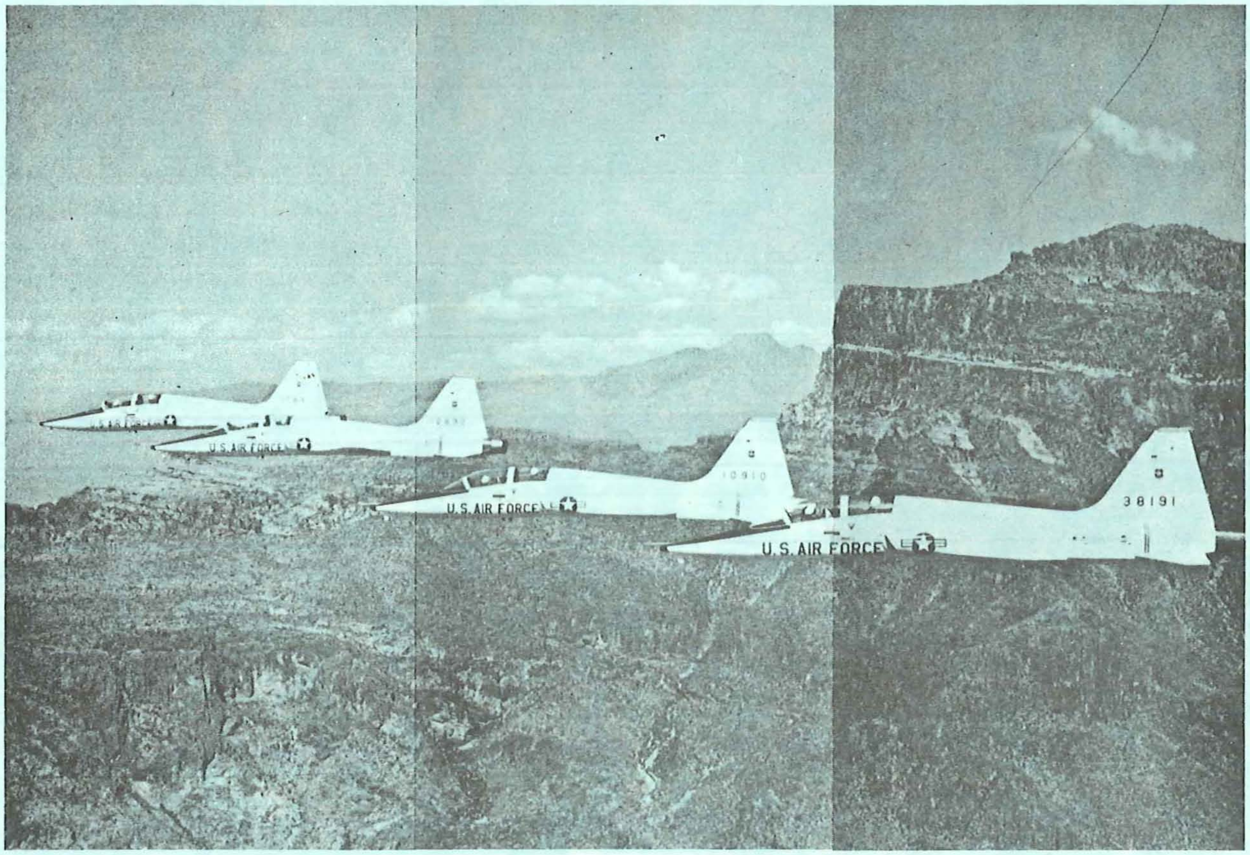
GL03004 - 1 of 2

GP-790007

THE POTENTIAL FOR USING GEOTHERMAL ENERGY



FOR SPACE COOLING AT WILLIAMS AIR FORCE BASE, ARIZONA

U.S. Department of Energy
Idaho Operations Office

EG&G Idaho, Inc

AUTHORS AND ACKNOWLEDGEMENTS

This feasibility study was prepared by EG&G Idaho, Inc., the prime contractor to the Department of Energy at the Idaho National Engineering Laboratory, and represents the collective effort of a number of people. The principal authors and project team members include:

- Dr. W. Darrell Gertsch and Joe G. Keller, EG&G Idaho, Inc.;
- W. Richard Hahman, Sr., CPG, Arizona Bureau of Geology and Mineral Technology;
- Captain Dave Ruschmann, 82nd Civil Engineering Squadron, Williams Air Force Base.

Valuable planning assistance in certain specialized areas was also provided by the following individuals:

- Susan Prestwich of the Department of Energy's Idaho Operations Office in developing the drilling costs in Section III;
- Coleman Kuhn of the 82nd Civil Engineering Squadron for researching the legal and environmental questions noted in Section VI;
- Tom Lawford, Jim Twohy, Jim Mills, and Andy Lau of EG&G Idaho for providing costs on geothermal electric and solar development;
- Dr. Howard Ross, Earth Science Laboratory of the University of Utah Research Institute, and Dr. Clayton Nichols, Department of Energy, Idaho Operations Office, for reviewing the exploration program recommendations;
- Alice Campbell of the Arizona Bureau of Geology and Mineral Technology for estimating reservoir capacities.

We also acknowledge the important assistance provided to the study by Loyd Donovan, EG&G Idaho; Lt. George Bozenhard, Lt. Mike Fisher, Alton Cannon, and other members of Williams' engineering staff. Lt/Colonel Ray D. Schwartz, Base Civil Engineer, and Richard Steed from Air Training Command Headquarters, Randolph Air Force Base, were the principal advisors to the project team.

CONTENTS

CONTENTS (continued)

TABLES

CONTENTS (continued)

FIGURES

EXECUTIVE SUMMARY

This study analyzes the feasibility of geothermal project development at Williams Air Force Base, Arizona, using the deep geothermal resource identified by recent private company drilling near the base. The analysis focuses on a district chilled water loop providing space cooling to most of the central base area. Economic feasibility is presented in conventional terms as well as in relation to DOD's Energy Conservation Investment Program (ECIP). Less comprehensive analyses are also included for alternative energy supply systems including solar, coal, and geothermal electric.

The report includes an assessment of present and projected energy use and distribution systems, an analysis of available geologic and reservoir data, an examination of drilling options and costs, a discussion of alternative energy systems development including economic evaluations, an identification of regulatory concerns, conclusions and recommendations.

In view of the considerable sums of public funds implicit in developing extensive alternate energy systems at the base and the important policy decisions involved, caution has been taken to use conservative assumptions and cost projections in the calculation of economic benefits. In calculating benefits according to the ECIP format, for example, we have assumed only an 8 percent annual real price increase for purchased electricity at the base. We also neglected recurring material and labor benefit differentials, electricity demand charge reductions, and potential fuel displacement in a hospital auxiliary boiler. Included in project costs were a 25 percent project contingency and a 6 percent A&E contingency.

The total energy cost for Williams AFB in 1978 was $1.8 million, with the nonhousing cost being $1.3 million. Electricity consumption accounts for approximately 80 percent of the total base energy cost. The installation's present annual energy requirements are approximately 169,000 million Btu from electricity and 161,000 million Btu from natural gas. Most of the purchased electrical power is used to supply space cooling. The central base area, including the flight simulator buildings, hospital, BX, commissary, BOQ and BEQ, community activities area, and offices comprise about 850,000 square ft of conditioned space within a half square mile area. The total installed load in the central base area approximates a 4,300 ton cooling and 86.5 million Btu/hr heating requirement. A 16 percent rise in electric power rates will cause a price increase from $470,172 in 1978, to $545,000 in 1979 for the cooling energy bill for the central area. During the cooling season, peak demands escalate the rate at which electric power is purchased. Coupled with the projected population growth of the Phoenix area (85% to 1985), the efficient use of electric power is a prime concern. A geothermal resource that could provide space cooling and heating could greatly reduce the base's total purchased energy and ensure lower electric power rates by reducing peak demand.

The base is situated in the southwestern half of the Higley basin. Gravity data for the area suggests a depth of 16,000 ft to the Precambrian basement. The stratigraphic sequence consists of an upper sedimentary section and a lower pre-basin volcanic section. Geothermal Kinetics, Inc. (GKI) has drilled two wells one-half mile southwest of the base, the deepest being 10,454 ft. Temperature data indicate that temperatures in excess of 100°C (212°F) can be expected below 7,000 ft and that temperatures in excess of 150°C (302°F) can be expected below 9,000 ft. Temperatures approaching 200°C (392°F) might be expected at depths of 10,000 to 11,000 ft. Recoverable water has been estimated at 29 million acre-feet in the upper basin fill and 900,000 acre-feet in the volcanic sequence. Due to this volcanic sequence, fluid withdrawal from the deep aquifer system could be achieved without accompanying ground surface subsidence. The potable water supply can be adequately protected by casing the production well(s) and injecting the fluid well below the near-surface aquifer system.

Drilling costs have been estimated for a new 10,000 ft production well (WP-1 or WP-2 on Plate 1) on base property. Ideally, the well should be located as near as possible to the cooling system loop in order to minimize fluid distribution line costs. Production well costs would total $1.933 million, exclusive of contingency. Provided the geothermal reservoir can be proven, one well should suffice for production of the required 900 gpm flow rate (assuming 350°F) with the existing energy supply system available for backup. An injection well (WR-1), drilled to approximately 5,000 ft, would cost about $758,000. An alternative resource development option would be to use the existing GKI wells (see Plate 1), assuming negotiations could be completed with private parties. Well purchase and refurbishing costs, including sidetracking the original wellbore by directional drilling, would approximate $2.670 million.

The district cooling system is based on centralized lithium-bromide absorption water chillers, located within a perimeter loop, which circulate chilled water through existing coils located in the buildings of the central area. Six chillers and cooling towers would supply the required 4,300 tons. Accrued energy savings with this system would be about 168,000 million Btu (pre-generation), or 49,000 million Btu (purchased electricity). This basic distribution system would be the same whether fluid production was from the WP or GKI wells. In either case, injection is assumed to be possible within one-half mile of the perimeter loop.

A heat pump system, based on providing geothermal fluid from an intermediate depth ($\sim$ 5000 ft) well, was evaluated and determined to be noncompetitive with the deep well options.

Total project costs would be $7.828 million for the most promising case based on a production well near the perimeter loop. (Excluded are costs for preliminary and final system design.) In the ECIP feasibility analysis, the benefit/cost ratio is 1.39, and the energy-to-cost ratio is 23.17. The payback period for the system is about 11 years. A conventional economic analysis, based on a 10-year amortization schedule, is also provided, showing total project benefits of $30.8 million over a 25-year project life. The development predicated on the GKI wells is less favorable (B/C = 1.15 and E/C = 19.1) because of the higher well and piping costs (estimated total capital of $9.484 million) and somewhat higher electrical pumping requirements. In this case, we have also neglected royalty payments which might be 10 percent, based on a Btu equivalency with alternate fuels.

At the present time, the solar system option for providing the hot water does not look competitive. Requiring a collector area not less than 25 acres, the capital, contingency, and operating costs (based on a similar conventional 10-year, amortization schedule) are such that project savings at the end of 25 years is still \$7 million less than project costs.

An interesting alternative is the possibility of geothermal electric development at the base, probably based on a binary power cycle, provided a resource between 350 and 400°F can be obtained. Firm decisions regarding geothermal system selection, however, can be made when final resource temperatures are determined. Project costs scaled down from a 50-MWe plant to a 9-MWe power plant for the base electric demand suggest an \$18.4 million project, including design and project contingency. Using the ECIP format, the benefit/cost ratio is about 1.70 and the energy/cost ratio is 26.01.

The total geothermal development option is, of course, highly dependent on the temperature and volume of fluids accessed by the drill holes. Existing data are sufficiently interesting, however, that project development at Williams Air Force Base should be pursued further, at least through the drilling phase. The project shows favorable ECIP energy/cost and benefit/cost ratios required for Defense Department funding. Life-cycle energy cost savings could be achieved in two, and perhaps three, of the options discussed in this report. If the project was a commercial, private venture, the previous statement would have to be balanced against a considerably longer payback period than the 5-year or so nominal payback expected in the private industrial sector. In addition to achieving significant life-cycle energy savings and decreased consumption of conventional fuels at a major defense installation, the project, if successful, would provide an important stimulus to private geothermal exploration and development throughout the rapidly growing southern Arizona metropolitan areas.

INTRODUCTION

The purpose of this report is to assess the feasibility of using the geothermal energy source thought to be present at Williams Air Force Base, Arizona. The energy source would be used with existing technology to meet cooling and, possibly, heating requirements for major existing and proposed buildings in the central base area.

The possibility of replacing conventional cooling systems with geothermal resource systems is particularly attractive for Williams Air Force Base due to a combination of the steadily increasing electrical utility rates, the replacement of many separate energy-inefficient buildings with consolidated complexes, and an emphasis on using simulator facilities for pilot training.

Williams Air Force Base is located in south-central Arizona, nine miles east of Chandler and approximately 35 miles southeast of Phoenix. The base is the largest undergraduate pilot training base in the Air Force Air Training Command, providing flying training both in the T-37 and the T-38 jet aircraft. The configuration of facilities on the base is very similar to that of light industrial parks which are commonly found throughout the United States and in the Phoenix area. The principal high-investment facilities on base are community support buildings (hospital, service clubs, base exchange/commissary complex), bachelor housing units, and simulator/training facilities. The base has a daytime population of 10,300.

The climate is a desert type, with low annual rainfall and low relative humidity. Daytime temperatures are high throughout the summer months, while winters are mild. The average daytime relative humidity is about 30 percent, and the valley floor, in general, is rather free of wind. The period of sunshine averages 86 percent annually, ranging from a minimum monthly average of 77 percent in January and December to a maximum of 94 percent in June. A six-year annual average of cooling-degree days is approximately 3,950, while the average of heating-degree days is 1,350 for the same six-year period.

Williams AFB is directly located within an active geothermal resource area (both low and high temperature), and any application of geothermal resources would demonstrate the potential for the use of similar systems in the Phoenix area. There are over 1,020,000 people in the Phoenix urban area northwest of Williams AFB, and, given the rapidly growing population and industrial activity, the successful demonstration of geothermal energy systems at the base would have an important stimulative effect on the private sector.

I. ENERGY USE AND DISTRIBUTION SYSTEMS AT WILLIAMS AFB

A. Present Energy Use

The primary requirement for energy at Williams AFB comes from heating and cooling. Heating is provided to each facility by natural gas for individual boilers. Cooling is provided to individual facilities or pairs of common facilities, by using electricity to produce and circulate chilled water. Only the hospital has an alternate fuel source, which is natural gas. During infrequent power failures, small local generators provide power to key facilities. No central standby generation station exists. At present, there is no central heating or cooling plant at Williams AFB, although a plant is scheduled for the FY 85 Military Construction Program (MCP). That project, however, could be moved into an earlier year.

The installation's present annual energy requirements are approximately 169,000 million Btu from electricity and 161,000 million Btu from natural gas. The total cost for all facility energy usage is $1.8 million, with the nonhousing energy cost being $1.3 million. Electricity consumption accounts for approximately 80 percent of the total energy cost. Due to the increasing prices for electricity and gas, and due to changing rate schedules, Williams AFB is faced with an escalating cost for heating and cooling buildings. A 16 percent rise in electrical rates will cause a price increase from $470,172 in 1978 to $545,400 in 1979 for the cooling load in the central area, and an approximate 40 percent rise in the unit cost of gas will increase costs by $100,000.

Williams AFB has been reducing energy consumption by eliminating many of the World War II structures on the base. Replacement facilities and future construction of consolidated structures will replace many existing older, separate facilities with one or two structures. These complexes, along with several existing major facilities which are already grouped together, will be more efficient in their use of energy and will also lend themselves to a central heating-cooling system.

The facility replacement program should continue to ensure that the base's overall energy consumption remains at least constant. Based on current and predicted future tight supplies of natural gas and electricity, energy supplies should be presumed to be finite. Although the Williams AFB electrical distribution system has sufficient capacity to handle increased electrical loads, the availability of electricity may be questionable. During the cooling season, peak demands escalate the rate at which electrical power is purchased. Coupled with the Phoenix area's population growth (base year 1970) of 45 percent to 1978 and a projected growth of 85 percent to 1985, the efficient use of electrical power is a prime concern. A geothermal resource that provides space heating and cooling could both greatly reduce the base's total purchased energy and ensure lower electrical rates by reducing the base's peak energy demand.

B. Present Systems

As shown in Figure 1, the base is effectively divided into three areas: housing and recreation, central base activities, and flightline-support/runway. Of prime interest to this study is the high energy load of the central base area, shown in Figure 2, which consists of: 1) bachelor officer quarters (BOQ), 2) bachelor enlisted quarters (BEQ), 3) flight training-simulators, 4) hospital, 5) base exchange-commissary complex, 6) community activities area, and 7) administrative-support facilities. As noted from the map, most facilities are grouped together into specific use areas, with the flightline-support facilities acting as the boundary between aircraft operations and the rest of the base.

The main use of energy within the central base area is space conditioning. Flight training-simulator facilities require additional cooling for equipment, while the flightline-support facilities use steam heating for light industrial applications similar to offbase industrial parks.

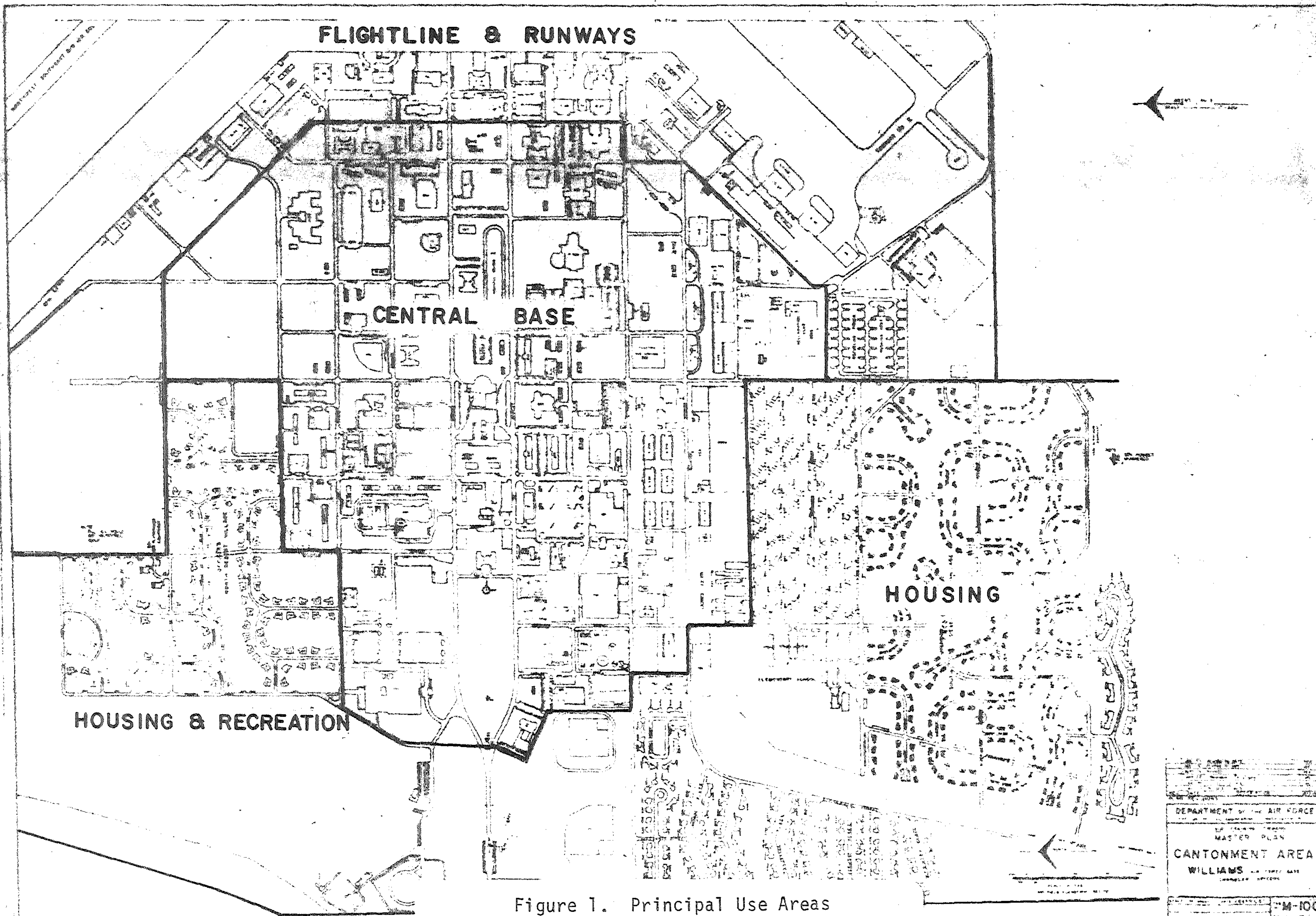
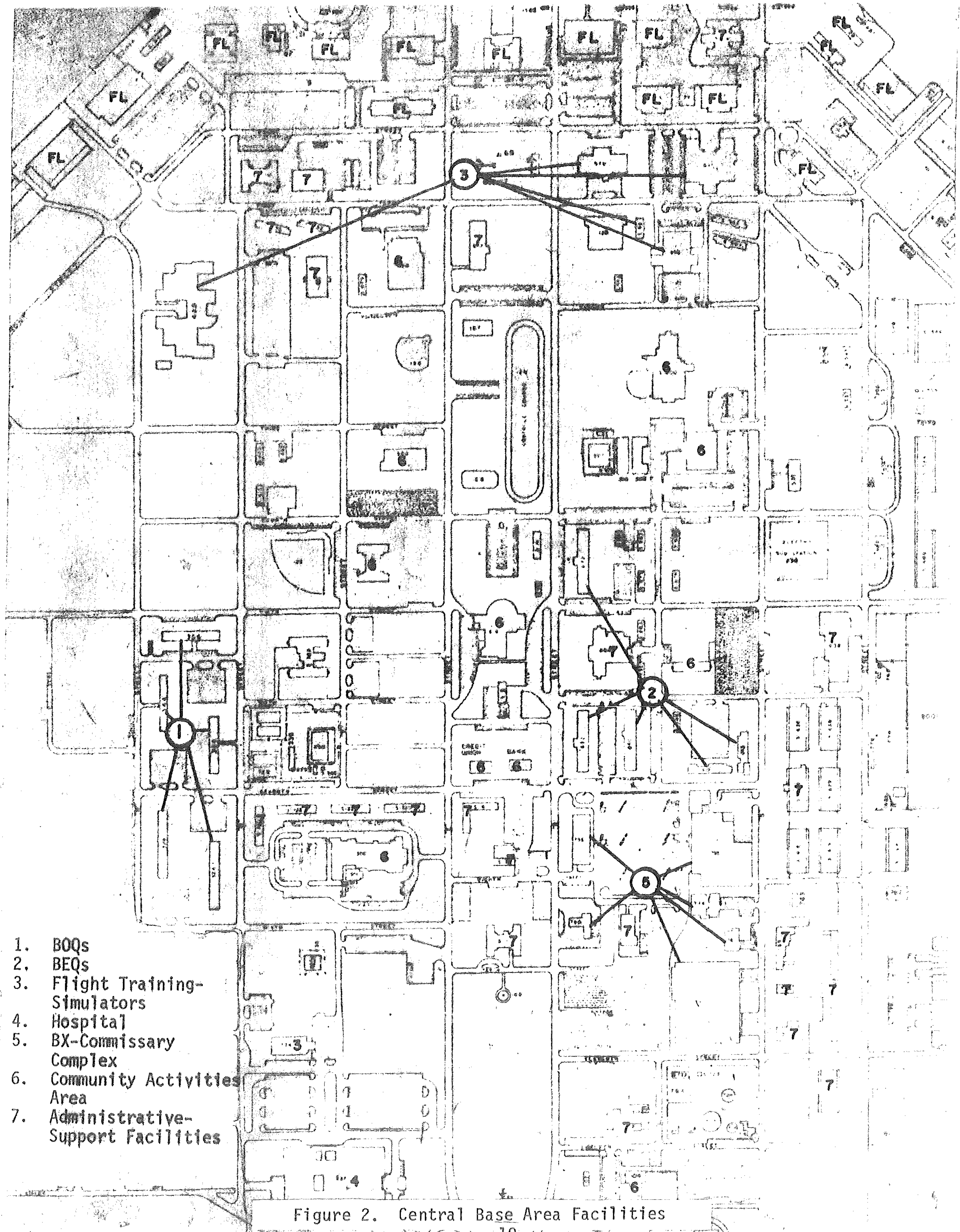


Figure 1. Principal Use Areas



1. BOQs
2. BEQs
3. Flight Training-Simulators
4. Hospital
5. BX-Commissary Complex
6. Community Activities Area
7. Administrative-Support Facilities

Figure 2. Central Base Area Facilities

The present cooling load for major groupings of buildings is:

		Total
1.	BOQ area (5 buildings)	155 tons
2.	BEQ area (5 buildings)	275 tons
3.	Flight training-simulators (6 buildings)	1,150 tons (1,438 tons max)
4.	Hospital (1 building)	430 tons
5.	BX-commissary complex	594 tons

The community activities areas and administrative-support facilities are scheduled for replacement by MCP projects. When the new consolidated complexes are constructed in the east and southeast portions of the central base area, the major facilities on the base will form a U-shaped loop extending from the main gate on the west to the flightline on the east.

II. HYDROTHERMAL RESERVOIR ASSESSMENT

A. General Geology

Williams Air Force Base is located in the southeastern portion of Maricopa County, Arizona, just east of the town of Higley and approximately thirty miles southeast of Phoenix. The base is situated in the southwestern half of the Higley basin (Scarborough and Peirce, 1978), a small northwest trending basin approximately thirty miles long and fifteen miles wide. The Higley basin is a part of the Basin and Range physiographic province of southwestern Arizona. The basin is bounded on the north by the Usery and Goldfield mountains; on the south by the Santan mountains; on the east by the Superstition mountains; and on the west by the South mountains. A study of the Bouguer gravity data for the area (Peterson, 1968) indicates that it could be as much as sixteen thousand feet to the Precambrian basement beneath the base.

The stratigraphic sequence beneath the present valley surface is divided into two parts: an upper sedimentary, or basin-fill section and a lower pre-basin volcanic section (see Figure 3). The sediments of the upper section, late Cenozoic in age, consist of coarse clastics nearer the basin margins derived for the most part from the surrounding mountains. Nearer the basin center lower energy deposits, including evaporites, prevail. A portion of Cooley's map (1973) showing the distribution and estimated thickness of the alluvial deposits in the Phoenix area is reproduced as part of Plate 1 of this report. Stratigraphic logs of the Geothermal Kinetics wells (Plate 1 and Figure 4), drilled a few thousand feet south of the air base, show an excess of 6,600 ft of basin-fill sediments overlying what is believed to be the top of a volcanic sequence correlative with the Superstition volcanic complex exposed in nearby ranges (Stuckless and Sheridan, 1971). In outcrop the Superstition volcanic complex has been dated as ranging between 15 and 29 million years in age (Sheridan, 1978). The volcanic rocks have been relatively down-dropped several thousands of feet by the late Cenozoic Basin and Range disturbance. It was this event that created the Higley basin, which became filled with basin-fill sediments.

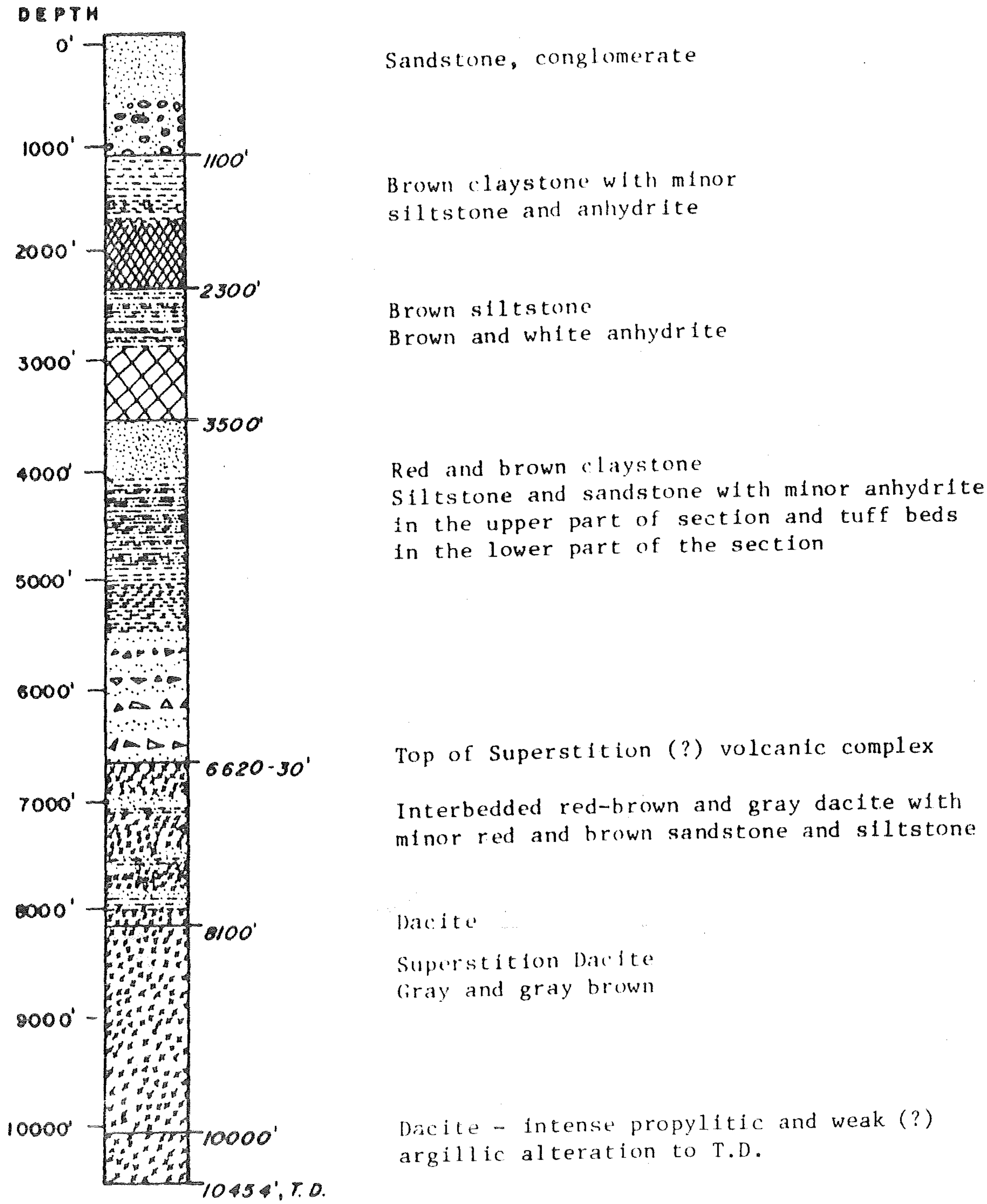


Figure 3. Generalized Stratigraphic Log: Williams AFB, Maricopa County, Arizona

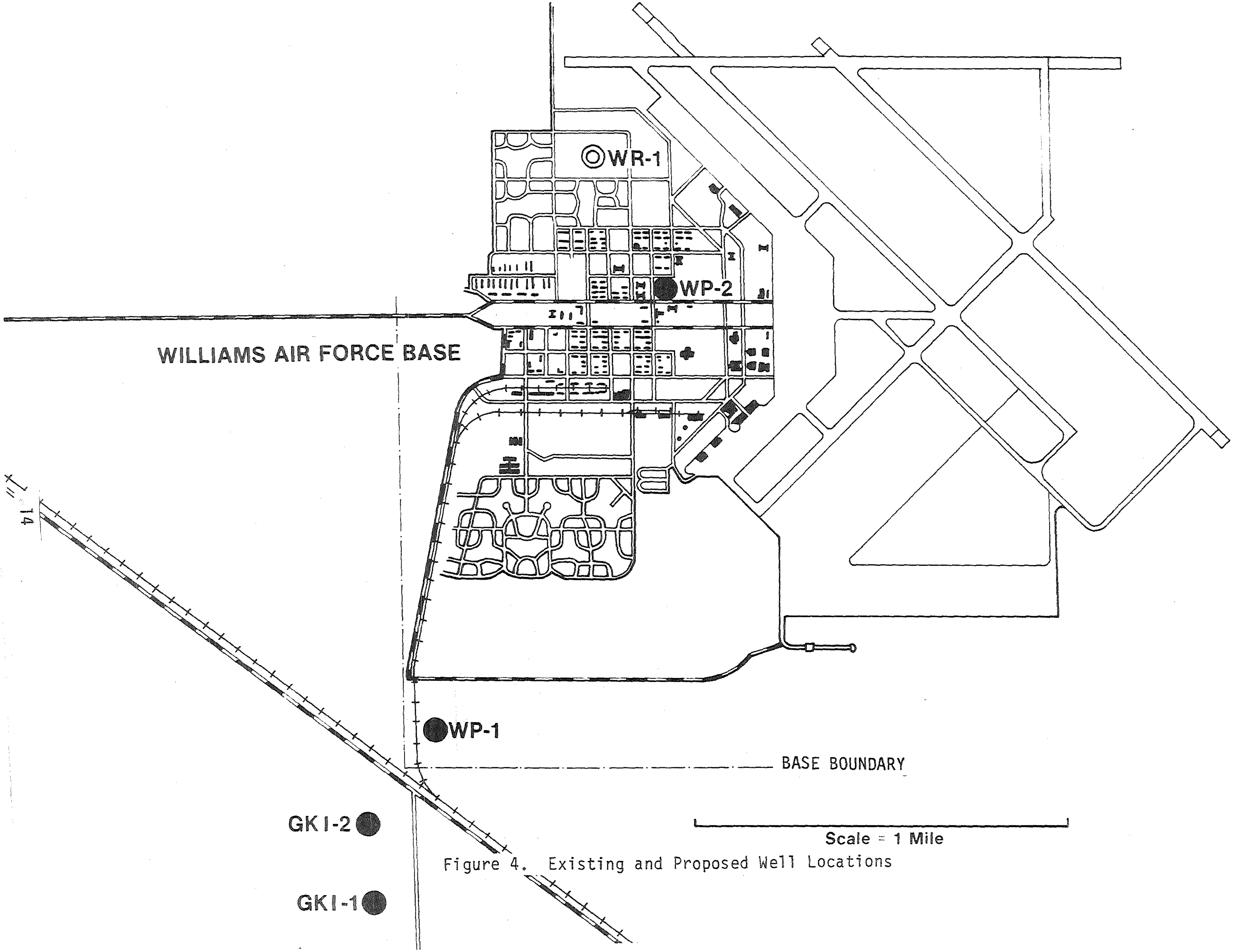


Figure 4. Existing and Proposed Well Locations

At the top of the Superstition volcanic complex, from 6,620 to 6,630 ft, is a 10-foot thick section of gray dacite. From 6,620 to approximately 8,100 ft, the lithology is primarily gray dacite interbedded with minor red, brown, and gray sandstone, siltstone and shale. The possibility of contamination of the dacite drill cuttings by cuttings from the overlying basin-fill sedimentary section cannot be ruled out. From 8,100 to 10,454 ft, the bottom of the deepest hole, Power Ranch No. 2, the lithology is all dacite. The log of Power Ranch No. 2 shows a unit of conglomerate and sandstone from 10,050 to 10,440 ft. An examination of the cuttings revealed only altered dacite, intense propylitic and weak to possibly strong argillic alteration, with some silicification. Confirmation of the conglomerate and sandstone, therefore, was not possible. It is thought that the base of this massive dacite sheet was not encountered in either drill hole.

Osterkamp (1973), on a map showing the depth to water in wells in the Phoenix area, indicates the water level to be between 300 and 400 ft in the area of Williams Air Force Base. A portion of Osterkamp's map is reproduced as part of Plate 1. Information obtained from the Civil Engineering Squadron at the base shows static water levels of 328 ft, 398 ft, and 411 ft for wells that are currently being pumped. Well No. 1, which has been abandoned, has a standing water level of approximately 212 ft. The water level in this abandoned well probably reflects a perched water table overlying the main zone of groundwater. Temperature gradient logging was done in this well to a depth of 328 ft. From a depth of approximately 164 ft, the well was isothermal, with a temperature of approximately 25°C (77°F).

There is promising potential for developing geothermal energy at Williams Air Force Base. Geothermal Kinetics, Inc., has drilled two wells just south of the base, the deepest being 10,454 ft. Temperature data furnished by GKI indicate that temperatures in excess of 100°C (212°F) can be expected below depths of 7,000 ft and that temperatures in excess of 150°C (302°F) may be expected below 9,000 ft. In fact. temperatures approaching 200°C (392°F) might well be expected at depths of 10,000 to 11,000 ft. Whether the required volume of fluids also exists, however, can only be determined by deep drilling. If present, the geothermal reservoir most likely will be in the dacitic volcanic rock. The geothermal resource will be superheated water largely from fracture and possible porous pryoclastic zones in the dacite. This type of fracture-controlled production is similar in some respects to other geothermal fields in the United States: The Geysers in California, Valles Caldera in New Mexico, and Roosevelt in Utah.

B. Reservoir Estimate

Williams Air Force Base lies within the eastern part of the Salt River Valley groundwater basin. Although this valley is now drained to the ocean by the Salt River, for most of its history the basin has had closed, internal drainage. For the purpose of this estimate, the reservoir area for the Air Force Base has been set at a 5-mile radius centered on the base.

The GKI wells, 1,320 ft apart, passing through the full thickness of basin-filling sediments into a volcanic sequence are found within this 5-mile radius. These wells have been assumed to represent the stratigraphic conditions beneath the base. The average thickness of the sedimentary sequence was 6,800 ft, and about 3,600 ft of underlying volcanics was penetrated. During the drilling of both wells, no pre-volcanic rocks were encountered. The mean porosity and specific yield were computed by inspection of the well logs. For the basin fill, the mean porosity was about 20 percent, and specific yield was 10 percent. For the volcanic sequence, the mean porosity was 5 percent, and the specific yield was estimated as 0.5 percent. The water in the uppermost 1,000 ft of the basin fill is now used as agricultural, municipal, and military water supply in the basin.

The total water in storage within the 5-mile radius amounts to 58 million acre-feet in the basin fill, and 9 million acre-feet in the volcanic sequence, as shown in Table I. The upper 1,000 ft of the basin fill has been excluded. Recoverable water amounts to 29 million acre-feet in the upper basin fill and 900,000 acre-feet in the volcanic sequence.

Table I

Reservoir Estimate

Sediment Type	Thickness	Area	Porosity	Specific Yield
Basin fill	6,800 ft	78.5 mi.^{2}	20%	10%
Volcanics	3,600 ft	78.5 mi^2	5%	0.5%

Volume of basin fill	340 million acre-feet
Volume of volcanics	180 million acre-feet
Water in storage in basin fill	58 million acre-feet
Water in storage in volcanics	9 million acre-feet
Fresh water in upper 1,000 ft.	5 million acre-feet
Recoverable water in basin fill (net)	29 million acre-feet
Recoverable water in volcanics	0.9 million acre-feet

Except for water in the upper 1,000 ft of sediments in the basin, almost all groundwater may be expected to occur under confined (artesian) conditions. Withdrawal of large volumes of geothermal water from these aquifers may present the same problems as withdrawal of fresh water under similar conditions. Subsidence resulting from groundwater pumping has been well-documented in many parts of the southwest and is linked to withdrawal of water from fine-grained, nonindurated sediments. However, the volcanic sequence from which hydrothermal resource production would occur would not be susceptible to subsidence. Geothermal resource development must ensure the protection of high quality water in the upper aquifers from lower quality water produced from deeper sources. The potable water supply can be adequately protected using reasonable care and currently available technology.

III. RESOURCE DEVELOPMENT OPTIONS

The well development options discussed below are based on the geologic and hydrologic information presented in the preceding chapter, as well as on information obtained from the existing wells drilled by GKI.

A. Drilling New Production Well

In Section V, which discusses project costs and payback, the analyses are premised on the economic advantages of drilling a new production well (WP-1 or -2 on Plate 1) to near the 10,000 ft depth and hopefully obtaining a geothermal resource near 300°F. Ideally, the well should be located as near as possible to the cooling system loop, as with site WP-2, in order to minimize additional fluid distribution line costs. Figure 5 presents a cross section of this new production well.

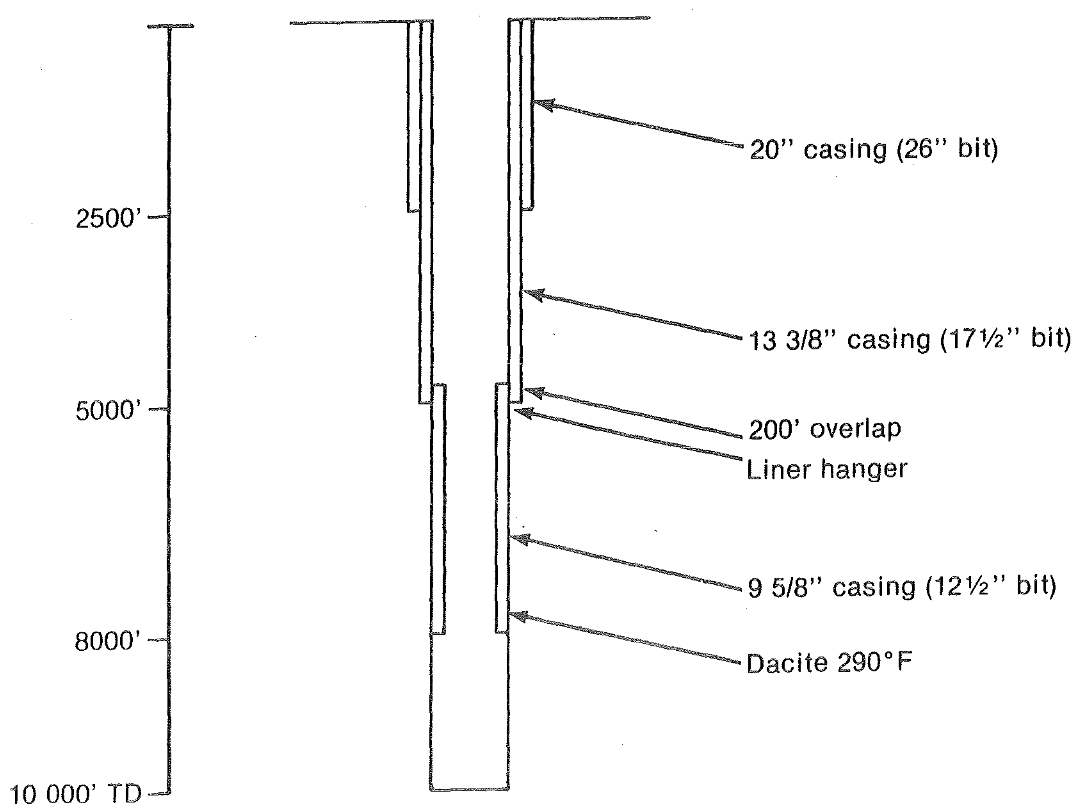


Figure 5. Cross Section of New Well

The well, whether WP-1 or -2, is designed as a vertical completed well, similar to the existing GKI wells. It would be cased to 8,000 ft to seal out cooler fluids. We would recommend drilling with mud to 8,000 ft and then using water as a drilling fluid through the open-hole production interval, to reduce wellbore damage. Water drilling has become a good geothermal drilling practice because of the unstable mud conditions created by high temperatures. If hole cleaning becomes a problem, then occasional high viscosity mud "pills" can be pumped down to clean the wellbore.

Costs associated with drilling a new 10,000 ft production well are presented in Table II.

Table II

Production Well Drilling Costs ($1,000)

Site Preparation			$ 27
Rig Mob-Demob			450
$7K/day for 60 days			420
Casing	20 in	$55/ft; 2,500 ft	137
	13-3/8 in	$25/ft; 5,000 ft	125
	9-5/8 in	$23/ft; 8,000 ft (3,200 ft)	74
Casing Hardware			10
Liner Hanger			15
Wellhead			75
Mud Logger			50
Mud to 8,000 ft			100
Welding			5
Shocks & Sub-Jars			15
Casing Crews			15
Stabilizers			20
Cement			150
Bits			130
Logs			70
Coring	(3)	Two in dacite, one bottom hole	15
Testing			30
		Total	$1,933

B. Reworking Existing GKI Wells

In considering the costs of reworking the existing GKI wells and, in Section V, estimating the life-cycle economics of using those wells, we emphasize that we have not fully inquired into the business or legal problems of acquiring those wells for use by the Air Force. Their availability is simply a working assumption which enables us to make cost and economic comparisons with alternative resource development options.

Figure 6 represents the existing GKI wells and the directional drilling technique to sidetrack the original wellbore. We suspect that damage to the original wellbore through the production zone has been so severe that cleanout methods would be very costly and probably ineffective. This proposed sidetrack method would use the existing wellbore to about 6,000 ft. The kickoff would be made in the 9-5/8-inch casing at that point.

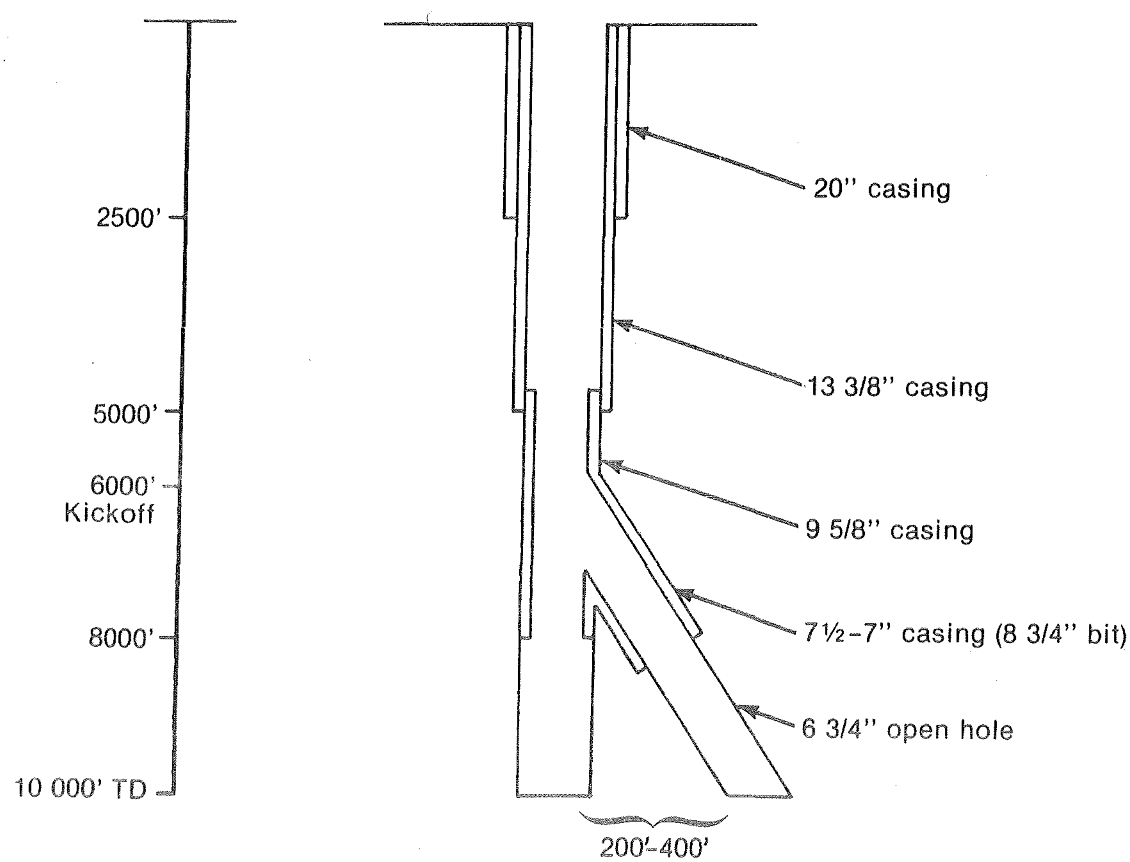


Figure 6. Cross Section of Directional Drilling in GKI Well

Directional drilling would commence, using a 2 to 6° buildup angle to 8,000 ft where temperatures would approach 290°F. The casing would be 7 to 7-1/2-inch liner, hung inside the 9-5/8-inch casing. Directional drilling would continue with a 6-3/4-inch bit to a total depth of 10,000 ft. The 7 to 7-1/2-inch OD casing should allow for the required production of 900 gpm. This technique would create a separation of 200 to 400 ft between the old and new wellbores, which places the new wellbore well away from the mud-damaged area of the old wellbore.

The same sidetracking method could be applied in the lower portion of the 13-3/8-inch casing (∿ 4,000 ft) to increase hole sizes for greater production capacity. This shallower sidetrack would also increase the well cost by ∿ $100,000.

The directional drilling technique described has been used for many years in oil well drilling, primarily to drill around tools and other "fish" obstructing the hole. New technology has expanded the use of directional drilling. At The Geysers in California directional drilling techniques are used to drill multiple holes from one platform. Multiple legs sidetracked from a single wellbore have been used as a stimulation method to enhance production in the Raft River, Idaho geothermal wells.

Assuming a purchase price for the wells at $1.4 million, costs associated with this development option are found in Table III.

Table III

Estimated Costs to Recondition Existing Wells ($1,000)

Logs	$ 15
Directional Drilling	25
Bits	18
Casing - 7 inch; 2,000 ft; $15/ft	30
Cement	50
Rig (10,000 ft cap.); 20 days; $7,000/day	140
Mob - Demob	350
Drilling Supervision	7
	635
Drilling Costs (2 x 635)	1,270
Assumed Purchase Price	1,400
TOTAL	$2,670

C. Injection Well

In addition to the production well costs, an injection well will be necessary to dispose of the geothermal fluids after heat extraction. The injection well design, shown in Figure 7, has casing to shallower depths than the production well. An injection depth of at least 3,700 ft would be required to eliminate contamination of the groundwater aquifers and reach a zone where formations would be permeable enough to accept the fluid. This well design could also be used for shallow production wells; however, existing data indicate temperatures less than 150°F at this intermediate depth.

Costs associated with the injection well are found in Table IV.

Table IV
Injection Well Drilling Costs ($1,000)

Site Preparation			$ 20
Casing	13-5/8 inch;	1500 ft	30
	9-5/8 inch;	3700 ft	63
Cement	13-5/8 inch		13
	9-5/8 inch		17
Casing Hardware			7
Wellhead			50
Rig	$5K/day	35 days	175
Mob-Demob			200
Drilling Supervision			13
Mud			35
Shock Sub-Jars			5
Casing Crews			10
Stabilization			10
Bits			50
Logs			35
Coring (1)			5
Testing			20
		Total	$758

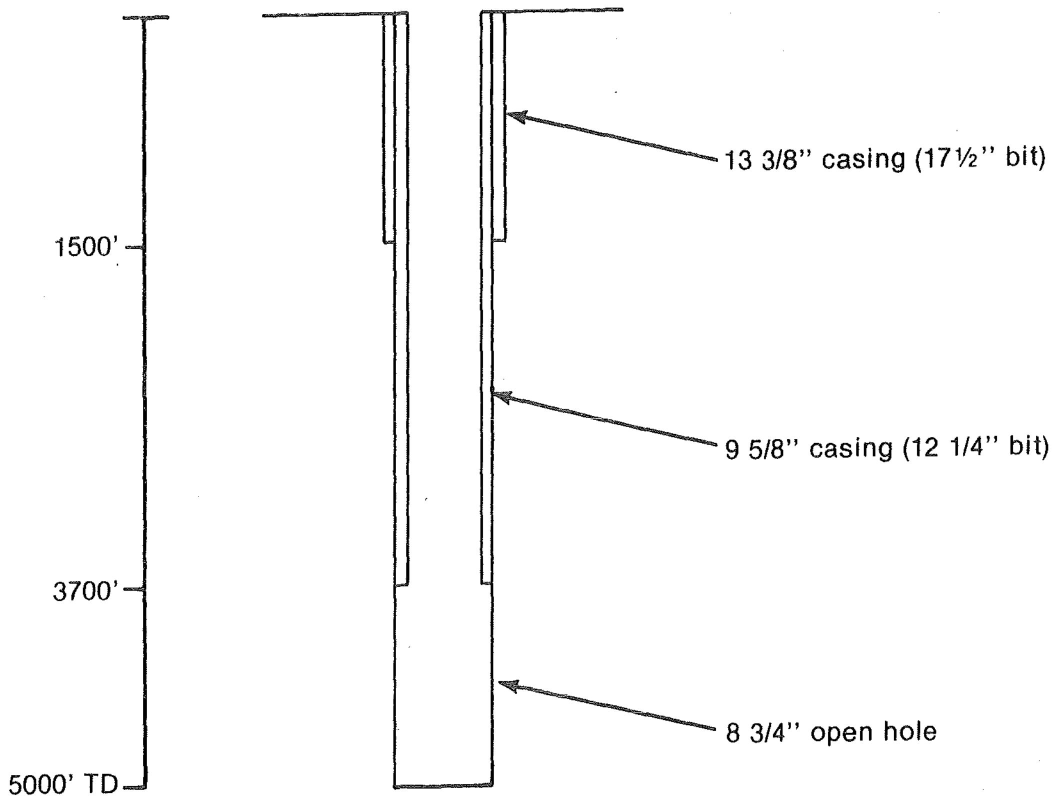


Figure 7. Cross Section of Injection Well

IV. ALTERNATIVE GEOTHERMAL SYSTEMS DEVELOPMENT AND COSTS

The base cooling load represents a primary consumption of energy presently supplied by expensive electricity. Several alternative energy sources are abundant in the area and would be available for long-range planning. Coal, solar, and geothermal resources are all viable alternatives that could supplant a large fraction of present energy use. All of these sources are conventionally used for either direct or steam-generated firing of absorption cooling systems.

A. Space Cooling Load and Distribution System

Most of the purchased electrical power is used to supply space cooling requirements. This systems analysis is based on using a centralized cooling system to supply the base's requirements. We excluded from consideration the housing areas to the north, west, and south, owing to the high initial capital cost of distribution piping relative to the low benefits of replacing a small percentage of the total cooling load. The central base area, including support buildings, hospital, commissary, BX, maintenance facilities, offices, etc., total approximately 850,000 square feet of conditioned space within a half square mile area. All existing buildings with a cooling system larger than 5 tons were considered for connection to the centralized space cooling district. The total installed load was determined to be 4,300 tons cooling and 86.5 million Btu/hr heating within the central base area.

All of the air conditioning load is met by electrically driven compression expansion units, except for one small gas-fired steam absorption chiller system in the hospital complex. Of the electrically driven units, nearly 90 percent are of the water-chiller type, with the remaining units of the direct expansion air type. Therefore, the most readily adaptable centralized space conditioning system would be of the water-chiller type to match existing equipment, with modification of the few direct expansion units to utilize chilled water. Existing building air conditioning systems will remain intact, and presently assigned maintenance personnel will remain to maintain the existing systems and operate the new centralized system. Retaining the existing system will provide backup capability and "topping off", if required, during extreme temperature days.

Many possibilities exist for the layout of piping, and one such example is shown in Figure 8. Final design of the layout would optimize piping length and configuration. As noted in Figure 9, a centralized absorption water chiller is located within a perimeter loop circulating chilled water to provide air conditioning through existing chilled water coils located in the buildings. The absorption chillers are fired with water temperatures up to 300°F, and provide chilled water at 43-45°F temperatures. The chillers are of the lithium-bromide absorption type and will require a source of cooling water provided by cooling towers. Included in the capital cost calculations is a total of six absorption chillers and cooling towers. The currently installed capacity of 4,300 tons, which includes some redundancy, could be supplied by these six units under full load. Under partial load conditions, the number of operating chillers can be reduced to most effectively match required load conditions. Maintenance time and manpower would also be minimized with a centralized system. The absorption chiller sizes selected have a coefficient of performance of approximately 65 percent. Double-staged absorber water chillers are currently on the market, with reported 95 to 99 percent effiencies, and could improve the overall project economics. Sixty-five percent was used in this report, however, to realistically illustrate energy analysis under partial load and to simulate other losses that might be attributed to heat exchanger fouling. The energy savings are shown in Table V.

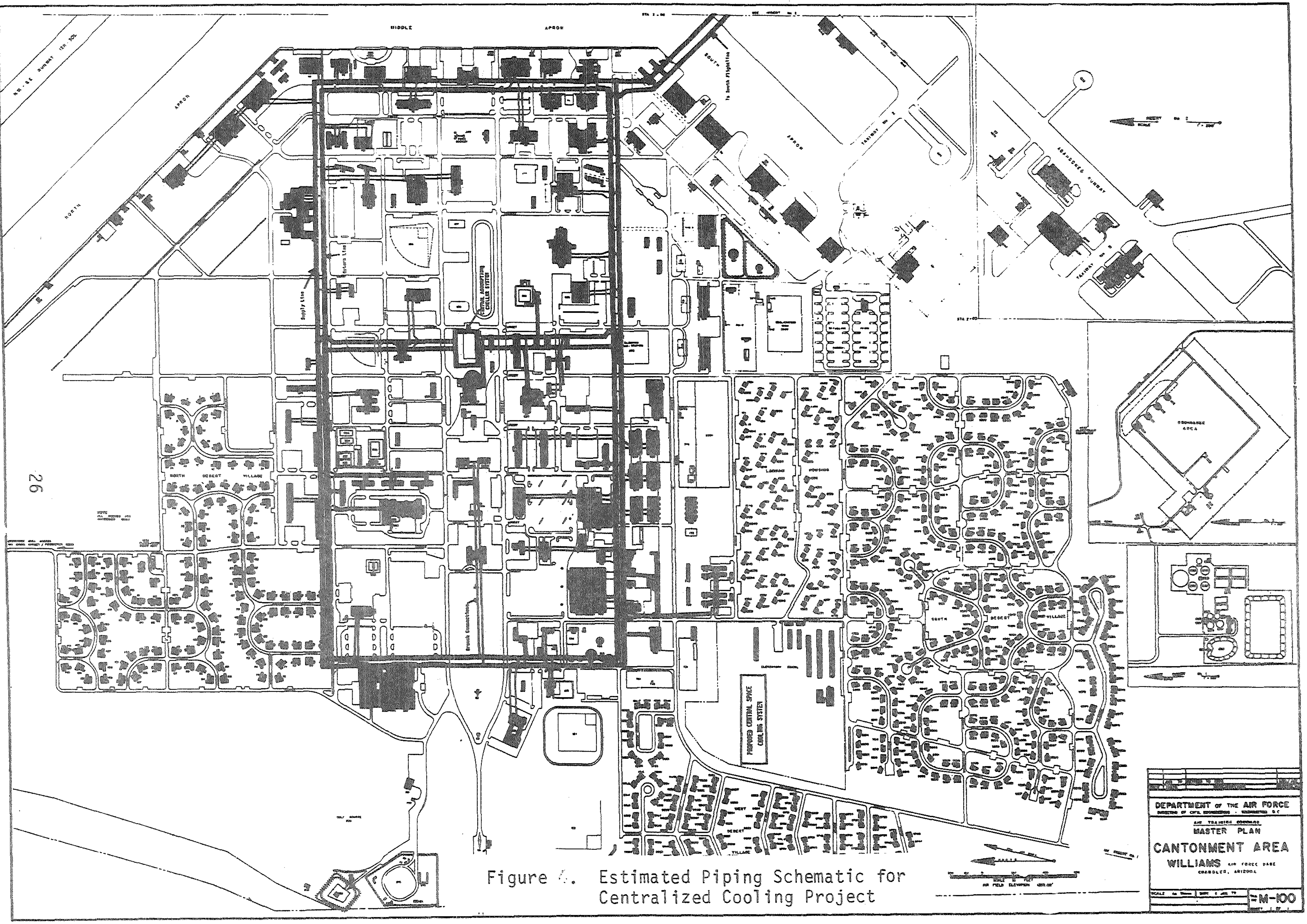


Figure 4. Estimated Piping Schematic for Centralized Cooling Project

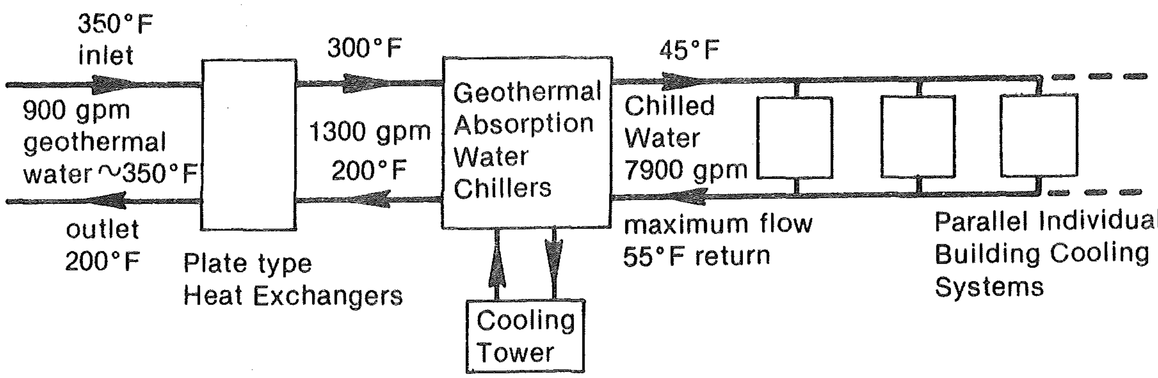


Figure 9. Schematic of Central Cooling System

Table V

Cooling System Requirements
(millions of Btu)

	Pre-Electrical Generation (11,600 Btu/kWhr)	Purchased Electricity (3,414 Btu/kWhr)
Present Cooling System	208,800	61,433
Geothermal District System	40,785	12,000
Savings	168,015	49,433

The energy used in the geothermal system would be electrical energy for circulating chilled water, pumping geothermal fluids, operating cooling tower fans, cooling fan motors, and control function requirements. The present cooling system uses approximately 18 million kW/yr. The cooling system energy costs for 1979 are expected to be $545,500.

The perimeter chilled water circulation loop selected is a two-pipe design, consisting of double-walled cement asbestos insulated pipe. The majority of main piping is 12-inch diameter, allowing a flow of 2,000 gpm with velocities near 5 feet per second. The choice of this size pipe allows for future expansion of the system for increased velocities should the need arise. The majority of branch line connections is sized with 4-inch diameter pipe, with the exception of those buildings with larger energy loads. Large supply lines were also sized to include several buildings in the south flightline area. Return lines would run in the same trench with the supply piping, and are of identical size. The estimated capital cost, installation, and project contingency costs are provided in Section V.

B. Space Cooling from New Production Well

Coal, solar, and geothermal resources could be used to provide hot water for the absorption chillers. Maximum efficiency, though, occurs at the highest allowable inlet temperature, near 300°F. The geothermal potential at Williams, as evidenced by the two GKI wells approximately one-half mile to the southwest, could possibly produce water temperatures of 350°F or higher. The chemical nature of this geothermal resource, with respect to its effect on component materials, is expected to be moderately saline (4,000 to 20,000 ppm). For estimating purposes, a plate-type heat exchanger was selected to isolate any possible harmful effects of the geothermal water from vapor generators in the absorption water chiller units. As noted elsewhere in this report, it is possible that a deep well could be located within a half-mile radius of the central base area. The depth of the new well would be about 10,000 ft, and the estimated cost is shown in Section V. A reinjection well, 5,000 ft, deep, was also assumed to be located within a half-mile radius of the central base. Estimated costs were included for well pumps, circulation pumps, and possible reinjection pumps needed to extract 350°F geothermal fluids, circulate, and reinject 200°F fluid. An alternative use of this still relatively hot water is discussed below. A total of 900 gpm, at a temperature of 350°F, would be needed to displace the present cooling load. Water temperatures much above 350°F may pose well pump problems, which at present are undetermined.

C. District Cooling Option Based on Existing Wells

The possibility exists for the acquisition of the two existing GKI geothermal wells, located on private property one-half mile to the southwest of the base. Section III addressed this option, including estimated costs for well refurbishment and flow enhancement through directional drilling. An obvious advantage is apparent with two separate wells, each of which can supply total flow requirements while one serves as backup. Higher initial capital costs will be incurred due to additional required supply piping, circulation pumps, well pumps, and interconnecting well piping. These costs are tabulated in Section V. The basic centralized cooling system remains identical, irrespective of well placement.

D. Heat Pump Application

Another option exists to utilize lower-temperature geothermal resources from some intermediate-depth well (perhaps 5,000 ft) to supply the cooling requirements. For this option, a centralized heat pump could be employed, using 140°F water, which could be boosted to 230°F. This output water could then be used to drive the absorption water chillers, although at a somewhat lower efficiency than with 300°F water.

A heat pump operating on 140°F supply water has an overall coefficient of performance of 3.5. (Discounting the electricity needed for pumping supply water, every electrical energy unit supplied yields 3.5 equivalent heat energy units.) The hot water (230°F) thus generated could be used as supply water for absorption water chillers, whose efficiency is 55 percent or less, due to the lower-temperature water. An overall system performance becomes:

$$\begin{aligned}\text{overall efficiency} &= \text{heat pump coefficient of performance} \times \text{absorption chiller efficiency}\\ &= 3.5 \times 0.55\\ &= 1.93\end{aligned}$$

Thus, the overall performance is higher than the required electrical input. Typically, a coefficient of performance for conventional electrical compression/expansion water chillers is usually around 4. With an overall efficiency of 1.93, therefore, the replacement of existing equipment with a centralized heat pump would actually consume more electricity than is presently used. Other design possibilities do exist. For example, a hot water circulation loop at 150°F could provide each building with the water and temperature needed to drive water/air heat pumps. In comparison, the considerable expense in retrofitting costs will make this system uneconomical and removes the backup capability now provided by the existing equipment. In the system economics analysis which follows, therefore, we have not considered this option as competitive with the two deep well options.

E. Corollary Heating System Development

Space heating on the base accounts for nearly one-quarter of the annual energy usage and is presently accomplished by hot water heated by natural gas. Terminal reheat system humidity control accounts for nearly 60 percent of the remaining non-heat natural gas usage for the central base area. These systems could be converted relatively easily to geothermal use without major retrofitting costs. The heating and humidity control system annually consumes about 115 billion Btu, at a 1978 cost of \$218,500, and is expected to increase to \$299,000 for 1979. These heating systems have a low annual utilization factor, with the exception of the hospital complex which employs terminal reheat for humidity control. The hospital's installed capacity accounts for about 40 percent of the large heating systems installed.

Geothermal water could replace the bulk of the heat currently produced by fossil fuel. A second perimeter loop, two-pipe system would need to be installed. Smaller 10-inch supply and return lines could be used for an assumed 35°F temperature differential across heating system exchangers. The hospital complex would need a slightly larger supply and return system. An estimated project cost of \$1.4 million, including contingencies, would be needed for the supply, return, and branch piping, miscellaneous valving, and heat exchangers. This does not include any retrofitting cost. This cost would be contingent upon the installation of the piping within the same trenching as the cooling system. This heating system, if provided by geothermal water, could result in an annual \$299,000 natural gas cost savings, which needs to be weighed against an increase in electrical energy for circulation pumps.

The presently assumed geothermal flow rate to meet cooling demands is 900 gpm. The exit temperature from the cooling system is 200°F, and could be applied via a heat exchanger to the centralized heating perimeter loop. The maximum fraction of heat available, owing to reduced temperature, is 22.5 million Btu/hr, adequate only for a small part of the total heating load, yet large enough to provide heat for the hospital complex. A capital cost of \$550,000, including retrofitting, would be needed for piping and installation for only the hospital complex. The annual natural gas cost savings would be nearly $45,500, and, again, needs to be weighed against increased electrical energy for circulation pumps. This and possibly other alternatives for heating may be considered during the preliminary design phase of project implementation when well temperatures are better defined.

F. Alternative Development Options

1. Solar

Solar-produced hot water could provide alternatives to the present electrically driven cooling equipment. The solar option, at first glance, might seem especially suitable to the sunny southern Arizona area. An 86 percent annual average of sunshine is available, with a high of 94 percent in June. ASHRAE[1] data was analyzed for incident solar radiation at 32° N latitude, assuming a north-south axis tracking concentrating collector, with a tilt angle fixed at 40°. The minimum insolation daily total thus calculated was 1,360 Btu/ft^2 during June and July. A further assumption was made that the cooling system, requiring 65 million Btu/hr, operates a total of 14 hr/day. No extended storage capability was included in the capital cost estimate. Calculations thus assume a storage capable of handling the daily peak load, with no carryover from day-to-day. However, using an 86 percent sun factor for calculating available energy results in a collector area that will have a higher peak output in totally clear weather days that can carry over through part of the next day. Smaller daily cooling loads will also result in carryover. Additionally, winter output should result in carryover, due to the availability of sunlight combined with reduced loads. Cloudy weather will, of course, result in greatly reduced output.

For the solar development option, the collector area and cost are calculated as follow:

---

[1] American Society of Heating Refrigeration and Air Conditioning Engineers. Handbook of Fundamentals, 1972, p. 389.

$$\text{Total Daily Heat Demand} = 65\ \frac{\text{MBtu}}{\text{hr}}\ (14\ \text{hrs}) = 910\ \text{MBtu}$$

$$\text{Available Collector Energy} = 1360\ \frac{\text{Btu}}{\text{ft}^2}\ (86\%\ \text{sun})\ (70\%\ \text{Collector Efficiency})$$

$$= 820\ \frac{\text{Btu}}{\text{ft}^2}$$

$$\text{Collector Area Required} = \frac{910\ \text{MBtu}}{820\ \frac{\text{Btu}}{\text{ft}^2}} = 1.1 \times 10^6\ \text{ft}^2$$

$$\text{Installed Collector Cost} = (\sim \$25/\text{ft}^2)\ (1.1 \times 10^6\ \text{ft}^2)$$

$$= \$27.5\ \text{million}$$

The hot water produced can be used in absorption water chillers, as discussed above. Economics of the system are addressed in Section V. The above capital cost does not include installation, collector mounting hardware, or system connection components.

2. Coal

Coal could also provide an available option in the Williams Air Force Base project. Coal is an abundant resource in the nearby Four Corners area, and could be used to produce the hot water for the central chiller. An equivalent displacement of fossil fuel-generated electricity could be achieved as with the geothermal option. However, coal priced at $60/ton, or $2.68 per million Btu, would experience a higher annual operating cost than the geothermal system. The payback, as shown in Section V, will also be longer than the geothermal system option.

3. Geothermal Electric Development

The development of a geothermal electric power plant is another possible energy system alternative. Such a plant should be sized to satisfy the entire base electrical load, not just the portion of the load used for the present cooling system. This option has the advantage of not requiring retrofit of the existing base air conditioning units.

A power plant to meet the entire base electrical load would have a net output of 9 MWe. Monthly base electrical consumption data for 1978 would indicate a plant capacity factor of 63 percent. Sizing the plant only for the cooling load would result in a much smaller capacity factor, and would probably not be economically competitive.

Plant design and cost estimates are based upon an assumed geothermal resource temperature of 350°F, suggesting a binary plant cycle using pentane as a working fluid. In this power cycle the geothermal fluid is passed through a heat exchanger, where some of its heat is transferred to a working fluid. The working fluid is vaporized and used to turn a turbine generator. The vapor is then run through a condenser, where it is liquified and returned to the system to repeat the cycle. The working fluid is one which has a low boiling point and, therefore, a high vapor pressure. A higher resource temperature than the assumed 350°F will significantly improve the economics of this alternative. A simplified schematic of a binary plant is shown in Figure 10.

The binary power cycle is not just an R&D experiment, but rather a developed concept using commercially available components, as evidenced by the following activities using this technology:

a) Since April 1978, a 60-kW prototype binary system has been in operation at the INEL's Raft River, Idaho geothermal test site, using a 290°F resource.

b) During the summer of 1979, the first commercial binary-cycle plant will go on-line in the Imperial Valley of California. It will produce 10 MWe of power from a 360°F resource and will be operated by the Imperial Magma Corp.

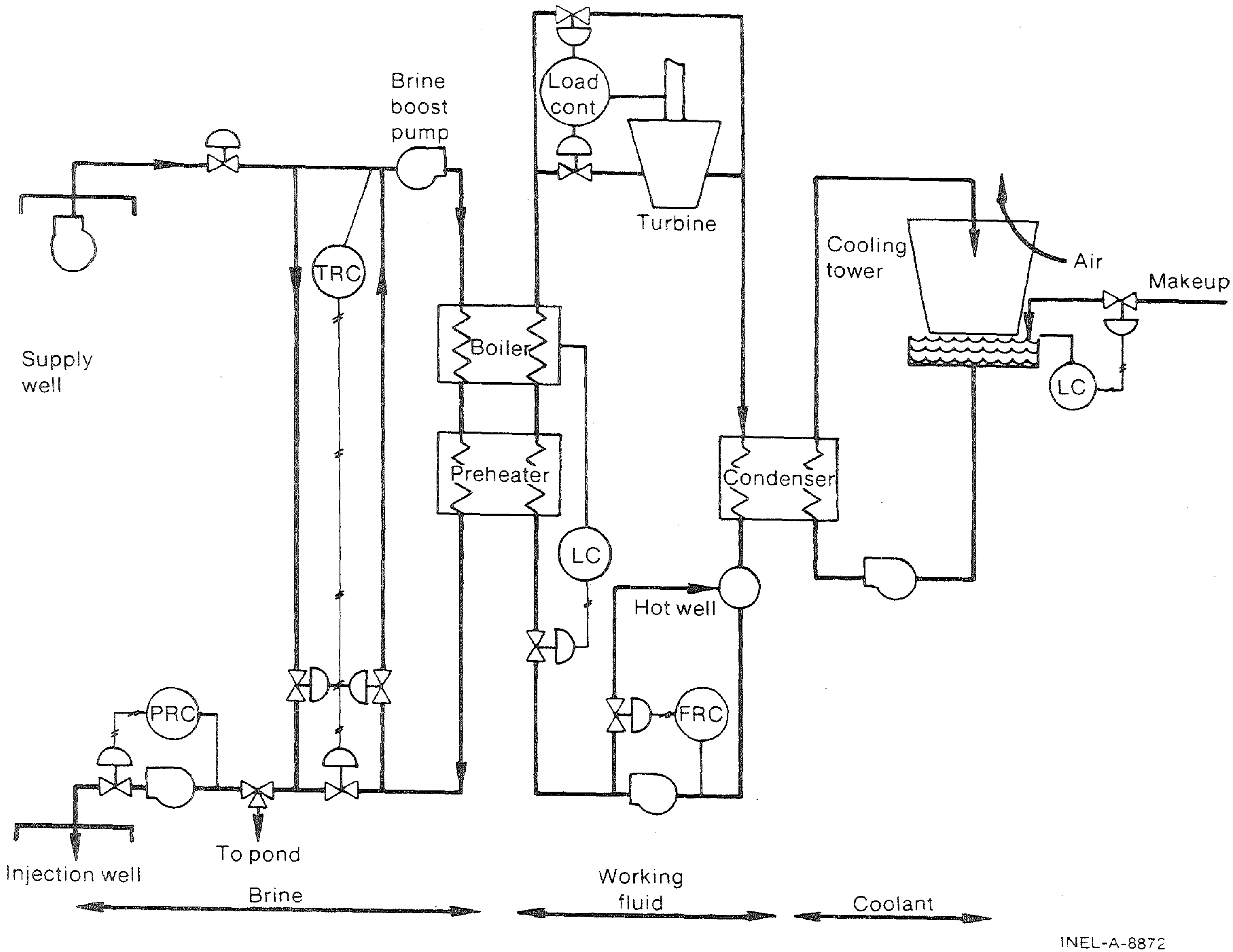


Figure 10. Geothermal Binary-Cycle Plant

3. Construction is presently underway at the Raft River test site on a 5 MW power plant using a 290°F resource, which is scheduled to begin operation in October 1980.

Costs for the geothermal electric plant are broken into four items for use in economic evaluations: (1) well and piping system (field system) capital cost, (2) conversion plant capital cost, (3) field system operations and maintenance, and (4) conversion plant operations and maintenance. These costs are shown in Table VI.

TABLE VI

Geothermal Electric Plant: Basic Costs

Field System Capital Cost	$\$6.14 \times 10^6$
Conversion System Captial Cost	$\$12.3 \times 10^6$
Field System Operations & Maintenance Cost	$271,000/yr
Conversion System Operations & Maintenance Cost	$628,000/yr

V. SYSTEM ECONOMICS

Provided below are economic analyses of the two principal development cases involving the chilled water loop. The first development profile is based upon drilling a new production well to approximately 10,000 ft and conveying the fluids to a central chiller plant and district circulation loop (Case A). Fluid disposal is presumed to be possible near the vicinity of the loop. The possibility of acquiring, developing, and using the two private wells located near the southwest corner of the base provides the basis of the "Case B" analysis. All costs for the circulation loop, components, and building retrofit (later called mechanical costs) will be the same for both cases, except Case B will contain about 1.5 miles of additional piping (since the wells are off base), as well as additional pumping requirements. Less detailed cost estimates are also provided for alternative energy systems, including solar, coal, and geothermal electric.

For both principal cases, we have provided two feasibility formats. Since Williams AFB is a government installation, project feasibility is approached differently than would be the case for a private commercial or industrial project. Thus we have followed the guidelines of DOD's Energy Conservation Investment Program (ECIP) contained in AFR 178-1 to arrive at the several determinants of feasibility. Since we expect, however, that this report will also be read by others in Arizona interested in industrial or commercial geothermal development, we have included a more conventional economic analysis comparing the sum of amortization of capital expenditures and operating expenses against projected energy savings over the economic life of the proposed project.

A. Project Costs

The project costs (in 1979 dollars) common to both Case A and Case B are as follow:

1. Piping:

Chilled water supply and return lines (25,500 ft)	$987,345	
Branch lines (∿ 28,275 ft)	595,900	
Miscellaneous valves, controls	115,000	
Geothermal water supply and return (0.5 mile supply, 0.5 mile reinjection)	227,395	
Geothermal well piping (miscellaneous)	24,000	
Expansion tanks (geothermal)	12,000	
Total 1		$1,961,640

2. Heat Exchangers:

1 Unit (1 smaller unit for standby)	$ 65,000	
Fittings and controls	20,000	
Installation	5,000	
Total 2		90,000

3. A/C Units:

6 units @ 610 tons/unit	$480,000	
Miscellaneous valves, controls	50,000	
Installation @ $35/ton	140,000	
Total 3		670,000

4. Cooling Towers:

6 units @ 9.275 M Btu/hr/unit rejection rate	$115,000	
Miscellaneous valves, controls	20,000	
Installation @ $10/ton	46,375	
Total 4		181,375

5. Retrofitting:

DX coils changeover	$ 73,230	
Installation	17,500	
Valving and controls @ $1,780/building x 35 buildings	62,300	
Total 5		153,030

6. Subtotal of common costs: $3,056,045

		Case A	Case B
7.	Pumps:		
	Production pump & wellhead equipment	$125,000	$331,000
	Loop circulation pumps	35,000	35,000
	Supply line circulation pumps	18,000	45,000
	Reinjection pump & wellhead equipment	135,000	150,000
	Total 7	$313,000	$561,000
8.	Project contingency @ 25%	$842,261	$904,261
9.	A&E fee @ 6%	$252,678	$271,278
10.	Subtotal of mechanical dimensions of the project, including contingencies	$4,463,985	$4,792,585
11.	Well Costs:		
	Supply well	$1,933,000	$2,670,000
	Reinjection well	758,000	758,000
	Extra supply line (1.5 mi + 6% A&E fee on 25% contingency)	---	329,658
	Contingency @ 25%	672,750	933,664
	Total 11	$3,363,750	$4,691,322
12.	Total Estimated Costs	$7,827,735	$9,483,907

Excluded from the above tabulations are costs associated with additional geophysics studies or exploration prior to deep drilling, as well as costs for preliminary and final system design.

B. Feasibility Evaluations: ECIP Format

Tables VII and VIII summarize the feasibility evaluation of Cases A and B according to the Air Force's ECIP. Part 1 consists of all capital costs, A&E contingency, and project contingency. The costs for CWE (mechanical plus well expenses) are those from the preceding current year costs escalated to FY 1982, the end of the fiscal year in which construction might be programmed. Contingencies are similarly escalated according to short-term escalation rates stipulated in AFR 178-1.

For recurring benefit or cost differentials (part 2), such as changes in material or labor requirements as a result of the geothermal project, we are assuming negligible differences, although in reality it is quite likely that some present labor and material requirements will be negated with a centralized cooling system.

Table VII

Case A Feasibility Summary

COSTS

1. Non-recurring Initial Capital Costs

a.	CWE[1]	$ 7,251,656	
b.	Design[2]	$ 1,812,911	
c.	Other[3]	$ 302,363	
d.	Total		$9,366,930

BENEFITS

2. Recurring Benefit/Cost Differential Other Than Energy

a.	Annual Labor Decrease (+)/Increase (-)	$	
b.	Annual Material Decrease (+)/Increase (-)	$	
c.	Other Annual Decrease (+)/Increase (-)	$	
d.	Total Costs	$	
e.	10% Discount Factor	$	
f.	Discounted Recurring Cost (d x e)		$ -0-

3. Recurring Energy Benefit/Costs

a. Type of Fuel Electricity

(1)	Annual Energy Decrease (+)/ Increase (-)	+ 168,015 MBtu
(2)	Cost per MBtu	$ 3.87
(3)	Annual Dollar Decrease/Increase ((1) x (2))	$ 650,218
(4)	Differential Escalation Rate (8 %) Factor	20.05
(5)	Discounted Dollar Decrease/ Increase (3) x (4)	$13,036,872

4.	Total Benefits (Sum 2f + 3a(5))	$ 13,036,872
5.	Discounted Benefit/Cost Ratio (Line 4 ÷ 1d)	1.39
6.	Total Annual Energy Savings	168,015 MBtu
7.	E/C Ratio (Line 6 ÷ Line 1a/1000)	23.17
8.	Annual $ Savings (2d+3a(3))	$ 650,218
9.	Payback Period ((Line 1a - Salvage) ÷ Line 8)	11.15

(1) Includes all mechanical costs and wells, escalated to end of FY 1982.

(2) Project contingency @ 25% of mechanical costs & wells escalated to end of FY 1982.

(3) A&E contingency @ 6% of mechanical costs of (a) + (b).

Table VIII

Case B Feasibility Summary

COSTS

1. Non-recurring Initial Capital Costs

a.	CWE[1]	$ 8,797,297	
b.	Design[2]	$ 2,199,324	
c.	Other[3]	$ 352,143	
d.	Total		$11,348,764

BENEFITS

2. Recurring Benefit/Cost Differential Other Than Energy

a.	Annual Labor Decrease (+)/Increase (-)	$	
b.	Annual Material Decrease (+)/Increase (-)	$	
c.	Other Annual Decrease (+)/Increase (-)	$	
d.	Total Costs	$	
e.	10% Discount Factor	$	
f.	Discounted Recurring Cost (d x e)		$ -0-

3. Recurring Energy Benefit/Costs

a. Type of Fuel Electricity

(1)	Annual Energy Decrease (+)/ Increase (-)	168,015 MBtu	
(2)	Cost per MBtu	$ 3.87	
(3)	Annual Dollar Decrease/Increase ((1) x (2))	$ 650,218	
(4)	Differential Escalation Rate (8 %) Factor	20.05	
(5)	Discounted Dollar Decrease/ Increase (3) x (4)	$13,036,872	

4.	Total Benefits (Sum 2f + 3a(5))	$13,036.872
5.	Discounted Benefit/Cost Ratio (Line 4 ÷ 1d)	1.15
6.	Total Annual Energy Savings	168,015 MBtu
7.	E/C Ratio (Line 6 ÷ Line 1a/1000)	19.1
8.	Annual $ Savings (2d+3a(3))	$ 650,218
9.	Payback Period ((Line 1a - Salvage) ÷ Line 8)	13.53

(1) Includes all mechanical costs and wells, escalated to end of FY 1982.

(2) Project contingency @ 25% of mechanical costs & wells, escalated to end of FY 1982.

(3) A&E contingency @ 6% of mechanical costs of (a) + (b).

Part 3 is a calculation of recurring energy benefits attributed to displacing the use of electric energy for space cooling in the system layout specified in the previous section. Annual energy saved is calculated at the front end of the electrical generating plant (11,600 Btu/kWh). Cost per MBtu is also calculated prior to generation ($2.61 MBtu, compared to $8.88 MBtu at the point of use), escalated at 16 percent for FY 1980 and 13 percent each for 1981 and 1982, according to the guidelines. A long-term differential escalation of 8 percent[1] (resulting from factors unique to the fuel market over and above those experienced by the general economy), with a government discount rate of 10 percent, is then applied over the expected 25-year life of the project, for a total discounted dollar savings of $13,036,872. Under recurring benefits, we have neglected both the demand-charge reduction charged by the electric utility in the present system as well as the value of a small amount of natural gas used in one of the hospital boilers, which would also be replaced by the geothermal system.

A discounted benefit/cost ratio, E/C ratio (energy saved/cost), annual dollar savings, and payback periods are then calculated. The guidelines suggest a minimum E/C ratio of 20 and benefit/cost ratio of 1 for project consideration. Table VII is the analysis for Case A, showing a B/C ratio of 1.39 and E/C ratio of 23.17, and Table VIII for Case B, with a B/C ratio of 1.15 and E/C ratio of 19.1.

The inclusion in Case A of a corollory heating loop to provide heat for the hospital complex would mean an additional $550,000 in capital costs (including contingencies), and would result in an approximate $45,000 annual savings in natural gas costs. Calculating recurring benefits, and escalating as described above, the B/C ratio increases to 1.44 and the E/C ratio to 23.95.

---

[1] Eight percent is probably a very conservative estimate, and it is quite likely that factors indigenous only to the energy supply industry will be reflected in a significantly higher long-term escalation rate. An assumption of 15 percent per year increase in real fuel costs, for example, would suggest a benefit/cost ratio of about 2.08, compared to 1.39.

C. Conventional Economic Analysis, Case A

For what appears to be the most cost effective development scenario, Case A, we have included in Table IX a life-cycle cost analysis for the expected 25-year life of the geothermal project. The amortized cost is based on a total project cost of $7,827,735, including mechanical, well development, A&E contingency, and project contingency. Cumulative fuel savings are based on present costs of electric energy for space cooling in those facilities included in the district system, less the estimated electric pumping costs for the geothermal system included in the third column.

As noted in the table and from Figure 11, the geothermal system crosses the payback point in the conventional economic analysis between the 16th and 17th years, longer than in the ECIP format. More attractive, however, is the total life-cycle cost analysis, which shows nearly $30.8 million in project benefits over the 25-year project period. Case B would be less favorable, because of the higher capital requirements ($9,483,907) and a somewhat higher electrical pumping cost. Additionally, we have not included in the Case B analysis, for either format, royalty payments that would probably have to be made to the owner of the land on which the wells are located. Such payments could be expected to approximate 10 percent, based on a Btu equivalency with alternate fuels.

Table IX

Cumulative Cost Comparisons Over Project Life

Year	Amortized System Cost[a]	Geothermal System Operating Cost[b]	Total Geothermal System Cost	Fuel Savings[c]
1	$1,241,329	$ 106,560	$ 1,347,889	$ 438,965
2	2,482,658	223,776	2,706,434	438,965
3	3,723,988	352,714	4,076,702	1,452,975
4	4,965,317	494,545	5,459,862	2,095,664
5	6,206,646	650,559	6,857,205	2,738,353
6	7,447,975	822,175	8,270,150	3,445,311
7	8,689,304	1,010,953	9,700,257	4,222,964
8	9,930,633	1,218,608	11,149,241	5,078,383
9	11,171,962	1,447,029	12,618,991	6,019,344
10	12,413,292	1,698,292	14,111,584	7,054,401
11	12,413,292	1,974,681	14,387,973	8,192,963
12	12,413,292	2,278,709	14,692,001	9,445,382
13	12,413,292	2,613,140	15,026,432	10,823,042
14	12,413,292	2,981,014	15,394,306	12,338,468
15	12,413,292	3,385,675	15,798,967	14,005,937
16	12,413,292	3,830,802	16,244,094	15,839,103
17	12,413,292	4,320,442	16,733,734	17,856,135
18	12,413,292	4,859,046	17,272,338	20,674,871
19	12,413,292	5,451,511	17,864,803	22,515,480
20	12,413,292	6,103,222	18,516,514	25,200,150
21	12,413,292	6,820,104	19,233,396	28,153,287
22	12,413,292	7,608,675	20,021,967	31,401,738
23	12,413,292	8,476,102	20,889,384	34,975,034
24	12,413,292	9,430,272	21,843,564	38,905,660
25	12,413,292	10,479,859	22,893,151	43,229,348

(a) Cumulative capital cost based upon a loan amortized over 10 years at 10% interest on a total project cost of $7,827,735.

(b) Electrical energy for circulation pumps and cooling tower fans is estimated to be ∿ 12,000 million Btu/yr. A 10% escalation rate is applied over the 25-year project life.

(c) Current cooling electrical energy minus anticipated electrical pumping cost is estimated to save 49,433 million Btu/yr, escalated at 10% per year for the 25-year project life. Continued use of the present cooling system would cost $53,648,316 over the 25-year project life.

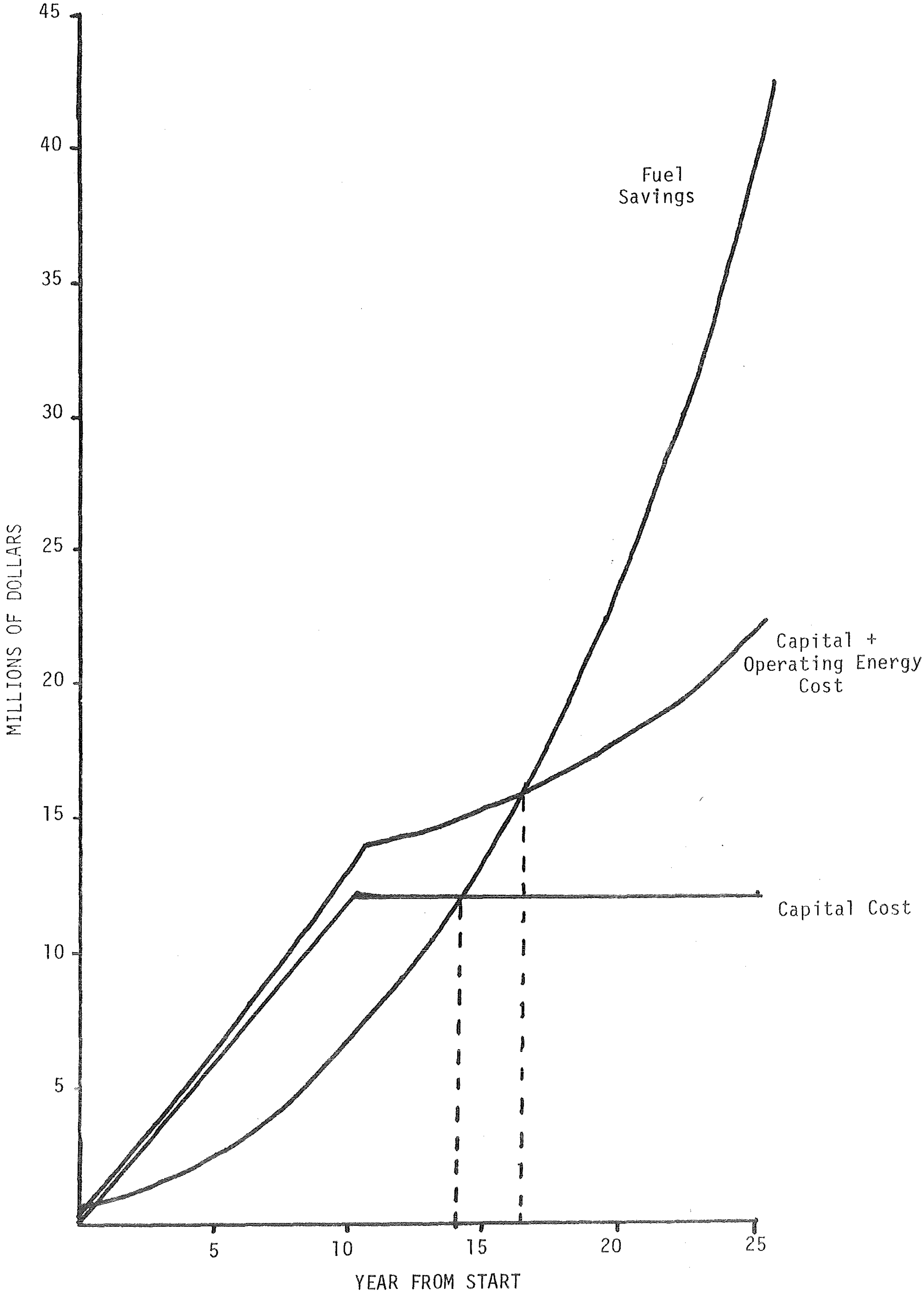


Figure 11. Amortized Capital Cost Versus Escalated Fuel Savings (Cumulative)

D. Solar System Economic Analysis

The life-cycle costs of the solar-based hot water system described in Section IV appear to be less attractive than the geothermal space cooling system. Using the $27.5 million cost for the collector, as noted earlier, and including mechanical costs, project and A&E contingencies, front-end capital costs approximate $42 million. Amortized at 10 percent over 10 years, project savings at the end of 25 years, as noted in Table X, is still $7 million less than total operating costs for the solar-based system. It would also be near this 25-year period that equipment replacement would then become a concern. The capital costs, operating expenses, and savings are estimated as follow:

Solar collectors		$27,500,000
Mechanical (pumps, A/C units, piping, etc.)		4,600,000
	Subtotal	32,100,000
Project contingency @25%		8,025,000
	Subtotal	40,125,000
A&E contingency @ 6%		2,407,500
	TOTAL	$42,532,500

Operating costs = $87,000/yr (includes electricity for pumps)

Table X

Solar System Costs and Savings (Cumulative)

Year	Capital Cost	Operating Cost	Total System Cost	Savings in Cost of Electrical Energy
1	$ 4,416,394	$ 87,000	$ 4,503,394	$ 458,525
2	8,832,789	182,700	9,015,489	962,902
3	13,249,184	287,970	13,537,154	1,517,717
4	17,665,578	403,767	18,069,345	2,128,014
5	22,081,973	531,143	22,613,116	2,799,340
6	26,498,368	671,257	27,169,625	3,537,799
7	30,914,763	825,382	31,740,145	4,350,104
8	35,331,158	994,920	36,326,078	5,243,639
9	39,747,552	1,181,412	40,928,964	6,226,528
10	44,163,947	1,386,553	45,550,500	7,307,706
11	44,163,947	1,612,209	45,776,156	8,497,001
12	44,163,947	1,860,430	46,024,377	9,805,226
13	44,163,947	2,133,473	46,297,420	11,244,273
14	44,163,947	2,433,820	46,597,767	12,827,225
15	44,163,947	2,764,202	46,928,149	14,568,473
16	44,163,947	3,127,622	47,291,569	16,483,855
17	44,163,947	3,527,384	47,691,331	18,540,755
18	44,163,947	3,967,123	48,131,070	20,908,356
19	44,163,947	4,450,836	48,614,783	23,457,717
20	44,163,947	4,982,920	49,146,867	26,262,014
21	44,163,947	5,568,212	49,732,159	29,346,741
22	44,163,947	6,212,034	50,375,981	32,739,940
23	44,163,947	6,920,238	51,084,185	36,472,459
24	44,163,947	7,699,262	51,863,209	40,578,231
25	44,163,947	8,556,189	52,720,136	45,094,580
26	44,163,947	9,498,808	53,662,755	50,062,564
27	44,163,947	10,535,690	54,699,637	55,527,346
28	44,163,947	11,676,260	55,840,207	61,538,607
29	44,163,947	12,930,887	57,094,834	68,150,993
30	44,163,947	14,310,977	58,474,924	75,424,618

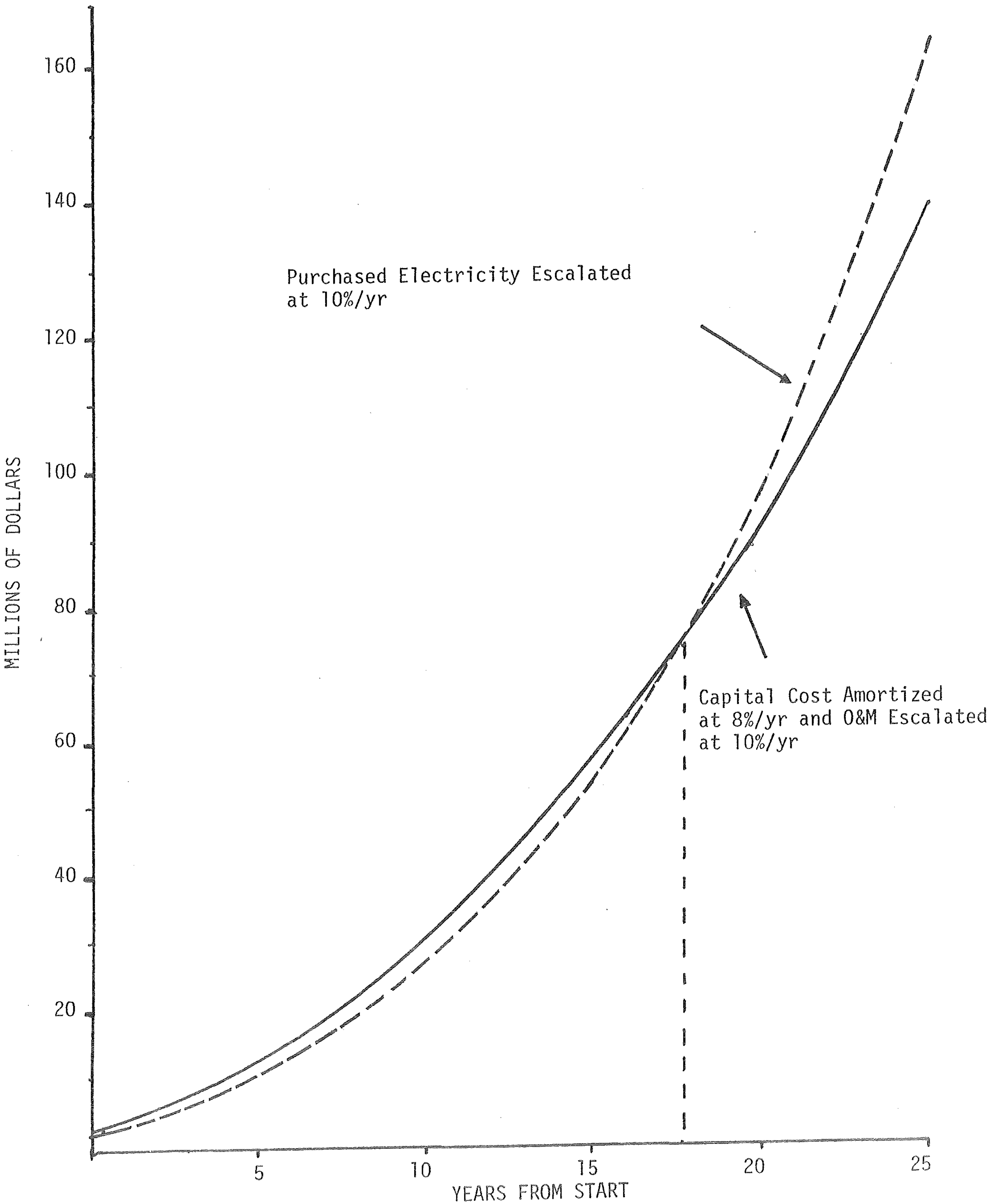


Figure 12. Amortized Capital and Escalated O&M versus Escalated Electrical Costs

E. Coal System Economic Analysis

The coal system option, because of the significantly higher operating costs, appears less attractive than the geothermal option, and is roughly comparable to the life-cycle economics of the solar project described above.

Approximately 4,200 tons of coal/yr, at an annual cost of $248,000 ($60/ton), would be required to furnish the 65 x 10^6 Btu/hr peak demand to run the absorption chillers (at 17 percent utilization factor). Capital costs would be roughly as follow:[1]

1.	1950-hp boiler, stoker, and handling equipment	$1,750,000
2.	Mechanical costs (cooling unit, exchangers, piping, circulation pumps, etc.)	2,737,650
3.	Project and A&E contingencies (25% and 6%, respectively)	1,458,486
	Total Costs	$5,946,136

The above costs include SO_2 scrubbers, but do not reflect expenses for storage and waste disposal.

Amortizing these capital expenses over 10 years at 10 percent, and including a 10 percent annual fuel cost increase with an assumed $50,000 annual electrical energy cost, suggests a total life-cycle coal system cost of nearly $39,000,000 over a 25-year project life. Yet, electrical savings amount to only $24,000,000 over the same period. As with the solar option, system payback occurs near or after the point of expected major equipment replacement. Together with the environmental objections to storing and using large quantities of coal, these economic considerations suggest that such a system does not warrant further consideration.

[1] Major equipment costs obtained from telephone conversations with Pace Industries, Salt Lake City, Utah.

F. Cost Comparisons - Geothermal Binary Power Plant versus Projected Electricity Cost

As described in Section IV, a 9-MWe (net) power plant would be required to supply the WAFB electrical needs. To get a valid approximation of the total cost involved, both the capital and operations and maintenance (O&M) costs had to be evaluated. These costs consist of estimates which were calculated for both the geothermal field and the conversion (power) plant. These costs were compared against the cost of power currently being purchased by WAFB. (Detailed cost estimates and assumptions are presented in the Appendix.)

Based on an assumed project period of 25 years and a cost of money of 8 percent, (representative of a publicly owned utility), the capital recovery rate (CRR) was calculated to be 9.37%/year. Using the CRR and the field and plant capital costs from Section IV, the fixed annual payout against the total capital cost was calculated to be $1.728 million. Broken down, this amounted to 11.6 mill/kWhr for the field and 23.2 mill/kWhr for the plant. The total O&M cost (field and plant) amounted to $899,000/yr in 1979 dollars or 18 mill/kWhr. Collectively, these costs amount to a 1979 electric generation price of 52.8 mill/kWhr (see Appendix). The O&M cost is a non-fixed cost and was estimated to increase at 10 percent per year over the 25-year project life. The escalated O&M cost for each year of the geothermal plant operation was added to the fixed annual cost of invested capital ($1.728 million, to determine the annual cost of generated electricity. The amounts were accumulated over a 25-year period and plotted in Figure 12.

Based on the current average electricity rate (near 30 mill/kWhr) and the most recent annual electricity consumption (50 MkWhr), the base cost for the presently purchased electricity was calculated at $1.5 million. Using this base figure, the projected annual costs were determined by escalating the anticipated 1979 costs at 10%/year over a 25-year period. The cumulative purchased costs are also plotted in Figure 12. As can be seen, the breakeven period is 18 years for the geothermal binary power plant. This time span would be shortened substantially if the cost of purchased electricity escalates more rapidly than 10%/year, or if the actual resource temperature is discovered to be significantly greater than the assumed 350°F.

Table XI summarizes the feasibility evaluation according to the Air Force's ECIP. Part 1 consists of all capital costs, A&E contingency and project contingency escalated to FY-82. These costs were not subdivided and were merely totalled equal for part 1a and 1d. Labor and material increases were included in Part 2 to reflect the additional manpower requirements to initiate and operate this new project. The benefit/cost ratio thus derived is 1.7, the energy/cost ratio is 26.01, and the payback period is 14.9 years.

Table XI

Geothermal Electric Plant Feasibility Evaluation

COSTS

1. Non-recurring Initial Capital Costs

a.	CWE	$	
b.	Design	$	
c.	Other	$	
d.	Total		$ 22,070,717

BENEFITS

2. Recurring Benefit/Cost Differential Other Than Energy

a.	Annual Labor Decrease (+)/Increase (-)	$ -435,813	
b.	Annual Material Decrease (+)/Increase (-)	$ -307,911	
c.	Other Annual Decrease (+)/Increase (-)	$	
d.	Total Costs	$ -743,724	
e.	10% Discount Factor	$ 9.52	
f.	Discounted Recurring Cost (d x e)		$-7,080,256

3. Recurring Energy Benefit/Costs

a. Type of Fuel Electricity

(1)	Annual Energy Decrease (+)/ Increase (-)	574,000 MBtu	
(2)	Cost per MBtu	$ 3.87	
(3)	Annual Dollar Decrease/Increase ((1) x (2))	$ 2,221,380	
(4)	Differential Escalation Rate (8 %) Factor	20.05	
(5)	Discounted Dollar Decrease/ Increase (3) x (4)	$44,538,669	

4.	Total Benefits (Sum 2f + 3a(5))	$37,458,413
5.	Discounted Benefit/Cost Ratio (Line 4 ÷ 1d)	1.70
6.	Total Annual Energy Savings	574,000 MBtu
7.	E/C Ratio (Line 6 ÷ Line 1a/1000)	26.01
8.	Annual $ Savings (2d+3a(3))	$ 1,477,656
9.	Payback Period ((Line 1a - Salvage) ÷ Line 8)	14.9

VI. REGULATORY AND ENVIRONMENTAL CONSIDERATIONS

A. Introduction

The purpose of this section is to outline the role of the State of Arizona in development of geothermal resources at Williams Air Force Base. The state legislature has enacted a law that regulates the development of geothermal resources, and that law also governs any development on Williams AFB. The development of geothermal resources in Arizona is exempt from water laws unless such resources are co-mingled with surface waters or groundwaters, or the development of geothermal resources causes impairment of or damage to the groundwater supply.

B. Legal Control of Geothermal Resources in Arizona

1. The regulation of geothermal resources exploration and production, standards, and procedures is accomplished by amendment of Section 2, Title 27, Chapter 4, IRS, with the addition of Article 4, Sections 27-651 through 27-666, as enacted by the state legislature.

2. This law establishes the Oil and Gas Conservation Commission located at 1645 West Jefferson, Suite 420, Phoeniz, Arizona, 85007. The commission controls the drilling of all oil, gas, and geothermal wells in the state.

3. In 1972 the commission published Rules & Regulations - Geothermal Resources, which require a $5,000 per-well bond to be filed with the commission or a blanket bond for $25,000 for all the wells planned to be drilled.

4. The commission rules and regulations require the filing of an application for a permit to drill for each well (fee $25.00). Drilling must start within 90 days after approval unless extension is granted, or the permit is null and void. The permit must also be filed if an old well is reentered.

5. The commission approves or prescribes changes or modifications to well spacing plans that it determines necessary for proper development of the area.

6. The rules and regulations have separate casing requirements for surface casing and well casing, and these are inspected closely during installation. They also require blowout preventers, pressure tested to a minimum of 1,000 psig on installation, and the blowout preventer shall be operated at least once every 24 hours. A well completion report must be filed with the commission, along with all logs and surveys, after it has been certified as correct, but within 30 days after completion of the well.

7. Operating practices specify measurement and monthly reporting of production of the well. Fluid disposal in the Williams AFB area will require an injection well for environmental reasons. The commission will require that all federal and state air and water quality standards be met to protect the environment, and, as stated above, will require disposal by injection at a level low enough to protect groundwaters. The Oil and Gas Commission provides monitoring during construction and operation.

8. If the site of a well is located south of "D" Street and a line that extends across the airfield as an extension of "D" Street, it will require an archeological clearance.

CONCLUSIONS AND RECOMMENDATIONS

The promising evidence of hydrothermal resources underlying or in close proximity to Williams AFB, combined with the favorable life-cycle costs and energy savings associated with the geothermal development scenarios presented in this report suggest that the project should continue to be pursued through the drilling phase, subject to the discussion and expectations set forth below.

The factor giving rise to optimism concerning the existence of a usable geothermal resource at the base is, of course, the high temperatures in the GKI wells. The initial fluid flow from the wells eventually dropped off, though, and attempts at stimulation failed. However, drilling and well completion technology for geothermal reservoirs is continuing to advance since the GKI wells were drilled in 1973, and it is possible its employment today may result in better near hole permeability. The GKI exploration experience, therefore, is inconclusive with respect to the extent of a geothermal reservoir at depth. The geologic controls on the area of high temperature at depth are not well-known, and a new production drill hole would have to gain access to an area of substantial fracture or fault-controlled permeability to produce the required fluid volume.

Consideration has been given to geophysical exploration tools, particularly the employment of a reflection seismic survey, that might help delineate these major structural features and related fracture permeability. There is some doubt about the probability of obtaining definitive data from the seismic survey, in view of some past unsuccessful attempts by industry to obtain data from the same stratigraphic section. An expenditure of $100,000 for 10 to 15 line miles of seismic data would be required. However, in view of the limited selection of sites available on base and the uncertainty of success with the seismic approach, further geophysical exploration is not recommended.

In the absence of additional geophysical information and exploration, well location WP-1, being the closest on-base location to the GKI wells, would be most likely to intersect a similar temperature regime. Location

WP-2, while preferable from an engineering and economic sense, would be a somewhat higher risk effort. A resource discovered at either location would provide the basis for an energy project with positive life-cycle cost benefits.

In selecting the production drilling site on base, two options exist, depending on the funding levels available. Site WP-2 might initially be selected on the basis of more favorable engineering and cost advantages. If a favorable resource is proven at that site, the injection well could then be located at WR-1. If no resource or an inadequate resource is encountered in the drilling of WP-2, that site might then be considered the injection well, obviating the need for WR-1, and the production well then sited at WP-1. If the drilling of WP-2 was unsuccessful, the net cost of taking an initial chance on that site would be about $1.18 million, since drilling WR-1 was estimated at $758,000. Considering WP-2 as the injection site should pose no problems with WP-1 as the production well, due to the one and one-half mile separation. Even though WP-2 would be a 10,000-ft well similar to WP-1, appropriate casing and cementing as WP-2 is drilled would preserve the option of using that well for fluid disposal at an intermediate level ($\sim$ 5,000 ft). Given adequate financial support, we believe this option possesses the greatest project flexibility and increases the prospects for developing a geothermal resource on the base.

If, on the other hand, the commitments to the project are sufficient for only a single exploration effort, that effort should be made at site WP-1, on the basis of proximity to proven temperatures.

Given the favorable life-cycle cost advantages inherent in the geothermal energy supply systems discussed earlier, firm decisions on system selection could be made at the conclusion of the resource exploration program when the quality of the resource is determined. When the geothermal reservoir is confirmed and if temperatures exceed 350°F, principal consideration should be given to the development of an electrical supply system for the entire base. If the temperatures encountered are less than 350°F, the preferred alternative would be a more limited district cooling system for the principal load areas, perhaps including a corollary heating loop for the hospital complex. Either development alternative would be cost effective at both WP well sites.

There are no known environmental or regulatory deterrents that would impede pursuance of the project.

APPENDIX A

COST DETERMINATION FOR A BASE GEOTHERMAL POWER PLANT

BASE GEOTHERMAL ELECTRICAL POWER PLANT

A. Introduction

Cost and size determinations were made for a proposed geothermal power plant for WAFB. The assumed geothermal resource temperature was taken as 350°F, which suggested that the type of conversion plant be binary. Actual energy consumption rates were supplied by WAFB for a 12-month period and these data served as a basis for determining the plant size and, subsequently, the field size (Table A-1).

B. Field Capital Costs

Using the assumed reservoir temperature of 350°F and Figure A-1, the amount of geothermal fluid required to run a 9-MWe net power plant was found to be 1.3×10^6 lb/hr (24 Btu/lb of geothermal fluid). It is possible that one production well could provide the required amount of fluid. However, in order that fluid can be provided at all times, at least two wells will be required. This will allow well and wellhead maintenance to be performed while still providing some fluid to the power plant, which in turn will result in a better capacity factor. One injection well will be required to dispose of the cooled fluid.

Spacing for both production and injection wells was assumed to be 40 acres/well. Oversize pipe was specified to keep the design on the conservative side. The oversized pipe will also allow for higher well flow during maintenance periods when one well would be shut in.

Total field capital cost amounted to $\$6.144 \times 10^6$, or \$683/kW (Tables A-2 and A-3).

C. Power Plant Capital Cost

The majority of binary plant information in the INEL data bank pertains to 50-MWe plants. These costs are shown in Figure A-2 as a function of reservoir temperatures. The cost per kWhr for a 9-MWe plant was scaled down by using the following equation:

$$C_2 = C_1 (\frac{Q_2}{Q_1})^n$$

where C_1 = cost of the 50-MWe plant

Q_2 = 9 MWe

Q_1 = 50 MWe

n = exponential factor (0.68 in this case)

Using this equation, the cost of a 9-MWe binary power plant was calculated to be $\$12.3 \times 10^6$, or \$1,367/kW.

D. Capacity Factor

Based on a 30-day month and a 9-MWe power plant, the maximum net monthly output will be 6.5 MkW hr. Using the actual annual consumption figure, the net capacity factor was calculated. This results in an average capacity factor of 0.63, and this value is used in any calculations where capacity factor is required.

E. Annual Field O&M Costs

Field O&M costs were calculated for surface quipment and well maintenance. No labor cost was included because it was assumed that the plant O&M crew would perform the field O&M function. Total field O&M cost amounted to \$271,000/yr, or 5.4 mill/kW hr (net), based on a capacity factor of 63 percent. Surface equipment maintenance was calculated as 2 percent of the initial equipment cost of \$748,000. Well maintenance costs were computed using annual amounts of \$29,500 for production and \$62,500 for injection.

F. Annual Plant O&M Costs

O&M labor costs for both the field and power plant are listed in Table A-5. Maintenance cost was again calculated as 2 percent of the initial plant capital cost of $\$12.3 \times 10^6$. The total annual plant O&M cost of $628,000/year, or 12.6 mill/kWhr, is included as Table A-6.

G. Capital Recovery Rate (CRR)

Based on a useful plant life of 25 years and an interest rate of 8 percent, the CRR was determined to be 9.37 percent. Using this CRR, the fixed field recovery cost was found to be 11.6 mill/kW hr and the fixed plant recovery cost was 23.2 mill/kW hr. Adding the O&M costs to these amounts results in an overall CRR of 52.8 mill/kW hr.

The fixed recovery rate compares with the annual WAFB electricity cost for CY 1978 of 9.4 mill/kWhr. By increasing the capacity factor from 63 percent to 80 percent, an improvement in the CRR of 11 mill/kWhr would be effected. Decreasing the payoff interest rate would also improve the CRR.

Totals are shown in Table A-8.

TABLE A-1

ACTUAL MONTHLY ELECTRICAL CONSUMPTION
AT WILLIAMS AFB, ARIZONA

Month, Year	Amount, MkW hr	Capacity Factor
April 1978	3.33	0.51
May	4.31	0.66
June	5.10	0.78
July	6.24	0.96
August	6.08	0.94
September	4.94	0.76
October	4.87	0.75
November	2.98	0.46
December	3.14	0.48
January, 1979	3.13	0.48
February	2.79	0.43
March	3.06	0.47
TOTAL	49.97	

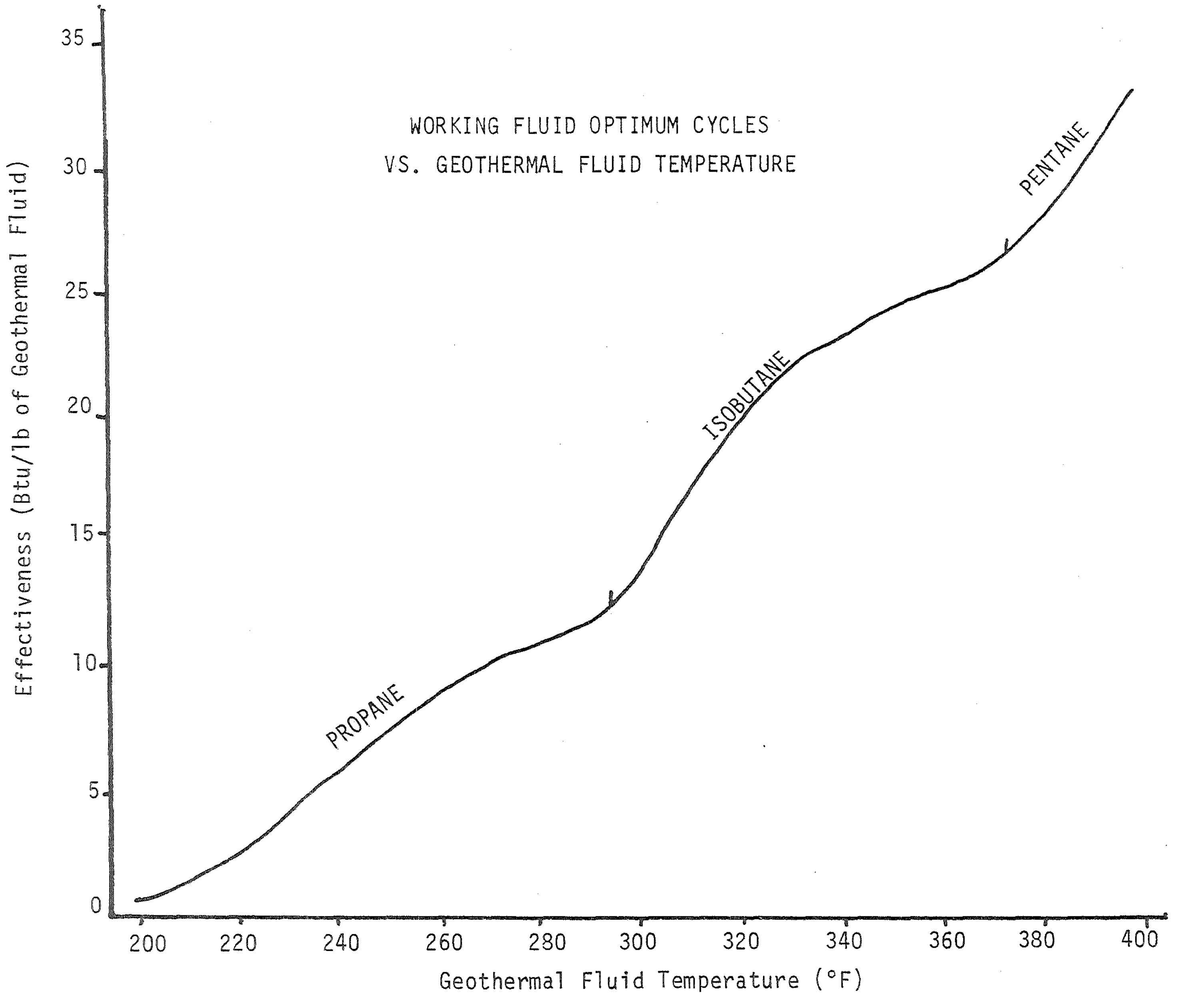


Figure A-1. Working Fluid Optimum Cases, Regardless of Working Fluid or Cycle

TABLE A-2

WELLHEAD & PIPING COST DETERMINATION

ITEM		COST
Production Pumps (2 x $44,270)		$ 88,540
Injection Pump (1 x $35,770)		35,770
Production Wells:		
Wellhead Equipment (2 x $21,000)		42,000
Piping		127,409
Injection Well:		
Wellhead Equipment		34,000
Piping		87,636
	TOTAL HARDWARE	415,355
Labor and O/H @ 80%		332,284
	TOTAL	$747,639

TABLE A-3

FIELD CAPITAL COSTS

Drilling Cost:		
Production Wells ($2 \times 2.319 \times 10^6$)		$4,638,000
Injection Well (0.758×10^6)		758,000
Well Equipment & Piping (Table A-2)		748,000
	TOTAL	$6,144,000

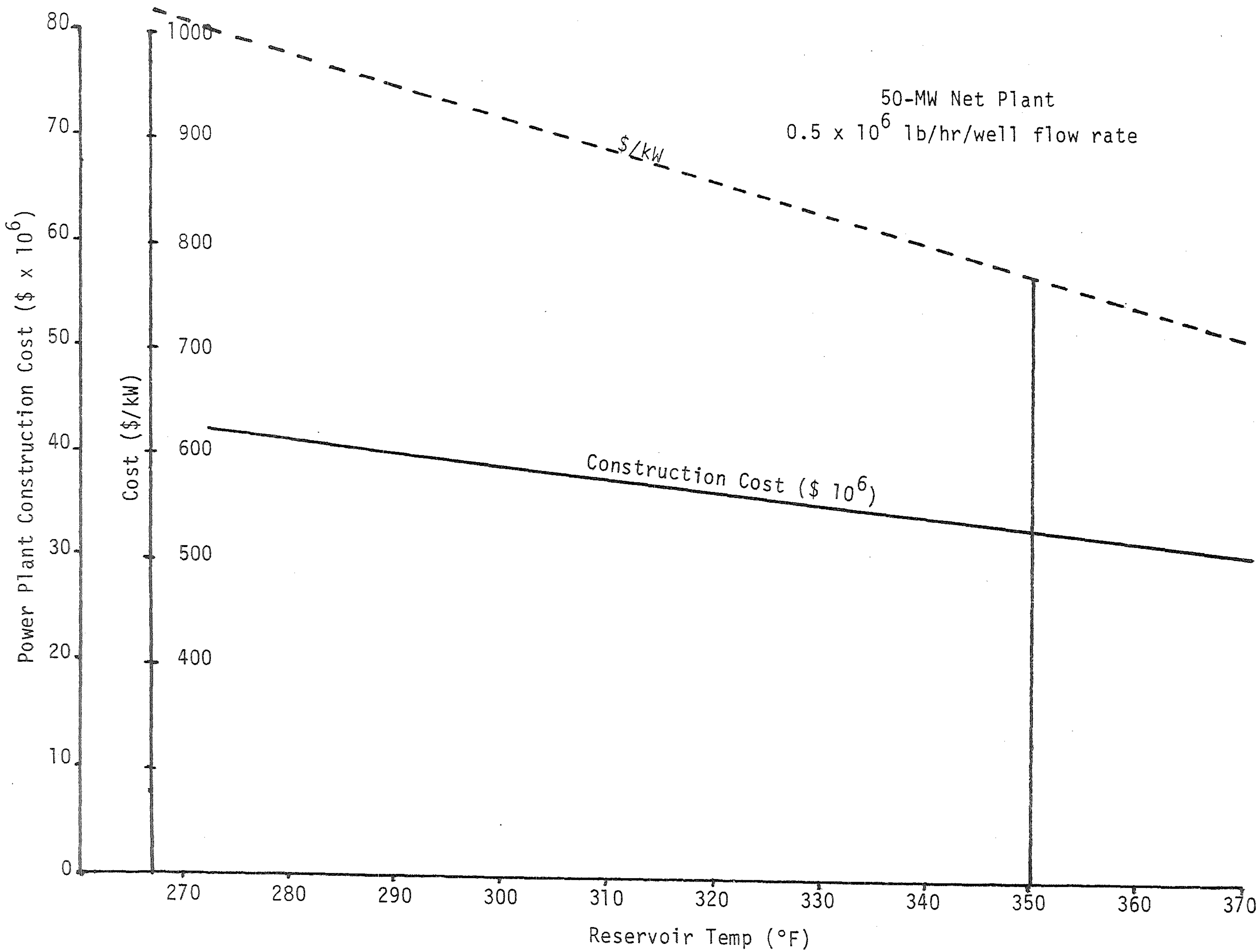


Figure A-2. Estimated Binary Plant Capital Cost as a Function of Reservoir Temperature

TABLE A-4

ANNUAL FIELD O&M COSTS

Surface Equipment Maintenance	$149,600
Production Well Maintenance	59,000
Injection Well Maintenance	62,500
TOTAL	$271,000

TABLE A-5

PROPOSED MANNING FOR FIELD AND POWER PLANT

9 Operators @ $1,125/month	$ 10,125
1 Laborer @ $850	850
1 Electrician @ $1,350	1,350
1 Mechanic @ $1,750	1,750
1 Office Manager @ $1,125	1,125
1 Superintendent @ $2,250	2,250
	17,050
80% Overhead	13,640
	$ 30,690/month
Annual Cost	$368,000/year

TABLE A-6

ANNUAL PLANT O&M COSTS

Labor	$368,000
Plant Maintenance	250,000
Miscellaneous	10,000
TOTAL	$628,000

TABLE A-7

CAPITAL RECOVERY @ 8% INTEREST

Field Fixed		11.6
Plant Fixed		23.2
Field O&M		5.4
Plant O&M		12.6
	TOTAL	52.8 mill/kWhr

TABLE A-8

PERTINENT INFORMATION DERIVED DURING EVALUATION
(WAFB Binary Geothermal Electrical Power Plant)

Plant	Field Capital	Total
$12.3 x 10^6	$6.144 x 10^6	18.444 x 10^6
$1,367/kW	$683/kW	$2,050/kW
	O&M	
$628,000	$271,000	$899,000
12.6 mill/kWhr	5.4	18.0 mill/kWhr
	Fixed Recovery Cost	
23.2 mill/kWhr	11.6	34.8 mill/kWhr
	Capital Recovery Cost	
35.8 mill/kWhr	17.0	52.8 mill/kWhr

BIBLIOGRAPHY

Amstrat, Inc., Logs of Wells GKI No. 1 and 2, Logs No. D-4113 and D-4335, 1976.

Cooley, M. E., Map Showing Distribution and Estimated Thickness of Alluvial Deposits in the Phoenix Area, Arizona; Map I-845-C, USGS, Washington, D.C., 1973.

Dart, R. H., et al, "Conceptual Design and Cost Evaluation of Organic Rankine Cycle Electric Generating Plant Powered by Medium-Temperature Geothermal Water," ANCR-1226, Aerojet Nuclear Co., December 1975.

Eberly, L. D. and T. B. Stanley, "Cenozoic Stratigraphy and Geologic History of Southwestern Arizona, Geol. Soc. Am. Bull., Vol. 89, pp. 921-940, 1978.

Gertsch, W. D., et al, "A Preliminary Assessment of the Feasibility of Developing Geothermal Energy for Space Heat and Process Applications at Hill Air Force Base, Utah," Idaho National Engineering Laboratory, GP-122, February 1978.

Holt, B. and E. L. Ghormley, "Energy Conversion and Economics for Geothermal Power Generation at Heber, California, Valles Caldera, New Mexico, and Raft River, Idaho - Case Studies," EPRI ER-301, November 1976.

Ingvarsson, I. J. and S. E. Turner, "Working Fluid and Cycle Selection Criteria for Binary Geothermal Power Plants with Resource Temperatures in the Range of 220°F to 400°F," TREE-1108, EG&G Idaho, Inc., April 1977.

Osterkamp, W. R., Map Showing Depth to Water in Wells in the Phoenix Area, Arizona, 1972; Map I-845-D, USGS, Washington, D.C., 1973.

Peterson, D. L., Bouguer Gravity Map of Parts of Maricopa, Pima, Pinal, and Yuma Counties, Arizona; Map GP-615, USGS, Washington, D.C., 1968.

Scarborough, R. B., and H. W. Peirce, "Late Cenozoic Basins of Arizona," New Mexico Geol. Soc. Guidebook, Land of Cochise, pp. 253-259, 1978.

Sheridan, M. F., "The Superstition Cauldron Complex, Guidebook to the Geology of Central Arizona, Special Paper No. 2," Bureau of Geology and Mineral Technology, Tucson, Arizona, pp. 85-96, 1978.

Stuckless, J. S. and M. F. Sheridan, "Tertiary Volcanic Stratigraphy in the Goldfield and Superstition Mountains, Arizona," GSA Bull., Vol. 82, No. 11, pp. 3235-3240, 1971.