GL01046

PHASE II
PRELIMINARY EVALUATION OF DIXIE VALLEY, NEVADA:

GEOTHERMAL POTENTIAL AND ASSOCIATED ECONOMICS

FOR
MILLICAN OIL COMPANY
HOUSTON, TEXAS
SEPTEMBER 16, 1977

KEPLINGER and Associates, inc.—
INTERNATIONAL ENERGY CONSULTANTS

3430 ENTEX BUILDING
1200 MILAM STREET
HOUSTON, TEXAS 77002
AREA 713/651-3127
CABLE: KEPPET TELEX: 762-324

September 16, 1977

Mr. Tom Clay
Millican Oil Company
908 Town & Country Blvd.
Suite 400
Houston, Texas 77024

Subject: Dixie Valley
Geothermal Project

Dear Mr. Clay:

Enclosed is our report entitled: "Phase II Preliminary Evaluation of Dixie Valley, Nevada: Geothermal Potential and Associated Economics". We have evaluated the potential of Millican Oil Company's holdings on the basis of: (1) the geology and structure of the Stillwater and Clan Alpine Ranges as they may affect the geothermal potential of the Dixie Valley area; (2) the local ground-water geochemistry as it may relate to subsurface temperature in the Dixie Valley area; and (3) a comparison of various hypothetical reservoir conditions and their possible affects on the economics of future geothermal production.

We have concluded that two reservoirs may exist in the Dixie Valley area. The upper reservoir may involve a hot-water convection system within upper volcanic sequences and lower intervals of the overlying alluvial fill. The lower reservoir, which could be vapor dominated, may be below the base of a gabbroic lopolith in either fractured quartz arenite or other metamorphic sedimentary rocks below the gabbroic complex. With the exceptions of the structural interpretations made in the enclosed report and the forthcoming geophysical data to be received from Southland Royalty in the near future, little detailed information is available that can be used at this date to evaluate the potential of the lower reservoir. At this date, however, it appears that only the areas along the western front-range fault system could be underlain by a relatively shallow gabbroic complex (i.e. less than 7,500 feet depth). The depth of the lower reservoir would increase toward the center of the Dixie Valley basin, where drilling depths would be economically prohibitive.

The economic foundation for the upper, hot-water reservoir of Dixie Valley has been established during this evaluation. The general economic foundation for a vapor-dominated reservoir has been assessed briefly in our previous report (April 21, 1977), which incorporated data from The Geysers area as a

TULSA OFFICE: 320 SOUTH BOSTON • SUITE 320 • TULSA, OKLAHOMA 74103 • AREA 918/587-5591

KEPLINGER and Associates, inc.

general analogy of production costs, cash flow and profitability. While the earlier report may not be directly applicable to the postulated lower reservoir, it will serve as the basis for later detailed evaluations of the lower reservoir, if merited.

We can discuss the conclusions and ramifications of our evaluations at your convenience after my return from Europe in a few weeks. I will advise you as soon as my return date is known.

Very truly yours,

KEPLINGER AND ASSOCIATES, INC.

Michael D. Campbell
Director, Alternate Energy,
Mineral and Environmental
Programs

MDC:fl

PHASE II PRELIMINARY EVALUATION
OF DIXIE VALLEY, NEVADA:
GEOTHERMAL POTENTIAL
AND
ASSOCIATED ECONOMICS

TABLE OF CONTENTS (Cont'd)

Page

ILLUSTRATIONS

PLATES

FIGURES

TABLE OF CONTENTS (Cont'd)

Page

FIGURES (Cont'd)

TABLES

PHASE II

PRELIMINARY EVALUATION
OF
DIXIE VALLEY, NEVADA:
GEOTHERMAL POTENTIAL
AND
ASSOCIATED ECONOMICS

I. SUMMARY

A ground-water geochemical survey was conducted on selective springs in the Dixie Valley Area. Geothermometric calculations indicate a maximum subsurface temperature of 175 degrees Centigrade (347 degrees Fahrenheit) with considerable mixing of fresh water from recharge areas at the sampling sites. A structural analysis suggests three types of structures are present in the basin. Type I is the range-front fault zone. This zone receives recharge from the Stillwater Ranges and is considered of lower potential than the area within the major east-west graben structure (Type II). The third type of structure is basinward and parallel to the strike of the range-front fault system. Expected reservoir rock is either the lower intervals of the alluvial fill or the upper, highly fractured Tertiary volcanics at depths of 4,000 to 7,000 feet. In addition, the interval at or below the base of the gabbroic complex or lopolith may be a vapor-dominated reservoir. However, the depth to such a reservoir may be excessive, except for areas along the western edge of the basin.

The economic potential of the Dixie Valley area has been compared to other geothermal operations of the world. This allows minimum resource characteristics to be set during an early stage of development for an assessment of the viability of the prospect.

Economic viability for the Dixie Valley area (beyond 1980) will require a minimum wellhead temperature of 200 degrees Centigrade (392 degrees Fahrenheit), a minimum of approximately 475,000 lbs/hr well flow rate, and a maximum well cost of $400,000. An analysis of producer's cost is presented that illustrates the economic effects of variations in the above factors.

II INTRODUCTION

General: Dixie Valley Potential

A Stage I exploration program is presently underway to evaluate the geothermal potential of Dixie Valley, located in Churchill County, Nevada (See Figure 1), with an emphasis on the areas presently held or controlled by Millican Oil Company (see Plate I-back pocket). This report summarizes the results obtained to date. The program has consisted of three concurrent projects: 1) a ground-water geochemical evaluation - to indirectly assess the potential subsurface temperature and chemical characteristics of the reservoir fluids; 2) a structural evaluation of the Stillwater and Clan Alpine Ranges - to determine the history and interrelationships of the inferred structural features in the Dixie Valley as they relate to potential geothermal production; and 3) a geological evaluation of the Stillwater and Clan Alpine Ranges flanking Dixie Valley - to determine the possible geological character of the potential geothermal reservoir rock in the basin.

As the development of geothermal energy proceeded in the United States over the past decade, dry-steam resources (or vapor-dominated reservoirs) gained industrial acceptance because the resources were found to be a readily available and dependable source of easily-converted energy that could be produced at relatively low cost and thereby displace conventional energy sources. The availabilty of this type of high-quality (high-grade) energy resource, however, is limited, but hot-water-dominated reservoirs containing medium-grade resources are approximately twenty times more numerous than the vapor-dominated, high grade resources. Industry has begun to develop these medium quality (medium grade) resources over the past few years in the United States, and are now searching for the highest quality, medium-grade resources, as conversion technology is developed from long-term experiences in the high-quality resources (vapor-dominated reservoirs) of the Geysers and other areas and from recent experiences in the medium quality resources (liquid-dominated reservoirs) of New Zealand, Mexico and elsewhere in the world. The latter resources are developed and produced as high-temperature water

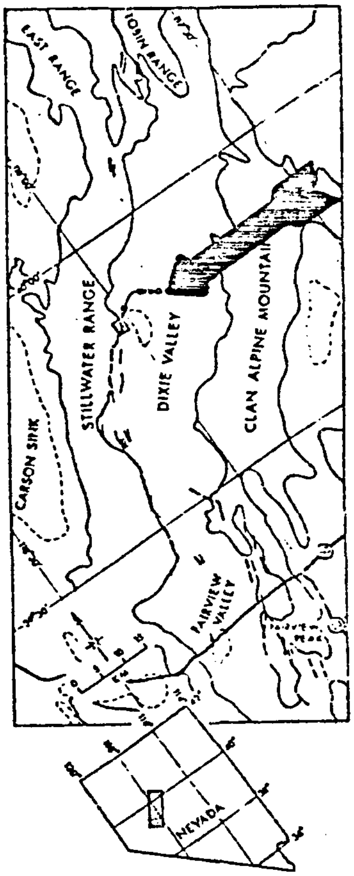


FIGURE 1: LOCATION MAP - DIXIE VALLEY, CHURCHILL COUNTY, NEVADA: ARROW SHOWS AREA OF INTEREST (FROM THOMPSON AND BURKE, 1974)

(greater than 230 degrees Centigrade (446 degrees Fahrenheit) that is steam flashed either at the wellhead or within the power plant under pressure.

Medium quality (medium grade) resources that may be developed and produced from medium temperature water (less than 230 degrees Centigrade) are now under review in many areas of the western United States and the energy conversion technology, according to theoretical models developed to date, is presently available. The economic viability, however, is uncertain because the models have not yet been fully tested under field conditions, although optimistic activity is continuing in a number areas of the western U.S. with favorable results obtained to date.

The potential of Dixie Valley as a medium quality (medium grade) source of energy is dependent upon the nature of the reservoir (temperature, permeability, volume, and chemical characteristics of the produced fluids) and upon the economics of reservoir production and power-plant conversion of the contained energy for electrical power generation. The initial results of the exploration program presently underway indicate that the Dixie Valley area has an excellent geological potential for developing hot water of sufficient high temperature and volume to supply a power plant with a minimum of 100-150 MW capacity. In order to assess the area's economic factors, certain assumptions must be made at this date on the nature of the reservoir until data from the forthcoming drilling program can be used to confirm reservoir character, which will increase the level of confidence of future economic analyses.

General: Dixie Valley Economics

A search and evaluation of all available economic information and data have been conducted in order to identify the salient features that affect the economic potential of the Dixie Valley area. Based on the information now available from the exploration conducted to date and on other geothermal operations in the world, a general economic framework can be established for the Dixie Valley area. This report will summarize the various factors involved and will serve as: 1) a foundation for future, more detailed cost analyses as the knowledge improves on the Dixie Valley area with time; 2) a general guide to future exploration and development costs; and 3) a preliminary assessment of the various production-cost models to determine minimum reservoir and land requirements and associated economic demands that will affect the economic viability of the Dixie Valley area generally and the holdings of Millican Oil Company specifically.

The most important factors that affect the economics of geothermal energy conversion to electricity are:

1) wellhead temperature of produced water.
2) wellhead flow rate
3) cost of the multiple-well system supplying the power plant.

The capital cost of the powerplant is significant but is not highly sensitive to variations in the above factors, which individually or in combination determine the economic viability of the particular prospect. The optimum power-plant size will probably remain relatively small, usually in the 50 to 150 MWe range because the opportunities for achieving significant cost reductions through "economics of scale" are small.

The steam-flash method (which directly drives turbines) and the binary method (which uses the heat contained in the produced water to vaporize a working fluid (isobutane is presently favored to drive turbines) are now theoretically competitive. However, a binary system has yet to be tested over sufficient time to indicate its effectiveness, although pilot plants in southern California are showing favorable results. One plant has been in operation in the Soviet Union for some years, also with reportedly good results. The binary system is considered to be cost effective when the produced water is below 200 degrees to 230 degrees Centigrade (292 degrees to 446 degrees Fahrenheit), while the flashed steam approach may be cost effective when the water is above 230 degrees Centigrade. However, recent cost inflation for binary systems has eroded their apparent economic advantage to the point that in-plant steam flashing costs may now be similar to binary system costs (see Appendix for power-plant configurations).

As a potential producer of geothermal energy, Millican Oil Company will not be directly involved in either plant design or selection of the type of conversion process. The producer's role is to explore, discover and produce geothermal energy; since flashing at the wellhead is very inefficient (although flashing in the formation would be highly desirable), the energy produced will be hot water under pressure. The product is then delivered to a power-generating plant erected in proximity to the geothermal reservoir by an electric utility company. The producer, therefore, is responsible for gathering of the hot water (or steam), transmitting the liquid to the power plant, and subsequent disposal of warm water and condensate by subsurface injection. Recovery of fresh water for use in agriculture instead of reinjection is a possibility, especially in the arid regions of Nevada; by-product recovery of marketable metals and/or nonmetals is also a possibility, if economically recoverable.

The price received by the producer for his geothermal product is determined from the cost of power leaving the power plant and other factors such as: 1) proximity of the geographical locations of the geothermal reservoir to a load or use region; 2) the capital, operating, and maintenance cost of power generation from the produced fluids; and 3) the conversion efficiency of the power plant incorporating the produced fluids.

The price received by the utility in a given geophysical area depends upon the future cost of base-load electricity supply from competition sources, such as nuclear power, low-sulfur fuel oil, coal, and hydroelectric power. The cost of a new based-load electric power supply in the period 1975-1985 has been determined from the projected cost of primary fuels and their respective capital requirements for conversion into electric power. The mean marginal power costs have been calculated for various load centers in the western United States, based on projections by the National Petroleum Council (1971) as to the market share held by each primary fuel in the electric power-generating sector. The mean marginal "city gate" power cost in the western United States ranges from 20-30 mills/kW hr.

By establishing the prospective utility company's power cost-rate structure, which is generally necessary in producers-utility contract negotiations, the contract price paid to the producer (cost plus profit - which includes rewards for early risk), is determined for a ten to twenty year period with provisions for price escalations due to inflation and other factors that serve to increase the producer's cost.

Given the utilities cost-rate structure, a maximum negotiated producer price range can be estimated. If a 20 mill/kW hr. utility cost is assumed, a producer price of 15-17 mills to the utility could be expected for present contracts (1977-1980). It should be emphasized that producer price increases direct influence utility costs and therefore "city-gate" prices. The producer price depends on the ability of the particular reservoir to produce and on the cost to produce fluids at economically acceptable temperatures and flow rates. In order to test the potential economic viability of the Dixie Valley area within the areas held or presently controlled by Millican Oil Company, the geological potential has been evaluated and will be discussed on the basis of presently available information, followed by a review of the economic ramifications of this potential.

On behalf of Millican Oil Company, the exploration programs and preliminary economic evaluations have been conducted by Keplinger and Associates, Inc., under the direction of Mr. Michael D. Campbell. Mr. Charles C. Wielchowsky conducted the field programs and was assisted by Mr. Randy Foutch.

III GEOLOGICAL POTENTIAL

Reservoir Temperature

A geochemical survey of selected springs and wells was conducted during June, July and August, 1977 (Plate II indicates sampling locations). The survey was designed to evaluate the following factors:

1) Representative chemical content of the springs and wells
2) Chemical content flux over time of the springs sampled
3) Temperature flux over time of springs sampled
4) Chemical relationship of hot-water sources to cold-water sources
5) Analytical variations
6) Reservoir temperature
7) Subsurface hydrological conditions

Table 1 presents the results of chemical analyses conducted on the samples taken during the survey. Samples and temperature of the springs were obtained over a nine day period. Duplicate samples were taken at the beginning and at the end of the survey period from each of the three springs sampled (two hot-water springs and one cold-water spring) for analysis of analytical error. Temperatures were obtained in the morning and evening. Samples were taken on alternate days in the morning for chemical analysis. The suite of chemical analysis tested is that commonly conducted in geothermal exploration and development.

TABLE 1

CHEMICAL DATA ON SELECTED
DIXIE VALLEY SPRINGS AND WELLS

Date	Sample#	Time	Li*	Na*	K*	Mg*	Ca*	pH	HCO_3*	Cl*	SO_4*	U**	B*	Ag**	Au**	CO_2***	H_2S*	SiO_2*	Temp. °C Water	Temp. °C Ambient
SPRING #1 (Elevation: 3430')																				
6-29	1-40	8:25 AM	0.88	422.	14.8	0.70	65.3	7.76	42.3	530.	82.3		≤20.			≤1	≤0.03	81.	57.2	28.0
6-29	1-30	8:25 AM	0.89	473.	14.5	0.89	65.1	7.84	38.3	840.	74.9		≤20.			≤1	0.06	83.	57.2	28.0
6-29	1-41	6:05 PM	0.88	473.	14.3	0.72	65.2	7.86	67.3	700.	87		≤20.			≤1	≤0.03	88.	57.2	36.0
6-30	NS	7:55 AM																	57.2	27.2
7-1	1-42	8:00 AM	0.88	495.	14.8	0.72	65.2	7.87	54.1	800.	78		≤20.			≤1	≤0.03	90.	57.3	28.0
7-1	NS	5:05 PM																	57.3	24.7
7-2	NS	7:55 AM																	57.3	24.9
7-2	NS	7:00 PM																	57.3	28.0
7-3	1-43	9:25 AM	0.89	495.	14.5	0.78	64.5	7.91	78.9	700.	86		≤20.	39.	≤5.	≤1	0.08	90.	57.5	26.0
7-3	NS	5:50 PM																	57.2	31.0
7-4	NS	9:05 AM																	57.4	23.5
7-4	NS	7:10 PM																	57.3	25.0
7-5	1-44	9:40 AM	0.89	493.	14.8	0.70	65.2	7.91	58.3	720.	91		≤20.			≤1	≤0.03	93.	57.2	22.9
7-6	NS	7:00 PM																	57.4	30.0
7-6	NS	8:55 AM																	57.3	23.1
7-6	NS	9:30 PM																	57.3	24.2
7-7	1-45	9:25 AM	0.88	487.	15.0	0.71	65.5	7.69	63.7	720.	89	≤2	≤20.			≤1	≤0.03	91.	57.3	26.0
7-7	1-46	9:25 AM	0.88	482.	14.6	0.74	64.4	7.70	57.7	620.	75.3		≤20.			≤1	≤0.03	90.	57.3	26.0
		Mean	0.88	477.5	14.66	0.75	65.05	7.82	57.6	703.8	82.65		-			-	-	88.3	57.3°C	
		Std. Deviation	0.01	24.2	0.23	0.06	0.39	0.09	7.4	96.8	6.38		-			-	-	4.1	0.09 (135.1°F)	
SPRING #2 (Elevation: 3430')																				
6-29	2-20	8:45 AM	0.64	191.	8.3	0.44	8.4	7.99	99.9	160.	57.2		≤20.			≤1	≤0.03	143.	67.2	27.8
6-29	2-10	8:45 AM	0.64	207.	8.1	0.34	8.1	8.13	98.6	190.	52.3		≤20.			≤1	≤0.03	143.	67.2	27.8
6-29	2-21	6:20 PM	0.64	197.	7.6	0.43	8.4	8.15	159.8	170.	62.1		≤20.			≤1	≤0.03	143.	69.2	36.2
6-30	NS	7:50 AM																	68.0	26.1
7-1	2-22	7:50 AM	0.64	189.	8.3	0.41	8.4	8.03	93.1	200.	60.1		≤20.			≤1	≤0.03	143.	68.1	28.8
7-1	NS	5:10 PM																	68.2	24.0
7-2	NS	7:50 AM																	67.2	24.0
7-2	NS	7:05 AM																	67.2	28.0
7-3	2-23	9:20 AM	0.64	189.	8.3	0.40	8.6	8.31	93.7	200.	58.0		≤20.	10.	≤5.	≤1	≤0.03	144.	67.5	25.0
7-3	NS	6:00 PM																	67.0	31.0
7-4	NS	9:00 AM																	67.7	26.0
7-4	NS	7:15 PM																	67.0	29.0
7-5	2-24	9:30 AM	0.63	210.	8.5	0.17	7.4	7.98	100.4	180.	58.8		≤20.			≤1	0.05	138.	67.5	22.7
7-5	NS	7:05 PM																	67.3	33.5
7-6	NS	8:45 AM																	67.2	24.0
7-6	NS	9:35 PM																	67.5	23.0
7-7	2-25	9:15 AM	0.64	187	7.4	0.42	8.3	8.25	105.2	360.	53.9		≤20.			≤1	≤0.03	142.	67.4	26.0
7-7	2-26	9:15 AM	0.64	187.	8.1	0.19	6.7	8.09	100.9	270.	56.4		≤20.			≤1	≤0.03	142.	67.4	26.0
		Mean	0.64	194.0	8.08	0.35	8.04	8.116	106.4	216.3	57.35		-			-	≤0.03	142.3	67.6	
		Std. Deviation	0.004	8.3	0.38	0.11	0.63	0.119	21.9	67.0	3.18		-			-	-	1.83	0.57 (153.7°F)	
SPRING #3 (Elevation 3420')																				
6-29	3-60	9:45 AM	0.07	460.	7.4	24.8	39.3	8.17	215.9	490	93.8	≤2	≤20.			≤1	≤0.03	32.	20.2	33.3
6-29	3-70	9:45 AM	0.08	452.	7.8	24.9	39.9	8.08	203.6	700.	93.8		≤20.			≤1	≤0.03	31.	20.2	32.3
6-29	3-61	5:45 PM	0.07	424.	7.4	25.8	40.9	9.00	213.5	490.	95.9		≤20.			≤1	≤0.03	36.	20.2	34.8
6-30	NS	8:15 AM																	20.2	27.5
7-1	3-62	8:25 AM	0.07	460.	7.2	24.4	39.3	7.93	211.1	540.	120.6		≤20.			≤1	≤0.03	33.	20.4	28.0
7-1	NS	4:45 PM																	20.4	25.2
7-2	NS	8:15 AM																	20.3	25.2
7-2	NS	6:40 PM																	20.3	27.2
7-3	3-63	9:50 AM	0.08	469.	7.6	24.4	39.3	8.10	181.9	600.	94.0		≤20.	243.	≤5.	≤1	≤0.03	33.	21.0	28.0
7-3	NS	3:30 PM																	20.3	31.0
7-4	NS	9:25 AM																	20.0	23.5
7-4	NS	6:50 PM																	20.1	27.0
7-5	3-64	10:00 AM	0.08	424.	7.4	24.9	40.1	8.20	197.6	500.	101.6		≤20.			≤1	≤0.03	34.	20.0	25.8
7-5	NS	6:40 PM																	20.1	28.8
7-6	NS	9:10 AM																	20.1	26.2
7-6	NS	NT																	-	-
7-7	3-65	10:00 AM	0.08	380.	7.2	24.4	38.9	8.07	234.2	640.	102.5		≤20.			≤1	≤0.03	36.	20.0	28.8
7-7	3-66	10:00 AM	0.07	433.	8.0	25.8	39.9	8.08	208.6	540.	97.1		≤20.			≤1	≤0.03	36.	20.0	28.8
		Mean	0.075	437.8	7.5	24.93	39.7	8.079	208.3	562.5	99.91		-			-	-	33.38	20.24	
		Std. Deviation	0.005	29.1	0.28	0.58	0.63	0.086	15.1	77.3	9.03		-			-	-	1.51	0.25 (69.4°F)	
7-7	4-1 Frenchman Well		0.14	380.0	6.5	4.9	10.8	8.49	523.0	140.0	97.5	12	≤20.	304.	≤5.	≤1	≤0.03	86.0	-	

---

* parts per million (mg/l)
** parts per billion (µg/l)
*** analyzed as carbonate, reported as CO

Although the data are still under review, the following interim conclusions can be made:

1) Springs No. 1 and No. 2, although separated by less than a mile, differ significantly in chemical content, the former being a chloride-sulphate-bicarbonate type ($Cl-SO_4-HCO_3$)and the latter a chloride-bicarbonate-sulphate type ($Cl-HCO_3-SO_4$). This suggests that the fault or fracture systems feeding the two springs may not be in mutual communication or that mixing of deep reservoir water with shallow meteoric ground water is occuring. A combination of both possibilities is postulated at this time.

2) Chemical and temperature short-term flux (9 day period) in both hot-water springs is remarkably constant, although the planned future geochemical sampling may show variation within a long-term flux period over months). This suggests that stable conditions are present at depth, either as a result of constant subsurface influx of meteoric ground water from the Stillwater Ranges, or of equilibrium conditions within the reservoir. The former is postulated at this time.

3) Springs No. 3, located some 6.5 miles north of Springs No. 1 and No. 2, and the Frenchman Well located approximately 60 miles south in Fairview Valley (see Figure) are cold-water sources and were selected for sampling as a base-line for establishing the local and regional characteristics of meteoric ground-water influx and recharge to the local basin and recharge areas

at some distance from the Dixie Valley area of interest. The chemical data of the cold spring suggest that this water is representative of ground-water systems recharged in the Stillwater Range area. Its non-involvement with hot-water systems is structurally controlled by fault and fracture systems above geothermal influence. The data from the Frenchman Well indicates near-typical mid-basin ground-water, with minor exceptions.

4) Calculated subsurface temperature and mixing components using the standard methods indicate wide but significant variations:

I. Spring No. 1 - 57.3 degrees Centigrade (135 degrees Fahrenheit

A. <u>Ca-Na-K method</u>

$$\log K^* = \log \frac{Na}{K} + \beta\ (1/3) \log \frac{\sqrt{Ca}}{Na}$$

Calculated as: 132 degrees Centigrade (270 degrees Fahrenhe

B. $\log \frac{Na}{K}$ method

Calculated as: 105 degrees Centigrade (221 degrees Fahrenhe

C. <u>Silica Method - Model 2</u>

<u>Mixing</u>: 57% Cold water
43% Hot water

Indicated Temperature: 155 degrees Centigrade (311 degrees
Fahrenheit) of Hot water

II. Spring No. 2 - 67.3 degrees Centigrade (153 degrees Fahrenheit

A. <u>Ca-Na-K method</u>

Calculated as: 146 degrees Centigrade (295 degrees Fahrenh

B. $\text{Log} \frac{Na}{K}$

Calculated as: 125 degrees Centigrade (257 degrees Fahrenh

C. Silica Method - Model 2

Mixing: 39% Cold Water
61% Hot Water

Indicated Temperature: 175 degrees Centigrade (347 degrees Fahrenheit)

The effects of mixing meteoric ground-water and upwelling reservoir water are clearly indicated in the calculated mixing components. In addition, disequilibrium conditions between the rock (through which hot water has migrated) and the produced water are also indicated. This reduces the reliability of the Ca-Na-K and log $\frac{Na}{K}$ methods of subsurface temperature calculation. The silica method, however, is less affected by disequilibrium effects and since travertine deposits around the spring outlets were not apparent (siliceous sinter was also not apparent), the reliability of silica-based calculations for temperature and mixing is considered reasonable minimum temperatures for relatively shallow, mixed sources. This suggests that deeper sources may be in excess of 175 degrees Centigrade (347 degrees Fahrenheit) and that the spring data show the effects of shallow involvement of meteoric ground water.

It should be emphasized here that using all of the above methods for reservoir temperature estimations, in conjunction with samples derived from hot-springs, can be misleading if the hydrogeological conditions are ignored. But, minimum temperatures can be established with relative confidence if the effects of meteoric ground water influx can be estimated. The above methods and other geochemical ratios will be of particular benefit when initial drilling permits deep sampling of reservoir fluids to estimate maximum temperatures present in the reservoir system. An estimation of proximity to heat source will also be possible and will be one of the important guides to exploration and well-site selection in the future.

5) Chloride content suggests that the Dixie Valley system in the vicinity of the springs sampled is a hot water-dominated type reservoir. Chloride content less than 50 ppm indicates a vapor-dominated reservoir, as in The Geysers area. If a vapor-dominated reservoir is present at depth (at the base of the gabbroic complex or lopolith) there is no indication of its presence in the ground-water geochemistry of the hot springs sampled. The upper reservoir could be obscuring any manifestations of a deep, vapor-dominated reservoir.

Structural Elements

A field evaluation of the structural geology of the Stillwater and Clan Alpine Ranges was conducted during the summer of 1977 in conjunction with the geochemical and spring sampling program. A preliminary view of the pertinent structural aspects of the Dixie Valley area is shown in Plates II (Plan) and III (cross-sections). Although important data and interpretations are forthcoming from areomagnetic surveys presently underway, which will serve to significantly improve the knowledge of the structural setting of Dixie Valley, an interpretation independent of the new geophysical input will serve to either support or alter future interpretations of the Dixie Valley structure based strictly on such geophysical interpretations.

It is reasonably clear at this date that potential geothermal production may be associated with three general types of structures. The first type of structure (Type I) is the major fault zones (range-front faults) that border the Dixie Valley on the west. The second type of structure (Type II) is the broad graben structure that trends northwest-southeast, originating in the Stillwater Range north of Section 10 of Range 35E: 24N Township and splits southeastward into two fault zones, within which is a major downthrown block or complex of blocks that appear to extend into the basin. The third type of structure (Type III) of potential significance is the fault zone that runs parallel to the major fault zones of the western border of Dixie Valley in a position 4-5 miles basinward of Type I structures. The relative potential of the three structure types is discussed. The conclusions made here are tentative and subject to revision based on the new geophysical information soon to be available.

Type I - This type of structure will extend to considerable depths and are responsible for the hot springs located in Dixie Valley, two of which were sampled, as discussed previously (see Plates II and III).

The principal fault zones (associated with range-front faults) on the west will probably be the principal carrier of sinking meteoric ground water (see Plate III - northwest edge of cross sections). As it is heated to the boiling point consistent with the effects of hydrostatic pressure and increasing heat at depth, an upward migration of less dense, heated ground water would occur, perhaps along the second of the major fault zone, located to the east of the principal range-front fault zone. This mechanism is inferred from the interpretations of the chemical data generated by the spring sampling program. The depth at which rising, hot ground water would be encountered by meteoric ground water would be the depth at which the meteoroic water was introduced into the fracture system, which may be shallow or deep. The chemical differences between Spring No. 1 and No. 2 support this view and further indicate that the point of entry will affect the equilibrium conditions.

In general, the Type I structure is not considered to be prospective until it reaches sufficient depth to allow the introduction of rising, hot fluids into associated fracture systems having significant communication with either the basin convection cells or heat released from below the gabbroic complex. This type, therefore, will not be prospective at shallow depths because it serves as the recharge points for the basin until a depth of approximately 4,000-7,000 feet is reached, whereupon it may feed fractured systems of sufficient permeability to be of interest for possible geothermal production.

Plate II shows the areas held or controlled by Millican Oil Company and other companies that appear to have potential for Type I associated structure. It should be noted that only intervals below 4,000 feet and above 7,000 feet depth are considered at this date to have potential, the latter depth limitation is based on the apparent economic limitations of drilling, as will be discussed later. The areas are located in the Northern Region (See Plate II). 4.25 sections (or 2,720 acres) are deemed prospective out of 18 sections (or 11,520 acres) presently under control by Millican Oil Company. It should be noted that the base of the gabbroic complex or lower reservoir will be at its shallowest along the western margin of the basin.

Type II - This type of structure involves complex and highly permeable fracture systems produced by the late development of a major graben that separates the Northern Region from the Southern Region. The systems are sufficiently basinward to be involved in the area of upward or lateral migration of the postulated convection cell in the upper reservoirs, fed by Type I structures from the west and by the graben system extending from the Stillwater Range into the basin (see Plate III cross-section A-A').

Again, only the areas below 4,000 feet depth (into the upper volcanics) and above a 7,000 feet depth are considered at this date to have potential. The area under consideration here is in the Southern Region (see Plate II). 6.33 sections (or 4,051 acres) are deemed prospective out of 9 sections (5,760 acres) within the graben structure presently under control by Millican Oil Company.

Type III - This type of structure (shown in Plate II) is inferred from an interpretation of structural mechanisms and previous information on a segment of this type of structure. It represents the most significant structure of all three types present for the upper reservoir and may extend through a large part of the Millican holdings. Subsequent geophysics and drilling will test this conclusion. However, on the basis that the upwelling convection cell will be present in this part of the basin, the relative position of this type of structural feature is favorable not only because it may intersect the high temperature part of the convection cell, but the Type III structure may also be fed at depth by the recharge faults of the Type I structure. Type III structure (faults) occur between the range-front fault and the axis of the assumed maximum depth to basement, but dip toward the range rather than away from the range as in Type I structures.

Additional Type III or related structures may be present and parallel to that structure shown in Plates II and III (cross-section A-A' and B-B'). Of particular significance is the area within the graben structure. The present geophysical program should produce information that may: 1) support the existence of Type III structure, 2) support the view that the Type III structure within the graben is of particular significance and 3) define and locate the Type III structure in the Eastern Region. Open land is present between the Southern and Eastern Regions and acquisition may be desirable if Type III structures are confirmed.

Favorable areas have been defined along the inferred trend of the Type III structure and assigned an area of interest that represents the structure from 4,000 to 7,000 feet depths. 5.45 sections (or 3,488 acres) are considered as highly prospective within the Southern, Northern and Eastern Regions of Millican Oil Company holdings.

Based on a preliminary structural analysis of potentially favorable land in Dixie Valley, Table 2 is a summary of potential company holdings of Millican Oil Company, Southland Royalty, Sunoco, Republic Geothermal and Geothermal Resources; the potential is defined by type of structure they control at this date. The potential is based on the upper reservoir.

It should be emphasized that an assessment of potential at this time, while necessary, is purely speculative. It is clear, however, that the other companies with holdings in the Dixie Valley area are interested in Type I structure, the structure associated with the front-range faults on the western border of the basin. This is shown in Table 2 by the total holdings compared to Type I

Table 2

Comparison of Company Holdings Relative to Type of Structural Potential

Company	Total Acreage In Area (Approx.)	Potential Acreage Defined by Structural Type			% Total Favorable Land: All Structures	% Favorable Land of Companies with Type III Holdings
		Type I	Type II	Type III		
		(% Total Company Holdings in Area)				
Millicen Oil	33,920	2,720 (8.0)	4,051 (11.9)	3,488 (10.3)	30.2	37.3
Southland Royalty	14,080	5,920 (42.0)	2,816 (20.0)	3,328 (23.6)	85.6	35.6
Sunoco	10,240	6,515 (63.6)	0 0	1,472 (14.4)	78.0	15.7
Republic Geothermal	5,440	1,069 (19.7)	0 0	640 (11.8)	31.5	6.8
Geothermal Resources	2,240	0 0	0 0	429 (19.2)	19.2	4.6
TOTAL	65,920	16,224	6,867	9,357	49.2	100.0

holdings. Sunoco, for example, has 63.6% of their total holdings as Type I structure. Millican Oil has only 8.0% over Type I structure. However, if the assumptions are correct regarding the potential of Types II and III, only Millican Oil and Southland Royalty will have adequate acreage to develop large geothermal reserves. The interest in Type I structure may also indicate interest in the lower reservoir at the base of the gabbroic complex.

Geological Elements

In conjunction with the structural evaluation, an analysis of the probable character of the reservoir rocks was undertaken. Although the evaluation has not been completed to date, certain conclusions can be made:

1) The Quaternary alluvium may range from 300 to 5,000 feet (maximum) projected thickness in the center of the basin - see Plate III.
2) Tertiary volcanic sequences underlie Quaternary sediments, and range from less than 1,000 feet to approximately 4,000 feet in thickness, are probably severely faulted and highly permeable along their fracture systems, and are composed of rhyolitic and basaltic flows and tuffs.
3) A Jurassic gabbro and diorite complex in the form of a lopolith is present below the Tertiary volcanics; the rocks are not highly fractured, but are probably individually faulted with major displacements and are approximately 3,000 feet in thickness, thinning toward the edge of the basin. See Plate II for approximate limits of the gabbroic complex in subsurface.

4) Triassic slate, phyllite, siltsone and mudstone are present below the gabbro and diorite complex.

The potential upper reservoir is the lower intervals of the Quaternary alluvial sequences and/or upper intervals of the Tertiary volcanics. If sufficiently fractured, the latter may be an acceptable reservoir because it is in fluid communication with recharge areas and the heat source below the gabbroic complex. The volcanics may have a tendency to seal fractures and reduce permeability since they often contain minerals that alter rapidly, which would suggest potential plugging of presently open fracture systems. The overlying alluvial fill sequences will probably have excellent permeability.

The location of heat source is probably at depth below most of the basin in the area. There are some possibilities that intrusives have migrated upward along the major fracture zones; one intrustion may have reached the lower section of the alluvial material (see Figure 2). If this can be confirmed or indicated via the aeromagnetic survey it obviously will have a major impact on the potential of Dixie Valley. For the present, little direct or indirect evidence is available either for the existence of such a shallow intrusion or for most of the structural features shown in Figure 2, except for the Type III structure as shown.

Another potential reservoir is at the base of or below the gabbroic complex, either in highly-fractured Jurassic quartz arenite, or in the Triassic metamorphic sedimentary sequences. Minimum depth of the base of the gabbroic complex in the vicinity of Type I structure is no greater than 7,500 feet.

It should be noted that the possibility exists that such a reservoir may be vapor-dominated. If this is the case, the economic requirements of such a reservoir will be significantly different than the water-dominated reservoir discussed herein (e.g. higher wellhead temperature, lower average flow rates, higher well costs, etc.). If it becomes apparent that a lower reservoir has potential then the economics of steam production will have to be assessed much in the same way as conducted in this report for the potential upper reservoir. Non-specific data on vapor-dominated reservoir were the basis for the discussions contained in a previous report by Keplinger and Associates, Inc. entitled: "A Preliminary Evaluation of the Hughes Geothermal Properties in Churchill County, Nevada", dated April 27, 1977. Specific data relative to the Dixie Valley could be used for an economic comparison with The Geysers area of California. Considerable cost data are available on such systems and a reliable operational estimate could be made on the Dixie Valley holdings after reservoir minimums were established by analogy with The Geysers area and others.

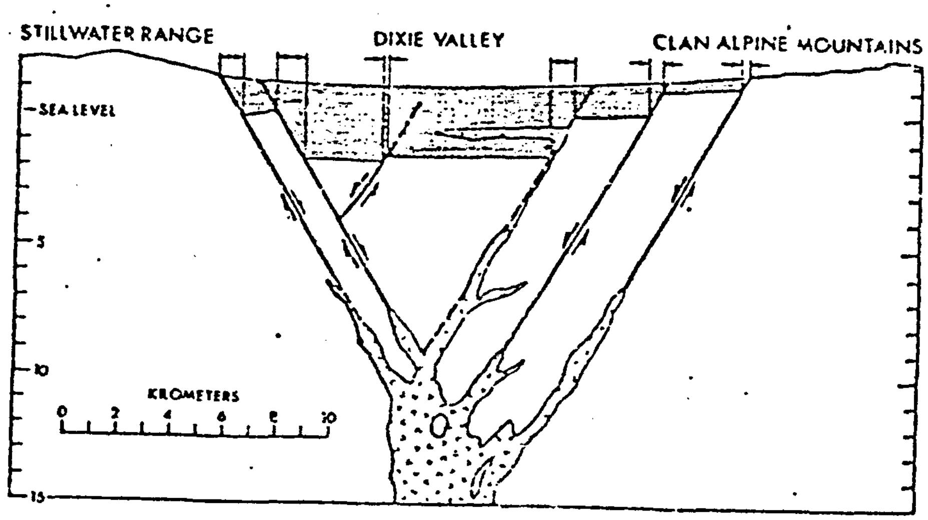


FIGURE 2: CROSS SECTION OF DIXIE VALLEY, NEVADA. THE SUBSURFACE STRUCTURE TO DEPTH OF THE SEDIMENTARY FILL (YELLOW) IS BASED ON GEOPHYSICAL EXPLORATION. DIKE AT DEPTH IS POSTULATED TO ACCOMMODATE SURFACE EXTENSION, AS SHOWN BY ARROWS AT SURFACE (FROM THOMPSON AND BURKE, 1974)

IV ECONOMIC POTENTIAL

As summarized in the INTRODUCTION, the factors that determine the economic suitability, or the lack thereof, for geothermal prospects are as follows:

1) Temperature of the reservoir
2) Temperature at the wellhead
3) Flowrate, a function of:
    a) fluid productivity (reservoir fracture system)
    b) size of reservoir
    c) production lifetime of reservoir (response of reservoir to development)
4) Well cost, a function of:
    a) depth to producing zones
    b) fluid quality
    c) productive lifetime of well structure
5) Distance from producing field to power plant

Effects of Temperature and Flow Rates

As a general rule, a moderate temperature (200 degres Centigrade), a relatively shallow reservoir containing less than 10,000 TDS fluids may be more attractive than a high temperature (300 degrees Centigrade), deep and saline reservoir. However, the cost of producing geothermal electric power declines with increasing fluid temperature. High-temperature wells producing from liquid-dominated reservoirs tend to produce fluid at greater flow rates than low-temperature wells. Consequently, less fluid is required to generate the same amount of power, and fewer wells are needed to supply the fluid. The importance of reservoir temperature is shown in Figure 3; an exponential increase in the number of wells is required to supply a power plant of 200 MW capacity.

Power costs vary inversely with wellhead temperature, i.e. reservoir temperature less well losses as the fluid is transmitted up the well, (see Figure 4). At lower wellhead temperatures, small changes in temperature have a large impact on power costs, while at high temperatures the impact is smaller. Temperature, in combination with the wellflow rate, determines the available power output from a well (see Table 3 and Figure 5).

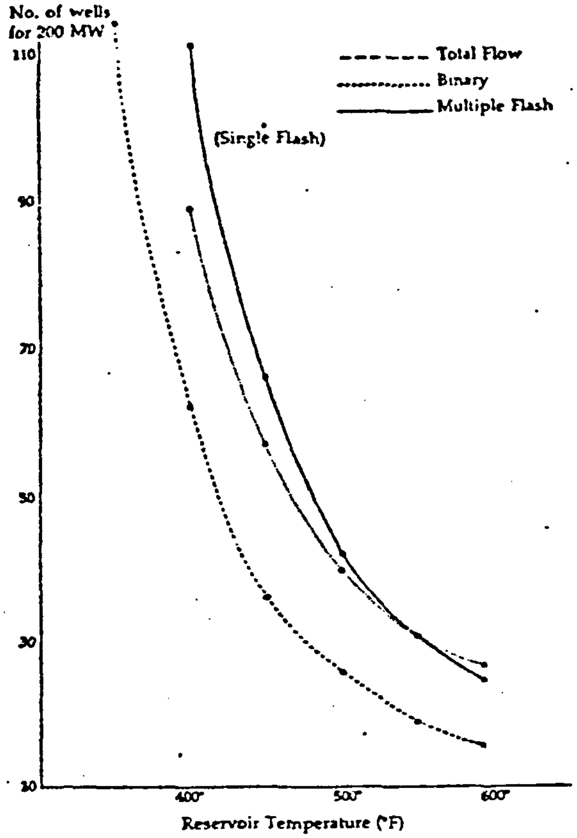


FIGURE 3: Effects of Reservoir Temperature on Required Number of Wells to Produce 200 MW (From Sacarto, 1976)

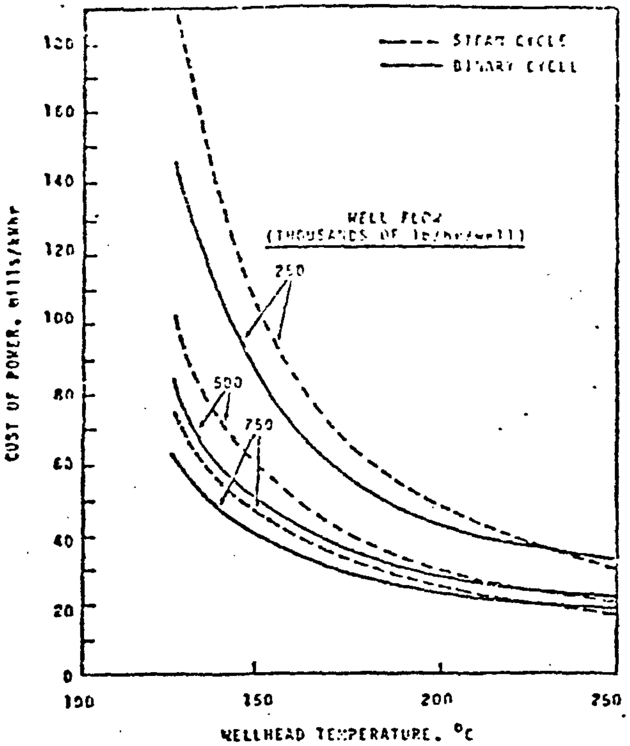


FIGURE 4: EFFECTS OF WELLHEAD TEMPERATURE ON POWER COST (FROM BLOOMSTER AND KNUTSEN, 1975)

Wellhead Temperature °C	Wellhead Flow Rate 10^3 lb/hr	MW (Thermal)/Well[a] Maximum	MW (Thermal)/Well[a] Actual	MWe/Well Gross	MWe/Well Net	Electrical Conversion Efficiency %[b] Gross	Electrical Conversion Efficiency %[b] Net
125	250	14.3	11.9	.5	.4	4.2	3.4
	500	28.6	23.6	1.0	.8	4.2	3.4
	750	43.0	34.9	1.4	1.2	4.0	3.4
150	250	17.7	14.6	.9	.7	6.2	4.6
	500	35.4	29.2	1.8	1.5	6.2	5.1
	750	53.1	43.0	2.6	2.2	6.0	5.1
200	250	24.6	20.0	2.0	1.6	10.0	8.0
	500	49.3	40.0	3.9	3.2	9.7	8.0
	750	73.9	56.0	5.5	4.5	9.8	8.0
250	250	32.0	26.0	2.9	2.4	11.2	9.2
	500	64.0	49.4	5.5	4.6	11.1	9.3
	750	95.9	70.5	7.9	6.6	11.2	9.4

---

[a] The maximum is based on the specified wellhead flow rate. The actual is based on the reduced average flow rate using 20% excess producing wells. The variation in conversion efficiency within a temperature category is caused by rounding to an integer number of wells.

[b] For binary isobutane cycle.

TABLE 3: EFFECT OF WELLHEAD TEMPERATURE AND WELLHEAD FLOWRATE ON POWER CONVERSION EFFICIENCY (FROM BLOOMSTER AND KNUTSEN, 1975)

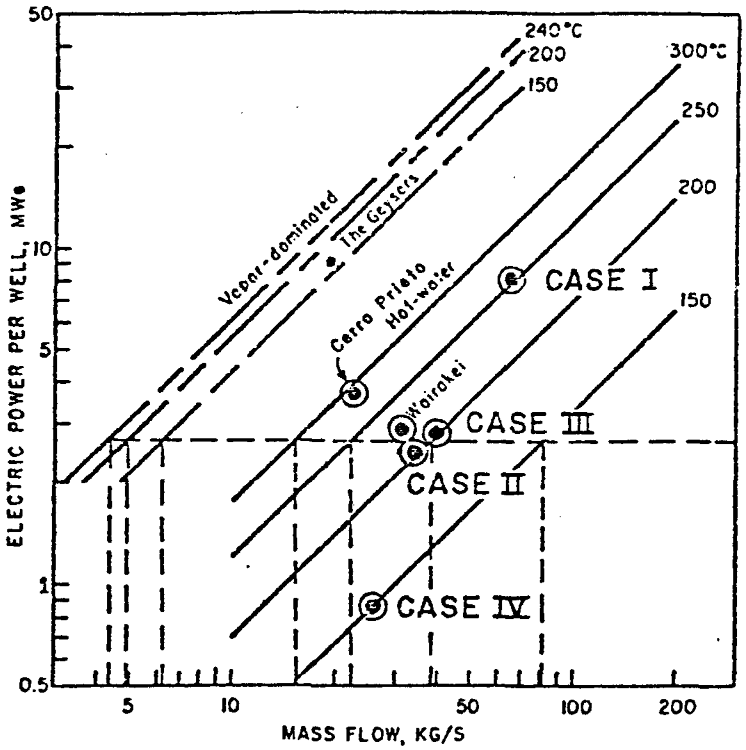


FIGURE 5: ELECTRIC POWER PER WELL AS A FUNCTION OF MASS FLOW FOR VARIOUS TEMPERATURES OF HOT-WATER AND VAPOR-DOMINATED RESERVOIRS SHOWING RELATIVE POSITIONS OF OPERATIONAL SYSTEMS AND CASES I THROUGH IV (AFTER NATHANSON AND MUFFLER, 1976)

In order to be competitive, energy supply (or producer's) cost for low temperature resources (less than 230 degrees Centigrade) must be lower than high temperature resources (greater than 230 degrees Centigrade). This must be achieved through either high well-flow rates, low drilling costs (shallow reservoirs), compact well spacing, extended well life (low-saline reservoir, optimum well design in materials selection and construction), relatively low exploration costs, and/or proximity to market.

Power costs also vary inversely with well-flow rates (see Figure 6). Power costs are more sensitive to flow rate at lower temperatures that at higher temperatures because the thermodynamic efficiency declines rapidly with a decrease in temperature. As previously indicated, wellhead temperature and well-flow rates are two of the most important resource parameters in the cost

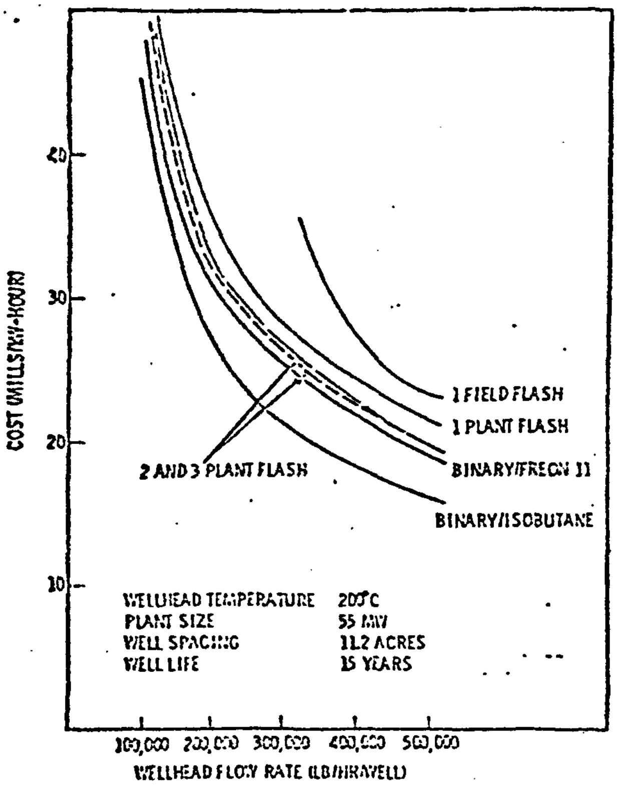


FIGURE 6: EFFECTS OF WELL-HEAD FLOW-RATE ON POWER COST (FROM BLOOMSTER, 1974)

relationship. The importance of the flow rate to power cost is that, for a constant temperature, the power production potential from a well is proportional to flow rate. Therefore, the number of wells and the cost of the energy supply to the powerplant are directly related to the flow rate; low flow rates require more wells and an increase in transmission lines.

Effects of Well Cost

Power costs of the producer are directly related to the well cost (see Figures 7, 8 and 9). The effect of well cost is much greater on low quality (low temperature and flow) resources than on high-quality resources. Since temperature and flow are determined by the reservoir, and since powerplant costs are not subject to wide variation, the well cost is the single most important factor in determining the economic viability of a medium-quality geothermal resource, particularly for a low temperature resource (below 230 degrees Centigrade).

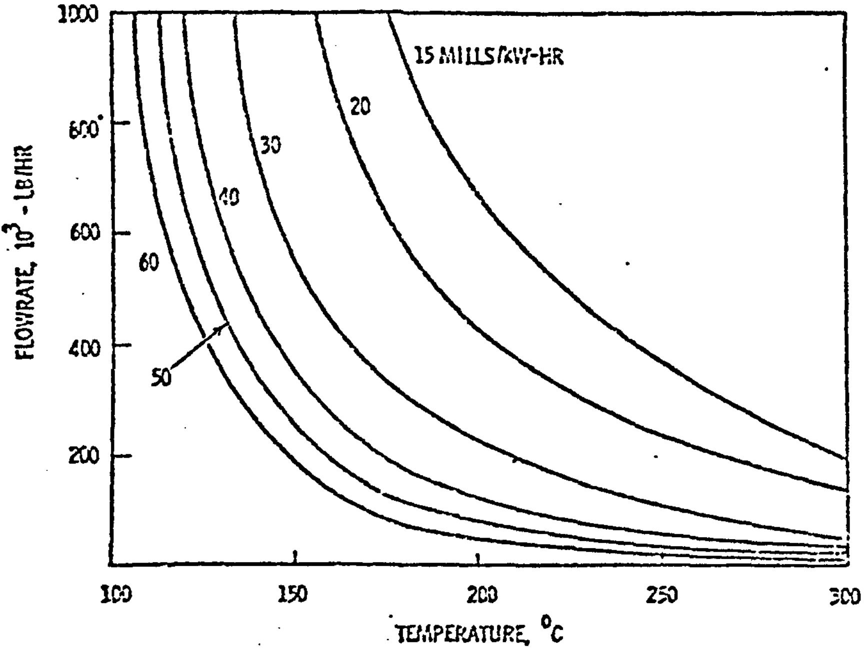


FIGURE 7: EFFECTS OF WELL COST OF $150,000 ON POWER COST AS A FUNCTION OF WELL-HEAD FLOW-RATE AND TEMPERATURE (FROM BLOOMSTER, 1974)

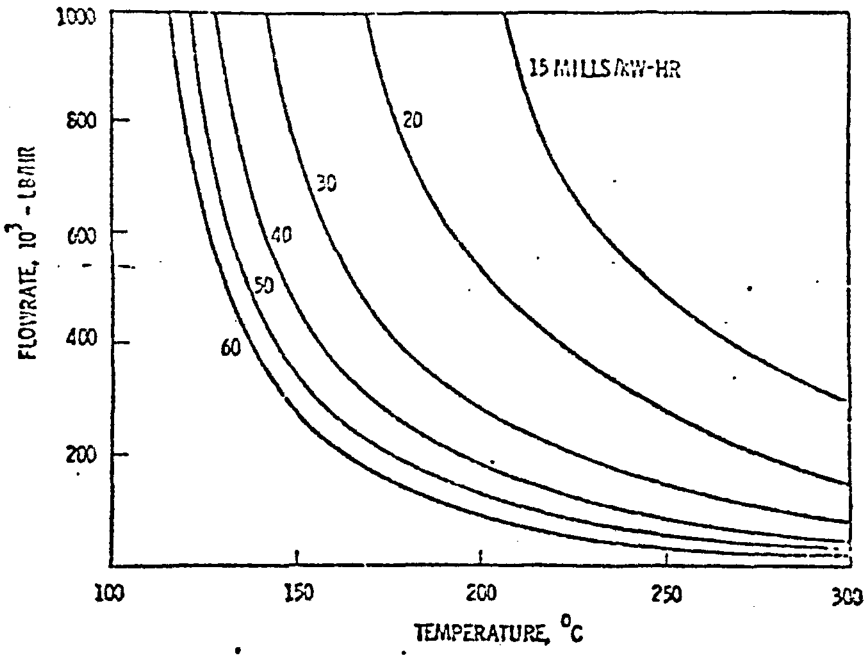


FIGURE 8: EFFECTS OF WELL COST OF $300,000 ON POWER COST (FROM BLOOMSTER, 1974)

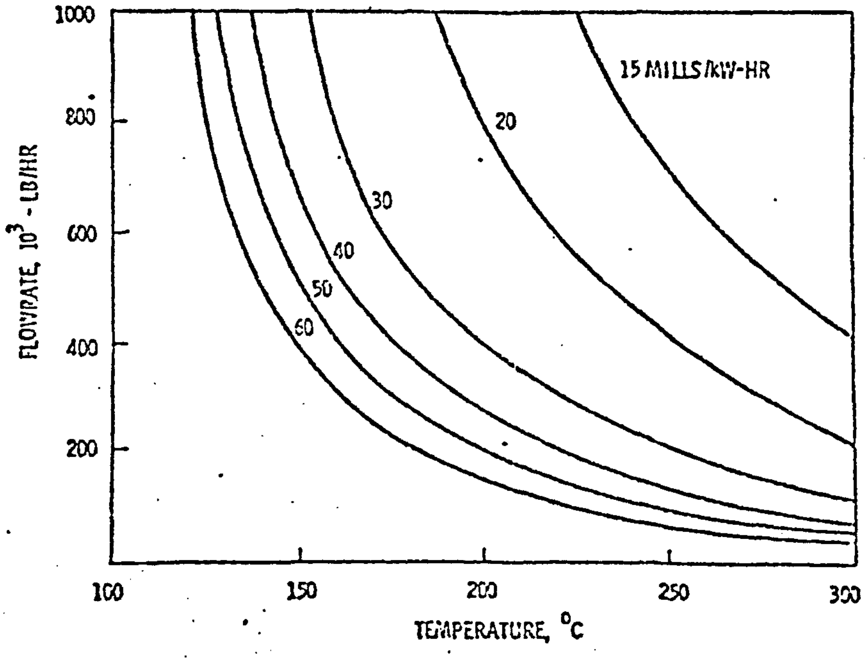


FIGURE 9: EFFECTS OF WELL COST OF $500,000 ON POWER COST (FROM BLOOMSTER, 1974)

Effects of Well Spacing

Power costs also vary directly with well spacing. The increase is associated with increased fluid transmission costs which result from the following conditions:

1) Additional piping is required to transmit the fluid from the field to the powerplant, resulting in increased capital and maintenance costs.
2) Increased heat loss as a result of long pipe runs which decrease usable energy delivered to the power plant.
3) Increased pressure drops over the increased distances so that either pumping costs or pipe distances must be increased.

In the Dixie Valley, the reservoir may be structurally controlled; if production wells are drilled, they can be located either on a triangular lattice along the structural features of Types II or III, or on a grid, if the structural feature is similar to Type I (see Figure 10). A well spacing of 10 to 20 acres is typical in operating hot-water systems.

Effects of Well-Replacement Rate

Power costs increase with the well replacement rate. The replacement rate is the annual rate at which new producing wells are added to augment declining flow rate due to formation sealing, well structure failure, etc.

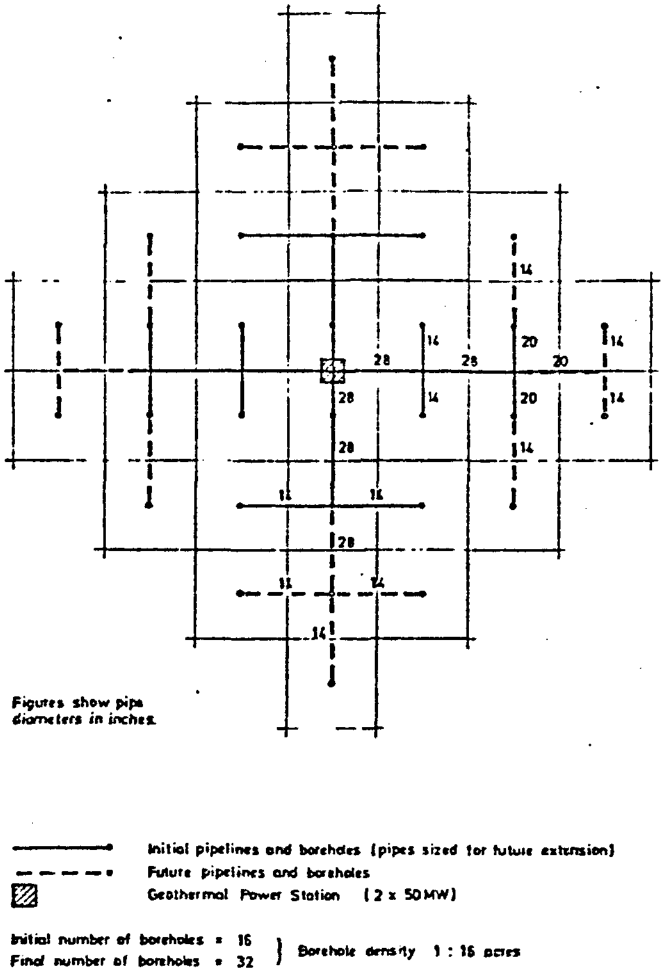


FIGURE 10: TYPICAL MULTIPLE-WELL SYSTEM LAYOUT WITH PROVISIONS FOR EXPANSION OF SYSTEM (FROM GOLDSMITH, 1976)

Case Histories

In an attempt to make an economic comparison between the Dixie Valley area and related fields presently in operation, the geothermal plants (liquid-dominated reserves) in Wairakei (New Zealand) and in Cerro Prieto (Mexico) were selected for detailed study.

The Wairakei field has been in operation for a number of years. Cerro Prieto has just commenced operation since the early 1970's. Both, however, flash at the wellhead and are generally inefficient operations. Both operations are managed by their respective federal governments or their designee. Cerro Prieto is an especially high-quality geothermal field with very high reservoir temperatures and pressures. Wairakei is also a high quality field with substantial bottom-hole pressures.

They both are relatively shallow fields (less than 3,300 feet). The Cerro Prieto field is produced by 15 wells that average 266,000 lbs/hr (22.1 kg/s) or 3.5 MW per well. Figure 5 illustrates the most important economic factor involved in assessing economic viability, i.e. massflow per well, translated into equivalent electric power per well. The average well for the Wairakei and Cerro Prieto fields has been plotted in Figure 5.

In order to define the minimum wellhead temperature, well-flow rates, well costs, etc., four example conditions have been constructed that are based on estimates of producer's costs. Table 4 states the assumptions made regarding: 1) power-plant type, 2) wellhead temperature, 3) well-flow rate, well cost, number of wells required, plant size and final cost to explore, produce, deliver and dispose of geothermal liquids.

Table 5 is a summary of producer costs over the projected life in dollars (1974) and their equivalent in mills per kilowatt-hour. Case I is clearly economically viable at 1974 prices, primarily because it was based on a high-quality reservoir (high temperature and high well-flow rates (see Figure 5 for comparison with other fields and Cases II, III and IV).

Table 4

RESERVOIR AND PLANT ASSUMPTIONS FOR PRODUCER COST ANALYSIS

	Power Plant Type	Well-head Temp.°C	Well Flow-Rate 10^3 lbs/hr.	Well Cost ($M)	Number of Wells	Plant Size (MW)		Cost of Power (Mills/kWhr.)
						Gross	Net	
CASE I	Steam Flash (Double) Implant	250	750	500	10	55	53.0	9.8
CASE II	Binary (Isobutane)	200	430	300	24	55	46.7	10.9
CASE III	Binary (Isobutane)	200	500	500	27	55	46.1	19.6
CASE IV	Binary (Isobutane)	150	250	500	95	55	45.9	75.9

TABLE 5

VARIATIONS IN GEOTHERMAL POWER PLANT & SOURCE AND THE EFFECTS ON DISTRIBUTION OF PRODUCER'S COST

	CASE I		CASE II		CASE III		CASE IV	
	$MM	Mills/KWhr	$MM	Mills/KWhr	$MM	Mills/KWhr	$MM	Mills/KWhr
I Exploration:	2.39	0.7	1.71	0.5	2.39	0.7	2.39	0.7
II Field Development:	9.58	2.8	11.97	3.5	17.10	5.0	72.16	21.1
Producing Wells	(4.79)	(1.4)	(5.81)	(1.7)	(9.58)	(2.8)	(42.41)	(12.4)
Fluid Transmission	(1.36)	(0.4)	(2.05)	(0.6)	(2.05)	(0.6)	(7.87)	(2.3)
Fluid Disposal	(2.74)	(0.8)	(3.08)	(0.9)	(4.10)	(1.2)	(16.42)	(4.8)
Non-Prod. Wells	(0.34)	(0.1)	(1.03)	(0.3)	(4.79)	(0.4)	(5.47)	(1.6)
TOTAL	11.97	3.5	13.68	4.0	19.49	5.7	74.55	21.8
III Field Operation:	10.60	3.1	11.63	3.4	19.15	5.6	80.03	23.4
Producing Wells	(2.39)	(0.7)	(2.39)	(0.7)	(3.76)	(1.1)	(13.68)	(4.0)
Fluid Disposal	(3.08)	(0.9)	(3.76)	(1.1)	(7.18)	(2.1)	(31.46)	(9.2)
Fluid Transmission	(1.71)	(0.5)	(2.05)	(0.6)	(2.39)	(0.7)	(9.58)	(2.8)
Other	(3.42)	(1.0)	(3.76)	(1.1)	(6.16)	(1.8)	(25.31)	(7.4)
TOTAL	10.60	3.1	11.63	3.4	19.15	5.6	80.03	23.4
IV State Income Tax:	0.34	0.1	0.34	0.1	0.68	0.2	3.08	0.9
V Federal Income Tax:	3.08	0.9	2.39	0.7	5.13	1.5	20.86	6.1
VI Royalty Payment:	3.08	0.9	3.42	1.0	4.79	1.4	19.15	5.6
VII Bond Interest:	1.71	0.5	1.71	0.5	2.74	0.8	10.26	3.0
	30.78	9.0	33.17	9.7	51.98	15.2	207.93	60.8
VIII Charge for Internal Power Consumption:	1.37	0.4	2.39	0.7	12.31	3.6	41.38	12.1
IX Revenue Taxes (4%) Related to Energy Supply:	1.37	0.4	1.71	0.5	2.74	0.8	10.26	3.0
TOTAL COST OVER LIFE OF PROJECT:	33.52	9.8	37.27	10.9	67.03	19.6	259.58	75.9

Case II, although of relatively low temperature and flow rate, is also within 1977-1980 economic limits (below 11 mills/kW hr), but this is primarily due to low well costs, indicating a shallow reservoir. Case III is a low temperature reservoir, but has high well-flow rates, and high well costs. This is representative of a field that may not become economic during this period to 1980 but, if utility prices increase from 20 to 25 mills/kW hr over the period, the field could become economic to operate. Case IV is clearly not economically viable now nor will it become economic until energy costs reach at least 85 mill/kW hr ($2.50/million BTU). The economic factors involved in Case II, III and IV will be evaluated further in terms of the Dixie Valley area as additional data becomes available.

V CONCLUSIONS

Based on the evaluations of Dixie Valley to date, the geological and economic potential of the upper reservoir can be summarized as followed:

1) Reservoir temperature of 200 degrees Centigrade (392 degrees Fahrenheit) appears to be possible at depth of 4,000 to 7,000 feet.
2) Reservoir fluid quality appears to be good, but confirmation can only be made via drilling.
3) Three types of structure have potential for production.
4) Millican Oil Company does not hold dominant acreage in areas where competition has targeted either the shallow Type I front-range fault zones that border Dixie Valley on the west or the base of the gabbroic complex at depth.

5) Millican Oil Company does hold significant acreage in areas of potential production (Types I, II and II), i.e. 30% (10,260 acres) of total acreage; Millican holds a dominant acreage position on Type III structures, i.e. 37% of the land of all companies with Type III holdings.

6) Southland Royalty is co-dominant with Millican Oil in such areas, i.e. 85.6% (12,064 acres) of their total acreage is potentially productive.

7) Sunoco has significant Type I holdings; 78% (7,987 acres) of their total acreage has potential.

8) The land to the east of the Millican's Southern Region is apparently open. Based on the evaluations recently completed, a part of the border acreage is now considered to have a reasonable potential for Type III structures.

9) The relatively shallow volcanic sequences may have sufficient fracture systems to produce hot-water at acceptable rates.

10) The relatively deep, lower reservoir (below the gabbroic complex or lopolith) may be sufficiently fractured to produce steam at acceptable rates.

11) Geophysical information forthcoming from Southland Royalty will be of value in assessing the potential of areas defined herein, especially the potential of Type III structures.

12) As soon as Phase II geological and geophysical evaluations have been completed, well-site selection evaluations can begin.

13) Preliminary analyses suggest that for the upper reservoir

of Dixie Valley to be economically viable for the period 1977 to 1980, the following requirements should be met:

a) average wellhead temperature: minimum of 200 degrees Centigrade (373 degrees Fahrenheit).

b) average well-flow rate: minimum of 475 lbs/hr.

c) average well costs: maximum of $400,000 (completed).

d) maximum number of wells to supply a 55 MWe plant: 25.

e) maximum producing depth: 7,000 feet.

f) Based on the above requirements, producer's selling price (cost plus profit) should be approximately 15 mills/kW hr.

14) Future producer selling price is subject to inflationary factors. Plant costs will increase but increases of future geothermal-generated prices of electricity will depend on well costs and associated materials and services.

15) The utility price of electricity will depend on the competitive prices of conventional and other alternate energy sources of power for electrical generation (e.g. coal, nuclear power, hydroelectrical power and other competing geothermal power sources). If geothermal energy can be produced and sold competitively, suitable resources will be developed.

16) Assuming the upper reservoir of Dixie Valley has an adequate temperature, and an acceptable reservoir at relatively shallow depths (4,000 to 7,000 feet, the following producer selling

price could be realized over the next ten years beginning with production in 1980:

1980-1983	1983-1986
20 mills/kW hr	30 mills/kW hr

It should be emphasized that the above conclusions are based on a number of assumptions. Further updating of the economic factors used in this analysis will be necessary as the Dixie Valley project moves forward. As additional data becomes available on the Dixie Valley prospect and as other geothermal projects based on hot-water reservoirs are brought into operation, a more precise estimation of the economic viability of the upper reservoir and of Millican Oil Company's holdings can be undertaken.

In the interim period, the potential of Millican Oil Company's holdings in the area appears to be excellent at this time but should be further defined by additional geological and geophysical evaluations. A Stage I drilling program should be undertaken to test the various geological, structural and geophysical interpretations made herein and these to be made in the near future. The general economics of geothermal production in Dixie Valley also appear to be favorable at this date, assuming shallow reservoir requirements can be met. If the lower reservoir is explored, areas of Type I structures may represent the only areas of interest because of excessive depths basinward.

VI REFERENCES

Austin, A. L., 1975, "Prospects for Advances in Energy Conversion Technologies for Geothermal Energy Development," Lawrence Livermore Laboratory Rept. UCRL-76532, 30 p.

Bloomster, C. H., 1974, "An Economic Analysis of Geothermal Energy Costs" Battelle Pacific Northwest Laboratories Report BNWL-SA-5596, 30 p.

Bloomster, C. H., and C. A. Knutsen, 1975, "The Economics of Geothermal Electricity Generation from Hydrothermal Resources", Battelle Pacific Northwest Laboratires Report (BNWL-1989, UC-13 43 p.

Ellis, A. J. and W. A. J. Mahon, 1964, "Natural Hydrothermal Systems and Experimental Hot-Water/Rock Interactions", Geochim. Cosmochim. Acta, Vol. 28, pp. 1323-1357.

Fournier, R. O., and J. J. Rowe, 1966, "Estimation of Underground Temperatures from the Silica Content of Water from Hot Springs and Wet-Steam Wells", Amer. Journ. Sci., Vol. 264, November, pp. 685-697.

Fournier, R. O., and A. H. Truesdell, 1973, "An Empirical Na-K-Ca Geothermometer for Natural Waters", Geochim Cosmochim. Acta, Vol. 37, pp. 1255-1275.

Fournier, R. O., D. E. White and A. H. Trusdell, 1974, "Geochemical Indications of Subsurface Temperature - Part 1, Basic Assumptions", Journ. Research U.S. Geol. Sur., Vol. 2, No. 3 May-June, pp. 259-262.

Goldsmith, K., 1976, "Economic Aspects of Geothermal Development", In Proc. 2nd U. N. Symp. on the Development and Use of Geothermal Resources, San Francisco, Calif., May 20-29, 1975, pp. 2301-2303.

Grens, J. Z., 1975, "The Effect of Salinity on Geothermal Well Performance", Lawrence Livermore Laboratory Rept. UCID-16791., 14 p.

Hill, J. H., and C. J. Morris, 1975, "Sampling a Two-Phase Geothermal Brine Flow for Chemical Analysis", Lawrence Livermore Laboratory Dept. UCRL-77544 (Conf. 751086-1), December 5, 25 p.

Juul-Dam, T., and H. F. Dunlap, 1976, "Economic Analysis of a Geothermal Exploration and Production Venture", In Proc. 2nd U. N. Symp. on the Development and Use of Geothermal Resources, San Francisco, Calif., May 20-29, 1975, pp. 2315-2324.

Keplinger, C. H., 1976, "OPEC Oil Price Enhances U. S. Geothermal Development," World Oil, August, 4 p.

Meidav, T., 1975, "Costs of Geothermal Steam Capacity", Oil and Gas Journ., March 10, pp. 94-96.

Mercado, S. G., 1976, "Movement of Geothermal Fluids and Temperature Distribution in Cerro Prieto Geothermal Field, Baja California, Mexico", In Proc. 2nd U. N. Symp on the Development Use of Geothermal Resources, San Francisco, Calif., May 20-29, 1975, pp.492-495.

Mifflin, M. D., 1968, "Delineation of Ground-Water Flow System's in Nevada", Tech. Rept. Series H-W, Hydrol. & Water Resources Publ. No. 4, Center for Water Resources Research, Desert Research Institute, Univ. Nevada, Reno, July, 78 p.

Nathensón, M. and L. J. P. Muffler, 1976, "Geothermal Resources in Hydrothermal Convection Systems and Conduction-Dominated Areas", In Assessment of Geothermal Resources in the United States - 1975, D. E. While and D. L. Williams, U.S. Geol. Surv. Circ. 726, pp. 104-122.

National Petroleum Council, 1971, "U. S. Energy Outlook - An Initial Appraisal 1971-1985", Vol. 2, 186 p.

Sacarto, D. M., 1976, "State Policies for Geothermal Development", National Conference of State Legislatures, Report NSF/RA-760230, Denver, 94 p.

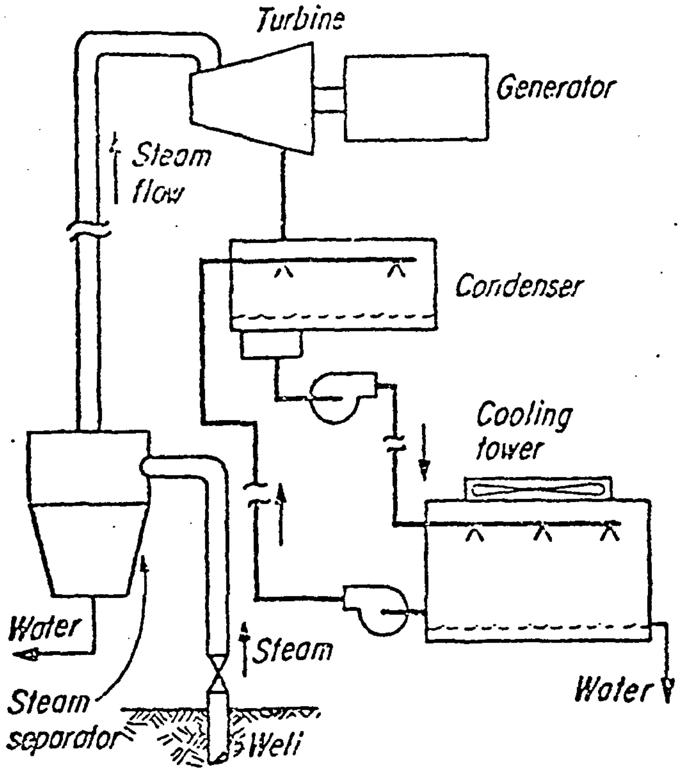
Sorey, M. L., 1971, "Measurement of Vertical Ground Water Velocity from Temperature Profiles in Wells", Water Resources Research, Vol. 7, No. 4, Aug. pp. 963-970.

Thompson, G. A., and D. B. Burke, 1974, "Regional Geophysics of the Basin and Range Province", Annual Review of Earth and Planetary Sciences", Vol. 2, pp. 213-238.

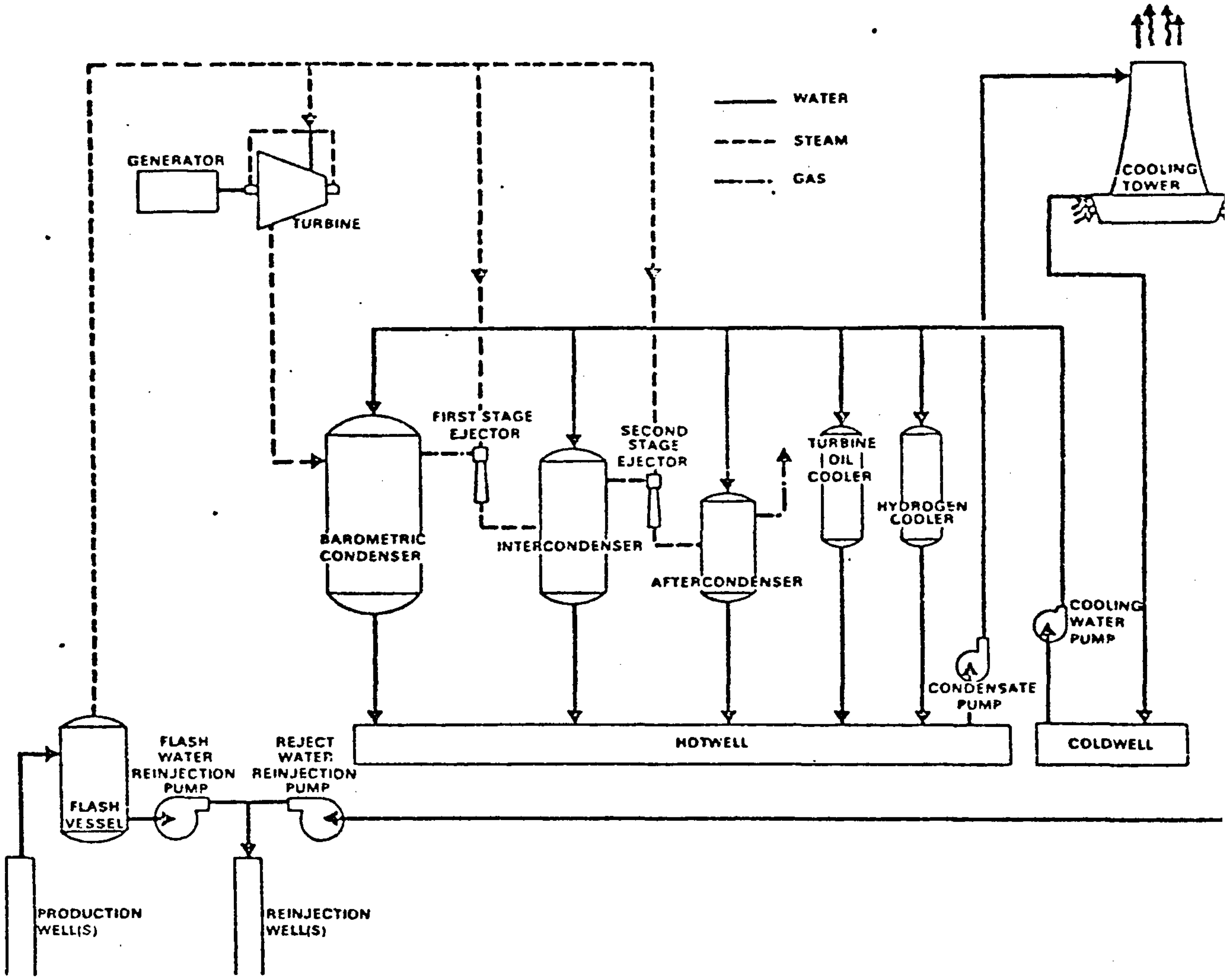
Tolivia, E. M., 1976, "Evaluation of the Geothermal Potential of Cerro Prieto, Baja California (Mexico)", In Proc. 2nd U. N. Symp. on the Development and Use of Geothermal Resources, San Francisco, Calif., May 20-29, pp. 279-281.

Truesdell, A. H., and R. O. Fournier, 1976, "Calculation of Deep Temperatures in Geothermal Systems from the Chemistry of Boiling Spring Waters of Mixed Origin", In Proc. 2nd U. N. Symp. on the Development and Use of Geothermal Resources, San Francisco, Calif., May 20-29 pp. 837-844.

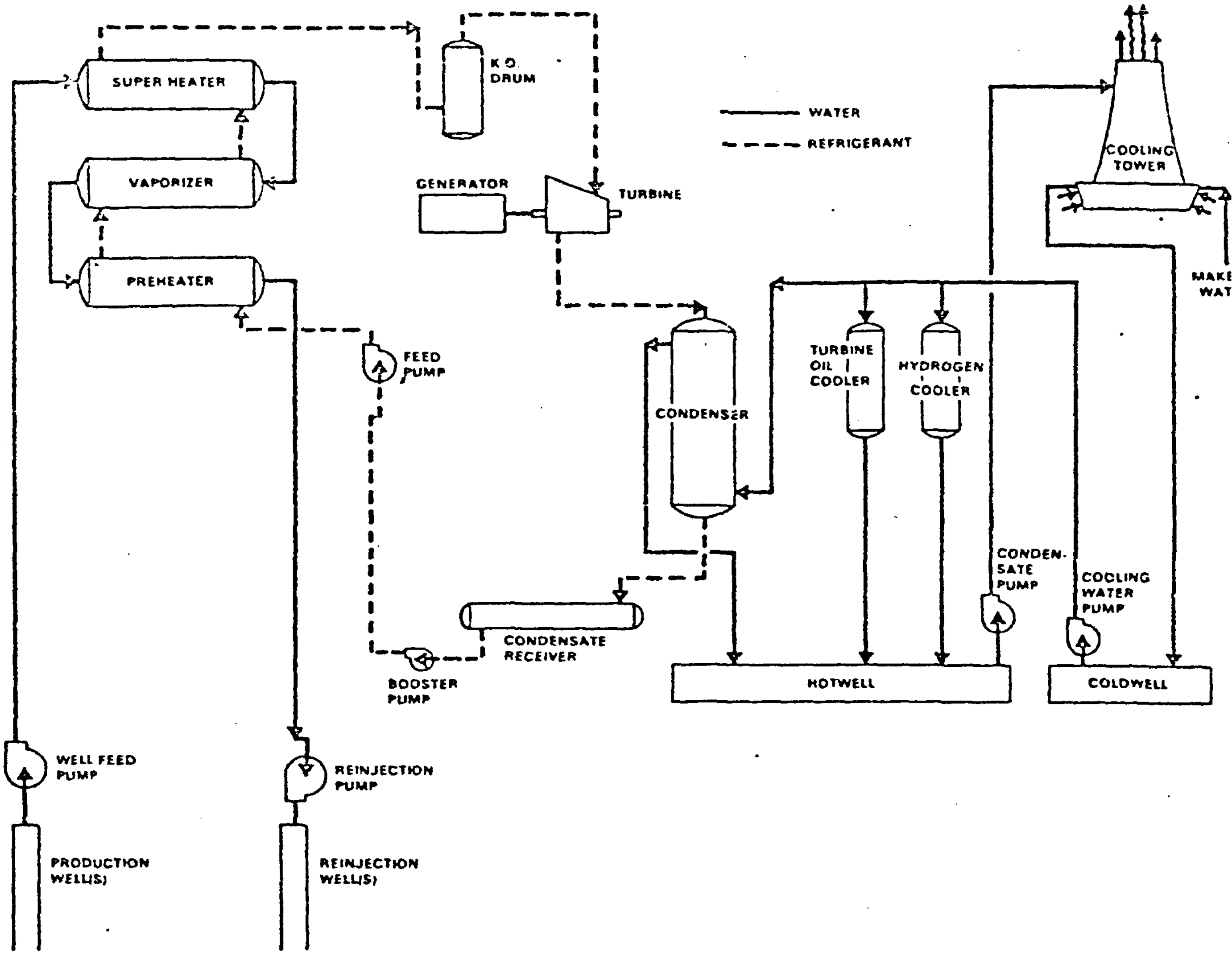
VII APPENDIX



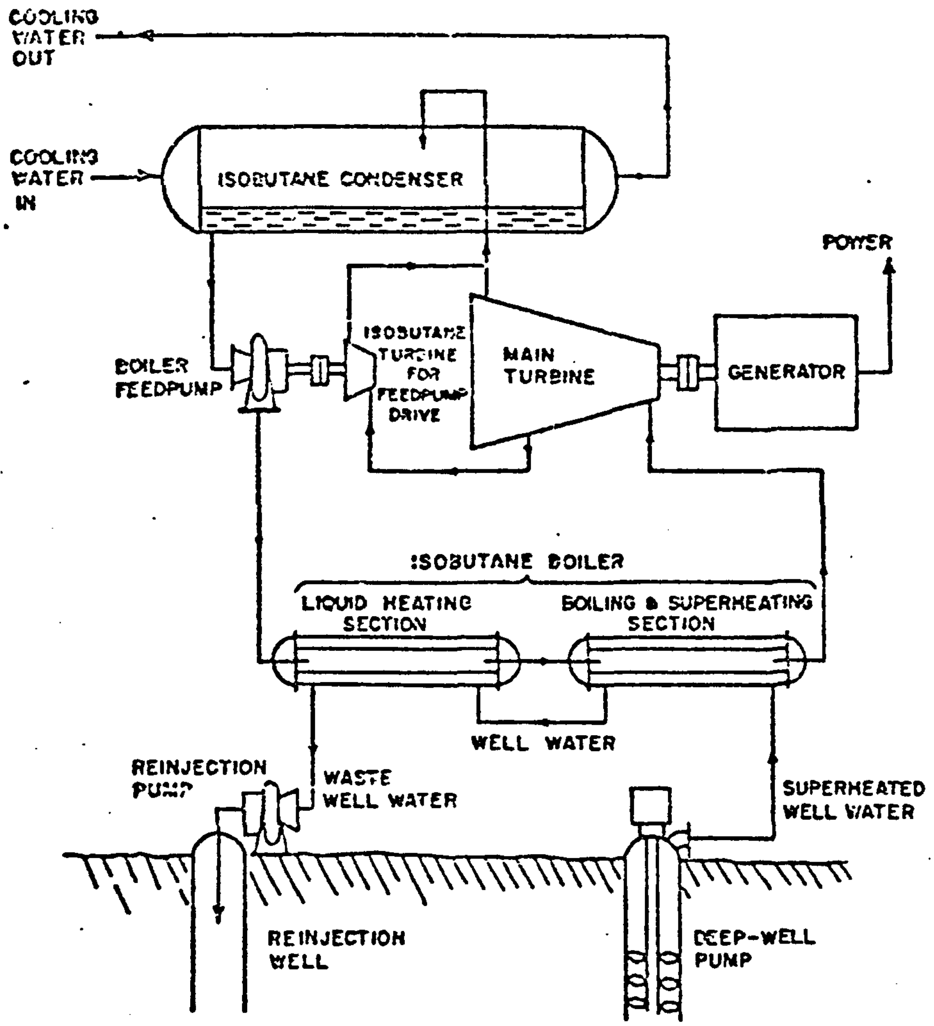
Schematic of a geothermal power plant.



Flash steam plant.



Sub-critical binary fluid cycle power plant.



Schematic of the Magmamax Process (hot water from a geothermal well flashes isobutane).