nuclear Energy as a Community Energy Source

Applications

The most common means of utilizing nuclear energy in the U.S. is in large base load power plants. It is possible for Riverside to share in the ownership and costs of large nuclear plants with other municipalities or with the utilities. These plants would be too large for one municipality such as Riverside to own and manage but when Riverside's resources are pooled with those of other communities, economy of scale can be realized and the cost of power shared by the participants is considerably less than the average wholesale rates charged by the utilities. The power is transmitted over utility lines and, in the case of Riverside, Southern California Edison Company grants a capacity credit of 80 percent of Riverside's share of ownership in such plants. Riverside is currently considering participation in three large nuclear plants as described below[2,3].

San Onofie	- Two new 1100 MW units to be located at an existing site of one 450 MW unit situated at Camp Pendelton Marine Base, south of San Clemente. Riverside's share of ownership is 1.8 percent or 40 MW. The the first of the two units is to be operational in 1981.
Palo Verde	- Two new 1270 MW units. Riverside's share of ownership is 1 percent of the first unit, which is expected to be operational in 1988.
Intermountain Power Project	- Four 750 MW units located in Wayne County, Utah. Riverside's share of ownership is 6 percent or a total capacity of 176 MW. the first unit is expected to be operational in 1987.

The projects, their background, and Riverside's participation in them are described in detail in references 2-4.

Although most efforts have centered around applying nuclear technology to large electric generating plants, efforts have also been made to develop small-scale nuclear systems for supplying heating, cooling, and electric needs at the community level. Much of this interest has evolved from the Scandinavian and European countries. In Stockholm, Sweden, a nuclear reactor supplied steam for heating and electricity production from 1964 to 1974. It was discontinued due to poor economics of such a small-scale plant.(3) Reportedly, in the Soviet Union's province of Bilibino, a small nuclear reactor is currently in operation supplying district heating.(5) Decisions to proceed with nuclear-based district heating system are currently pending in Czechoslovakia, Denmark, West Germany, and Finland.(5)

The French are currently developing a series of reactors in three size ranges for use in district heating type systems. In the larger size ranges, from 420 to 1100 MW thermal, pressurized water reactors would be used. The smaller sizes, down to about 150 MW thermal, would use pool-type reactors. Prototypes are currently in operation in France at about 120 MW thermal.(5)

The Finns and Swedes recently developed a concept for an underground nuclear reactor for community use. This reactor, called SECURE (Safe Environmentally Clean Urban Reactor), would be designed to operate within the community with the maximum of safety and minimum environmental impact. The nominal reactor size is about 200 MW thermal, and would occupy an underground cavern of about 84,000 m^3 with surface structures occupying an additional 28,000 m^3. Specific safety features of the reactor include the following: it is underground, thus minimizing radiation and safety problems; it has a walk-away accident system, which allows shutdown of the plant automatically under upset conditions without operator attention; and it features a low power density, and hence low fission product release.(6)

In the U.S., the Babcock & Wilcox Company is currently planning to alter the steam system of an 800-MW nuclear plant to supply Dow Chemical Corporation. B&W is also evaluating the possibilities of using a 100-MW marine reactor for steam and power production in communities.(5) Also,

General Electric Company is evaluating the possibility of several nuclear reactor types being modified for use in district heating systems for steam and electricity generation. One of these units in Wyodak, Wyoming, is a 330-MW reactor scheduled to be operational sometime during 1978.[2]

Environmental Considerations

The use of nuclear energy involves quite different environmental considerations than the use of fissil fuels such as coal, refuse, or biomass. Unlike fossil fuels, nuclear energy emits negligible particulates, sulfur oxides, nitrogen oxides, hydrocarbons, carbon monoxide, or carbon dioxide. As mentioned earlier, the principal environmental concerns revolve around plant safety and radiological emissions, as well as disposal of radiological waste from spent fuel.

Much effort is currently being expended throughout the United States to develop acceptable solutions to these environmental problems. The acceptability of these environmental impacts is still, at present, argumentative in nature. Until some concensus is reached regarding the environmental acceptability of nuclear power, its future is very uncertain.

Options for Riverside

The following are some basic conclusions that resulted from consideration of nuclear energy for supplying Riverside's energy needs.

- The utilization of nuclear fuel as an energy resource is not new. However, the extent of nuclear reserves depends largely on development of new technology, such as the breeder reactor. Therefore, long-term decisions to become reliant on nuclear energy depend heavily on the development of this technology. At this point it appears that this technology will be delayed indefinitely.
- The use of nuclear energy in community-size systems at the community level is not new. Some reactors have been used in Europe in the past and commercial-size reactors for these applications are currently being developed both in this country and in Europe.

- According to one recent study [4], the use of nuclear heating reactors for supplying district heating systems is cost competitive with oil-based fuels at about $2/million Btu. Therefore, nuclear based district heating systems can probably compete with more conventional systems based on coal or oil but....
- The economic competitiveness of nuclear reactors to supply district heating systems in this country is highly dependent on regulatory and licensing requirements. Given the current licensing and regulatory restriction on nuclear utility plants and subsequent long lead times (at least 10 years) it is doubtful that nuclear-based district heating systems would be competitive with more conventional systems.
- The most viable nuclear option for Riverside at the present time is participation in remote power generating facilities.
- The environmental attributes and lack of air emissions from nuclear plants makes nuclear technology well suited for use in Southern California. However, the safety and radiation problems associated with nuclear plants may be offsetting. Until these risks are better known and accepted by the public, implementation of nuclear technology - especially in community systems - probably will not occur.

As a result of the above conclusions, nuclear technology was not considered as a viable alternative energy resource for Riverside within the time frame of this study.

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D5. SOLID WASTE AND BIOMASS AS ENERGY SOURCES

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D5. SOLID WASTE AND BIOMASS AS ENERGY SOURCES

Introduction

As the U.S. population becomes more densely congregated in major urban centers, greater emphasis has been placed on finding alternatives to landfill techniques used for municipal refuse disposal. Refuse, which contains a number of hydrocarbon compounds, is potentially usable as an energy source. Refuse compositions vary substantially throughout the U.S., but on the average refuse has about 6200 Btu/lb heating value on a dry basis and about 5000 Btu/lb on a wet basis with a moisture content of 20 percent.(1)

A recent study of landfill alternatives for the Riverside community examined the quantities of refuse available.(2) Table D5. summarizes the daily quantities available at the preferred new Beltown landfill site in West Riverside. The Belltown site is located just northwest of the existing West Riverside landfill which is nearing completion.

TABLE D5-1. REFUSE QUANTITIES AVAILABLE IN RIVERSIDE AREA

	Daily Quantity, tons/day	Annual Quantity, tons (5-day weeks)
Riverside	290	75400
West Riverside	170	44200
Highgrove	90	23400
Badlands	5	1300
TOTAL	555	144300

As can be seen from Table D5-1, the quantity of refuse available for energy recovery is about 555 tons/day or 144,300 tons/year assuming 5 days per week collection practice. Assuming 5,000 Btu/lb (10×10^6 Btu/ton) this amounts to 1.44×10^{12} Btu per year, which is approximately 21 percent of Riverside's annual natural gas consumption.

Two generic types of processes for energy recovery from refuse can be defined: (1) those based on combustion using water-tube wall incinerators and (2) those based on conversion of refuse to a gaseous or liquid fuel through gasification or pyrolysis.

Combustion in Water-Tube Walled Refuse-to-Steam Plants

Of all the refuse-to-energy systems which are now employed, the most highly developed system is the water-tube-walled incinerator, which is now operating in hundreds of plants in Europe, Japan, and North and South America. This type of incinerator is referred to as "water-walled" because, following fossil-fuel burning practice, the combustion occurs in large chambers, the walls of which are lined with vertical tubes in which the boiler water is heated.

These successful systems have evolved from the influence of three complementary forces in modern society:

First - The need to conserve landfill areas by incinerating the waste to the smallest disposable volume

Second - The need to reduce the pollution effects of fly ash from older, refractory-walled incinerators

Third - The need to conserve the heat value in combustible waste.

The second factor, the pollution control, is particularly dependent upon heat recovery because in the very process of extraction of heat from the hot, dusty gases, the cooled gases are reduced in volume and this greatly reduces the size and cost of pollution-control equipment needed. Thus, the conservation of heat by means of the water-tube-walled furnaces assists in solving the pollution problem.

Before the advent of the water-tube-walled furnace in fossil-fuel power generation, numerous attempts were made to recover useful energy from the combustion of community wastes. One of the earliest on

record was in 1905 on lower Manhattan Island in New York City. Here, the Delancey Street incinerator, burning approximately 100 tons of refuse per day, utilized a waste-heat boiler following the incinerator for steam-electric generation to provide lighting for the nearby Williamsburg bridge over the East River. This plant was described briefly in the Saturday Evening Post, December 15, 1906, which also referred to a "less than successful" Bradford plant in London.

Over the years, there have been many other small examples of heat recovery from incineration. Until the dust emission regulations became too severe, many downtown buildings in Atlanta, Georgia, were steam heated from municipal incinerators. Then in the '50's the evolution of the large water-tube walled, power generating incinerator units began in Switzerland and Germany. The objective was to obtain energy from wastes, but an important incentive behind the water-wall development was cooling of the very hot incinerator gases to a temperature level at which a high-efficiency dust removal apparatus, usually an electrostatic precipitator, could operate and survive.

Refuse as a Fuel. Although refuse or waste is today being fired as fuel in hundreds of steam generating plants all over the world, community refuse has important deleterious characteristics that make it undesirable as a fuel:

(1) Nonuniform composition, particularly variable moisture content
(2) Nonuniform size of refuse
(3) Contaminants such as chlorine and fine ash which may foul and corrode the boiler and cause air pollution.

Some attempts have been made to minimize some of these undesirable characteristics by shredding, classifying, cleaning and drying prior to firing[3], but these efforts to date have not produced significant practical results. Thus, most plants still burn the

raw refuse, as-received, without preparation. The success of these raw refuse-burning plants is attributable to a number of ingenious stokers or grates on which the refuse is burned, which have been developed over the years to cope with this highly heterogeneous fuel. A basic principle common to all of these stokers is their provision for gentle agitation of the fuel mass as it is moved slowly along the bottom of the furnace. The agitation is provided by a combination of grate motion and slope of the grate.

In each design, there is provision for two actions:

(1) Movement of the refuse through the combustion region

(2) Mixing of the nonuniform mass by steady or intermittent tumbling, rolling, or other motion imparted by the grate mechanism.

Gaseous Combustion and Heat Absorption in Water-Tube Walls. The primary combustion air is usually forced uniformly through many fine apertures in the grate. As it flows upward through the heterogeneous bed of refuse (of varying depths up to 1 meter), the air flow as diverted order to channel through the burning mass. As a consequence, the flames and burning gases rising into a water-tube-wall furnace are usually very nonuniform and poorly mixed. Secondary or overfire air jets are then employed to mix the nonuniform gases. This is important for two reasons:

(1) Overfire air jets supply and mix sufficient combustion air with the burning gases to prevent smoke formation.[4]

(2) The occurrence of reduced gas conditions in the furnace is minimized. This helps to reduce the threat of corrosion on the water-walled tubes.

Most water-tube walls near the grate are now routinely covered with silicon carbide, alumina, or other protective coverings to reduce the corrosion and to discourage buildup of slag on the wall.[5]

Above the protected area, the water-tube wall is usually formed of closely spaced vertical water tubes, each connected to the neighboring tube by a welded fin of steel. This construction thus comprises the furnace wall. The outside of this assembly of water tubes is covered by lightweight insulation and a metal casing to conserve heating and to prevent gas or air leakage in or out of the furnace.

Boiler Passes. The gases leaving the top of the furnace have given up approximately half of their heat content to the water walls by radiation and convection. They then usually enter a second pass or a superheater section where the saturated steam from the rest of the boiler is superheated to the temperature desired. In a few cases auxiliary burners firing oil or pulverized coal are fired into the main furnace below the superheaters to supplement the heat released by the burning refuse.

Because of the still relatively high temperature of the gases entering the superheater passes, 1800 F to 2000 F (980 C to 1090 C), the superheater tubes are the most vulnerable to corrosive attack by the chlorides and alkali pyrosulfates in the gases.[5,6] If the steam temperature is below approximately 600 F (320 C) experience and extensive research indicate that corrosion is not rapid. Above 320 C, however, the higher the steam and tube temperature rise, the more severe corrosion attack is likely to be.

From the superheater, the gradually cooling gases pass through the boiler convection passes and economizer and on to the electrostatic precipitator.

The efficiency of heat recovery of typical water-tube walled boiler furnaces is in the range of 60 to 80 percent. This is less than for similar fossil-fuel-heated boilers because of the higher moisture loss from high-moisture refuse and the need for enough excess air to avoid the occurrence of smoke and unburned gases.

Pollution Control. While older refractory incinerators were usually considered nuisances because of annoying fly-ash discharge, water-tube wall units are usually equipped with electrostatic precipitators that typically capture more than 95 percent of the fly ash in the gases. In Germany beginning in August, 1974, new plants were required to control chloride emission to not more than 100 mg/Nm^3 at 11 percent O_2 and fluorides to 5 mg/Nm^3. Where these limits must be attained, flue gas scrubbers will be required. This will entail the problems of handling and disposing of highly corrosive scrubbing liquids as well as reheating the wet, corrosive gases to insure their buoyancy when released from the chimney.

Residue. The modern agitating grates described earlier provide excellent burn out of raw community refuse; hence the residue falling off the end of the grate is inert and very suitable for landfill. However, it also usually contains substantial quantities of ferrous metals which many plants now separate magnetically for recycling to the steel manufacturers.

Costs. This section presents the estimated costs of supplying steam from a water-wall incinerator for Riverside. It is assumed that this steam would be supplied to a district heating system similar to that described in geothermal analysis of Appendix D3.

The basis for the cost estimate is the Saugus steam plant in Saugus, Massachusetts, as described in Reference 7. The Saugus plant, which was completed in 1975, is the most recent large steam generating incinerator in the United States. Capital costs were scaled for inflation to 1977 dollars at 7 percent per year and for plant capacity according to the formula

$$I_R = I_s \left(\frac{C_R}{Cs}\right) 0.7$$

where I_R = Investment cost for Riverside

I_s = Investment cost for Saugus

C_R = Peak refuse capacity for Riverside

Cs = Peak refuse capacity for Saugus.

The peak refuse capacity of the Riverside plant was chosen at 750 tons/day in two 375 ton/day units. This allows for meeting the existing refuse delivery rate of 555 ton/day with some redundancy and room for growth. The Riverside plant would have exactly half the refuse capacity of the Saugus plant.

Table D5-2 summarizes the capital and annual operation and maintenance costs associated with the Riverside plant. As shown in Table D5-2, the cost of steam from the Riverside plant is estimated at approximately $4.00 per million Btu with municipal financing and $6.00 per million Btu with utility financing. Note that these costs do not include the cost of steam distribution which is assumed consistent with thermal distribution costs shown in Appendix D3. Also, the costs do not allow for a dump-fee credit that is discussed later in this section.

Gasification

This section presents the results of a study on the state of the art of technology for converting municipal solid waste into gaseous or liquid fuels for application in Riverside. Preliminary material balances and cost estimates have been made for a Purox synthesis gas with methanol and hydrogen process plants handling 144,300 tons of refuse per year.

Conversion technology may be categorized as primary thermochemical, primary biochemical, and secondary conversion processes. The primary thermochemical processes are those which utilize elevated temperature to directly convert solid waste materials into energy forms or intermediate products.

There has been some process development work done on wood chips conversion by acid hydrolysis and fermentation to ethanol. However, its application to municipal solid waste has been far from practical demonstration. Therefore, the bioconversion process has not been considered here.

TABLE D5-2. CAPITAL AND ANNUAL OPERATION AND MAINTENANCE COST SUMMARY FOR RIVERSIDE REFUSE FIRED STEAM PLANT (750 tons/day capacity)

Item	Cost, $
Capital Cost (10^3)	
Based on $31,000 per ton/day capacity	23,392
Annual O&M (10^3/year)	
Based on $9.8/ton	1,414
Steam Produced (10^9 Btu)	
Based on 144,300 tons refuse per year at 5000 Btu/lb with 65 percent energy recovery	938
Cost of Energy (10^6 Btu)	
Municipal financing (10% annualization)	4.0
Utility financing (18% annualization)	6.0

Thermochemical processes may be classified as hydrogasification, catalytic gasification, and pyrolysis. Gasification involves reacting the organic feed with oxygen, steam, CO_2 or mixture of these gases under pressure and high temperature to produce a hydrogenated gaseous product. Hydrogasification involves hydrogenating the thermally degraded organic solid with steam. Catalytic gasification serves to accelerate the conversion to gas and lower the operating conditions by adding a metal catalyst to the solid feed. These high-pressure and high-temperature processes have been applied to coal but are not well defined or developed for municipal solid waste. Of the four processes, pyrolysis is currently the most active scheme for converting municipal solid waste into gaseous or liquid fuels.

A number of pyrolysis processes have been reported in the literature. Most of these are under various stages of development. Depending on operating conditions, some produce liquid fuels while others produce synthesis gas.

Purox, Lurgi, Kopper-Totzek, Winkler, Landgard and Garrett are among the processes that are near commercial stage for synthesis gas and liquids production. Lurgi, Kopper-Totzek and Winkler processes have never been applied to municipal solid waste but rather to coal gasification. Of these coal gasifiers, the Winkler is the only fluidized-bed process and therefore is a better potential candidate for converting municipal solid waste, providing appropriate development work is done.

Other pyrolysis processes for refuse conversion are under development at Torrax, Georgia Tech, Battelle, Barber-Coleman, Devco, Texas Tech, and Pullman-Kellogg.

Two basic reactor types have been used for refuse pyrolysis: the shaft kiln and rotary kiln. The shaft kiln reactor may be either horizontal or vertical and is the simplest of the three reactor types; it is also the least capital intensive. The Purox process is an example of a vertical shaft kiln. The rotary kiln is much like that used in iron ore reduction and cement manufacture. The Landgard process is an example of a rotary kiln process.

Pyrolysis is an endothermic reaction and thus requires a source of heat. There are two methods of providing heat to the reactor, direct and indirect. In the direct method, part of the feedstock is burned in the reactor. In the indirect method, heat is applied to the outside of the reactor vessel.

The decomposition of the solid waste material occurs at a temperature of 360 F to 3000 F, producing a mixture of solid, liquid, and gaseous products, the compositions and proportions depending on the operating conditions. Upon decomposition, the solid waste breaks into carbon monoxide, hydrogen, carbon dioxide, methane and various hydrocarbons. Fuels from some processes are of sufficient quality that they may be blended with or substituted for conventional fossil fuels, or used to synthesize fuels such as hydrogen and methanol. Other fuels are of lower quality and are amenable to on-site combustion for the production of steam or electricity. Typical heating values for various fuels are 100 to 600 Btu/scf for gases, 10,000 to 11,000 Btu/lb for solid char, and 6000 to 9000 Btu/lb for liquids.

Brief descriptions of the major pyrolysis processes applicable to municipal solid waste conversion are given below.

Union Carbide Purox Process. The Purox process employs a vertical shaft furnace and oxygen for converting the municipal solid waste into gaseous products. It is a direct heat process where part of the combustion heat of the waste solids is utilized in decomposing the feed in the upper portion of the reactor. A temperature of approximately 1650 C (3000 F) is maintained in the lower portion of the reactor. The molten slag mixture consisting of metals, glass and other materials is continuously drained into a water quench tank where a hard granular aggregate material referred to as "frit" is formed. Figure D5-1 is a flow diagram of the process.

Gases leaving the reactor contain 30 to 40 percent moisture. This is removed in a gas clean-up step, along with ash, tars and other condensable liquids. The remaining gas, with the typical composition shown in Table D5-3, contains about 75 percent CO and H_2 in approximately

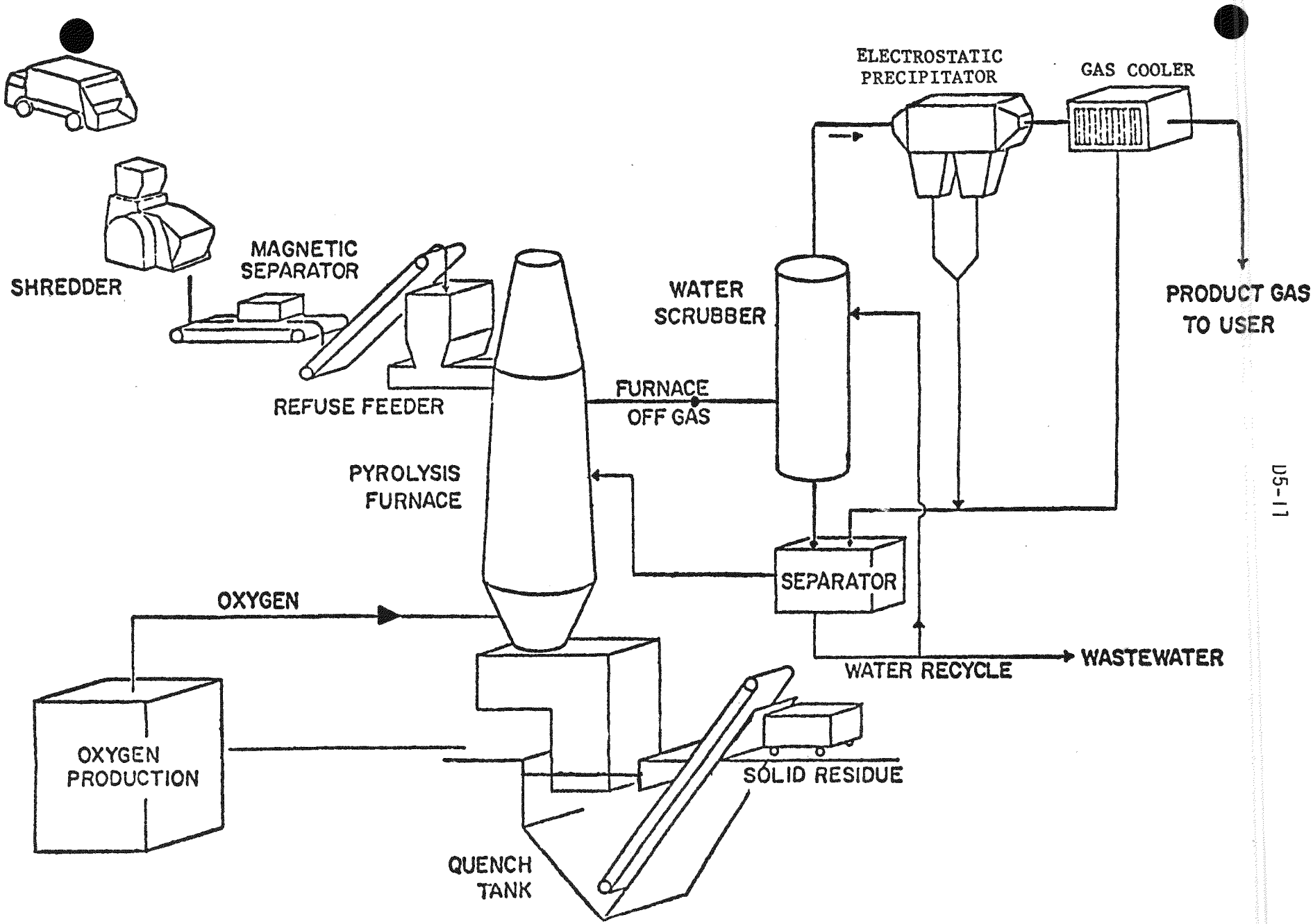

FIGURE D5-1. SIMPLIFIED FLOW DIAGRAM OF THE UNION CARBIDE "PUROX" PYROLYSIS SYSTEM

TABLE D5-3. PUROX SYSTEM PRODUCT GAS ANALYSIS [8]

Component	Volume Percent - Dry Basis Typical	Range
H_2	24	21-31
CO	40	38-42
CO_2	25	20-26
CH_4	5.6	4-7
C_2H_2	0.7	0.4-1.0
C_2H_4	2.1	1-3
C_2H_6	0.3	0.2-0.4
C_3H_6	0.3	0.2-0.4
C_3H_8	0.2	0.1-0.3
C_4	0.5	0.3-0.6
C_5	0.4	0.2-0.5
C_6H_6	0.3	0.2-0.5
C_7H_8	0.1	0.05-0.15
$C+_6$	0.2	0.1-0.7
H_2S	0.05	0.02-0.06
CH_3-OH	0.1	0.5-0.15
Organic Vapors[a]	0.15	0.05-0.3
Heating Value, Dry Basis, kcal/m^3 (Btu/scf)		
Higher	3330 (370)	2700-2100 (300-390)
Lower	3100 (345)	2520-3240 (280-360)

(a) Higher alcohols, aldehydes, ketones, and organic acids.

a two to one ratio, the other 25 percent consisting of CO_2, CH_4, N_2, and organic compounds. Its heating value is approximately 13,500 kJ/m^3 (300 Btu/cu ft).

After completing evaluation work on a 200-ton-per-day Purox system, Union Carbide has decided to market 350-ton-per-day modules. In addition, the Company is conducting a multiphase test program consisting of the receiving, feeding and pyrolytic conversion of mixed municipal solid waste without size reduction or sorting or with minimal preprocessing of incoming solid waste.

Energy is consumed in the Purox process primarily in the waste and in the production of the 0.2 pound of oxygen that is required for each pound of solid waste burned. Each pound of solid waste processed yields about 11.4 cu ft of gas, having a heating value of about 300 Btu/cu ft. The synthesis gas boiler combustion efficiency has been on the order of 90 percent with a net system efficiency of about 58 percent.

Gas from the Purox process can either be burned directly or used to synthesize higher grade fuels such as hydrogen and methanol, as will be discussed later.

Occidental Flash Pyrolysis Process (Garrett). The Garrett process, shown in Figure D5-2, also uses a vertical shaft kiln, although it utilizes air instead of oxygen. It requires more expensive feed preparatory equipment to shred and sort the particles down to 0.125 inch. By virtue of its relatively low-temperature operation (i.e., about 1400 F), it manufactures both a liquid and a gaseous fuel. The gaseous fuel is normally used within the process and only the liquid fuel would be available for outside use or sale. The liquid fuel is claimed to be similar to low-quality No. 6 residual oil.

A 200-ton-per-day EPA demonstration facility has been constructed at El Cajon, California. Evaluation results are not yet available. The costs of the Garrett process in relation to alternative processes are yet to be resolved, but are expected to be high. The energy conversion efficiency is relatively low because most of the energy is lost in a char by-product having 33 percent ash.

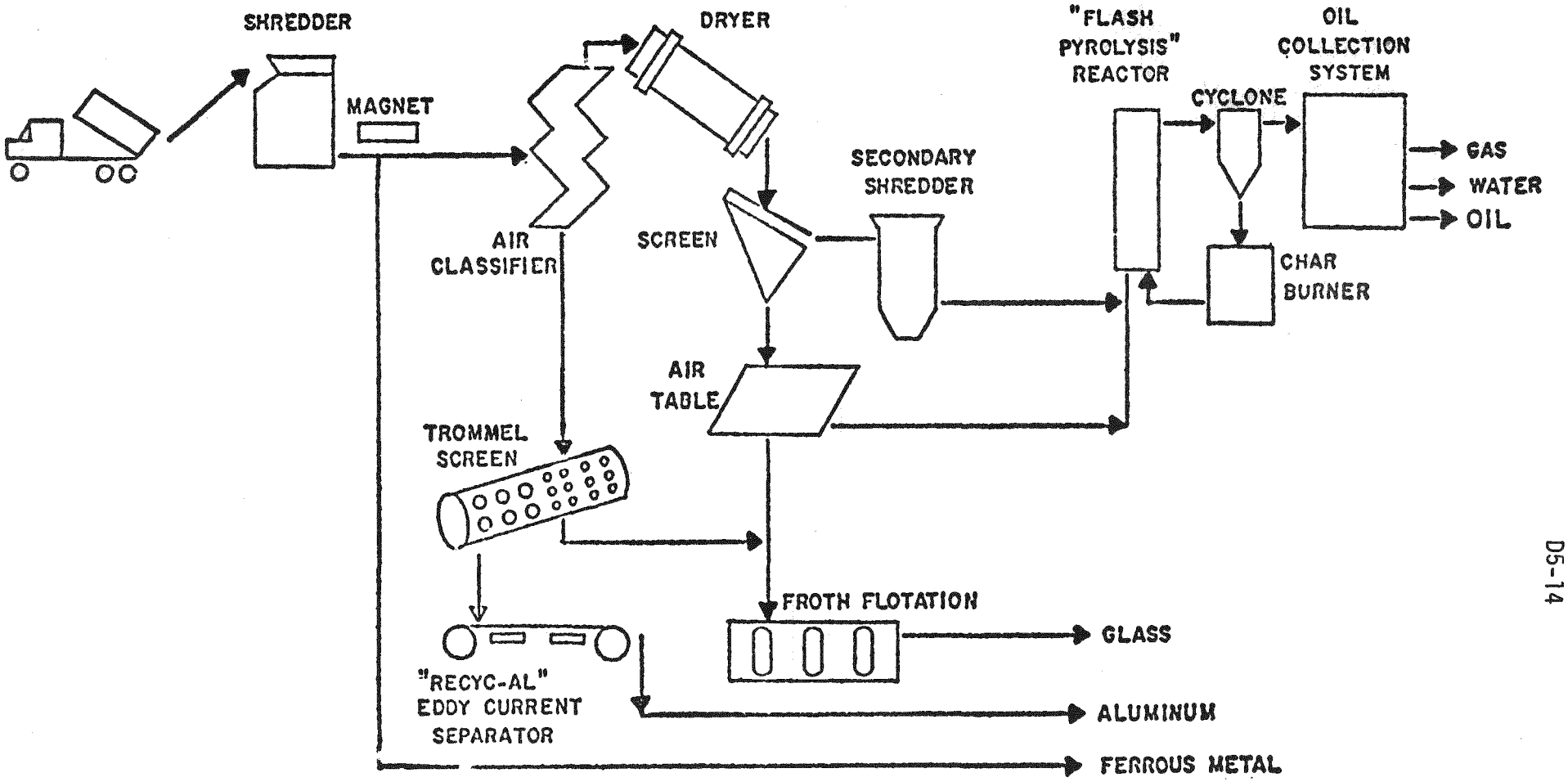

FIGURE D5-2. SIMPLIFIED FLOW DIAGRAM OF THE OCCIDENTAL RESEARCH CORPORATION'S "FLASH" PYROLYSIS SYSTEM

Monsanto Landgard Process. The Monsanto Landgard process shown in Figure D5-3 employs controlled air pyrolysis in a rotary kiln. Shredded waste from a storage silo is fed into the primary chamber of the rotary kiln where it is pyrolyzed. Some supplemental fuel oil is also burned in the kiln to provide some of the heat for the pyrolysis reaction. The burner is arranged such that the waste is subjected to progressively higher temperatures as it passes through the kiln in a countercurrent flow with the gases. The residual product leaving the kiln at about 1000 C (1800 F) is quenched in a water-filled tank and then split into glassy aggregate, ferrous and char fractions. While ferrous materials and glassy aggregate are recovered for sale, the char is dewatered and landfilled.

Since the Landgard process produces low-energy gas with a heat content of 100 to 150 Btu/scf, its off-site transportation has been found uneconomical. Therefore, an afterburner is included in the system to immediately combust the gases. These gases then pass through waste heat boilers where steam is generated for distribution.

A 1000-ton-per-day prototype plant was built in 1975 in Baltimore, Maryland. Several modifications are now being made to improve the performance of the process. Most of the modifications relate to pollution control equipment. Monsanto is no longer involved in the Baltimore demonstration.

Selection of Processes. The preceding review of the status of technology for converting municipal solid waste into gaseous and liquid fuels resulted in the selection of the Purox process as the most viable candidate for further analysis.

This selection was based on the following criteria: state of development of the process, thermal efficiency, process versatility, and quality and quantity of synthesis gas, which can also be used for production of hydrogen and methanol.

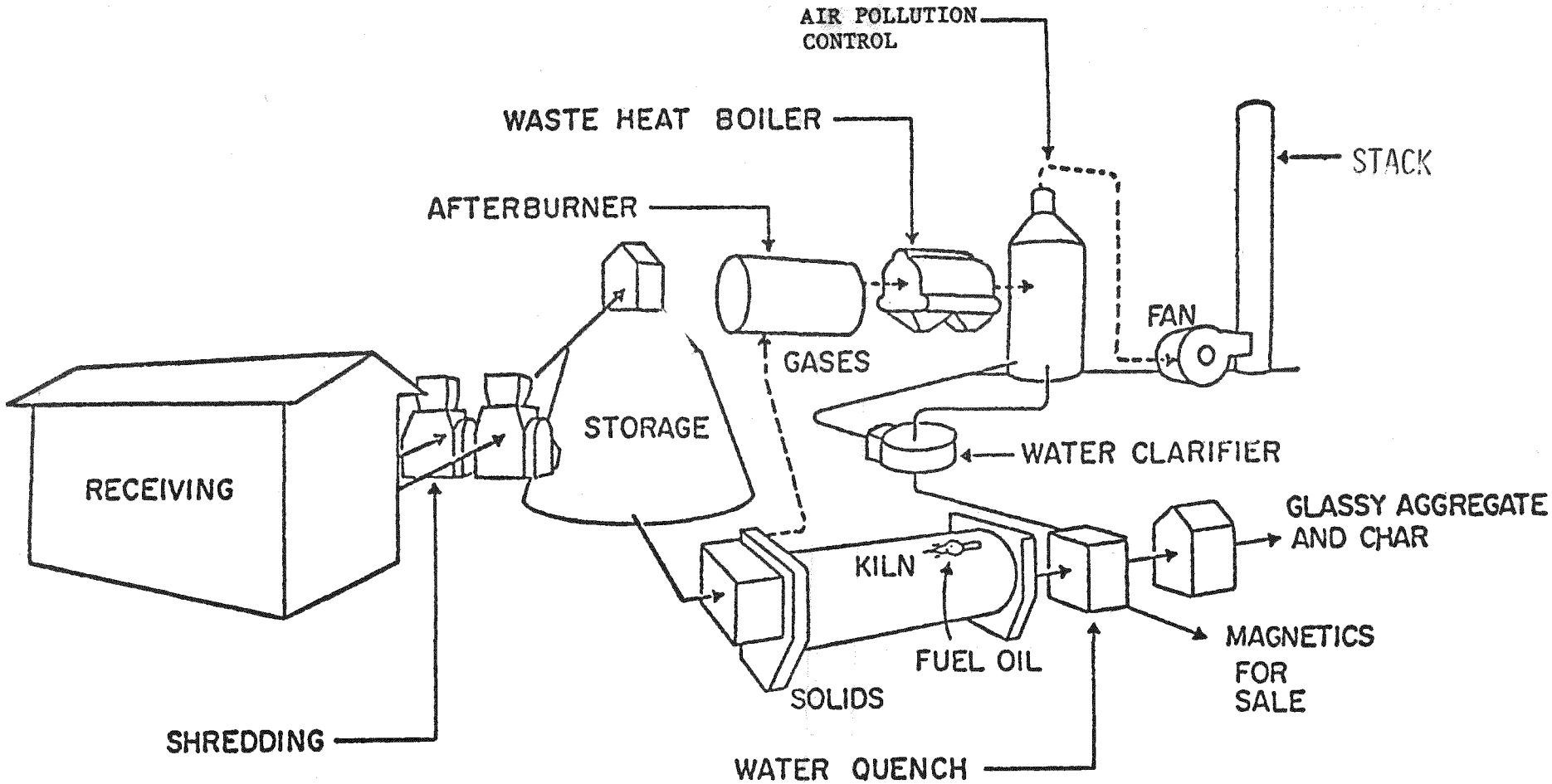

FIGURE D5-3. SIMPLIFIED FLOW DIAGRAM OF THE MONSANTO LANDGARD PYROLYSIS SYSTEM

Cost Analysis. Tables D5-4 and D5-5 present estimates of the capital and annual operation and maintenance costs associated with a 750-ton-of-refuse-per-day Purox plant. Table D5-6 gives the estimated cost per unit of synthesis or fuel gas produced with amorization of capital costs under municipal and utility financing assumptions.

Such a plant would produce about 987×10^9 Btu/yr of gas from the 144,300 tons of refuse available in Riverside. This represents a conversion efficiency of 58 percent based on a dry refuse heating value of about 12×10^6 Btu/ton.

As mentioned, the Purox synthesis gas can also be used to manufacture methanol and hydrogen. The following analysis is an estimate of the possible production rates and costs for producing these two fuels.

Methanol. Most commercial methanol is currently produced from natural gas as the feedstock through the synthesis gas route. The conversion of the shifted synthesis gas mixture into methanol is done through an established technology. The technology is available in high- and low-pressure versions. While the high pressure process operates at 300 atm, the low-pressure version is conducted at 50 to 100 atm, using a fixed-bed copper-zinc chromium catalyst.

The modern low-pressure methanol technology has substantially reduced capital and operating costs and produces a much purer methanol product than the high pressure version. A schematic flow diagram, based on the Imperial Chemical Industries, Ltd. (ICI) low-pressure process, is shown in Figure D5-4.

The synthesis gas, after compression to about 50 atm, is subjected to purification and hydrogenation steps for the removal of sulfur compounds in order to protect the water-gas shift and methanol catalysts from contamination.

After the purification, the H_2 and CO molar relationship of the gas is adjusted to about 2 to 1 by employing the water-gas shift reactor with an iron oxide-chromium oxide-type catalyst. The normal temperature range for the reaction is 380-510 C (650-850 F).

TABLE D5-4. CAPITAL COSTS FOR 750 TON/DAY PUROX PLANT

Cost Element	Cost, in Tens of Dollars
1. Battery Limits Plant (BLP)	29,200
2. Land, Site Preparation (2.8 Percent of 1)	818
3. Utilities (10 Percent of BLP)	2,920
4. Services (12 Percent of 1+2+3)	3,953
5. Interest During Construction (12 Percent of 1+2+3+4)	4,427
6. Estimated Total Fixed Capital	41,318
7. Start-up (at 8 Percent of 6)	3,305
8. Working Capital (at 3 Percent of 6)	1,240
9. TOTAL ESTIMATED CAPITAL COST (Items 6+7+8)	45,863

Note: These are tentative results. In any case, they are intended to be only plus 50 or minus 30 percent accurate.

Source: Battelle-Columbus estimates based on information supplied by Union Carbide Corporation.[13]

TABLE D5-5. ESTIMATED ANNUAL OPERATING AND MAINTENANCE COSTS - PUROX PROCESS

Cost Element	In Millions of 1978 Dollars	
Labor - Front End, 200 hr/day @ $10/hr	0.730	
Maintenance and Materials @ 3.5% of capital cost/yr	1.21	
Utilities, 2667 kw @ $0.03/kwh	0.701	
Miscellaneous	0.190	
Total Estimate	2.831	6.2% of cap

Note: These are tentative results. In any case, they are intended to be only plus 50 or minus 30 percent accurate.

Source: Battelle-Columbus estimates.

TABLE D5-6. ESTIMATED PRODUCT COST OF PRODUCING THE PUROX GAS FROM 500 TONS PER DAY MUNICIPAL SOLID WASTE (NO DUMP FEE)

Cost Element	In Millions of 1978 Dollars	
Annual Operating Cost	Municipal[a] Financing	Utility[b] Financing
Operating and Maintenance	2.83	2.83
Annualized Capital Charges @ 6-1/2% for 12 years	4.59	8.26
Total Operating Cost	7.42	11.09
Annual Revenue Credits		
Ferrous Metals @ 120 lb/ton of Refuse and $40/ton	0.44	0.44
Net Annual Operating Costs	6.98	10.65
Cost per MM Btu of Gas Output 987 x 10^9 Btu/yr @ 11.4 cu ft gas/lb refuse, 300 Btu/cu ft gas product	7.07	10.79

(a) 10 percent annualization.
(b) 18 percent annualization.

Source: Battelle-Columbus estimates.

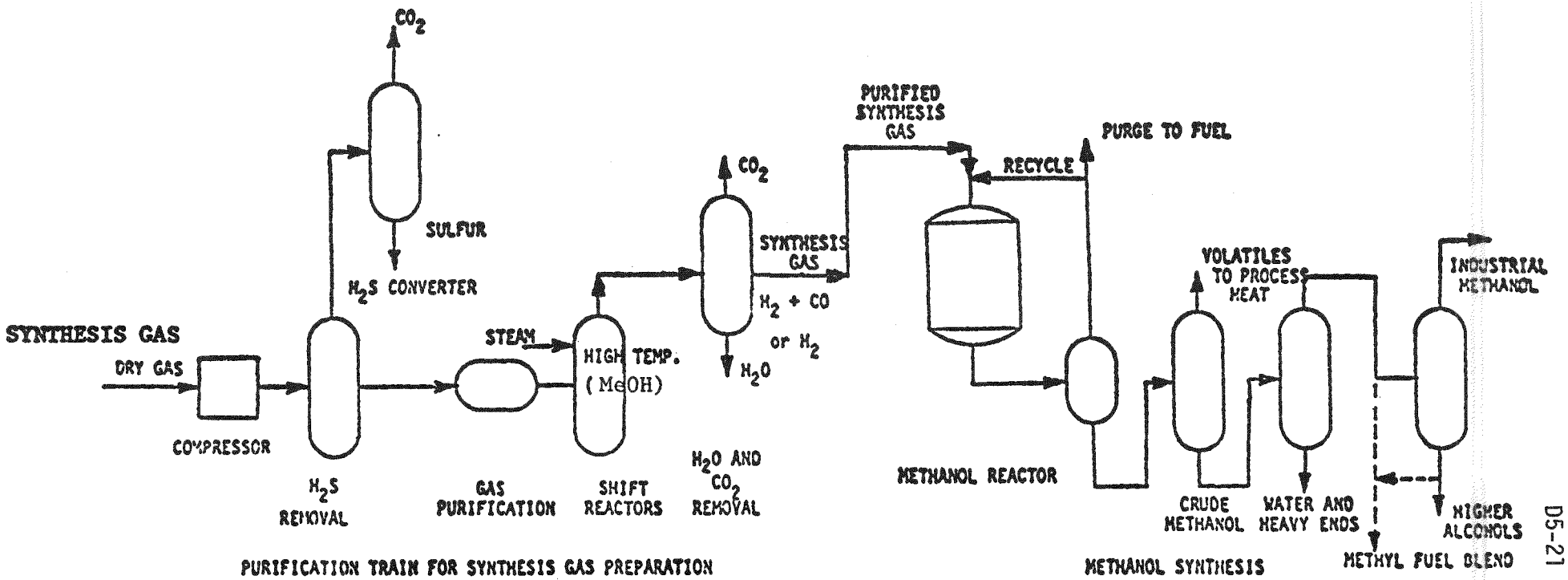

FIGURE D5-4. LOW PRESSURE METHANOL PROCESS (BASED ON ICI PROCESS)[3]

The purified shifted gas is first subjected to CO_2 removal before it is fed to the methanol reactor at about 50 atm and 250 C (480 F). The reactor product containing methanol is purified in devolatilization, dewatering and distillation columns.

Tables D5-7 and D5-8 give estimated capital and annual operation and maintenance costs for methanol production from Purox gas. Table D5-9 gives the estimated cost per unit of methanol under municipal and utility financing assumptions. About 477×10^9 Btu per year of methanol can be produced from the Riverside refuse, which yields an overall refuse-to-methanol conversion efficiency of about 28 percent.

Hydrogen. Hydrogen represents a certain fraction of the product gas of solid waste pyrolysis processes. This fraction depends upon the composition of the refuse, the ratio of steam to air or oxygen, and other factors including the temperature at which the gasification reactor occurs. More hydrogen can be obtained at the expense of the carbon monoxide content by reforming the gas with residual or additional steam. The maximum amount of hydrogen is obtained when all the reducing power of carbon monoxide is converted to carbon dioxide. In performing this conversion subsequent to the gasification step, additional heat energy is required to produce the steam and to provide the endothermic reaction energy. Therefore, this conversion step is indicative of further material efficiency loss of the primary synthesis gas produced from municipal solid waste. Figure D5-5 is a schematic of the hydrogen conversion process.

Tables D5-10 and D5-11 present estimates of the capital and annual operation and maintenance costs associated with producing hydrogen from the Purox gas. Table D5-12 gives the cost per unit of hydrogen produced based on municipal and utility financing assumptions.

It is estimated that about 808×10^9 Btu/year of hydrogen can be produced from Riverside refuse, which represents a refuse-to-hydrogen conversion efficiency of about 48 percent.

TABLE D5-7. ESTIMATED CAPITAL COSTS - METHANOL PLANT

Cost Element	In Millions of 1978 Dollars
1. Compressors	3.93
2. Shift Reactor	0.58
3. Waste Heat Recovery	0.41
4. CO_2 + H_2S Removal	2.40
5. Converters	3.13
6. Distillation	1.56
7. Offsites (33 percent of 1+2+3+4+5+6)	3.96
8. Interest During Construction (12 percent of 1+2+3+4+5+6+7)	1.92
9. Estimated Total Fixed Capital	17.89
10. Start-up (@ 8 percent of 9)	1.43
11. Working Capital (@ 3 Percent of 9)	0.54
12. TOTAL ESTIMATED CAPITAL COST (Items 9+10+11)	19.86

Note: These are tentative results. In any case, they are intended to be only plus 50 or minus 30 percent accurate.

Source: Battelle-Columbus estimates.

TABLE D5-8. ESTIMATED ANNUAL OPERATING AND MAINTENANCE COSTS - METHANOL PLANT

Cost Element	In Millions of 1978 Dollars
Labor, 32 hr per shift @ $10/hr	0.317
Maintenance and Material, M&L @ 5.0 percent of capital/year	0.993
Utilities	2.877
Steam, 30,000 lb/hr @ $4/1000 lb	
Power, 108,000 kwhr/day @ $0.03/kwhr	
Process and Cooling Water 3540 gpm @ $0.40/1000 gal	
Indirect Costs[a]	0.317
TOTAL ESTIMATE	4.504

(a) Does not include cost of input gas.

Note: These are tentative results. In any case, they are intended to be only plus 50 or minus 30 percent accurate.

Source: Battelle-Columbus estimates.

TABLE D5-9. ESTIMATED PRODUCT COST OF PRODUCING METHANOL FROM THE PUROX GAS AS RAW MATERIAL (FROM 500 TONS PER DAY MUNICIPAL SOLID WASTE)

Cost Element	In Millions of 1978 Dollars	
	Municipal Financing	Utility Financing
Annual Operating and Maintenance	4.50	4.50
Annualized Capital Charges @ 6-1/2% for 12 years	1.99	3.57
Synthesis Gas Cost	6.98	10.65
Total Annual Estimate	13.47	18.72
Cost per MM Btu of Methanol Output (Based on 9750 Btu/lb, 477×10^9 Btu/year, 24,464 tons/year)	28.24	39.24

Note: These are tentative results. In any case, they are intended to be only plus 50 or minus 30 percent accurate.

Source: Battelle-Columbus estimates.

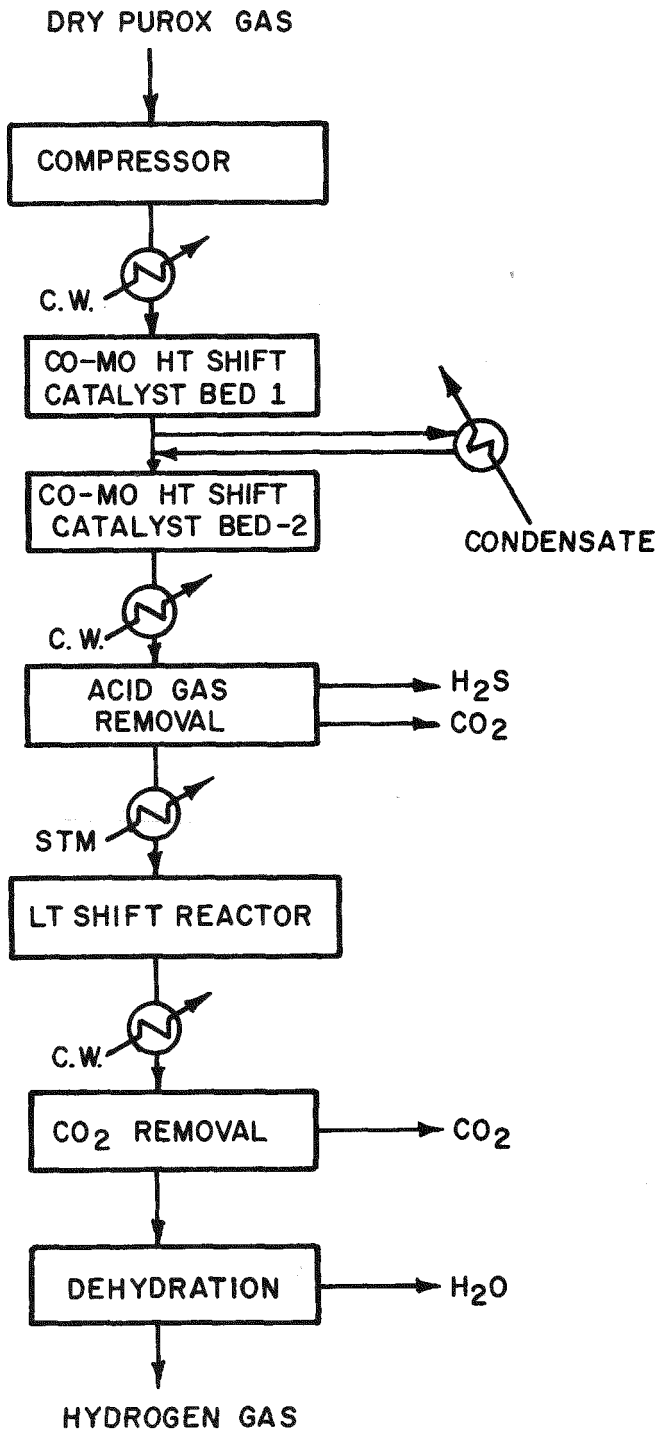

FIGURE D5-5. BLOCK FLOW DIAGRAM - HYDROGEN PLANT

TABLE D5-10. ESTIMATED PRODUCT COST OF PRODUCING HYDROGEN FROM 500 TONS PER DAY MUNICIPAL SOLID WASTE

Cost Element	In Millions of 1978 Dollars	
	Municipal Financing	Utility Financing
Annual Operating and Maintenance	3.691	3.691
Annualized Capital Charges @ 6-1/2 Percent for 12 years	0.731	1.320
Synthesis Gas Cost	6.98	10.65
Total Annual Estimate	11.40	15.66
Cost per MM Btu of Hydrogen Output (Based on the Output of About 808×10^9 Btu/year, 6.8×10^6 scf/day of H_2)	14.11	19.38

Note: These are tentative results. In any case, they are intended to be only plus 50 or minus 30 percent accurate.

Source: Battelle-Columbus estimate.

TABLE D5-11. ESTIMATED CAPITAL COST - HYDROGEN PLANT

Cost Element	In Millions of 1978 Dollars
Compressor 2500 BHP, 7900 SCFM	0.533
Heat Exchangers 5 units with a total surface of 7000 ft^2	0.280
HT Shift Reactor 10' x 20' S.S. Column @ 450 psig max	0.325
LT Shift Reactor 4' x 10' S.S. Vessel	0.058
Acid Gas (Both H_2S and CO_2) Removal System	0.600
Sulfur Plant, 0.47 Tons Per Day	0.195
CO_2 Removal System	0.300
Dehydration Unit	0.100
Total	2.391
Estimated Total Fixed Capital @ 3.0 times $2.391 MM	7.173
Working Capital @ 2 Percent of Total Fixed Capital	0.143
Total Estimated Capital Cost	7.316

Note: These are tentative results. In any case, they are intended to be only plus 50 or minus 30 percent.

Source: Battelle-Columbus estimates.

TABLE D5-12. ESTIMATED ANNUAL OPERATING AND MAINTENANCE COSTS - HYDROGEN PLANT

Cost Element	In Millions of 1978 Dollars
Labor, 32 hrs per shift @ $10 per hr	0.317
Maintenance and Materials M&L @ 5% of capital cost	0.366
Utilities	2.691
Steam - 40,000 lb/hr @ $4/1,000 lb	
Power - 86,000 kwhr/day @ $0.03/kwhr	
Process and Cooling Water 2722 gpm @ $0.40/1,000 gal	
Indirect Cost(a)	0.317
TOTAL ESTIMATE	3.691

(a) Does not include cost of input gas.

Note: These are tentative results. In any case, they are intended to be only plus 50 or minus 30 percent accurate.

Source: Battelle-Columbus estimates.

Methane Gas Recovery From Landfill Processes

The anaerobic digestion (or natural bioconversion) of solid wastes within a landfill results in the production of "landfill decomposition gas". Methane and carbon dioxide are the major constituents of landfill decomposition gas while other products and gases (i.e., hydrogen sulfide) are also generated. Historically, operating and postoperating landfills have incurred adverse environmental effects from landfill gas generation as the methane portion can represent an explosion hazard, noxious odors may prevail, and mineralization of groundwater can occur if the carbon dioxide fraction dissolves and forms carbonic acid. Along with a desire to eliminate environmental problems, recent trends in energy costs and availability have stimulated both private and public sectors to develop landfill gas treatment technology for extraction of the usable methane portion of the landfill gas.

The basic configuration entailed in this waste-to-energy concept includes gas collection, processing, and a distribution system for the landfill gas generated within a conventional land waste disposal operation. In this system, disposal of wastes actually occurs before recovery of energy as opposed to other systems that recover energy prior to final residue disposal.

Raw gas from landfills generally contains about 45 percent methane and the remainder is composed chiefly of carbon dioxide, nitrogen and a variety of contaminants. The heating value of the gas, as extracted, is about 450 to 550 Btu/scf. This gas can be partially upgraded to about 750 Btu/scf, or upgraded even further at additional expense to natural gas quality with a heating value of about 950 Btu/scf.

The partially upgraded gas at 750 Btu/scf can be injected into existing natural gas pipelines in small quantities without substantially affecting the quality of the pipeline gas. The fully upgraded gas at 950 Btu/scf can be injected in natural gas pipelines in nearly any quantity. The raw gas from the landfill is best suited to on-site or nearby use in a captive manner.

Two examples near Riverside where methane is being recovered from existing landfills are:

1. Sheldon-Arleta landfill in Los Angeles. Initiated in 1974 by the Los Angeles Department of Water and Power (LADWP) and the Los Angeles County Sanitation District (LACSD). The raw gas is burned directly in a 300 kw internal-combustion-engine-driven electric generator set.
2. Palos Verdes landfill. Initiated in 1975 by LACSD and Southern California Gas Company. The gas is upgraded to 990 Btu/scf through a molecular seive process and injected into existing pipelines.

Table D5-13 estimates the cost of recovering methane gas from a landfill similar to the nearly completed West Riverside location. As can be seen, these costs (based on scaling of cost data in Reference 14) result in a gas cost substantially below the projected costs of natural gas.

Biomass

Biomass, not including municipal refuse, consists of a wide variety of organic materials generally associated with the food industry, although timber harvesting waste and non-food-related plants that may be grown specifically for energy recovery may also be included. The technology for converting biomass to energy is largely the same as that discussed earlier in this section for municipal refuse, i.e., incineration to raise steam and gasification or pyrolysis to produce gases and liquids. Certain technologies have special attractiveness for certain types of biomass which, although applicable too, are not especially attractive for refuse. Examples are animal manures, which are well adapted to producing methane through anaerobic digestion, and certain crop wastes, which are especially attractive for producing alcohols through fermentation.

TABLE D5-13. ESTIMATED COSTS FOR METHANE RECOVERY FROM RIVERSIDE LANDFILL BASIN (288 x 10^6 Btu/day[a])

Capital Investment	$617,000[14]
Annual Capital Charges	
Municipal Financing (10%)	$ 61,700
Utility Financing (18%)	$111,060
Annual Operation and Maintenance	$ 35,000[14]
Total Cost	
Municipal Financing	$ 96,700
Utility Financing	$146,060
Energy Cost ($/$10^6$ Btu)	
Municipal Financing	$ .92
Utility Financing	$ 1.39

(a) Gas partially upgraded to 750 Btu/scf, suitable for pipeline injection.

The types of biomass and their availability are very geographically dependent. The cost of collection and transport per unit of energy content precludes shipment over long distances. In Riverside, the types of biomass of any significance can be grouped into four categories, agricultural residue, dairy and feedlot manures, and timber harvesting waste. The amounts of these biomass types available, estimated energy recovery potential, and energy cost are shown in Table D5-14.

Agricultural Residues. This category is broken into two groups - industry wastes and field residues. Industry wastes consist of hulls and other wastes left over after processing of grain, nuts, and other foods. Field residues consist of corn, popcorn, sorghum, cotton, dry bean residue, wheat, barley and rice. Much of this material is currently recycled to higher uses such as fertilizer and animal feed and, as such, is not readily available for energy recovery. The lower quantities available in Table D5-14 generally represent quantities currently being wasted and, hence, available for energy recovery, as well as those quantities which are available in sufficient concentrations to allow economic collection. Therefore, in general, the lower numbers in Table D5-14 represent amounts that are realistically available, while the higher numbers give an upper bound. Also, the data in Table D5-14 are for all of Riverside County and, as such, amounts economically available to the City of Riverside would be somewhat less than those shown. No data were available for the City of Riverside locale.

Both incineration and gasification would be applicable to converting agricultural residues to useful energy. Based on the preceding analysis, refuse incineration to raise steam would offer the lowest costs and the estimates shown in Table D5-14 represent an incineration option. The amount of energy realistically available (about 47×10^9 Btu/year) is about 5 percent of that from incineration of Riverside refuse. The cost of collection in this case would be

TABLE D5-14. BIOMASS ENERGY AVAILABILITIES FOR RIVERSIDE

Type	Quantity, tons/year[14] Low[a]	High[b]	Energy Content Low	High	Cost, $/10^6 Btu
Agricultural					
Industry	866	9,942	5.6	65.6[c]	4.50[f]
Field	6,264	188,030	40.7	122.2[c]	9.70[g]
Dairy & Feedlot Manures	124,792	361,104	312.0	902.8[d]	2.00[h]
Timber Harvesting Waste	2,514			26.4[c]	4.50[i]

(a) Sufficient quantity for 200 ton/day capacity at each source.
(b) All sources.
(c) When incinerated at 0.65 efficiency at 5000 Btu/lb.
(d) Methane from anaerobic digestion at 2.5×10^6 Btu/ton[1].
(e) When incinerated at 0.65 efficiency at 8000 Btu/lb.
(f) Delivered cost of $3.00/ton[14] plus cost of incineration at $4.00/$10^6$ Btu.
(g) Delivered cost of $23.00/ton[14] plus cost of incineration at $4.00/$10^6$ Btu.
(h) Methane delivered to pipeline [15].
(i) Delivered cost $5.00/ton plus cost of incineration at $4.00/$10^6$ Btu.

added to the cost of incineration (municipal refuse must be collected regardless). As such, it is more expensive to use agricultural residue than to use municipal refuse.

Dairy and Feedlot Manures. As was mentioned before, this type of waste is especially well suited to anaerobic digestion to produce pipeline quality methane gas. Such an operation is currently being tried in Oklahoma, where manure from 170,000 head of cattle is producing gas that is ultimately used in Chicago.[15] Also, the amount of manure that appears realistically collectible is capable of producing a substantial amount of gas (over 4 percent of Riverside's current natural gas consumption). The cost of gas is estimated at $\$2.00/10^6$ Btu, based on the Oklahoma operation.

Timber Harvesting Waste. The amounts of this type of biomass available are not substantial (about 3 percent of that from municipal refuse). As with agricultural residue, wood waste can be burned or gasified, with burning to raise steam probably being the least expensive. The costs shown also represent the additional cost of collection, which must be added to the cost of burning refuse in a refuse-fired incinerator.

Conclusions

It appears that the most attractive biomass alternative is to convert feedlot manure to methane to supplement existing natural gas supplies.

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D6. WIND

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D6. WIND

Background

The oldest recorded knowledge of man's use of the wind as a source of energy is a 5000 year old drawing of a sailing craft on the Nile river. The first attempts at using wind turbines to do useful work were probably by the Persians, as early as 200 BC. They used simple verticle axis machines for grinding operations.(1)

In the United States over 6 million small windmills, each less than 1 and having about a 12 to 15-foot-diameter rotor, have been built since the mid-19th century for use in rural areas, principally for generating electricity and pumping water. The advent of rural electric cooperatives in the 1930's made many of these uneconomic and today only about 150,000 are estimated still in use.(1)

The largest wind turbine ever built and operated was on 2000-foot-high Grandpa's knob near Rutland Vermont. This machine had a 110 foot tower with a 175 foot diameter rotor and produced 1.25 megawatts (MW) of electricity at wind speeds over 30 miles per hour (mph). The unit operated intermittently between 1941 and 1945 until a blade failure forced it to be shut down. It was never retarted due to unattractive economics.(1)

The purpose of the foregoing discussion is to illustrate that man has had a long history of using the wind as an energy source. In recent history the United States, as well as most European countries, has had extensive experience with wind machines. However, in the 20th century, the use of wind energy has generally declined throughout the world due to the availability of cheaper, more dependable sources of energy.

Today, there is renewed interest in using wind energy in the United States. The reason largely stems from the environmental burden associated with fossil and nuclear fuels and the growing scarcity of relatively clean natural gas and oil. The environmental impact of wind machines is limited to relatively minor effects such as visual impact of towers, birds and insects colliding with propellers, and possible television interference in the immediate vicinity of the unit, which can be minimized by use of nonmetal blades.(2,3)

However, wind energy has some substantial disadvantages. It is highly variable both in time and location and requires large expensive machines per unit of energy production capacity. Thus the decision to build and operate a wind energy machine depends heavily on the cost of energy produced from it versus other alternatives.

Current Wind Programs

In 1973, a program under the direction of the National Science Foundation was initiated to develop cost effective wind generator designs matched to user needs. This program was transferred to the Energy Research and Development Administration in 1975 which subsequently has been absorbed into the Department of Energy.

The major thrust of the program thus far has been the development of a series of wind turbine designs in the 100 to 2500 kw range. These machines are divided into three series: MOD 0 (100 to 200 kw), MOD 1 (1500 kw), and MOD 2 (2500 kw). All three series are advanced variable pitch, 2 blade, horrizontal axis machines based on the German Hutter-Allgaier design. The MOD 0 series has a 100-foot tower with a 125-foot diameter-rotor, while the MOD 2 machine has a 300-foot rotor.

The first MOD 0 unit, rated at 100 kw, became operational in Plumbrook, Ohio in 1975 and is shown in Figure D6-1. A second unit, rated at 200 kw, termed MOD 0A, went into operation in Clayton, New Mexico in early 1977.[4] Two additional MOD 0A units are scheduled, one on Block Island, off the coast of Rhode Island, and one on Culebra Island in Puerto Rico. A MOD 1 unit is scheduled to be demonstrated in Boone, North Carolina, in mid 1978.[4] A demonstration of the MOD 2 machine is scheduled for late 1979.[4]

In addition to pursuing the development of the larger machines DOE has also begun an evaluation of smaller machines in the 1 to 40 kw range at its Rocky Flats, Colorado, facility. Several contracts have been awarded to develop advanced prototypes of small machines.[4] However, the unit capacity cost of small machines is expected to always remain higher than that of large machines for similar designs due to economy of scale.[5]

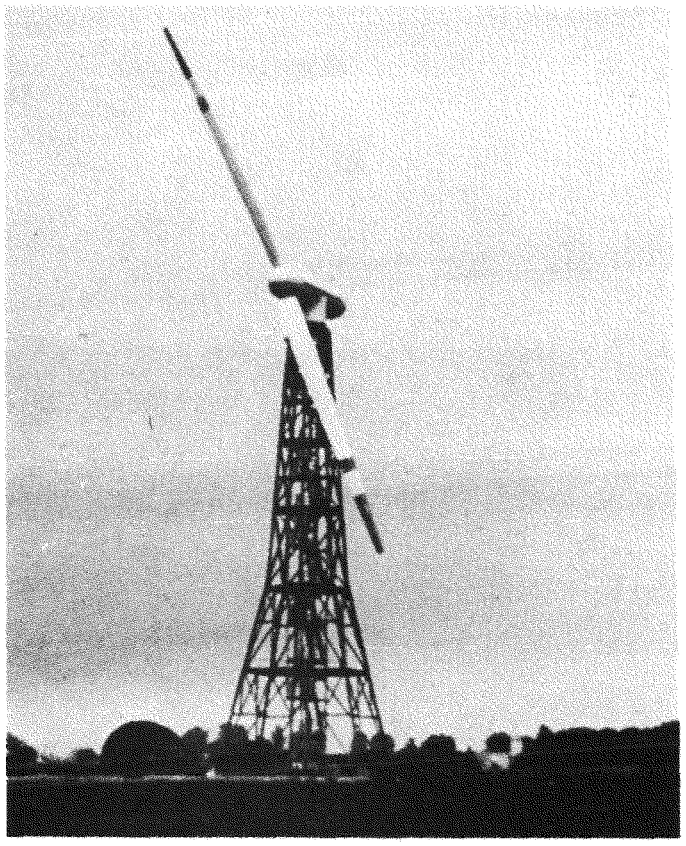


FIGURE D6-1. DOE MOD 0 INSTALLATION AT PLUMBROOK, OHIO[3]

A number of private companies are also currently involved in producing wind machines. One example is WTG Inc. in Angola, New York which has built and is operating a 200 kw turbine on Cuttyhunk Island off the coast of Massachusetts. The WTG machine is a simpler, less expensive design than the DOE MOD series and consists of an 80 foot diameter, three bladed rotor with fixed blades on an 80 foot tower.[6] There are also a number of small companies producing machines in the 1 to 30 kw size range.[2]

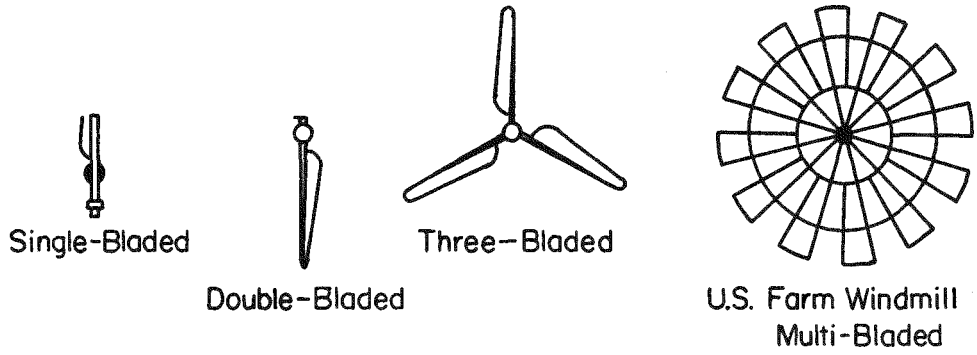
Types of Wind Machines

A wide variety of types of machines have been devised for harnessing the power of the wind. Reportedly, more patents have been issued for wind systems than almost any other category.[1]

Broadly, wind machines can be divided into two categories--horizontal axis and vertical axis. The most widely used historically is the horizontal axis propeller type. Other designs of significance are the Darrieus and Savonius--both vertical axis machines. Examples of propeller, Darrieus, and Savonius designs are shown in Figure D6-2.

The amount of energy that can theoretically be extracted from a flowing air stream is about 60 percent of that which is theoretically available.[1] This is the amount of energy that could be extracted with a 100 percent efficient turbine. Real turbines have efficiencies substantially less than 100 percent. The efficiency of real turbines, expressed as a power coefficient, can be as high as about 0.47 for modern high efficiency propellers. Power coefficients for several wind turbine designs are given in Table D6-1.

Both the DOE MOD series and the WTG Inc. design are representative of the modern high-speed propeller designs whose maximum power coefficients are around 0.47 (the highest shown in Table D6-1). Figure D6-3 shows typical power output versus wind speed curves for the DOE MOD 0 machine and the WTG model MP 1-200. Neither machine will operate with wind speeds below 8 mph and both are inactivated at speeds above 60 mph to prevent damage. The DOE machine reaches its rated output at a wind speed of 18 mph and through control of blade pitch angle produces a constant power level out to its cutoff of 60 mph. The WTG machine reaches its rated power output at about 30 mph wind speed at which point the fixed pitch blades stall and produce a somewhat constant lower power level out to its cutoff speed of 60 mph. As will be seen later these power characteristics are important in determining the cost of power from various machines.



VERTICAL AXIS

PRIMARILY DRAG-TYPE

PRIMARILY LIFT-TYPE

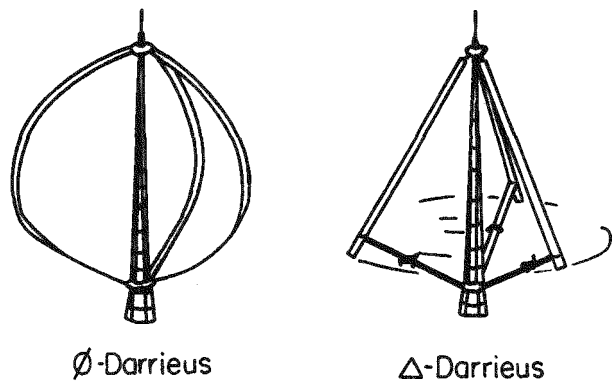


FIGURE D6-2 TYPES OF WIND TURBINES[1]

TABLE D6-1. TYPICAL MAXIMUM POWER COEFFICIENTS FOR VARIOUS WIND GENERATORS(1)

Rotor Type	Power Coefficient
Modern High Speed Propeller	0.47
Darrieus	0.35
Savonius	0.31
Early American Propeller (Farm)	0.15
Dutch Four Arm	0.17

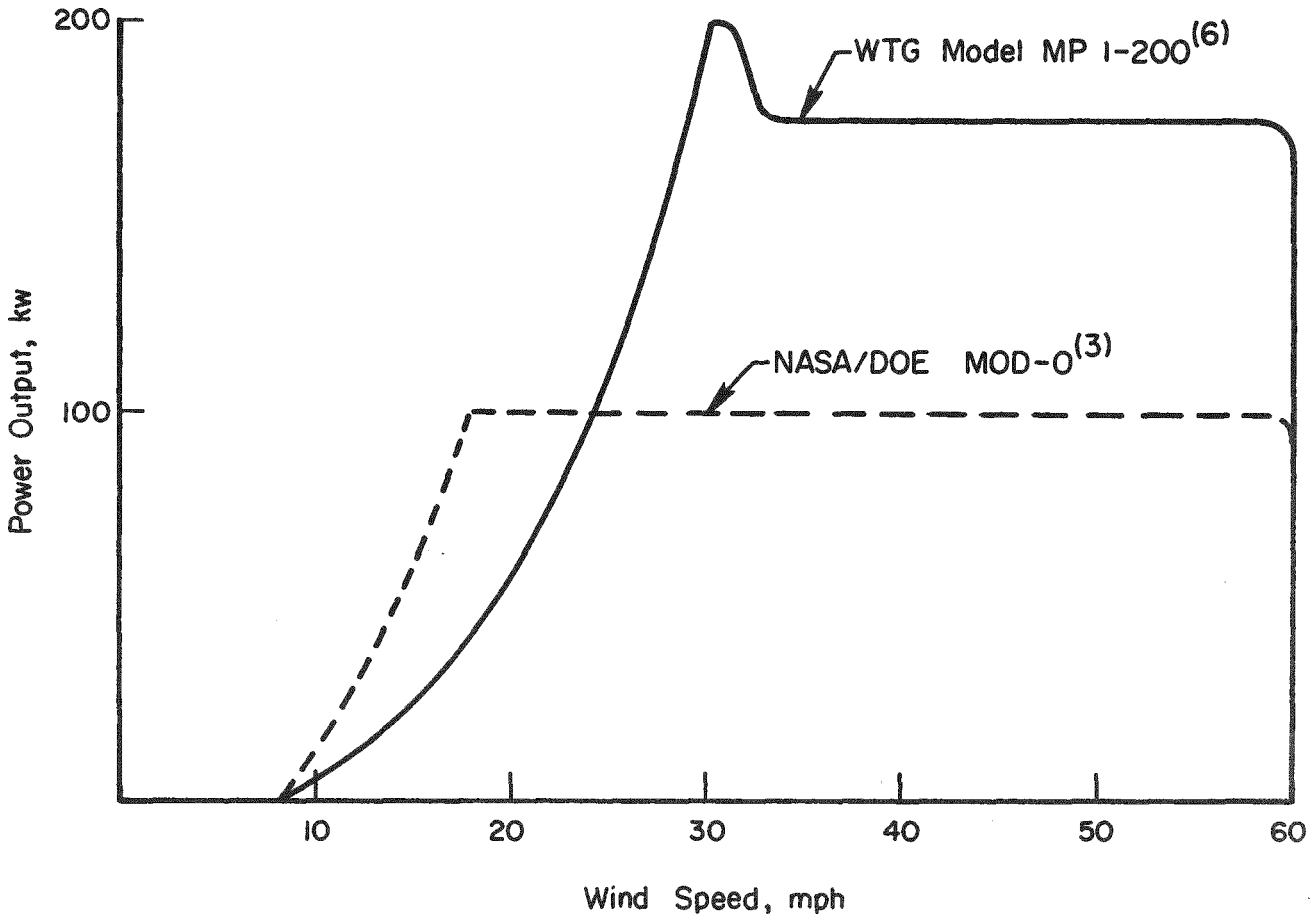


FIGURE D6-3. POWER OUTPUT VS WIND SPEED FOR REPRESENTATIVE WIND GENERATORS

Costs of Wind Energy

Three important factors in determining the cost of wind energy are: 1) the installed cost of the wind machine; 2) the power output of the wind machine at different wind velocities; and 3) the wind conditions at the wind machine location.

The costs of wind machines are usually expressed as dollars per unit of capacity, where the capacity is the peak or design production rate of the unit. This is essentially the way conventional power plants are rated. Costs per unit of capacity vary considerably depending on the degree of sophistication and resulting performance of a specific design. For any particular design the costs per unit of capacity are lower for larger units due to economy of scale.

The DOE MOD series represents a sophisticated, high-performance design. The installed costs of the first two installations at Plumbrook, Ohio and Clayten, New Mexico have been about $5000/kw[4,7]. Table D6-2 gives a breakdown of the costs of various components in this design. The MOD 2 (2.5 MW) machine, due for construction in late 1979, is currently projected to cost about $4000 kw. The lowest realistic cost for the MOD series is expected to be about $750 to $1000 kw [2].

The WTG MP1-200 wind turbine is somewhat less sophisticated in design than the DOE MOD series machines, but also costs considerably less. The installed cost of the first installation on Cuttyhunk Island was about $1000 kw. This cost is expected to drop to about $750 kw after the first few installations.[6]

As was mentioned earlier, the first or installed cost is not always indicative of the cost of energy from wind turbines. Equally important is the load factor or the annual amount of energy actually recovered divided by that which would be recovered if the unit operated at rated capacity for the entire year. The performance of the wind machine versus wind velocity, along with site specific wind velocity data, can be used to determine the amount of annual recoverable wind energy for a particular application.

TABLE D6-2. COST BREAKDOWN FOR DOE/NASA MOD 0 GENERATORS(7)

Item	Percent of Total Cost
Rotor	50.4
Mechanical	10.8
Generator, Controls	13.5
Tower, Foundation	25.3

Figure D6-4 shows wind speed duration data for March Air Force Base near Riverside.[8] These data are considered representative of wind conditions in Riverside.[8,9] By combining the wind speed duration data of Figure D6-4 with the performance curves for the DOE and WTG machines in Figure D6-3, the power duration curves shown in Figure D6-5 result. The actual amount of energy recoverable by each of the two machines over the course of a year is represented by the areas under each of the respective curves in Figure D6-5. The DOE MOD 0 machine, rated at 100 kw, produces about 37,600 kwh per year under Riverside wind conditions, while the WTG MP 1-200, rated at 200 kw, produces 15,600 kwh per year. Note that even though the WTG machine is rated at twice the capacity of the DOE unit, it produces just less than half the power over the course of a year.

The costs per unit of energy is computed by amortizing the installed cost under utility and municipal financing rates and dividing by the annual energy recovered for each of the two machines. These costs are shown in Table D6-3. Two cases are presented, one using the current installed cost of each of the units and the other using the expected lowest cost that can be achieved after design optimization and production.

It is interesting to note that the costs of electricity produced from both the DOE and WTG machines are approximately the same at current installed proces despite the 5 to 1 cost differential. At the expected lowest costs, the DOE machine is considerably more cost effective but the lowest cost for the WTG machine is probably more realistic than that for the DOE machine.

Even under the best expected conditions--lowest expected cost for the DOE machine with municipal financing--the cost of electricity from wind energy at 27¢ kwh is considerably greater than the current cost of purchased electricity at about 3¢ kwh. The cost of purchased electricity is expected to approximately double by the year 2000 to about 6¢ kwh, which would still be considerably lower than that of wind-generated electricity. From this it is concluded that wind energy in Riverside will not be economically competitive with purchased electricity in the time frame of this study (through the year 2000).

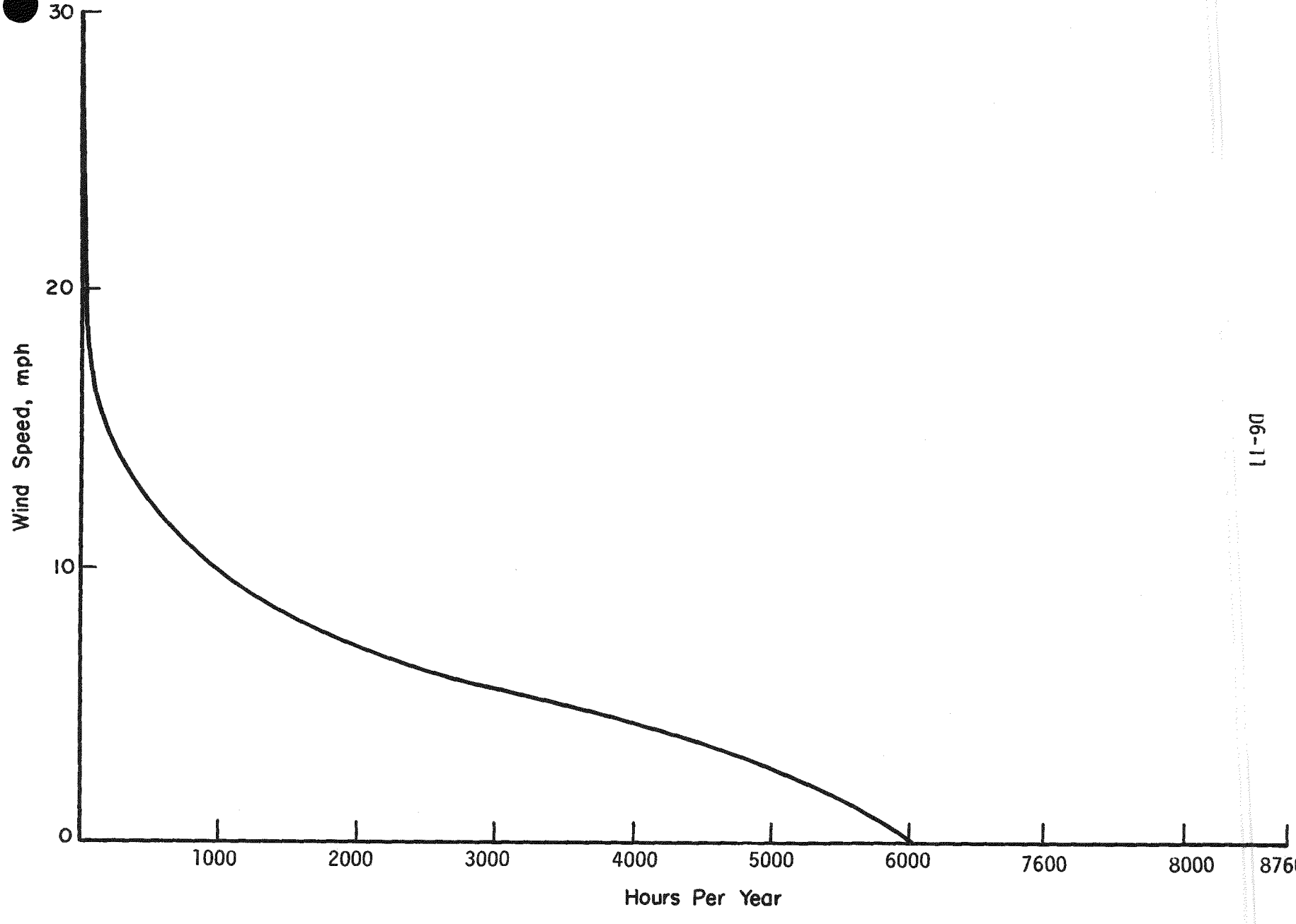


FIGURE D6-4. WIND SPEED DURATION FOR RIVERSIDE
Hours per year wind speed is above stated velocity.(8)

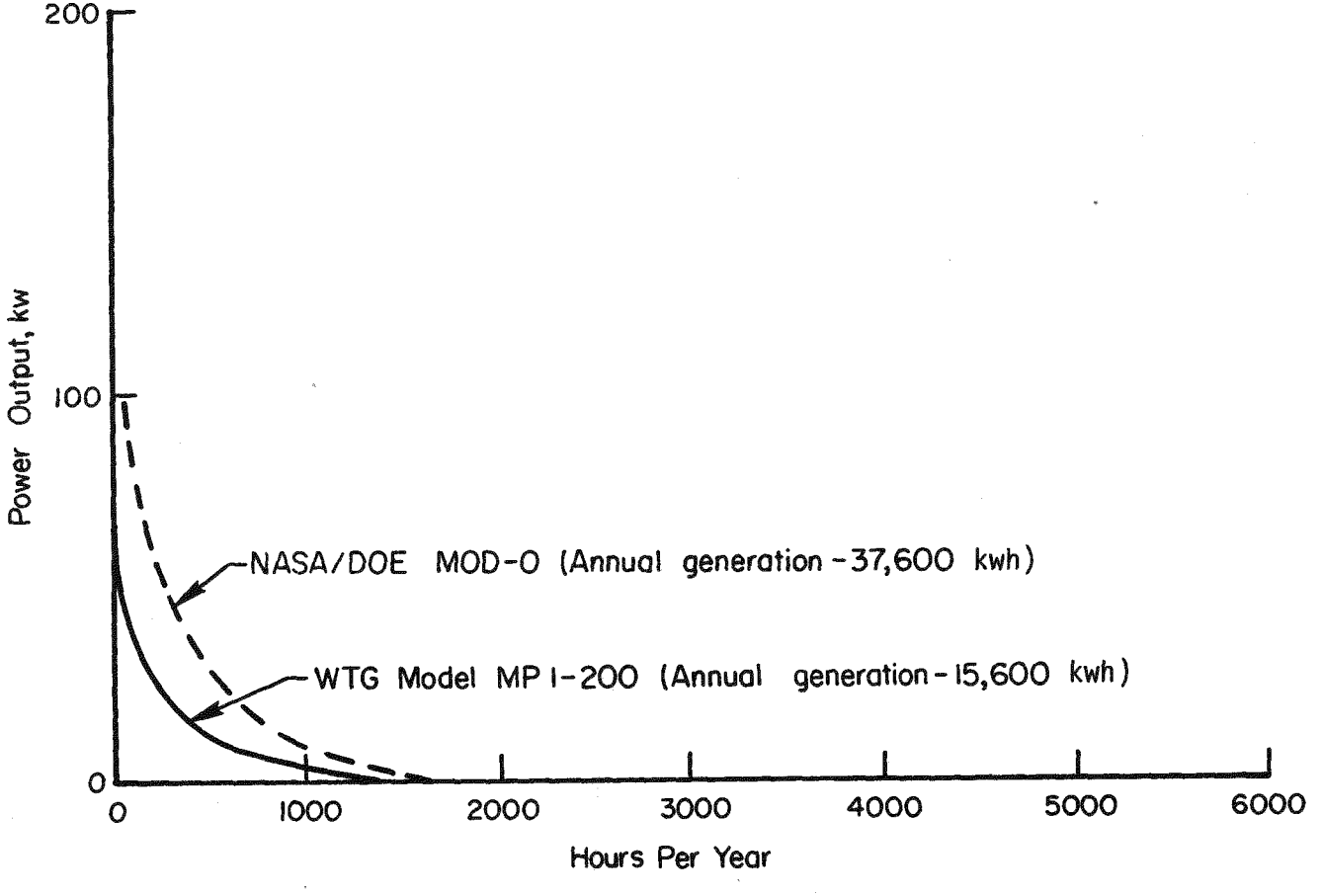


FIGURE D6-5 POWER DURATION FOR REPRESENTATIVE WIND TURBINES IN RIVERSIDE

TABLE D6-3. COSTS OF WIND ENERGY RECOVERY IN RIVERSIDE

Unit	Installed Cost $/kw	Cost of Power in Riverside ¢/k2-hr	
		Utility[a] Financing	Municipal[b] Financing
DOE MOD	5000[c]	213	133
WTG	1000[c]	208	128
DOE MOD	1000[d]	43	27
WTG	750[d]	154	96

(a) Annualization factor 0.16.
(b) Annualization factor 0.10.
(c) Current costs as installed.[2,6]
(d) Expected lowest eventual cost.[2,6]

The major factor contributing to high wind energy costs in Riverside is the relatively low wind velocity on an annual basis (exceeds 10 mph only about 10 percent of the time). Approximately 35 miles from Riverside is an area called San Gorgonio Pass (sometimes called Banning Pass) where known high wind velocities exist. For the past year DOE has been monitoring wind speed in the Pass in preparation for a possible wind turbine demonstration. Reportedly the average annual wind velocity at the DOE monitoring station is about 17 mph,[5] which, with a DOE MOD series machine, would result in a load factor of 0.6.[10] Thus, on an annual basis, a MOD 0 machine rated at 100 kw would produce 525,600 kwh of electricity in San Gorgonio Pass as opposed to only 37,600 kwh in Riverside. Therefore, the cost of electric energy produced, using the expected low installed cost of $1000 kw and utility financing, is 3¢/kwh, which is competitive with current purchased electricity.

DOE currently has no plans for demonstration of wind energy systems in San Gorgonio Pass.[5] However, Southern California Edison Company (SCE) recently signed a 2 million dollar contract with Wind Power Products Company of Seattle, Washington to build a 2.5 MW wind turbine on the east side of the Pass. SCE feels the output of electric power from this turbine will be cost competitive with conventional oil-based electricity.[11]

Nonelectric Wind Applications.

Producing electricity is not the only means of using energy from the wind. Wind turbines can also be used for direct mechanical applications such as pumping water or driving machinery. Wind-generated electricity can also be used to produce hydrogen through electrolysis of water.

By producing something other than electricity one avoids the problems of intertying a wind generator, with its uncertain generation rate, with a utility grid. However, backup or energy storage may be required to ensure power when needed. One interesting application involves combining wind turbines with hydroelectric projects to pump water from a lower pool to an upper pool to be used when needed for generating electricity.[12] As such, a change in elevation of water is used as storage to moderate the uncertainties of wind power availability. Hydrogen produced from wind energy can also effectively be stored in metal hydrides, under pressure, or cryogenically.

However, the use of wind energy for applications other than generation of electricity still depends on cost compared to alternatives. For pumping or other mechanical applications the electric generator module and related controls could be replaced with a gear and shaft arrangement at reduced cost. Likewise, for hydrogen production a less expensive generator with less sophisticated controls could be used since utility interties would not be required. However, the cost breakdown in Table D6-2 shows that only approximately 13 1/2 percent of the cost of the DOE MOD series units is for the electric generator and related controls.

Thus, the cost reduction possible in the generator module is a relatively small fraction of the overall cost of the machine. Therefore using wind power for doing direct mechanical work or producing hydrogen in Riverside, as with producing electricity, is not considered cost competitive with purchased electricity or other alternatives for the time period of this study. In remote applications, such as San Gorgonio Pass, the availability of electric distribution lines favors generation of electricity. Nonelectric application would require the construction of other facilities such as hydrogen conversion, storage, and transport or a hydroelectric facility at the remote location.

Options for Riverside

The relative low wind velocities in the Riverside area make wind energy recovery economically unsound locally for the time period of this study (1980-2000).

San Gorgonio Pass, about 35 miles east of Riverside, is an attractive area for wind energy recovery and Southern California Edison Company is planning a 2.5 MW demonstration there in the near future. Riverside's low financing rates compared to those of utilities, along with an agreement with SCE for wheeling rights over 220 kv distribution system[13] make it attractive for Riverside to pursue joint involvement in wind energy programs, or separate involvement in the future. However, at the present time, Riverside should monitor the success of the planned SCE demonstration to verify cost estimates and expected equipment performance before making a decision.

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D 7. HYDROGEN

Hydrogen was discussed earlier in both the coal and solid waste/biomass sections of this Appendix. Hydrogen is discussed separately here largely because of its unique characteristics as a low-polluting fuel (the only pollutant of concern appears to be NO_x from hiatren of N2 in combustion air which can in large part be controlled), because it can be produced by means other than gasification of a carbonaceous fuel as discussed earlier in this Appendix, and because Riverside has taken a progressive lead in demonstrating hydrogen as a motor vehicle fuel, thus underscoring local interest in the use of hydrogen to reduce vehicle pollution. Appendix C provides a more detailed discussion of the use of hydrogen and other alternative energy sources for use in vehicles.

In addition to its use as a low-polluting vehicle fuel, hydrogen is also unique in its ability to convert its chemical energy directly to electrical energy (electric chemical conversion) in a device called a fuel cell. Fuel cells are receiving considerable interest as low-polluting, high-efficiency electrical production devices suited to being deployed on a small scale (1 to 25 MW). First generation fuel cells use phosphoric acid as an electroable, operate at relatively low temperatures, and are capable of electrical conversion efficiencies of 40 percent without waste heat recovery and 80 percent with waste heat recovery. Second generation fuel cell technology is assumed in the high impact integrated utility system district heating option discussed elsewhere in this Appendix. Costs of fuel cells vary widely with a range of 450 to 850 $/kw, potentially getting as low as 350 $/kw with some technological advancement.

Figure D7-1 illustrates the estimated costs of producing hydrogen by several means including coal gasification, gasification of solid waste (see Appendix D 5) and electrolysis. Tables D7-1 and D7-2 present data used for coal gasification and electrolysis hydrogen cost estimates.

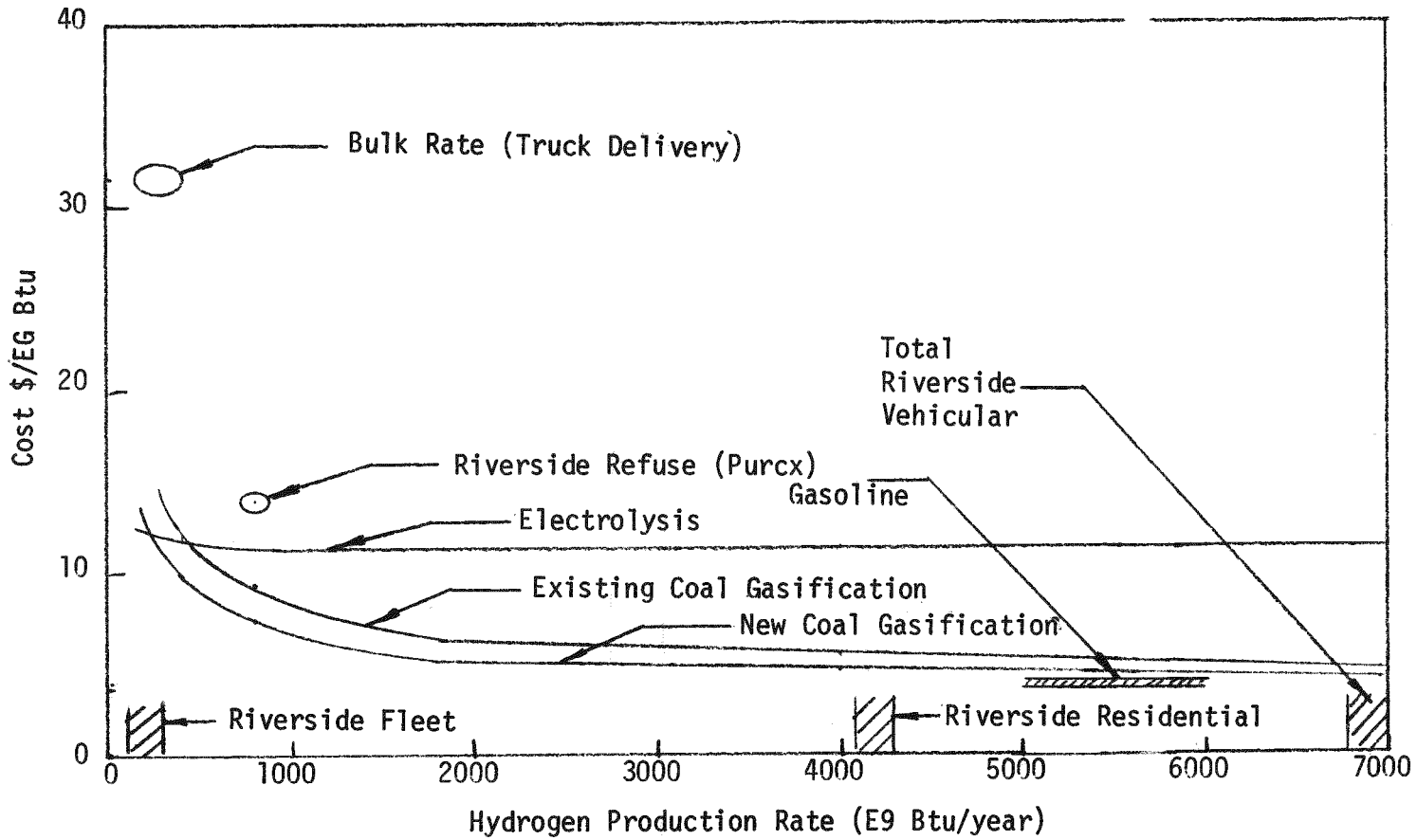

FIGURE D7-1. COSTS OF HYDROGEN PRODUCTION

TABLE D7-1. COST OF HYDROGEN MANUFACTURE FROM COAL

Source: Corneil, H. G., et al., "Production Economics for Hydrogen, Ammonia, and Methanol During the 1980-2000 Period", Exxon Research and Engineering, 1977.(a)

Plant Size: 100 E6 SCF/SD, 330 SD/year
10.72 E12 Btu/year - 1353 E6 Btu/year
Plant Load Factor 330/365, 0.90

	Existing KT	New Technology
1. Capital Cost, $\$10^6$	200	153
2. Plant Efficiency	0.60	0.64
3. Coal Costs, $\$/10^6$ Btu (coal at $\$1.40/10^6$ Btu)	2.33	2.19
4. O&M Costs, $\$/10^6$ Btu	0.43	0.35
5. Capital Charges (Municipal at 10%)	1.87	1.52
6. Capital Charges (Utility at 18%)	3.36	2.74
Cost of H_2, \$/1977		
Municipal, $\$/10^6$ Btu	4.63	4.06
Utility, $\$/10^6$ Btu	6.12	5.28

(a) All source costs in \$/1980 - costs above corrected to \$/1977 at 7 percent per year inflation.

TABLE D7-2. COSTS OF HYDROGEN BY ELECTROLYSIS AND COAL

Plant Size: 100 E6 Btu/hr ≈ 800 E9 Btu/year

	Electrolysis	Coal Gasification	
		Existing	New
Capital Cost ($ E6)	6.02	32.3	26.3
O&M Cost ($/E6 Btu)	0.42	2.66	2.17
Fuel Cost ($/E6 Btu)	10.51	2.33	2.19
Efficiency	0.78	0.60	0.64
Capital Charges ($ E6/year)	0.60	3.23	2.63
Capital Charges ($/E6 Btu)	0.76	4.08	3.32
Total Cost ($/E6 Btu)	11.69	9.07	7.68

As can be seen the size of plant has considerable influence on cost of production for coal based systems. This size relationship also exists for refuse however the cost shown in Figure D7.1 is based on refuse quantitites available in Riverside. Hydrogen produced through electrolysis (the opposite of a fuel cell) is relatively size independent and is competitive with coal based systems in smaller sizes representative of that required by Riverside's captive fleet (see Figure D7.1). The current price of gasoline (at 43 cents per gallon without tax) and of bulk delivered hydrogen is also shown in Figure D7.1.

The recommendation of this study are that Riverside eventually extend the use of hydrogen to as much of its captive fleet as possible as both a technical demonstration of the use of hydrogen and as a demonstration of the use of hydrogen and as a demonstration of low pollution vehicles Initially electrolysis will be most economical method of hydrogen production due to low first cost and low cost of production on a small scale. Eventually, as the project scale expands and new gasification technologies develop coal gasification will probably become a better long term production technique.

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D-8. ENERGY PRICE PROJECTIONS

Introduction # 2

A series of price projections was made for selected fuels and electric power for use in assessing the relative economics of various options included in this study. These projections were made in constant 1977 dollars assuming no inflation and include delivery costs to Riverside. Table D8-1 presents the results of these projections and the following discussion provides some background information on their development.

Fuel Oil Prices

Delivered prices of No. 2 distillate fuel oil are estimated at about 7 cents per gallon (50 cents per million Btu) higher than crude oil prices at the refinery. Low-sulfur residual fuel is estimated at about 5 cents per gallon (35 cents per million Btu) higher than crude oil prices at the refinery to cover additional processing and transportation costs to the Riverside area.

Natural Gas Prices

Increases in natural gas prices reflect the continuing impact of price controls on interstate supplies. By 1990, high-cost Alaskan gas and synthetic gas from coal will determine the price structure, which is estimated to be comparable to that of No. 2 distillate-fuel prices.

Coal Prices

Coal prices are based on estimates of prices for long-term contracts of low-sulfur Utah coal, plus transportation costs to the Riverside area.

TABLE D8-1. PROJECTED PRICES OF SELECTED FUELS AND ELECTRIC POWER DELIVERED TO RIVERSIDE, CALIFORNIA, 1976-2000 (Constant 1977 Dollars)

	Base Year Price	Escalation Rate, percent/year		Year 2000 Price	Percent Price Variation
		1977-1990	1990-2000		
Saudi Light Crude	2.30[1]	2.06	1.55	3.50	±20
U.S. Composite Crude	2.04[1]	3.01	1.55	3.50	±20
No. 2 Distillate Fuel	2.75[2]	1.87	1.34	4.00	±20
No. 6 Residual Fuel	2.65[3]	1.81	1.40	3.85	±20
Natural Gas	2.00	4.40	1.84	4.20	±20
Utah Coal	1.40	3.17	1.76	2.50	±20
Electric Power	11.39	4.86	3.48	31.16	±20

Electric Power Rates

Average rates have been estimated to increase at approximately the same rate as fossil fuel prices. It is assumed that electricity costs for the new nuclear power installations will be similar to fossil-fuel-fired steam generation plants.

A major uncertainty at this time is the changes in rate structures that may be mandated by Federal or State regulatory agencies. Costs for new generating capacity are appreciably higher than present average installed costs. This has created intense pressures to shift present rate structures and to reduce peak demands. Various schemes have been proposed that incorporate elements of

- Inverted rates
- Flattened rates
- Special rates for disadvantaged
- Peak-load (time-of-day) pricing
- Incremental costing.

The impact these potential changes have on wholesale rates of electric power to Riverside will depend on specific regulations, as established.

The Southern California Edison Company has forecast an average annual growth rate in electricity consumption of about 4.4 percent to 1955. This will require a generating capacity of about 2.25 times that of present capabilities. Nuclear units will supply half of this growth, supplying 35 percent of total requirements in 1995. Most of the other growth will be produced equally from coal and from combustion turbine and combined-cycle facilities using No. 2 distillate fuels. Geothermal units are anticipated to supply about 3.5 percent of the total requirements--equivalent to hydroelectric supplies. Residual fuel oil requirements are anticipated to increase from 52 million barrels in 1977 to 59.8 million barrels in 1985--then declining to 50.8 million barrels in 1995.(4)

The actual per unit cost of electricity varies from month to month depending on the fuel adjustment charge and peak demand. The base year electric price shown in Table D8-1 is a composite of energy charge (cost of energy consumed) and demand charge (cost levied against peak demand each

month or 50 percent of peak demand for the previous eleven months, whichever is higher) expressed as an average for the entire year of 1976. These costs and projections to 1990 are broken down in Table D8-2.

In 1976 the energy charge accounted for 72 percent of the cost shown in 1976 and the demand charge was the remaining 28 percent. The projected costs to the year 1990 are based on projections for energy charge and demand charge made in reference 6 . Based on these projections and assuming the same monthly demand to consumption ratio as 1976, the demand charge will be approximately half of Riverside's electric bill in 1990. Projections from 1990 through 2000 are highly speculative. Those shown in Table D8-1 are based on reducing the electric price growth rate the same as for the price forcasted reduction of residual oil.

TABLE D8-2. RIVERSIDE CURRENT AND PROJECTED PURCHASED ELECTRIC SUMMARY TO 1990

1.	Average Monthly Consumption[5]	78,832,000 kwh
2.	Average Peak Demand[5]	183,570 kwh
3.	Maximum Peak Demand [5]	267 kwhr
4.	Average Energy Charge[5]	0.028164 $/kwhr
5.	Annual Energy Charge (1. x 4. x 12 mos.)	26,642,693.4 $
6.	Annual Demand Charge[a]	
	a. Based on averages	10,133,064.0 $
	b. Based peak & ratchet	7,448,688.0 $
7.	Total Annual Charge (5. + 6a)	36,775,757.4 $
8.	Average Charge per kwhr	0.038876 $/kwh
	a. Percent energy charge	72
	b. Percent demand charge	28
9.	Average Charge per E6 Btu	11.39 $/E6 Btu
10.	Projected Electric Costs - 1990[6]	
	a. Energy charge	0.04132 $/kwh
	b. Demand charge	$14.71/kw-month
11.	Rate of Cost Increase per Year, 1976-1990	
	a. Energy charge	2.77%/year
	b. Demand charge	8.6%/year
12.	Projected Average Charge (1990)	
	a. Energy charge	12.02 $/E6 Btu
	b. Demand charge	10.12 $/E6 Btu
	c. Total	22.14 $/E6 Btu
	d. Composite percent increase	4.86%/year

(a) Based on a demand charge of $4.60/kw-month from Reference 6.

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D9. INTEGRATED UTILITY SYSTEM ANALYSIS

Introduction

This section of Appendix D presents an analysis of various options for an Integrated Utility System (IUS) for Riverside. As discussed earlier in Appendix D1, an IUS is a system which combines a number of utility services into a central plant, thus, providing for a number of positive effects on utilizing non-scarce and waste fuels in a local community system. The chief characteristics of such a system are that it would produce steam from the waste heat resulting from the production of electricity. This concept is known as cogeneration and is most applicable where there is a use for steam in the immediate locale of the plant, thus, requiring the plant to be located in or near the community where the steam is to be used. The steam so generated is then distributed to various points of end use for process or space heating purposes or is used to generate chilled water through an absorption cooling cycle, which in turn is then distributed to the point of end use for cooling purposes.

In this analyses three types of IUS plants are compared. The list involves existing technology, where coal and refuse are combusted in conventional boilers to generate steam and electricity. Figure D9-1 is a simple schematic showing the key features of such a plant. The second plant involves use of advanced technology that has not yet been commercialized. This plant consists of gasification of coal and refuse to a low heating valve gas which in turn is combusted in a gas turbine to generate electricity. The waste heat from the turbine is then used to generate steam. Figure D9-2 shows a simple schematic of this cycle. This technology is expected to be commercialized in the late 1980's. the third plant involves even more advanced technology. The process involved is similar to that of the second plant described above except that the low heating valve gas is used to drive a molten carbonate fuel cell instead of a simple schematic of this plant is shown in Figure D9-3 a gas turbine. This plant allows for somewhat higher efficiency and lower cost. The waste heat from the high temperature fuel cell exhaust is used to generate steam.

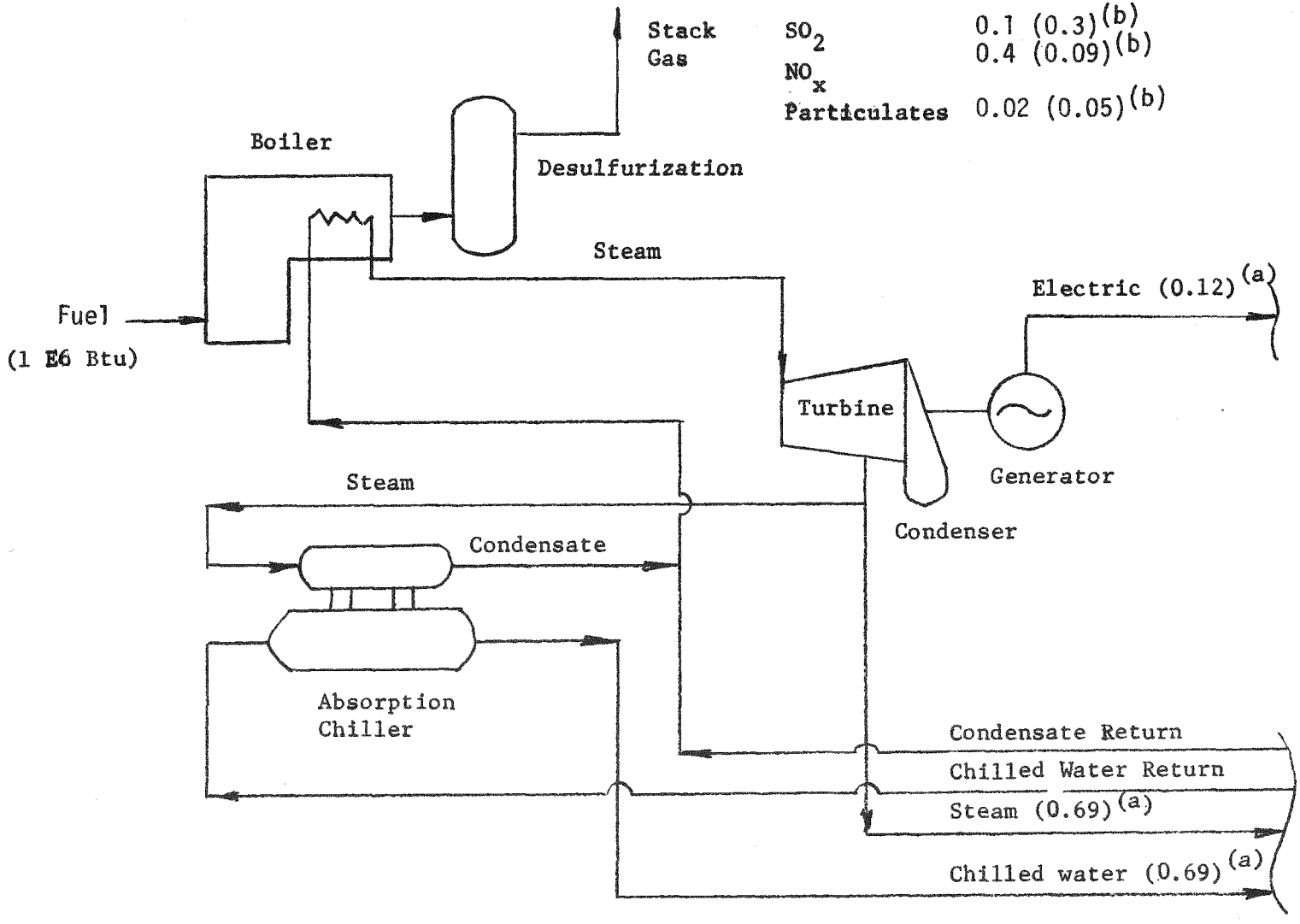

FIGURE D9-1 STEAM EXTRACTION COGENERATION

(a) E6 Btu to distribution per E6 Btu fuel input based on coal
(b) lbs per E6 Btu fuel input (See Table D10-1) based on coal (based on refuse)

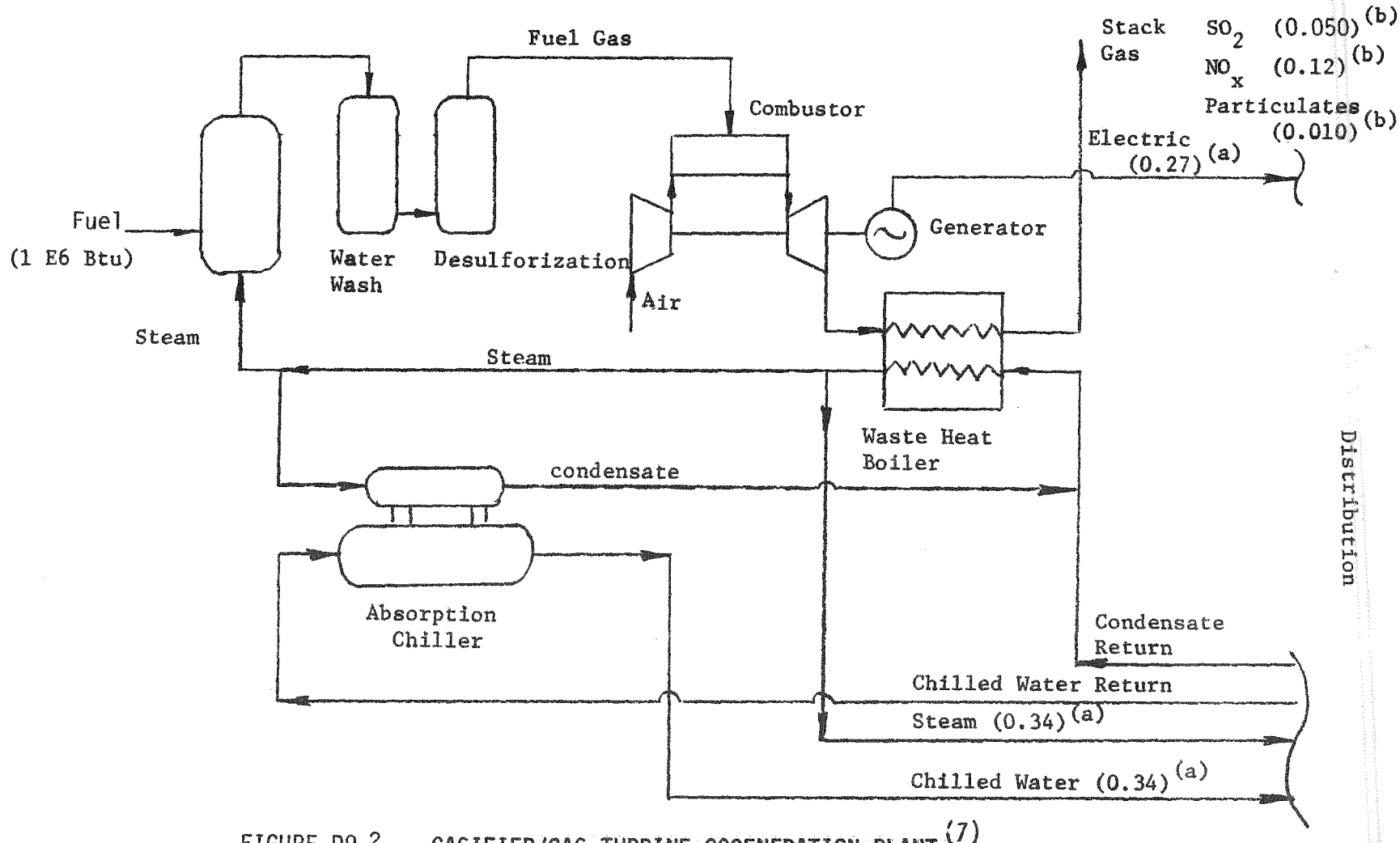

FIGURE D9-2. GASIFIER/GAS TURBINE COGENERATION PLANT [7]

(a) E6 Btu to distribution per E6 Btu fuel input
(b) lbs per E6 Btu fuel input

Distribution

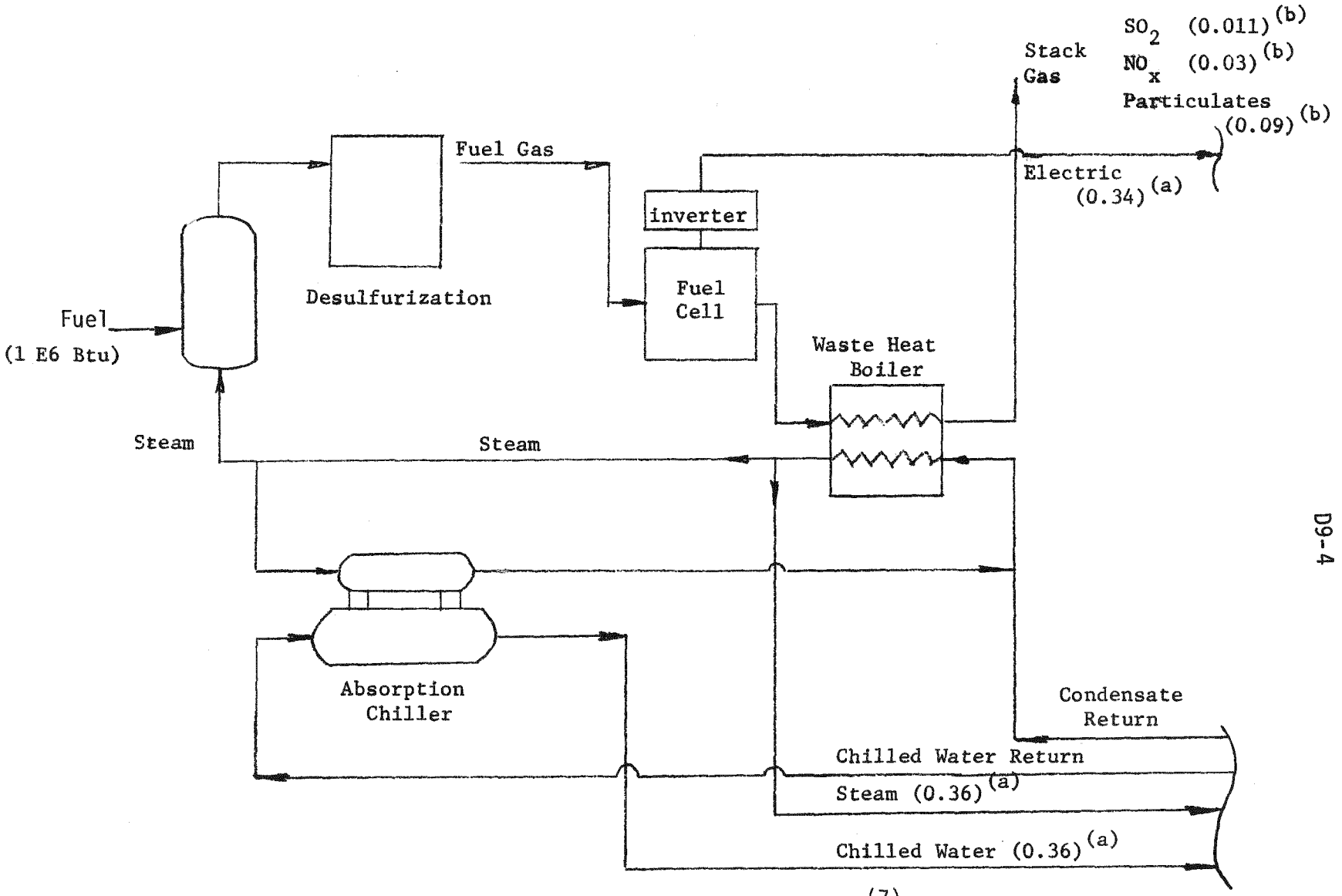

FIGURE D9-3. ADVANCED GASIFIER/FUEL CELL COGENERATION[7]

(a) E6 Btu to distribution per E6 Btu fuel input
(b) lbs per E6 Btu fuel input

Table D9-1 summarizes the base year (1976) energy demand and consumption data used as the basis for the integrated utility systems analysis. These data were used in deriving energy demand data in subsequent tables in this Appendix. Specific features of this table are as follows:

a) The table is divided into four sets of columns. The first three represent areas of the city that would be served within an Integrated Utility System (IUS) framework. Citywide data is shown in the fourth set of columns.

b) The IUS options involve serving specific areas of the City with steam or hot water for space heat and base load or process heat requirements and chilled water for cooling requirements. These energy flows would be generated from a central plant. A number of fuels or energy sources can be considered for the central plant including geothermal (Arrowhead Springs), coal, refuse/biomass, and nuclear. Each of these energy resources and their associated technologies are discussed elsewhere in this report. Nuclear was discarded as an energy source for a Riverside IUS on the grounds of unfavorable public acceptance. The IUS concept also allows for cogeneration (synergistic production of electric and thermal energy) which can be used with any energy source to enhance the utilization of available thermodynamic energy.

c) The IUS options are divided into low, moderate, and high impact strategies in keeping with the general format of this study. The three strategies differ only in the area of the City served. Figure D9-4, D9-5 and D9-6 show the areas of the City included in each of the three strategies. The areas are defined by census tracts as follows:

Low --Tracts 303, 304, 305, 422.03

Moderate--Tracts 303, 304, 305, 422.03, 422.02

High --Tracts 303, 304, 305, 422.03, 422.02, 307, 311

TABLE D9-1. BASEYEAR ENERGY DEMAND AND CONSUMPTION DATA (1976)

Energy Requirement		IUS Stragegy									City Wide		
		Low			Moderate			High					
		Res	Com	Ind	Res	Com	Ind	Res	Com	Ind	Res	Com	Ind
1. Thermal Demand													
Peak	E6 Btu/hr	9.6	47.7	155.9	9.9	113.7	155.9	11.7	199.7	157.5	1320.0	380.0	290.0
Hourly Space Heat	E6 Btu/hr	2.6	16.2	24.3	2.7	39.2	24.3	3.2	68.3	24.5	360.0	130.0	45.0
Hourly Base Load	E6 Btu/hr	2.6	19.0	80.7	2.7	45.0	80.7	3.2	79.4	81.5	275.0	150.0	150.0
Annual Space Heat	E9 Btu/yr[(a)]	7.6	47.0	70.6	7.8	113.8	70.6	9.2	198.3	71.1	1045.4	377.5	130.7
Annual Base Load	E9 Btu/yr[(b)]	22.8	166.4	706.9	23.6	394.2	706.9	27.8	695.5	713.9	2409.0	1314.0	1314.0
2. Electric Demand													
Peak	MW	1.2	9.8	31.6	1.3	19.2	31.6	1.5	40.7	31.9	121.0	85.4	44.4
Cooling	kW	170.2	1170.0	2290.0	175.5	2320.0	2290.0	207.3	4840.0	2310.0	16700.0	10000.0	2500.0
Base Load	kW	283.5	4885.0	8570.0	292.5	9725.0	8570.0	345.5	20295.0	8650.0	29300.0	42000.0	12000.0
3. Cooling Demand													
Peak	MW	0.90	3.9	21.2	0.94	7.9	21.2	1.11	16.7	21.4	85.8	35.0	30.0
Hourly Peak	E6 Btu/hr[(c)]	12.4	53.2	289.4	12.8	107.8	289.4	15.1	228.0	292.1	732.1	477.8	409.6
Annual Demand	E9 Btu/yr[(d)]	10.2	70.5	138.0	10.6	139.9	138.0	12.5	291.8	139.3	629.2	602.3	150.7
4. Thermal Consumption													
Annual Space Heat	E9 Btu/yr[(e)]	10.1	62.7	94.1	10.4	151.7	94.1	12.3	264.4	94.8	1742.3	503.3	174.3
Annual Base Load	E9 Btu/yr[(f)]	22.8	166.4	706.9	23.6	394.2	706.9	27.8	695.5	713.9	2409.0	1314.0	1314.0
5. Cooling Consumption	E9 Btu/yr[(g)]	7.7	53.4	104.5	8.0	106.0	104.5	9.5	221.1	105.5	762.7	456.3	114.2

(a) Hourly space heat times 2904 hours/year in heating season.

(b) Hourly base load times 8760 hours/year.

(c) Peak (MW) times 3413 E3 Btu/MW-hr times 4.0 [coefficient of performance (COP)] for res in IUS and all com and ind. Res in city wide case used COP of 2.5 to account for smaller unitary equipment.

(d) Cooling demand (kW) times 34.3 Btu/kW-hr times 4416 hours/year in cooling season times COP [see (c) above].

(e) Assumed efficiency for IUS res and all com/ind is 0.75. Efficiency for city wide res is 0.60.

(f) Assumed efficiency is 1.0 (see Appendix A).

(g) Cooling demand in kW times 4416 hours/year in cooling season times 10200 Btu/kW-hr (heat rate for Southern California Edison).

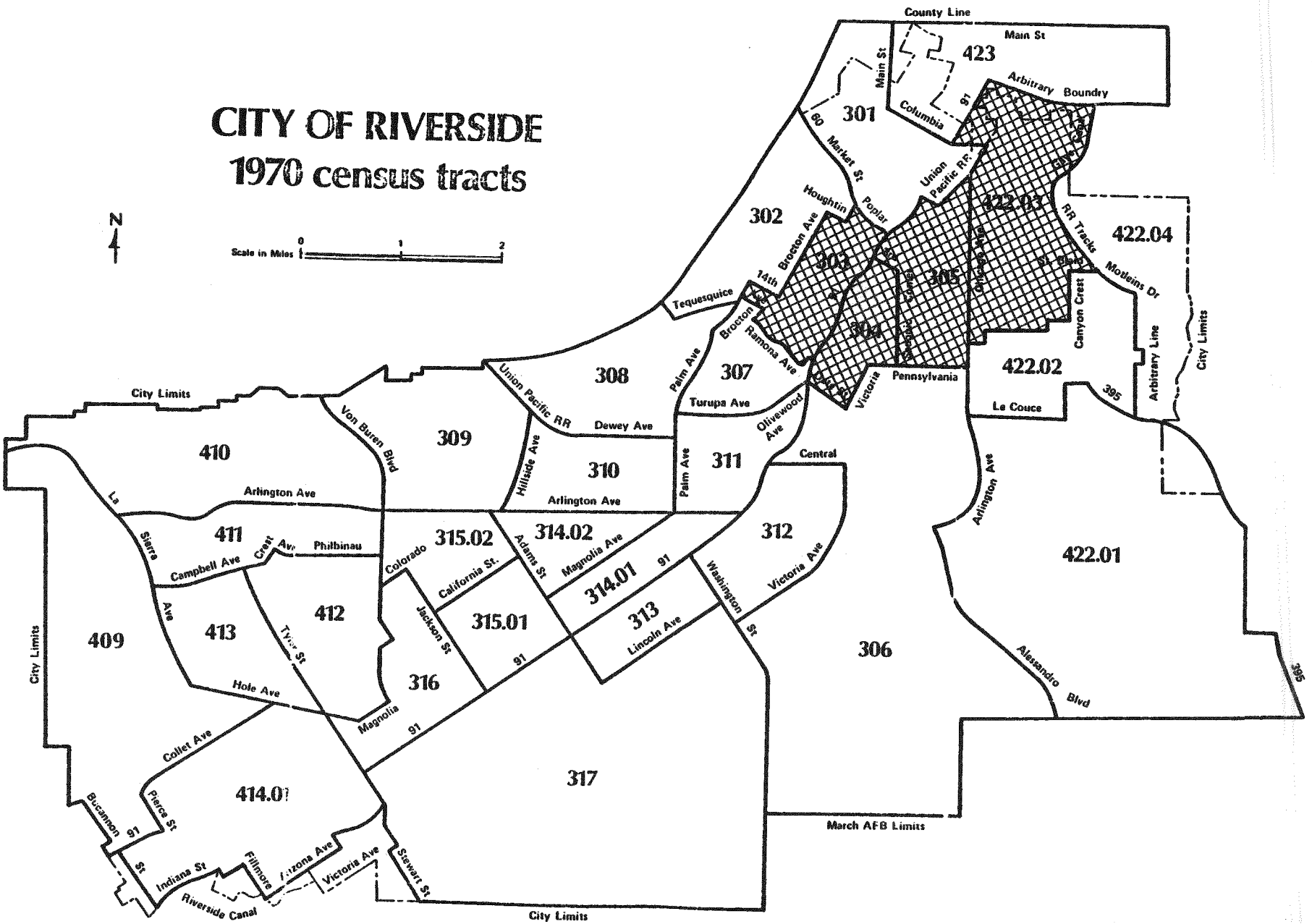

FIGURE D9-4 CENSUS TRACTS INCLUDED IN LOW IMPACT STRATEGY

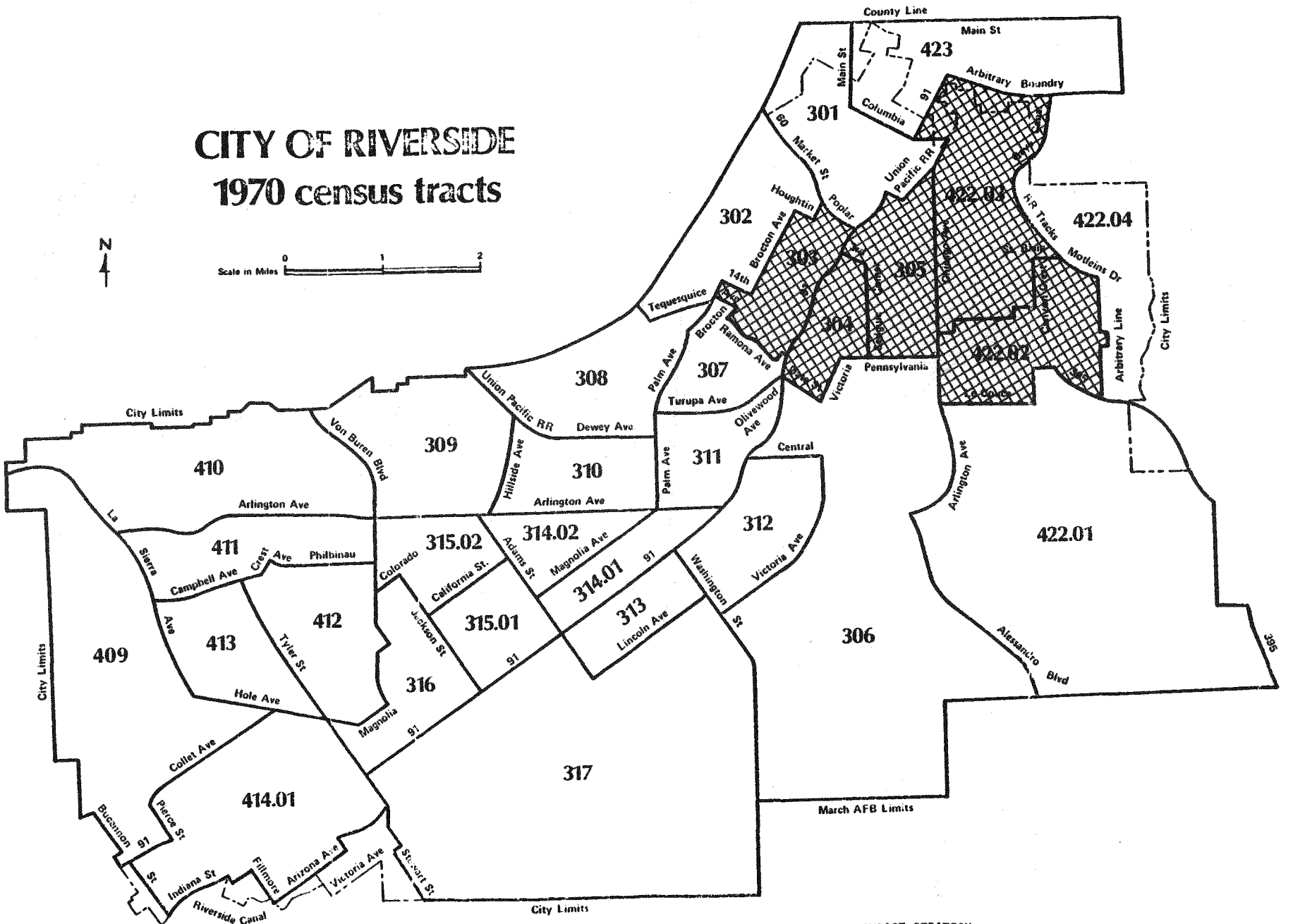

FIGURE D9-5. CENSUS TRACTS INCLUDED IN MODERATE IMPACT STRATEGY

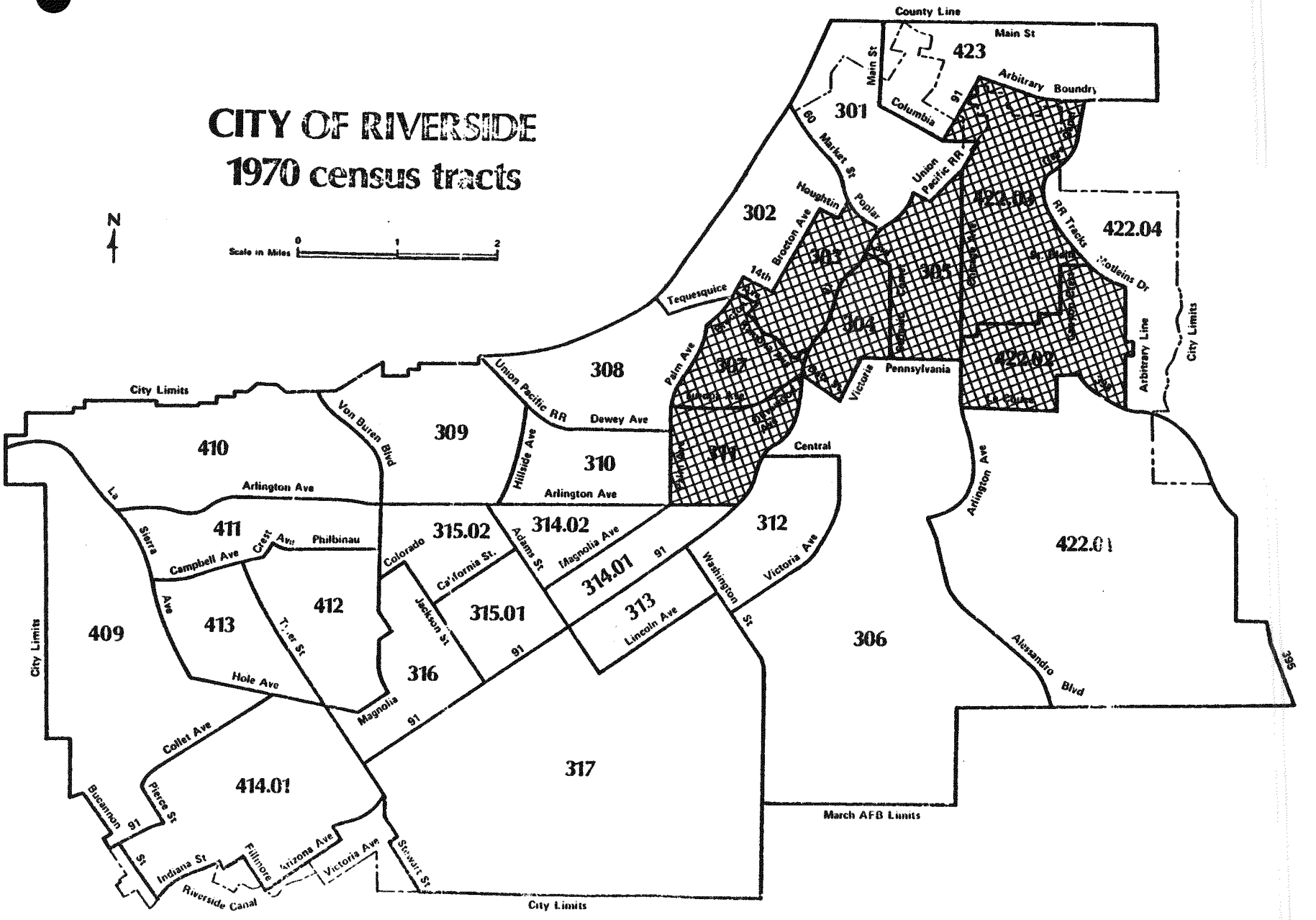

FIGURE D9-6 CENSUS TRACTS INCLUDED IN HIGH IMPACT STRATEGY

In each case all census tracts are contiguous and represent the core of the City with highest energy use density (energy consumption per unit area). The low strategy includes the downtown core along with the Central, Riverside Brown, and Hunter industrial areas. The moderate strategy adds the University of California at Riverside, which already has its own steam and chilled water distribution system. The high strategy adds the Magnolia Center area.

d) Each set of columns is separated into three parts representing residential (res), commercial (com), and industrial (ind) end-use categories. Residential includes high-rise dwelling units only. Low-rise and single-family units are better served by individual heating and cooling units with the use of active and passive solar-based designs. A better definition of the number of high-rise residential units in each case is given in Table D9-2.

e) Each of the energy demands is self-explanatory with the footnotes provided in Table D9-1.

f) By comparing items 4 and 5, it can be seen that the low to high IUS strategy areas represent from 14 to 24 percent of energy used for thermal needs and 12 to 25 percent of energy used for cooling needs of the City as a whole, respectively.

TABLE D9-2. NUMBERS OF HIGH-RISE MULTIFAMILY RESIDENTIAL UNITS CONSIDERED IN INTEGRATED UTILITY SYSTEM OPTIONS[a]

	Strategy		
	Low	Moderate	High
Existing multifamily units as of 1976	4928	5083	6009
Existing high-rise units (11.5% of multifamily)	567	585	691
New high-rise units added[b] by year 2000			
Low growth	440	971	1500
Moderate growth	783	1500	1500
High growth	1232	1500	1500
Total high-rise units in IUS by year 2000			
Low growth	1007	1556	2191
Moderate growth	1350	2084	2191
High growth	1799	2084	2191

(a) In the residential category, only high-rise dwelling units are considered part of the integrated utility system because of the high costs of hot and chilled water distribution to low rise and single family units on a cost-per-unit-energy-delivered basis.

(b) The maximum number of high-rise units that could reasonably be added to the IUS area was set at 1500. In low strategy/low growth scenarios, this would allow addition of all planned high-rise units to the IUS.

In order to develop conceptual alternative energy supply system designs for the Integrated Utility System (IUS) options, it was necessary to develop energy demand data for the year 2000 in order to account for various population growths and the savings resulting from conservation and community design. The conservation and community design options included in the low, moderate, and high impact strategies and their resultant effect are the same as those presented in Appendix C. (As they would impact on the City covered by the IUS system). Table D9-3 gives revised energy demand data for the three IUS impact areas.

TABLE D9-3. ENERGY DEMANDS IN YEAR 2000 ADJUSTED FOR CONSERVATION AND COMMUNITY DESIGN

Energy Requirement	IUS Strategy											
	Low				Moderate				High			
	Res	Com	Ind	Total	Res	Com	Ind	Total	Res	Com	Ind	Total
Low Population Growth (0.9%/yr.)												
Peak Thermal Demand E6 Btu/hr	11.9	47.8	201.4	261.1	16.4	104.7	189.3	310.4	21.6	168.1	178.6	368.3
Annual Space Heat Demand E9 Btu/yr	8.1	40.8	81.6	130.5	10.4	84.7	71.4	166.5	13.2	122.9	61.5	197.6
Annual Base Load Demand E9 Btu/yr	39.0	200.1	1001.7	1240.8	59.6	469.2	991.4	1520.2	83.4	819.2	987.9	1890.5
Peak Cooling Demand E6 Btu/hr	13.3	46.2	310.2	369.7	17.1	80.2	271.4	368.7	21.6	141.3	234.2	397.1
Annual Cooling Demand E9 Btu/yr	11.0	61.2	139.4	206.6	16.2	104.1	122.1	242.4	17.8	180.9	105.3	303.5
Moderate Population Growth (1.55%/yr)												
Peak Thermal Demand E6 Btu/hr	15.3	55.9	255.8	327.0	21.6	122.4	240.5	384.5	21.6	196.6	226.4	444.6
Annual Space Heat Demand E9 Btu/yr	10.2	47.7	103.5	161.4	13.6	99.0	90.6	203.2	13.2	143.7	77.9	234.8
Annual Base Load Demand E9 Btu/yr	52.0	234.1	1272.2	1558.3	79.7	548.7	1259.2	1887.6	83.4	958.1	1253.0	2294.5
Peak Cooling Demand E6 Btu/hr	16.7	54.0	379.0	449.7	22.3	93.8	331.6	447.7	21.6	165.3	285.8	472.7
Annual Cooling Demand E9 Btu/yr	13.7	71.5	164.6	249.8	18.5	121.7	144.1	284.3	17.8	211.6	124.3	353.7
High Population Growth (2.17%/yr)												
Peak Thermal Demand E6 Btu/hr	19.8	64.4	312.8	397.0	21.6	141.0	294.1	456.7	21.6	226.4	276.6	524.6
Annual Space Heat Demand E9 Btu/yr	12.9	54.9	126.6	194.4	13.6	114.0	110.7	238.3	13.2	165.6	95.2	274.0
Annual Base Load Demand E9 Btu/yr	69.1	269.6	1555.6	1894.3	79.7	632.0	1539.7	2251.4	83.4	1103.4	1530.5	2717.3
Peak Cooling Demand E6 Btu/hr	21.1	62.2	451.0	534.3	22.3	112.9	394.7	529.9	21.6	190.4	339.9	551.9
Annual Cooling Demand E9 Btu/yr	10.9	82.4	191.2	284.5	18.5	293.3	167.3	479.1	17.8	243.6	144.2	405.6

In order to compare various IUS plant options, it was necessary to develop basic energy demand design data and establish a design philosophy.

Table D9-4 summarizes the IUS energy demand data used in preliminary design of IUS plants. The following describes how these data were used to develop conceptual IUS central plant designs based on various technologies.

a) The peak thermal demand is the most important factor in establishing the size of the central plant. In this case there are three contributors to peak demand: (1) the base load thermal component (This component is assumed to be constant throughout the year) (2) Peak thermal demand due to space heat and (3) Peak thermal demand due to cooling.

   As can be seen, the maximum peak thermal demand occurs when the peak cooling demand is added to the base load thermal component. However, the annual cooling demand is relatively small and designing a central plant based on cooling peak would be unnecessarily expensive.

   Figure D9-7 is a load duration curve for the low impact strategy/low population growth case which allows more incisive analysis of the data in Table D9-4. The design philosophy decided upon was to allow for sufficient capacity in the central plant to handle the thermal load due to space heat plus base load. As can be seen this would allow sufficient thermal capacity to supply about half the annual cooling needs through steam-driven absorption chillers. The remaining cooling requirements would be satisfied with electrically-driven centrifugal chillers.

b) In establishing the true energy demands at the central plant, a 10 percent energy loss in distribution was assumed. Item B in Table D9-4 contains the energy demands for thermal and cooling energy seen at the central plant.

TABLE D9-4 ENERGY DEMAND DESIGN DATA FOR IUS IN THE YEAR 2000

	Strategy								
	Low			Moderate			High		
	Growth			Growth			Growth		
	low	mod	high	low	mod	high	low	mod	high
A. At the Point of End Use									
1. Base Thermal Demand E6 Btu/hr	141.6	177.9	216.2	173.5	215.5	257.0	215.8	261.9	310.2
2. Peak Space heat Demand E6 Btu/hr	119.5	149.1	180.8	136.9	169.0	199.7	152.5	182.7	214.4
3. Peak Cooling Demand E6 Btu/hr	369.7	449.7	534.3	368.7	447.7	529.9	397.1	472.7	551.9
4. Annual Thermal Demand E9 Btu/yr (a)	1371.3	1719.7	2088.7	1686.7	2090.8	2489.7	2088.1	2529.3	2991.3
5. Annual Cooling Demand E9 Btu/yr (b)	206.6	249.8	284.5	242.4	284.3	479.1	303.5	353.7	405.6
B. At the Central Plant (c)									
1. Thermal Peak E6 Btu/hr	290.1	363.3	441.1	344.9	427.2	507.4	409.2	494.0	582.9
2. Cooling Peak E6 Btu/hr	410.8	499.7	593.7	409.7	497.4	588.8	441.2	525.2	613.2
3. Annual steam Generation E9 Btu/yr	1648.4	2049.6	2478.8	2008.6	2481.0	3032.4	2488.7	3006.8	3549.0

(a) Annual demand for steam to satisfy process heat and space heat requirements. Sum of space heat and base load from Table 09-3.

(b) Annual cooling demand from Table D9- 3.

(c) Includes 10 percent distribution losses.

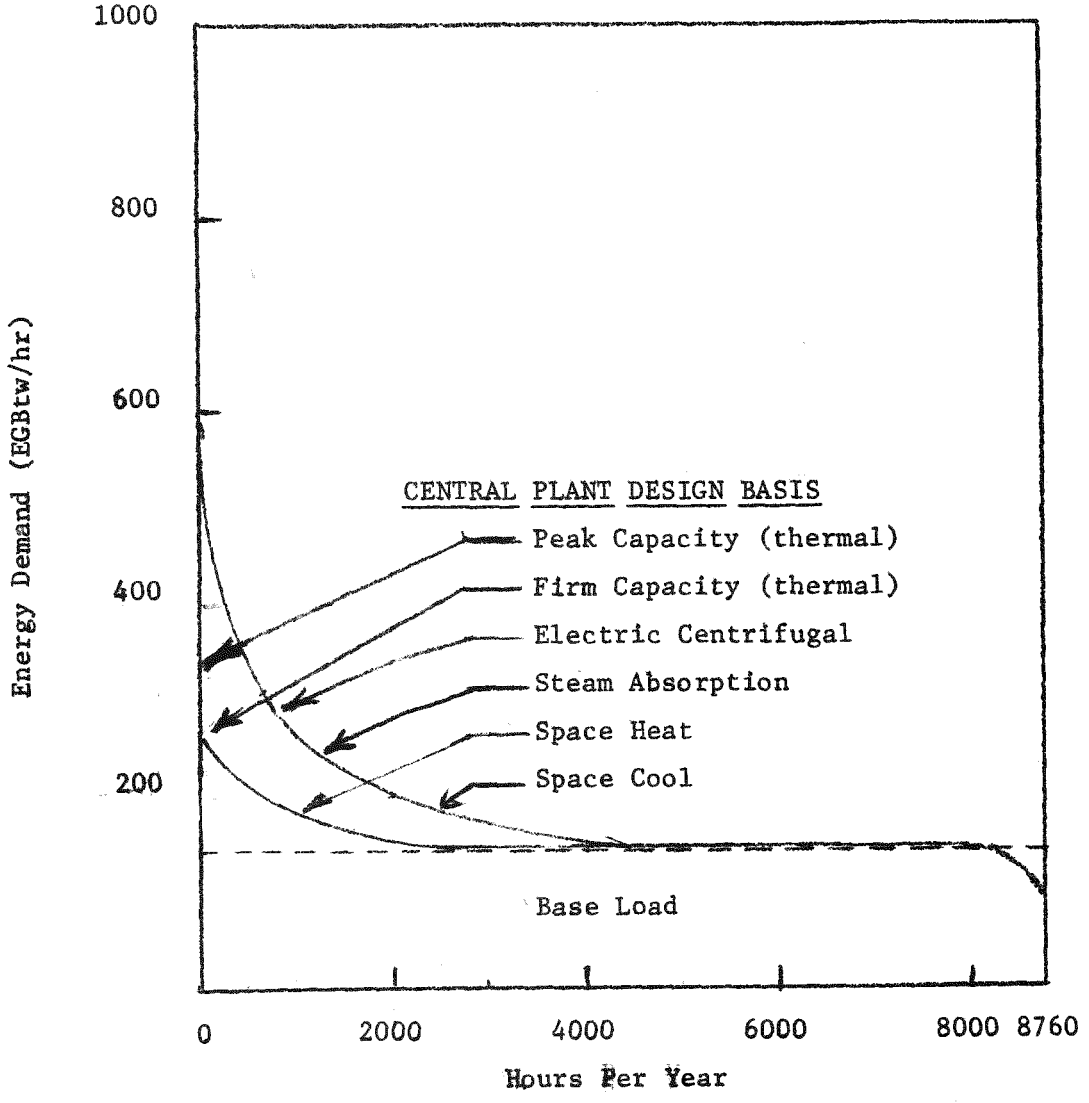

FIGURE D9-7. THERMAL AND COOLING LOAD DURATION CURVES FOR INTEGRATED UTILITY SYSTEM-LOW IMPACT STRATEGY, LOW POPULATION GROWTH-WITH CENTRAL PLANT DESIGN PHILOSOPHY

Cost Breakdowns

Tables D9-5 through D9-7 give cost breakdowns for integrated utility system plants representative of the three technology variations shown in Figures D9-1 through D9-3, respectively. These cost estimates are all for the moderate impact, moderate population growth energy demand case in Table D9-4.

Cost Analysis

In order to determine the potential economic viability of the integrated utility concept, a cost analyses was done comparing the three cases in Tables D9-5 through D9-7 with Riverside's participation in the Intermountain Power Project nuclear generating plant in Utah and with combined purchase of utility electric supplies. Table D9-8 presents the results of this cost analysis and Tables D9-9 and D9-10 give more detailed breakdowns of costs presented in Table D9-8. The following general assumption were used in computing the costs in Table D9-8.

General inflation rate	5 percent per year
Natural gas escallation rate	6 percent per year
Nuclear fuel escallation rate	5 percent per year
Coal escallation rate	5 percent per year
Project life	30 years
Bond rate	6.5 percent
Debt	100 percent

These assumptions are essentially the same used in the "official statement for Riverside's issue of $43,000,000 in Revenue Bonds to support participation in the Intermountain Power Project" - Wainright and Ramsey August, 1978 - which was used as the basis for the Intermountain Power and SEC costs.

TABLE D9-5. DESIGN SUMMARY FOR LOW IMPACT IUS STRATEGY
(costs in 1978 $)

1.	Peak Thermal Demand (E6 Btu/hr)	427
2.	Annual Thermal Demand (E9 Btu/yr)	2481
3.	Peak Cooling Demand (D3 Btu/hr)	497
4.	Refuse Boiler	
	a. Annual refuse supply (E3 tons/yr)	209
	b. Firm capacity (E6 Btu/hr) 260 days/yr 24 hrs/day	174
	c. Design capacity (E6 Btu/hr) 2b. + 25%	217
	d. Capital Cost ($E3)[2]	38,800
	e. Maintenance and supplies ($E3/yr)(6% of d)	2,330
5.	Coal Boiler	
	a. Firm capacity 1. - 4.7	253
	b. Design coal capacity (E6 Btu/hr) 5a. + 25%	316
	c. Capital cost ($E3)	13,000
	d. Maintenance and supplies ($E3/yr)(4% of b)	520
6.	Turbine Generator	
	a. Design capacity (MW) Total design steam 5.14 - from Doherty	30
	b. Capital cost ($E3)(at 200$/kw)[4]	6,000
	c. Maintenance and supplies ($E3/yr)(4% of b)	240
7.	Chillers	
	a. Design capacity - E6 Btu/hr	621
	- tons (E3) 3. + 25%	51,750
	b. Capital cost ($E3)[5]	10,350
	c. Maintenance and supplies ($E3/yr)(4% of b)	410
8.	Distribution System	
	a. Annual thermal supply (E9 Btu/yr)	2,233
	b. Capital cost ($E3)[6]	23,900
	c. Maintenance and supplies ($E3/yr) (4% of b)	956
	d. Retrofit[6]	19,000
9.	Total capital cost ($E3)	
	a. Equipment	92,050
	b. Retrofit	19,000
10.	Annual O&M ($E3)	
	a. Maintenance and supplies	4,456
	b. Labor (50 people at $20,000/year each)	1,000
11.	Annual Refuse Consumed	
	a. E3 ton/yr	209
	b. E9 Btu/yr	2,090
12.	Annual Coal Consumed	
	a. E3 ton/yr	83
	b. E9 Btu/yr	2,020
13.	Annual Electricity Generated	
	a. E6 Kw-hrs/yr	126
	b. E9 Btu/yr	431

TABLE D9-6. DESIGN SUMMARY FOR MODERATE IMPACT IUS STRATEGY[7]
(Costs in 1978 $)

1.	Peak Thermal Demand (E6 Btu/hr)	427
2.	Annual Thermal Demand (E9 Btu/yr)	2,481
3.	Peak Cooling Demand (E6 Btu/hr)	497
4.	Refuse Gasification	
	a. Annual refuse supply (E3 tons/yr)	209
	b. Firm capacity (E6 Btu/hr) 260 days/hr 24 hrs/day	114
	c. Design capacity (E6 Btu/hr)	142
	d. Capital cost ($E3) (Appendix D-5) 45,800 E3$ 750 ton/day	56,300
	e. Maintenance and supplies ($E3/yr) (6% of d)	3,380
5.	Coal Gasification	
	a. Firm coal capacity (E6 Btu/hr)	313
	b. Design coal capacity (E6 Btu/hr)	391
	c. Capital cost ($E3)[7] 329 E6$ for 1890 E6 Btu/hr	109,000
	d. Maintenance and supplies ($E3/yr) (4% of c)	4,360
6.	Turbine Generator - Waste Heat Boiler	
	a. Design capacity (MW)	128
	b. Capital cost ($E3) (220 $/kw)[7]	25,600
	c. Maintenance and supplies ($E3/yr) (4% of b)	1,025
7.	Chillers	
	a. Design capacity - E6 Btu/hr	621
	- tons (E3)	51,750
	b. Capital cost ($E3)[5]	10,350
	c. Maintenance and supplies ($E3/yr) (4% of b)	414
8.	Distribution System	
	a. Annual thermal supply (E9 Btu/yr)	2,233
	b. Capital cost ($E3)[6]	23,900
	c. Maintenance and supplies ($E3/yr) (4% of b)	956
	d. Retrofit[6]	19,000
9.	Total Capital Cost ($E3)	
	a. Equipment	225,150
	b. Retrofit	19,000
10.	Total O&M Cost ($E3)	
	a. Maintenance and supplies	10,135
	b. Labor	1,005
11.	Annual Refuse consumed	
	a. E3 tons/yr	209
	b. E9 Btu/yr	2,090
12.	Annual Coal Consumed	
	a. E3 tons/yr	183
	b. E9 Btu/yr	5,207
13.	Annual Electricity Generated	
	a. E6 BW hrs/yr	577
	b. E9 Btu/yr	1,969

TABLE D9-7. DESIGN SUMMARY FOR HIGH IMPACT IUS STRATEGY
(Cost in 1978 $)

1.	Peak Thermal Demand (E6 Btu/hr)	427
2.	Annual Thermal Demand (E9 Btu/yr)	2,481
3.	Peak Cooling Demand E6 Btu/hr)	497
4.	Refuse Gasification	
	a. Annual refuse supply (E3 tons/yr)	209
	b. Firm capacity (E6 Btu/hr)	121
	c. Design capacity (E6 Btu/hr)	151
	d. Capital cost ($E3) (Appendix D-5)	56,300
	e. Maintenance and supplies ($E3/yr) (6% of d)	3,380
5.	Coal Gasification	
	a. Firm coal capacity (E6 Btu/hr)	306
	b. Design coal capacity (E6 Btu/hr)	382
	c. Capital cost ($E3)[7]	84,000
	d. Maintenance and supplies ($E3/yr)(4% of c)	3,370
6.	Fuel Cell Generator - Waste Heat Boiler	
	a. Design capacity (MW)	147
	b. Capital cost ($E3)[8](350 $/kw)	51,560
	c. Maintenance and supplies ($E3/yr)(4% of b)	2,060
7.	Chillers	
	a. Design capacity - E6 Btu/hr	621
	- tons (E3)	51,750
	b. Capital cost ($E3)[5]	10,350
	c. Maintenance and supplies ($E3/yr)(4% of b)	414
8.	Distribution System	
	a. Annual thermal supply (E9 Btu/yr)	2,233
	b. Capital cost ($E3)[6]	23,900
	c. Maintenance and supplies ($E3/yr)(4% of b)	956
	d. Retrofit ($E3)[6]	19,000
9.	Total Capital Cost ($E3)	
	a. Equipment	226,110
	b. Retrofit	19,000
10.	Total O&M Cost (RE3/yr)	
	a. Maintenance and supplies	10,180
	b. Labor	1,005
11.	Refuse	
	a. E3 tons/yr	209
	b. E9 Btu/yr	2,090
12.	Coal	
	a. E3 tons/yr	197
	b. E9 Btu/yr	4,802
13.	Electricity generated	
	a. E6 kw-hrs/yr	686
	b. E9 Btu/yr	2,341

TABLE D9-8. ANNUALIZED COST COMPARISON OF IUS OPTIONS VERSUS REMOTE GENERATION AND UTILITY ALTERNATIVES

		Year 1								
		1990 Option			1995 Option			2000 Option		
		1	2	3	1	2	3	1	2	3
Integrated Utility System (IUS)										
1. Total Capital Cost of Project[a]	E6$	146.5	358.3	360.0	--	--	--	--	--	--
2. Amortization of capital[b]	E6$/yr	11.2	27.4	27.6	11.2	27.4	27.6	11.2	27.4	27.6
3. Operation and Maintenance[c]	E6$/yr	9.9	19.9	20.1	12.6	25.4	25.7	16.1	32.5	32.8
4. General and Administrative[d]	E6$/yr	3.3	6.6	6.6	4.2	8.4	8.5	5.3	10.7	10.8
5. Insurance[e]	E6$/yr	1.6	6.4	6.5	2.1	8.2	8.2	2.7	10.5	10.5
6. Refuse Consumed[f]	E3 tons/yr	179	179	179	193	193	193	209	209	209
7. Dump Fee[g]	$/ton	9.0	9.0	9.0	11.5	11.5	11.5	14.6	14.6	14.6
8. Refuse Credit	$E6/yr	1.6	1.6	1.6	2.2	2.2	2.2	3.0	3.0	3.0
9. Coal Purchased[h]	E9 Btu/yr	2000	5010	4632	2014	5108	4717	2020	5207	4802
10. Coal Price[i]	$/E6 Btu	2.77	2.77	2.77	3.54	3.54	3.54	4.52	4.52	4.52
11. Cost of Coal	$E6/yr	5.5	13.9	12.8	7.1	18.1	16.7	9.1	23.5	21.7
12. Steam Sold[j]	E9 Btu/yr	1938	1938	1938	2012	2012	2012	2091	2091	2091
13. Steam Price (see Table D9-10)	$/E6 Btu	6.1	6.1	6.1	7.8	7.8	7/8	9.5	9.5	9.5
14. Steam Credit	$E6/yr	11.8	11.8	11.8	15.7	15.7	15.7	19.9	19.9	19.9
15. Chilled Water Sold[k]	E9 Btu/yr	275	275	275	279	279	279	284	284	284
16. Chilled Water Price (see Table D9-10)	$/E6 Btu	5.9	5.9	5.9	7.3	7.3	7.3	9.0	9.0	9.0
17. Chilled Water Credit	$E6/yr	1.6	1.6	1.6	2.0	2.0	2.0	2.6	2.6	2.6
18. Total Annual System Cost (2 + 3 + 4 + 5 + 11 - 8 - 14 - 17)	$E6/yr	16.8	59.2	58.6	17.3	67.6	66.8	18.9	79.1	77.9
19. Electricity Generated[e]	E9 Btu/yr	402	1835	2181	416	1899	2258	431	1969	2341
	E6 Kw-hrs/yr	118	538	639	122	556	662	126	577	686
20. Cost of Electricity	mills/kw-hr	140	110	92	142	121	100	150	137	113
Alternatives										
21. Cost of Electricity from Intermountain Power Project[m]	mills/kw-hr		32			40			52	
22. Average cost of Electricity from Southern California Edison	mills/kw-hr		66			84			107	

TABLE D9-8. (Continued)

(a) Plant is assumed to be installed in 4 equal increments during the 4-year construction period. Cost in each year is equal to 1/4 the total capital cost from Tables D9-5. D9-7 escalated at 5 percent per year. Interest during construction is included in the capital cost. See Table D9-9 for details.

(b) Based on the sale of 30-year, 6.5 percent revenue bonds in mid 1989.

(c) Based on total operation and maintenance cost from Table D9-7-9, escalated at 5 percent per year.

(d) Assumed at 1/3 of O&M as per reference D11-1.

(e) Assumed at 1 percent of total capital cost escalated at 5 percent per year.

(f) Based on 144,300 tons per year in 1976 (Table D5-1) escalated with population growth (1.55 percent/year). Assumed heating value is 10 E6 Btu/ton.

(g) Based on 5 $/ton dump fee in 1978 escalated at 5 percent per year.

(h) Fuel required in addition to refuse to supply thermal plus cooling demand shown in Table D9-6 using cycle shown in Figure D9-6.

(i) Assumed base year (1976) price of 1.40 $/$10^6$ Btu from Table D8-2 escalated at 5 percent per year.

(j) Steam sold to distribution (Table D9-6).

(k) Chilled water sold to distribution (Table D9-6).

(l) Amount of electricity produced from IUS using data from Table D9-6.

(m) Cost of electricity from Intermountain Power Project with escalation at 5 percent per year.

(n) Average cost of electricity to Riverside assuming cooperation in Intermountain Power Project (most of Riverside's electric needs still being met by purhcases from Southern California Edison). Escalation at 5 percent per year.

TABLE D9-9. CONSTRUCTION COST SCHEDULE FOR IUS OPTIONS ($MILLIONS IN CURRENT YEAR)[a][b]

IUS OPTION	Year 1978	1986	1987	1988	1989	1990[c] Total
Plant 1 - conventional combustion	92.0	34.0	35.7	37.5	39.3	146.5
Plant 2 - Advanced gasification gas turbine	225.1	83.1	87.3	91.7	96.2	358.3
Plant 3 - Advanced gasification fuel cell	226.1	83.5	87.7	92.1	96.7	360.0

(a) Costs escallated at 5 percent per year

(b) Each plant constructed in equal 25 percent

(c) Total plant cost in 1990 dollars. Sum of 1986 through 1989 installments.

TABLE D9-10. CALCULATION OF STEAM AND CHILLED WATER CHARGES FOR INTEGRATED UTILITY SYSTEM

Steam

The allowable steam charge is based on the alternative of a customer purchasing his own gas/oil fired boiler in the base year of 1976 and operating it with gas for the life of the project (through 2000). The following assumption and calculations were used.

Cost of gas (1976)	$2.00/E6 Btu
Boiler capital cost (1976)	$9/E3 Btu/hr
Uniform capital recovery factor[a]	0.30
Capacity factor[b]	0.60
Boiler efficiency	0.75
Operation and maintenance (4% of capital)	$0.36/year

Annual steam production = 1000 Btu/hr X 8760 hrs/year X 0.6

= 5.26 E6 Btu

Annual fuel requirement = 5.26 E6 Btu/0.75 = 7.01 E6 Btu/yr

Annual Capital cost = 0.3 X 9 = 2.7 $/year

Cost per unit of steam is

$$\frac{2.00\ \$/E6\ Btu \times 7.01\ E6\ Btu/yr + 2.7\ \$/yr + 0.36\ \$/yr}{5.26\ E6\ Btu/yr}$$

= 3.25 $/E6 Btu 1977 cost

Chilled Water

The allowable chilled water charge is based on the alternative of a customer purchasing an electric driven compression type chiller in the base year of 1976 and operating it over the life of the project (through 2000). The following assumptions and calculations were used.

Cost of electricity (1990)( )	66.5 mills/mo-hr
Chiller capital cost (1976)	$200/ton
Uniform capital recovery factor[a]	0.3
Capacity factor[b]	0.6
Boiler efficiency	0.75
Operation & Maintenance (4% of capital)	$8.0/yr
Chiller (COP)	4.0

Annual chilled water production is

$$1\ ton \times 12000\ \frac{Btu}{hr\text{-}ton} \times 8760\ hours/year \times 0.6 - 63.07\ E6\ \frac{Btu}{yr}$$

Annual purchased electric requirement is

$$63.07\ \frac{E6\ Btu}{yr} \times \frac{1\ Btu\ electric\ consumed}{4\ Btu\ cooling\ effect} \times \frac{1}{3413}\ \frac{kw\text{-}hrs}{Btu}$$

= 4.6 E3 kw-hrs.

Cost of electric in 1990 is

4.6 E3 kw-hrs X $66.5 E-3/kw-hr = $306/yr

Cost of capital is 0.3 X $200 = $60/yr.

Cost of cooling per unit of chilled water is (1990).

$$\frac{\$306/year + \$60/year + \$8/year}{63.07\ E6\ Btu/yr} = \$5.93/E6\ Btu$$

As can be seen from Table D9-8 the most advanced technology (option 3) provides the lowest cost of electricity. However, this cost is estimated to be about 3 times that of Intermountain Power in 1990 and about twice as much in 2000. The IUS system cost of power begins to approach the SCE rate in the year 2000.

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D10. ENVIRONMENTAL ASSESSMENT OF IMPACT ASSOCIATED WITH INTEGRATED UTILITY SYSTEM

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D10. ENVIRONMENTAL ASSESSMENT OF IMPACT ASSOCIATED WITH INTEGRATED UTILITY SYSTEM

Because the implementation of an integrated utility system in Riverside greatly increases the use of potentially high-pollution, fuels in the Riverside locale, it is necessary to carefully consider environmental impact. The following analysis estimates the effects of the five major air emissions: SO_2, hydrocarbons, CO, particulates and NO_x. This analysis was done for the moderate impact-moderate population growth case The following tables describe the methodology and results.

Table D10-1 presents emission factors based on fuel use for each of the different types of fuels considered in the analysis. This table was derived from a number of sources as indicated.

Table D10-2 estimates the amount of emission which would occur due to combustion of natural gas in the various end uses within the IUS. These are the emissions that would occur in Riverside if no IUS were installed and natural gas were still used in the year 2000. If it becomes necessary for industry to shift to oil these emissions would be substantially higher.

Table D10-3 gives estimates of emissions from the IUS for each of the three optional technologies discussed in Appendix D9. These are the emissions that would replace those of Table D10-2 in the Riverside area. As can be seen a net emissions increase would occur in nearly every case. However, the IUS also generates electricity that would be used in Riverside. This electricity is generated as a by-product of satisfying thermal and cooling requirements.

Table D10-4 presents the amount of electric generating capacity and annual generation of two of SCE's power plants within a 10 mile radius of Riverside as well as the generating capacity of the IUS. These two SCE plants are used sparingly by SCE due to low efficiency and it might be assumed that if Riverside were to install an IUS, the power generation from these two SCE plants could be

TABLE D10-1. EMISSION FACTORS

End Use	Fuel	Emission Factor (lb/E6 Btu of Fuel) Particulate	SO_2	NO_x	Hydrocarbons	CO
Residential[a]	Natural Gas	0.006	0.0006	0.097	0.003	0.040
Commercial[b]	Natural Gas	0.006	0.0006	0.098	0.004	0.020
Industrial[c]	Natural Gas	0.006	0.0006	0.098	0.04	0.020
	No. 2 Oil	0.009	0.187	0.177	0.001	0.004
Large Boiler (Power Plant)	Pulverized Coal	0.02[d]	0.10[e]	0.40[f]	0.008[g]	0.02[b]
	Refuse[h]	0.050	0.300	0.090	0.100	0.03
Large Boiler	Residual Oil[e]	0.053	0.523	0.700	0.013	0.0003
	Natural Gas	0.006[m]	0.0006[m]	0.400[n]	0.040[o]	0.0004[m]
Gasifier/Gas Turbine	Coal/Refuse	0.010[i]	0.05[j]	0.120[i]	0.004[k]	0.02[k]
Gasifier/Fuel Cell	Coal/Refuse	0.09[i]	0.05[j]	0.030[i]	0.004[k]	0.02[k]

(a) Reference 1--Barrett/Miller.
(b) Reference 2--DeWerth.
(c) Assumed the same as commercial as per reference AP42. Oil emissions from reference 2.
(d) Reference 4.
(e) Assumes 90 percent removal of SO_2 from flue gas (see Table D1-2).
(f) Assumes low NO_x burners with pulverized coal firing (see Table D1-2).
(g) Reference 5.
(h) Reference 6.
(i) Reference 7.
(j) Assumes 95 percent sulfur removal from both refuse and coal gasification. This is equivalent to about 60 ppmv of H_2S in low energy gas (see Table D1-3).
(k) Battelle estimate.
(l) See Reference 3.
(m) Assumed the same as residential/industrial/commercial.
(n) Reference 8.
(o) Assumed the same as industrial.

TABLE D10-2. BUSINESS AS USUAL EMISSIONS FOR IUS AREA (MODERATE IMPACT/MODERATE POPULATION GROWTH CASE)

	Res.	Com.	Ind.	Total
Fuel Consumption (E9 Btu/yr)	124.4	863.6	1799.7	2787.7
Annual Emissions (E3 lb/yr)[(a)]				
Case 1 Particulate	0.8	5.2	10.8	16.8
SO_2	0.1	0.5	1.1	1.7
NO_x	12.1	84.6	176.4	273.1
Hydrocarbons	0.4	3.4	72.0	75.8
CO	5.0	17.3	36.0	58.3

(a) Using Emission Factors from Table D10-1

TABLE D10-3. EMISSIONS FROM INTEGRATED UTILITY SYSTEM (MODERATE IMPACT/MODERATE POPULATION GROWTH)

	Option 1	Option 2	Option 3
Annual Fuel Consumption			
Coal E9 Btu/yr	2020	5207	4802
Refuse E9 Btu/yr	2090	2090	2090
Total E9 Btu/yr	4110	7297	6892
Annual Emissions E3 lb/yr[(a)]			
Particulate	144.9	73.0	620.3
SO_2	829.0	364.8	344.6
NO_x	996.1	875.6	206.8
Hydrocarbons	225.2	29.2	27.6
CO	103.1	145.9	137.8

(a) Using emission factors from Table D-10-1.

TABLE D10-4. ELECTRICITY PRODUCTION FROM UTILITY PLANTS NEAR RIVERSIDE AND POTENTIAL DISPLACEMENT BY IUS

Generating Option	Power Generated (F6 kw-hr/yr)	Generating Capacity (MW)
Southern California Edison[(a)]		
Highgrove	48	154
San Bernardino	759	126
Total	807	280
Riverside IUS		
Option 1	126	30
Option 2	577	128
Option 3	686	147

(a) Both of these plants are within 10 miles of downtown Riverside.

displaced by an equivalent amount. Because these two plants are so close to Riverside it might also be assumed that their operation impacts directly on Riverside's air quality.

Table D10-5 estimates the total annual emissions from the SCE San Bernardino and Highgrove plants. It is assumed that these emissions could be affected by an IUS system in Riverside proportionately with the amount of electricity displaced as given in Table D10-4.*

Table D10-6 summarizes the emissions impact of IUS. By taking into account the local displacement plus the electric offset from nearby SCE plants, the net emission reductions are possible for all but CO emissions for the two advanced technology cases. The substantial reduction is for option 3.

* In actuality SCE would probably not reduce the operation of just these two plants to compensate for the Riverside IUS generation. However, because most of SCE's generations capacity is upstream in the Los Angeles basin it is still reasonable to assume that the reduced SCE generation would have a direct impact on Riverside's air quality.

D10-5. FUEL USE AND EMISSIONS FROM SCE PLANTS NEAR RIVERSIDE

Fuel Consumped by Highgrove and San Bernardino Plants[b]	
Oil (0.5T (sulfur) (E9 Btu/yr)	3758
Natural Gas (E9 Btu/yr)	4661
Total	8419
Annual Emission (E31b/yr)[a]	
Particulates	227.1
SO_2	1968.2
NO_2	4495.0
Hydrocarbons	235.3
CO	2.0

(a) Using emission factors from Table D-10-1.

(b) Source "Steam Plant Factors - 1977", U.S. Federal Power Commission

TABLD D10-6. SUMMARY OF EMISSIONS EFFECT FROM IUS OPTION IMPLEMENTATION

	Part.	SO_x	NO_x	HC	CO
Local Displacement of Emissions (All options)	16.8	1.7	273.1	75.8	58.3
Emissions From IUS					
Option 1	144.9	829.0	996.1	225.2	103.1
Option 2	73.0	364.8	875.6	29.2	145.9
Option 3	620.3	344.6	206.8	27.6	137.8
Emissions Offset from SCE Generation					
Option 1	35.5	307.3	701.8	36.7	0.5
Option 2	162.4	1407.2	3213.9	168.2	2.1
Option 3	193.0	1673.1	3821.0	200.0	2.6
Net Emissions Reduction in Riverside Area Due to IUS					
Option 1	-92.6	-520.0	-21.2	-112.7	-44.3
Option 2	106.2	1044.10	2611.4	214.8	-85.5
Option 3	410.5	1330.2	3887.3	248.2	-76.9

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APPENDIX E

THE LEGAL/INSTITUTIONAL ENVIRONMENT

APPENDIX E

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THE LEGAL/INSTITUTIONAL ENVIRONMENT

An assessment of the existing institutional environment is essential to integrated community energy planning. In this analysis attention is confined primarily to public sector institutions, which most directly impact energy development in the Riverside community. Although some reference is made to private sector organizations, such as Southern California Edison, Battelle maintains that the most immediate and measurable opportunities for promoting alternative energy systems rest with local and state government institutions. The roles of the Federal Agencies such as the Nuclear Regulatory Commission, the Federal Power Commission, and the Environmental Protection Agency do, of course, impact the energy future of Riverside. From a policy design and implementation standpoint, however, these agencies fall outside the set of institutions with which the Riverside community may plausibly exert some direct influence.

Within the subset of all local and state public sector institutions which impact energy policy in Riverside, each may be viewed as either a major or minor actor. Among the former are: the Riverside Public Utilities Department (RPUD), the Riverside Planning Department (RPD), and the California Energy Resources Conservation and Development Commission. The minor actors, which receive a more cursory examination in this discussion, are: the Riverside County Government and the Southern California Council of Governments. In the following discussion the authority, roles, and policy implications of each institution are evaluated.

The Riverside Public Utilities Department (RPUD)

The RPUD is one of 12 departments within the Riverside City Government (Figure E-1). The RPUD is charged with the supply of electricity and water to all areas within the city's jurisdiction. A

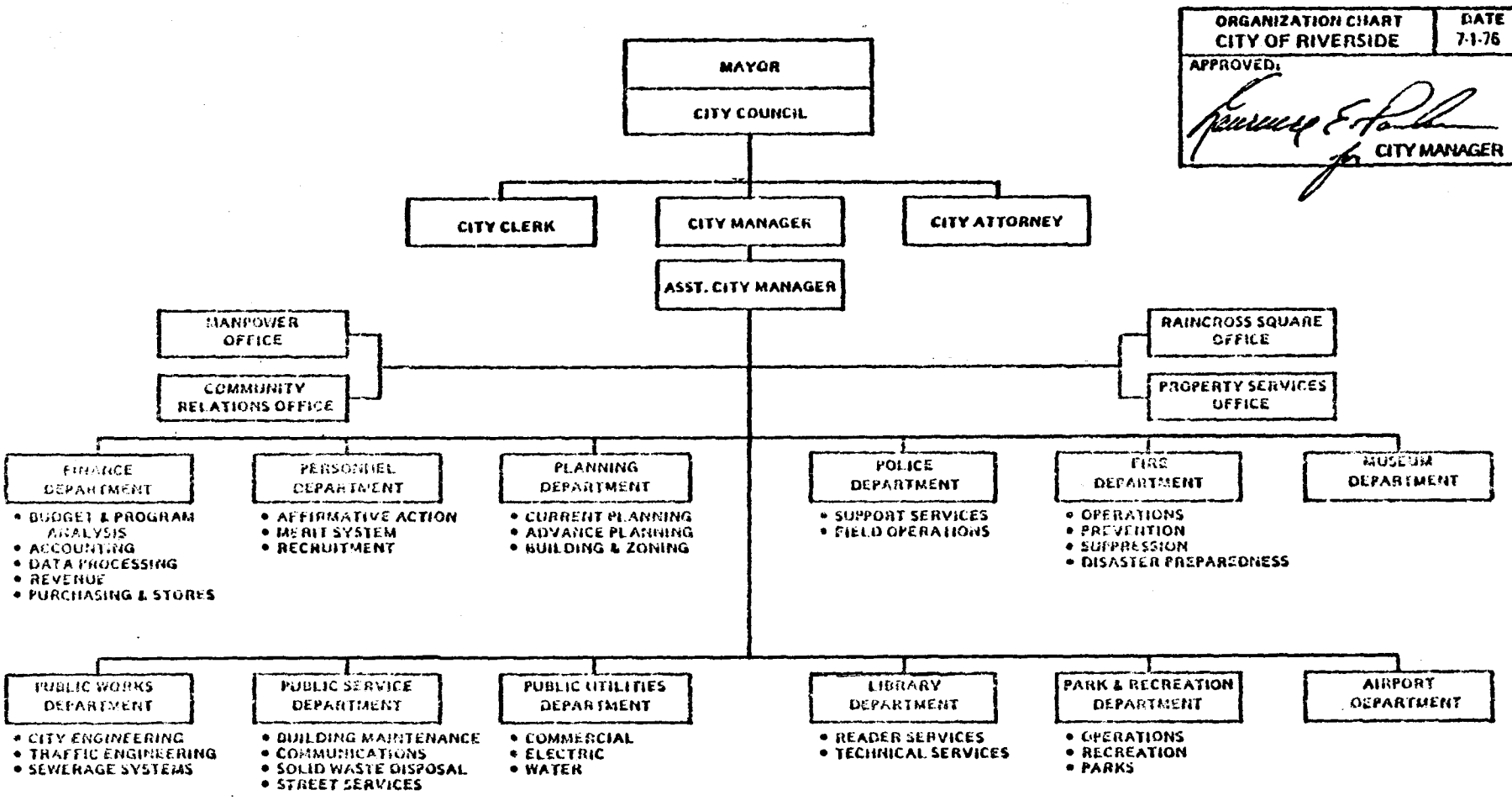

FIGURE E-1. ORGANIZATION OF THE RIVERSIDE CITY GOVERNMENT

five-person Public Utilities Board appointed by the City Council governs the operation of the Department, including its budgeting, capital expenditures, and rate-setting (subject to Council approval) activities.

RPUD's electric system operates as a subtransmission and distribution system for wholesale power purchased from Southern California Edison (SCE) and, since 1976, the Nevada Power Company. All transmission is handled by the SCE system which connects to the City's 66,000-volt transmission system for distribution throughout the municipality. In 1976, the system consisted of 1,041 circuit miles of lines, including street lights. A total of 56,902 customers are served, of which 91.8 percent are domestic, 7.6 percent commercial, and 0.3 percent industrial (Table E-1). Domestic customers as a percentage of all customers have increased consistently since 1962. Total kilowatt usage has increased 225 percent since 1962 and 23.7 percent since 1970. As in the case of total customers, domestic consumption as a percentage of total consumption has steadily increased. Operating revenues in 1976 totalled $33.2 million, as compared to $5.3 million in 1962 and $10.8 million in 1970.

The financial performance of the RPUD is crucial to the overall fiscal position of the City Government. First, RPUD's investment in nuclear generation represents the largest capital expenditure in the Riverside's FY 1977-78 budget of $136.6 million. An investment of $28 million in the San Onofre Generating Plant alone represents 48.9 percent of the proposed capital improvements budget of $57.3 million. An additional $1.8 million is budgeted for the new Jurupa substation and related facilities. Of the City's total debt service budget of $7.9 million, the electric utilities account for $2.1 million, or 26.6 percent. The bond issue of $4.7 million in 1966 was the first issue since 1900. Since 1962, 64.1 percent of a total $36.5 million in capital improvements has been financed from current revenues, reflecting the financially sound and conservative mode of operation characteristic of RPUD.

Besides the general budgetary impact of the municipal electric system, the City's general fund receives annually a transfer of 11.5 percent* of the electric utility's gross operating revenues, including

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* City Council has initiated a gradual reduction of this rate to 5.9 percent by FY 1981.

TABLE E-1. NUMBER OF ELECTRIC SYSTEM CUSTOMER BY TYPE--
RIVERSIDE PUBLIC UTILITIES DEPARTMENT

As of June 30	Domestic	Commercial	Industrial	Other	Total	By Per Cent of Total		
						Domestic	Commercial	Industrial
1962	28,061	2,865	529	607	32,062	87.5%	8.9%	1.6%
1963	29,999	2,991	548	671	34,209	87.7	8.7	1.6
1964	31,402	3,103	546	706	35,757	87.8	8.7	1.5
1965	32,884	3,230	555	707	37,376	88.0	8.6	1.5
1966	42,101	3,309	563	762	46,735	90.1	7.1	1.2
1967	42,422	3,367	569	689	47,047	90.2	7.2	1.2
1968	42,559	3,327	572	686	47,144	90.3	7.1	1.2
1969	43,214	3,366	580	603	47,763	90.5	7.0	1.2
1970	43,729	3,429	583	599	48,340	90.4	7.1	1.2
1971	43,023	4,181	181	206	47,591	90.4	8.8	0.4
1972	43,883	4,355	149	156	48,543	90.4	9.0	0.3
1973	47,923	4,351	153	199	52,626	91.1	8.3	0.3
1974(a)	50,070	4,312	156	198	54,736	91.5	7.9	0.3
1975	51,285	4,253	144	211	55,893	91.8	7.6	0.3
1976	52,239	4,304	143	216	56,902	91.8	7.6	0.3

(a) Beginning in May of 1974, reflected in electric revenue, is revenue derived from the fuel cost surcharge, which basically is a flow thru of increased fuel expense related to electric generation.

Source: Riverside Public Utilities Department.

the 5 percent fuel surcharge, as a payment in lieu of taxes (City Charter Article XIII, Sec: 1304). As illustrated in Table E-2, this transfer totaled $2.7 million in 1976, an increase of 115 percent since 1970. This reflects the rapid increase in fuel costs and the wholesale price at which RPUD purchases electricity from SCE. The Department estimates a transfer of $3.5 million in FY 1977-78, which exceeds the taxes a privately owned utility would pay on the existing system by an estimated 2.8 million. Under the current arrangement, the electric fund transfer provides approximately 16.9 percent of FY 1977-78 estimated General Fund revenues.

In summary, the municipal electric utility is a key component in the City's fiscal system. Next to property and sales taxes, the annual transfer is the largest source of revenue to the City's General Fund. Revenues from sales of electricity are the single largest source of revenues from any source, and the utility's capital expenditures represent nearly half of all budgeted outlays. By virtue of its fiscal position and bonding authority, RPUD can play a key role in the development of a number of alternative energy sources for the Riverside Community.

Policy Implications

A number of policy implications may be derived from the preceding discussion:

(1) RPUD can play a pivotal role in achieving the avowed objectives of greater independence from Southern California Edison.

At present, the Federal Power Commission reviews all wholesale rate schedules under which Riverside purchases electricity. New rates automatically take effect 5 months after filing by the private utility. This arrangement has, in RPUD's view, led to unjustified high rates by SCE which exceed the rates charged to its

TABLE E-2. CITY OF RIVERSIDE ELECTRIC FUND:
CONDENSED COMPARATIVE STATEMENT OF REVENUES AND EXPENSES
FOR THE YEARS ENDED JUNE 30, 1971 THROUGH 1976

	Fiscal Year Ended June 30					
	1976	1975	1974	1973	1972	1971
Operating Revenues...	$33,235,382	$29,119,048	$18,259,934	$14,758,609	$13,290,601	$11,744,099
Operating Expenses....	28,249,146	23,458,719	13,809,172	10,815,967	10,206,116	8,723,722
Depreciation..	1,548,756	1,486,275	1,441,578	1,325,321	1,196,437	1,074,906
Total.....	29,797,902	24,944,994	15,250,750	12,141,288	11,402,553	9,798,628
Net Operating Income.....	3,437,480	4,174,054	3,009,184	2,617,321	1,888,048	1,945,471
Other Income	465,673	539,677	507,217	213,010	256,163	142,189
Total.....	3,903,153	4,713,731	3,516,401	2,830,331	2,144,211	2,087,660
Other Deduction..	570,985	596,985	622,985	463,812	465,915	315,674
Net Income....	$ 3,332,168	$ 4,116,746	$ 2,893,416	$ 2,366,519	$ 1,678,296	$ 1,771,986
Contribution to General Fund.....	$ 2,679,665	$ 2,085,407	$ 1,697,240	$ 1,528,419	$ 1,350,571	$ 1,246,717

Source: Riverside Public Utilities Department.

largest retail customers. Riverside, together with the City of Anaheim, are jointly suing SCE for damages resulting from rate hikes in 1974 and 1976. The City claims that its competitive advantages vis-à-vis nearby communities are eroded by higher utility costs. The lawsuit, however, is viewed as only a short-run measure. RPUD sees a stable and equitable energy future contingent upon diversification of suppliers and sources. The 1977 investments in 1.79 percent share of two nuclear reactors at the San Onofre Plant and the 1976 agreement with the Nevada Power Company for electric power wheeled by SCE are examples of recent efforts to achieve greater energy independence.

(2) RPUD can play a pivotal role in the development of alternative fuels.

--Local environmental conditions, the escalating cost of scarce fossil fuels, and the recent demise of the proposed Sundesert nuclear plant all point to an energy future in Riverside increasingly dependent upon relatively clean, renewable alternative fuels. These may include various mixes of geothermal, waste-to-energy, wind, solar, and biomass resources. Whereas some of these systems - e.g., solar - characteristically are decentralized, and purchased and maintained by individual consumers, most will require the financial resources and expertise of an experienced energy organization. This is the case, for example, of a refuse-burning electric plant or a system to tap the geothermal resources of the Imperial Valley. (It is also

true for a conventional coal-fired plant which, in light of the recent Sundesert decision, appears to be increasingly probable.) In the Riverside community, such financial resources and expertise are found only in RPUD. Although RPUD has not been involved in the generation of electricity since 1924, its willingness and capability to re-enter the generation business is evidenced by its commitment to the Sundesert plant and the Intermountain coal project in Utah. The apparent lack of public support for the sale of the electric system to SCE, as well as SCE's consistent disavowal of interest in such a purchase, further increases the likelihood of RPUD involvement in power generation using alternative fuels.

(3) RPUD is in a position to develop and implement conservation programs.

As the exclusive supplier of electricity to nearly 60,000 customers in Riverside, RPUD is in a unique position to develop and supplement energy conservation programs in the domestic, commercial, and industrial sectors. Unlike communities dependent upon investor-owned utilities which are regulated by the California Public Utilities Commission, RPUD retains the authority to design its operations to achieve consistency with specific community policy objectives. Within the constraints of maintaining financial solvency, RPUD may, for example, experiment with an inclining block rate structure or offer special incentives for reducing consumption among residential customers to retrofit their properties. In addition, RPUD's monthly communication with its

60,000 customers represents an existing medium for disseminating educational materials to virtually every property owner in Riverside. Through effective utilization of this medium, RPUD has the capability to raise the general awareness of energy conservation techniques and alternative fuel potentials and, furthermore, to mobilize public opinion in support of a specific energy strategy.

In summary, the existence of a municipal utility in Riverside represents a major advantage to the community in its efforts to implement alternative energy supply systems, promote conservation, and achieve greater energy stability and independence. RPUD is key actor in both building a public consensus in support of an alternative energy strategy and implementing the specific programs which collectively comprise that strategy. Within the limitations of its existing mandate and authority, RPUD possesses many of the capabilities necessary for realizing the community's energy goals. Where such capabilities are lacking, ample opportunity exists for collaborative efforts with other municipal agencies. One such agency is the Planning Department, the subject of the following discussion.

The Riverside Planning Department

The Riverside Planning Department (RPD) is one of 12 functional departments within the City Government. In 1977-78 the RPD budget totaled $827,644, covering 43 employees distributed among four major programs: Administration, Advance Planning, Current Planning, and Building and Zoning. The RPD, by virtue of its planning, zoning, and inspection functions plays a key role in shaping urban development and, thereby, energy consumption patterns and levels in the City. The major activities of each program are:

Administration

- Coordination and supervision of the Advance Planning, Current Planning, and Building and Zoning programs

- Staff support to City Council, the City Planning Commission, the Design Review Board, the Environmental Protection Commission, the Board of Zoning Adjustment and various ad hoc committees.

Advance Planning

- Preparation and implementation of the General Plan
- Preparation of environmental impact reports
- Preparation of major land-use and growth policies for the Planning Commission, Environmental Protection Commission, and the City Council.
- Preparation and processing of annexation plans
- Preparation of special planning and zoning studies and ordinances.

Current Planning

- Review of rezoning applications, planned residential development permits, conditional use permits, variance applications, design review cases, site plan review cases, subdivision maps, parcel maps, street, alley, and walkway plans
- Provision of zoning and subdivision information and counseling
- Preparation of community designs for underdeveloped property
- Preparation of zoning and subdivision ordinances.

Building and Zoning Services

- Issuance of all building permits
- Review of construction plans and inspection of ongoing construction
- Inspection of existing structures and enforcement of zoning regulations.

In a variety of ways, the authority, decisions, and recommendations of the RPD partially determine the levels and spatial distribution of energy demand in Riverside. Virtually every action taken by the Current and Advance Planning programs generates energy impacts, although such impacts are not

explicitly incorporated into the planning or environmental review process. These impacts are summarized in Table E-3 according to programs, major responsibilities, activities, and scale of impact.

The Advance Planning Program impacts total energy consumption through its responsibility for preparation and revision of the General Plan. Specifically, annexation and growth management activities are the two key activities by which population growth is controlled and distributed across the city. (Significant annexation by Riverside has not occurred since the 1960-70 period when the City's area grew from 43.59 square miles in FY 1960-1961 to 71.52 square miles in FY 1970-1971.* Its present area is 71.58 square miles.)

Growth management is an activity of post-1970 origin resulting from public concern with total population which has increased 94 percent since 1960. While land area during the same period increased by 64 percent, most residential development occurred in peripheral areas through the conversion of land from agricultural to residential use. This issue is the focal point of the current controversy over the proposed public service point system for controlling additional residential development.** The nature of the system, and the stringency with which it is enforced, will have wide-ranging impacts on total energy consumption. (Its is worth noting that an energy criterion is not contained in the proposed point system).

In contrast to Advance Planning, the Current Planning program operates primarily at the subdivision level through its zoning and community design responsibilities. Through its control over the spatial distribution of residential, commercial, and industrial development site plans, subdivision layouts, and zoning ordinances, Current Planning is a key actor in determining the per-capita energy consumption of Riverside households. Its policies actually or potentially generate substantial energy impacts, although--as in the case of Advance Planning--these impacts are not explicitly recognized. Among the most prominent are:

- the solar access of individual housing units through

* City of Riverside, Preliminary Program Budget, 1977-1978, p. B-1.

** Riverside Press-Enterprise, April 16, 1978, p. B-2.

TABLE E-3. ENERGY IMPACTS OF PLANNING DEPARTMENT PROGRAMS

Program	Major Responsibilities	Activities with Direct Energy Impacts	Scale of Impact
Advanced planning	General plan	Annexation, growth management	Community-wide, major subareas
Current planning	Zoning, Subdivision controls Community design	Residential, commercial, industrial land use	Subdivision tract
Building and zoning services	Permits, inspection	Building Codes	Individual structure

regulation of orientation, landscaping, and setback distance

- the availability and promotion of bikeway plans.

Through these responsibilities, actions taken by Current Planning are crucial to achieving the full solar heating and cooling potential in the City, as well as reducing the length of trips and altering the modes of transportation to places of work and shopping.

Building and Zoning Services is the third major component of the RPD. It serves primarily in an enforcement role through its authority to issue permits and inspect buildings for conformance to local and State codes. Its responsibility has increased in the aftermath of the new State energy code which will require an increase in manpower and orientation of its inspectors. Although this program is not involved with policy development, the effectiveness with which it executes its permit and inspection functions is a key determinant of the energy efficiency of Riverside's building stock.

Policy Implications

The following policy implications may be derived from the preceding discussion:

(1) The RPD will play a pivotal role in the design and enforcement of energy-conservation programs in Riverside.

Specific RPD actions which impact the energy consumption levels of Riverside residents include both transportation- and building-related policies. The readiness of the RPD to incorporate an energy element into its General Plan and Zoning Ordinance--including a possible solar-access component--will to a large degree determine the community's ability to achieve significant energy conservation.

(2) RPD policies can facilitate the adoption of both passive and active solar systems through flexibility and innovation in zoning ordinances.

Possible modifications include flexible setback regulations, ground cover standards in new planned unit developments, and tree shading requirements in tract developments. These are discussed in further detail in Appendix C-4.

The California Energy Resources Conservation and Development Commission

The California Energy Resources Conservation and Development Commission (CERCDC) was created by the State to streamline the maze of energy planning and siting requirements in California. Under the Warren Alquest Act of 1974 (Assembly Bill No. 1575) the commission is charged with numerous key responsibilities, the most pertinent of which are:

- forecasting energy demand and supply for the State
- conserving energy resources by designated methods
- certifying electric power sites and facilities
- compiling--and where appropriate, adopting--relevant local, regional, state, and federal land use, public safety, environmental and other standards to be met in designing siting and operating facilities in the State, except for air and water quality standards
- studying and rendering findings on the state of development, and federal approval, of a demonstrated technology or means for the disposal of high-level nuclear waste.

All thermal electric power plants with a capacity of 50 MW or more fall under CERCDC's jurisdiction. The only exceptions are those plants for which, at the time of enactment, (1) the Public Utilities Commission had issued a Certificate of Public Convenience or (2) construction was planned to commence within 3 years. Although the Sundesert Plant was included in this exempted group, subsequent amendments to the act concerning nuclear waste disposal requirements (Section 25524.2) were, in the Commission's view, not fulfilled and this was the cause for rejection of the San Diego Gas and Electric's (SDG&E) Notice of Intent and Application for Certification.

The relationship of CERCDC to existing regulatory agencies is subject to some interpretation and still evolving. Although the enabling legislation grants CERCDC virtually exclusive authority in the mandated responsibilities noted above, its authority does not override existing standards of design siting and operations issued by other local, regional, state, and federal agencies. Its powers are further limited by the PUC and the Coastal Zone Conservation Commission (CZCC). The PUC retains the authority, through its certificate of public convenience and necessity, to judge the economic, financial, rate system reliability, and service implications associated with new power plants of greater than 100-MW capacity proposed by investor-owned utilities. (The PUC exercises no authority over municipal utilities.) The CZCC retains authority to review and approve new plants located within 1,000 yards of the coastline. Thus, although CERCDC grants exclusive authority to new plants, either the PUC or CZCC may reject a new facility under its own authority. In the case of the PUC, the review occurs after CERCDC's ruling; in the case of the CZCC, the review and judgment precedes that of CERCDC's.

Policy Implications

The following policy implications may be derived from the preceding discussion:

(1) CERCDC will play a key role in RPUD's efforts to achieve greater energy dependence through investment in both conventional and alternative energy supply systems.

CERCDC, in contrast to the PUC, governs both private and municipal electric systems. No special treatment is awarded to municipal utilities by CERCDC in its siting approval process. Furthermore, because RPUD will almost certainly jointly venture with private utilities in future energy supply projects--e.g., Sundesert, Intermountain Coal, San Onofre Nuclear plants--its sucess will depend heavily on PUC regulations from which it is legally exempt.

(2) CERCDC's jurisdiction and relationships with other governmental agencies is still in its formative stages; the final form of this relationship will directly impact alternative fuels development.

The still evolving CERCDC regulatory processes leave many unresolved jurisdictional issues. In the use of geothermal wells for example, uncertainty exists over the CERCDC's authority vis-à-vis other agencies. At present, counties have jurisdiction over surface environmental impacts (except for water quality) and drilling permits; the Department of Oil and Gas regulates subterranean impacts; and the PUC evaluates the construction and operation of the plant. However, since a utility will not invest in a geothermal resource without exploratory drilling, the question arises as to whether such wells are "appurtenant facilities" regulated by CERCDC (Section 25120). If so, they would be subject to the 18 month review process, which clearly would impede geothermal exploration and development. Jurisdictional conflicts of this type will directly impact the ability of Riverside to utilize alternative energy resources.

The Riverside County Government

Riverside County contains approximately 540,000 people and covers an area of 7,310 square miles. In FY 1976-77, the County's budgeted expenditures totaled $180 million, as illustrated in Table E-4. Public assistance accounted for almost 40 percent of all expenditures, public protection 22 percent, and general government 17 percent. On the revenue side of the budget, property taxes accounted for 27.0 percent and intergovernmental transfers 55.4 percent of total revenues. Thus, the County government fits the typical expenditure/revenue mould of county governments throughout the nation, acting primarily as a provider of social and public protection services financed largely through property taxes and state and federal transfers.

TABLE E-4. MAJOR BUDGETARY CATEGORIES OF RIVERSIDE COUNTY GOVERNMENT, FY 1976-1977

Expenditure Category	Amount	Percent of Total
Total Budget $179,867,261		
Public Assistance	71,037,319	39.5
Public Protection	39,369,199	21.9
General Government	30,579,234	17.0

SOURCE: County of Riverside, Final Budget FY 1977.

Only recently has the County begun to assume significant responsibilities in the provision of traditionally municipal services as a result of rapid urbanization in unincorporated areas. This evolving role will have a significant impact on the rate and pattern of land development in the County and the City of Riverside. County land use and zoning policies, for example, affect the relative attractiveness of Riverside City for new residential development. Insofar as County policy permits large-lot, quasi-agricultural developments adjacent to the City, developers will continue to concentrate new housing within the City limits. However, should developmental pressures combined with the economics of service provision compel the County to revise its land use policy toward more conventional tract developments, relatively inexpensive land in unincorporated areas may siphon off a substantial portion of current development pressures within Riverside. In this way, County planning policy will impact the continuation of Riverside's recent demographic trends and, therefore, its future energy demand profile.

Riverside County also exerts influence over the City's energy future in a second way: the exploitation of local geothermal resources for nonelectrical purposes. Although the most promising nearby resource for potential space and process heating is Arrowhead Hot Springs in San Bernadino County, other lower temperature resources are located in Desert Hot Springs

and at least 20 other sites within 50 miles of the City.* Although the specific procedures for geothermal development in California are still not completely delineated**, the experience of recent years suggests that county governments will exercise jurisdiction over all surface impacts (except water quality) and in this capacity, grant the initial drilling permits for exploration. To date, the willingness of counties to permit geothermal wells has varied widely.*** In Sonoma County, geothermal development provides the single largest source of tax revenue, and officials have permitted fairly intense development within the federal KGRA portion of the County. Imperial County has been even more supportive of geothermal development; Napa Valley, on the other hand, has been cautious and a few years ago imposed a moratorium on new wells. In any case, the variation in County attitudes reflect a mix of factors: the compatibility of geothermal development with the dominant economic activities, the level of environmental awareness and potential damage, and the local supply of alternative fuels. To date, Riverside County has not been compelled to squarely face these issues with a comprehensive policy. However, such decisions probably will be required in the near future if the geothermal option becomes increasingly competitive. Given the size and diversity in the County, a consensus may be difficult to achieve. The City of Riverside's future energy alternatives will be directly affected by the geothermal policies which finally emerge.

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*See the analysis of geothermal resources, Appendix D-3, for a complete listing of these sites.

**CERCDC, for example, is still in the process of defining its siting regulations for geothermal power plants.

***C. Richard Schuller, et al, "Legal Institutional & Political Problems in Producing Electric Power from Geothermal Resources in California", Battelle Human Affairs Research Centers, 1976.

THE SOUTHERN CALIFORNIA COUNCIL OF GOVERNMENTS (SCAG)

SCAG is the A-95 review agency for five counties in the Los Angeles Metropolitan area: Ventura, Los Angeles, San Bernadino, Orange, and Riverside. Approximately 150 municipalities and counties belong to the Association which comprises various committees responsible for policy formulation along functional lines. SCAG, like most A-95 agencies, is essentially a coordinative and advisory body to its members, with no authority to mandate adoption of, or conformance with, its policies at the local level.

In mid-1977, SCAG created an ad hoc Energy Advisory Committee which has since evolved into the Energy Technical Committee (ETC). The ETC serves as an advisor to SCAG's Environmental Quality and Resource Conservation Committee and the Transportation and Utilities Committee, as well as other SCAG committees on an as-needed basis. Specifically, ETC

- facilitates information exchange among all levels of government including A-85 prepublication review of draft federal regualtions
- provides policy advice and recommendations on areawide energy policies to SCAG's Executive Committee and its policy committees
- reviews and comments of SCAG energy documents
- informs and educates regional elected officials, technicians, and citizens the region on energy issues.

ETC members are state, federal, and local energy officials and planners from offices within SCAG's jurisdiction.

The creation of the ETC reflects SCAG's recognition for a regional approach to energy issues. ETC in its role as disseminator of energy information can provide Riverside with data on current developments in energy conservation in the South Coast area. It may also assist the RPUD in keeping abreast of innovations among other municipal utilities such as Burbank, Glendale, Pasadena, and Los Angeles City. These municipals, in contrast to Riverside, are power generators as well as distributors, and represent a source of experience which may guide RPUD as it strives toward entry into the energy production activities. ETC and SCAG provide an available forum

for municipals to organize a cohesive policy in dealing with the private utilities in issues concerning, for example, cogeneration, wheeling, and joint exploration of alternative energy resources.

In addition to these activities, SCAG is the logical agent for encouraging regional solutions to a number of energy related problems. These include:

- developing model energy conservation programs for jurisdictions to encourage workable standards which minimize the impacts of competitiveness for new economic and residential activity

- developing model solar access ordinances specific to the needs of Riverside and other South Coast cities

- encouraging the adoption of an energy element in local general plans and providing technical assistance for implementation of the same.

These are three of the more obvious opportunities for SCAG involvement in energy planning from which Riverside could directly benefit.

ATTACHMENT E-1

CITY OF SANTA CLARA
MODEL SOLAR ZONING ORDINANCE

ATTACHMENT E-1

CITY OF SANTA CLARA
MODEL SOLAR ZONING ORDINANCE

AN ORDINANCE AMENDING CHAPTER _____ OF THE CODE OF THE CITY OF _____ RELATING TO ZONING FOR SOLAR ENERGY COLLECTIONS, ESTABLISHING THE OFFICE OF CITY FORESTER, AND PROVIDING FOR THE PROTECTION AND ENCOURAGEMENT OF SOLAR ENERGY COLLECTORS

WHEREAS, the City of _____ and its inhabitants have experienced direct and tangible effects of the shortage of non-replenishable energy sources through higher prices and threats of interrupted service, "brownouts," or the inability to secure new utility connections; and

WHEREAS, the technology is currently available to utilize solar energy to provide all or a portion of residential or commercial space heating and cooling and hot water needs; and the use of solar collectors would benefit the health and welfare of all the inhabitants of the City of _____; and

WHEREAS, it has been found that as a general rule, existing zoning regulations for R through R-____ zones for height, setback and lot density limitations are sufficient to provide most lots with a minimum of protection from neighboring structures blocking the sunlight from falling upon a solar collector placed upon the northern half of each lot; and

WHEREAS, should solar energy become the sole or major source of heating and cooling within the City of _____, or should the increased utilization of solar energy be impeded by widespread fears or doubts concerning protection of solar rights, then it will be appropriate to provide greater zoning protection of the use and opportunity to use solar collectors by prohibiting the construction of structures which would cast shadows upon adjacent lots; and

WHEREAS, for the present, in addition to the protection provided by the existing zoning regulations, and to provide a degree of protection where existing zoning regulations do not protect a solar collector from encroachment because of topographical and other conditions, it is deemed to be in the interest of the public health, safety and welfare to prohibit the granting of building permits for the construction or modification of any structure or building which shall interfere with any air space solar easement recorded with the Building Department.

NOW, THEREFORE, BE IT ORDAINED BY THE CITY COUNCIL OF THE CITY OF _____:

Section 1. (Amendatory Language)

Section 2. Solar Energy Collectors, Use of -

A. Purpose

Because of the existing shortage of conventional energy sources, it has been determined to be in the public interest to encourage the use of solar energy for the heating and cooling of buildings and providing hot water for use in buildings or in swimming pools. As a general rule existing zoning regulations for height, setback, and lot density limitations in residential areas are sufficient to permit adequate access to sunlight by each lot without obstruction by adjacent structures. Trees should be planted in such a manner as to prevent the casting of shadows upon solar collectors. However, where existing zoning is insufficient to provide adequate protection from interference by structures, trees or topography, it is the intent of this section to provide adequate protection for the use of solar collectors without at the same time causing undue hardships on the rights of property owners.

B. Definitions:

(1) Airspace Solar Easement - Is a specific volume of airspace defined by a plane sloping upward to the south at a specified angle from the horizontal (22 degrees is recommended), and the plane is further defined in both plane view and elevation with reference to the property lines over which it passes. The plane view description shall be in terms of the bearings and horizontal distances, and the elevation shall be with reference to mean sea level.

(2) Solar Collector - Any device relying upon direct solar radiation is employed in the collection of solar radiation for heating and/or cooling of a structure or building or water.

C. Use Permitted:

The use of solar energy collectors for the purpose of providing energy for heating and/or cooling is a permitted use within all zones, whether as a part of a structure or incidental to a group of structures in the nearby vicinity. Use of solar energy collectors is subject to the restraints imposed by the diversity of topography within the City of _____ city limits plus the zoning, height and setback limitations contained within this Code, and existing trees. No guarantee is hereby given that all property within the city limits of the City of _____ is entitled to the use of solar collectors. However, as a general policy, reasonable care should be taken to protect the opportunity for the utilization of solar collectors at all the locations available.

D. Protection of Solar Collectors' Access to Light:

(1) Airspace easements across contiguous or nearby lots, tracts, or land may be created to establish a window of exposure to the sun so as to protect an existing or intended solar collector's exposure to the sun from obstruction of buildings and trees.

(a) Airspace solar easements may be purchased, reserved granted or otherwise obtained. Adverse possession cannot create such an estate.

(b) An easement infringed upon is a compensable property right through private remedy.

(2) An airspace solar easement may, at the discretion of the owner, be recorded and filed with the Building Department.

(3) Any person seeking a building permit to construct or modify any structure or building so as to increase the consumption of airspace over that lot shall certify in writing that no airspace solar easement exists over that lot. Where an airspace solar easement exists, the applicant for the permit shall present a copy of the deed containing the legal description of the easement unless the easement is already recorded with the Building Department. Should the Building Department determine that the proposed construction would intrude upon the easement, no building permit shall be granted.

E. Variances:

Variances shall be granted by the Board of Adjustment from zone restrictions such as height, setback, and lot density where such variances are necessary to permit unimpaired access to the sun during the hours of 1000 to 1400 so long as such variances do not interfere with an existing solar collector to any degree or preclude the construction of a solar collector on northerly property within the reasonable vicinity and are not otherwise injurious to adjacent property.

F. Solar Orientation of Unit Development:

If, for the reason of solar orientation, an entire area between two intersecting streets in a block is developed cooperatively or as a unit, all yard regulations may be varied to carry out said purpose, providing that the Zoning Board of Adjustment after public notice and hearing is of the opinion that such a development will not be injurious to adjacent property.

Section 3. Adjacent Property -

No variance shall be granted from the height limitation nor side yard setback limitation in R through R-_____ zones where such a variance would be upon the northerly property boundary, unless the applicant establishes that such a variance will not adversely affect an existing solar collector or the opportunity to reasonably install a solar collector upon northerly adjacent property.

Section 4. Solar Energy Collectors - Protection Of -

A. Purpose:

Because of the existing shortage of conventional energy sources, it has been determined to be in the public interest to encourage the use of solar energy for the heating and cooling of buildings and providing hot water for use in the building or in swimming pools. Trees and other growth planted along property lines can often grow to such heights as to interfere with the efficiency of a solar collector on adjacent property, and it is the intent of this section to provide a means of protection for the use of solar collectors.

B. Definitions:

(1) "City" is the City of _____.

(2) "City Forester" is the City Forester of the City of _____.

(3) "Person" is any person, firm, partnership, association, corporation, company or organization of any kind.

(4) "Tree" is any object of natural growth.

C. City Forester:

There is hereby established in the Division of _____ of the Department of Public Works in the Administrative Service of the City the office of City Forester.

(1) Preserve or Remove - The City Forester shall have the authority and it shall be his duty to trim or remove trees, which by their location or nature of their growth, are blocking or otherwise interfering with the access to sunlight of any solar collector located on any adjacent property, in order to benefit the general welfare of the inhabitants of the City by preserving, protecting and encouraging the investment in alternative non-polluting, replenishable energy supplies.

(2) Order to Preserve or Remove - The City Forester shall have the authority and it shall be his duty to order the trimming or removal of trees upon private property when he shall find such action necessary to protect the access to sunlight between the hours of 1000 and 1600 of any solar collector located on adjacent property, or any property so affected, or threatened to be affected by the tree.

E. Duties of Private Owners:

It shall be the duty of any person growing a tree along or near a property line to trim his trees so as not to cause any interference with the access to sunlight of any existing solar collector or to preclude the construction of a solar collector on adjacent property.

F. Procedure Upon Order to Trim or Remove:

When the City Forester shall find it necessary to order the trimming or removal of trees upon private property as authorized in Section D herein shall serve a written order to correct the interfering condition upon the owner, operator, occupant or other person responsible for its existence.

(1) Method of Service - The order required herein shall be served in one of the following ways:

(a) By making personal delivery of the order to the person responsible.

(b) By leaving the order with some person of suitable age and discretion upon the premises.

(c) By affixing a copy of the order to the door at the entrance of the premises in violation.

(d) By mailing a copy of the order to last known address of the owner of the premises, by registered mail.

(e) By publishing a copy of the order in a local paper once a week, for three successive weeks.

(2) Time for Compliance - The order required herein shall set forth a time limit for compliance, dependent upon the nature and degree of interference created by the violation.

(3) Appeal from Order - A person to whom an order hereunder is directed shall have the right, within twenty-four hours of service of such order, to appeal to the Chief Administrator, who shall review such order within _____ days and file his decision thereon. Unless the order is revoked or modified it shall remain in full force and be obeyed by the person to whom directed. No person to whom an order is directed shall fail to comply with such order within _____ days after an appeal shall have been determined.

(4) Failure to Comply - When a person to whom an order is directed shall fail to comply within the specified time, the City Forester shall remedy the condition or contract with others for such purpose and charge the cost thereof to the person to whom the order is directed. The person remedying a condition under a contract made hereunder shall be authorized to enter premises for that purpose.

(5) Special Assessment - If the cost of remedying a condition is not paid within _____ days after receipt of a statement therefore from the City Forester such cost shall be levied against the property upon which said condition exists, as a special assessment. The levying of such assessment shall not affect the liability of the person to whom the order is directed to fine and imprisonment as herein provided. Such special assessment shall be

certified by the City Forester to the City Treasurer and shall thereupon become and be in a lien upon such property, shall be included in the next tax bill rendered to the owner or owners thereof unless paid before, and shall be collected in the same manner as other taxes against such property.

BE IT ORDAINED by the City Council of the City of _____ this _____ day of _____, 19___.

_____

ATTEST:

_____

APPENDIX F

ENVIRONMENTAL QUALITY

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APPENDIX F

ENVIRONMENTAL QUALITY

Air Pollution Regulation

Clean Air Act Amendments of 1970

A major impetus toward the control of air pollution in the United States was passage of the Clean Air Act Amendments of 1970. These amendments required that each state promulgate a plan for implementing air pollution controls which would result in the attainment of ambient air quality standards by 1975. The pollutants for which national ambient standards were established were airborne particulate matter (also called total suspended particulates), sulfur dioxide, carbon monoxide, nitrogen dioxide, nonmethane hydrocarbons, and photochemical oxidants. For particulates and sulfur dioxide, there are national primary and secondary standards. The primary standards are based on criteria that will ensure protection of human health while the more restrictive secondary standards would also protect vegetation, materials, animals, and visibility from air pollution damage. In establishing the ambient standards, various averaging times for measuring the pollutants are used, ranging from 1 hour to 1 year depending upon the criteria periods that were used in the original pollution damage studies.

States have the option of establishing their own ambient standards for the pollutants regulated nationwide as well as for other air pollutants. The National and California ambient air quality standards are listed in Table F-1. It can be noted that California has ambient standards for lead, sulfates, hydrogen sulfide, and visibility in addition to standards for some of the six "criteria" pollutants which differ from the Federal standards.

Another set of standards has been established to protect against imminent danger to human health from a buildup of atmospheric pollutants under adverse meteorological conditions. During these air pollution

TABLE F-1. CALIFORNIA AND NATIONAL AIR QUALITY STANDARDS

Air Contaminant	Air Quality Standards[a]		
	California	National[b] Primary	National[b] Secondary
Photochemical Oxidants (O_3)	0.10 ppm, 1 hr avg	0.08 ppm (160 $\mu g/m^3$) 1 hr avg	0.08 ppm (160 $\mu g/m^3$) 1 hr avg
Carbon Monoxide (CO)	10 ppm 12 hr avg	9 ppm (10 mg/m^3) 8 hr avg	9 ppm (10 mg/m^3) 8 hr avg
	40 ppm 1 hr avg	35 ppm (40 mg/m^3) 1 hr avg	35 ppm (40 mg/m^3) 1 hr avg
Nitrogen Dioxide (NO_2)	0.25 ppm 1 hr avg	0.05 ppm (100 $\mu g/m^3$) AAM	0.05 ppm (100 $\mu g/m^3$) AAM
Sulfur Dioxide (SO_2)	0.04 ppm 24 hr avg	0.14 ppm (365 $\mu g/m^3$) 24 hr avg	
			0.50 ppm (1300 $\mu g/m^3$) 3 hr avg
	0.50 ppm 1 hr avg	0.03 ppm (80 $\mu g/m^3$) AAM	
Particulate Matter	100 $\mu g/m^3$ 24 hr avg	260 $\mu g/m^3$ 24 hr avg	150 $\mu g/m^3$ 24 hr avg
	60 $\mu g/m^3$ AGM	75 $\mu g/m^3$ AGM	60 $\mu g/m^3$ AGM
Lead (Pb)	1.5 $\mu g/m^3$ 30 day avg		
Nonmethane Hydrocarbons		0.24 ppm (160 $\mu g/m^3$) 3 hr avg 6-9 a.m.	0.24 ppm (160 $\mu g/m^3$) 3 hr avg 6-9 a.m.
Hydrogen Sulfide (H_2S)	0.03 ppm 1 hr avg		
Visibility Reducing Particles	In sufficient concentration to reduce visibility to less than 10 miles at relative humidity of less than 70%		

(a) Standards shown in parenthesis are restatements of the preceding standard but expressed on an alternative basis.
(b) Concentrations other than annual averages not to be exceeded more than once a year.

Source: "Air Quality and Meteorology", 1975 Annual Report of the Southern California Air Pollution Control District, R. W. Keitn, Editor.

episodes, the normal dispersion of pollutants is hindered by low wind speeds and temperature inversions. Table F-2 lists the ambient pollutant concentrations at which different stages of episodes are declared in California and in the South Coast Air Basin. The South Coast Air Basin comprises Los Angeles County, Orange County, and western portions of San Bernardino and Riverside Counties.

Clean Air Act Amendments of 1977

While considerable progress in the reduction of air pollution was made as a consequence of the 1970 Clean Air Act Amendments, the National Ambient Air Quality Standards were not attained throughout the country by 1975. It was found that tighter controls would be required to meet these standards and that the State Implementation Plans should also be revised to include methods for maintaining good ambient air quality in the future. The Clean Air Act Amendments of 1977 have set out revisions to the 1970 methods and schedule for attaining and maintaining air quality.

Some of the requirements of the 1977 Amendments which are important to the implementation of an energy plan for Riverside include:

- The designation of areas where air quality does not meet ambient standards as "nonattainment" areas with restrictions on any new sources of air pollutants proposed for those areas.
- The issuing of guidelines to the states and local pollution control agencies demonstrating how they can reduce carbon monoxide and photochemical oxidant precursors from motor vehicles through transportation control measures such as car pools, parking restrictions, promotion of mass transit, fuel conversion, etc.
- Identification of fossil-fuel-fired steam electric plants which have more than 250 million Btu per hour heat input and which produce 100 tons per year or more of any air pollutant

TABLE F-2. CALIFORNIA AIR QUALITY EMERGENCY STANDARDS

Air Contaminant	Stage 1 Health Advisory	Stage 2 Warning	Stage 3 Emergency
Photochemical Oxidants (O_3)	0.20 ppm 1 hr avg	0.35 ppm 1 hr avg	0.50 ppm 1 hr avg
Carbon Monoxide(CO)	20 ppm 12 hr avg	35 ppm 12 hr avg	50 ppm 12 hr avg
	40 ppm 1 hr avg	75 ppm 1 hr avg	100 ppm 1 hr avg
Sulfur Dioxide(SO_2)	0.20 ppm 24 hr avg	0.70 ppm 24 hr avg	0.90 ppm 24 hr avg
	0.50 ppm 1 hr avg	1.0 ppm 1 hr avg	2.0 ppm 1 hr avg
Actions to be Taken	Voluntary reduction in physical activity.	Action ranges from voluntary to mandatory.	Mandatory abatement measures. State can take action if local efforts fail.

Source: "Air Quality and Meteorology", 1975 Annual Report of the Southern California Air Pollution Control District, R. W. Keith, Editor.

as two examples of "major emitting facilities". These facilities would require special analysis regarding air pollution impact before they could be constructed in a nonattainment area. One requirement is that attainment of air quality standards must be shown and another is that before a new source can emit pollutants, its pollution emissions must be offset by an equivalent or greater reduction in emissions from an existing source in the area.

- The requirement that a new source must comply with the lowest achievable emission rate of pollutants.
- The requirement that State Implementation Plan revisions must demonstrate that national primary ambient air quality standards will be achieved by December 31, 1982. It is possible for this deadline to be changed to December 31, 1987, for photochemical oxidants and carbon monoxide if the state can show that attainment is not possible for these two pollutants by 1982 despite the implementation of all reasonably available measures.
- A revision of new source performance standards for steam generating units which will impose percentage reduction requirements for sulfur dioxide, nitrogen dioxide, and particulate matter emissions without regard to the type of fuel burned.

Air Quality for Criteria Pollutants

Attainment and Nonattainment Areas

Figure F-1 is a map delineating the boundaries which separate the South Coast Air Basin from the Southeast Desert Air Basin

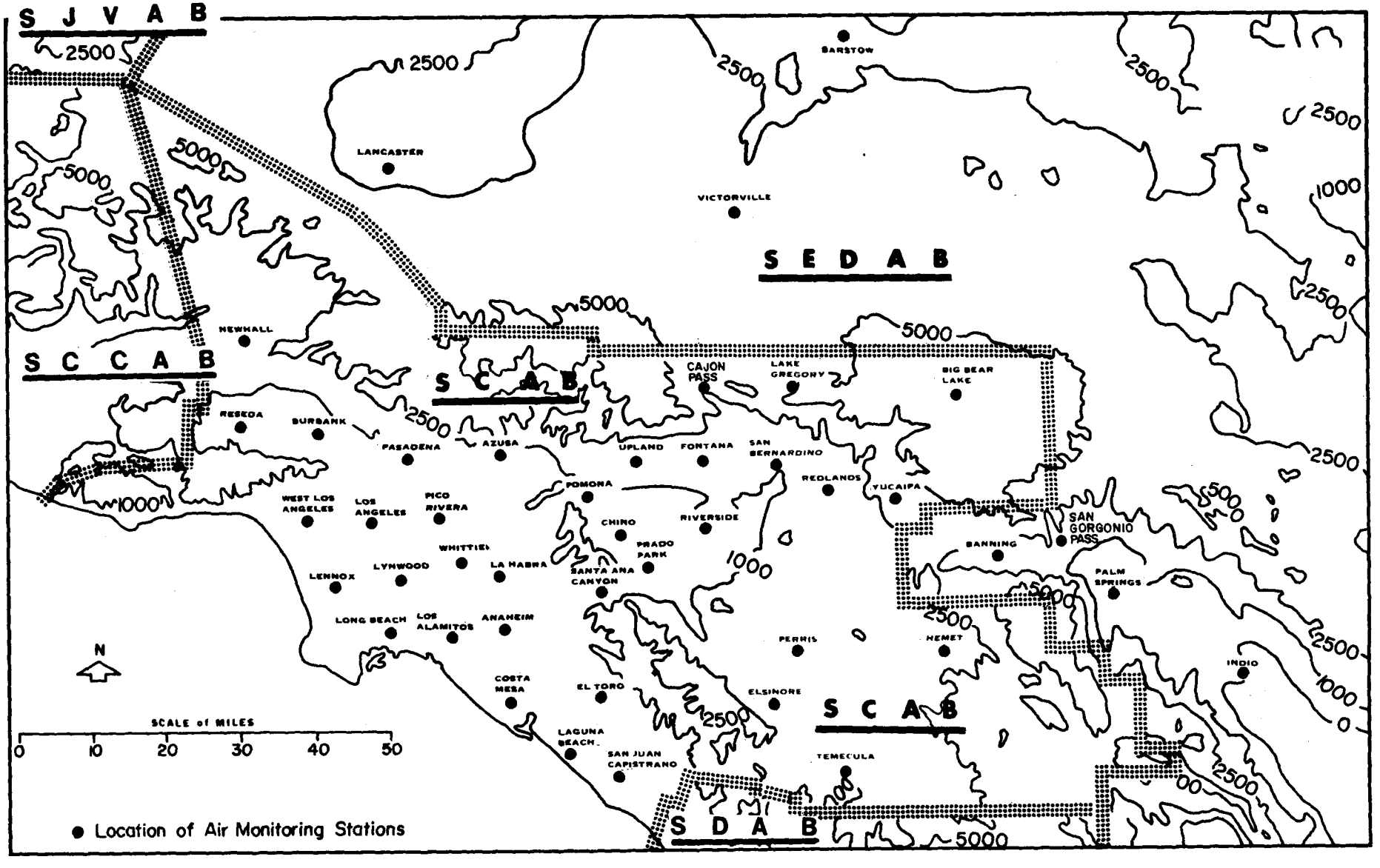


FIGURE F-1. MAP SHOWING THE AIR BASINS, MONITORING STATIONS, AND TERRAIN IN THE AREA SURROUNDING RIVERSIDE. TERRAIN HEIGHTS ARE IN THOUSANDS OF FEET. SCAB = SOUTH COAST AIR BASIN, SEDAB = SOUTHEAST DESERT AIR BASIN, SDAB = SAN DIEGO AIR BASIN, SCCAB = SOUTH CENTRAL COAST AIR BASIN, SJVAB = SAN JOAQUIN VALLEY AIR BASIN.

on the north and east. Ambient concentrations of total suspended particulates, carbon monoxide, nitrogen dioxide, and oxidants measured in the South Coast Air Basin during the eight quarters preceding August, 1977 (the month of enactment of the 1977 Clean Air Act Amendments), were higher than the primary standard concentration. As a result, the entire South Coast Air Basin was designated as a nonattainment area for these four pollutants. Sulfur dioxide concentrations were found to be better than national standards so this air basin is an attainment area for SO_2. For oxidant, the nonattainment designation includes all of eastern Riverside County as well as the western portion where the City of Riverside is located. Riverside County from the Los Angeles County border to the Coachella Valley (Indio) is also a nonattainment area for particulates. However, with respect to sulfur dioxide, nitrogen dioxide, and carbon monoxide, the portion of Riverside County outside of the South Coast Air Basin has been found to be better than national standards or cannot be classified because of insufficient measurements.

Trends of Individual Pollutants

Measurements of oxidant, carbon monoxide, and nitrogen dioxide have been made in the City of Riverside for 15 years; however, there have been some years in which no measurements were made or in which too few measurements were made to satisfy statistical requirements for a trend analysis. Another deterrent to establishing a trend is that after 10 years the Riverside monitoring station was changed from the 11th Street Mall to a point near where Magnolia and Arlington Avenues cross. Thus, the measurements for 1973 are not directly comparable to those for the 1963-1972 period.

Measurements of total suspended particulate in Riverside did not begin until 1970. This monitor was also moved from the 11th Street Mall to Magnolia Avenue between 1972 and 1973. No measurements of sulfur dioxide have been made in Riverside. However, sulfur dioxide has been measured in Rubidoux every year back to 1966. None of these years has enough measurements to classify them as sufficient data for calculating mean values. Available ambient concentration records and episode frequencies are discussed in the following sections.

Total Oxidant

On the basis of the frequency with which ambient standards are exceeded, oxidant is the most troublesome pollutant in the South Coast Air Basin. Furthermore, Riverside is one of the stations with the highest number of excessive readings (Figure F-2). The pattern of excessive concentrations reveals that the highest oxidant concentrations do not occur over the most densely populated portions of the basin, but further inland. This is the result of the time required for the photochemical change which converts nitrogen oxides to oxidant. During this period of several hours, the air mass into which the pollutants were emitted has been transported inland by the daytime breeze from the ocean.[1]* In 1976, there were 176 days when the State standard of 0.10 part per million was not met at the Riverside monitor. In 1977, the number of violation days increased to 193. Episode days in Riverside over the past 3 years are tabulated below.

Number of Oxidant Episode Days in Riverside

	Stage 1 (≥0.20 ppm)	Stage 2 (≥0.35 ppm)
1975	61	2
1976	46	2
1977	66	1

A newspaper article[2] reporting the variation of hours of first stage oxidant episodes between 1973 and 1977 related the comments of state and district agency personnel that the increases in 1977 were likely due to the combination of poor meteorological dispersion conditions and an increase in automotive emissions resulting from increased highway travel.

Several other measures of total oxidant, as portrayed in Figure F-3, indicate that the magnitude of the excursions of oxidant above standards has decreased since 1970 even though the frequency of the occurrences may have increased.

* References are listed at end of Appendix.

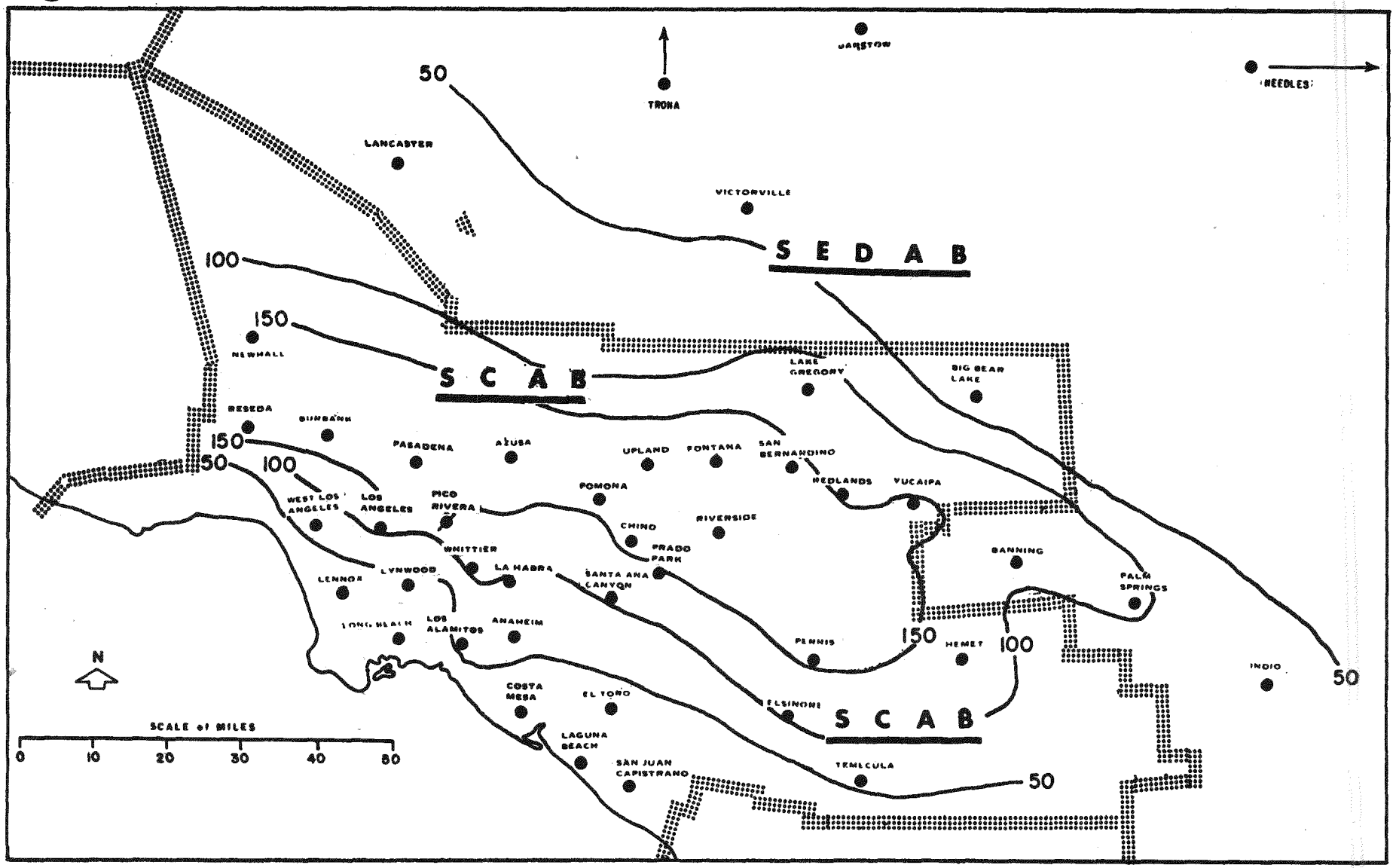
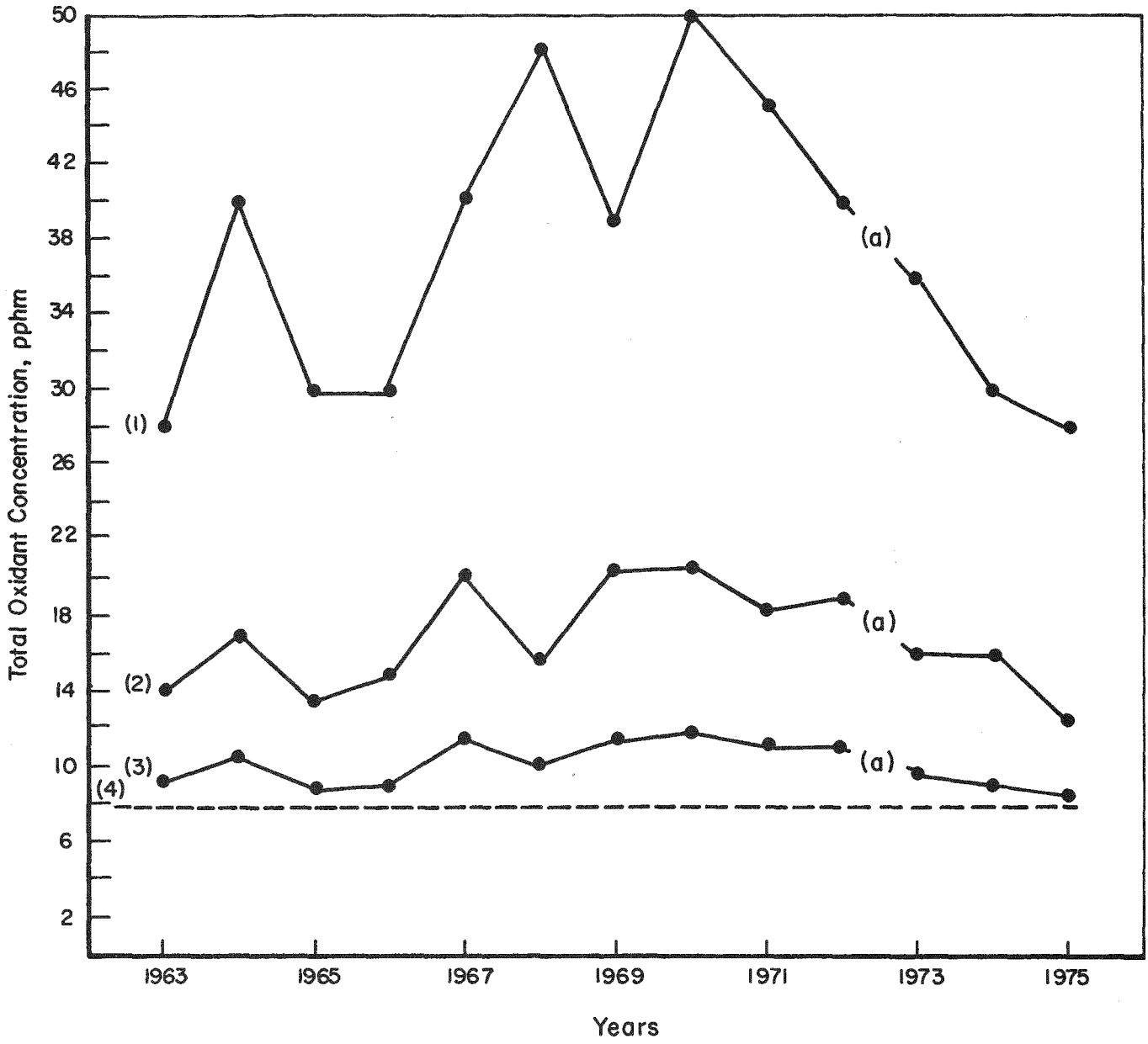


FIGURE F-2. NUMBER OF DAYS IN 1976 ON WHICH STATE OXIDANT STANDARD (1-HR. AVG. $O_3 \geq 0.10$ ppm) WAS VIOLATED

Source: "Contour Maps of Air Quality in the South Coast Air Basin -- 1976" South Coast Air Quality Management District, July, 1977; M. Hoggan, A. Davidson and M. F. Brunelle



(1) Highest hourly concentration for the year.
(2) Mean of the daily maximum concentrations during July-September.
(3) Mean of the daily maximum concentrations during the entire year.
(4) The ambient standard concentration which should not be exceeded more than one hour per year.

(a) Riverside monitoring station moved

Sources of Data: "Ten-Year Summary of California Air Quality Data, 1963-1972", State of California Air Resources Board, January, 1974 and "Three-Year Summary of California Air Quality Data, 1973-1975", State of California Air Resources Board, January, 1977.

These data reflect application of a factor of 0.8 to hourly averages reported prior to June 1, 1975, as recommended by the Air Resources Board.

FIGURE F-3. TRENDS OF TOTAL OXIDANT CONCENTRATIONS IN RIVERSIDE AIR

Total Suspended Particulates

Riverside is also in an area of the South Coast Air Basin where particulate concentrations frequently exceed the standard (Figure F-4). While there is a major industrial source of particulates northwest of Riverside, there may also be significant contributions from windblown dust in this desert climate. Minor portions of the particulates include soot, sea salt, lead, sulfate, organic matter, and nitrates.

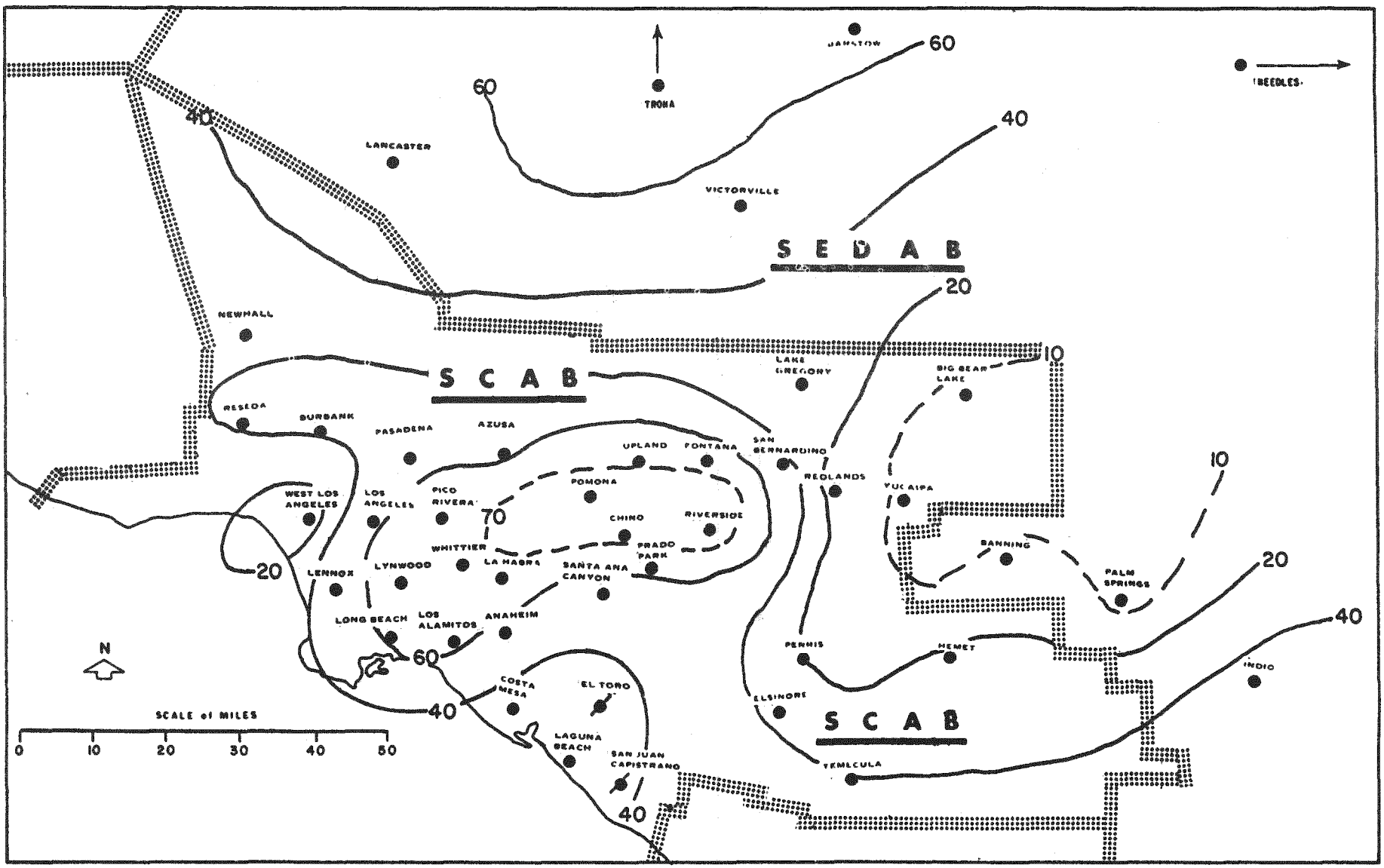
The following tabulation presents the record of total suspended particulates (TSP) measurements at the Riverside stations since 1971.

TSP 24 Hour Measurements (mg/m^3) at Riverside

Year	Number of Observations	Minimum	Maximum	Geometric Mean
1971	34	42	384	137.2
1972	38	40	359	136.2
1973	34	55	652	161.7
1974	76	39	259	134.5
1975	98	24	272	127.4
1976				
1977	NA*	35	508	NA*

* NA = not available.

In 1977, at the Riverside station where the high-volume sampler is run for 24 hours every sixth day, the measurements varied between 35 $\mu g/m^3$ and 508 g/m^3. The national 24-hour primary standard, which is not to be exceeded more than once a year, is 260 $\mu g/m^3$, this was exceeded at least once in each of 5 months in 1977. In 1974, when 76 measurements were made, the 260 $\mu g/m^3$ value was never exceeded, and in 1975 it was exceeded only once in 98 measurements at Riverside. The large number of high particulate concentrations in 1977 is very likely related to the drought conditions.



—— solid lines are at intervals of 20 ug/m^3.

– – dashed lines are at intervals of 10 ug/m^3.

FIGURE F-4. PERCENTAGE OF DAYS IN 1976 WHEN THE STATE TOTAL SUSPENDED PARTICULATE STANDARD (TSP $\geq$ 100 µg/m^3) WAS VIOLATED.

Source: "Contour Maps of Air Quality in the South Coast Air Basin -- 1976", South Coast Air Quality Management District, July, 1977; M. Hoggan, A. Davidson and M. F. Brunelle.

Carbon Monoxide

Carbon monoxide concentrations are highest in areas which are in close proximity to heavy automobile traffic. While hourly measurements of carbon monoxide have been taken in Riverside since 1963, first at the 11th Street Mall and then at Magnolia Avenue, there have been only 6 years when the number of readings were sufficient to meet statistical criteria.

Based on this lengthy but sometimes inadequate record, there were no occasions on which the national hourly standard of 35 ppm was exceeded. However, the national 8-hour standard of 9 ppm was exceeded 120 times in 1973 and 31 times in 1975. In 1976, the California 12-hour standard of 10 ppm was never exceeded.

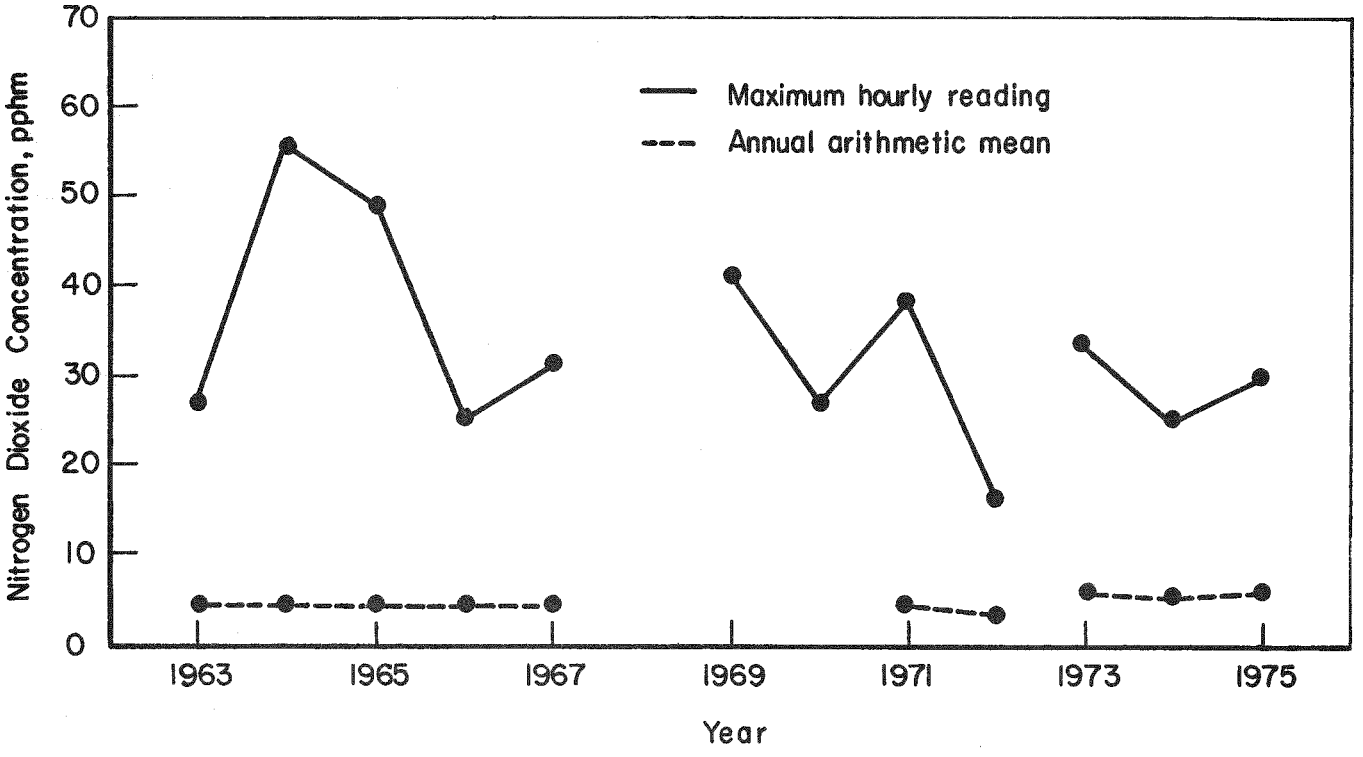
Nitrogen Dioxide

Two nitrogen dioxide (NO_2) statistics for the period between 1963 and 1975 are shown in Figure F-5. The maximum hourly reading for each year can be compared with the California standard of 25 pphm while the annual arithmetic mean can be compared with the U.S. standard of 5 pphm. At Riverside, the NO_2 annual average has always been quite close to the national standard, but with a slight increasing trend. On the other hand, the trend of the maximum 1-hour readings has been downward. As an addendum to the figure, there were no occasions in 1976 when the 1-hour maximum was exceeded; but there were 4 days in 1977 when the 1-hour concentration rose above 25 pphm. Maximum NO_2 readings at Riverside generally occur in the October-December quarter.

In the South Coast Air Basin, the greatest number of NO_2 violations (on the order of 40 or 50 days per year) occur in the western portions such as Los Angeles and Long Beach.

Sulfur Dioxide

A limited number of measurements of sulfur dioxide were made at Rubidoux between 1966 and 1975. There were no occasions when the maximum



No measurements taken in 1968.

Monitor moved between 1972 and 1973.

California Standard: 25 pphm for 1 hour .
U.S. Standard: 5 pphm annual arithmetic average.

Sources of Data: "Ten-Year Summary of California Air Quality Data, 1963-1972", State of California Air Resources Board, January, 1974 and "Three-Year Summary of California Air Quality Data, 1973-1975", State of California Air Resources Board, January, 1977.

FIGURE F-5. NITROGEN DIOXIDE CONCENTRATIONS IN RIVERSIDE

1-hour standard for California (50 pphm) nor the U.S. annual arithmetic average standard (3 pphm) were violated. During this period, the highest 1-hour reading (25 pphm) was observed in 1966 and the maximum annual average (2.0 pphm) occurred in 1975.

However, there have been violations of SO_2 standards in other portions of the South Coast Air Basin. In 1976, the California 24-hour standard of 4 pphm was exceeded at Fontana and in the Los Angeles area. In both areas, there are major stationary sources of SO_2 such as power plants or refineries.

Transport and Dispersion of Air Pollutants

It is becoming apparent nationwide that air pollutants can be transported a considerable distance beyond their sources. This is especially true for secondary pollutants, such as oxidant and sulfate, which are produced as a result of chemical changes in the primary emissions--nitrogen oxides and sulfur dioxide in the case of oxidant and sulfates. Nationally, recent interest in air pollutant transport is on the movement of large air masses containing oxidants and their precursors from the Rockies to the East Coast. These air masses accumulate oxidant precursors and oxidant as they pass over an urban area; then the next urban area and the region downwind of it must contend with this transported oxidant as well as oxidant precursors added locally.

Transport of pollutants is an important factor in analyzing Riverside's air pollution situation. Oxidant, the pollutant whose concentration is highest in relation to ambient standards, is formed as a result of the photochemical changes which nitric oxide and hydrocarbon undergo during several hours of exposure to solar radiation. When the wind is blowing, the nitric oxide emitted in one area will be transported elsewhere before the oxidant is formed. Thus, Riverside may receive some oxidant from sources in Los Angeles and Orange Counties while some of its own emissions of oxidant precursors are transported elsewhere.

Topography and Winds

While transport of pollutants into the South Coast Air Basin from other urban areas is not a significant factor in the air pollution situation of this air quality control region, transport within the basin is important in the explanation of the air quality variations throughout the region. To understand the effect that transport and dispersion have on pollutant concentrations in Riverside one must first understand the topography and meteorology of the South Coast Air Basin with relation to the air pollution sources in the basin. Figure F-1 again provides a view of the topography of the South Coast Air Basin.

Air from the lowland area between Santa Monica and Santa Ana can be transported to Riverside by three routes. It can flow directly west from Los Angeles. through the valley beside Pomona, it can proceed from the Long Beach area through the Santa Ana Canyon, or it can move eastward from the central lowlands by crossing the relatively low Puente Hills and China, which lie between Pomona and Santa Ana Canyon. In a program in which constant-level balloons were released from Downey and Los Angeles at various morning hours on different days, Angell et al.[3] tracked the balloons as they left the lowlands by each of the three routes. The balloons which went through Santa Ana Canyon had first been blown south to Long Beach and then proceeded eastward.

In the lowlands between Pomona and Riverside-San Bernardino the transported air can spread out and by rising upward 450 feet can also cover the area to the southeast of Riverside. The air may exit from the eastern portion of the South Coast Air Basin by traveling northwest through the Cajon Pass. It can also move through the San Gorgonio Pass 40 miles to the east of Riverside, entering the Palm Springs area and the Coachella Valley.

Sea Breezes, Land Breezes, and Drainage Winds

Transport of air containing pollutants from the Los Angeles lowland to Riverside and on to the east or northwest is primarily done by the daytime sea breeze. It can begin to flow across the coastline at about 9 or 10 a.m., may attain speeds of 8-16 mph, and will reach Riverside by mid-afternoon.

There is also a land breeze at night which can blow outward from the Los Angeles lowland. This breeze can be enhanced by the drainage winds from the mountains. Sometimes there are stagnant conditions in the Los Angeles Basin and the drainage winds are dominant. If they come from the north in the morning they can move the Los Angeles air to Long Beach where the air mass stagnates until the sea breeze begins. The sea breeze transports the air through the Santa Ana Pass toward Riverside. If stagnant conditions persist all day in the Los Angeles Basin, the drainage winds will begin in the late

afternoon. They will help in keeping the air in the basin so that the pollution builds up there and is not transported eastward over the Puente Hills or through the passes to the north and south.

Sea breezes are stronger in summer as a result of the increased solar radiation. At this time of the year there is a large, subtropical, high-pressure area lying above this region. Storm centers pass to the north of this high-pressure area and the sea breeze can develop each day. In other seasons the sea breeze will be lighter and will not proceed as far inland. Earlier evenings bring an earlier onset of the drainage winds.

In winter the storm tracts shift southward. If a low-pressure area moves across Southern California it may be followed by very strong and dry Santa Ana winds which flow into the area from the Mojave Desert and the mountains via the Cajon Pass. These Santa Ana winds may occasionally be as strong as 60 miles per hour, but their occurrence is so infrequent that, on the average, summer winds are stronger than winter winds. At Riverside the Santa Ana is typified by a persistent 20-mph wind from the northern quadrant.(4)

Temperature Inversions

Another meteorological factor important to air pollutant conditions in the South Coast Air Basin is the temperature inversion. Whenever the high-pressure area overlies the Basin it is accompanied by a subsidence inversion with its base above 2500 feet. This places a lid over the entire basin, preventing air from moving upward. There may be no exit out of the Basin through the Cajon (4301 feet) or San Gorgonio (2615 feet) passes if the subsidence inversion is low enough.

There are also inversions whose bases are at the ground. They may form either at night when radiation from the earth's surface cools off the lowest air layers or at times when colder air is blown inland from the ocean. These surface inversions are more frequent in winter (an average of 22 days in December) than in summer (2 days in June) because of the longer nights and increased terrestrial radiation.(5)

Other Meteorological Factors

In addition to the wind and temperature inversions there are several other weather elements which affect air pollution in the South Coast Air Basin. Solar radiation is necessary for the formation of photochemical oxidants and, as a consequence, oxidant concentrations reach their peak in the summer and early autumn. The warmer temperatures of summer also increase the evaporation rate of hydrocarbons into the air and the increased hydrocarbons contribute to increased oxidant formation.

It has been found that sulfate concentrations are higher in the Basin when the moisture content of the atmosphere is high.(6) Dew point temperature has been incorporated into the forecast formula for predicting sulfate episodes in California. With more moisture in the air there is a greater likelihood that sulfur trioxide will join with the water to form sulfuric acid.

Inversions and Pollutants

The height of the inversion base exerts considerable control over the concentration of pollutants. While the subsidence inversion can keep oxidants, oxidant precursors, and other pollutants within the Basin from one day to the next, the presence or absence of a surface inversion may have a more immediate impact upon the effect these pollutants have. When the base of this inversion is only a few hundred feet off the ground, the heaviest smog will be forecast. On hot summer days, the solar radiation can destroy the inversion in the mid to late afternoon and the smog will suddenly clear up as the pollutants are mixed through a much deeper layer of the atmosphere.

Carbon monoxide and nitrogen oxide concentrations are higher in winter than in other seasons because the winter inversions are more frequent and their bases are lower. These pollutants, primarily emitted from automobiles, are trapped beneath the low inversion during the night and early morning hours when wind speeds are low.(7) All carbon monoxide episodes in the Basin occur in November, December, and January.

On the other hand, sulfate concentrations at the ground are not expected to be as high when the base of the surface inversion is low. The principal sources of the sulfate precursors, sulfur dioxide and sulfur trioxide, are power plants. Power plants have stacks which may be several hundred feet in height; consequently, unless the base of the inversion is well above the stack, the sulfur oxide plume will be emitted at a height such that where downward mixing to ground level will not take place.

Oxidants and Transport

Photochemical oxidants are a secondary pollutant produced by the reaction of solar radiation on the primary pollutant nitrogen oxides with hydrocarbons acting as a catalyst. Automobiles are the major source of nitrogen oxides and hydrocarbons, with nitrogen oxide emissions increasing as vehicle speeds increase. The principal injection of these two precursors of photochemical oxidant occurs during the morning rush-hour traffic. Once emitted the precursors remain in the atmosphere, ready for the daytime radiation which will instigate the photochemical reaction and produce the oxidant. Although the urban areas with their heavy traffic are the source of most oxidant, the heaviest concentrations do not occur in the urban areas but in the regions downwind of the urban center. The wind transports the urban air mass while the photochemical change proceeds. By the time this change has been completed, the air mass may be 10 or more miles away, depending on wind speed, solar radiation, and the reactivity of the hydrocarbons taking part in the reaction. After the more reactive hydrocarbons in the air mass have been depleted, the less reactive hydrocarbons can continue to contribute (even at night) to oxidant production at a lower rate. While ozone half-life is 15 to 30 hours, continued oxidant formation may result in the persistence of high oxidant concentrations over a region 100 miles from the source if inversion conditions prevent dispersion.

Initial studies of oxidants in the Riverside area revealed that ozone concentrations reached a peak during the day and then dropped during the night, while peroxyacetyl nitrate (PAN) persisted through the night.(8)

Later evidence shows that the ozone and its precursors may remain aloft within an inversion layer during the night, avoiding destruction, and then undergo photochemical reactions and downward mixing during the next daylight period. As a result, they can contribute to the oxidant concentration on a second day.

Nitric oxide (NO) emitted from automobile exhausts is the initial pollutant in the chemical changes which ultimately lead to the creation of photochemical oxidant during daylight hours. However, NO also reacts to destroy ozone, and in the absence of sunlight there is no further chemical reaction. It is by this process that ambient ozone concentrations near the ground reach a minimum at night. Because there are more vehicles exhausting NO in urban areas than in rural areas, the nighttime ozone minimum is lower in urban areas than in rural areas. Similarly, the late afternoon peak of ozone can be lower in heavily traveled areas than in surrounding residential areas because afternoon conditions do not promote photochemical actions like morning conditions do. The late afternoon and evening NO emissions do not contribute to the creation of more ozone. Instead, they destroy the ozone that was created in the area earlier or that had been advected into the area.

A significant example of this destructive reaction is seen in the comparison of oxidant concentrations measured by monitors on Magnolia Avenue in Riverside and along Mission Boulevard in Rubidoux, 4 miles away. Oxidant concentrations average lower at the Magnolia Avenue sampler and in the first 10 months of 1977, the number of days when measurements called for a first-stage oxidant episode announcements was 28 compared with 66 at Mission Boulevard. One important reason for this disparity is the greater amount of nitric oxide in the vicinity of the Riverside monitor. This is verified by the readings of the nitric oxide monitors at the two stations.[9] Thus, the greater traffic along Magnolia Avenue produces more nitric oxide which destroys oxidant created in Riverside or transported from Los Angeles. It should be noted that this destruction is localized within the area of the heavy traffic and that in residential areas of Riverside the oxidant transported from Los Angeles is likely to be just as strong as that measured at Rubidoux.

Nor do the nitric oxide emissions in Riverside reduce Riverside's own downwind effects. Wind measurements made at the Magnolia Avenue monitor during 1976[10] (Table F-3 show a predominance of northwest winds, especial during the high oxidant months of May through September. This suggests that emissions from automobiles in Riverside are providing the precursors for the oxidant concentrations at Perris and Hemet. In 1976, there were 154 days at Perris and 68 days at Hemet when oxidant air quality standards were not met.[11] Perris had 13 first-stage episode days that year.

TABLE F-3. MONTHLY AVERAGE WIND SPEEDS (MPH) AND PREVAILING DIRECTION (BY QUADRANT)

WINDS AT RIVERSIDE MAGNOLIA AVENUE STATION, 1976, BY 6-HOUR AND DAILY PERIODS, WIND SPEED (MPH) AND DIRECTION

Time Period / Month	00-05	06-11	12-17	18-23	Daily
January	2NE	3NE	5NE	2NE	3NE
February	1SE	3SW	7NW	3NW	3NW
March	2SE	3NE	7NW	2NW	4NW
April	2SE	3NW	7NW	3NW	4NW
May	2NW	3NW	8NW	3NW	4NW
June	1SE	4NW	8NW	3NW	4NW
July	1NW	3NW	8NW	4NW	4NW
August	1SE	3NW	8NW	3NW	4NW
September	1NW	3NW	5NW	2NW	3NW
October	1NE	3NE	6NW	2NW	3NW
November	2NE	3NE	5NE	2NE	3NE
December	2NE	3NE	5NE	2NE	3NE

Source: "California Air Quality Data: -- quarterly reports for 1976, Technical Services Division, California Air Resources Board, Sacramento.

Air Pollutant Emissions

Emission Inventories

An air pollutant emission inventory can be prepared for an area in terms of tons of each pollutant emitted into the air each year from stacks, exhaust pipes, open burning, fugitive emission sources, and evaporation. Fugitive emissions include dust blown from storage piles or injected into the air from unpaved roads and agricultural operations, as well as pollutants which enter the air from windows, doors, and uncovered conveyors. The emission inventory does not represent the measurement of emissions from the large number of sources in the area. Rather it is the application of a set of emission factors to the actual or estimated operations of the sources such as fuel consumed, amount of raw material consumed, amount of product manufactured, and vehicle miles traveled. The emission factors represent average emissions derived from a few examples of each type of operation.

The sources can be categorized as point or area, where point sources produce a large tonnage of emissions from a single emission point, while area sources represent a small individual emission but are summed over areas the size of a square mile or more. Sources can also be divided into stationary and mobile sources where the latter category refers primarily to emissions from transportation.

Information on production, fuel use, and equipment for point sources in an area can be obtained by questioning industries and institutions. Area and mobile source data are obtained from various summaries of data prepared for states and counties. These data, when used with the standardized emission factors, provide the emission inventory estimate for an area. Emission inventories for individual counties can be summed to produce district or regional inventories. Additional combinations lead to statewide and nationwide inventories. On the district or regional level, the emission inventory is used in conjunction with mathematical meteorological dispersion models to estimate the ambient concentrations of air pollutants. The relationships among these three parts of the air pollution

problem--emission source, meteorological transport, and ambient concentration--are examined when control strategies are developed for reducing the ambient concentrations. A desired improvement in ambient air quality can be related to a specification for emission reduction.

Air Pollutant Emissions from Riverside, California

An estimate of the average emissions of organic gases, particulates, nitrogen oxides, sulfur dioxide, and carbon monoxide from sources in part of Riverside County was prepared for 1975. The portion of Riverside County treated was the western part which lies in the Southern California Air Pollution Control District, this district also includes the western portion of San Bernardino County as well as all of Los Angeles and Orange Counties. Table F-4 presents this emission estimate for western Riverside County separated into contributions from various categories under stationary sources, miscellaneous area sources, and mobile sources. Air pollutants from natural sources such as windblown dust from the desert or sea salt carried into the air are not included in this summary.

When these Riverside County emissions are combined with the emissions from the other three counties, the emission inventory for the District is obtained. These total emissions are the ones that must be reduced in order to improve the air quality in the South Coast Air Basin. Table F-5 lists the estimates of 1975 emissions of each pollutant from the entire district and from western Riverside County, as well as the percentage of the District's total contributed by Riverside County.* Riverside County contributes less than 10 percent of the emissions in all categories except

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* This 1975 Southern California APCD emission inventory should be considered as only a tentative approximation and guide. The District is developing better approximations. For instance, 1976 District emission estimates (in tons per day) compiled by the Southern California APCD in 1977 are as follows:

Organic Gases	Particulates	NO_x	SO_2	CO
87.6	71.5	63.6	47.2	380.9

The differences between 1975 and 1976 do not necessarily represent actual changes in emissions between the 2 years, but rather result primarily from different methods of computing the emissions from operation data and emission factors.

TABLE F-4. RIVERSIDE COUNTY ESTIMATED AVERAGE EMISSIONS OF POLLUTANTS FOR 1975 (tons per day)

	Emissions, tons/day				
Stationary Sources	Organic Gases	Part.	NO_x	SO_2	CO
Petroleum					
Production					
Refining					
Marketing	7.5				
Subtotal	7.5				
Organic Solvents					
Surface Coating	14.8				
Dry Cleaners	1.4				
Degreasing	0.3				
Other	0.5				
Subtotal	17.0				
Chemical	0.1	0.1			
Metallurgical	0.5	8.1	13.3	41.8	3.4
Mineral		1.3	2.9		3.0
Food and AG Processing	0.4	0.9	0.2		
Pesticides	4.0				
Wood Processing					
Subtotal	5.0	10.4	16.4	41.8	6.4
Combustion of Fuels					
Refineries					
Power Plants	0.1	0.1	1.0	0.6	0.2
Industrial		0.1	1.2		0.2
Domestic & Commercial	0.2	0.1	2.3		0.6
Orchard Heaters	0.1	6.5			0.5
Subtotal	0.4	6.8	4.5	0.6	1.5
Waste Burning					
Agricultural Debris	0.3	0.2			1.0
Forest Management					
Range Improvement					
Dumps					
Conical Burners					
Incinerators		0.1			0.1
Other					
Subtotal	0.3	0.3			1.1
Total Stationary	30.2	17.5	20.9	42.4	9.0

TABLE F-4 (Continued)

	Emissions, tons/day				
	Organic Gases	Part.	NO_x	SO_2	CO
Misc. Area Sources					
Wild Fires					
Structural Fires	1.4	1.1	0.1		4.6
Farming Operations		13.3			
Const. & Demolition		1.3			
Unpaved Roads		1.6			
Utility Equip: Mowers, Etc.	0.8				5.2
Total	2.2	17.3	0.1		9.8
Mobile Sources					
Motor Vehicles - On Road					
Light Duty VEH Exhaust	30.6	6.8	49.0	1.5	412.8
Heavy Duty VEH Exhaust	4.5	0.5	5.4	0.1	49.2
Diesel Powered Vehicles	2.3	1.0	22.6	1.8	14.3
Motorcycle Exhaust	2.0				5.5
Evaporation	13.0				
Subtotal	52.4	8.3	77.0	3.4	481.8
Aircraft	4.0		0.9		6.6
Railroads and Ships					
Other Off-Road Vehicles	3.4	0.3	5.0	0.7	23.4
Total Mobile	59.8	8.6	82.9	4.1	511.8
Summary					
Stationary Sources	30.2	17.5	20.9	42.4	9.0
Area Sources	2.2	17.3	0.1		9.8
Mobile Sources	59.8	8.6	82.9	4.1	511.8
GRAND TOTAL	92.2	43.4	103.9	46.5	530.6

Source: Unpublished tabulation by Southern California Air Pollution Control District, October, 1976.

TABLE F-5 ESTIMATED CONTRIBUTION OF RIVERSIDE COUNTY SOURCES TO AIR POLLUTANT EMISSIONS IN THE SOUTHERN CALIFORNIA AIR POLLUTION CONTROL DISTRICT

Source	Emissions, tons per day				
	Total Organic Gases	Particulates	NO_x	SO_2	CO
Stationary					
Riverside County	30.2	17.5	20.9	42.4	9.0
Entire District	662.8	90.2	388.9	326.2	312.7
Percentage from Riverside	4.5	19.4	5.4	13.0	2.9
Miscellaneous Area					
Riverside County	2.2	17.3	0.1	neg	9.8
Entire District	78.4	83.8	10.7	neg	474.9
Percentage from Riverside	2.8	20.6	0.9	---	2.1
Mobile					
Riverside County	59.8	8.6	82.9	4.1	511.8
Entire District	779.9	131.2	1,085.8	73.1	6,955.5
Percentage from Riverside	7.7	6.5	7.6	5.6	7.3
Total					
Riverside County	92.2	43.4	103.9	46.5	530.6
Entire County	1,521.1	305.2	1,485.4	399.3	7,743.1
Percentage from Riverside	6.1	14.2	7.0	11.6	6.9

Source: Unpublished tabulation by Southern California Air Pollution Control District, El Monte, California, October, 1976.

particulates and sulfur dioxide from stationary sources and particulates from miscellaneous area sources. By referring to the Riverside County emission inventory listing in Table F-4, one can identify the types of sources that produced these three larger contributions to the District emissions. Metallurgical operations emitted almost 50 percent of the stationary source particulates and almost 100 percent of the stationary source sulfur dioxide. Farming operations produced about three-fourths of the miscellaneous area source emissions of particulates.

Riverside City Air Pollutant Emissions

A review of industry and population within the City of Riverside can narrow down the air pollutant emissions from the City as compared with those from the County and District. The major stationary point sources (those emitting over 100 tons per year of any pollutant) as included in the Southern California APCD listing are Riverside Cement (which is in Rubidoux) and Rohr Industries in Riverside. It is estimated that Rohr Industries emits over 2 tons per year (0.57 tons per day) of hydrocarbons/organic gases. This emiss would be listed under Stationary Sources - Organic Solvents in Table F-4. Most of the emissions categorized under Stationary Sources in the 1975 Riverside County inventory are not within the Riverside city limits.

Besides the one major point source in the City, there are numerous other smaller point sources. However, Riverside's largest contribution to the County emission inventory is the emissions which can be related to population. The City has about 35 to 40 percent of the population in the Riverside County portion of the SCAPCD. It can be assumed that this percentage of the motor vehicle, petroleum marketing, dry cleaning, and structural fire emissions in Riverside County is produced in the City. The City would also be responsible for most of the aircraft emissions listed in the inventory. The other major airports in the area--Ontario and Palm Springs--are, respectively, in San Bernardino and in the non-SCAPCD portion of Riverside County.

Another major contribution from Riverside County to the District emissions-- farming operations--is produced outside the City.

Noncriteria Air Pollutants

The six air pollutants previously discussed (particulates, sulfur oxide, photochemical oxidants, nitrogen oxides, hydrocarbons, and carbon monoxide) are sometimes referred to as criteria pollutants, since before national ambient air quality standards are established the US EPA must issue that criteria that support these standards. Other substances have also been identified as pollutants. For some, such as lead, national ambient standards will soon be in effect and these substances will be added to the list of criteria pollutants. For others, national standards may be established some time in the future.

California has set state ambient standards for several air pollutants in addition to the six criteria pollutants. These additional California ambient standards cover particulate lead, particulate sulfate, hydrogen sulfide and visibility-reducing particles. Hydrogen sulfide is objectionable primarily because of its odor. Principal sources of hydrogen sulfide emissions are the oil refineries and the chemical processing industry in the South Bay portion of western Los Angeles County. Their odors do not affect Riverside.

The other three standards are discussed in this section, as is a pollutant that is currently receiving attention in the South Coast Air Basin, but for which there is no ambient standard -- nitrate.

Presented in Table F-6 are the results of an analysis to determine the contribution that several substances (which are not criteria pollutants) made to the 24-hour particulate concentrations collected at three South Coast Air Basin stations between 1967 and 1973.[12] It can be seen in the table that the sulfate percentage in the particulate catch decreases from the coast (Long Beach) to the inland stations while the nitrate percentage increases. Both of these pollutants are secondary products of anthropogenic sources and they are primarily of submicron size. Thus they contribute to the scattering of light and the reduction of visibility. The concentration percentages presented above are for the entire 24-hour period and are a year's average. Hidy et al,[13] in their California Aerosol Characterization Experiment (ACHEX) presented measurement results demonstrating that

TABLE F-6. SOUTHERN CALIFORNIA HI-VOL PARTICULATE COMPOSITIONS FOR 1967-1973 FOR SEVERAL SUBSTANCES

Station	Annual Geometric Mean ($\mu g/m^3$)	Annual Arithmetic Mean ($\mu g/m^3$)	Lead ($\mu g/m^3$)	Sulfate ($SO_4^{=}$) ($\mu g/m^3$)	Nitrate (NO_3^{-}) ($\mu g/m^3$)	Ammonium (NH_4^{+}) ($\mu g/m^3$)	Benzene Solubles ($\mu g/m^3$)
Riverside	140	150	1.8 (1.2%)	11.7 (7.8%)	15.1 (10.1%)	1.5 (1.0%)	11.0 (7.3%)
Ontario	110	120	1.9 (1.6%)	10.2 (9.5%)	10.8 (9.0%)	1.0 (0.8%)	9.4 (7.8%)
Long Beach	95	105	2.3 (2.3%)	11.2 (10.7%)	5.6 (5.3%)	1.5 (1.4%)	10.2 (9.7%)

secondary conversion products such as sulfates, nitrates, and photochemical aerosols tend to be of sizes between 0.1 and 1.0 micrometers. They also showed that the fraction of the South Coast Air Basin atmosphere occupied by these particles increases sharply between early morning and midday.

Sulfates

Sulfur dioxide (SO_2) in the atmosphere is gradually converted to sulfur trioxide (SO_3) by a photochemical change and subsequently converted to sulfate compounds including sulfuric acid, ammonium sulfate, and lead sulfate. These compounds exist in the air as liquid droplets or solid particles. The photochemical conversion of SO_2 to SO_3 is speeded up in polluted atmospheres, specifically those containing nitrogen oxides and hydrocarbons.

Sulfur dioxide emissions are transformed to sulfate faster and more completely in the South Coast Air Basin than in any other region of the country because of the combination of abundant sunshine, polluted conditions and the poor dispersive characteristics of the Basin (the low wind speeds and the confining nature of the surrounding mountains.)* In the South Coast Air Basin 13 percent of the SO_2 emissions are transformed to sulfate each hour compared to 2 percent in most metropolitan areas of the country.[14] During the periods of maximum transformation of the SO_2 that is emitted along the Pacific Coast will be converted to sulfate by the time it travels the width of the basin. In other metropolitan areas of the country no more than 15 percent conversion might occur in this distance.

* SO_2 oxidation rates are more rapid in oil-fired than in coal-fired power plant plumes. In the first 30 miles downwind the rate is 1 to 2 percent per hour for coal fired versus 10 to 20 percent per hour for coal oil-fired. The difference is believed to be due to the lack of particulate controls in the oil-fired-plant plume. Consequently, the vanadium and other catalytic particulates in the oil-fired-plant plume escape with the SO_2 and accelerate the conversion to sulfate. After 30 miles both rates are about 3 percent per hour. However, the coal plume contains higher SO_2 concentrations that can convert to more sulfate over wide areas downwind than do plumes from low-sulfur oil-fired sources.[15]

Major sources of SO_2 in the Basin result from petroleum refining and the combustion of sulfurous fuel oils, both undertaken in Los Angeles County. There are also natural sources of sulfate of which oceanic bacteria is the major one. Decaying animal or plant tissue releases organic-sulfur-containing gases that are oxidized to sulfates. Even the natural source contribution to sulfate concentrations is greater in Southern California -- 4 $\mu g/m^3$.

Sulfate particles generally have mass mean diameters in the submicron range ($\leq$ 1.0 μm). Particles of this size are significant for two reasons.

(1) They can infiltrate the deeper regions of the respiratory system and are likely to be retained in the lungs. As a consequence they aggravate breathing difficulties and respiratory diseases. It has been found that these adverse effects are magnified when the high sulfate concentrations are concurrent with excessive oxidant concentrations and high humidities.

(2) Particles in the size range of 0.1 to 1.0 μm are most effective in reducing visibility. They have been shown to be responsible for about 20 percent of the visibility reduction in the Basin.[16]

Sulfate concentrations make up only about 10 percent (7.8 percent in Riverside) of the total suspended particulates (as analyzed between 1967 and 1973).[17] However, there is special interest in sulfates because of the possibility that there will be an increase in sulfurous fuels used in the Basin in future years. The resultant growth in SO_2 emissions coupled with the Basin's fertile conditions for transformation of SO_2 to sulfate and the presence of high oxidant concentrations in the area portend a sharp rise in sulfates and their consequent effects.

Sulfate concentrations are generally highest in the summer months of June through August and lowest during the winter months of November through February. Concentrations peak between noon and 2 p.m. in the Los Angeles Basin area; however, in Riverside the most probable time for peak sulfate concentrations to occur during the summer is between 6 a.m. and 8 a.m.[18]

Between 1965 and 1975 sulfate concentrations in the Basin reached a maximum in 1972 and then declined. The highest concentration in the Basin during this period was 84.6 $\mu g/m^3$, measured at Thousand Oaks (Ventura County) in 1972. Maximum 24-hour sulfate measurements at several sites in the Basin between 1972 and 1974 are given below.

Highest 24- Hour Sulfate Concentrations ($\mu g/m^3$) 1972-1974

Station	Maximum Concentration
Anaheim	65.8
Lennox	53.3
Los Angeles	72.2
Ontario	29.1
Riverside	31.4
Thousand Oaks	84.6
West Covina	62.5

In 1975 the maximum 24-hour concentration was 59.7 at West Covina. A comparison of data from Riverside, West Covina, and Oakland, California is shown in Table . Oakland was chosen because it is a heavily industralized area but is in a different climate. There are markedly higher sulfate concentrations in southern California than in the northern part of the State. One can note that while the average sulfate concentration is a maximum in the third quarter at all three stations, the maximum 24-hour concentration does not necessarily occur in that quarter.

High concentrations of sulfate are an areawide problem. In 1975 the annual averages were between 9 and 15 $\mu g/m^3$ for all the South Coast Air Basin stations except several on the far eastern side of the Basin (e.g., Redlands with 7.0 $\mu g/m^3$).

It was predicted that sulfate concentrations in the Basin would rise in the summer of 1976 as a consequence of the increased use of fuel oil; however, the number of days on which the 24-hour standard was exceeded any place in the basin dropped to 35 from a figure of 37 in 1976. One explanation of this decrease is that the subsidence temperature inversion,

which lies above the Basin, was not as pronounced in 1976 as it had been in previous years.[19] Thus conditions for the dispersion of emissions in the Basin were better than normal.

California's ambient standard for sulfate is 25 $\mu g/m^3$ for a 24-hour averaging period. When a 24-hour sulfate concentration of 25 $\mu g/m^3$ is accompanied by a 1-hour oxidant concentration of 0.20 ppm or more, a sulfate episode is declared. Unlike the episodes for other pollutants the sulfate episodes have one stage, not three. During sulfate episodes power plants are required to reduce sulfur dioxide emissions by 20 percent through such measures as importing electricity from outside the air basin, reducing consumption of fuel oil, and using low sulfur fuel oil.

Development of predictive methods for forecasting sulfate episodes 24 hours in advance have shown that when today's sulfate concentrations, moisture levels, and temperature inversion base heights are relatively high and today's visibilities are relatively low, tomorrow's sulfate concentrations are likely to be high. The reason that a high rather than a low inversion height is a predictor of elevated sulfate concentrations is that a large fraction of sulfate forms from SO_2 emissions that are injected from tall stacks. When the base of the inversion is low, it prevents mixing of the sulfate down to the ground from the stacks above the inversion's base.

Lead

Airborne lead in the South Coast Air Basin derives almost entirely from the combustion of gasoline in motor vehicles. Vehicle lead emissions are small particles with a mean diameter of about 0.25 μm. About half of this lead from automobile exhausts settles out of the air within 100 yards of roadways. The concentration of lead in the air is closely correlated with the density of traffic. Over 63,000 cars daily use the Riverside Freeway which has houses or apartments on one or both sides in the 5 mile stretch between Van Buren Boulevard and 14th Street.[20] The site of the lead monitoring station at Magnolia and Arlington Avenues is about 1200 meters from the Riverside Freeway.

The major source of human exposure to lead is from injestion of food and water. However, in urban areas, especially near freeways, where atmsopheric lead concentrations are high, inhaled lead is an important source of body lead. This importance stems from the fact that a greater percentage (20-50 percent) of inhaled lead than of injested lead (5-10 percent) is absorbed by the body. In blood level studies of urban versus rural populations the most noticeable increases are among children. Long exposure to lead concentrations above 2-3 $\mu g/m^3$ can result in an accululation of lead in the blood. Acute forms of toxicity, such as cramps and nervous system effects, can occur when lead levels in blood are high.

The California Air Resources Board has set the ambient lead standard at 1.5 $\mu g/m^3$ for a monthly average. In 1975 and 1976 this standard was exceeded at the Riverside monitoring site (Magnolia and Arlington Avenues) in every month except one and then the monthly average was 1.47 $\mu g/m^3$ (Table F-7). In most months the concentration was over 2 $\mu g/m^3$. By comparison the monthly lead concentrations in Rubidoux exceeded the standard in 9 of 23 months during this period with five values above 2 $\mu g/m^3$. Maximum lead concentrations occur in winter. The higher winter lead concentrations have been attributed to the lower heights of the temperature inversion base in those months. During 1976 the maximum 24-hour averages of lead concentrations occurred in December (6.73 $\mu g/m^3$) and November (6.40 $\mu g/m^3$).

With more vehicles using gasoline with lower lead content the concentrations of airborne lead would be expected to decrease. However, measurements in the Los Angeles Basin between 1966 and 1975 failed to reveal any clear downward trend. This lack of a trend may be the result of an increased number of vehicles and travel or it may be a consequence of the trend being so small that it is obscured by variations in the weather from year to year.(21)

TABLE F-7. MONTHLY AVERAGE LEAD PARTICLE CONCENTRATIONS AT THE RIVERSIDE MAGNOLIA AVENUE AND THE RUBIDOUX MONITORS -- 1975 and 1976

Month	Magnolia Avenue	Rubidoux	Magnolia Avenue	Rubidoux
January	2.37	2.13	3.00	1.65
February	2.76	1.28	2.36	1.08
March	1.68	1.18	2.12	1.34
April	1.47	0.72	2.37	1.22
May	1.98	1.11	2.52	.83
June	1.89	1.05	2.74	1.07
July	2.41	1.26	2.12	----
August	2.42	1.61	2.08	1.18
September	2.94	2.02	2.18	1.39
October	2.71	2.86	2.90	1.37
November	3.55	1.96	4.14	2.61
December	2.93	1.56	4.52	2.94

Source: "California Air Quality Data", Quarterly Reports for 1976, Vol. VIII, California Air Resources Board, Sacramento, California.

Nitrates

Nitrate aerosols, mostly in the form of ammonium nitrate, comprise a significant fraction of the particulate loading in the eastern South Coast Basin. Nitrates are created through the transformation of gaseous nitrogen oxides that are emitted from motor vehicles and power plants. Intermediate steps in the process may include the formation of nitrous and nitric acid as well as organic nitrates.

Nitrogen dioxide concentrations in the industrialized Long Beach area are higher than those in Riverside. However, Riverside's concentrations of nitrates, after transport and transformation of the NO_x, exceed values along the coast. For example, concurrent measurements of nitrates along the Los Angeles Harbor Freeway and in Riverside were 4.1 $\mu g/m^3$ and 20 mg/m^3 respectively.(22)

Nitrate concentrations reach their maximum in the summer and their minimum in the winter. Near Azusa, in 1975, the average June concentration was 19.0 $\mu g/m^3$, while it was 3.5 $\mu g/m^3$ in January. However, the variation from year to year can be even greater. Between 1971 and 1975 the annual average of nitrate content in airborne particulates at this station varied from 18.4 $\mu g/m^3$ in 1972 to 3.7 $\mu g/m^3$ in 1974 and then rose back to 12.4 $\mu g/m^3$ in 1975.(23)

Unlike sulfates and the aerosols created during the daily photochemical oxidant creation process nitrates generally reach their maximum concentration in the morning.(24) This maximum accompanies the morning peak of NO_x emissions associated with traffic. Variation during the day can be quite large. A two-hour average concentration of 247 $\mu g/m^3$ was measured at a South Coast Air Basin station for which the 24-hour average that day was 19.2 $\mu g/m^3$.(25)

Most nitrate aerosols are in the submicron range. Thus they contribute to the reduction in visibility and are respirable. However, additional research is needed to determine if nitrates are actually a respiratory irritant.

It has been observed that there is a statistical correlation between high concentrations of nitrogen dioxide (NO_2) and a high incidence of cancer in urban areas; but neither NO_2 nor NO have been shown to cause cancer. It has been speculated that nitrosamines, which have been establis as an animal carcinogen, may be responsible for urban cancer.[26] If this hypothesis is substantiated, there may be additional efforts to control atm pheric NO and NO_2. Under certain conditions both NO and NO_2 when combined with water, can form nitrous acid. This nitrous acid can then combine with amine to form nitrosamines. Additional study of these possibilities is required before any linkage between cancer in urban areas and the secondary products of nitrogen oxide emissions can be verified.

Visibility

California has a state standard for visibility-reducing particle: It requires that visibilities be 10 miles or more when the relative humidi is less than 70 percent. With higher relative humidities, reductions in visibilities are likely to be the result of natural fogs. For instance, during the summer when photochemical smogs are most frequent in the Los Angeles Basin, the visibility reductions that occur in the morning are generally caused by the natural sea haze. As temperatures rise during the day the relative humidity decreases and the water droplets evaporate. At the same time the photochemical changes that produce oxidant and sulfate are progressing and the visibility-reducing aerosols produced by them are increasing. By midafternoon these aerosols are responsible for most of the visibility reduction.

The formation process for the visibility-inhibiting smog which accompanies the production of photochemical oxidant has been described as follows. [27]

"The aerosol-forming reactions involve primarily the oxidizing of various hydrocarbons and hydrocarbon derivatives. In this process, the first products are gases that have no effect on visibility reduction. As oxidation proceeds further, the chemical compounds formed are characterized by higher and higher molecular weights, with the consequent lower volatilities and lesser tendencies to remain in the gaseous phase. Eventually, if the molecular weights and the concentrations are high enough, these compounds can no longer remain gaseous and they condense out into tiny liquid particulates that reduce visibility. They also act as nuclei for additional condensation that reduces visibility even further."

At Riverside and the other inland stations there are fewer days when the relative humidity exceeds 70 percent than there are at coastal stations.

Thus poor visibilities in Riverside are seldom the consequence of a natural fog, but rather, are caused by the presence of submicron (0.1 to 1.0 μm) particles. These submicron particles are anthropogenic in origin and arise from chemical transformations involving sulfur oxides, nitrogen oxides, and hydrocarbons. One demonstration of the antropogenic source of these particles was a set of ACHEX measurements made at Rubidoux.[13] When a reversal of wind direction occurred during a 30 minute period and the air came from the west instead of the east there was no change in the number of supermicron (>1 micrometer) particles, but there was a large increase in the number of submicron particulates that had their origin in the more populated and industrialized areas to the west of Rubidoux. With east winds, the air volume had almost no submicron particles but a considerable number of supermicron particles. With west winds the fraction of the volume occupied by submicron particles was even greater than that occupied by the larger particles. The increase in submicron particles was accompanied by an increase in the scattering coefficient for visible light.

Table F-8, which presents minimum visibility measurements from one year, illustrates the variation in smog days across the basin. In summer the inland areas (Riverside and Ontario) have very few days on which there is no smog and frequently the visibility is quite poor (<3 miles). Near the coast there are more days of high relative humidity, fewer days when

TABLE F-8. MINIMUM VISIBILITIES AT RIVERSIDE[a], ONTARIO[b], AND LONG BEACH[c]

	Riverside						Ontario						Long Beach					
	Winter, 1976-77			Summer, 1977			Winter, 1976-77			Summer, 1977			Winter, 1976-77			Summer, 1977		
	Dec.	Jan.	Feb.	June	July	Aug.	Dec.	Jan.	Feb.	June	July	Aug.	Dec.	Jan.	Feb.	June	July	Aug.
Number of days when relative humidity dropped below 70%	29	27	26	30	31	30	29	27	27	30	31	29	30	28	27	27	31	29
Number of days not meeting State Standard for Visibility[d]	8	8	11	30	29	28	11	13	18	30	31	28	16	12	19	20	27	24
Number of days with R.H. <70% and visibility <3 miles	0	1	4	16	6	17	1	3	7	25	13	23	2	2	5	3	1	4
Highest minimum visibility during month (miles)	40	50	45	7	15	20	35	25	25	4	9	15	20	15	35	14	14	12
Lowest minimum visibility during month (miles)	4	2	1 1/4	1 1/4	2	1 1/2	1 1/2	2 1/2	1 1/2	1 1/4	1 1/4	1 1/2	2 1/2	1 1/2	1	2 1/2	2 1/2	2

(a) Observations made at March AFB.
(b) Observations made at Ontario International Airport.
(c) Observations taken at Long Beach Municipal Airport.
(d) State standard is visibility less than 10 miles when relative humidity is less than 70 percent.

Source: "Air Quality and Meteorology -- Monthly Reports", Southern California Air Pollution Control District, El Monte, California.

the state visibility standard is violated and very few days when the minimum visibility is very poor. In winter, visibility conditions at Long Beach and Ontario are comparable with about a third to a half of the days violating the standards. At Riverside during winter, the number of days with smog drop off sharply and there are some days when visibilities are outstanding (greater than 40 to 50 miles).

Submicron particles are important air pollutants both for their light-scattering potential and their ability to penetrate the respiratory system. Thus poor visibilities are an indication of possible respiratory difficulties. With a better understanding of these consequences more attention is being given to fine particles. It is probable that the Federal Government will establish ambient standards for fine particles. The cutoff size has yet to be decided since there are some deleterious effects to the respiratory system from particles as large as 15 μm. [28]

At this time only New Mexico has emission standards that are specific for small particles. As has been discussed here southern California, with its climate that is so conducive to the photochemical changes that produce sulfates and nitrates, is more concerned with controlling the emissions of SO_x and NO_x which are transformed to fine particulates than with controlling emissions of the smaller size particulates themselves.

Air Pollutant Effects

Table F-9 presents a list of California and Federal ambient air quality standards for comparison with examples of measurements made in Riverside for the same averaging times used in the standards. Based on the listed numbers, Riverside is clean with respect to sulfur dioxide, but has problems with the other air pollutants. However, measurements made by a sampling instrument are just indicators of whether the atmosphere is clean or polluted. The actual determinants which we try to represent by numbers are whether one can see mountains in the distance or cannot even see across the city. The difference between clean and polluted air is the difference between healthy, productive ornamental or farm plants versus a region where flowers or crops are damaged and agricultural yields are low. A polluted atmosphere is indicated by eye irritation, the fading of draperies, or the aggravation of bronchial problems. Air pollution episodes in some parts of the world have brought an increase of factory emissions in a valley until breathing becomes a problem and there is a noticeable increase in the death rate for several days. Riverside's pollution does not result in episodes during which the death rate increases. If there are any air pollution caused changes in the mortality rates of Riverside, they are subtle, such as a reduction of the average lifetime by a fraction of a year.

Numerical standards for ambient air quality have been set to protect against damage to health, vegetation, and materials. These standar were chosen based on the results of laboratory and field or epidemiologica studies which investigated the relationship among air pollution concentrations and its damaging effects. Many of these studies were conducted in the Los Angeles Basin and at the University of California at Riverside.

Additional research is currently under way to supplement and reexamine the earlier studies since we have found that the air pollution cause-effect relationship is complex. For instance:

(1) Some of the standards set in 1970 were based on evidence gathered from English studies. It is now believed that the differences, such as climate, between the British Isles and North America need to be taken into account

TABLE F-9. RIVERSIDE* AMBIENT CONCENTRATIONS OF AIR POLLUTANTS FOR RECENT YEARS IN COMPARISON WITH STATE AND NATIONAL STANDARDS

Substance	Applicable State or Federal Standards		Recent Riverside Measurements		
	Concentration	Averaging Time	Year	Concentration	Averaging Time
Oxidant (as O_3)	0.10 ppm	1-hour	1975	0.28 ppm	Highest 1 hour maximum during the year
			1975	0.084 ppm	Average of all the daily 1-hour maxima
			1975	0.031 ppm	Average of all 1-hour readings
Total Suspended Particulates	100 $\mu g/m^3$	24-hour sample	1975	467 $\mu g/m^3$	Maximum 24-hour average
	60 $\mu g/m^3$	Annual geometric mean	1975	149.0 $\mu g/m^3$	Annual geometric mean
Sulfur Dioxide	0.50 ppm	1-hour	1975	0.06 ppm	Maximum 1-hour reading
	0.03 ppm	Annual arithmetic average	1975	0.008 ppm	Annual arithmetic average
Nitrogen Dioxide	0.25 ppm	1-hour	1975	0.30 ppm	Maximum 1-hour reading
	0.05 ppm	Annual arithmetic average	1975	0.056 ppm	Annual arithmetic average
Carbon Monoxide	40.0 ppm	1-hour	1975	24.0 ppm	Maximum 1-hour reading
Lead	1.5 $\mu g/m^3$	Monthly average	1976	4.52 $\mu g/m^3$	Maximum monthly reading
			1976	2.70 g/m^3	Annual average of monthly readings
Sulfate	25 $\mu g/m^3$	24-hour average	1974	39.8 $\mu g/m^3$	Maximum 24-hour reading
			1974	28.6 $\mu g/m^3$	Highest monthly average for the year
			1974	15.3 $\mu g/m^3$	Annual average of 24-hour readings

* All measurements except SO_2 were made at the Magnolia Avenue monitor. The SO_2 measurements were made in Rubidoux. Values given are the ones that were most recent and readily available for comparison with standards.

when assessing the effects of sulfur oxides and particulates on health.[29]

(2) "There is a requirement for extensive and reliable data on the 'dose' portion of dose-response curves of not only the criteria pollutants, but also of a multitude of ...organic compounds"[30] and other airborne substances.

(3) Synergistic effects among air pollutants are more common than was originally thought. Earlier investigations identified a synergism between particulates and sulfur dioxide, but there are others, such as the increased damage that occurs when oxidant and sulfur dioxide or sulfate occur together. (California Air Resources Board has established episode criteria for these two combinations).

(4) We must be more specific with our pollutant identification. Total suspended particulates is too broad a category. The fine particles of 3 μm or less in diameter are the ones most instrumental in reducing visibility and the ones that can penetrate into the lungs. Sulfates produced from the oxidation of sulfur oxides are probably a more important air pollutants than their precursor, SO_2; however, control of sulfur oxide emissions is the best way of reducing ambient sulfate concentrations.

(5) Some of our air pollutants are in the "secondary" category, meaning that they are created, while in the atmosphere, as a result of photochemical or other transformations. Several factors, including solar insolation, humidity, and the presence of other air pollutants affect the rate of transformation. The effects of these factors need to be considered in assessing the damage caused by secondary pollutants.

(6) Air pollutants, especially secondary air pollutants, are emitted from a multitude of sources, are not easily removed from the atmosphere, and can spread over a wide area. The extensiveness of these pollution "clouds" indicates that the

original source and the ultimate receptor may be quite distant from each other. Also, the same pollutant concentration may occur in concert with a variety of ambient conditions (topography, other pollutants, meteorological variables) which will have different impacts on the observed effects.

(7) Measurement techniques for pollutant concentrations and effects need to be refined in some instances.

(8) Epidemiological studies of the relation between air pollution and human health must meet a number of requirements before their results can be accepted. In evaluating the conclusions of an epidemiological study, one must take into consideration a set of criteria which include: strength of the association, consistency, specificity, plausibility, "direct correlation" (agreement between epidemiological and clinical results), and coherence. [31,32]

(9) Smoking overwhelms other factors in respiratory studies.

The remainder of this section discusses the conclusions of several criteria-pollutant dose-response investigations with emphasis on ones that were performed in or apply to the Southern California Air Basin. Effects on human health, vegetation, and materials are presented for each pollutant.

Oxidant

Much of the research done on the effects of oxidant has been performed in Southern California. The human symptoms of respiratory distress and eye irritation caused by photochemical smog were first observed in the Los Angeles Basin. Middleton, et al,[33] identified oxidant injury to Los Angeles vegetation in 1944. In 1961 Stephens, Darley, Taylor and Scott[34] at the University of California, Riverside, reported that the undersurface glazing and bronzing of certain sensitive leaves was caused by peroxyacetyl nitrate (PAN), a small but significant component of atmospheric oxidant. Table F-10 presents some responses observed in human health, vegetation, and materials at different concentrations of oxidant or ozone. Some additional comments are given in the following paragraphs.

Human Health. Short-term (one to two hour) exposures to ozone concentrations between 0.15 and 0.25 ppm may induce respiratory symptons in sensitive humans. The occurrence of these respiratory symptoms may have important health implications, especially for the developing lungs of children. While these effects appear to be reversible for healthy young adults, they may at times overwhelm the biological defense mechanisms of some persons. Laboratory experiments demonstrate that above a minimal ozone exposure level, the joint presence of ozone and sulfur dioxide affects lung function as though the entire dose was ozone.[47]

A high proportion (about 5 percent) of Los Angeles residents reports difficulty in breathing during smog episodes. Respiratory difficulties are also more prevalent in Los Angeles, regardless of episode conditions. Among outside telephone workers in the age group of 50 to 59, a significant excess of persons with coughs was observed among Los Angeles residents when compared with those in San Francisco and other United States cities.[48] These differences could not be explained by social class, occupation or smoking habits.

TABLE F-10. SOME RESPONSES TO OXIDANT CONCENTRATIONS

Location	Oxidant Concentration (ppm)	Duration	Comments	Reference
Human Health				
	0.06	Period of exposure	No decrease in pulmonary function among people with chronic respiratory disease	Rokaw & Massey,[35] 1962
Los Angeles	>0.10	1 hour before race	Long distance runners failed to show improvement in running times	Wayne, et al.,[36] 1967
Los Angeles Lab.	>0.1-0.15	Period of exposure	Decreased pulmonary function among people with chronic respiratory disease	Motley, et al.,[37] 1959
Pasadena	0.20	Maximum hourly reading for the day	Significant excess of asthma attacks	Schoettlin & Landau, 1961[38]
Los Angeles	0.25-0.29	Maximum hourly reading for the day	Rate of chest discomfort increases among student nurses	Hammer, et al.,[39] 1974
Laboratory	0.30*	Few minutes	Throat dryness	Young, et al.,[40] 1963
Los Angeles	0.30-0.39	Maximum hourly reading for the day	Rate of cough increases among student nurses	Hammer, et al.,[39] 1974
Eye Irritation				
Los Angeles	0.15-0.25	Period of exposure	Moderate eye discomfort among student nurses	Hammer, et al.,[39] 1974
	0.30	Period of exposure	Tearing or burning of eyes	Altshuller, 1977[32]
Vegetation				
California	>0.10	Maximum for each day during growing season	42% reduction in yield of lemons	Thompson & Taylor,[41] 1969
California	>0.10	Maximum for each day during growing season	54% reduction in yield of oranges	Thompson & Taylor,[41] 1969
California	>0.25	Maximum for each day from May-September	12% reduction in yield of grapes during first year	Thompson, et al.,[41] 1969
	0.1-0.25*	1 hour	5% injury to sensitive plants	Nat. Res. Council,[43] 1976
		or		
	0.04-0.09*	4 hours		
	0.20-0.35*	1 hour	20% injury to sensitive plants	Nat. Res. Council,[43] 1976
		or		
	0.10-0.15*	4 hours		
	≥0.55*	1 hour	20% injury to resistant plants	Nat. Res. Council,[43] 1976
		or		
	≥0.35*	4 hours		
Materials				
Field Test in Homes	0.10		Fading of blue disperse dyes	Salvin & Walker,[45] 1955
Laboratory	0.05		Visible fading in one third of sensitive fabrics	Beloin, 1972[45]
Laboratory	0.05	3 years	Penetration of cracks through the white sidewalls of tires	Haynie, et al.,[46] 1976

* Ozone.

There is no evidence for an increased risk of mortality in association with the daily oxidant concentrations measured in the Los Angeles Basin. It has been found that the increase in deaths which accompany oxidant episodes result from the higher temperatures present during those periods not from the oxidant. One illustration of this cause-effect relationship is the two community study conducted by Landau et al.[49] They divided the area of Los Angeles County, California into regions that had similar autumn temperatures, but differing oxidant concentrations and then examined records to see whether there was any difference in daily mortality attributable to the differences in oxidant concentrations. None was found.

Eye Irritation. While eye irritation may be the most frequent complaint during Southern California oxidant episodes, ozone which is the principal component of the oxidant, is not the eye irritant. Eye irritation appears to be a summed effect of a number of organic products in the smoggy air. These include formaldehyde, acrolein, and peroxyacyl nitrates. Formaldehyde and acrolein, while they are products of the photochemical process, are not oxidants. Additionally, particulate matter in either relatively pure air or oxidant-laden air may cause a person to squint because of the high reflectance and scattering of sunlight and the consequent production of glare. The person may relate this squinting to eye irritation. The tearing or burning of eyes does not being until oxidant concentrations reach 0.30 ppm. Concentrations of this magnitude are infrequent outside of Southern California and this probably explains why eye irritation does not occur in the ambient atmosphere of cities outside of this region.[32]

Vegetation. Two components of oxidant smog have been identified as phytotoxicants. Ozone makes the upper surfaces of leaves appear splotched or stippled. If the concentration is high enough, holes may develop in the leaves. The other oxidant that damages plants is peroxyacetyl nitrate (PAN), which can make the underside of leaves of susceptible plants -- citrus trees in particular -- turn silver or bronze. Apparently PAN is a phytotoxicant for which the effects have been rarely observed outside California.[50]

Decreased growth and possible reductions in yield and productivity have been reported from mixtures of ozone and sulfur dioxide.[51] Optimal conditions for plant growth increase the sensitivity of plants to ozone. Drought during growth increases the resistance of plants to ozone damage.

Materials. Erosion of auto and industrial paints has been observed to occur at a greater rate in Los Angeles than in parts of the country which have clean air. By considering the composition of these paints and their reactivity to various air pollutants it was deduced that the increased damage to these types of paints resulted from the higher ozone concentrations in Los Angeles.[52] Losses from air pollutant damage can be of two types -- costs to replace the damaged item and costs to prevent damage to the item.

Carbon Monoxide

Human Health. Carbon monoxide effects on human health far outweigh any CO effects on vegetation and materials. Automobile exhaust is the chief source of ambient CO and maximum ambient concentrations occur near street and freeways. However, smoking is a much greater contributor than auto exhaust to increased levels of carboxyhemoglobin in the blood -- the direct measure of CO dosage.

The greater the amount of CO intake, the higher the level of carboxyhemoglobin in the blood. As carboxyhemoglobin levels increase, the capacity of the blood to carry oxygen decreases. When air quality standards were first set in California in 1959 the effects of carbon monoxide on the limitation of oxygen transport were a guiding criterion. Among the persons to be specially protected were those with heart disease. During acute attacks the heart needs an increased supply of oxygen. Although some human organs can increase their oxygen supply by increasing the oxygen amount they extract from the blood the heart can only get more oxygen through an increased flow of blood. Persons with heart disease have rigid blood vessels supplying their hearts, therefore, an increase in circulation is difficult. Consequently, it is beneficial for their blood to contain a maximum amount of oxygen.[53]

Because of their high mobility, urban residents are exposed to a wide range of carbon monoxide concentrations during a day. Numerous studies of CO levels in automobile traffic have been conducted, there there is a dearth of reliable epidemiologic data on the health effects of chronic carbon monoxide exposure. Deane[54] found that Los Angeles drivers had an increase in carboxyhemoglobin during the morning commuting period. Aronow et al[55] found that angina pectoris patients who rode around the streets and freeways of Los Angeles for 90 minutes were exposed to air containing approximately 50 ppm of CO. Two hours after the trip the patients were still experiencing a decrease in their exercise capacity.

Nitrogen Oxides

Human Health. Nitrogen dioxide is the nitrogen oxide that can be directly responsible for health effects; however, the long-term ambient concentrations are considerably below the concentrations that have been found to be detrimental to human health. Remmers and Balchum,[56] in a study of oxidant effects, found no significant effect of nitrogen dioxide on airway resistance in persons with chronic respiratory disease. It appears that more information on the impact of nitrogen oxides on health will have to come from the nitrosamines studies.

Taylor[57] has noted that the short-term NO_2 concentrations that cause vegetation damage are on the order of 4 to 20 ppm, but NO_2 is decomposed photochemically and therefore these concentrations this high are never observed in the ambient air. Long-term exposure to lower concentrations may inhibit growth without producing visible damage. However, even these concconcentrations are higher than ambient average levels. Taylor and Eaton[58] observed a decrease in the weight of pinto beans (in NO_2 concentrations of 0.3 ppm) and in the weight of tomatoes (in NO_2 concentrations between 0.15 and 0.26 ppm) after exposures of 10 to 19 days. Thompson, et al.,[59] found that naval oranges had increased amounts of leaf drop and decreased yields when exposed to NO_2 concentrations of 0.25 ppm for 8 months.

Materials. Breakage of the nickel-brass wire springs in some relays in Los Angeles was discovered by the Pacific Telephone and Telegraph Company. It was later shown that the failures were produced by nitrates in the dust which had accumulated on surfaces adjacent to the cracked areas.[60] Upon further investigation it was learned that the nitrate content of the Los Angeles dust was 5 to 10 times greater than that of dust in eastern or midwestern cities and that the Los Angeles dust was more reactive to moisture. Failures in the relays were observed when nitrate depositions exceeded 2.4 $\mu g/cm^2$ and the relative humidity was greater than 50 percent.

Levels of nitrogen dioxide which exist in urban areas produce visible fading in a number of fabrics. High relative humidity and high temperature contribute to the fading.

Hydrocarbons

Human Health. Hydrocarbon compounds of greatest importance in air pollution fall into two groups olefins or cthylene series and aromatics or benzene series. Few studies have looked at the direct effect of olefins on human health. Generally olefin emissions are considered in their role as a precursor for photochemical oxidants.

Aromatic hydrocarbons can be produced by any combustion process involving hydrocarbons, but the emissions are greater from inefficient combustion. Among the aromatics there are a number of compounds which are believed or known to be carcinogenic. The most potent of these is benzo [a] pyrene, abbreviated BaP. Taking cigarette smoking into account as a major factor in lung cancer, there is an additional urban factor that appears in epidemiological studies. One suggestion has been that the concentration of BaP is a significant indicator of this urban factor. However, there is also evidence that the relationship between lung cancer death rates and BaP concentrations in urban areas is not as pronounced as that between lung cancer death rates and sulfate concentrations.[61]

Vegetation. Ethylene a major product of auto exhaust is more than 50 times as phytotoxic as other hydrocarbon gases. It causes damage to cotton, tomatoes, and orchid blossoms as well as reducing plant yield.(62)

Particulates and Sulfur Oxides

Many health studies have considered the effects of particulates and sulfur oxides or particulates and sulfates concurrently. This approach is used because in general these pollutants come from the same source -- the combustion of fossil fuels -- and because their concentrations have been very high in areas where acute episodes have occurred. Some health studies have tried to determine the amount of damage which can be attributed to each of these pollutants when they occur in combination.

Human Health. While the episodes, such as those in London in 1952 and 1962, and Donora, Pennsylvania, in 1948 have given clear evidence of the mortality that accompanies high concentrations of sulfur oxides and particulates it is much more difficult to demonstrate mortality as a consequence of long-term exposure to low levels of these pollutants. In fact it is probable that sulfur oxides alone at the concentrations generally observed are not especially hazardous to health unless they are oxidized into sulfate aerosols. Lave and Seskin(63) studying death rates in 117 metropolitan areas of the United States believe that concentrations of particulates and sulfates are significant factors in explaining mortality. However, their conclusions can be questioned on the basis that they used monitoring data from only one site in each city.(64)

There is general consensus that concentrations of SO_x and particulates which exceed the ambient annual standards will be accompanied by

(1) increased susceptibility to acute lower respiratory infections
(2) aggravation of chronic respiratory disease, such as bronchitis or ashtma and
(3) decreased lung function.

Annual average ambient concentrations that accompanied some of these investigations ranged from 85 to 250 $\mu g/m^3$ for particulates and from 0.01 to .16 ppm for sulfur oxides. Many investigators concluded that particulates were a more significant factor than sulfur oxides.(65)

Hazucha and Bates(66) found that while the exposure of healthy subjects to ozone at 0.37 ppm for two hours produced little change in lung function, the combination of 0.37 ppm of O_3 with 0.37 ppm of SO_2 produced a marked decrease in pulmonary function.

Vegetation--Particulates. There has been little research on the effects of mixtures of settleable particulates on vegetation. Generally, the studies have been directed at the effects of particulates from a specific source, such as cement dust from Portland cement plants. Another class of aerosols receiving considerable study are the sulfuric and nitric acid aerosols which produce acid rain. The effects of acid rain on vegetation include leaf necrosis and the creation of excessive acid levels in the soil.

Vegetation--Sulfur Dioxide. While low ambient concentrations of sulfur dioxide can stimulate growth in some plants, high concentrations can cause chlorosis in older leaves. Two plants sensitive to SO_2 are cotton and alfalfa. Heck and Brandt(67) have reviewed a number of SO_2 vegetation exposure experiments to develop a table of threshold response levels for three susceptibility groups of plants. A portion of this table is shown here.

Projected SO_2 Concentrations for Short-Term Exposures That Will Produce About 5% Injury to Vegetation Grown Under Sensitive Conditions

Time (hours)	Concentrations (ppm) Producing 5% Injury		
	Sensitive Plants	Intermediate Plants	Resistant Plants
0.5	1.0 - 4.0	3.5 - 10	$\geq$ 9.0
2.0	0.3 - 2.0	1.5 - 5.0	$\geq$ 4.5
8.0	0.10 - 0.75	0.50 - 2.0	$\geq$ 1.5

Materials -- Particulates. Generally material damage by particulates also involves other air pollutants. Airborne particles can act as nuclei for adsorbed or absorbed gases and gases can form aerosols. Masonry and concrete can be discolored or eroded by the combination of particulates and sulfuric acid. The combination of particulates with sulfur oxides or ozone can cause paints, enamels, and finishes to be discolored or lose their glossy appearance. Particulate matter in the atmosphere soils fabrics but does not damage them. Economic loss occurs from the costs of cleaning and the eventual deterioration of the fabric resulting from repeated cleanings.

Materials -- Sulfur Oxides. As mentioned in the particulate discussion of material effects, the impact of sulfur oxides is caused by a combination of particulates with the acids created by the combination of SO_2 and SO_3 with moisture in the air. These acidic gases can react with limestone to produce a slow erosion of building surfaces. Paints exposed to 1 to 2 ppm of SO_2 require 50 to 100 percent more drying time.

Water Quality

The Santa Ana River, from which Riverside derives its name, forms the nominal boundary along the northwest side of the city. Several streams from the San Bernardino Mountains join to supply the Santa Ana with its water. There has been no surface flow in the Santa Ana past Riverside since the 1950's. At that time, the Santa Ana's flow was diverted to the covered Gage Canal in order to reduce evaporation loss and provide greater amounts of water for human consumption and irrigation. Subsurface flow still continues below the Santa Ana riverbed.

California's groundwaters have experienced widespread degradation caused primarily by percolation of salt-laden agricultural water into the rivers. The Sacramento, the San Joaquim, and the Santa Ana are considered to present the State's three most difficult water quality problems resulting from the contributions of irrigation return flow.(68) In 1975, the water supply for the City of Riverside was affected by excessive salts. At other times chloride, sulfate and conductivity have also caused problems with the City's water. The segment of the Santa Ana River from Riverside to Anata Ana is classified as a Water Quality Limited Class Segment because concentrations of salts, coliform bacteria, and nutrients exceed adopted standards.(69)

Treatment of Riverside Sewage

Residential and industrial sewage is treated at the City's sewage treatment plant and then discharged into the Santa Ana River at Riverside Narrows.(70) Approximately 19 million gallons of treated sewage is discharged daily and of this amount, about three million gallons is from industrial sources. Facilities were expanded in 1968 to handle an increasing load from Riverside. Another expansion is currently under way. At its completion, the Riverside plant will become a regional facility by handling an additional 5 to 6 million gallons of sewage piped in from Rubidoux every day. Up to this time, Rubidoux has been processing its own sewage and discharging into the Santa Ana riverbed above the Riverside plant.

There are 20 large point sources in Riverside which send their sewage to the Riverside plant. Under U.S. EPA definitions, a point source for sewage treatment classification is one that (1) discharges 50,000 gallons

per day, (2) discharges any toxic material, or (3) constitutes 5 percent of the flow of the treatment plant. Rohr Industries, the largest point source for the Riverside Sewage Treatment Plant, contributes about 1 percent to the Plant's daily intake.

The City of Riverside sewage regulations are considered to be strong. Larger companies are encouraged to pretreat their own wastes before dischargin them into the sewer. The city recommends that companies with air pollution control devices collect the catches from these devices in a sump and then haul them to a landfill rather than discharging them into the sewer. The sewage plant itself collects its sludge in basins and then has the sludge hauled to a landfill periodically.

Santa Ana Water Quality Above and Below Riverside

Even though there is only minimal flow in the Santa Ana River, monitoring is done along the river for several water quality indicators. One relatively long-term record is available above the Sewage Treatment Plant at the Metropolitan Water District Crossing which is downriver from the Union Pacific Railroad Bridge. Downriver of the Riverside sewage treatment plant, the best long-term record is at Norco.

Table F-11 presents the range of measurements between January, 1974, and July, 1977, made for several water quality indicators which are monitored at the Metropolitan Water District crossing and at Norco. The major outflow along this portion of the river comes from the Riverside Sewage Treatment Facility. Of the variables listed in the table, sulfates, chlorides, and pH were within the acceptable range at both sampling sites, although there were higher amounts of sulfates and chlorides at the downstream station. Dissolved solids were excessive at both samplers and did not show much higher amounts downstream than upstream.

Dissolved oxygen concentrations were satisfactory at the upstream site, but at Norco some measurements were recorded below the reference level of 4 mg/l, at which point the water can become anerobic. A long-term view of the dissolved oxygen (DO) measurements is provided in Figure F-6 which

TABLE F-11. SANTA ANA RIVER WATER QUALITY NEAR RIVERSIDE -- JANUARY, 1974 - July, 1977

Type of Data	Units	Reference Level	Good Quality Water With Respect to Reference Level	Range of Values Upstream(a)	Range of Values Downstream(b)
pH	--	6.0-9.0	within	7.4-7.9	7.2-8.0
Chloride	mg/liter	250	below	92-106	114-138
Sulfates	mg/liter	250	below	94-145	116-135
Dissolved Solids	mg/liter	500	below	589-756	670-770
Dissolved Oxygen	--	4	above	5.9-9.2	2.5-7.6

(a) Metropolitan Water District Crossing in Riverside above the Riverside Sewage Treatment Plant outflow.

(b) Santa Ana River at Norco.

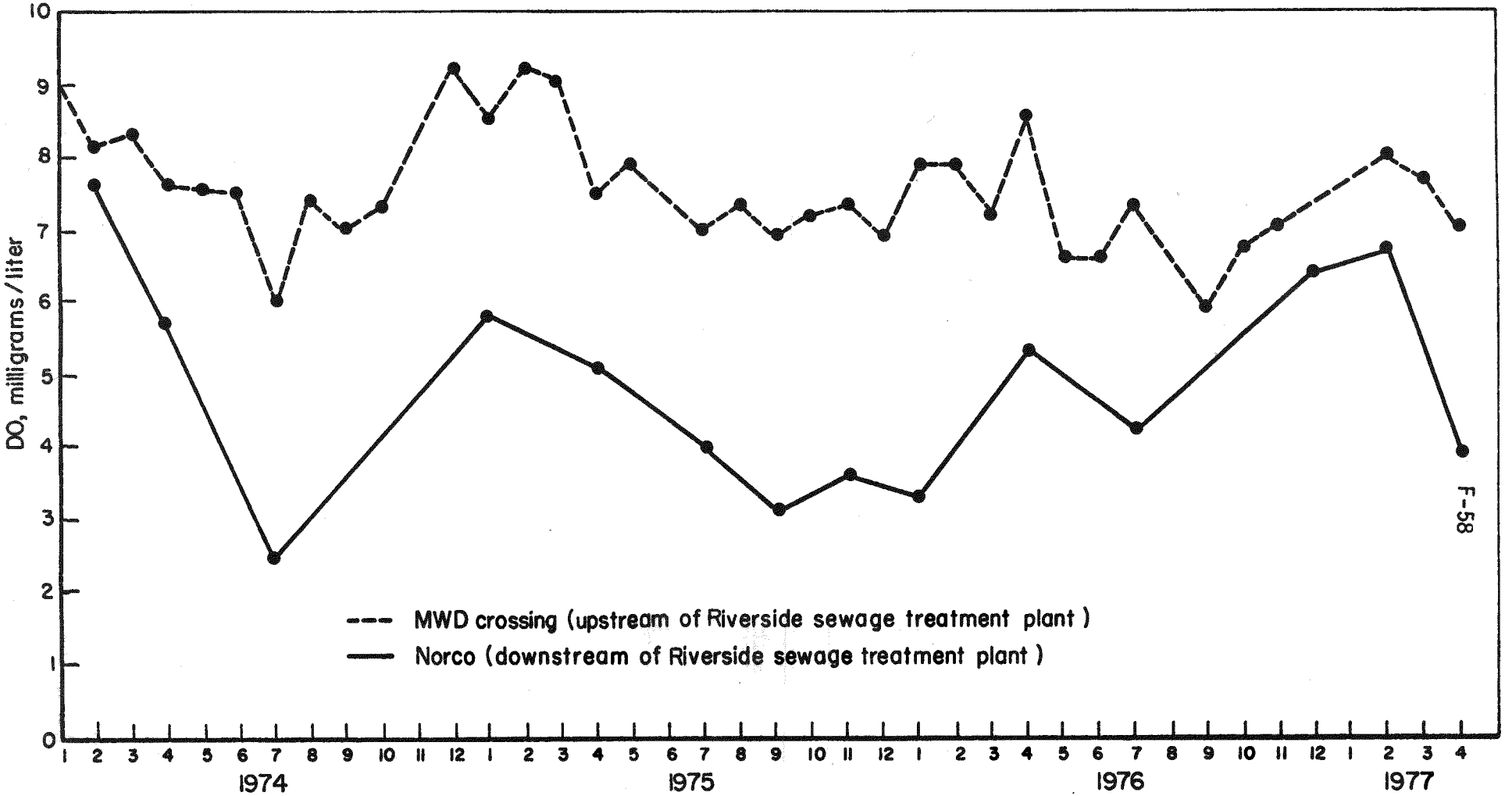

FIGURE F-6. COMPARISON OF DISSOLVED OXYGEN CONCENTRATIONS IN THE SANTA ANA RIVER ABOVE (METROPOLITAN WATER DISTRICT CROSSING NEAR ARLINGTON) AND BELOW (CITY OF NORCO) THE CITY OF RIVERSIDE.

Source: Surface Water Analysis for Stations Y-6-1225 and Y-6-1410 Suupplied by State of California, Resources Agency for Southern District: Dept. of Water Resources, Resources Evaluation Section, 849 S. Broadway, Los Angeles.

traces the variations in DO over a period of about 10 years with a break of 3 years in the middle. With some exceptions (such as the last half of 1968), DO at the MWD Crossing and NORCO were similar 10 years ago. Since 1974, however, the Norco readings have been consistently below the MWD values.

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APPENDIX G

USER AND PUBLIC RESPONSE AND EDUCATION

APPENDIX G

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USER AND PUBLIC RESPONSE AND EDUCATION

Task IV-b had a twofold objective. The first was to determine the status of the current energy education program in the Riverside community and make recommendations for improved conservation education. The second was to evaluate user and community acceptance of conservation techniques and programs recommended by this study for consideration in the Phase II demonstration projects. In carrying out this task, the following activities were completed:

- Related studies were reviewed.
- Conservation education programs and opportunities in the Riverside community were assessed.
- Study recommendations in the areas of transportation, buildings, and alternative sources of energy were reviewed from the viewpoint of community response.

The results of this task, together with related discussions in the area of user and public response and education, are presented in three major sections:

(1) "Promotion of Energy Conservation", which discusses impediments to energy conservation, and the role of energy information and education programs. Pertinent studies are referenced with respect to these issues, as appropriate.

(2) "Conservation Education in Riverside", which discusses the current energy education program in Riverside, applicable energy education programs, and recommendations for an improved energy information/education program for Riverside.

(3) "User and Public Response", which reviews general factors relating to public response and cites the anticipated response to recommendations contained in the integrated community energy system plan for Riverside.

Each of these three sections is discussed in greater depth in the following pages.

Promotion of Energy Conservation

The human behavior aspect of energy conservation is an important element which needs to be considered in the development of any energy plan. Without due attention to the human element in the process of planning and implementing energy conservation strategies, a sound and effective energy system cannot be developed for the community. One of the principal needs is adequate public education as a means of increasing knowledge, changing attitudes and preparing the public for needed policy changes.

Impediments to Energy Conservation

The United States appears to face some particular difficultie

in promoting an energy conservation viewpoint and in leading citizens to act in the national interest as far as energy use is concerned. These problems are not specific to any region of the country or to any particular community. They are of as much concern to the State of California and to the City of Riverside as they are to any state or any city. They can be characterized as impediments because they represent forces or tendencies that need to be overcome if a more substantial level of energy conservation is to be achieved. Included among these impediments* to energy conservation are the

- consumption ethic
- technological fix
- special-interest group politics
- urban-suburban sprawl
- spirit of nondependence
- unconsciousness of life-cycle costs
- territorial myths.

Consumption Ethic. The "consumption ethic" refers to a very pervasive and ingrained set of attitudes which many Americans have toward the consumption, not only of energy, but of a whole variety of material products and commodities. This "ethic" has its roots in the history and course of development of the United States. The United States, until recently, has been a "land of plenty" and of seemingly unlimited natural resources (including energy, specifically oil and natural gas). European and other settlers on the North American

* Welling, L.G., "Shaping Consumer Attitudes: The Hidden Ingredient", paper presented at the Battelle Executive Energy Briefings; Chicago, Los Angeles, Atlanta, and Boston, 1977-1978.

continent discovered what seemed to be an inexhaustable supply of everything: land, wood, water, and mineral resources. Coal outcroppings were discovered along ridges in Virginia, West Virginia, Pennsylvania, Kentucky, and Ohio which would initially be mined cheaply and without sophisticated engineering technology. The United States appeared to have superabundant resources of petroleum and soon became the world's largest producer.

Knowledgeable people now realize that there is no such thing as an unlimited natural resource. In fact, we are entering a period of shortage of some natural resources, including oil and natural gas. Unfortunately, the "consumption ethic" is so deeply ingrained in the general population that it will be difficult to change the values and attitudes which comprise it. In other words, moving people from a consumption ethic to a conservation ethic will be difficult. Education, information, and persuasion programs can be of assistance in changing the consumption ethic and in developing a new (i.e., conservation) ethic.

Technological Fix. The term "technological fix" is used here to refer to the attitude or belief held by many U.S. citizens that any problem is capable of being solved through an application of our technological skill, ingenuity and resources. There is a great faith in "technology" in the United States. Many people feel that given enough time and enough money, any problem will succumb to our technological abilities. We have conquered many major diseases. We have put men on the moon. Common opinion is that we will find a technological solution to our energy problems.

To a degree, a technological viewpoint is a good viewpoint, because it gives man the impêtus to use his imagination and skill to solve the problems which confront him. However, in the arena of the "energy crisis" it can be a harmful viewpoint to the extent that it decreases motivation to conserve. That is, it can decrease motivation to do even the little things which may pose some inconvenience or require some change in life style. The fact of the matter is that government has tended to foster the "technological fix" to the detriment of conservation by placing a disproportionate amount of emphasis and money into the "technological" areas of energy "supply" as opposed to the conservation areas of energy "demand". This situation appears to be undergoing some change in recent years, however. That is, the importance of conservation is beginning to receive more recognition. Many government and industrial entities are beginning to view conservation as a potentially cheap "source" of energy, one which is as worthy of capital investment as any other "source" of energy.

Unfortunately, a large proportion of the general public is bound by the "technological fix ". When even knowledgeable advocates of a technological solution to our energy problems will admit that any solution is several (perhaps as many as 20) years in the future, the "technological fix" is a detriment and needs to be changed. In the interim period, until technological solutions are found, conservation is the major energy factor that we are able to work with. Additionally, there is always the possibility that completely adequate technological solutions may not be possible. Therefore, conservation may be a long-term necessity. Also, a number of good things can be said in favor of

conservation from a purely philosophical point of view, regardless of the adequacy of energy supplies. Education programs may be able to help move people away from the "technological fix" in a very positive way which does not negate the real value of technology in general.

Special Interest Group Politics. Special interest group politics refers to the tendency of the political system in any democracy to degenerate, in a time of noncrisis (or a time of near crisis) to a system of mediation between special interest groups. Substantially, although the energy crisis is very real, we are actually in an environment of noncrisis in the United States because most of our citizens do not believe that we have a serious energy problem. There is no shortage of gasoline at the present time. Other recent energy crises have been regional in scope and have also been manageable. Many people feel that the crises which we have had in the past were due to poor government and/or industry management or were actually a manipulation in order to provide a basis for increasing prices. This is an extremely important point since it is the attitudes of citizens which give most political leaders in a democracy the freedom to act. As long as citizens view the energy situation as a noncrisis many political leaders will be constrained from making difficult political decisions or taking courageous action.

Since political leaders do not have a firm basis of power or consensus in the matter of energy policy, they are reluctant, with good reason, to act on legislation which may require sacrifice on the part of powerful constituent groups. More than a few politicians in

history have removed themselves from office or power by not attending to their constituents or by acting in the absence of a firm consensus. Therefore, political leaders tend to mediate between or attempt to satisfy all special interest groups in a period of noncrisis. It is the nature of each special interest group in a period of noncrisis to try to obtain the best advantage or to limit the impact of policy for the members of their group. Recent government inaction on energy policy demonstrates this situation.

Since the United States is a very large country and a very diverse country, it remains to be seen if we are really "governable" in a period of noncrisis. Certainly, education and persuasion programs may help to build the public consensus which many politicians need in order to act in a positive way and to make difficult decisions. There is of course, much need for actual "leadership" in the energy arena. There is need for political leaders who have the charisma and skill to exercise that delicate balance between the exercise of power and public consensus. Such leaders have the ability to create a consensus or basis of power that they can then act from. This is an iterative process, exercising power to help create a consensus which then provides the basis for the exercise of greater power, etc. Energy education programs directed toward the public can help this process.

Urban-Suburban Sprawl. Urban-suburban sprawl is a serious detriment to workable energy conservation programs, especially in the area of transportation, which is a major source of petroleum consumption

in the United States. The reasons for urban-suburban sprawl are many. but certainly government policy, explicit or implicit, is a major contrib utor. For example, highway construction policy in the United States is an "implicit" energy policy. The construction of new highways makes travel more convenient and faster and opens new areas to development. Thus, it becomes feasible for people to locate farther from their place of business and from other necessities. Another implicit energy policy in this regard is the income tax advantages which have been provided for home ownership to help absorb the impact of property taxes and interest payments. Because of this policy, it has been economically advantageous for most Americans, in a period of inflation, to move up to larger homes with larger mortgages. Many of these homes are new homes which are poorly located as far as transportation energy conservation is concerned. Thus, development of our cities is extremely poor from the point of view of mass transit efficiency. Also, American homes provide a high ratio of space on a per capita inhabitant basis. This translates into higher costs for heating and cooling, if other factors such as the amount of insulation are held constant.

Certainly there are reasons other than government policy for urban-suburban sprawl, although reasons which are sometimes given are specious. For example, it is sometimes said that people have fled to the suburbs to escape the decay of the cities. A good argument could be made for the obverse, namely that the cities are facing serious problems because so many people of certain socioeconomic groups have left. To a large extent many of these people may have relocated for reasons such as the economic advantages of owning a more expensive home.

Another reason for urban-suburban sprawl has certainly been the increase in population, which is also a factor having a direct impact on the growth of energy consumption. While education programs alone cannot reverse the trend of urban-suburban sprawl, they can contribute to a change in peoples' attitudes regarding the advantages of where they live and how much space is needed for their enjoyment of life. For example, education and persuasion programs could probably be designed to support a "back to the city" trend. Education and persuasion programs could also be designed to prepare people for policy changes which may be needed in the future to put an end to urban/suburban sprawl. They can also contribute to people's understanding and acceptance of the importance of factors such as land use planning, population control, development of functional mass transit systems, use of car-pooling systems, and the planning of personal transportation requirements from an energy conservation perspective.

Spirit of Nondependence. The spirit of nondependence or spirit of alienation is a serious one with respect to American culture in general.* It impacts the energy problem to the extent that people are reluctant to place themselves in a position of being dependent upon their fellow man and getting too closely involved with other people and in the problems confronting our society. For example, this spirit of nondependence is probably an important factor in the poor acceptance of car-pooling and in the lack of use of mass transit in some cities.

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* Slater, P.E., The Pursuit of Loneliness: American Culture at the Breaking Point, Beacon Press, Boston, 1970.

Americans in general do not like to be dependent on others regarding "when" and "where" they can go. Although a spirit of non-dependence and "independence" are not synonymous, they are related. The automobile is a symbol of independence for large numbers of American youth since it offers an excellent means of escape from family control and family environment at the very time that personality development is providing for an assertion of self-dependence. The rapid growth in popularity of vans which are equipped for living and entertainment as well as transportation is probably associated, at least in part, with this natural desire for independence. Such symbols, associated with the automobile, can be carried over from youth to adulthood. Mass media campaigns (i.e., advertisement) have often been utilized to promote these maladaptive energy attitudes. Education and mass media programs could and should be used to promote energy adaptive attitudes.

With respect to mass transit systems, the spirit of nondependence and noninvolvement is undoubtedly connected with their lack of use by certain segments of the population. In some cities, mass transit tends to be used principally by lower socioeconomic groups of people. Also, in most major cities, travel via mass transit and the accompanying travel which is required to get to the mass transit station or from the station to one's final destination is unsafe at certain hours and/or in certain neighborhoods. This is a problem which our society should be made aware of, since it will have to be solved if mass transit is to attain its full potential.

Unconsciousness of Life-Cycle Costs. Many people are oblivious of the significance of life-cycle costs when they purchase a product. Typically, people make comparative purchases in which the initial cost is weighed more heavily than are use costs, such as energy or maintenance. This attitude appears to be gradually changing. However, consumer education and information programs are greatly needed to foster life-cycle cost considerations. An absence of life-cycle cost consciousness can place the innovator, or the manufacturer who builds energy conservation into his product, at a disadvantage. For example, two builders are producing homes which are generally identical in style, space, quality of neighborhood, and other features. One of these builders has installed energy-saving devices and features into his homes at an additional cost. He seeks to recoup this cost with a higher price for his homes. In an economically governed market place, where buyers are unconscious of life-cycle costs, this builder will be at a disadvantage, even though the pay-back period for his energy conservation features may be relatively short. Education and information programs can make people aware of the importance of life-cycle costs and provide data on pay-back periods.

Territorial Myths. Territorial myths are common with respect to problem areas such as energy supply and demand. They take two basic forms. The first is that many people feel that it is somebody else's responsibility to solve the problem. Thus, many individuals do nothing, under the erroneous impression that it is not their problem or, at least, that it is not their responsibility to try to solve the problem. The second form of the territorial myth is that of the "impending solution".

That is, someone else (e.g., the government) is working on the problem, so there is no reason to become personally involved. Certainly, in a complex society, there has to be a division and specialization of responsibility. However, in an area such as energy conservation, there is much that the individual citizen can and should do. Education and information programs are needed to bring each individual to an awareness of his personal responsibility for energy conservation. Also, adequate information is needed on what government, industry, and other segments of the society are or are not doing, and can or cannot do.

The Role of Energy Information and Education Programs

Energy information and education programs can play a significant role in helping to surmount the impediments to effective energy conservation in the United States. Specifically there are three approaches to energy conservation which make extensive use of information, education, and persuasion. Each of these three approaches is closely related to a particular theory of human behavior. (Olsen, and Goodnight, 1977)* The theories are:

- Subjective Utility
- Attitude Congruence
- Cultural Values.

The approach to energy conservation associated with these theories focuses on changing the perception, attitudes, and values of individuals in our society. Each of these three theories is discussed in the following

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* Olsen, M., and Goodnight, J., "Social Aspects of Energy Conservation", Northwest Energy Policy Project, Battelle Human Affairs Research Center, 1977.

pages. Also discussed are the general benefits and limitations of information and education programs.

Subjective Utility. According to the theory of subjective utility, an individual will act in accordance with the personal benefits which he perceives to be associated with his actions. To increase personal benefits toward energy conservation, it would be necessary to convince people that their efforts as individuals will help achieve the common goal of conservation. It would also be necessary to convince them that energy conservation is personally important to them. That is, information must demonstrate that there is some "payoff" or personal benefit that will accrue to the individual by directly conserving energy, car pooling, moving closer to places of business, etc. This theory would indicate that a primary means of implementing energy conservation should be massive information and education efforts directed toward the energy crisis and conservation.

Attitude Congruence. The theory of attitude congruence postulates that individuals try to maintain a balance between their attitudes and their behaviors. Any incongruence can result in painful psychological stress. In this event, people will either change their attitudes to bring them into line with their behavior, or else they will change their behavior to bring it into line with their attitudes. Since behavior can follow attitudes, the indicated method of implementing energy conservation would be extensive and persuasive communications concerning the seriousness of the situation and the need for personal involvement and action. If such persuasion programs were well done and were initiated for a significant period of time, it could be expected that attitudes and, subsequently, energy conservation behavior would change.

Cultural Values. Prevailing cultural values are internalized within an individual's personality through the process of socialization. Once this internalization has occurred, an individual acts in accordance with these values. The approach to energy conservation through cultural values would be to alter prevailing values (i.e., promote a "conservation ethic") or to convince people that energy conservation behaviors are actually in keeping with prevailing values at the present time. The latter could be very difficult to implement, however. Implementation through large-scale educational and communications programs utilizing the mass media would be indicated. This approach would be a direct response to the significant impediment of the prevailing consumption ethic in the United States, which was discussed earlier.

Benefits of Information, Education, and Persuasion Programs. An information or education approach would concentrate on imparting knowledge about the overall energy problem, ways to conserve energy, or feedback on individual or group consumption levels. Information would be imparted through mass media campaigns or by incorporation of energy conservation messages into a variety of educational programs for different segments of the population. In addition to any direct effect which information programs may have in shaping up energy conservation behavior, there are other benefits. For example, it should be noted that the dissemination of information is also an important aspect of other conservation strategies, such as pricing, inducements and government regulations.

Persuasion programs would concentrate on altering individual attitudes or beliefs regarding the seriousness of the energy problem.

Mass media and education campaigns would be utilized to bring about attitudes which are more favorable to energy conservation. Another benefit is that persuasion programs may pave the way for other energy conservation strategies. Persuasion programs which utilize the immediate surrounding social environment would probably be more effective than more generalized mass media approaches.

There appears to be extensive talent in the United States in the area of mass media persuasion. Many of our daily behaviors and the images or values upon which they are based are in part created or accentuated by our advertising industry. It is conceivable that a well organized "Madison Avenue" approach to the problem of energy could result in an increase in energy conservation. Also, as noted above, such persuasion programs may pave the way for the other energy conservation strategies of pricing, government regulations and inducements.

Limitations of Information, Education, and Persuasion Programs. Any information, education, or persuasion program will be limited with respect to its effectiveness in solving the energy problem and/or in its impact on energy conservation. One way in which these programs are limited is that they rely upon substantial individual volunteerism. While this element of volunterrism may also be viewed as an advantage of information and persuasion programs, in that they may be more acceptable to the publice than other strategies, it could be a limitation if the objective of energy conservation is kept in mind. For example, it may be expected that while some elements of the population will contribute to the common good in the area of energy conservation as a result of education, other elements of the population will not contribute unless

they are coerced. This is especially true since the "common good" benefits everyone, whether they contribute or not. Also, while it may be expected that information and persuasion programs will be effective when they point out real "subjective utilities" for the individual, they will not have a long-term effectiveness in areas where there are no "subjective utilities". For example, if an education program provides persuasive information on how a homeowner can save a significant amount of money through some specific energy conservation action, we may expect that the homeowner will take this action or repeat this action as appropriate. However, if the conservation behavior is going to be personally costly, in terms of money, time, inconvenience, etc., we may expect that information on energy conservation will not, in itself, be sufficient to cause significant conservation behaviors to occur. In this instance, sanctions for noncompliance and/or rewards for compliance may be necessary. Additionally, while information on energy may increase an individual's stated willingness to conserve, there is no guarantee that this attitude will be translated into behavior.

Research conducted to date has shown little relationship between an individual's belief in the energy problem or his belief in the need for conservation, and in actual energy conservation behavior.* Also, many attitudes are formed or changed in the process of personal interaction rather than through mass media communications. This indicates that information and persuasion programs may be more effective if implemented through the immediate social environment surronding the individual.

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* Olsen, M., and Goodnight, J, "Social Aspects of Energy Conservation", Northwest Energy Policy Project, Battelle Human Affairs Research Center, 1977.

Finally, it should be noted that the effectiveness of information, education, and persuasion programs is limited because they are necessarily a long-term approach. While strategies in the areas of pricing, regulation, and policy formation in general may have an almost immediate effect, education programs could be expected to require a significantly long period of time before their impact is realized.

In closing this discussion of limitations of energy information, education, and persuasion programs, it should be reemphasized that these programs can have an effect by making the public more accepting of other energy conservation strategies. Also, they may have a direct impact on the conservation behavior of some people or on the general level of conservation over a relatively long period of time.

Conservation Education in Riverside

Objective

The objective of this subtask was to review current energy education programs in Riverside and make recommendations for improved community education.

Approach

Included in the approach used in completing this subtask were:

1. Discussions, in person or via telephone, with a variety of organizations* in the Riverside

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* A list of organizations contacted with respect to this task is provided in Attachment G-1.

community regarding current energy education programs in Riverside. This step included an analysis of the resources or channels available for energy education in Riverside.

2. A review of relevant literature on energy education programs which have been implemented elsewhere in California or the nation.
3. Development of recommendations for the implementation of energy education programs for Riverside.

Current Energy Programs in the Riverside Community

Energy education programs can range from those which impart general information about the energy problem to those which impart very specific information. Programs at the "general information" end of the continuum frequently emphasize the fact that there is an energy problem, why there is a energy problem, and, in general, what we need to do to solve the problem. These general information programs, if done well, have some usefulness in that they may serve to change individual and group attitudes over a period of time. They may also help to prepare people for other types of conservation programs, such as incentive programs or allocation schemes. When utilized as part of a school curriculum they help to shape or develop conservation attitudes in young people. Irrespective of their audience, these general education/information programs may be considered "persuasion" programs if their goal is to bring people to a change in their life-style or in their consumption patterns.

Programs at the "specific information" end of the continuum are usually directed toward an individual or select group of individuals such as homeowners, drivers, etc. These programs usually relate to providing specific information about specific solutions to specific areas of energy waste. It is assumed that there is a specific need that members of these groups have and that there are specific benefits or "subjective utilities" that members of these groups will realize if they follow a particular course of action. For example, a program may inform a homeowner of the subjective utility (i.e., dollar savings) associated with insulating his home. Or a program may supply the homeowner with "feedback" on his rate of consumption and indicate the amount of money which could be saved by varying degrees of conservation.

Many energy education programs are a combination of these two types of programs or fall somewhere on the continuum between programs which are intended to change attitudes and programs which are intended to provide solutions to specific needs.

The energy education programs currently being planned for or implemented in the Riverside Community area include the following.

City of Riverside Public Utilities Department. The city of Riverside Public Utilities Department serves approximately 57,300 customers. The department distributes energy purchased from Southern California Edison. Customers are 91.8% residential, 7.6% commercial, 0.3% industrial, and 0.3% other. The electrical peak load occurs in the summer and is caused mostly be residential air conditioning. Since the summer peak averages 50 to 60% higher than the winter peak load, the Public Utilities

Department has selected residential air conditioning as the most important consideration in any conservation effort. As part of their UCAN Action Plan*, the Riverside Public Utilities Department has proposed several activities. The following are most relevant to community education and information in the area of energy conservation and efficiency measures.

- Dealer Support Programs:
  - Manufacturers of highly energy efficient products would be contacted to obtain information and advertising materials.
  - An information file would be maintained on highly efficient products for customer handout.
  - A home economist would be available for store and home demonstrations of products and conservation programs.
  - Mailers and bill stuffers would be used to encourage customer acceptance to new energy efficient products.
- Customer Education Programs: These programs would consist of the following - utilization of bill stuffers, handouts, and dealer ads, as well as field contacts by power service personnel. Subjects would be:
  - Load management devices

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* City of Riverside Public Utilities Department, UCAN Action Plan, May, 1976.

- Heat pumps
- Demand metering and rate application
- Energy savings through end-use efficiency
- Nuclear generation
- Home economics (insulation, kitchen planning, etc.)

Proposed programs in the "load management" area which are relevant to energy educational and information would include:

- Energy Audits
  - A comparative month-by-month study of demand and kWh consumption on customers who use 150 kWh or more--to be used for customer information on energy conservation
  - Field visits with the customer's Plant Maintenance and Plant Engineering personnel to aid them in energy conservation
  - Energy efficiency awards.
- Deferred Demand
  - Keep a file on current demand limiting devices for customer handout and advice.
- Load Management
  - Contacts with large users would be intensified to encourage the reduction of peaks, including an evaluation of the applicability of time-of-day rates.

- Conservation
  - Better insulation in existing homes would be encouraged through direct marketing and by counselling on tax incentives and benefits.
  - Contacts with large industrial and commercial users to conserve on lighting and air conditioning would be increased.
  - Talks and demonstrations to directly provide information, service and marketing of conservation devices to individuals in their homes would be continued.
  - The information program would be continued and a program to reduce use of water, especially hot water, in the home would be implemented.

There are other aspects of this proposed program which are not referenced here because they are not directly relevant to the information/education area. Establishment of a new division in the Public Utilities Department is proposed. This division, formed with existing personnel, would have as its purpose the further development and implementation of load management and conservation programs. It should be noted, however, that due to limited staff and budget restrictions, the Riverside Public Utilities Department is not presently able to initiate new programs. There is no anticipated change in this situation for the near future. The Riverside Public Utilities Department has no energy conservation section at the present time. They do not have the money or staff to get

deeply involved in energy conservation activities. There is no energy conservation advertising or public relations program for the residential sector. They have instituted a consulting service for business and industry. This is a one-to-one approach, which utilizes a "walk thru program", frequently in response to requests. The program provides advice on load management.

Brochures (advertisements, conservation and public relations material, etc.) directed to the residential consumer are available from Southern California Edison. However, the City Utilities Department wants to maintain its separate indentity, and the Edison materials have the Edison logo and/or advertisment on them. On the other hand, Edison does not want to print and give away material which does not contain their logo. Therefore, the City has not distributed Edison conservation materials.

Southern California Edison Company. Programs offered by the Southern California Edison Company could be applicable to the City of Riverside since these programs are directed toward the Southern California region and since the Riverside Public Utilities Department purchases power from Southern California Edison. Southern California Edison's February, 1977, rate adjustment application before the Public Utilities Commission of the State of California (Application No. 57111)* sets forth several energy conservation programs which involve public education or information exchange. These programs are reiterated in Southern California Edison's Conservation Report for the California Public Utilities Commission, March 31, 1977.**

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* Application of Southern California Edison Company for offset rate adjustment to cover expenses associated with supplemental conservation programs; before the Public Utilities Commission of the State of California, February, 1977.

** Southern California Edison Company, "Conservation Report for the California Public Utilities Commission", March 31, 1977.

In a letter dated December 19, 1975, the President of the Commission requested Southern California Edison to expand their conservation efforts and stated the Commission's intention as:

> "The PUC will expect utilities to develop a sophisticated analytic capability to evaluate conservation measures which may go beyond the conventional scope of utility activities, to make aggressive use of their marketing capabilities to educate the public in conservation and, where reliable and cost-effective, to promote energy-saving design and technological changes."

Application No. 57111 (February, 1977) describes three levels of conservation programs. These are:

- Level I - ongoing conservation programs as reflected in Application No. 54946.
- Level II - additional conservation programs submitted in connection with General Rate Applications No. 54946.
- Level III - supplemental conservation programs, the cost of which Edison seeks to recover through offset rate relief.

Programs listed under these three levels, which fall within the area of public education and information, are described in the following pages.

Level I

1. Consumer Education Program

Consumer Services Consultants hold group meetings and address the need to conserve energy with residential consumers.

2. Advertising Program

Customers are encouraged to conserve electricity in their homes through publicized conservation tips.

Level II

1. Sure Actions for Valuable Energy Savings (S.A.V.E.S.) Program

Through the use of a customer-prepared energy audit questionnaire, an analysis of the customers' electric energy savings potential and a letter providing suggestions to save that energy will be prepared by computer.

2. Solar Water Heating Demonstration/Publicity Program

The electric company will have solar water heating systems installed in new residential developments through a participation program with selected builders. The purpose is to stimulate public and builder interest in solar water heating systems.

3. Electric Water Heating Conservation Program

Involves distribution to electric water heating customers of a shower flow regulating device. In addition to the kWh saved through electric water heating, further benefits accrue through water savings and the energy usage attributable to water and sewage pumping.

4. Energy Conservation Kit for New Customers

Involves mailing of a conservation kit to all customers requesting service to be turned on.

5. Expanded Information/Publicity Programs

Involves expansion of information and publicity regarding methods to achieve kWh reduction. Newspaper columns and published material concerning appliance consumption/operation cost data would be produced.

Level III

1. Energy Mart

The objective of this program is to encourage energy savings actions and the installation of conservation devices in residential dwellings. Six conservation centers would be set up to display conservation devices and literature. Each center would be manned by a conservation counselor who would be available to help customers plan and implement energy savings actions and/or obtain and install conservation devices. Appropriate symbols or certificates of recognition would be developed for award to residential customers who install conservation devices in their residences. A variety of conservation devices would be promoted through bill stuffers and other media. Different devices would be featured throughout the year.

2. "Hy Efficiency"

The objective of this program is to secure the permanent deferral of energy requirements of residential refrigerator/freezers and room air conditioners. Consumers would be provided information to enable the purchase of the most efficient appliances. Special award programs for appliance dealers and their sales representatives would be conducted.

3. "Sherlock Homes Program" (Save Household Energy, Reduce Load, Optimize Conservation Quickly)

The objective of this program is to reduce the consumption

of electricity use in the residential customer group through personal-call energy audits. A personal energy audit would be made to assist in identifying usage, and special methods that can be used to achieve energy conservation would be suggested. The S.A.V.E.S. computer questionnaire would be used when applicable.

4. Commercial and Industrial New Customer Kit

The objective of this program is to provide, to every commercial and industrial customer requesting service, an energy conservation kit describing methods to reduce energy use. The kit would contain a booklet and pamphlets on conservation and operating techniques that provide cost-effectiveness suggestions on how to reduce kWh use and lower demand. Topics would include tips on operating air conditioning/heating and lighting systems. A return card would be enclosed to enable the customer to request Edison field personnel to conduct an individual energy audit.

5. "Lumen Lesson"

The objective of this program is to conserve energy through proper design and application of lighting systems. Through this effort, proper lighting design, application and use methods would be provided to architects, engineers, and consumers to improve existing and new installations and reduce the growing number of inefficient lighting systems. Throughout the year specific lighting campaigns would be conducted to focus on particular user groups to maximize conservation in lighting applications and use.

6. Public Awareness Program

The objective of this program is to stimulate public awareness of conservation and load management ethics, techniques and needs. The proposed program recognizes that consumer education is an important ingredient in any conservation program. Increased public awareness would be accomplished through a multifaceted program that would have the following components:

- Conservation Services

  A pool of skilled personnel would provide support to staff and line organizations in:

  - Planning events and implementing activities
  - Conducting field surveys and interviews
  - Coordinating meetings, forums and seminars
  - Assisting other departments, such as Edison's Research and Development Department in communicating information about other energy systems and sources such as: wind, geothermal, and solar.

- Educational Support Services

  Programs and teaching materials would be provided to inform students and teachers of the need and means by which energy management principles can be effectively adopted. Methods presented could be applied in school activities, at home, and in the community. Programs and materials would include teacher training institutes

workshops and seminars, each supported by audio-visual and instructional guides

An instructor and a mobile energy conservation exhibit would visit school locations, demonstrating conservation ideas and techniques. In addition, the instructor would provide experiments in solar isolation levels and assist in science projects involving alternative energy sources.

- Exhibits and Displays

  Exhibits and displays would be provided for energy fairs, trade shows, community energy programs, shopping centers, exhibits and other events that provide an audience for energy conservation information.

- Public and Employee Communication

  Conservation communications, through prepared publications and statements, would be provided for general media distribution. A broad range of activities would include: media reference packets on alternative energy sources; specialty and technical publications; and employee-oriented papers and news items. It is anticipated that this central corporate point for the media to obtain current information would be invaluable since it would provide a quick and factual dissemination of reference material and prepared statements on energy conservation. Direct public and employee inquiries received would be answered promptly through

personalized responses.

- Speakers Bureau

  Edison's present Speakers Bureau maintains a Task Force of 30 people selected from various corporate levels. Each individual is prepared to effectively communicate on the conservation/load management ethic. Their interface with public groups would provide a foundation for proper understanding of energy topics and assist in establishing communication with influential consumer groups.

- Speech and Educational Materials

  Brochures, pamphlets, bill stuffers, slides, tapes, filmstrips and speech material would be developed and assembled to aid public contact personnel. Conservation and energy education materials would provide the foundation for understanding the various conservation and load management concepts.

- Workshops, Seminars and Forums

  The following specific public-awareness programs would be presented to support energy conservation to key focus groups:

  - Architect, Engineer, and Design Consultant Forums

    Forums would be conducted to focus on energy management techniques that are useful, cost-effective and available for use in constructing residential, commercial and industrial facilities

- Community Leader Forums

  Conservation forums would be held for select leadership groups to increase community awareness of energy management and alternative sources of renewable energy. This effort would stimulate community involvement through its leaders.

- Dealer/Contractor Heat Pump Seminars

  Seminars would be designed to reaffirm dealer and contractor confidence in heat pump application, performance and cost-effectiveness as an alternative to other space conditioning systems.

- Electrical Maintenance Seminars

  Seminars would be directed to industry plant managers, superintendents and maintenance personnel, covering such areas as power factor, maintenance of electrical equipment, efficient electrical systems, proper sizing of equipment, scheduling of equipment use, etc., in terms of conservation/load management ethics.

- Plant Engineers

  Four specific "Nuts and Bolts" workshops would be held for plant engineers to discuss the actual function of installing and operating conservation and load management "hardware" to reduce energy use.

- P.I.P.E. Institute

  Training seminars would be conducted to assist the

Plumbing Industry Progress and Education Institute with solar energy and end-use applications.

- Specifier Workshops

  Miniseminars for architects and engineers would be conducted in offices and at their associations' monthly meetings. These efforts would fortify the conservation ethic and provide the communication of energy-related information that is required but lacking to these groups.

- Lighting Workshops

  These programs would be directed toward architectural schools and designers involved in specification of lighting systems.

This particular program on "public awareness", proposed by Southern California Edison, has many good features which could be emulated by the City of Riverside Public Utilities Department.

7. "Give Your Appliance the Afternoon Off"

The objective of this program is to reduce the system peak demand by deferring the use of residential appliances such as washers, driers, and dishwashers to off-peak periods. This load management program involves a promotional campaign to encourage major appliance use at times of the day other than afternoon. The campaign would utilize all methods of customer contact, including newspaper, radio and other media.

8. Conservation and Load Management for Resale Customers

The objective of this program is to encourage resale customers to implement conservation and load management programs with their customers. SCE energy management activities would be presented to resale accounts. Resale customers would be encouraged to adopt similar programs with assistance from SCE where requested.

Southern California Edison has initiated or proposed numerous other energy conservation programs. However, those referenced above represent programs which rely most heavily on an education, information, or persuasion approach. The programs are not directly available to Riverside, however, since Riverside operates its own electric utility Few programs of this type have been implemented in Riverside.

Southern California Gas Company. The Southern California Gas Company markets directly to individual customers in the City of Riverside. Some of their energy conservation programs which incorporate an education or information aspect include:

1. Insulation Program

The company uses private contractors to install the insulation. The customer can presently choose a 30, 60, or 90 day period to pay for the insulation. Cost to this customer is 10 percent less than the contractor's cost. There is a 3 month backlog for this program.

2. Consulting Service to Industry

Upon request, the company will send in an engineer to

survey facilities and operations and recommend efficient energy use ideas. Also, if necessary, a technician will be loaned to the industry to adjust gas-fired equipment. This program is conducted at no cost to the consumer.

3. Advertising Program

The company conducts a general energy conservation advertisement campaign via newspapers, magazines, billboards, radio and T.V. Examples of how to save energy are given.

Also, builders are encouraged to build homes with energy-saving features. Those who excel are given an "Operation Concern" award by the gas company. The gas company will place ads in the media about the builder and the development. Gas company representatives will also man stations in the model homes to explain the energy-saving features of the homes. The gas company will also place ads in newspapers praising restaurants and apartment complexes that have initiated energy-saving measures.

4. Direct Sales Program

The company markets water-saving devices, insulating jackets for hot water heaters, swimming pool covers, and electric spark ignition devices to replace gas pilot lights.

5. Conservation Hot Line

This is a toll-free "800" number which is manned 8:00 a.m. to 5:00 p.m. A telephone answering device is used at other times.

The company has approximately 3,000,000 residential customers and has received 100,000 telephone calls since April, 1977, as part of this program.

6. Consumer Information Program

This program, which provides speakers for clubs, schools, etc., is manned by eight full-time representatives. The company receives an average of five requests per day for a speaker.

7. Conservation Centers Program

The company mans five conservation centers in mobile vans which travel to shopping centers and various exhibits. Also, one indoor conservation center is maintained. This is inset up in various locations.

8. Insulation Program for Existing Homes

The gas company works with local realtors to persuade homeowners to insulate their home prior to sale. The gas company finances the insulation costs. The cost of insulation is added to the asking price of the home. The realtor then advertises the house as an energy-efficient home. The cost of insulation is repaid to the gas company upon sale of the home.

People's Energy Fair. A people's energy fair was held on October 1, 1977 at the Riverside downtown mall. The energy fair was organized by Representative George Brown's office. The main objective of

the fair was to bring people together to discuss energy conservation programs which had been implemented locally and to exchange ideas. This appears to be a concept of merit in increasing awareness and providing for information exchange.

Media. Riverside local media includes two major newspapers, the Press - Enterprise, and a number of smaller publications. Included among the smaller publications are the Riverside Community News and a number of newsletters. A good example of the newsletter type of media is the Pollution Crier, published by the Pollution Control Research Institute. While all of these sources occasionally publish informational articles on energy conservation, there does not appear to be any directed, long term energy information program which they adhere to.

Also included among local media are four radio stations. Riverside does not have its own TV station. The City receives TV transmission from Los Angeles stations and is therefore somewhat limited in the use of the TV medium, since energy information presented via TV would generally have to be national or regional in scope, rather than local.

Educational Institutions. One major asset of the City of Riverside is a number of universities/colleges. The principal resource among these is the University of California at Riverside. UCR is a potential source of expertise which can be employed in many community information/education programs. UCR also offers a variety of courses, such as solar energy classes, which include conservation measures. The availability of courses of this type is important to the community, in spite of the limited appeal which they are likely to have. For example, the UCR Physics

Department and the Extension Service cooperated in organizing an international conference "Toward a Model Energy Community", which was held in Palm Springs in April, 1978.

Other institutions of higher education in the Riverside community include: La Sierra campus of Loma Linda University, California Baptist College and Riverside City College (a 2-year community college). It is conceivable that all of these institutions would have some faculty members who could serve as a source of expertise to the community in the area of energy education.

Additionally, the City of Riverside is served by two public school systems: (1) Riverside Unified School District and (2) Alvord School District. These include 31 elementary schools, 7 intermediate schools, and 6 high schools. The Jurupa School District serves some adjacent, nonincorporated areas.

The Riverside Unified School District has been providing some energy related instruction for approximately 2 years. Instructional materials on energy are obtained primarily from companies specializing in energy production, distribution, or related equipment. These materials, provided by the companies, are combined into a curriculum package which is made available to each school. There is no prescription regarding specific grade levels at which these materials should be used, however. In fact, since they are not part of the required curriculum, there is no guarantee that all students are exposed to energy information as part of their academic program. In grades K-8, which have one primary teacher, the energy information would probably be tied to science and/or social studies

subject areas. In grades 9-12, energy education would be most applicable to social studies or science classes.

One possible problem with the utilization of curricular materials provided by utilities/industry is a California law which requires school districts to screen such materials to assure that a particular company is not getting favored treatment or publicity via the curricular materials which they have provided. This law is intended to prevent the use of the school systems as a means of "proselytization". Of course, if their names cannot be used, the energy companies have less motivation for developing and donating materials.

It was the judgement of school district personnel that they have not seen a good, integrated energy curriculum for grades K-12. The natural gas utility has provided some materials which have applicability for use at the K through 12 grade levels, however. As stated previously, these materials, if used, would be used at the discretion of each teacher.

The Alvord School District has received some energy-related materials from the regional electric utility and has obtained some commercial film strip materials. These materials are available to interested teachers. There is no specification regarding grade levels at which these materials should be used; however, they are probably most appropriate for grades 6, 7 and 8. If utilized, it would be as part of science or social studies curricula. There apparently is no in-depth instruction relative to energy at any of the K-12 grade levels, however.

The Jurupa School District, which serves some nonincorporated areas adjacent to Riverside does not have any formal energy education curriculum or materials. Some of the science or social studies teachers may reference the energy topic of their own accord.

Libraries. There are six public libraries in Riverside. These could serve as a focal point for energy conservation information, by providing books and literature, through the sponsorship of special programs, and through utilization of library facilities by interested groups.

Industrial Programs. One potential means of implementing an energy conservation information program is within the work environment. The Riverside community area contains a number of moderate size manufacturers. The largest among these, with their approximate employment, are:

Fleetwood Enterprises	1,450
Bourns Incorporated	1,076
Rohr Industries Inc.	1,040
Riverside Cement Co.	599
Owens-Illinois/Lily Div.	420
Alumax Mill Products	418
Toro Company	350

Rohr Industries, Inc., typifies an industry which has an active energy conservation program. Their program has concentrated on in-house energy conservation, but has also provided information applicable to employee residences. Rohr has established an energy conservation committee which includes 20 hourly employees. This committee, which meets on a monthly basis, provides a link between management and employees. One information technique utilized at Rohr has been to post monthly energy use as means of supplying feedback on the effectiveness of energy conservation measures.

Large nonmanufacturing employers in the Riverside area, with their approximate employment, include:

County of Riverside	3,977
Univ. of Calif. Riverside	3,600
Riverside Unif. School District	2,368
City of Riverside	1,449
March AFB (nonmilitary empl.)	1,300
Alvord Unif. School District	850
Pacific Telephone Company	800
Riverside Community Hospital	787
E. L. Yeager Construction	500

These employers could also supply an excellent environment for energy conservation education.

Applicable Energy Education Programs

There is a growing increase in energy education plans and programs, both in California and in other parts of the United States. Some of these programs, which may have features that are applicable to the Riverside Community, are briefly referenced in this section. This section also discusses recent studies in the area of consumer feedback.

Energy Education Plans and Programs in California. California energy education programs which may have applicability to the City of

Riverside include the following.

(1) San Diego City/County Schools Energy Education Committee

According to a spokesman in "Emergency Planning and Education Programs" for the California Energy Resources Conservation and Development Commission, the San Diego schools are most active in energy conservation education in California. San Diego City and County schools have formed a committee to plan and promote energy conservation education. This committee is composed of media experts, school system personnel (including administrators, curriculum specialists, etc.), representatives of utilities and industry, environmentalists, local politicians, the State Energy Commission and a variety of consultants.

A summary of energy education plans for San Diego 1978-1979 is presented in Table G-1. Briefly, these programs are:

- Teacher Incentive Grants. The objective of this program is to provide between 5 and 10 teachers, K-12, with funds to initiate energy education projects with their students.
- Community Lecture Series. In this program, eight nationally known experts in their field will make presentations on the theme "Exploring Management of Basic Energy Resources". The presentations will be made for the general public at the community concourse. Teachers, K-12, will be encouraged to attend these free lectures.

TABLE 1. SUMMARY OF ENERGY EDUCATION FOR SAN DIEGO 1978-1979

Task	Date	Number Involved	Target Group	Cost	Funded?	Immediate Actions Needed	Committee Members Needed	Needed Funds
1. Teacher Incentive Grants	Jan.-June 1978	5-10	K-12 Teachers	$1,000	Yes	Report progress to Energy Ed. Committee		
2. Community Lecture Series	May-July 1978	200	K-14 Teachers	None to us	Yes	Assign Energy Education Committee person to this task	1	
3. Develop Mini Units Based Upon Community Lectures	May-Aug. 1978	Undetermined	K-12 Teachers	$1,500	No	Assign Energy Education Committee person to this task	1	$1,500
4. Teacher Seminars With Community Lecturers	May-July 1978	50	9-12 Teachers	None to us	Yes	Assign Energy Education Committee person to this task	1	
5. Student Seminars With Community Lecturers	May-July 1978	50	9-12 Students	None to us	Yes	Assign Energy Education Committee person to this task	1	
6. Develop K, 1, 3, 4, 6-12 Materials	Summer 1978	Undetermined	K,1,3,4,6-12 Teachers & Students	$35,000	Yes	Report progress to Energy Ed. Committee		
7. Develop 2,5 Materials	Jan.-May 1978	Undetermined	2,5 Teachers & Students	--	Yes	Report progress to Energy Ed. Committee		
8. Training Program For Inservice Workshop Leaders	Summer 1978	10	Teacher Trainees	$6,500	No	Assign Energy Education Committee person to this task	3	$6,500
9. Regional Inservice Workshops	Sept. 1978-May 1979	2,000	K-12 Teachers	$4,000-$10,000	No	Assign Energy Education Committee person to this task	3	$4,000-$10,000
10. Student Assembly Programs	Sept. 1978-May 1979	22,500	K-12 Students	$36,586	?Proposal pending	None at this time	1	
11. Materials Fair	Oct. or Nov. 1978	1,000	K-14 Teachers	$3,000-$8,000	No	Assign Energy Education Committee person to this task	3	$3,000-$8,000
12. Student Incentive Programs	Ongoing	5-10	7-12 Students	$2,000	No	Report progress to Energy Ed. Committee		$2,000
TOTALS		25,000		$87,586-$88,586			14	$17,000 $25,600

- Development of Mini Units Based Upon Community Lectures. In this program the lectures given by the community speakers will be prepared in formats useful for K-12 teachers in presenting the information to their students.
- Teacher Seminars With the Community Lecturers. In this program, a specific time in the afternoon before each lecture (previously referenced) will be established for teacher - lecturer interaction. The purpose of this session will be for a select number of teachers to interact with each expert/speaker in an in-depth seminar session with respect to classroom applications of the ideas to be presented in the lecture.
- Student Seminars with Community Lecturers. The objective of this program will be to establish a meeting in the afternoon before each evening lecture where a select number of students can listen to and interact with each speaker in an in-depth seminar session. The purpose is to promote additional study in the field of energy resources.
- Develop K, 1, 3, 4, 6-12 Materials. The purpose is to develop lesson plans for teachers to use with their students based on the "Energy Education Goals

and Objectives for San Diego County" developed by the Energy Education Committee.

- Develop Grade Level 2, 5 Materials. The purpose of this program is to produce lesson plans, film strips, pre- and post-tests, take-home materials and a teacher's guide according to the "Energy Education Goals and Objectives for San Diego County".
- Training Program for In-Service Workshop Leaders. The goal of this program is to train a cadre of teachers that would lead the regional in-service workshops during the 1978-79 school year. At these workshops teachers would receive copies and learn how to use the materials produced for grade levels K-12.
- Regional In-Service Workshops. The purpose of this program is to promote the K-12 energy education materials through ten regional workshops throughout San Diego County.
- Student Assembly Programs. In this program a troop of four repertory players will perform entertaining and educational skits directly for K-12 students about the country's energy problems. These skits would be performed at the school sites.
- Materials Fair. The purpose of this program is to gather a large amount of existing energy education

teaching materials for K-12 teachers to evaluate for their use. It would also provide information-exchange sessions and an input session for teachers.

- Student Incentive Grants. As part of this program awards will be given to students who display outstanding energy-related science fair projects at the Greater San Diego Science and Engineering Fair. Summer work exploratory experiences will also be provided to students who have a special interest in an energy-related career field.

(2) University of California Energy Extension Service. The university energy extension service is based at the University of California at Davis. However, all of the campuses in the university system, including the University of California at Riverside (UCR) participate in this program which was established by the Energy Extension Service Act of 1975. As presently noted, UCR's principal involvement to date has been solar energy courses held at UCR and the international conference (Toward a Model Energy Community) which was held in Palm Springs, California.

(3) California Public Utilities Commission (CPUC) Staff Conservation Unit. The CPUC Staff Conservation Unit was established January 1, 1976. Its purpose is to

obtain information relevant to energy conservation activities and to review the conservation efforts of all California Utilities. It may also serve as a source of information on education programs which are applicable to utilities.

(4) City of Davis, California. The City of Davis has been at the forefront of California communities in energy planning and energy conservation efforts. Davis has an ongoing public information program which is spearheaded by "Under The Sun", the energy conservation newsletter of the City of Davis.*

Also included in Davis's public information program are the Davis Retrofit Manual and the Energy Conservation Advisory Service. Each of these programs is briefly described as follows:

- Davis Retrofit Manual. This part of the education program is based upon a cost-effectiveness study of weatherization techniques for the Davis climate and on case studies of energy used in individual homes. The manual describes:

  - the most efficient methods of insulating a home
  -types of insulation materials on the market, where to buy them, and how to use them.

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*Other California cities/communities with ongoing public information programs include: Imperial County, San Diego, Palo Alto, Ventura County, Santa Barbara, and Santa Clara County.

- a list of area retailers of insulation materials
- comparative prices of insulation materials.
- specific information about insulation contractors who work in the area.

- Case Studies and the Energy Conservation Advisory Service. In this program, individual houses were evaluated for their heat gain and heat loss. The cost/benefits of different retrofit techniques were also assessed. The homes were evaluated from the point of view of developing the procedural basis for an "Energy Conservation Advisory Service". This advisory service is planned for availability to the homeowners.

(5) California Energy Resources Conservation and Development Commission. Public education programs developed/supported by the California Energy Resources Conservation and Development Commission include: an energy resources and conservation handbook; science fair award program; California energy tour; and teacher in-service training. Each of these programs is briefly described as follows:

- Energy Resources and Conservation Handbook. This handbook provides a general understanding of what energy is, where it comes from, how it's used, how much it costs, and how it can be conserved. It is meant to increase the reader's overall awareness with respect to the

energy situation rather than to make the reader an expert in any particular area. The handbook is available from the California Energy Commission.

- Science Fair Award Program. Regional science fairs are held throughout the State of California on a yearly basis. In order to recognize outstanding achievement at each regional fair, the California Energy Commission is developing a program to award the student (grade levels 7-12) who develops the best energy-related project. Teachers who have actively supported the winning student will also be recognized.
- California Energy Tour. The "California Energy Tour" publication is a guide to California's energy sources, historical sites, electrical generating plants, research facilities, and museums. When used as an information source, it is an informative guide for educators wishing to become knowledgeable on California's energy sources and production. The "California Energy Tour" identifies educational tours and administrators of major energy facilities, should the educator desire additional knowledge. The tour guide is also recommended as a reference for planning class field trips.
- Teacher In-Service Training. This plan is that the Energy Commission, working in concert with selected postsecondary institutions, will establish several energy/energy conservation education

in-service training centers. The primary function of the centers would be to prepare teachers (K-12) to disseminate energy-related information within the classroom.

Other Energy Education Plans and Programs in the United States.

Other education plans and programs in the United States include the following:

(1) State of Oregon

A report to the Governor of Oregon by the task force on energy co' servation, made the following recommendations regarding energy e .cation.

- The Department of Education and the Department of Energy should jointly develop program goals which incorporate the concept of energy conservation for all pertinent, required and optional instructional programs. The Departments of Education and Energy should provide the opportunity for all interested parties to provide input and should develop amended program goals on the basis of these inputs.
- The Department of Energy should assist the Department of Education in providing energy conservation information to local school districts to meet the amended program goals. The Tash Force recommends that particular emphasis be placed on providing the following:
  - information on energy efficient driving techniques and basic vehicle maintenance to be included in Traffic Safety Education classes.

- inclusion of energy conservation information in the elective Environmental Education classes.

- The Governor should create an Oregon Industrial Conservation Committee to coordinate existing programs and information on energy conservation within the commercial/industrial sector.
- The Department of Energy should
  - develop a public information program aimed at distributing information on energy conservation at the neighborhood level through existing organizations and agencies
  - incorporate information on the purchase of energy efficient automobiles, the advantages of car pooling, and the savings envolved from improved driving techniques into public information programs
  - incorporate information on home winterization in public information programs
  - incorporate information on alternative energy sources in public information programs
  - incorporate information on energy conservation in agriculture in public information programs
  - incorporate information on recycling in public information programs
- The Department of Energy in conjunction with the

Portland Advertising Federation should create, coordinate, and conduct a statewide media campaign specifically promoting those energy conservation recommendations the Task Force gave to the Governor. The media campaign should be a cooperative effort to include Oregon advertisers, broadcasters, publishers, and other communication organizations.

- The Department of Energy should develop and coordinate a statewide distribution program for the Family Energy Watch Calendar. Oregon utility and banking firms and other retail organizations should be encouraged to buy, sell, and promote this educational tool to the public. The statewide media program should include promotion of the calendars to the public.
- A state Energy Information Center should be provided to Oregonians by the Department of Energy with toll-free telephone access to gain information directly, or referral on, specific energy conservation options suited to individual needs. Statewide promotion of the Center should be provided through the media campaign mentioned above.

  The Information Center would be an ongoing program developed with the cooperation of the State Departments of Energy, Transportation, Commerce, Agriculture, Economic Development, and Environmental Quality; the PUC; state energy suppliers; transportation

companies; Oregon State University Extension Service; and other organizations related to energy supply and conservation. Printed publications and programs relating to energy conservation would be prepared and distributed by the Center.

- The Department of Energy should provide the media with a monthly report to the public announcing energy conservation progress and related energy supply information. This information will be available in conjunction with Oregon's participation in the State/Federal Energy Conservation Program.

(2) Kentucky Energy Conservation Plan. In the area of energy conservation education, the Kentucky Energy Conservation Plan cites a driver educator measure and a public education curriculum measure.

- Driver Education Measure. The Department of Transportation would utilize three points of contact for disseminating energy conservation information. The Department would: (a) work with the Kentucky State Police to revise driver training handbooks to include and emphasize energy conservation; (b) develop energy conservation materials to be included in other driver education materials; and (c) provide vehicle maintenance

information on back of annual Motor Vehicle Safety Inspection checklists, issued by the Department of Transportation.

The principal features of this program measure would be:

- revised driver training handbook to include and emphasize energy conservation
- development of training materials for use in Driver Improvement clinics, high school driver education classes, and other groups
- development of training literature specially adapted to commercial vehicles
- provision tune-up and energy conservation checklist and suggestions on back of annual Motor Vehicle Safety Inspection checklists.

- Public Education Curriculum Measure. The Kentucky Department of Education would develop and implement appropriate techniques for introducing energy concepts into the curricula and education program of the public elementary and secondary schools of Kentucky. Students would initiate energy saving projects and activities, as outlined in the curriculum materials which would be developed.
  - a set of classroom activities would be developed to deal directly and indirectly with energy and energy conservation. The set would contain various activities for different levels, kindergarten through grade twelve, and would involve all subject areas. Each activity

would center around one or more of the basic concepts of energy.

- two types of workshops would be held throughout the duration of the project to provide the teachers of Kentucky with in-service training geared toward the products and processes of this program measure.
  - -- a general awareness workshop would be conducted each year to acquaint teachers and administrators with the concepts of energy education.
  - -- during the initial year, four regional workshops would be conducted for the purpose of training teachers in the use of the materials developed in Kentucky, as described above. These workshops would serve as the initial vehicle for disseminating the new material; participants would gain firsthand orientation and training in the use of these materials as well as other materials available.
- additional distribution and dissemination of the curriculum materials would be made through cooperation with regional universities involved in teacher training. Also, all school libraries and resource centers would house copies of the materials developed.
- teachers involved in using the energy education materials would be kept up-to-date through the use of

Computer Based Resource Units (CBRU) dealing with energy topics. The CBRU program utilizes a computer data base which is constantly updated with new information about energy. This would help to ensure a continuing effort on behalf of the schools involved in this program measure.

- several energy education program series would be made available to all schools through the utilization of the Kentucky Educational Television system. The series aired would range from student-oriented programs, to teacher in-service programs designed to improve teaching of energy concepts, to live call-in programs utilizing experts in the fields of energy and energy conservation. This component of the program would directly increase the involvement of schools in the energy education program since educational television is available to all schools in the State.
- a project committee composed of persons involved in the fields of energy, energy conservation, and education would serve during the duration of the program to help establish criteria for specific program components and to conduct periodic evaluations of the project.
- studies evaluating the program would be conducted on a regular basis. The studies will assess the progress of the program in the following ways:
  -- number of schools and classes involved in the energy education program

-- number of energy saving projects and activities involving students at school and at home
-- knowledge of students and teachers regarding energy concepts
-- student attitudinal changes regarding the need for energy conservation.

(3) Ohio Energy Conservation Plan and Established Programs. A key feature of the Ohio Energy Conservation Plan in the area of public education is an information dissemination system that will enable the public to obtain technical information, instructional materials, or resources. Consumers will be able to contact the resource center through a statewide toll-free number or through a written request. The inquirer's questions will be entered on a computer terminal which will then display an appropriate list of printed materials and resources which apply to the inquiry. A postcard will be simultaneously printed for the inquirer and sources of information applicable to the request. The resource center will also include information sources such as films, mailing lists, model codes, current bibliographies of federal and state publications, as well as a calendar of energy activities throughout Ohio. A publicity campaign advertising the availability of the information service will be conducted throughout the State.

Ongoing energy information/education programs sponsored by the State of Ohio include:

- Speakers Bureau. The Ohio ERDA Energy Speakers Bureau includes energy experts from all over the State. Civic organizations are provided with a list of experts and are encouraged to utilize the experts as guest speakers.
- Information Hotline. This is a toll-free energy conservation information telephone number. Immediate response is given to homeowner questions on residential energy conservation and to questions regarding energy conservation in small commercial establishments. Manuals, fact sheets, brochures and reports are sent to callers with special needs or problems.
- Newspaper Supplements. The advertising managers of the eight major Ohio newspapers were contacted and encouraged to produce energy tabloids. Technical expertise is provided.
- Energy Fair. An energy fair was held at the statehouse at which companies could display energy saving appliances, home retrofitting equipment, insulation, and solar energy equipment. Other information was available.
- Television Energy Audits. Audiovisual energy audit segments were developed in conjunction with several television stations. These TV energy audits are to be aired during news broadcasts.

- Energy Calendar. A colorful wall sign and calendar which promotes residential energy conservation and offers home retrofit information was developed and distributed.

A number of the energy education programs mentioned in the preceding pages have aspects which are applicable to the City of Riverside.

Consumer Feedback. An interesting area which is related to public education and information is that of providing usable and timely consumer feedback on energy usage. Consumers may reduce their use of energy if they receive such feedback in a timely manner. At present, consumers are not aware of their gas and electricity consumption until they get their monthly bills and even then, they are not able to tell which appliances or pieces of equipment have contributed the most to energy usage and to cost.

The U.S. Energy Research and Development Administration and the Potomic Electric Power Company are currently engaged in a project to evaluate the Fitch energy monitor. This device can be placed in a convenient location and will indicate how much it will cost if the same amount of electricity usage is continued during the next hour. The monitors are also digital clocks, alternating every 4 seconds between electricity costs per hour and time of day. Homeowners using the monitor can see the cost differences when large energy using equipment, such as air conditioners, is operating and when it is not operating. Seventy homes were selected to receive the Fitch energy monitor. There is also a control group

of 70 homes. Electricity consumption will be monitored in all 140 homes. Specific information will be gathered on the efforts of the families to save energy, on their reactions to energy costs, and on their reactions to the monitors.

A previous study (Seligman and Darby, 1976*) demonstrated that feedback is effective in decreasing residential energy consumption. The homes studied all had central air conditioning. Since central air-conditioning is the largest single source of electricity usage during the summer, in homes so equipped, the households expected energy consumption could be predicted in terms of the average daily outdoor temperature. A modeling period based on the previous month's electricity usage was employed to predict normal (i.e., nonfeedback) electricity consumption. The feedback was expressed as a percentage of actual electricity consumption over predicted consumption. Homeowners in the feedback group received feedback four times a week for approximately 1 month. Prior to feedback, both the feedback and the control groups were consuming electricity at approximately equal rates. However, during the feedback period, the feedback group reduced electricity consumption by approximately 10.5 percent. The cueing, motivational, and commitment functions of the feedback procedure were indicated as reasons for the effectiveness of the feedback procedure.

Another study (Winett, et al, 1978)** investigated monetary rebates, feedback, and information on residential electricity conservation.

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*Seligman, C. and Darby, J.M., "Feedback as a Means of Decreasing Energy Consumption", U.S. Department of Energy Report PU/CES 34, August, 1976.

**Winett, R. A., Kagel, J. H., Battalio, R. C. and Winkler, R. C., "Effects of Monetary Rebates, Feedback, and Information on Residential Electricity Conservation", Journal of Applied Psychology, 63, (1), 73-80 (1978).

In the study, 129 volunteer households were divided into five experimental conditions as follows.

- A high monetary rebate condition in which participants received conservation information, weekly written feedback on their electric usage, and monetary rebates amounting to a 240 percent price change in electricity.
- A low monetary rebate condition with the same structure as the high rebates except payments amounted to only a 50 percent price change.
- A weekly feedback condition in which participants received information but no rebates
- An information condition
- A control condition.

The results showed that only the high rebate group curtailed electric usage to a significant extent (approximately 12 percent over the course of the study). It should be noted however that since the feedback utilized was infrequent (i.e., weekly) the findings of this study do not necessarily contradict other studies which have demonstrated the effectiveness of frequent feedback. General conservation information, by itself, was demonstrated to be ineffective, at least on a short-term basis. This does not negate the potential usefulness of such general information over a longer time period or in preparing the public for other energy conservation strategies.

Undoubtedly, many similar studies are being conducted on the effectiveness of feedback. Data on the effectiveness of feedback in

conserving energy should be carefully analyzed. Methods that work should be rapidly disseminated.

Recommendations for an Improved Energy Information/Education Program for Riverside

The following recommendations for an improved energy information/education program for Riverside are based on the:

- Present status of energy conservation education in the Riverside community
- Resources for energy conservation education/information in the Riverside community
- Innovative energy education programs which have been implemented elsewhere
- Reasonable expectations for the benefits of education programs and their limitations.

On this basis it is recommended that the City of Riverside implement the following programs/strategies.

1. An Energy Conservation Section should be established within the Riverside Public Utilities Department. This Section should be managed by an individual who can also serve as an energy conservation and public information coordinator for the City of Riverside. Specifically, the Energy Conservation Section should:
   - Implement the provisions of the UCAN Action Plan
   - Adopt and utilize programs such as those currently

being implemented or planned by utility companies such as Southern California Edison Company and the Southern California Gas Company*

- Consider a pilot feedback program on energy for homeowners consumption
- Publish an energy information newsletter for the Riverside community
- Coordinate/initiate a public information and persuasion program which utilizes local Riverside newspapers and radio stations. Contributed time/space should be solicited from these media with the Energy Conservation Section supplying content information.

  The basic goals of such a program would be

  - to establish credibility that an energy shortage exists
  - to provide an understanding of the implications of an energy shortage for Riverside and the country
  - to promote voluntary energy conservation
  - to develop compliance with mandatory control measures.

2. A City of Riverside Energy Education Committee for School Programs should be established.

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* These programs were previously described in Appendix C1.

A committee should be formed to coordinate/develop energy education programs for the Riverside Unified School District and for the Alvord School District. This committee should be comprised of community leaders drawn from the school systems, media, politics, business, consultants, etc., along the lines of the San Diego City/County Schools Energy Education Committee.* The energy conservation coordinator for Riverside (i.e., the head of the Public Utilities Department's Energy Conservation Section) should be a member of this Committee for School Programs. It is also recommended that a member of the public library system be included. As appropriate, the committee should be expanded to include the Riverside County Schools and other nearby school districts such as the Jurupa School District. In this way the resource demands will be spread out among several school districts, other individuals will be involved, and the benefits can be shared by all the participating school districts.

Specifically, the Energy Education Committee for School Programs should:

- Implement and monitor the development of an energy education curriculum for grades K through 12.
- Establish an "Energy Conservation Search Subcommittee" to identify and adapt existing programs/materials which may be available from U.S. DOE, energy utility companies, other school systems, the California

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* The San Diego City/County School Energy Education Committee is discussed on page G-41.

Public Utilities Commission, the California Energy Resources Conservation and Development Commission and other sources. This committee should also obtain speakers/resource personnel from UCR and other Riverside colleges and universities.

- Host a statewide, regional, or national conference on "Energy Conservation Education in the Schools". This 2 to 3 day conference should be held in Riverside and should be planned for calendar year 1979. The conference should be centered around national experts in the area of energy conservation and education and should feature small workshop sessions for teachers, curriculum experts and school administrators.

In general, the following points should be adhered to in developing energy conservation education programs for Riverside:

(1) All energy conservation materials developed and/or selected should contain well-documented, factual, jargon-free information.

(2) It is better to develop local examples of energy conservation than to write about abstract ideals. Once the example becomes "salable", then write about it. This lends credibility to energy conservation information.

(3) Wherever possible, try to show cause and effect relationships in energy conservation. Spell out what was done and what the effect in energy savings has been.

(4) Promote competition to excel in energy conservation.

(5) Where possible, nonconserving groups should be identified and a specific education/information approach should be designed to reach these nonconservers.

(6) Where possible, education/information activities should be regularly evaluated in terms of changes in consumer behavior, and revised as appropriate.

User and Public Response

Objective

The objective of this subtask was to evaluate user and community acceptance of recommendations made by this study in the areas of building retrofit, transportation, and alternative sources of energy.

Approach

Included in the approach used in completing this subtask were:

1. A review of relevant literature on public attitudes and response in the area of energy supply and conservation
2. A review of the recommendations of this study for Phase II demonstration projects

3. Development of the anticipated community response to study recommendations, on the basis of expert judgement.

This section, on user and public response to the recommendations of this study, focuses on recommendations in the areas of: (1) Energy Conservation Opportunities in Buildings; (2) Transportation Conservation Opportunities; and (3) Alternative Sources of Energy. It is divided into two subsections. The first subsection discusses general factors relating to public response. The second subsection discusses the anticipated public response to specific recommendations of this study, from the point of view of experience and professional judgement.

Factors Related to Public Response

Factors related to public response to energy conservation program/strategies can be discussed from the point of view of "effectiveness" and from the point of view of "acceptance". Both of these considerations can be positive or negative. That is, an energy conservation strategy could have positive effectiveness (i.e., could be expected to impact energy use) and at the same time have positive acceptance (i.e., could be widely accepted by the general public). An example of a program with positive effectiveness and positive acceptance might be one in which cash rebates were given on the purchase of small, fuel-economizing automobiles. On the other hand, strategies such as a fuel rationing program or a substantial toll for single passenger cars may be positive in effectiveness but have a very negative public acceptability.*

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*Pricing and inducement strategies are not discussed here since they are not included in the study recommendations.

A program such as a public appeal for car-pooling may be generally low (or negative) in effectiveness but may be high (or positive) in acceptance, because there is no added government control or penalities on individuals who do not want to comply.

Generally, the following considerations should pertain to energy conservation recommendations.

Public Information/Persuasion Programs. Public information/persuasion programs will not be as effective as other strategies because while some people will heed these appeals many others will not. In such programs, compliance is voluntary and an appeal to the "common good" will not be sufficient to obtain compliance from some members of the community. The benefits of these strategies from the effectiveness point of view occur when they:

- Point out real, subjective utilities (or personal benefits) for a user group. For example, an information program on home insulation directed toward homeowners will be effective if it demonstrates a potential for real monetary savings.
- Help to explain the need or pave the way for other strategies such as regulations, controls, incentive programs, policy changes.
- Help to establish a conservation ethic, although this is likely to be a long-term approach.

However, public information/persuasion programs will generally have positive acceptance because of their voluntary nature. That is, compliance is left up to the individual and those who do not want to comply are not penalized for their choice.

Regulation Programs. Regulation programs involve altering the structural framework within which people function and include allocation schemes, establishing operating rules, and setting performance standards.* While such strategies can be very effective, they can have a significant negative impact in the area of public acceptance, depending on the amount of compulsion involved. Degree of compulsion can vary from that of eliminating one of many possible courses of action to that of imposing a single mandatory course of action. A considerable amount of freedom of action can be maintained, therefore, with a well designed regulatory program. It is anticipated that the greater the freedom or flexibility of action, the more positive public acceptance will be. Also, it should be noted that regulations can be imposed sufficiently far "upstream" from the consumer so that their negative impact from a public acceptance point of view is minimized, although special interest groups may be negatively impacted in the area of acceptance. For example, a regulation which requires a specific fuel economy in new automobiles would have greater public acceptance than an allocation scheme for fuel purchases, although they could be equally effective in terms of saving gasoline.

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* Olsen, M., and Goodnight, J., op cit.

Anticipated Public Response to Specific Recommendations of this Study

The anticipated public response to the recommendations of this study, based on experience and professional judgement, are presented as follows.

Energy Conservation Opportunities in Buildings. Five programs are recommended for Riverside for energy conservation opportunities in buildings. These five programs are recommended at one or more of the following three levels.

1. Educational level. This level is characterized by appeals to conserve energy in buildings and also includes programs that teach people how to proceed to conserve energy in buildings. Of the three levels identified, this level is expected to have the least impact from a short-term effectiveness point of view but to be the most positive from a community acceptance point of view. This does not imply that level one programs will not be effective or should not be implemented.
2. Regulatory level. This level includes the implementation of State Energy Conservation Codes. It is expected to be less acceptable to individuals directly impacted by it.

3. Mandatory level. Under this level, the retrofit of existing buildings would be made mandatory by a certain date or penalties would be imposed. Programs at this level are expected to be more effective than level one or two programs but to be less acceptable by those directly affected than are level one and two programs.

Recommended Program No. 1. Prepare for Optimum Administration of New Residential and Nonresidential State Energy Codes. This program, as explained under Task IIa, can be implemented at all three levels of program operation. It will generally be more effective but less accepted at levels two and three than it will be at level one, as previously described. At level two, the program operates as a mechanism to regulate the design and construction of new residential and nonresidential buildings. Depending on the forcefulness with which these regulations are imposed, some negative acceptance may be expected from building contractors. If the design and construction requirements are costly, negative acceptance may be expected from members of the community who must purchase the buildings. Care should be taken that the regulations are equitably administered.

At level three, the program makes code compliance mandatory, or construction permits will not be issued. Significantly, greater acceptance problems may be expected from affected groups at this level.

Recommended Program No. 2. Establish a Division of Energy Conservation in the City Planning Department. This recommendation is

generally felt to have a positive effectiveness impact and a positive acceptance impact. Long-term public acceptance will be dependent on the nature of the programs which are developed by this Division and the way in which they are implemented.

Recommended Program No. 3. Reconcile Riverside's Role as a Municipal Electrical Utility with Conservation of Electricity. This program is expected to have positive effectiveness and positive acceptance. Some potential problems could be encountered if a rate increase is needed to cover the costs of conservation programs.

Recommended Program No. 4. Develop Programs to Increase the Energy Efficiency of Riverside's Existing Buildings. This program is judged to have positive effectiveness. However, if implemented at the mandatory level at which no property could be resold until it satisfied code requirements or at which time all property must be upgraded to meet the code by a specified date, it could be expected to have significant negative acceptance from property owners. Also, it could impact low-income property owners to a significantly greater extent than high-income property owners. The use of the program incentives could alleviate some of these negative acceptance problems.

Recommended Program No. 5. Seek Continued Improvement of the Energy Building Codes for New and Existing Residential and Nonresidential Buildings. This program is judged to have good potential for effectiveness. Public acceptance will depend on specific codes which are adopted and on the degree of mandatory compliance.

Transportation Energy Conservation. In general, the recommendations for transportation energy conservation are not new. They have been implemented in other communities with only minimal effectiveness. However, this does not imply that these programs are devoid of effectiveness with some user groups. Since these programs rely heavily on voluntary compliance, very positive public acceptance is expected to result. The effectiveness of the recommended programs can probably be optimized by the skillful use of mass media persuasion campaigns.

One recommendation, namely, that for using hydrogen as an alternative fuel in buses, etc., could have a significant effectiveness impact if widely used. It could also serve to reduce the air pollution problems of Riverside, especially if implemented on a regional basis. Some public acceptance problems with respect to the use of hydrogen may concern questions of safety. These concerns for safety should be adequately dispelled through public education and good management.

Alternative Fuels. None of the recommendations for alternative fuels are expected to have a direct impact on the community of Riverside from a public acceptance perspective. These recommendations will involve negative public acceptability on a regional basis to the extent that nuclear power is proposed for generation of electricity. Also, site selection for other types of facilities could pose public acceptance problems for local communities/property owners. Care should be exercised in the site selection process.

ATTACHMENT G-1

ORGANIZATIONS CONTACTED FOR TASK IV-b

ATTACHMENT G-1

ORGANIZATIONS CONTACTED FOR TASK IV-b

1. Riverside Public Utilities Department
2. Riverside Chamber of Commerce
3. Southern California Gas Company
4. Southern California Edison Company
5. Department of Sociology, University of California at Riverside
6. California Energy Resources Conservation and Development Commission
7. Air Pollution Research Institute
8. Congressman Brown's Office
9. Alvord School District
10. Jurupa School District
11. Rohr Industries.
12. Riverside Unified School District

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APPENDIX H

COMMUNITY INVOLVEMENT ACTIVITIES

APPENDIX H

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APPENDIX H

Community Involvement Activities

Studies such as the Riverside Phase I Program inherently require considerable contact with the community. One of the most important factors in developing and implementing on alternative energy strategy for Riverside is understanding and acceptance by the public of the need, costs and other impacts which they will face. Thus, extra efforts were made to inform and seek local advice through a variety of types of public contact. These were:

- Personal Contacts
- Advisory Committee Meetings
- Public Meetings/Presentations

Personal Contacts

A large number of personal contacts were made by Battelle staff members with various persons and/or organizations in Riverside. The primary reason for most of these contacts was to collect and review the site-specific baseline information required for the Program. All of these contacts represented an opportunity to discuss the objectives of the Phase I Riverside Program as an inherent part of the data-collection process. Many telephone contacts were also made, particularly to follow-up personal contacts.

No detailed log was kept of all the contacts made. Attachment H-1 illustrates the type of contacts made to about midway through the Program. It is estimated that a total of 200 or more personal contacts were made during the course of the Program.

Advisory Committee Meetings

An Advisory Committee was suggested when the Riverside Program was proposed. The function of the committee was to provide guidance and information pertinent to the program's operation and final results. All of the meetings except one were held in Riverside to facilitate participation of the local and state representatives. Dates of the meetings are listed below:

1. November 16, 1977
2. January 12, 1978
3. January 25, 1978 (At DOE, Oakland, California)
4. March 22, 1978
5. July 26, 1978 (approximate date--meeting held to review the draft final report).

Initially, the Advisory Committee was composed of representatives of DOE/Washington, DOE/San Francisco, The California Energy Commission, The Riverside Public Utilities Department, and Battelle-Columbus Management. This was the case for the first two meetings.

The January 25, 1978, meeting in Oakland, California was a special meeting called by DOE to restructure the Advisory Committee. This involved adding five Riverside members and removing Battelle from the Committee. The change was to enhance community involvement by the Riverside Members interfacing more closely and continuously with key groups in the community. The fourth meeting (March 22, 1978) included the full committee, which is listed in Attachment H-2.

The fifth Advisory Committee Meeting, scheduled for July 26, 1978, was held for a review of the Draft Final Report. The Draft Report was sent to all memebers of the Advisory Committee listed in Attachment H-2. Discussion at the July meeting included the members comments as well as inputs they have received from interfacing with other groups or individuals.

All of the regular Advisory Committee Meetings included a presentation by Battelle on the status of the Program at the time of the meeting. Discussions on various points were held during and after the presentations, including interchanges of communications several weeks after the meetings.

Active participation by all members present was excellent and very helpful in providing guidance to the Program. This was particularly true in the second half of the Program, when a wider scope of community involvement was obtained from the expanded Committee. Reports were written summarizing the results of all the Advisory Committee Meetings.

Public Meetings/Presentations

A major problem with public meetings and presentations during the course of the Phase I Program is that, characteristically, all the effort throughout the program until the past few weeks was concerned with collecting, analyzing, and generating baseline information, there are no specific results to report. Nevertheless, several such activities were carried out to acquaint people in Riverside and elsewhere with the Program. Several aspects of the Riverside Program are unique and much has been learned which should be beneficial to other programs and communities in regard to alternative energy planning, which is one of the objectives of the Phase I Program. In addition, it was important to lay the groundwork for the planned Phase II of the Riverside Program so that actions can be taken by Riverside, rather than to produce a Phase I Report which only "lays on the shelf". Public Meeting/Presentation activities included:

- A public meeting was held following the January 12, 1978 Advisory Committee Meeting. A total of around 60 community leaders from city/county/federal government, commerce, industry, and the university were specifically invited. About 20 attended in addition to all members of the Advisory Committee. A general status report on the program was presented, and questions answered.
- Two presentations were made to the Riverside Chamber of Commerce Energy Conservation Committee. One was brief, very early in the Program and covered the objectives and planned work. The second was made after the Advisory Committee meeting on March 22, 1978, where a condensed status report was given.

- Visual aides were provided for Mr. Everett Ross, Riverside Public Utilities Director, to make a general presentation on the Program at a League of Women Voters Meeting in Riverside on March 29, 1978.
- A briefing on the Program was given to Riverside City Officials on May 18, 1978 (Mayor, City Manager, City Council, etc). Some changes in officials had occurred since the Program started, and the briefing was to bring the present members up to date and to lay the groundwork for follow-on Phase II plans.
- Two presentations on the status of the Program were given to selected groups of Department of Energy personnel in Washington. The first, on March 17, 1978, was attended by a representative of Congressman George Brown, Representative of the 36th District of California, which includes Riverside. The second meeting was more oriented to the final results and follow-on Phase II plans.
- A paper, "An Audit of The Energy Consumption in The City of Riverside, California: Methodology and Results", by Sherwood G. Talbert and Frank E. Jakob, Battelle-Columbus Laboratories was presented at the State Audit Impact 78 Conference in Atlanta, Georgia, April 24-26, 1978.
- A paper, "Solar Energy Alternatives and Evaluation of Systems Analysis Results", by George H. Stickford, Battelle-Columbus Laboratories, was presented at the Second International Helioscience Institute Conference and Exhibit on Alternative Energy in Palm Springs, California on April 9-11, 1978. Riverside was used as an example in this paper.
- A Battelle-sponsored series of four briefings were given on "The State of The Art of Integrated Community Energy Systems Planning". These briefings were given in Chicago (November, 1977), Los Angeles (December, 1977), Atlanta (January, 1978) and Boston (March, 1978). Several examples using Riverside experience were part of these briefings.

A planned part of the Phase I Program is a public conference in Riverside following the issuance of the final report. Riverside members of the Advisory Committee will play an important part in planning and implementing this conference. Results of the Phase I Program will be presented, and public responses evaluated. It is anticipated that this will be a most important meeting for (1) aiding the City of Riverside in short- and long-range planning, and implementation of recommendations, such as energy conservation actions, which require no further work, and (2) providing baseline information for Riverside, the California Energy Commission, the Department of Energy, and others regarding planning and implementation of follow-on work.

ATTACHMENT H-1 BATTELLE PERSONAL CONTACTS

BATTELLE PERSONAL CONTACTS UP TO JANUARY 1, 1978, ON THE RIVERSIDE COMMUNITY ENERGY PROGRAM

Mr. Gordon Anderson Regional Water Quality Board	Riverside, California	Procurement of water quality data.
Mr. Dee Bachman, Park Superintendent, City of Riverside	Riverside, California	Park fees for land developers.
Mr. Dean Boen, Physical Plant Administrator, University of California-Riverside	Riverside, California	Briefing and tour of facility, which is Riverside's largest energy user.
Mr. William Brantley, Manager Industrial Relations, Rohr Industries	Riverside, California	Discuss program and Rohr energy use as largest industry in Riverside, obtain Rohr energy use data.
Mr. Brown, Brown and Rawdon, Architects	Riverside, California	To discuss the project, request assistance, and obtain applicable information.
Mr. Robert Brown, Architect	Riverside, California	Discussion of current energy conservation practice and future potentials.
Brown and Rawdon, Architects	Riverside, California	Developed rehabilitation plan for downtown Riverside. Showed interest in integrating energy conservation measures into rehabilitation plan.
Ms. Margaret Brunelle, South Coast Air Quality Management District	El Monte, California	Air quality data for Riverside County.
Mr. Warren Buckmaster, Developer, Hemet California, Blue Skies Solar Home Project and President of Blue Skies Radiant Homes	Hemet, California	Discussed and toured several of Mr. Buckmaster's 33 solar homes; requested assistance and obtained applicable information.

Dr. Edgar Butler, Chairman Department of Sociology, University of California at Riverside	Riverside, California	Discussed the possibility of using mini surveys in connection with Community Impacts and Public Response, and the possibility of having graduate students involved in conducting the survey.
Mr. James C. Cashman, Developer, President of the Homestead Company	Riverside, California	Discussed Riverside program; requested assistance and obtained applicable information on his recently completed 23 homes with special energy saving features.
City of Burbank: Ronald Snyder, General Manager, Public Services Department; Acey Floyd, Science Advisor; Greg Simay, Administrative Analyst	Burbank, California	Energy planning in Burbank: conservation, load management, industry cooperation, alternative fuels.
William F. Cornett, City Manager, Riverside, California	Riverside, California	General discussion of program, ways to obtain data.
Dr. Ellis Darley, University of California - Riverside State Air Pollution Research Center	Riverside, California	Air pollution effects on vegetation (November 1977). Briefing on State Air Pollution Research Center activities, identification of work going on and possible contacts. (August 1977).
Bruno Davis, Director, Operations Division, California PUD	San Francisco, California	PUD-Energy Commission/Local Government relations.
Joan Fill, Conservation Planning Consultant, Southern California Edison	Rosemead, California	Discussion of data availability on residential, commercial and industrial energy consumption by building type and of energy conservation programs initiated by electric company and others.
Robert Fitch, Riverside County Administrator	Riverside, California	Energy conservation programs undertaken by County; overview of County-provided services.
Bill Furey, Building Department City of Riverside	Riverside, California	Code enforcement, passive energy conservation (September 1977).

Bill Furey, Building Department City of Riverside	Riverside, California	Review of current and future building codes, enforcement problems, and land use/zoning regulations (December 1977).
Mr. Don Geister and others. Southern California Electric Company	Riverside, California	Discussion of SCE's policy on cogeneration.
Mr. Luther Goodwin, Aide to Congressman George Brown who represents the Riverside Area	Riverside, California	General discussions of the Riverside Program.
Mr. John Grissinger, California Air Resources Board	El Monte, California	Air quality management plan for Los Angeles Basin.
Eric Haley, City Councilman Riverside, California	Riverside, California	General discussion of the Riverside program (September 1977).
Eric A. Haley, City Councilman Riverside, California	Riverside, California	General discussion of the Riverside program.
Eric A. Haley, City Councilman Riverside, California	Riverside, California	Discussed development in Riverside and the future of the Municipal Power Company.
Warren Hinchee, Deputy Division Chief, Conservation Office, State Energy Commission (former Manager of Burbank PSD)	Sacramento, California	State involvement in cogeneration; options for local government energy planning.
Mr. George Hubbard, Director Riverside Public Services Department	Riverside, California	Discussed deriving fuel hydrogen from wastes (October 1977).
Mr. George Hubbard, Director Riverside Public Services Department	Riverside, California	General discussions (November 1977).
Mr. Aron Kliewer, Director of Research, Fleetwood Enterprise, Riverside	Riverside, California	Discussed his interest in solar energy as it applies to the mobile home market.

Mr. Lashbrook, County Assessor's Office, Riverside County	Riverside, California	Discussion of residential, commercial, and industrial tax lists for use as aid in determining current building inventory.
Mary Lindblom, Assistant Planner; Bill Wilkman, Senior Planner; City of Riverside Planning Dept.	Riverside, California	Residential development and land-use policy in Riverside.
Mr. Barry D. McClellan, Transportation Department, Public Works	Riverside, California	Status of hydrogen bus program (November-December Report).
Mr. Don McGregor, Technology Advisor in Anaheim	Anaheim, California	Information on the conservation activities of California Innovation Group.
Ronald Nordstrom, Chief, Electrical Engineer, Rohn Industries	Riverside, California	Discuss Riverside program and Rohr energy use as largest industry in Riverside; obtain Rohr energy use data.
Mr. Lawrence Paulsen, Assistant City Manager	Riverside, California	Status of studies of joint management of solid wastes.
Mr. Lawrence Paulsen, Assistant City Manager	Riverside, California	City-county relations;use of utility pricing as locational incentive to industry.
Mr. Lawrence Paulsen, Assistant City Manager	Riverside, California	Review of current city efforts in energy conservation.
Mr. Mario Perez Director, Solar Energy Development Institute (SEDI) Palm Springs, California (Also Executive Director Pollution Control Research Institute)	Riverside, California	Briefing on SEDI activities, identification of work going on and possible contacts.

Mr. Charles Phillips, Director of Buildings and Grounds, County of Riverside	Riverside, California	Energy consumption profiles for selected county buildings.
Arthur Pick, Executive Vice President, Riverside Chamber of Commerce	Riverside, California	General discussion of program; obtained statistical data on Riverside (September 1977).
Arthur Pick, Executive Vice President, Riverside Chamber of COmmerce	Riverside, California	Discussion of data availability on nonresidential building inventory, and economic implications of fuel cost and fuel availability (natural gas and electricity) (October 1977).
Mr. Blaine Rawdon, Brown and Rawdon Architects	Riverside, California	Discussed the Riverside project; requested assistance and obtained applicable information.
Herb A. Rogers, District Manager, Southern California Gas Company	Riverside, California	Discuss Riverside program; gas use in Riverside, conservation activities, ways to obtain data. (September 1977).
Herb A. Rogers, District Manager, Southern California Gas Company	Riverside, California	Data availability on residential commercial and industrial gas consumption (October 1977).
Everett C. Ross, Public Utilities Director, Riverside, California	Riverside, California	General discussions of Electric Use; identification of Riverside planning data (September 1977).
Everett C. Ross, Public Utilities Director Riverside, California	Riverside, California	Initial coordination of data collection activities at Riverside (August 1977).
Everett C. Ross, Public Utilities Director, Riverside, California	Riverside, California	Provided useful history of Riverside PUD - Southern California Edison relations, as well as future plans for the municipal utility (December 1977).
Fred Rowden, Sr. Plant Mechanical Engineer, Rohr Industries	Riverside, California	Discuss program and Rohr energy use as largest industry in Riverside; obtain Rohr energy use data.

Rosanna Scott, Riverside City Councilperson	Riverside, California	Southern California Association of Governments (SCAG) relations; PRUD - Southern California Edison relations (September 1977).
Rosanna Scott, Riverside City Councilperson	Riverside, California	Discussion of political acceptance prerequisites of energy conservation strategies for buildings (December 1977).
Rosanna Scott, Riverside City Councilperson	Riverside, California	Discussed development in Riverside (November 1977).
Mr. Robert Sheldon, Solar Energy, Inc. Riverside	Riverside, California	Builder of solar energy collectors; has a factory in Riverside.
Eldridge W. Sinclair, Utilities Administrative Officer, City of Riverside, California	Riverside, California	Introductions to industry leaders; general discussion of the program (August 1977).
Eldridge W. Sinclair, Utilities Administrative Officer, City of Riverside, California	Riverside, California	Discussion of electrical power consumption data by building type (October 1977).
Maurice Smith, Assistant to City Manager, Riverside	Riverside, California	General discussion of the Riverside Program.
Mr. David D. Sparks, Energy Coordinator, Riverside, California Public Utilities Department, Riverside, California	Riverside, California	Initial coordination of data collection activities at Riverside (August 1977).
Mr. David D. Sparks, Energy Coordinator, Riverside California Public Utilities Department Riverside, California	Riverside, California	Detailed data discussions; planning to obtain needed data; introductions to the Riverside Community (September 1977).

Mr. David D. Sparks, Energy Coordinator, Riverside, California Public Utilities Department, Riverside, California	Riverside, California	Background of organization and finances of the Public Utilities Department; other public services (September 1977).
Mr. David D. Sparks, Energy Coordinator, Riverside, California Public Utilities Department, Riverside, California	Riverside, California	Discussion of data needs, review of community energy conservation efforts with regard to buildings (October 1977).
Mr. David D. Sparks, Energy Coordinator, Riverside, California Public Utilities Department, Riverside, California	Riverside, California	Discussed general program and solid waste data (November 1977).
Mr. David D. Sparks, Energy Coordinator, Riverside, California Public Utilities Department, Riverside, California	Riverside, California	Burning of agricultural wastes (November 1977).
Robert Spires, Power Services Supervisor, City of Riverside	Riverside, California	Discussion of data on Riverside growth and energy consumption and conservation goals; data availability on electrical energy consumption by residential, commercial and industrial building types.
State Energy Commission, Meir Carasso, Manager, Energy Systems Integration; Mark Urban, Legal Office	Sacramento, California	Discuss the Riverside Program; State-PUC-Local government relations; state level energy planning.
Mr. Edgar Stephens, University of California-Riverside State Air Pollution Research Center	Riverside, California	Photochemical smog.

Vic Sterling, Marketing Manager Southern California Gas Company	Riverside, California	Discussion of energy conservation programs initiated by the gas company and by others.
Dr. O. Clifton Taylor, Executive Director, Statewide Air Pollution Research Center (SAPRC) University of California at Riverside	Riverside, California	Briefing on SAPRC activities; identification of work going on and possible contacts (August 1977).
Dr. O. Clifton Taylor, Executive Director, Statewide Air Pollution Research Center (SAPRC) University of California at Riverside	Riverside, California	State Air Pollution Research Center and vegetation effects research (November 1977).
Morgan L. Thomas, HVAC Contractor, Palm Springs	Palm Springs, California	Installed several solar heating systems in and around Palm Springs.
R. T. Thournier, Plant Manager, Rohr Industries, Riverside, California	Riverside, California	Discuss program and Rohr energy use as largest industry in Riverside; obtain Rohr energy use data.
Cliff Canderpool, Staff Assistant, Rohr Industries	Riverside, California	Discuss program and Rohr energy use as largest industry in Riverside; obtain Rohr energy use data.
Dane Westerdahl, California Air Resources Board	Sacramento, California	Pollution and health effects.
Stephen J. Whyle, Principal Planner, Riverside Planning Department	Riverside, California	Discussed the project, requested assistance, and obtained applicable information.
Stephen J. Whyle, Principal Planner, Riverside Planning Department	Riverside, California	Discussed Riverside development plan which is to be completed early in 1978. The emphasis of the study is land-use planning - no consideration is being given to energy conservation.

J. D. Williams, City of Riverside, Department of Public Works	Riverside, California	Sewage disposal.
Victor Yamada, Pacific Environmental Services of Santa Monica, California	Santa Monica, California	Pollution and health effects.
Peter Zweig, Associate Director, Pollution Control Research Institute (PCRI)	Riverside, California	Briefing on PCRI activities; identification of work going on and possible contacts. (August 1977).
Peter Zweig, Associate Director, Pollution Control Research Institute (PCRI)	Riverside, California	Air pollution problems; ways in which PCRI could help on the project (September 1977).
Peter Zweig, Associate Director, Pollution Control Research Institute (PCRI)	Riverside, California	To discuss the project, request assistance, and obtain applicable information (November 1977).
Peter Zweig, Associate Director, Pollution Control Research Institute (PCRI)	Riverside, California	Provided information on solar energy as applied to Riverside (December 1977).
Dr. R. M. Zweig, MD, Executive Director, Pollution Control Research Institute (PCRI)	Riverside, California	Briefing on PCRI activities; identification of work going on and possible contact (August 1977).
Dr. R. M. Zweig, MD, Executive Director, Pollution Control Research Institute (PCRI)	Riverside, California	Air pollution problems; ways in which PCRI could help on the project (September 1977).

Dr. R. M. Zweig, MD, Executive Director, Pollution Control Research Institute (PCRI)	Riverside, California	To discuss the direction in which the development in Riverside is going (November 1977).
Wayne Zwiackes, South Coast Air Quality Management District	El Monte, California	Air pollution emission data for Riverside County.

ATTACHMENT H-2

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APPENDIX I

RIVERSIDE AERIAL INFRARED PHOTOGRAPH EXPERIMENT

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RIVERSIDE AERIAL INFRARED PHOTOGRAPH EXPERIMENT

As an outcome of Advisory Committee discussions during the course of the Phase I Riverside Program, DOE/San Francisco Operations contracted separately with EG&G, Incorporated, 316 East Atlas Circle; Las Vegas, Nevada 89030 for an aerial infrared scan of the City of Riverside. The EG&G report on the infrared experiment and how it will be used in Riverside to encourage energy conservation activities is contained in this Appendix.

RIVERSIDE AERIAL PHOTO/INFRARED SCAN DISPLAY PROJECT

INTRODUCTION

During two of the early meetings of the Advisory Committee to the Riverside Integrated Community Energy Program, discussion often involved the issue of public awareness and involvement in the program. Many of the potential energy options to be explored and later implemented in the City of Riverside, such as conservation/ weatherization programs, changes in city planning and zoning policies, etc., could be expected to directly affect the average citizen. Some creative means of reaching, informing, and involving average citizens in the solution of energy problems related directly to their community was therefore required to help ensure the eventual success of the overall integrated energy planning program.

As a possible answer, the Advisory Committee recommended that DOE and BCL look into the cost and technical feasibility of doing an aerial infra-red scan of the City's 71 sq. miles, and using those photographs as the centerpiece of a public information project. It was pointed out that this approach has been used successfully in other cities across the country, such as Phoenix. Following discussions with the Arizona Public Service Company on their successful approach in the Phoenix area, funding was arranged by the San Francisco Operations Office and preparations made for the

Riverside overflight. An existing DOE contractor with the required technical capability, EG&G, Inc. located in Las Vegas, Nevada, was tasked and the missions flown in February 1978.

EQUIPMENT AND DETECTION PROCESS

To sense and record the heat radiation from the ground, a Daedalus multispectral scanner was used. While the scanner was configured with two infrared detectors, only the data from the longer-wavelength detector was used for interpretation. That detector was a tri-metal (mercury-cadmium-telluride) filtered to operate in the spectral region spanning 8.5 μm to 11.0 μm. It is within this spectral range that one finds the radiation peak for so-called gray bodies (wavelength insensitive emitters) at most ambient temperatures. A schematic diagram of the scanner system is shown in Figure 1.

A unit of digitized data is the picture element or "pixel", representing the area on the ground being detected at the time of digitization. A line of pixels (scan line) perpendicular to the line of flight is produced by the rotation of the scanner mirror. Scanning in the flight direction is produced by the motion of the aircraft. The altitude, groundspeed, and mirror rotational speed must be chosen to obtain contiguous, or overlapping, scan lines so that no ground spot is missed. Flight lines are chosen close enough to provide sidelapping coverage.

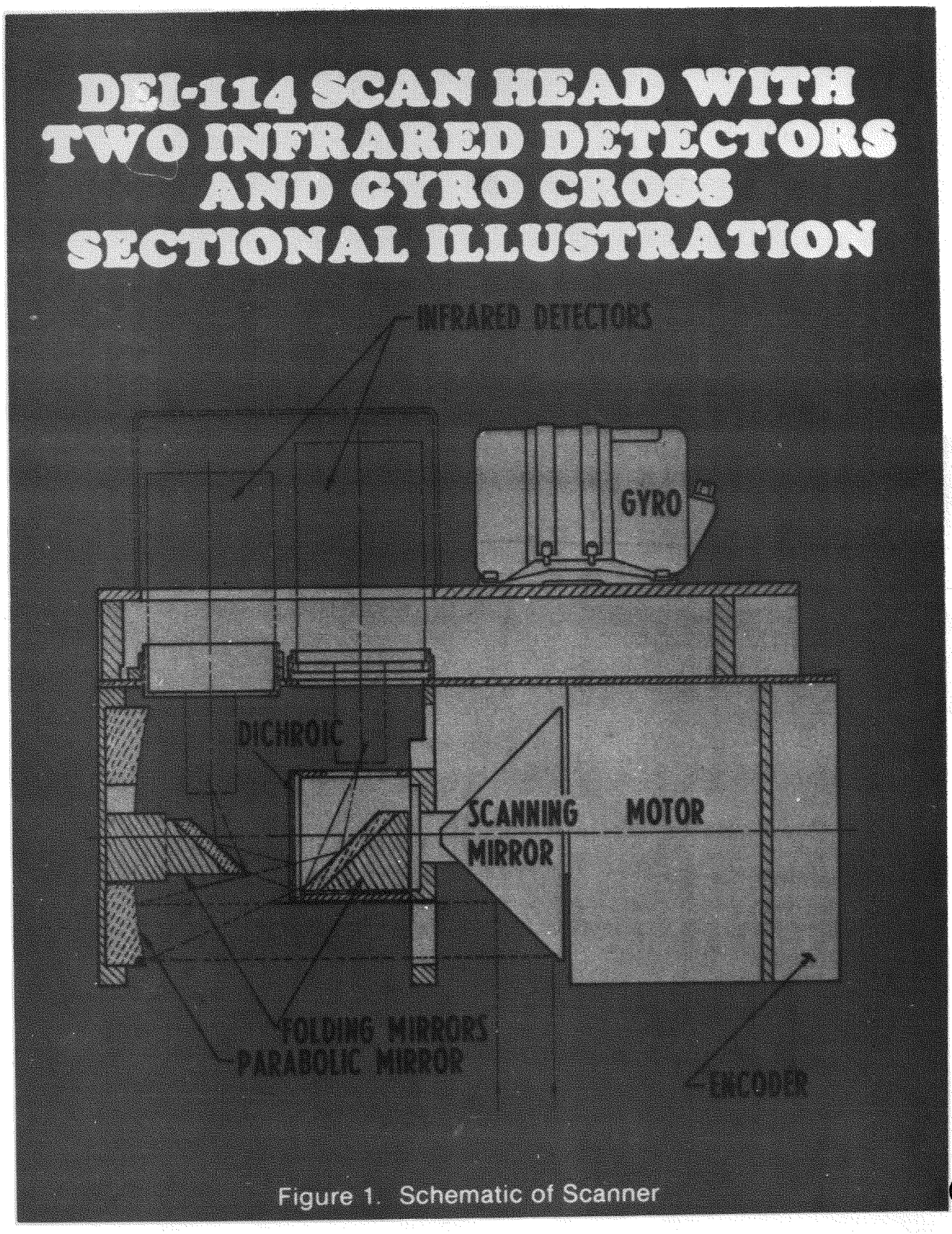

Figure 1. Schematic of Scanner

In addition to the ground below, the detectors also sense the radiation from two internal reference sources whose temperatures are controlled and monitored to better than one-tenth degree Celsius. This information and other support data are recorded on magnetic tape together with the signals produced by the radiation emitted from the ground. The magnetic tape from the scanner is used to produce computer compatible tape for processing and analyzing the data.

While the detection process appears straight-forward, the connection between signal and the temperature of the object on the ground is not. First, the radiation from the emitter has been modified in intensity and spectral content by its passage through the intervening atmosphere. The modification is of course angular dependent because the atmospheric path length is. Second, the amount of radiation emitted is not just a function of an object's temperature, but also of its surface composition and structure. An aluminum surface, for example, will emit less radiation than an asphalt surface at the same temperature. To complicate things further, a smooth fresh aluminum surface emits less than an older, rougher aluminum surface.

Because these effects of composition and atmosphere make it so difficult to determine the true temperature of a surface, the concept of "apparent" temperature is introduced. The apparent temperature is the temperature calculated for the emitting surface assuming:

(a) the emitter is a perfect radiator, its emissivity being unity,

(b) the intervening atmosphere has no effect on the radiation reaching the collector of the scanner.

The usefulness of this concept is directly related to the accuracy of the assumptions. While no control is possible over the emissivity of the surfaces, proper choice during the survey of the spectral band for sensing could determine whether or not the second assumption is valid.

Atmospheric effects can, fortunately, be reduced by the proper choice of spectral region in which to do the sensing. By using the 8.5 μm to 11.0 μm band, it was possible, within the range of needed accuracy, to assume that the radiation from all pixels is uniformly attenuated.

But the effects of surface composition and structure can be neither ignored nor considered uniform. Therefore, without information about the type of surface observed, it is impossible to determine the surface temperature from the value of the detector signal. As a result, when comparing buildings of different roof construction, it is essential to know the composition and state of the surface material. On the other hand, qualitative comparisons between similarly constructed neighboring buildings can easily be made without such detailed information.

DATA ACQUISITION AND PROCESSING

The size of a scanner pixel is fixed in angle, and thus the size on the ground depends on aircraft altitude and angle of view, objects on either side of nadir appear too narrow on the scanner imagery. This type of distortion is called "S-bend" distortion. Computer techniques exist for correcting it.

During the mission, the aircraft altitude was about 4000 feet above ground level - yeilding a pixel dimension of about 10 feet at nadir and almost twice that size near the edges of the scan lines. A second type of image distortion, much more difficult to correct, is produced by the overlap of scan lines. Some overlap is necessary to prevent loss of ground coverage due to variations in aircraft groundspeed and altitude. For the speed and altitude flown, the scan lines overlapped between about 35 to 45 percent.

The intent was to take infrared data sometime in mid-January 1978, predawn (0500-0630) when cold weather would produce optimal conditions for this task. Unfortunately for the project, the equipment and personnel had to respond to a governmental directive to search for the re-entered Russian satellite in Canada. The survey over Riverside was therefore rescheduled for 23 February 1978. Conditions, however, turned out to be less than optimal - the day before was the warmest 22 February of recent record. Better data would have been obtained if the weather had been colder, necessitating a greater use of heating equipment in the buildings.

A few days later, photographs were taken of the Riverside area with an RC-10 aerial mapping camera and Aerocolor film at a scale of 1:20,000. An example of the photos are shown in Figure 2. The photos were used as reference to more readily permit the location of particular buildings in the thermal imagery.

Processing of the data was performed with the objective of providing the apparent temperatures of various parts of each building. Then, having information on the surface material of the structures, qualitative estimates of the true temperature and heat losses can be made.

Only the most straightforward and simple processing techniques were applied to the thermal imagery. First, the predictable "S-bend" distortion was removed by an analytical expression which accurately corrected that type of distortion. The effect of overlapping scans is not predictable because it is not solely dependent upon the construction of the scanner, as is "S-bend". Since photogrammetrically correct imagery is not needed here, an approximate and easy correction method could be used. The method consisted of choosing three areas for each flight line - near the start, the middle, and the end - and using the average distortion to determine the single correction for the whole line. Although distortions were still noticeable after processing, the results were judged to be satisfactory.

Figure 2. RC-10 Photograph (1:20,000)

The next step in processing was to convert the signal values or grey levels of the thermal imagery into temperature. Examination of the statistics of the changes in the internal thermal references and the detector response indicated that an apparent temperature of $\pm 0.5^{o}C$ (about $\pm 1^{o}F$) could be obtained to better than 90% confidence using the following technique. The detector signal value as a function of temperature was determined for each flight line using the internal reference temperatures averaged over all the scan lines. Using that function, the signal level for each pixel was converted to the nearest integer temperature (^{o}C). A color was assigned to each of the ten temperature levels, and pixels having that temperature were color-coded accordingly. Thus by knowing the color of a pixel, its apparent temperature is known to $\pm 0.5^{o}C$. An example of one frame of such a color-coded image is shown in Figure 3.

DATA UTILIZATION AND INTERPRETATION

The procedures for locating and reading the apparent temperature of any given building is as follows:

I. Using the 40" X 40" shingle mosaic (Figure 4) of the total, scanned area, one locates on which individual frame the building can be found.

Figure 3. Color Coded, Infrared Image

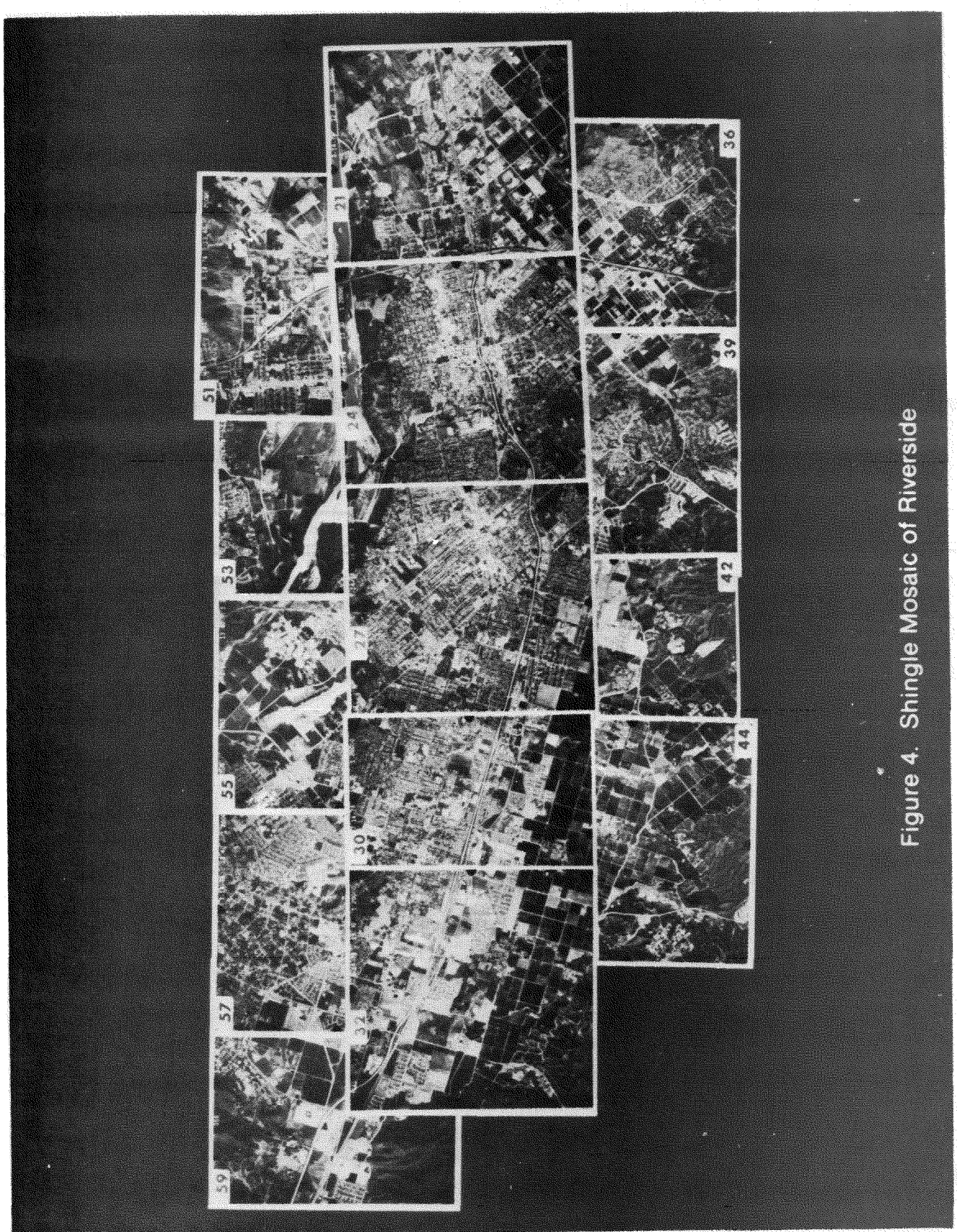

Figure 4. Shingle Mosaic of Riverside

II. Next, moving to the 40" X 40" single frame (an example is Figure 2) the building itself is located. On this frame, two or three street names are printed to provide bench marks for locating places.

III. In a spiral-bound booklet titled "INDEX" are copies of each colored photographic frame. Every photo is overlaid with the coverage of individual scanner frames, bounded by either solid or dotted lines. Within each scanner frame is printed a hyphenated number (Figure 5). The first half of the number refers to the roll or "perf" number, and the second number to the frame number. For example, 37-05 means the frame is number 05 on perf 1937 (19 is always prefixed to the stated perf number). After locating the building on the 40" X 40" photo, it is relatively simple to find, on the INDEX photo, the scanner perf and frame which includes in its coverage that structure.

IV. Each perf of scanner imagery is available in its own, separate, spiral-bound booklet. The booklet has the perf number printed on its cover. In the booklet, two scanner images with identical coverage are on facing pages (Figures 3 and 6). The black and white image represents the thermal image in terms

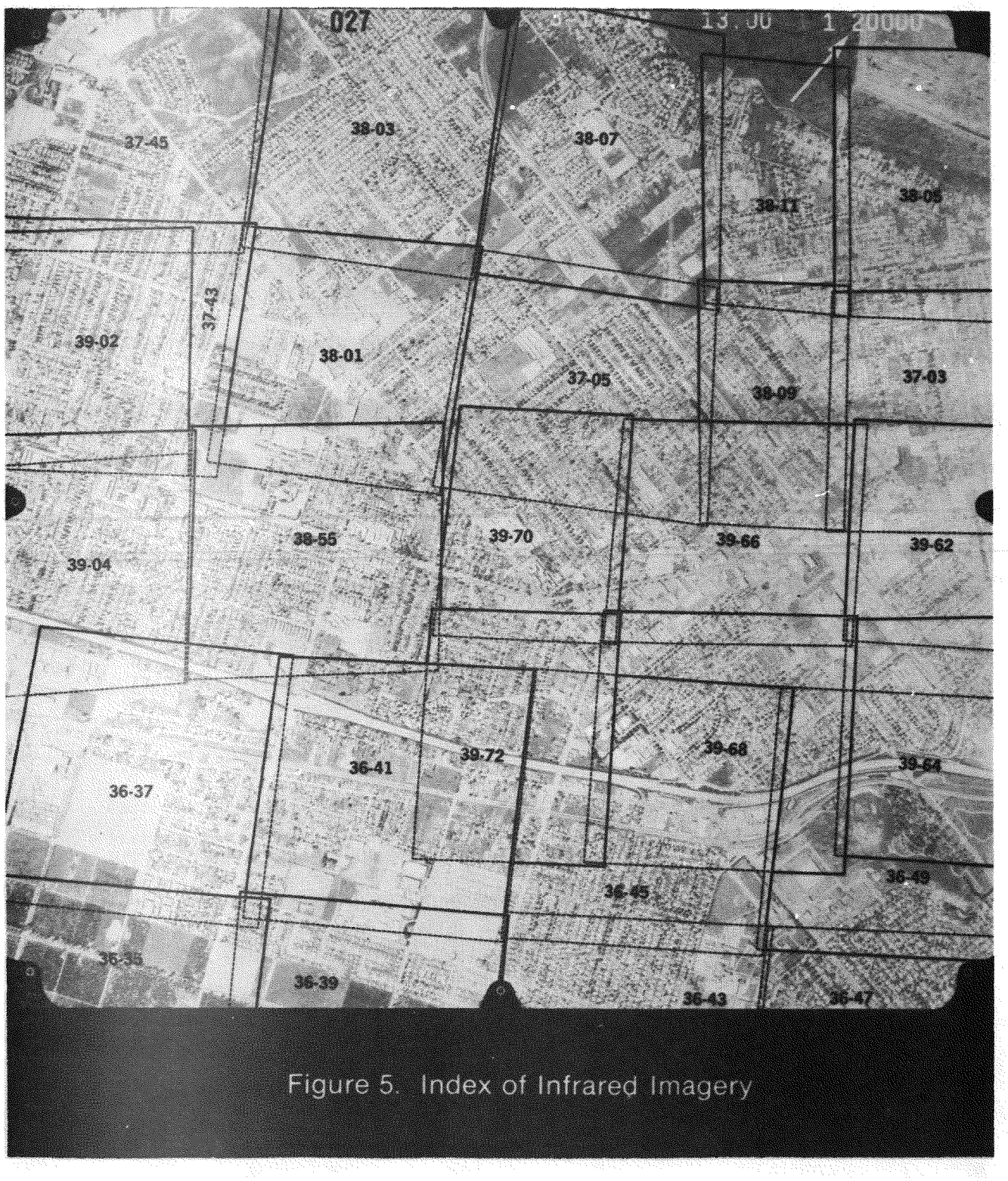

Figure 5. Index of Infrared Imagery

Figure 6. Black and white, infrared image

of grey level. The facing image is color-coded according to the previously stated scheme. Two images are provided because it is much easier to make transition from the aerial photo to the color frame by using the black and white frame as an intermediate step. If necessary, the color keyed strip identifying temperature with color can be compared to the image to obtain apparent temperature each pixel.

As previously stated, to obtain the true temperature from the apparent temperature, it is necessary to know the emissive property of the surface, namely the emissivity. The emissivity of a number of common types of materials, in the detector's spectral band, is given in Table 1. Figure 7 graphs the relationship between apparent and true temperature for a range of emissivities, assuming negligible atmospheric effects. Using this figure with the emissivity table, it is possible to obtain an estimate of the true temperature of buildings roofed with the materials in the table, as well as many other objects.

PUBLIC DISPLAY

Planning and fielding of the photo display in the City is a joint project of the Riverside Public Utilities Department and the Energy Conservation Committee of the Riverside Chamber of Commerce. A

Table 1. Emissivity of Various Common Materials

Material	Emissivity
Aluminum	0.85
Asbestos	0.93 - 0.95
Brick: red common	0.93
Concrete	0.92
Glass	0.94
Paint, oil; average of 16 colors	0.94
Plaster: rough coat	0.91
Soil: dry	0.92
Soil: saturated with water	0.95
Water	0.98
Wood: planed oak	0.90 - 0.95

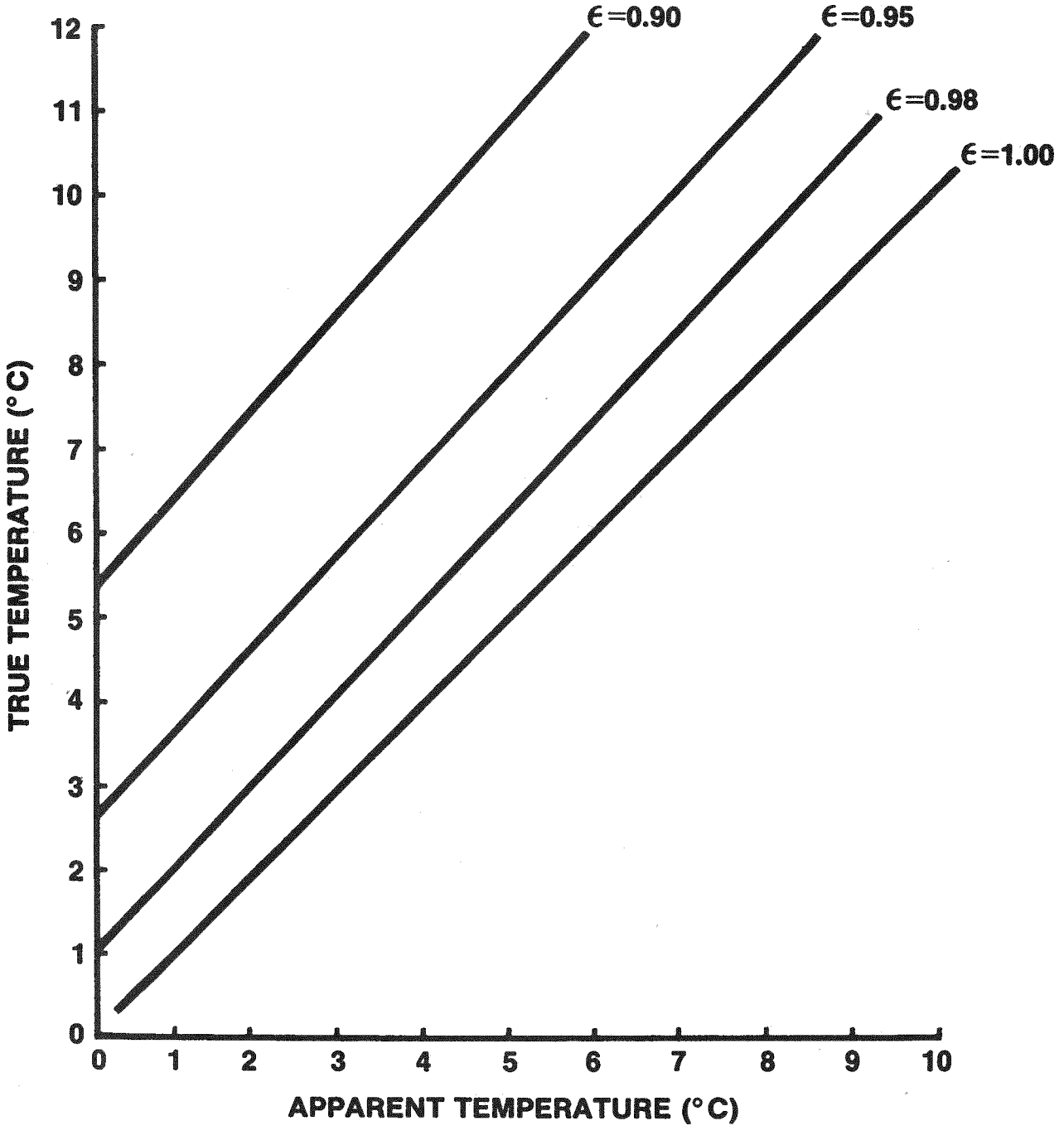

Figure 7. Graph of True vs. Apparent Temperature

movable display cabinet was specially constructed to house and safeguard the photos and an employee of the City of Riverside was hired and trained to explain the display to the public at field locations. The Riverside Public Utilities Department and the Southern California Gas Company are providing hand out literature on various conservation/weatherization topics as a part of the project.

Through 1979, the display (pictured in Figure 8) will be moved regularly around the City to various public loactions, such as shopping centers, banks, and Public buildings, with the Chamber of Commerce Committee coordinating advertising for each location. DOE has requested certain specific recordkeeping on visitors to the display to allow later follow-up for the purpose of determining what the true impact of this approach has been as a conservation/ weatherization inducement.

Figure 8. Thermogram Display.

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APPENDIX D

ALTERNATIVE ENERGY SUPPLY

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ALTERNATIVE ENERGY SUPPLY

D1 Coal
D2 Solar
D3 Geothermal
D4 Nuclear
D5 Solid Waste/Biomass
D6 Wind
D7 Hydrogen
D8 Purchased Fuel Prices
D9 Integrated Utility System Analysis
D10 Environmental Analysis