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SulPhurDALE GEOTHERMAL
ASSEESSMENT Geothermal Energy
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ROGERS ENGINEERING CO., INC.

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ThermaSource Inc.

CONFIDENTIAL

ASSESSMENT OF GEOTHERMAL ENERGY POTENTIAL

SULPHURDALE GEOTHERMAL FIELD

SULPHURDALE, UTAH

FOR

MOTHER EARTH INDUSTRIES

CAREFREE, ARIZONA

OCTOBER 1984

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SULPHURDALE GEOTHERMAL FIELD

SULPHURDALE, UTAH

FOR

MOTHER EARTH INDUSTRIES
CAREFREE, ARIZONA 85377

BY

THERMASOURCE, INC.
SANTA ROSA, CALIFORNIA

OCTOBER 1984

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Assessment of Geothermal Energy Potential
Sulphurdale Geothermal Field

by
Gerald Niimi
ThermaSource, Inc.

I. INTRODUCTION

The Sulphurdale Geothermal Field is located in Beaver County, Utah (Figure 1), within the boundaries of the Cove Fort - Sulphurdale Known Geothermal Resource Area (KGRA). During the past year, three wells drilled in Section 7, T-26-S, R-6-W, have produced dry steam from a fractured volcanic formation located at a depth of about 1100 feet. Two of these three wells are currently prepared to supply steam to a power plant, and one well has been plugged and abandoned. ThermaSource, Inc. was retained by Mother Earth Industries, the operator of the field, to conduct well tests and render an opinion as to the nature of the geothermal reserves and assess the commercial potential of these reserves. Because of the limited area that has been explored to date, there can be no assurance that the reserves estimate will prove accurate. Project economics are based on parameters believed to be accurate, but there is no assurance that such cash flow projections will be realized.

II. SUMMARY AND CONCLUSIONS

1. Two geothermal wells capable of producing dry steam have been completed to a depth of 1300 feet in the Cove Fort - Sulphurdale KGRA. The producing characteristics indicate that commercial development should be pursued.

2. The two wells were tested at an average rate of 115,000 lbs/hr, a flowing temperature of 244 - 255 degrees F, and a wellhead pressure of 32 - 38 psia. Based on the current power plant design, this is sufficient steam to operate a 5 MW power plant. Makeup (replacement) wells will have to be drilled occasionally to maintain steam deliveries to the power plant.

3. The produced steam contains 6% to 13% by weight of non-condensible gas. Nearly 98% of the gas is carbon dioxide, 1% is hydrogen sulphide, and the remaining 1% consisting of ammonia, argon, nitrogen, methane, and hydrogen. The steam condensate has a pH of 4.2.

4. Based on decline curve analysis, the two existing wells should produce a total of 26 billion lbs. of steam over a 20 year producing life. Future wells are assumed to behave in the same manner.

5. Both wells are completed in an altered and fractured volcanic formation that starts at a depth of about 1100 feet. Faulting, analogous to the proven area, surrounds

the successful wells.

6. Because of the fractured reservoir, a well drainage area and optimum well density cannot be precisely addressed at this time. A reasonable approach is to maintain an approximate spacing of 20 acres/well (1000' between wells) until actual reservoir performance can be observed.

7. An area within 2500 feet of a producing well can be considered potentially productive. Such an area would encompass 450 acres, where eight additional well locations can be sited. This would represent an additional 104 billion lbs. of steam reserves and would be equivalent to 20 MW of initial electric capacity. (Total of 25 MW for the current productive area.) Assuming a 25% chance of success over the entire 9000 acres operated by Mother Earth Industries, development of 125 MW could be feasible.

8. A phased wellhead generator development approach is the recommended strategy to prudently meet energy demand and utilize the resource. Initially 5 MW units could be installed followed by larger units if justified by resource definition and well performance. Well 42-7 would be utilized for water injection.

9. Economics for the initial 5 MW power plant project shows a pre-tax rate of return of 27% for a 20 year project life. The project would include two initial wells and four replacement wells.

III. FIELD HISTORY

A. 34-7

The Cove Fort - Sulphurdale area, in Beaver and Millard Counties, Utah, had been identified as a geothermal resource area based on surface H2S gas seeps and sulfur deposits (Muffler, 1978). The area around Sulphurdale was leased by Union Oil Company, and after drilling two deep tests in the area, they concluded that large scale geothermal development was not feasible. In 1980, these properties were acquired by Mother Earth Industries. After reviewing the geological, geophysical, and well data, a well site was selected in Section 7, T-26-S, R-6-W, in Beaver County.

The first well, 34-7 was spudded on October 12, 1983 and drilled to a depth of 1169 feet when the well started to flow steam. Subsequently the well blew out of control for 24 days before it was controlled and plugged. Measurements of discharge rates were not available, but a consensus field estimate indicated a rate of approximately 250,000 lbs/hr. Moore (1978) reported that cuttings from between 1100 and 1169 showed a strongly altered fractured zone with quartz monzonite veining. A review of the drilling history of Union Oil Company's Well 42-7 located 2000' to the northeast, indicates that a lost circulation zone was encountered at a depth correlative to the steam producing zone in Well 34-7. Thus it can be concluded that the steam producing fractures are likely to extend northeastward at least to 42-7.

B. 34-7B

Following the drilling of Well 34-7, a second well 34-7B was spud on December 18, 1983. This well reached a depth of 1165 feet on January 4, 1984. A flow test was conducted on January 9th and 10th, 1984, and the well produced dry steam and non-condensible gases as follows:

DATE	ORIFICE	FLOW PERIOD	MASS FLOW (LBS/HR)	FWHP (PSIG)	TEMP (F)
1-9-84	8"	19 HRS	124,000	51	250
1-10-84	6"	3 HRS	99,000	64	270

The data shows that the steam is not saturated, and in fact should have been a liquid under these conditions. Obviously the non-condensible gas in the produced flow steam was high enough to greatly affect the quality of the well production. In fact the concentration of non-condensible gases primarily CO_2 and H_2O was about 70% based on an analysis of partial pressures.

Hydrogen sulphide had been detected during the blowout of 34-7 but no precise measurements of concentrations were made. Wet chemical tests conducted on 34-7B indicated H2S concentrations in the range of 1000 to 5000 ppm by weight. The wide range of measurements was a result of the freezing weather affecting measurements and the fact that wells behave erratically when first produced.

Transmissivity calculations were made and resulted in permeability-thickness (Kh) products of 500,000 md-ft. This is indicative of fracture permeability and not necessarily an average rock property.

The completion of 34-7B was a significant event, however, in that it demonstrated that the Sulphurdale Field was a vapor dominated system when heretofore, only a liquid dominated system had been envisioned. Concentrations of chloride ions in the steam condensate were 1 ppm or less, thus suggesting that a boiling front was not located near the wellbore. Well 34-7B further demonstrated that commercial flow rates could be achieved and that the drilling and completion of wells could be accomplished safely and cost effectively.

Additional well tests were conducted later in January, in March, and an extended test in May and June, 1984. Results of the four day test conducted from January 18 - 21, 1984 is included in Appendix A. Flow rates nearly identical to the earlier tests were measured. Estimates of non-condensible gas content were obtained from water displacement tests. Results indicated an average gas content of 62% by weight compared to 60% calculated from partial pressure methods. Gas samples were collected but the results were mixed. Four out of the seven samples had results that were in agreement with the other two methods and the other three were anomalously low. Because of the high non-condensible gas content, it was necessary to determine whether this condition was transitory or permanent.

A 10 day period of testing was conducted from March 24 to April 2, 1984. During the testing, the gas content decreased from 60% to 45%. This was encouraging because gas content over 50% would drastically affect the steam to electricity conversion efficiency. It also indicated that continuous production would purge the limited amount of gas from the reservoir. Final flow of the well on a 6" orifice was 92,000 bls/hr at a flowing temperature of 280 degrees F, and a flowing pressure of 54 psig. Results of the well test are included in Appendix B.

C. 34-7A

Observations made by field personnel during the blow out of 34-7 indicated higher volumes and better steam quality than was being experienced at 34-7B. Well 34-7A was drilled from the same site as 34-7 to a depth of 1300 feet. The well encountered the same steam producing formations and was completed on May 8, 1984. Early results from rig tests indicated that the well was about the same as 34-7B. A profile of 34-7A is shown in Figure 3.

Following the drilling of 34-7A, Well 34-7B was deepened to 1300 feet with a 10-5/8" bit. A well profile is shown in Figure 4. Then a series of well tests was conducted to measure well performance from 34-7A for the first time and to observe the performance of both wells when produced simultaneously.

IV. WELL TESTS: MAY 23 - JUNE 14, 1984

Both wells, 34-7A and 34-7B, were equipped in the manner shown in Figure 5. A central monitoring station was set up so that all measurements could be recorded efficiently. In addition, strip chart recorders were used to create a permanent record of the measurements. A preliminary report of the test results is included in Appendix C. Representative flow capabilities of each well are as follows:

	MASS FLOW (LBS/HR)	FWHP (PSIG)	FWHT (F)	% NC GAS
34-7A	123,000	26	255	6
34-7B	106,000	20	244	13

An important result of the testing was that, non-condensible gas concentrations gradually decreased to levels that should not pose serious problems for power plant operations. During early testing in January 1984, Well 34-7B showed total gas concentrations of 60%. This was reduced to a range of 6% to 13% during the tests conducted in May and June 1984. Reduction in gas concentrations were noted in both the periodic gas samples that were taken and field tests using a water displacement by gas method. The reason for the drastic reduction in gas is probably due to the fact that the wells had penetrated a gas cap or pocket on top of a steam reservoir. Most likely the gas cap volume was much smaller than the steam volume and thus depleted quickly. There will probably be a lower value at which non-condensible gas concentrations will stabilize and reach a steady state condition. The exact value is not critical as long as the power plant can handle the existing levels of gas concentrations. Changes in the producing behavior of Well 34-7B from January to June, 1984, are shown in the following table:

34-7B WELL TEST COMPARISON

	1/21/84	4/2/84	6/6/84
Gas concentration(%)	60	44	20
Flowing Pressure (psig)	60	54	44
Gas Pressure (psia)	27.0	22.4	6.5
Steam Pressure (psia)	44.7	43.2	49.2
Total Flow (lbs/hr)	94,000	92,000	72,000
Gas Flow (lbs/hr)	56,400	40,000	15,000
Steam Flow (lbs/hr)	37,600	52,000	57,000

The above table only includes data during testing with a 6" orifice plate.

The interesting fact is that dramatic changes that appear in pressure and flow reflect mainly changes in non-condensible gases. This is further evidence that the gas cap is small and that steam should be predominate in the future. A point of concern that was first noticed during the well test was the interference between the two wells. The pressure communication between the two wells is instantaneous and results in about a 6% reduction of flow. This suggests that slightly wider spacing between wells may be appropriate but that the interference is not serious at the present time.

Predictions of future well performance were made by extrapolating the observed test data over a 20 year project life. Total steam produced over the 20 year period by an individual well is about 13 billion lbs. To test the reasonableness of these predictions, they were compared with the published decline curves of Budd (1972) and Dykstra (1981) for The Geysers Field. Figure 6 shows the decline curves from the literature and the expected performance of the Sulphurdale wells. The decline curve determined by Dykstra is based on actual performance of a sample of 18 wells from several areas of The Geysers Field. It is the most useful general decline curve available. Thus it is concluded that the projected performance of Sulphurdale wells is reasonable and is acceptable for use in planning and economic forecasts.

The well tests resulted in predictions of future well performance in terms of mass flow, pressure, temperature, and non-condensible gas concentrations. Next a power plant must be acquired to convert the geothermal energy into electricity. For this purpose, modular power plant units supplied by Ormat are planned for the initial development phase. It is expected that research and testing will continue during the early development to determine the optimum power plant for the Sulphurdale resource.

V. RESERVOIR MODEL

Although individual well behavior is important, the true scope of the Sulphurdale resource can only be understood with some insight into the reservoir. A detailed reservoir description, however, is difficult to construct at this time. Instead a conceptual model is presented here based on certain facts observed during the drilling and testing. The producing reservoir is under pressured because initial bottomhole measurements indicated a pressure of 95 psig and a temperature of 300 degrees F. Normal hydrostatic pressure should be approximately 500 psig. This leads to the conclusion that some sealing mechanism, either cap rock or mineralization has prevented ground water from flooding the steam filled fractures. This may explain the presence of shallow ground water at 42-7. Based on Dalton's Law of Partial Pressures, the estimated initial non-condensible gas saturation in the reservoir is 43%. After testing, partial blowdown of the gas cap resulted in total reservoir pressures dropping to its current level of 60 psig. However the partial pressure of steam has remained constant. Figure 7 illustrates the changes that the gas and steam phases have undergone, and it is clear that the pressure and volume of non-condensible gases have changed dramatically over a six-month period.

Moore (1984) indicates that the observed hydrothermal alteration of the volcanic rocks found in well 34-7 could not have occurred at temperatures lower than 400 degrees F. Thus hot water migrating from a deep source could have once resided in the volcanics. During the migratory process, the hot water passed through carbonate rocks and was enriched with carbon dioxide. Then something happened, possibly a tectonic event, to cause the hot water to gradually boil off, leaving a mineralized cap rock and a steam filled zone. Through time, gravity segregation occurred creating higher gas saturations at the top of the reservoir.

The hydrothermal system that charged the volcanic zone at 1100 feet in 34-7A and 34-7B with geothermally heated fluids may still be open. This system could provide the long term supply of steam needed for a commercial geothermal development. Figure 8 is an idealized picture of the reservoir as envisioned today. In an areal perspective, it is likely that fluids from the deep source are using the major fault systems as conduits to reach the near surface fractured rocks. These fault zones are the likely targets for future drilling. The risk involves finding those fault zones that have communication with or recharge from the deep source water zone. There could be faults that have been sealed off partially or competely. Any wells drilled into these fault zones would either not find any steam or would deplete rapidly.

Over the producing life of the field, reservoir pressures will decrease as steam is produced. The relationship between steam withdrawals and reductions in reservoir pressure will not be known until a production history is established. Because of low pressures initially, well performance will be sensitive to small changes in pressure. If there are excessive pressure drops when steam is withdrawn, indicative of poor or no recharge from the deeper source zones, the well rates will decline faster necessitating more frequent replacement well drilling. On the other hand, temperatures are expected to remain constant in the reservoir similar to performance in The Geysers.

The above description is similar to The Geysers Field. Another possible description is that Sulphurdale is analogous to the geothermal fields in Italy. James (1968) noted that initial conditions of the geothermal field in Larderello, Italy, occurred at the pressure and temperature of saturated steam near the point of maximum enthalpy (1205 BTU/lb). The reservoir at Sulphurdale is not at this state which may indicate that the reservoir rocks are undergoing cooling by surface water. This cooling caused part of the steam to condense thus increasing the concentration of non-condensible gases. This could explain why the reservoir temperature is much below the temperature that caused the alteration in the rock. The condensate then possibly drained away through the fracture system.

Atkinson et.al. (1978) reported on a field investigation of the Bagnore Field in Italy. This field has a corollary with Sulphurdale because it also had high initial gas concentrations on the order of 80%. However, the gas concentrations decreased rapidly as did the pressure. After two years, the gas concentrations stabilized at about 10% of the total flow stream. By then reservoir pressure had fallen to 1/3 of its original value. A water table was located about 400 feet below the top of reservoir and began encroaching into the steam zone as production began. In contrast to Sulphurdale where the gas concentrations decresed with decreasing flowing pressures, Bagnore wells showed no such relationship. Production of the steam phase in some wells at Bagnore showed declines of 50% in about 15 years while others showed little or no decline in steam deliverability. If Sulphurdale and Bagnore are similar, then the existing wells 34-7A and 34-7B may begin to produce water after a period of time and the current assumptions may not be valid. Bagnore produced a cumulative total of 35 billion lbs. of steam during the first 20 years of its life. If Sulphurdale if going to follow the behavior of Bagnore, it should be evident within the first two years of production.

VI. SULPHURDALE GEOTHERMAL FIELD DEVELOPMENT

Reserve determination methods for geothermal reservoirs have not been rigorously established. Many approaches have been attempted and they all fail to provide reliable estimates mainly because of an inadequate reservoir description. Heat content of the rock can be calculated, but without reservoir dimensions, the quantity is meaningless. Total fluids in place can be estimated, but these values invariably show an unbelievably low reserve figure. Because of recharge from a deep source, experience has shown that actual well recoveries are much higher than what was calculated to be originally in place. Brigham (1977) and Whiting (1973) showed that petroleum industry material balance methods could be applied to geothermal reservoirs. However, these methods require production histories to be useful. As a result, well decline curves have evolved as being the most useful tool for early predictions of performance. Reservoir behavior is not considered specifically since its performance is reflected in the decline curves. As shown in Figure 6, the predicted decline curves for Sulphurdale wells are in line with actual steam well performance in The Geysers. Expected steam recoveries are 13 billion lbs/well over a 20 year life.

It is common practice in geothermal fields to rely on well data to determine field productive boundaries. Geologic or geophysical boundaries are not usually reliable unless the anomaly defining the boundary is very strong, such as a major fault zone. It is also necessary that the geophysical data agree with the well data in proven areas. In the case of Sulphurdale, with only two wells drilled so far, it is easy to be very optimistic or very pessimistic. The approach chosen here is a step out approach around proven wells. In essence, areas that are geologically similar to a proven area can be considered potentially productive as long as the area is within 2500 feet of a productive well. The distance restriction is arbitrary but this limit has been used in The Geysers for several years. It could be more or less depending on the success of subsequent drilling. However, it is reasonable to expect that reservoir qualities that support productive wells are likely to hold for a distance of 2500 feet. Based on this assessment, a total area of 450 acres is potentially productive around the existing wells. As an initial estimate, a 20 acre spacing pattern is considered reasonable until additional information becomes available. In most fractured reservoirs, a strict drilling pattern is not followed unless the fractures are pervasive and extensive. In geothermal reservoirs such as Sulphurdale, reservoirs are fault controlled and therefore fault zones are usually the drilling targets. Because most fault systems have very high permeability, such as the 500,000 md-ft in 34-7B, wells can usually be drilled closer than normally justified. However, in order to minimize well interference, the 20 acre spacing pattern will keep wells 1000 feet apart. In the future, in-fill wells can be drilled if economically justified. A total of eight (8) additional well sites meet both criteria of being along an identified fault zone and within 2500 feet of a productive well. Figure 9 shows the potential well locations on a geologic base map.

Within the potentially productive area of the field, there is no indication of regional trends that would dictate a bias of well productivity in any direction. Therefore, future wells are assumed to have identical characteristics as the existing wells. Figure 10 summarizes the estimated well performance characteristics over a 20 year period. Thus the field can be assigned 130 billion lbs. of steam reserve. (13 billion lbs/well x 10 wells)

To put the steam reserves and well performance into an economic perspective, a cash flow model was developed. This model assumes a 5 MW power plant with both 34-7A and 34-7B tied-in initially. Because of well decline, a makeup or replacement well must be drilled and completed in the third year of the project. Additional makeup wells are needed in the 13th and 16th year for a total of 4 makeup wells. This schedule of drilling will maintain sufficient steam deliveries of approximately 200,000 lbs/hr to the power plant inlet. A total of 30 billion lbs. of steam is required to operate this plant for 20 years and the initial two wells provide 26 billion or 87% of the total. Thus the makeup or replacement wells provide mainly deliverability and not very much steam reserve. Wells are estimated to cost $500,000 each in 1984 dollars.

One of the key parameters that impacts the development economics is the plant conversion efficiency. As a first pass, a conversion efficiency of 40 lbs/KWH has been assumed. ? This is about twice the steam requirement for a power plant in The Geysers. Because of the higher non-condensible gas concentrations, such an efficiency may not be too unreasonable. Preliminary estimates from Ormat indicate that their units will consume about 40 lbs/KW. Whether or not the Ormat systems are the optimum for this resource will not be known until operations begin. There is, however, considerable incentive to improve the steam utilization through power plant design.

A suitable disposal well is available at 42-7. Although the well has not been tested, the fact that lost circulation was a problem during drilling infers that injection of water should be feasible.

In view of the above, the 450 acres with 130 billion lbs. of steam could potentially support 25 MW. If 25% of the 9000 acres around the Sulphurdale wells were proven to be productive, a potential output of about 125 MW could be considered.

Key assumptions for the cash flow analysis are presented in Figure 11. The most sensitive parameter is the price for the power. A price of 55 mils/KWH has been assumed which includes any wheeling expenses. The before tax economics of stand alone 5, 10, and 15 MW projects are shown in Figure 12. Details of the cash flows are shown in Appendix D. A 5 MW geothermal project yields an internal rate of return of 27%. If the same wells are used in a more efficient plant such that 7.5 MW can be generated, the internal rate-of-return increases to 32%. A 10 MW project yields a rate-of-return of 27%, while a 15 MW project also yields a 27% return.

All of the economics have assumed 100% equity financing. As a sensitivity, a 5 MW project that finances $3 million or 80% of the power plant cost was run. The financing was for 5 years at 15%. Project internal rate of return improved from 27% to 32%.

In conclusion, because of the similarity in geology between the proven area and surrounding areas, there is a reasonable chance that additional steam reserves will be found somewhere in the 9000 acres operated by Mother Earth Industries. The regional heat source for the area is not confined to the area of the two existing wells. There is nothing in the well test data or drilling history to suggest that the productive area is confined to only two wells. The geothermal resource at Sulphurdale is a shallow, vapor dominated resource that lowers the risk of drilling and is easily developed with existing technology. Figure 13 shows a comparison between The Geysers Field and Sulphurdale. This demonstrates that superior well production at The Geysers is mitigated by the equally advantageous cost considerations at Sulphurdale. Economics with conservative assumptions yield pre-tax returns of 25 - 35%. The primary unknown factor is long term well and reservoir performance, but use of a phased development strategy and wellhead generators will minimize this risk. Despite the reservoir risk and inefficient conversion due to non-condensible gas, the large reserve

potential, low cost, and dry steam resource presents a favorable investment opportunity.

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Registered Petroleum Engineer
#1372

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FIGURES

FIGURE 1

LOCATION MAP
SULPHURDALE GEOTHERMAL FIELD

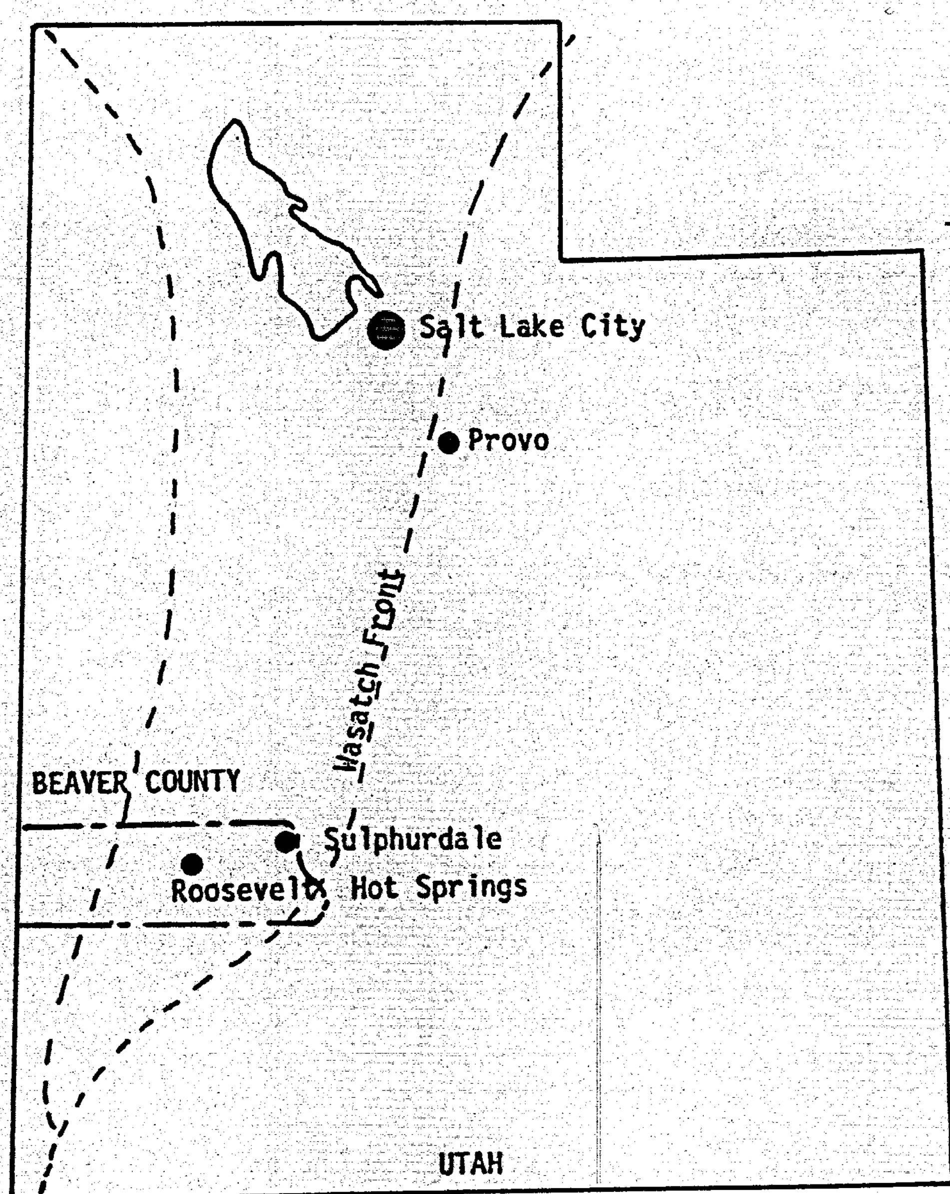
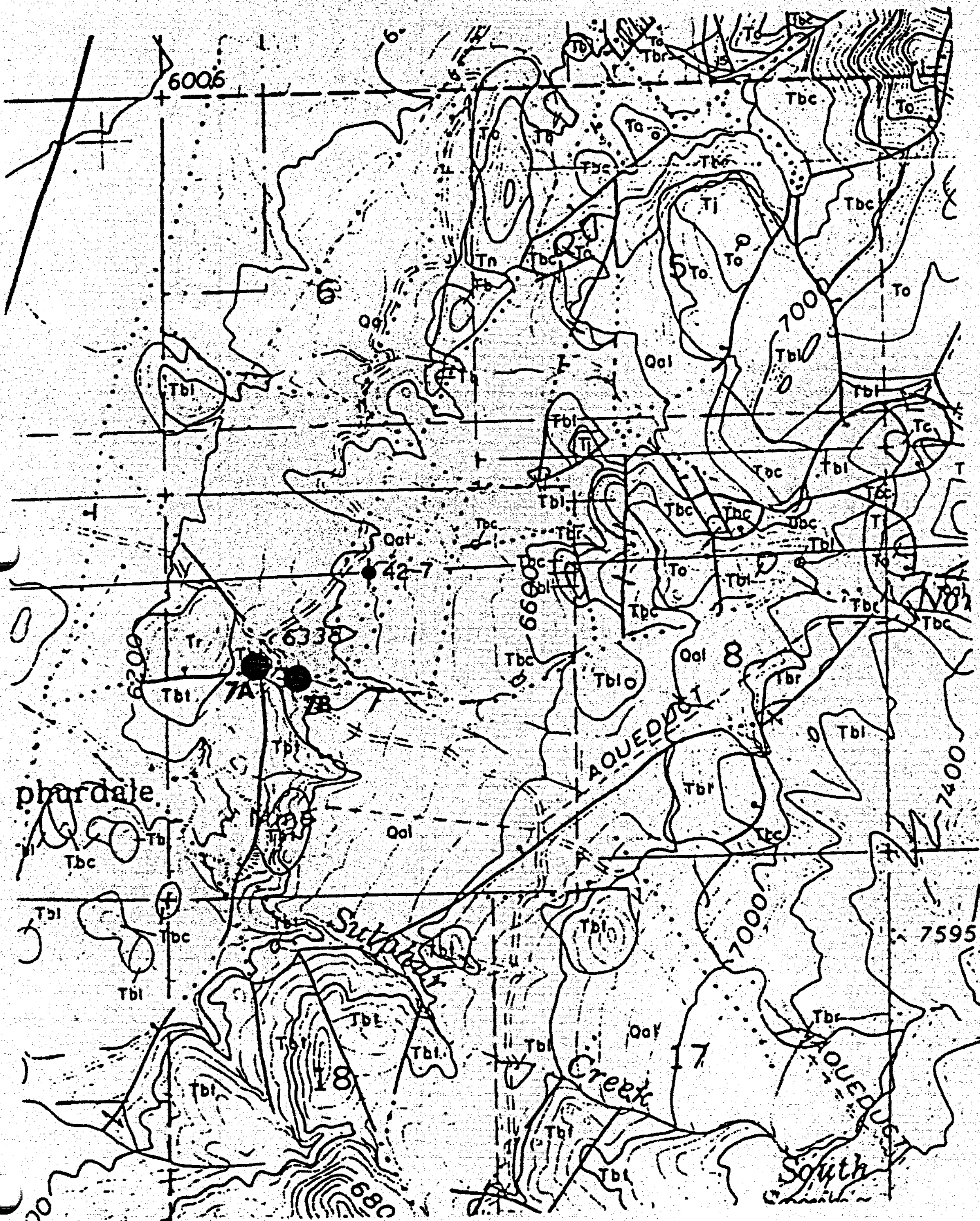


FIGURE 2
SITE MAP
SULPHURDALE GEOTHERMAL FIELD



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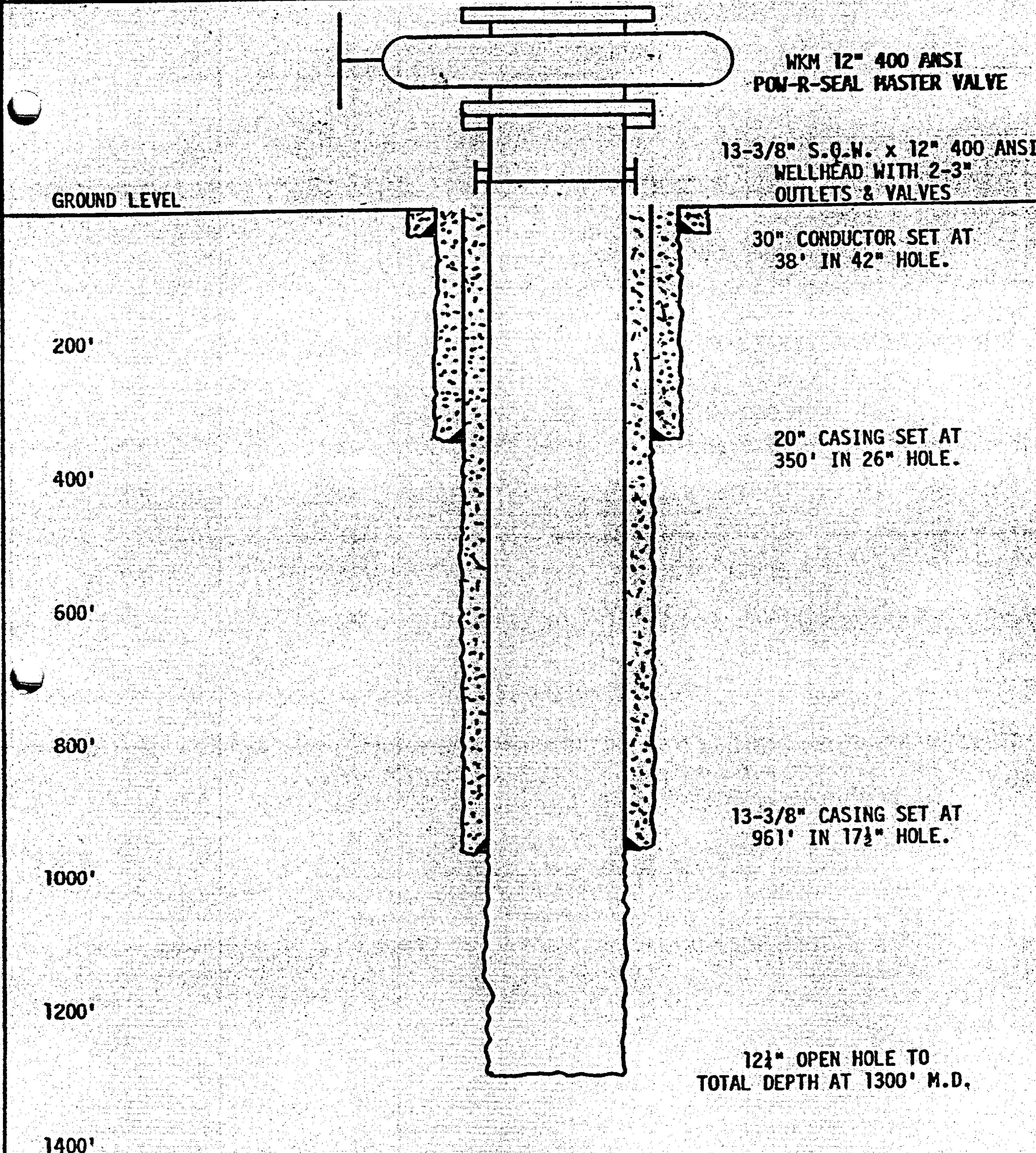
From: Moore and
Samberg (1979)



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(707) 523-2960 • Telex 171743 • TWX 510 7446439

FIGURE 3
Well Profile 34-7A
Sulphurdale Geothermal Field
Mother Earth Industries

DRAWN	
FOR:	MEI
BY:	L.E.C.
DATE:	5-22-84
SCALE:	1"-200'
DRAWING No.	001

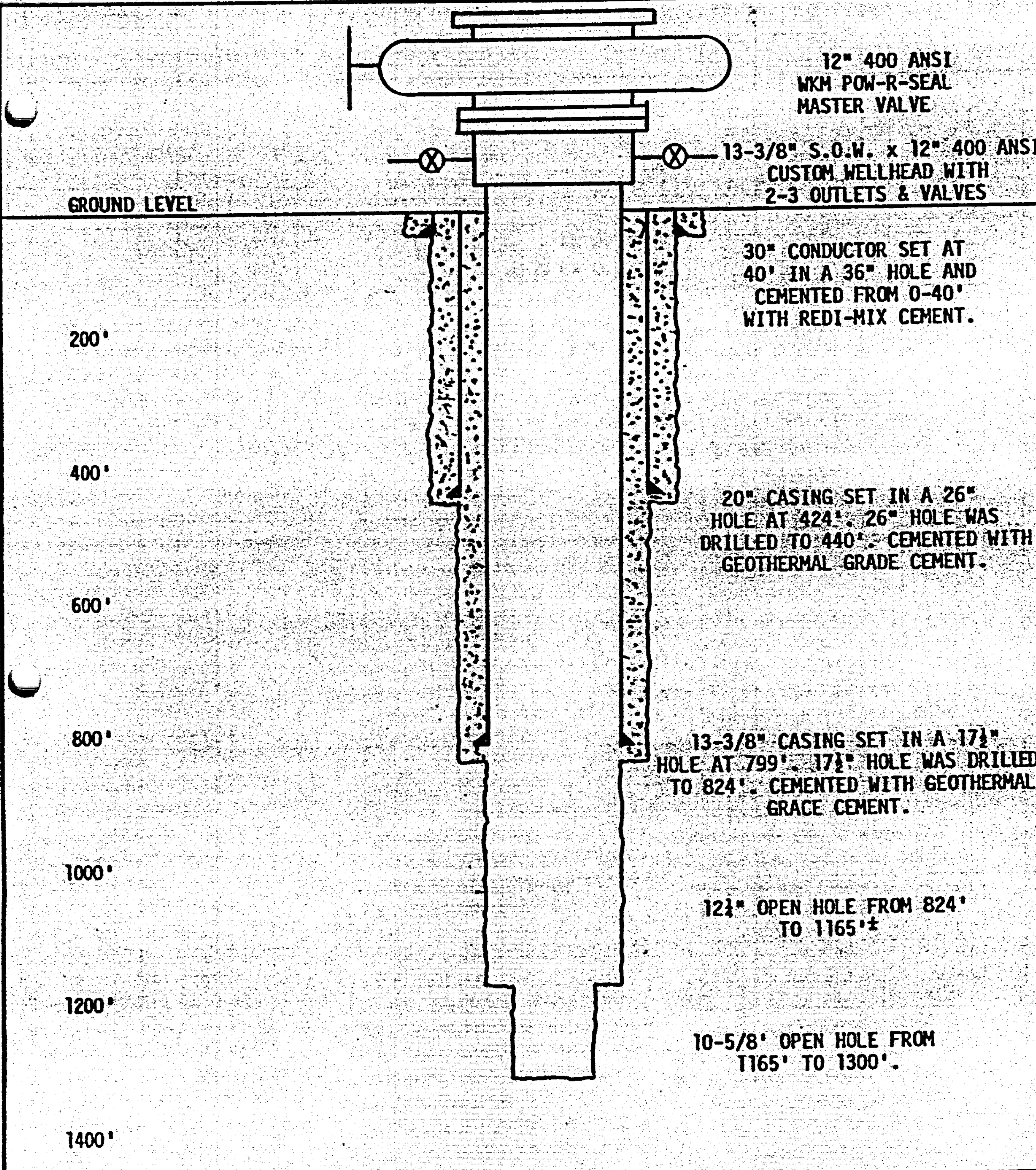

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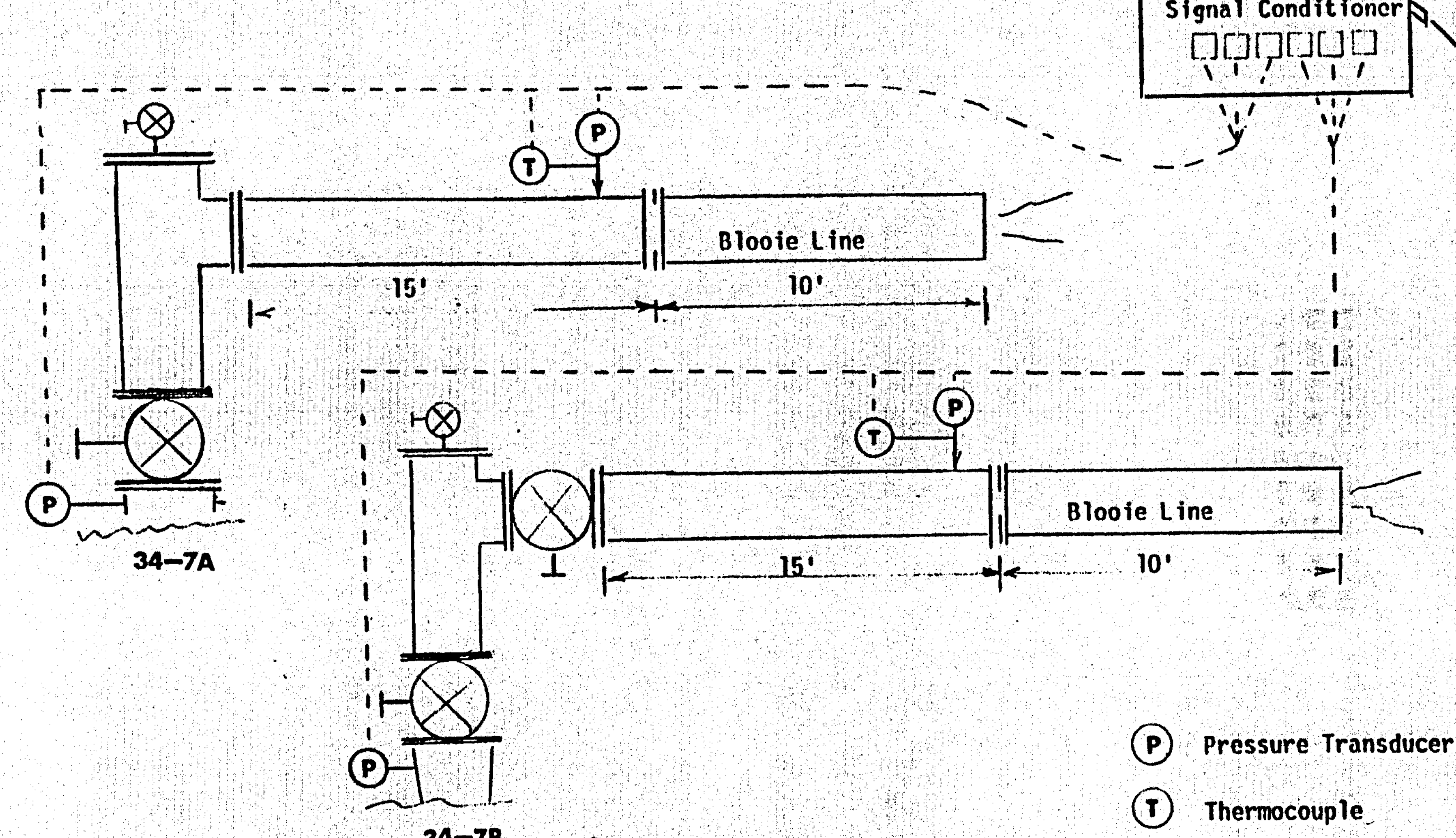
FIGURE 4
Well Profile 34-7B
Sulphurdale Geothermal Field
Mother Earth Industries

DRAWN
FOR: MEI/CCG
BY: L.E.C.
DATE: 5-23-84
SCALE: 1" = 200'
DRAWING No. 001

FIGURE 5

WELL TEST SCHEMATIC



Mass Flow:

$W = 359\ (Y_t)(S_p)D^2 \sqrt{P_t/V_t}$ lbs/hr

Where $(Y_t)(S_p)$ = orifice factor

D^2 = internal diameter (in)

P_t = upstream pressure

V_t = specific volume

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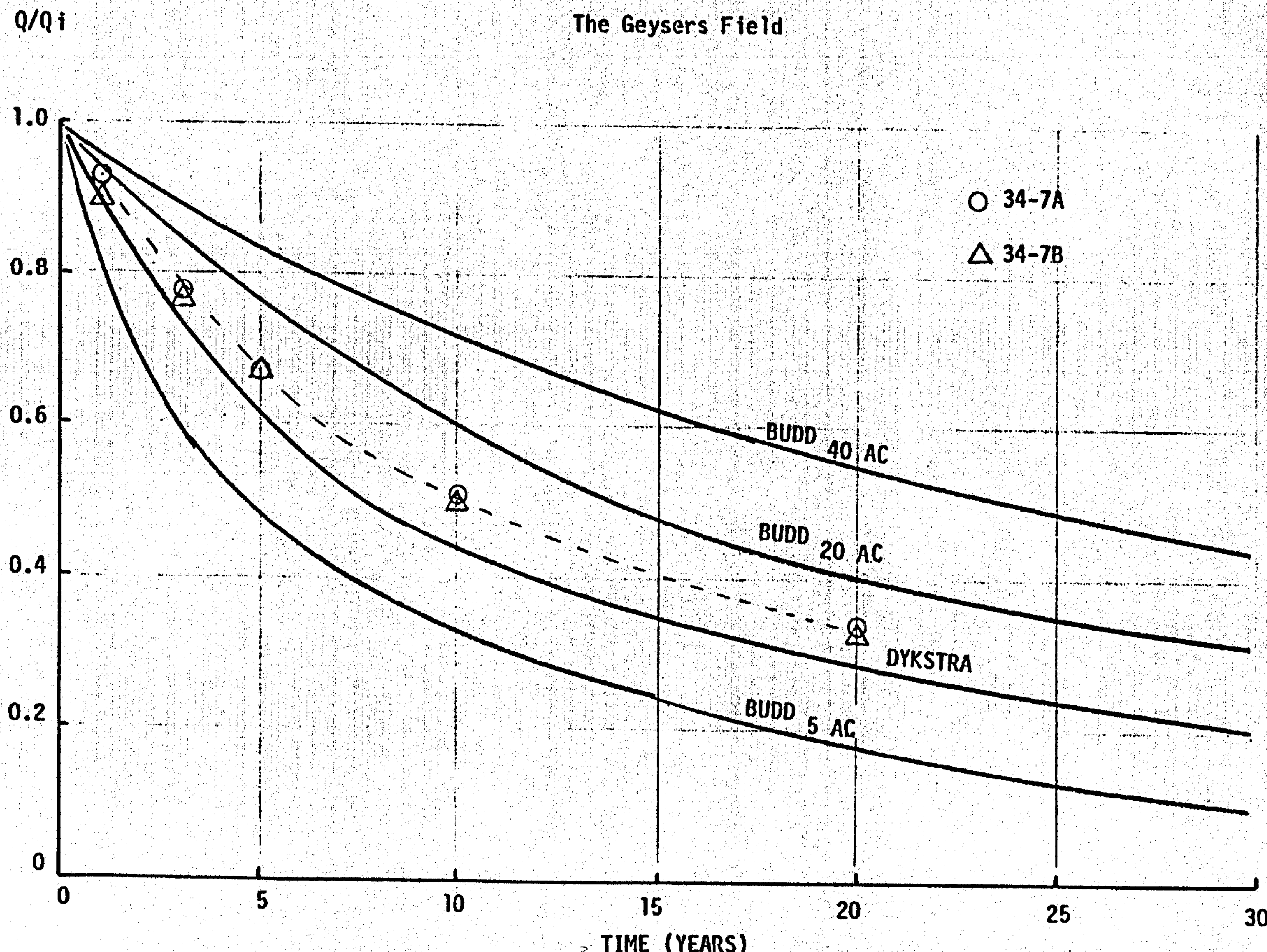
FIGURE 6

WELL DECLINE CURVES

The Geysers Field



RESERVOIR CONDITIONS

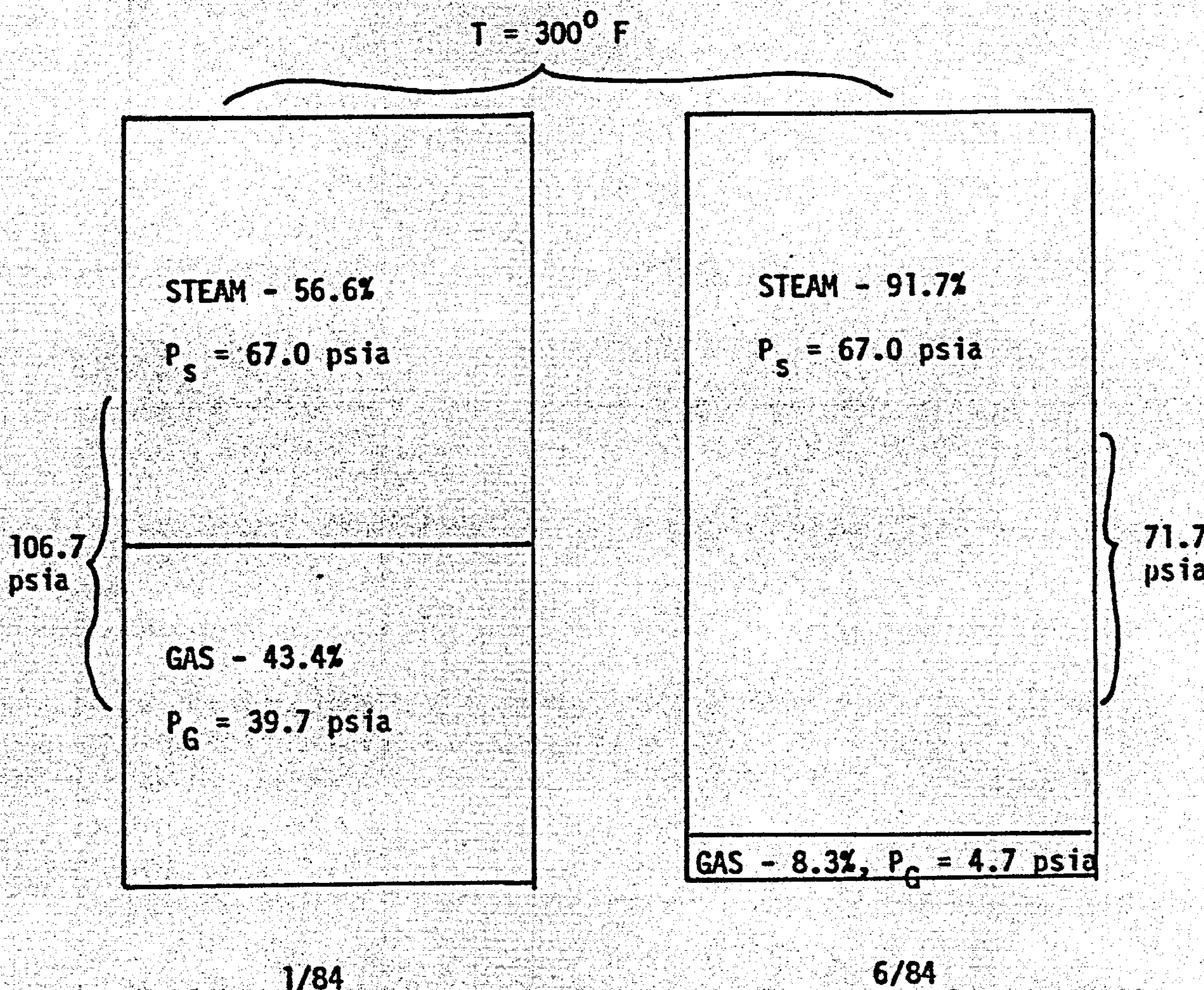


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FIGURE 7
PARTIAL PRESSURE ANALYSIS
SULPHURDALE GEOTHERMAL FIELD

DRAWN
FOR:
BY:
DATE:
SCALE:
DRAWING No.

FIGURE 8

SULPHURDALE RESERVOIR MODEL

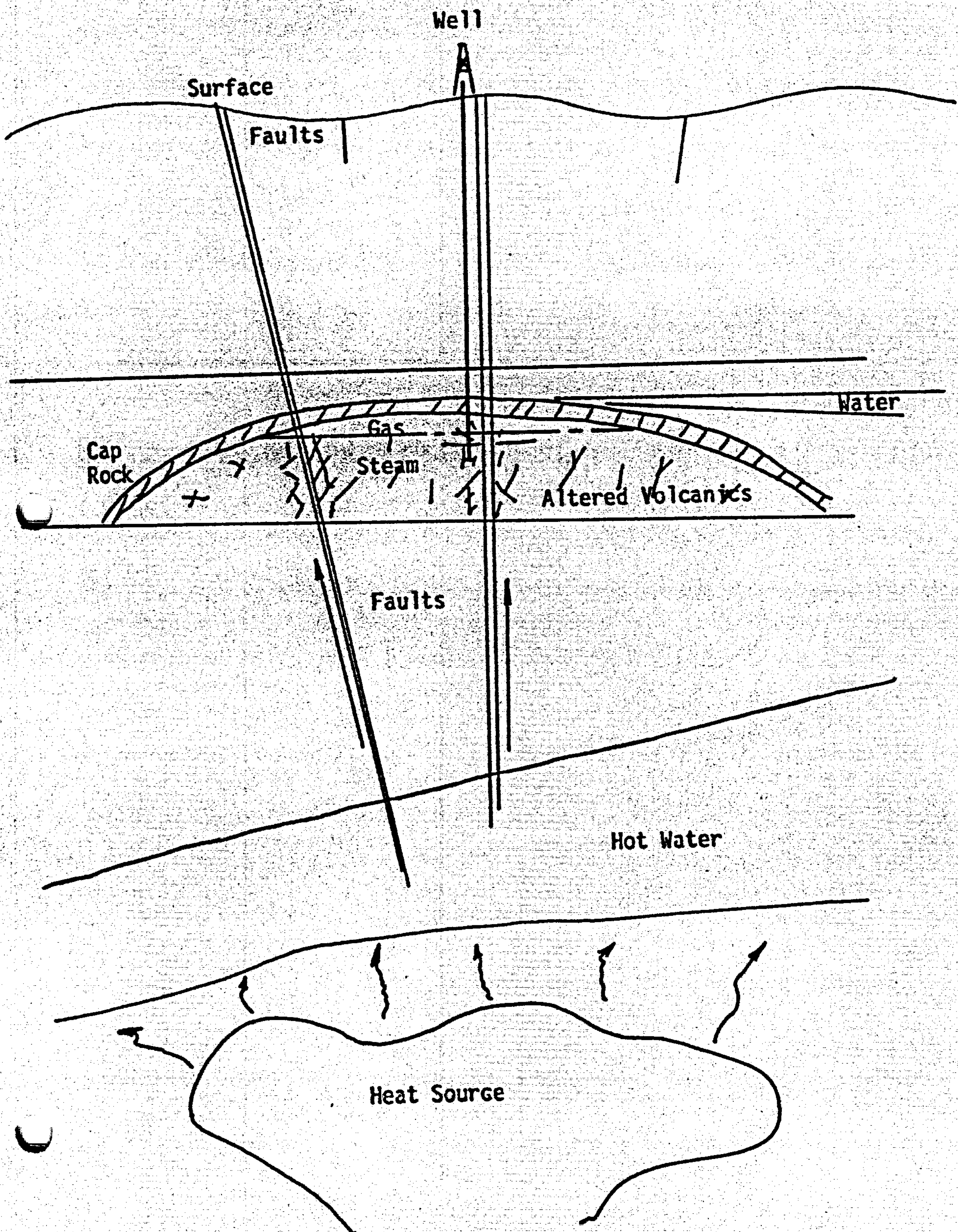
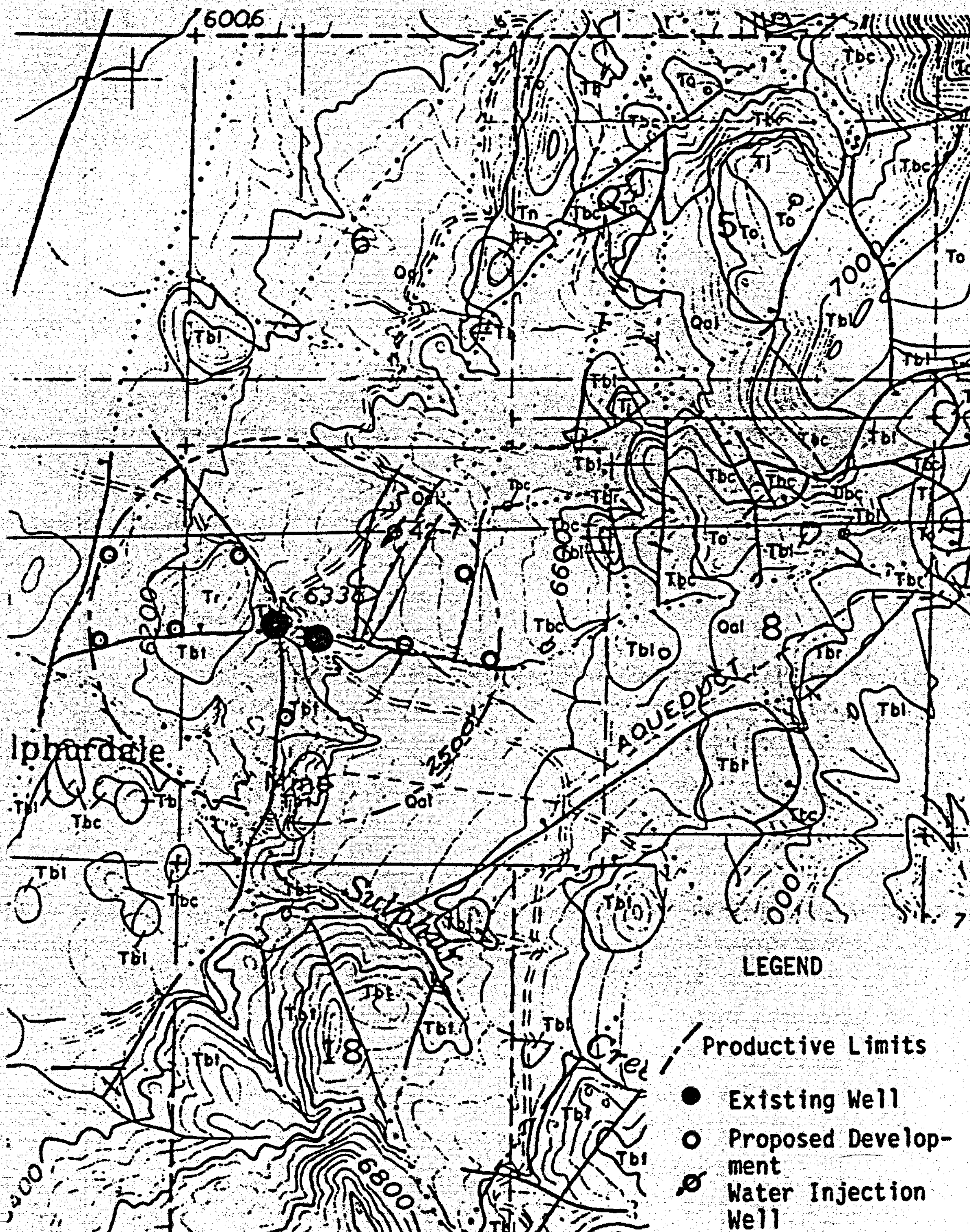


FIGURE 9

POTENTIALLY PRODUCTIVE AREA

SULPHURDALE GEOTHERMAL FIELD



SCALE = 1:24,000

FIGURE 10

ESTIMATED WELL PERFORMANCE

SULPHURDALE GEOTHERMAL FIELD

		End of Period				
34-7A	Initial	1 yr.	3 yr.	5 yr.	10 yr.	20 yr.
Mass Flow (Klbs/hr)	123	114	96	83	63	42
Non-Condensible Gas (%)	6	5	4.4	4.2	3.8	3.4

Assumes FWHP = 26 psig, FWHT = 255°F

34-7B						
Mass Flow	106	96	82	71	53	35
% Gas	13	11	10	9	8.5	7.5

Assumes FWHP = 20 psig, FWHT = 244°F

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FIGURE 11

ASSUMPTIONS

SULPHURDALE GEOTHERMAL PROJECT ECONOMICS

Conversion Efficiency	40 lbs of steam/KWH
Plant Capacity Factor	85%
Royalty	12.5%
Price (1985)	55 mils/KWH (includes wheeling)
Escalation Factor	4% on all items
Investments	
Wells	$500 M/EA
Pipelines (for 5 MW)	$500 M
Plant (5 MW)	$3750 M
Field Operating Expenses	
Plant	$100 M/YR.
Field	$250 M/YR.
Management	$ 50 M/YR.
Production and Ad Valorem Taxes	3% of net revenue

NOTE: Geothermal equipment is eligible for energy tax credit of 20%. Net revenue is eligible for depletion allowance.

FIGURE 12

PROJECT ECONOMICS

	Initial Investment		Internal	10 Year Cash Return
	Plant	P/L and Wells	ROR (%)	(%)
5 MW Base Case	3750	1500	26.8	184
7.5 MW (30 lbs/KW)	5250	1500	31.6	236
10 MW	7500	3000	26.8	184
15 MW	11250	4500	26.8	184
5 MW ($3M Debt)	750	1500	31.9	364

(All economics are pre-tax)

FIGURE 13

GEOTHERMAL FIELD COMPARISON

SULPHURDALE VS. THE GEYSERS

	Sulphurdale	The Geysers
Original Reservoir Pressures (psig)	90	500
Original Reservoir Temperatures (^{o}F)	297	470
Average Depth (feet)	1150	6500
Well Cost ($ 000)	500	1500
Output (MW/Well)	2.5	7.5
Plant Cost ($000/MW)	750	750
Latest Non-Condensible Gas Content (%)	9	0.4