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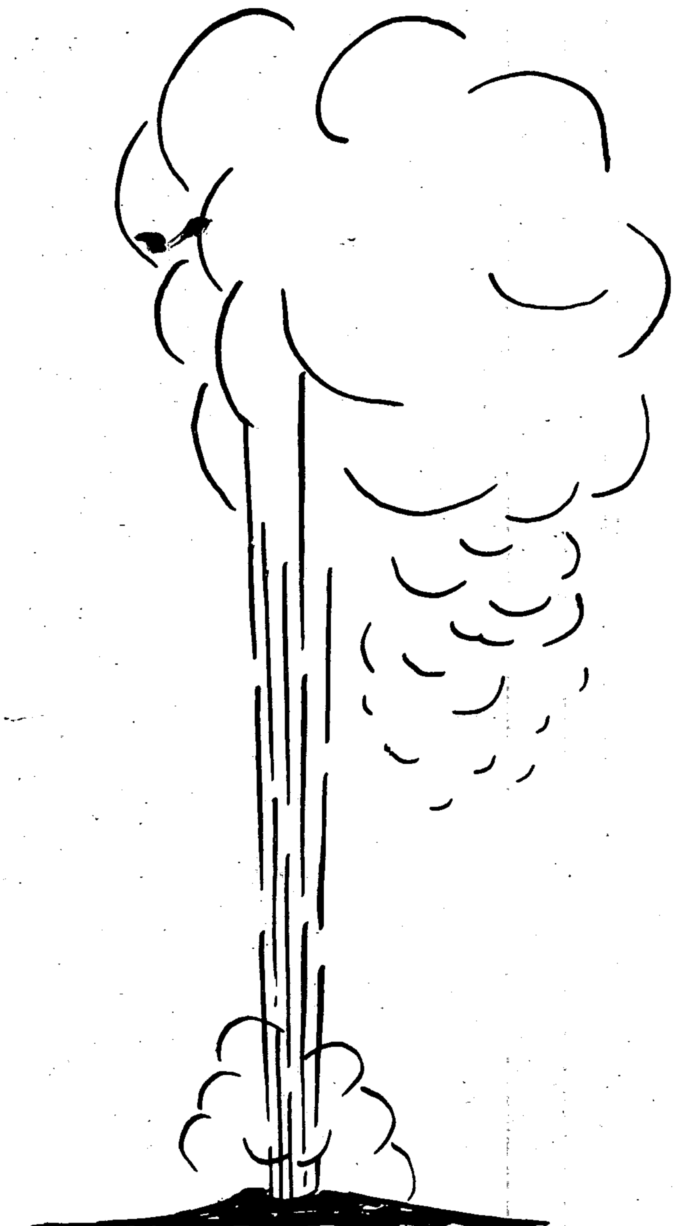

ECONOMIC FACTORS RELEVANT FOR ELECTRIC POWER PRODUCED FROM HOT DRY ROCK GEOTHERMAL RESOURCES

A Case Study for the Fenton Hill, New Mexico, Area

By
R. G. Cummings
G. Morris
C. J. Arundale
E. L. Erickson

December 1979

Work Performed Under Contract No. AS04-79ET27017

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ECONOMIC FACTORS RELEVANT FOR ELECTRIC POWER PRODUCED FROM HOT DRY ROCK GEOTHERMAL RESOURCES:

A Case Study for the Fenton Hill, New Mexico, Area

by

R. G. Cummings and G. Morris

with

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December 1979

ABSTRACT

This report is one of two case studies of economic factors that may influence the potential commercial feasibility of electricity produced from hot dry rock geothermal resources (HDR) funded under DOE Contract No. DE-AS04-79ET27017. The case study described here concerns an HDR system which provides geothermal fluids for a hypothetical electric plant located in the Fenton Hill area in New Mexico's Jemez Mountains. The second case study* concerns an HDR system which is hypothetically located in California's Imperial Valley.

Primary concern in this report is focused on the implications of differing drilling conditions, as reflected by costs, and differing risk environments for the potential commercialization of an HDR system. Drilling costs for best, medium and worst drilling conditions are taken from a recent study of drilling costs for HDR systems prepared by the Republic Geothermal Company. Differing risk environments are represented by differing rate-of-return requirements on stocks and interest on bonds which the HDR system is assumed to pay; rate of return/interest combinations considered are 6%/3%, 9%/6%, 12%/9% and 15%/12%.

The method of analysis used here is that of determining the minimum busbar cost for electricity for this case study wherein all costs are expressed in annual equivalent terms. The minimum cost design for the electric generating plant is determined jointly with the minimum cost design for the HDR system. The interdependence between minimum cost designs for the plant and HDR system is given specific attention

* Cummings. R. G. and G. E. Morris, December, 1979(b).

in this report; the optimum design temperature for the plant is shown here to be lower than one might expect for conventional power plants -- in the range 225°-$265^{\circ}C$.

Major results from the analyses of HDR-produced electricity in the Fenton Hill area are as follows. With real, inflation-free, debt/equity rates of 6% and 9%, respectively, the minimum busbar cost is shown to lie in the range 18-29 mills/kwh. When real debt/equity rates rise to 12% and 15%, busbar costs rise to 24-39 mills/kwh.

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I. INTRODUCTION

A. The HDR Geothermal Resource. To most people, reference to "geothermal resources" is taken to mean the existence of hot water and/or steam that is found below the surface of the earth. It is well-known that such resources, technically described as "liquid (or, vapor) dominated" geothermal aquifers (LDA's) are generally located only in areas with anomalous geological characteristics and such areas are frequently some distance from centers of demand for electric power and/or process heat. Moreover, in many cases the temperature of the liquids or brines associated with LDA's is low and this limits the number of applications to which they may be economically applied.

Another source for geothermal energy exists, however.* This source, the "hot dry rock" (HDR) geothermal resource, is represented schematically in Figure 1. In general, as one moves towards the center of the earth the earth's temperature increases. This increase in temperature (usually measured in degrees centigrade per kilometer of vertical depth, ^{o}C/km) is referred to as a "geothermal temperature gradient" or a "gradient"; generalized gradients for parts of the United States are given below in Figure 2. At any given geographical site, a well is drilled some 3 to 10 kilometers (kms) into areas of impermeable crystalline rock (granite) as shown in Figure 1. When a desired rock temperature is achieved (*via* depth of drilling, given the gradient at the site), a fracture (or system of fractures)

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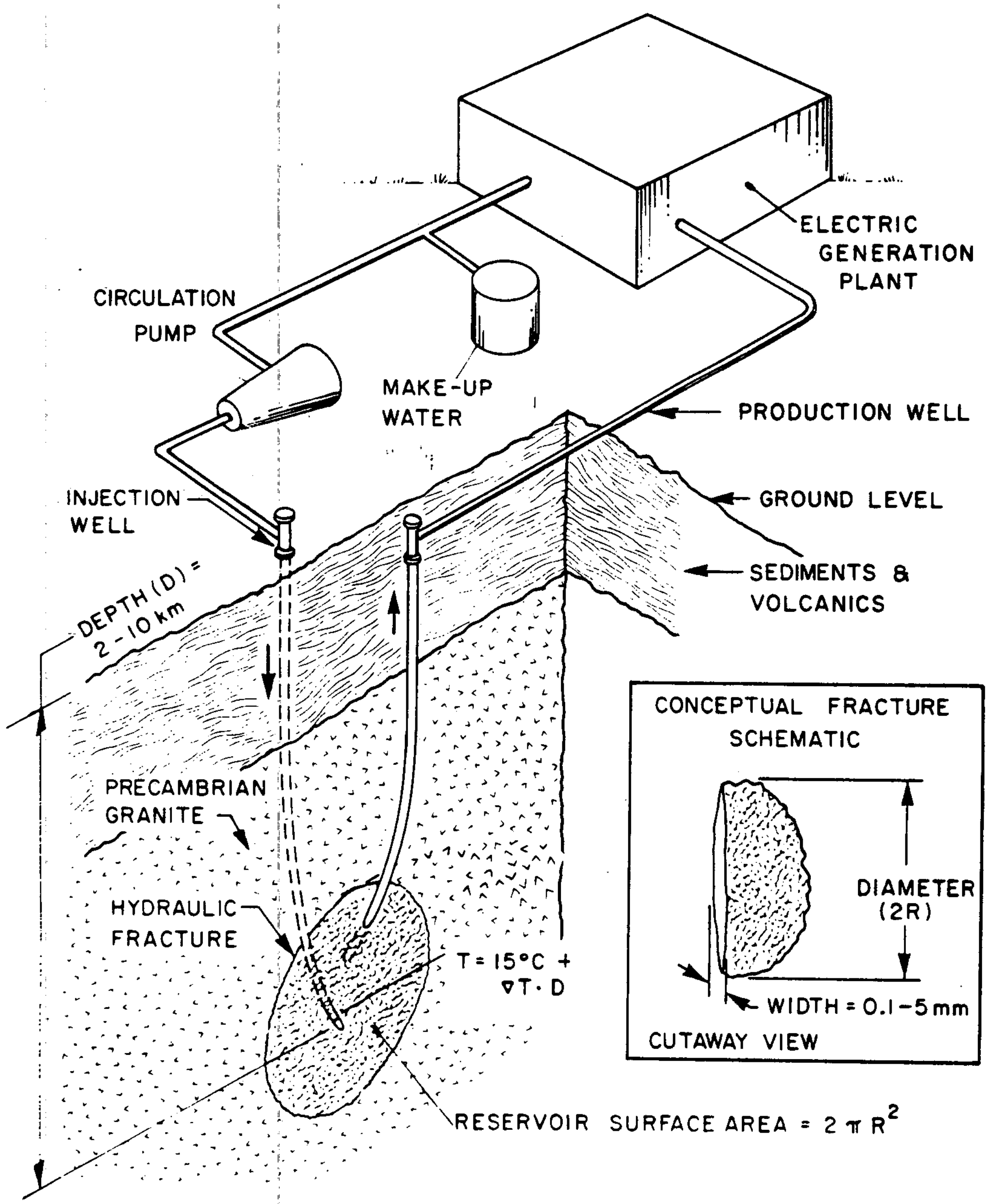
* Actually, one can categorize four sources for geothermal energy: natural convection systems (LDA's), conduction dominated systems (HDR), geopressured resources, and hot igneous (magma) systems; see Burness, *et. al.* (1979).

FIGURE 1

HOT DRY ROCK GEOTHERMAL CONCEPT



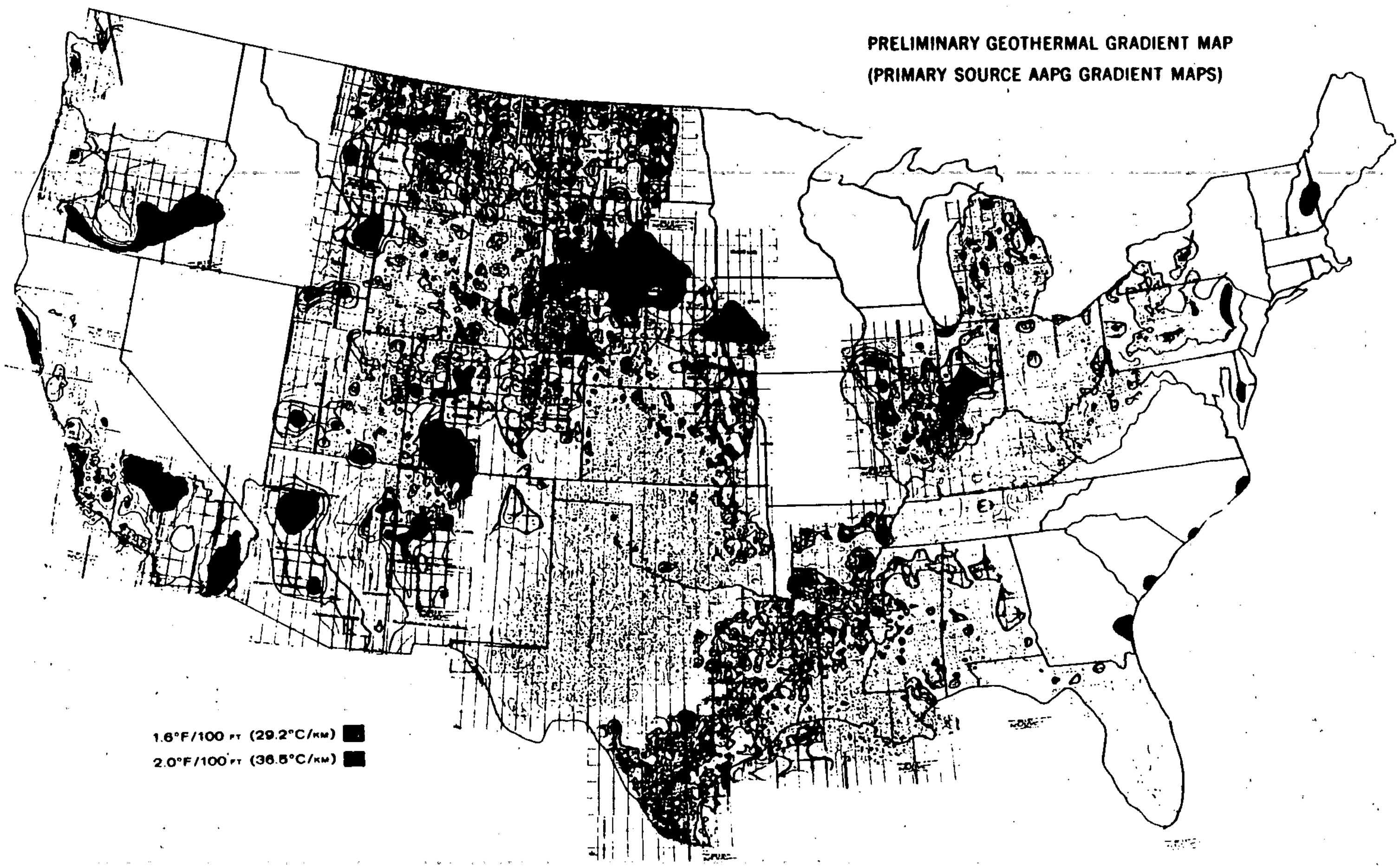

PRELIMINARY GEOTHERMAL GRADIENT MAP
(PRIMARY SOURCE AAPG GRADIENT MAPS)
1.6°F/100 FT (29.2°C/KM)
2.0°F/100 FT (36.5°C/KM)

FIGURE 2

is created in the rock. A second well is then drilled to intersect the fracture above its intersection with the first well. Water or other fluids may then be seen as being pumped (under high pressure) through the first, "injection" well, passing over the surface of the fracture (the HDR "reservoir") and returning to the surface *via* the second, production well; the retrieved hot fluid may then be used for many process heat applications or in the production of electricity. In contrast to the LDA, the HDR system as described is a man-made system, in which case, first, system temperature is fixed by design (*via* the choice of drilling depths) and, second, given the virtual omnipresence of the resource, location or siting is much less constrained.

B. Policy Questions of Relevance for HDR Systems. The world's first completed HDR system was created at Fenton Hill, located in the Jemez Mountains in central New Mexico, by scientists at the Los Alamos Scientific Laboratory in June 1977; the development of larger HDR systems is currently underway. The experimental systems will form the core of future HDR research. While, obviously, a large number of technological questions require resolution before claims for a "proven" technology can be made, research to date is sufficient to determine those technical and economic factors which will likely be of primary importance in determining the economic feasibility of the technology once proven [see EPRI, 1979]. Some of these more important factors-questions are:

(i) Temperature drawdown: Temperature drawdown -- the cooling of the hot rock as water is passed over it -- is determined by reservoir size (the surface area of the fracture) and the well-flow rate -- the rate (in kilograms per second, kg/sec) at which water is passed through the reservoir. Given a well-flow rate, larger reservoir size implies lesser temperature drawdown; given a reservoir size, smaller well-flow rates imply smaller rates of temperature drawdown. A major R&D question then concerns the possibility of designing reservoirs so as to have large enough surface areas to accommodate well-flow rates on the order of 75-150 kg/sec* with "acceptable"** rates of temperature drawdown.

(ii) Siting considerations: Given the dependence of drilling depths required for any target reservoir temperature on the geothermal temperature gradient (which is site-specific), what are minimum gradient ranges in which HDR systems might be commercially feasible? A response to this question has immediate implications for the potential magnitude of HDR's resource base.

(iii) How deep should HDR reservoirs be drilled? What is an optimum reservoir temperature? As is discussed in [EPRI, 1979] and [Hageman, 1979], a response to this question is inextricably tied to the question: What is the generating plant's design temperature? This interdependence between reservoir depth, and therefore temperature, and the plant's design temperature is developed below.

(iv) How much will drilling for HDR reservoirs cost? Given that drilling to large depths in hot granite is not a well established technology, estimated drilling costs [see Milora and Tester, 1976] for HDR systems is generally based on experiences in the petroleum industry wherein drilling will normally cease when granite is encountered. More recently, a Los Alamos-funded study of drilling costs by the Republic Geothermal Company provides a method for deriving detailed estimates of drilling costs for HDR, but such estimates will remain problematical until *ex post* analyses

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* Given the necessity of having sufficient fluids from HDR reservoirs to satisfy the generating plant's design flow rate, very small well-flow rates would imply the need for many HDR reservoirs for each generating plant.

** At some level of accumulated temperature drawdown, the reservoir must be re-established (re-drilling is discussed below) at a non-trivial cost; "acceptable", in this context, is then an economic question related to the costs of well re-establishment, an issue which is treated below.

of drilling costs actually incurred become available. At issue, then, is the sensitivity of one's assessment concerning the potential commercial feasibility of HDR systems to alternative estimates for drilling costs.

(v) Financial risk: It is not at all uncommon to find private businesses risk averse in terms of the adoption of dramatically different technologies; this is particularly true when large amounts of up-front capital investments are required before production even begins. A manifestation of a technology which is viewed as "risky" is, among other things, the necessity of the investor firm to pay very high rates of return on investment capital, i. e., very high interest rates which reflect a premium for risk. The implications of high interest rates for the commercial feasibility of HDR systems then become of particular importance.

C. The Fenton Hill Case Study. As noted earlier, the five issues described above (as well as others) have been considered in one context or another.* All of these earlier studies (with one exception noted below) have abstracted from site-specific problems as they would be reflected in costs, however; further, recent changes in tax provisions relevant for HDR systems (particularly, depletion allowances) were not considered in these works. All of this is to suggest the need for an assessment of HDR's potential commercial feasibility within the context of a case study wherein site-specific considerations are brought to bear on relevant costs and which would incorporate more recent data in drilling costs and taxes.

The purpose of this report is to provide such an expanded, site-specific analysis. A case study is provided which considers the potential

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* See, e.g., Cummings and Morris (1979a), Hageman (1979), and Cummings and Morris (1979b).

commercial feasibility of an HDR electricity-producing system located in the Fenton Hill area in New Mexico's Jemez Mountains. The analyses presented here focus primarily on the issues (iii), (iv), and (v) listed above--optimal drilling depths, the implications of alternative drilling costs estimates and the issue of risk. The issue of temperature drawdown (problem (i) above) is not given explicit treatment, but our analyses are predicated on a significant rate of temperature drawdown in the first five years of operation. Siting (gradient) considerations (problem (ii) above) are not relevant inasmuch as the only geothermal gradient of interest here is that relevant for the Fenton Hill site.

This report is intended as a companion report to a case study of HDR-produced electricity in the Imperial Valley, California [Cummings and Morris, 1979b]. The present Fenton Hill case study differs from the case study of the Imperial Valley in a particularly important way, however. In the Imperial Valley study, two separate business entities are assumed: a power producing company who "owns" the HDR reservoirs, and an electric generating plant. The power producing company sells hot water or steam to the electric generating plant. The design of the HDR system is based on a <u>given</u> design for the electric generating plant. In the present study, however, the HDR reservoirs and the power plant are assumed to be under a centralized management scheme wherein operating policies and system design for fluid producing and electricity generating activities are determined jointly. This "joint management" scheme, while different from the arrangement currently employed for LDA developments in the U. S., serves to call attention to a somewhat unique characteristic of HDR systems in their use to provide power for electric generation, <u>viz</u>, the <u>interdependence</u> between HDR reservoir design (as related to drilling depth) and power plant design.

This report is organized in the following manner. In section II, a sketch of the methodology used here for assessing the potential commercial feasibility of HDR-produced electricity is given. Feasibility analyses are presented in section III concerning the HDR system under alternative assumptions for drilling costs and risk. Concluding remarks are offered in section IV.

D. Some Caveats. The role of economic analyses, such as those presented here, at early stages of technology development has received considerable attention in the recent literature.* In the case of HDR, such "early" economic analyses are intended to serve two major purposes. A first purpose is to point to management and design strategies that may be somewhat unique to HDR systems *vis-a-vis* conventional technologies; defining these strategies may have the effect of suggesting priorities in terms of R&D efforts. The second purpose is to identify conditions under which the HDR technology, once a proven technology, might meet the market test of providing services at a competitive cost--i.e., the potential commercial feasibility of a proven HDR technology. From the standpoint of researchers and policymakers, therefore, a basis is established for comparative analyses concerning the cost effectiveness of R&D funds allocated to HDR research as well as for long-range planning related to the U.S. potential stock of energy resources.

In the Fenton Hill case study presented here, a wide range of reservoir and generating plant characteristics and parameters are held fixed at values based on plausible, perhaps even conservative, estimates given

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* See, e.g., Burness, *et.al*, (1979) and Cummings and Schulze (1979).

the current stage of technology development (see Table 1). Analyses of the sensitivity of busbar costs for HDR-produced electricity to drilling cost estimates, risk, etc., are then relevant for this particular set of values, assuming a proven technology for HDR. Obviously, if future research and/or economic conditions result in more or less favorable values for the parameters given in Table 1, the potential for feasible HDR systems is improved or diminished, respectively.

TABLE 1

PARAMETER VALUES FOR THE

FENTON HILL CASE STUDY

Power Plant Parameters:	
Plant capacity	50 MW(e)
Capacity factor	.80
System life	30 years
Operation & maintenance	5 mills/kwh
Income taxes	52% of taxible income
Plant design temperature	235°C
Design flow rate	346 kg/sec
Reservoir Parameters:	
Geothermal gradient	60°C/km
Fracture radius	300 m
Number of fractures	6
Operation & maintenance	$500,000/year

II. HDR-PRODUCED ELECTRICITY AT FENTON HILL: A METHODOLOGICAL SKETCH

A. Problem Setting. The Fenton Hill area is located in New Mexico's Jemez Mountains some 90 miles north of Albuquerque, New Mexico, and some ten air miles from the major facilities of the Los Alamos Scientific Laboratory. This is the area in which LASL established and enlarged its first HDR system and is currently drilling a commercial-scale second system. Based on drilling experience to date, the average geothermal temperature gradient in this area is thought to be on the order of 60°C/km.

For analyses of interest here, we posit the existence of a 50MW(e) electric generating plant in the Fenton Hill environment; the power plant uses a Binary Fluid Rankine Cycle technology. Surrounding the plant is the HDR well field (Figure 1) which provides the power required by the electric generating plant. Plant design, as represented here by the plant's design temperature (which plays a major role in determining plant costs), and the design of the HDR system are to be conjunctively determined. Thus, there is the implicit assumption that a single management entity determines the design for both the electric generating plant and the HDR reservoir system.

B. Revenues and Costs for the System. Revenues for this joint power producing-electricity generating system emanate from the sale of electricity. Rather than attempting to speculate as to the possible structure for future electricity prices (at the busbar), the busbar price per kilowatt-hour (kwh) of electricity is taken here to simply equal the busbar cost of producing electricity; the busbar cost is that amount per kwh which just covers all HDR system costs (including returns to invested capital) and excludes electricity transmission and distribution costs. As such, system "feasibility" may be assessed via the comparison of busbar costs estimated for electricity (in 1978 dollars) with estimated future busbar costs for electricity produced with other technologies. Such analyses are the subject of section III below.

Costs for the HDR system will fall into the following categories:

(i) exploration-development costs;

(ii) costs for plant construction;

(iii) drilling and fluid distribution costs for establishing HDR reservoirs;

(iv) re-drilling costs;

(v) operation/maintenance costs and other annual costs;

(vi) taxes.

Methods used for calculating annual equivalent values for each of these components of cost are described in the following; a summary of notation used in this section is shown in Table 2.

(i) Exploration-development Costs. Six types of exploration-development costs are included in HDR system costs. These are: the cost of land purchase for the power plant, lease costs for land required for the HDR reservoirs, costs of geophysical surveys required for site reconnaissance and for site selection and drilling cost for five shallow exploratory wells. These costs are incurred from six to nine years prior to the beginning of plant operation as shown in Table 3. Inasmuch as all revenues and costs are to be measured in constant, 1978 dollars in the initial year of plant operations, it is then necessary to include in these exploration-development costs all interest charges that would accumulate between the year in which the cost is incurred and the first year of

TABLE 2

SUMMARY OF NOTATION

EDC:	Exploration-development costs
MW:	Installed capacity of electric generating plant (in MW(e))
Td:	Design temperature of electric generating plant
PCC:	Plant construction cost
AVPCC:	Annualized value of plant construction costs
r_1:	Real rate of return on debt
$\hat{r}_1$:	Real rate of return on debt adjusted for taxes
PFR:	The design fluid flow rate for the plant (kilograms per second, kg/sec)
WFR:	Well-flow-rate for an HDR reservoir (kg/sec)
D:	Average drilling depth for the initial establishment of an HDR reservoir (feet)
DC:	Drilling costs for the initial establishment of an HDR reservoir
r_2:	Real rate of return on equity
$\hat{r}_2$:	Real rate of return on equity adjusted for taxes
N:	The number of HDR reservoirs (pairs of wells) required to satisfy the plant's fluid flow requirements
PC:	Pipe costs
TDC:	Total initial drilling costs
CRF:	Capital recovery factor
RDC:	Redrilling costs
DD,ST:	Redrilling techniques, "deeper drilling" and side-tracking
AVDC:	Annualized value of total (including redrilling) drilling costs
TXY:	Taxable income for the HDR system
p:	Busbar price of electricity
p*:	Busbar cost of electricity
PO:	Annual power output (in kwh)

TABLE 3

ESTIMATED EXPLORATION, LEASING, AND DEVELOPMENT COSTS

FOR A HOT DRY ROCK POWER PLANT

YEARS TO START OF PRODUCTION	TYPE OF ACTIVITY	COST ($1978)
9	Power plant site purchase	$ 125,000
9	Leased well site (per pair of wells)	293,000
8	Geophysical surveys for site reconnaisance	131,000
7	Geophysical surveys for site selection	131,000
7	Shallow exploratory drilling (5 holes)	262,000
6	Deep evaluation drilling (1-3 holes)	2,360,000

Exploration Development Costs "EDC" $3,302,000 plant operations. Thus, costs given in Table 3 for each exploration-development activity includes such accumulated interest.* For the purpose of later discussions, the sum of these costs is denoted "EDC" ("exploration-development costs").

(ii) Plant Construction Costs. Construction costs for the electric generating plant are estimated from an up-dated** version of the cost formulae for an optimized, binary cycle plant given in Milora and Tester [1976, p. 112]. Defining PCC as "plant construction costs", the general formulae for calculating such costs is given by the following, where MW is installed capacity (in megawatts, MW(e)) and T_d is the plant's design temperature (in $^{\circ}C$):

$$PCC = MW\ [\$976{,}910 - \$2{,}146(T_d)]$$

This formulation is assumed to hold for installed capacities between 50MW (e) and 100MW (e), and for design temperatures in the range 100° to $300^{\circ}C$.

Since installed capacity is fixed in our case study at 50MW(e), PCC is measured as

$$PCC = 50[\$976{,}910 - \$2{,}146(T_d)].$$

Included in this estimate for plant construction costs is accumulated interest during construction; i.e., PCC is measured in the first year of plant operation. In calculating this "present value" of PCC at the first year of operation, a 5-year construction period is assumed wherein 10%

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* Costs are inflated by the factor $(1+r)^t$ where r is the appropriate interest rate (discussed below) and t is the number of years between the year in which the cost is incurred and the beginning of plant operations (e.g., t = 7 for drilling costs for shallow walls, Table 3).

** Milora and Tester values, in 1976 dollars, were inflated by 20% for 1978 dollars.

of costs are incurred in the first year of construction, 17% in the second year and 24.33% in the third, fourth and fifth years of construction. Using an interest rate r_1, adjusted for income taxes deductions on interest payments*, a capital recovery factor is used to derive an annual equivilent value for PCC which is denoted AVPCC.

The reader should note that this formulation of plant construction costs reflects lower plant construction costs as higher values are chosen for the plant's design temperature. Thus, all else equal, incentives exist for designing the plant for working fluids at high temperatures. This observation will be important in our later discussions of drilling costs. Increased costs for "deeper" drilling (required to obtain "higher" temperatures for working fluids) are compared with cost savings in plant construction costs associated with higher plant design temperatures.

Finally, the choice of a design temperature for the generating plant has further implications of interest here. At higher design temperatures, more efficient use is made of working fluids and lower flow rates for such fluids are required. The relationship between the plant's design flow rate (in kilograms per second, kg/sec), denoted PFR, and the plant's design temperature is given in Figure 3. Once again, this observation will be relevant for later discussions of total drilling costs inasmuch as, given well-flow rates (WFR) for each HDR reservoir, well-flow rates from the HDR reservoirs must satisfy the rate for which the plant is designed. Thus, the number of well-pairs--HDR reservoirs--which must be drilled in order

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* Assuming a 52% rate, which includes state and federal income taxes, the real interest rate r_1 would be multiplied by .48 to determine $\hat{r}_1$.

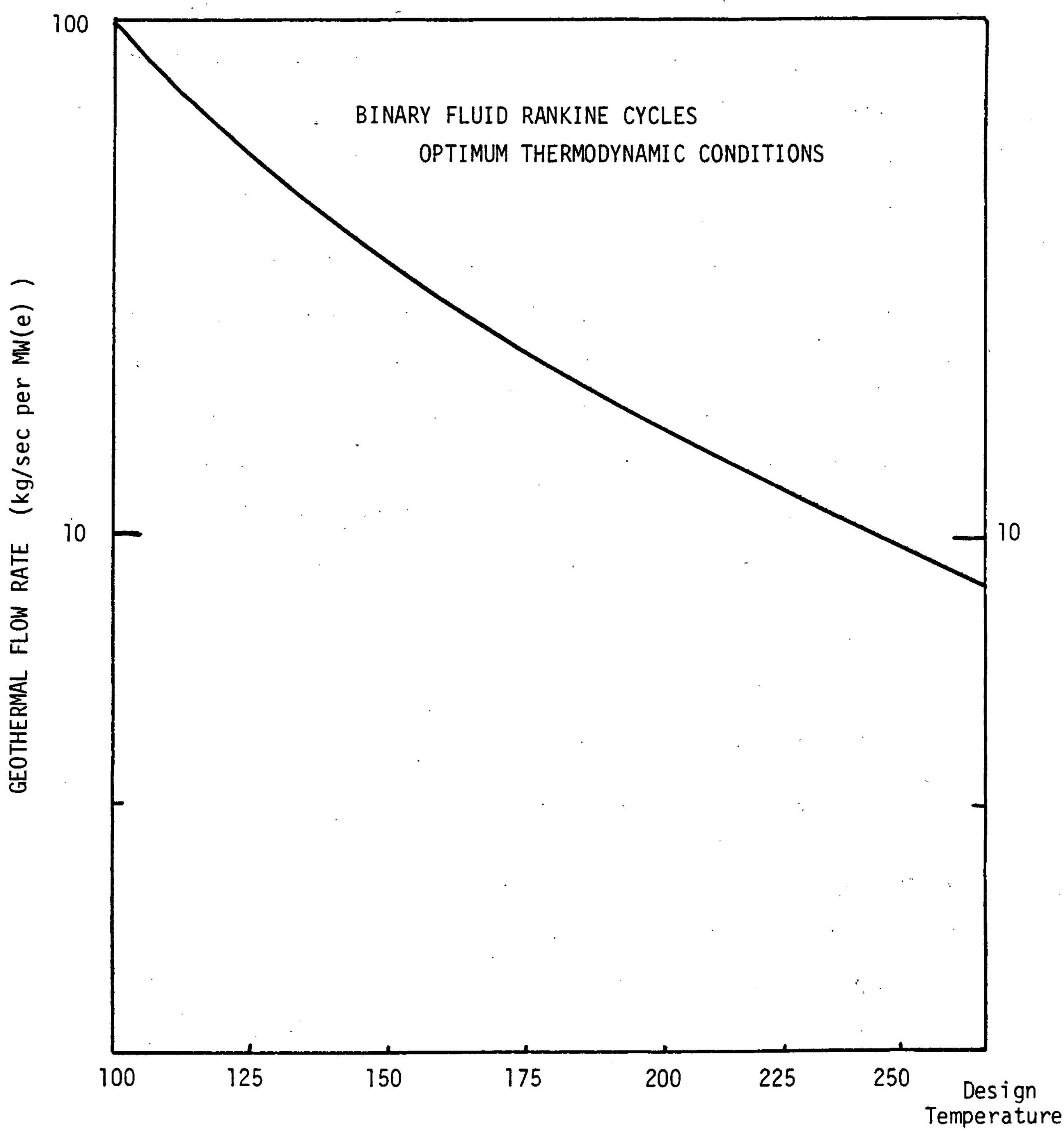


Figure 3

Relationship Between Design Flow-Rate and Design Temperature to satisfy plant design is determined by PFR and therefore the plant's design temperature. The larger Td, the smaller PFR and fewer HDR reservoirs are required to satisfy the plant's power requirements.

(iii) Initial costs for well systems. Three initial well system costs components are of particular interest: drilling costs per reservoir (pair of wells), the required number of reservoirs and costs for the fluid distribution system (pipe cost for gathering fluids from the HDR reservoirs and delivery of the fluids to the generating plant).

Consider first the costs of drilling for one reservoir. Based on a recent study of drilling costs for HDR reservoirs prepared for LASL by the Republic Geothermal Company [1979], the following are estimates for drilling an HDR reservoir (one pair of wells plus the creation of a system of six connected fractures with radii of 300 meters) at the Fenton Hill site, under worst, medium and best drilling conditions; DC and D denote drilling costs and depth of drilling (in feet), respectively.

$$\text{DC - worst} = -\$1{,}920{,}156 + \$607.7(\text{D});$$

$$\text{DC - medium} = -\$1{,}197{,}348 + \$384.2(\text{D});$$

$$\text{DC - best} = -\ \$510{,}704 + \$249.1(\text{D}).$$

The factors which account for these differences in drilling cost estimates are penetration rates, bit life, contingency factors, and differences between whipstock runs in directional drilling. Thus, underlying the DC-high equation are the assumptions of low-penetration rates, short bit lives, the use of large contingency factors and short distances between whipstocks. Values for these factors used for high, medium and low estimates are given in Table 4.

TABLE 4

RANGE OF VALUES USED FOR HDR DRILLING TIME ESTIMATES*

	Best Case Drilling Function #1	Median Case Drilling Function #2	Worst Case Drilling Function #3
Penetration Rate (ft/hr)			
Permeable Section			
26 " - 17½" bits	25	12	7
12¼" - 8½" bits	30	15	12
Impermeable Section			
all bits	15	8	5
Bit Life (hrs)			
26 " - 17½" bits	80	50	40
24¼" - 8½" bits	150	75	50
8 1/8" bits	75	25	20
Tripping Constants			
C_1 (Hours/1000ft)	.5	1.5	1.5
C_2 (Hours)	.5	1.5	3
Contingency Factor			
Permeable Section	8%	20%	50%
Impermeable Section	5%	8%	15%
Length of Whipstock Runs (ft)	300	200	100

* Republic Geothermal, Inc. "Industrial Assessment of Drilling Completion and Workover Costs of the Well and Fracture Subsystems of HDR Geothermal Systems".

If the three drilling cost estimates reflect best, medium and worst drilling conditions, there is some question as to whether or not one would encounter (for example) best or worst drilling conditions throughout the entire depth of the well. As a conjecture, one might encounter best conditions some part of the way, then medium and then worst conditions. In an effort to capture this possibility, a log-linear estimate for drilling costs was prepared for the Fenton Hill site based on the arbitrary assumption of best conditions to 10,000 feet, medium conditions at 15,000 feet and worst conditions at 20,000 feet. The resulting drilling cost relation takes the form:

$$\text{DC-HML} = (\$206{,}619)e^{.0001635(D+492)} + \$165{,}751e^{.000169(D-492)}$$

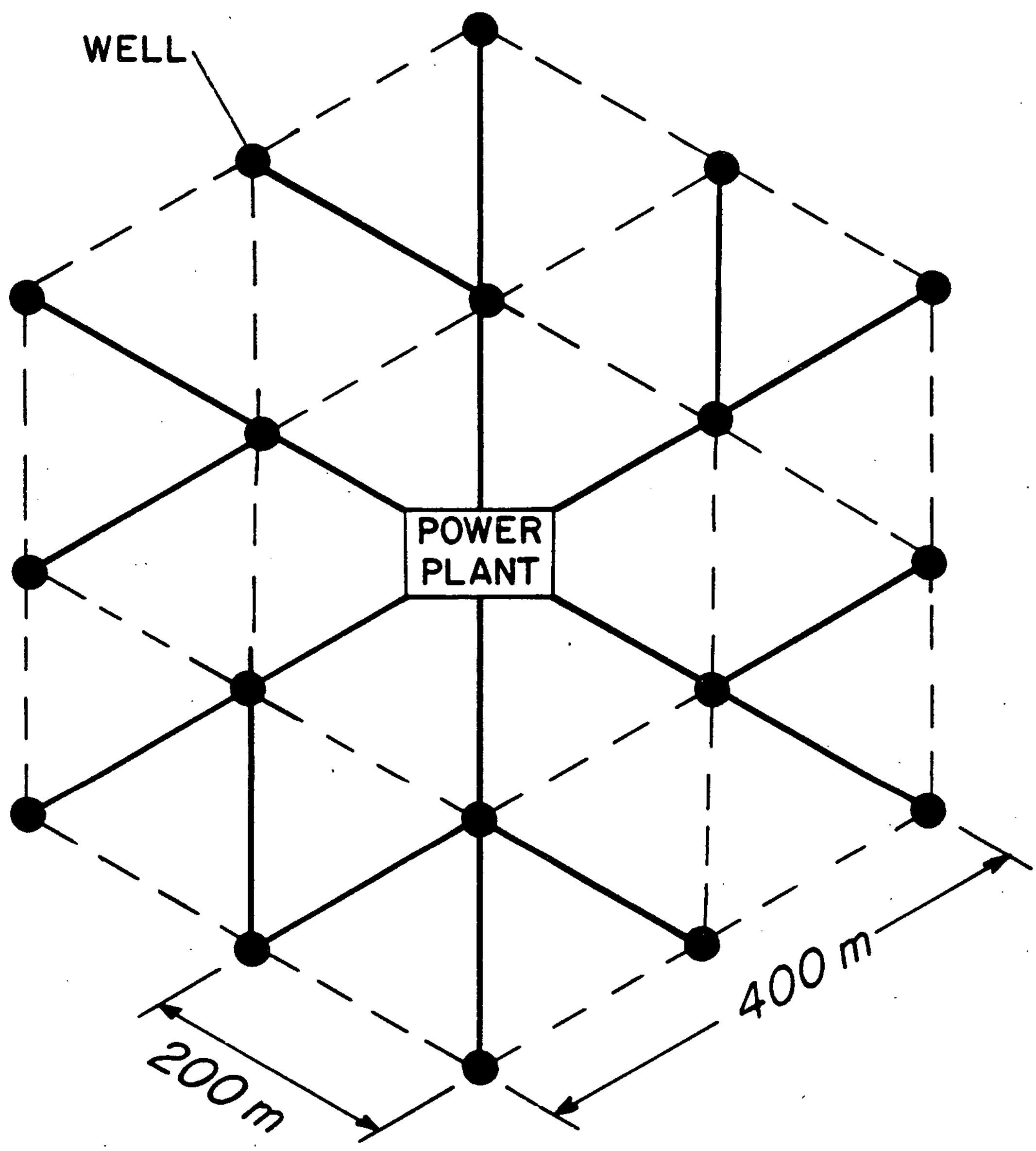
Annual equivalents for all drilling costs are derived via a capital recovery factor using a real interest rate (net of taxes) denoted r_2.

As suggested above, the second cost component of interest here--the number of required HDR reservoirs--is determined by the plant's design flow rate, PFR, and the well-flow rate (WFR) for each reservoir. If N is the required number of reservoirs, N = DFR ÷ WFR. For example, with Td = 200°C, PFR for a 50 MW(e) plant is roughly 500 kg/sec [see Figure 3-2 in EPRI, 1979, p. 3-14]. With a well-flow rate of 125 kg/sec, four reservoirs are required; with WFR = 62.5, eight reservoirs are required.

The third cost component relevant for the initial establishment of the HDR field is for the fluid gathering and distribution system. Costs for this pipe system are taken to be proportional to the linear footage required to make pipe connections among corners of equilateral triangles as shown in Figure 4. Pipe costs, in constant 1978 dollars, are estimated

FIGURE 4

REPRESENTATION OF FLUID GATHERING GRID



to be \$4.92/inch diameter/foot of length. A 12-inch pipe is assumed for all pipes. In the six well-pairs in the inner hexagon in Figure 4, pipe length is 600 feet, 1200 feet in the next hexagon and 1800 feet for well-pairs lying beyond the outer hexagon. Thus, denoting pipe costs as PC and N as the number of well pairs, we have:

$$PC = (\$70,848)N \qquad \text{if } N \leq 6,$$

$$PC = (\$70,848)(2N-6) \quad \text{if } 6 < N \leq 18,$$

$$PC = (\$70,848)(3N-24) \quad \text{if } N > 18.$$

A capital recovery factor is used to derive annual equivalent values for PC.

Annual equivalent values for total costs for the initial establishment of the HDR system (TDC) is then given by (CRF is the capital recovery factor $\frac{r}{1-(1+r)^{-T}}$):

$$TDC = [(DC)(N) + PC]CRF$$

which measures drilling cost per reservoir times the required number of reservoirs plus pipe costs for the fluid gathering-distribution system. This cost will, of course, depend on the form of the drilling cost function used, high, medium, low or the combined HML form.

(iv) Redrilling Costs. Given the initial establishment of the HDR reservoirs, reservoir temperatures and therefore the temperature of geothermal fluids delivered to the generating plant, will be at some given temperature. With the HDR reservoirs in operation, reservoir temperatures will decline over time.* As reservoir temperatures approach the generating plant's design temperature, it then becomes necessary to re-drill, or "reestablish", the HDR reservoirs in order to continue providing geothermal fluids at temperatures at least as great as Td.

Two alternative re-drilling techniques are used here. These are diagrammed in Figure 5. The first involves deeper drilling. The "old" fractures are sealed, and the original boreholes are extended 100 to 200 meters to new areas of hot rock at temperatures slightly higher than that in the original reservoir. The second technique is called "side-tracking". Here, the drill enters the original borehole but at some distance above the original fracture (the kick-off point) directional drilling techniques are used to drill obliquely to unaffected areas of granite at roughly the same temperature (vertical depth) as the original wells.

As in the case for drilling the original wells, re-drilling costs will depend on the drilling conditions encountered--best, medium or worst and HML-combinations. Thus, for each re-drilling technique we will have four alternative cost estimates which are given as follows:

Re-drilling Technique: (depth in feet)

Drilling Conditions	Deeper Drilling	Sidetracking
Best	\$438,917 + \$28.5(D)	\$ 732,833 + 56.9(D)
Medium	\$563,750 + 43.8(D)	\$ 992,500 + 71.5(D)
Worst	\$779,750 + 75.5(D)	\$1,524,417 + 89.3(D)
HML	(\$214,943)e .000118517(D)	(\$ 511,889)e .000092003(D)

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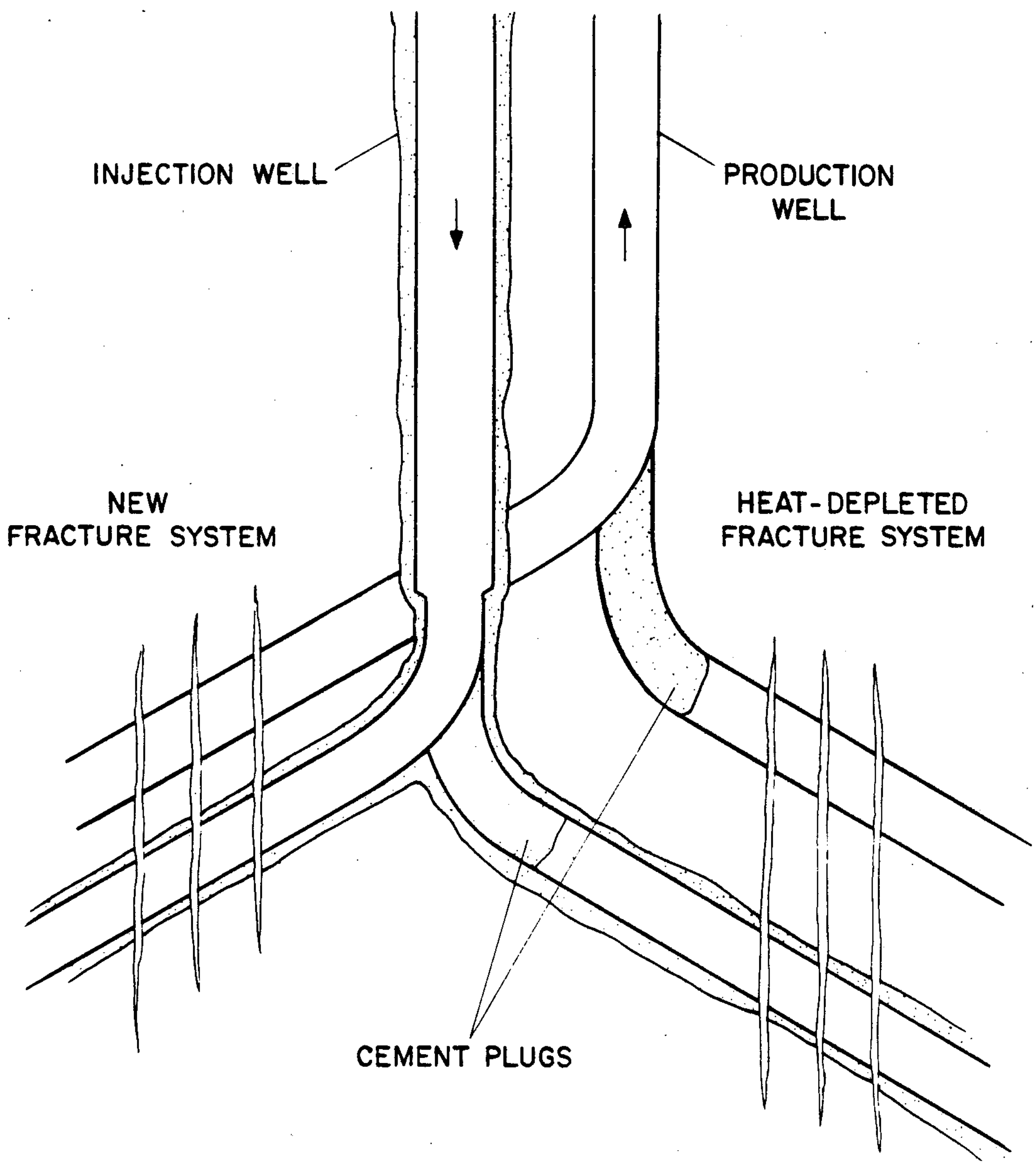
* See Appendix A for the method used in approximating temperature drawdown.

FIGURE 5.A

RECOMPLETION WITH PLUG BACK AND SIDETRACKING



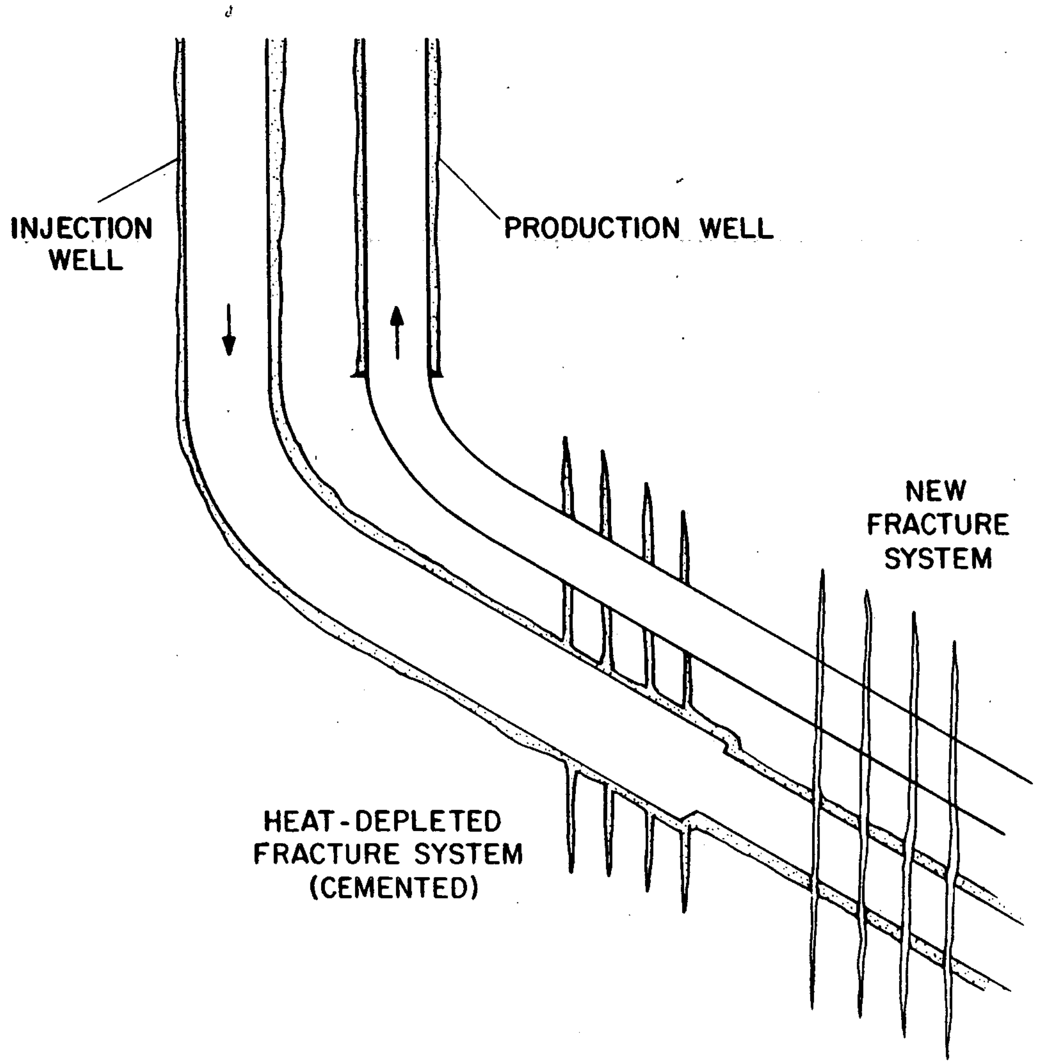


FIGURE 5.B

RECOMPLETION BY CEMENTING THE HEAT DEPLETED FRACTURE SYSTEM, DEEPENING THE WELL AND CREATING A NEW FRACTURE SYSTEM

In what follows, re-drilling costs are denoted RDC; drilling conditions are identified by B, M, W and HML, and the technique is identified as DD and ST. Thus, RDC-B-ST denotes re-drilling costs with best drilling conditions wherein the sidetracking technique is used.

Timing for drilling costs is determined in the following manner:

(1) A design temperature for the plant, Td, is arbitrarily chosen in the range $150^{\circ}C \leq Td \leq 300^{\circ}C$, and annualized plant construction costs, AVPCC(Td), are computed. Initial drilling costs are taken computed for depths yielding initial reservoir temperatures of Td up to (Td + $100^{\circ}C$).

(2) For well-flow rates between 75 - 150 kg/sec, the time-path of temperature drawdown (from initial temperatures) in the HDR reservoirs is estimated using the LASL drawdown model based on McFarland's [1976] model for an HDR reservoir. In the year that reservoir temperature approaches Td, re-drilling occurs; thus, reservoir temperatures are always at least as great as design temperatures.

(3) For <u>each</u> Td and well-flow rate (which determines the required number of HDR reservoirs), plant costs can be summed with initial drilling costs and with the present value of re-drilling costs for each initial drilling depth. The plant cost--well-flow rate--initial drilling depth combination that yields the minimum cost is the combination used for analysis.

Of course, analyses are based on annual equivalent values for all costs. To approximate average annual drilling and re-drilling costs which have been incurred, re-drilling costs incurred in each year (e.g.) t_1, t_2 and t_3 are weighted by the percent of the 30-year planning horizon that such costs must be carried by the enterprise and a CRF is applied to the present value of this weighted sum; i.e., for any given set of drilling conditions (H, M, L, HML) and a given re-drilling technology; the annual equivalent value of total drilling costs (AVDC) is given by:

$$AVDC = [(DC)(N) + PC]\ CRF + CRF\ [RDC(t_1)\left(\frac{30 - t_1}{30}\right)(1 + \hat{r}_2)^{-t_1}$$
$$+ RDC(t_2)\left(\frac{30 - t_2}{30}\right)(1 + \hat{r}_2)^{-t_2} + RDC(t_3)\left(\frac{30 - t_3}{30}\right)(1 + \hat{r}_2)^{-t_3}].$$

(v) O&M and Other Annual Costs. Annual operation-maintenance costs for the combined generating plant--HDR system enterprise is assumed to be \$.005/kwh. In addition to O&M costs, the enterprise pays \$69,370/year in property taxes and \$9.17/acre/year in leasing costs for land.

(vi) Taxes. In addition to property taxes identified above, the HDR enterprise pays a revenue tax of 2.5% of gross revenues and income taxes.

For the purpose of calculating income taxes, taxable income is computed as follows:

(a) under current legislation, the HDR facility would realize a depletion allowance in an amount equal to the smaller of: 15% of gross revenue or 50% of taxable income (before the depletion allowance). In all cases studied here, the smaller of these two is 15% of gross revenue. An add-on tax, referred to as a "minimum tax", of 15% of the depletion allowance less \$10,000, is also included.*

* This formulation may overstate the minimum tax in that the minimum tax is 15% of the depletion allowance reduced by the maximum of either \$10,000 or half of the firm's regular tax bill. If half the tax bill exceeds \$10,000, the minimum tax would then be lower.

(b) taxable income (TXY) for the enterprise, net of the 15% (of gross revenue) depletion allowance is assumed to be given by

$$\text{TXY} = \text{pxPO}(1\text{-Revenue Tax}-.15)-(\text{O\&M}_{\text{plant}})\text{PO}-\text{O\&M}_{\text{HDR}} - \text{EDC} - \text{AVPCC} - \text{Property taxes} - \text{Land Lease Costs} - \text{AVDC}$$

With a 52% rate for average state and federal income taxes, and recognizing that the annual return on stocks $r_2[(DC - N) + PC]$ is included in TXY, the annual tax bill is then given by

$$\text{Annual Tax} = .52\ [\text{TXY} + r_2(\text{DC x N} + \text{PC})] + .15\ [.15\ \text{p x PO} - \$10{,}000].$$

C. Net, After Tax Income and the Busbar Cost. From the discussions above, a least-cost combination of plant costs (determined by Td), initial drilling depths and well-flow rates are chosen for the HDR electric generating enterprise, which results in the following expression for annual net, after tax income (the revenue tax is 2.5% of gross revenue):

$$\text{Net After Tax Income} = .54\ (\text{p x PO}) - .48\ [\text{O\&M}_{\text{Plant}} \text{ x PO} + \text{O\&M}_{\text{HDR}} + \text{EDC} + \text{AVPCC} + \text{Property Tax} + \text{Land Lease} + \text{AVDC}] - .52\ r_2\ [\text{PC} + \text{N x DC}] + \$1500.$$

Of interest here is the busbar cost for HDR-produced electricity which is the cost/kwh which just covers all costs of production excluding transmission and distribution costs. A busbar cost, p*, for the HDR system described here corresponds to the value of p in the above expression for net after tax income, which makes net after tax income zero (note that the annual payments of returns on stocks are included in AVDC). Thus, given least cost values for Td, the well-flow-rate and initial drilling depths, the busbar cost p* is determined by:

$$p^* = \frac{.48\ [O\&M_{Plant}(PO)+O\&M_{HDR}+EDC+AVPCC+Prop.Tax+Land\ Lease+AVPC]}{.5235\ (PO)}$$

$$- \frac{.52}{.5235} r_2\ AVDC - \frac{\$1500}{.5235(PO)} .$$

Values of p* which result from the various parameters chosen here for analysis are given in Table 5.

TABLE 5

BUSBAR COSTS FOR HDR-PRODUCED ELECTRICITY
WITH ALTERNATIVE DESIGN TEMPERATURES,
DISCOUNT RATES, AND DRILLING COSTS

Design Temperature = 235°C
Plant Costs (PCC) = $23,630,000.
Property Taxes = $ 69,370.

Drilling Conditions/Technology for Recompletion:	Busbar Cost for HDR-Produced Electricity with Real Debt/Equity Rates:			
	3%/6%	6%/9%	9%/12%	12%/15%
	(mills/kwh, 1978 dollars)			
Best Conditions/Deeper Drilling	16	18	21	24
Sidetracking	17	20	23	26
Medium Conditions/Deeper Drilling	18	21	25	28
Sidetracking	19	23	27	30
Worst Conditions/Deeper Drilling	22	27	32	37
Sidetracking	24	29	34	39
H-M-L Conditions/Deeper Drilling	17	20	23	26
Sidetracking	19	22	25	28

III. POTENTIAL COMMERCIALIZATION OF HDR-PRODUCED ELECTRICITY

Based on the methodology set out in the preceeding section, estimated busbar costs for HDR-produced electricity may be used to assess the potential commercial feasibility of such an enterprise in the Fenton Hill area under alternative assumptions concerning drilling conditions and, therefore, drilling costs and conditions of risk. Drilling conditions are considered in subsection A, after which attention is focused on the issue of risk in subsection B. The interrelationship between plant design and the design of the HDR system is considered in subsection C.

A. Drilling Costs. As noted above, a recent study of drilling costs for HDR systems by the Republic Geothermal Company (1979) resulted in drilling costs estimates under best, medium and worst drilling conditions. These data may also be used to develop still a fourth estimate for drilling costs under conditions wherein one encounters best, then medium and then worst conditions (HML) in any drilling activity. Under any set of drilling conditions, well recompletion costs (re-drilling) will depend upon the technology used--"deeper drilling" or sidetracking. Estimates for busbar costs for our hypothetical 50MW(e) electric generating plant in the Fenton Hill area under each of these sets of drilling conditions are given in Table 5.

For the purpose of these discussions, consider busbar costs in Table 5 which obtain with real debt/equity rates 6%/9%. Under best, medium and worst drilling conditions, busbar costs are 18-20 mills/kwh, 21-23 mills/kwh and 27-29 mills/kwh, respectively. For the combination of drilling conditions (HML), the busbar cost of electricity is in the range 20-22 mills/kwh. In all cases, sidetracking technology for well-recompletion activities results in a busbar cost which is generally some one to two mills/kwh higher than those which obtain with the "deeper drilling" technology.

What do these data imply in terms of the potential commercial feasibility of HDR-produced electricity? A response to this question requires some basis for a comparison of estimated busbar costs for HDR-produced electricity with busbar costs of electricity from sources with which HDR must compete. While estimates for future busbar electricity prices from nuclear-coal mixes vary considerably, an FEA (1976) estimate of some 30 mills/kwh for 1985 busbar costs (in 1978 dollars) would appear to be a conservative estimate. Referring then to Table 5, HDR-produced electricity at Fenton Hill would then be competitive with alternative power sources--commercially feasible--under all drilling conditions with real debt/equity rates of 6%/9% or lower. With higher real debt/equity rates, HDR-produced electricity would seem to be commercially feasible except under "worst" drilling conditions.

As reflected in costs, drilling conditions are then shown to have a substantial impact on busbar costs for HDR-produced electricity, with busbar costs increasing by 50% or more as drilling conditions vary between best and worst conditions. Whether or not HDR-produced electricity may be potentially feasible under more pessimistic expectations as to drilling conditions than turns on the risk environment for technology adoption, an issue to which attention is now turned.

B. The Issue of Risk. Past experience with the adoption of new technologies, particularly in terms of LDA geothermal systems, suggests that the process of technology adoption for HDR (once a "proven" technology) might require relatively high rates of return for invested capital which essentially reflect "premiums" for risk. This is particularly true in cases like HDR wherein essentially all costs are "up front"--i.e., operation-maintenance and other annual costs are minescule relative to capital costs for establishing the HDR system and constructing the power plants.

The impact of the risk environment on the potential commercial feasibility of HDR-produced electricity is made manifest by the data in Table 5. Under best drilling conditions,the busbar cost increases by some 50% as debt/equity rates rise from 3%/6% to 12%/15%; similarly, the busbar cost rises some 60% under worst drilling conditions.

While a "competitive" future busbar cost for electricity will obviously vary from region to region in the U.S., if we continue to use 30 mill/kwh as a benchmark for future busbar costs (in 1978 dollars), the impact of risk conditions as reflected in real debt/equity rates of return become particularly striking. Referring to Table 5, HDR-produced electricity would be commercially feasible under all drilling conditions and well recompletion technologies (only marginally so with worst conditions and sidetracking) with real debt/equity rates of 6%/9% and lower. If one assumes an average rate of inflation of 6%, these rates correspond to nominal rates of 12%/15% and lower. With real debt/equity rates of 9%/12% (nominal rates of 15%/18%) HDR-produced electricity is competitive with alternative sources for electricity under all but worst drilling conditions, as is the case with real (nominal) rates of 12%/15% (18%/21%).

Thus, all else equal, the potential commercial feasibility of a proven HDR technology for electric power generation with worst drilling conditions may depend strongly on the risk environment relevant for its adoption. With more optimistic assumptions regarding drilling costs, HDR-produced electricity may be commercially feasible even in cases where required risk premiums are high. Given the uncertainty that remains concerning drilling costs, however, this suggests, among other things, the need for a well-designed program involving demonstration plants in various gradient areas and experimental programs designed to mitigate the uncertainties surrounding the nature of drilling costs and reservoir performance, all of which serves to reduce risk.

C. System Design Trade-Offs. Reference was made earlier in this report to the interdependence between the optional design of the power plant and that for the HDR system. Higher reservoir temperatures, achieved by deeper (more expensive) drilling, allow for higher design temperatures for the power plant and therefore, lower plant costs. One then "trades off" higher drilling cost for lower plant costs, or visa versa.

This trade-off is shown by data in Figure 6, wherein the minimum busbar electricity cost for the entire reservoir-power plant system is plotted against the plant's design temperature; these data are given for all four drilling conditions and re-drilling technologies analyzed above, using a 6% interest rate on debt and a 9% equity rate of return. With, e.g., "worst" drilling conditions and the "deeper drilling" technology (panel C in Figure 6), the busbar cost for HDR-produced electricity is almost 36 mills/kwh for a plant design with a design temperature of 160°C. With a higher design temperature, e.g., 205°C, drilling cost, increase due to the necessity of establishing HDR reservoirs at greater depths (higher rock temperatures), but the decline in plant costs* is sufficient to lower the resulting busbar cost from some 36 mills to 30 mills/kwh. The minimum busbar cost obtains with design temperatures between 235°C and 265°C. Interestingly enough, the range for the value of Td that minimizes the busbar cost is shown to lie between 225°C and 265°C across all drilling conditions and re-drilling technologies.

Thus, while one typically looks to high design temperature for power plants using conventional technologies, the drilling-plant cost trade-off

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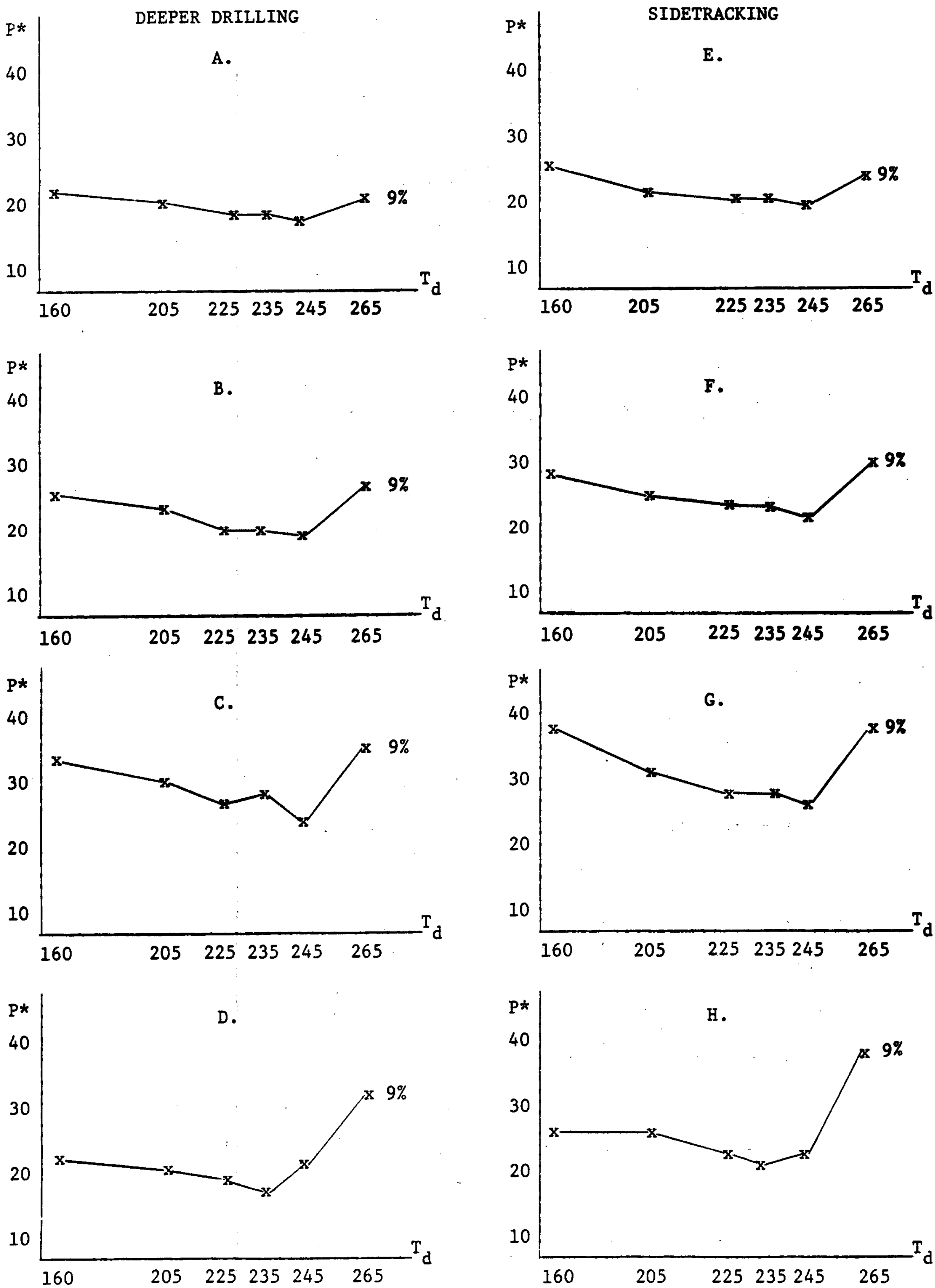
* Attending the higher design temperature is a reduction in the design flow rate (PFR) and, therefore, the requirement for fewer HDR reservoirs.

FIGURE 6 EFFECT OF DESIGN TEMPERATURE ON BUSBAR COST



apparent for the HDR technology suggests that the conjunctive determination of plant and reservoir design may be critical in achieving minimum cost production of electricity.

IV. CONCLUDING REMARKS

While the analyses given here concerning the potential commercial feasibility of an HDR-powered electric generating facility at the Fenton Hill area are based on estimated system parameters (see Table 1) for a technology which is still in its infancy, these analyses hopefully serve to draw attention to issues which earlier studies have suggested as being particularly relevant for feasibility assessments concerning this technology. Results from this study suggest grounds for cautious optimism in areas with gradients on the order of those found in the Fenton Hill area* with (i) any drilling conditions if real debt/equity rates are on the order of 6%/9% or less and (ii) best to medium drilling conditions if real debt/equity rates are as high as 9%/12%.

Currently, coal-fired electric generating plants require <u>nominal</u> debt and equity rates of some 9% and 12%, respectively; assuming an average inflation rate of 6%, this situation would correspond to their requirement of <u>real</u> debt/equity rates of 3%/6%. The condition (i) above would then suggest that HDR-produced electricity may be potentially competitive under all drilling cost estimates with required debt and equity rates of return which are 100% and 50%, respectively, higher than those currently paid by coal-fired electric generating plants.

Of course, as R&D efforts at Los Alamos and elsewhere continue, and more knowledge is acquired concerning such things as reservoir design and performance, estimates for busbar costs will vary from those presented

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* See, e.g., Cummings and Morris (1979a).

here. To the extent that system parameters used here are conservative, a proven technology for HDR may well result in busbar costs which are lower than those estimated here. This is particularly the case in terms of reservoir design related to the effective surface area of the reservoir and therefore temperature drawdown rates. If Los Alamos scientists are successful in their ongoing experimental efforts to create a system of multiple, connected fractures--thereby creating large surface areas in the hot granite--temperature drawdown in the HDR reservoirs (for any given well-flow rate) may well be less than that used in this work. Lower rates of temperature drawdown can be expected to result in smaller initial drilling depths and less frequent well recompletion activities and, therefore, lower drilling costs.

In closing this report, it is interesting to compare the results from this site-specific study of HDR-produced electricity in California's Imperial Valley.* Using a real rate of return on stocks of 9% and a real interest rate of 6%, and assuming the extension drilling technology for redrilling, a comparison of estimated busbar costs is given as follows.

Site	Estimated Busbar Cost with Drilling Conditions: Best	Medium	Worst
		(mills/kwh)	
Fenton Hill Area	18	21	27
Imperial Valley**	31	35	41

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* Cummings and Morris (1979b).
* *Ibid.*, Table 7.

As is obvious from the above, the estimated busbar costs for HDR-produced electricity is between 52% and 72% higher for Imperial Valley than for the Fenton Hill area; the reasons for these differences point to the importance of site specific studies for "early" evaluations of the potential commercialization of technologies such as HDR. The primary reasons for these large differences in estimated busbar costs may be summerized as follows:

(a) costs for the electric generating plant are some 35% higher in the Imperial Valley -- $32 million compared with $23.6 million for the Fenton Hill area. This difference reflects, first, higher costs due to the higher ambient temperatures in the Imperial Valley relative to the Fenton Hill area and, second, the lower design temperature used in the Imperial Valley -- 205°C compared with 235°C in the Fenton Hill area.

(b) higher taxes and royality payments required for the Imperial Valley; 15% of the HDR system's gross revenue is charged as a (conservative) royality rate in the Imperial Valley study and California's state income taxes average some 1% higher than those for New Mexico.

(c) drilling costs are higher in the Imperial Valley than in the Fenton Hill area due to the relatively large sedimentary overburden on crystalline rock (the most favored medium for HDR systems) in that area. Thus, the initial drilling cost for a pair of wells drilled to 3,000 meters under "best" drilling conditions is some $2.83 million in the Imperial Valley, but only about $1.98 million in the Fenton Hill area.

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APPENDIX A

Calculation of Temperature Drawdown

Temperature drawdown in a HDR reservoir is related to the effective area of the reservoir, and its well-flow rate. The effective surface area of the reservoir is measured as S.

$$S = \sqrt{F \cdot R^2} = 734.8 \text{ meters}$$

where F = the number of fractures, fixed in this study at six

R = the radius of each fracture, fixed in this study at 300 meters

Figure 7 on the following page depicts temperature drawdown as a fall in the percentage of initial reservoir temperature over time. Each curve, labelled μ, corresponds to a reservoir with effective surface S and well flow rate m, where:

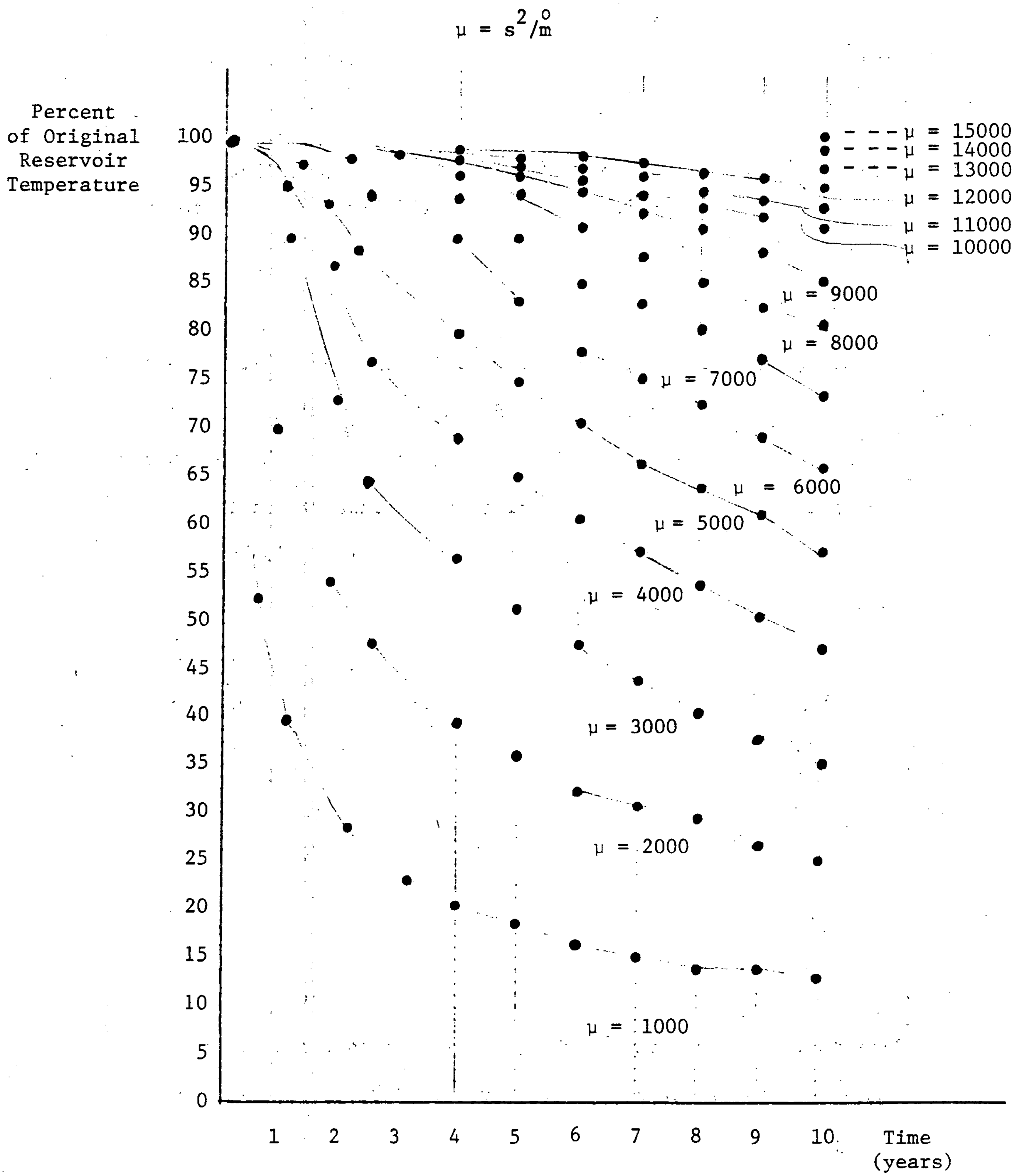
$$\mu = \frac{S^2}{m}$$

The following table relates each drawdown curve μ with an appropriate well flow rate m, given a fixed effective surface of 734.8 meters.

$\mu = \frac{S^2}{m}$	well flow rate m	number of wells N
15000	36	10
14000	38.6	9
13000	41.5	8
12000	45	8
11000	49.1	7
10000	54	6
9000	60	6
8000	67.5	5
7000	77.1	4
6000	90	4

FIGURE 7

SCHEMATIC FOR TEMPERATURE DRAWDOWN FOR ALTERNATIVE WELL FLOW RATES



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$\mu = \frac{S^2}{m}$	well flow rate m	number of wells N
5000	108	3
4000	135	3
3000	180	2
2000	270	1
1000	540	1

where the number of wells needed, N, is the ratio of the plant's design flow rate (346.304 kg/sec for a 235° HDR facility) to the reservoir's well flow rate.

$$N = \frac{346.304}{m}$$

In this study, we selected a range of initial reservoir temperatures above the design temperature of the HDR facility, and chose, for our calculations, those well flow rates that maintained the design temperature for five years or longer. The critical percentages of initial temperatures needed to maintain a design temperature of 235°C (the vertical axis in Figure 6) are as follows:

Initial Reservoir Temperature	% of Initial Temperature needed to maintain 235°C
260°	90%
285	83
310	76
335	70
360	65
385	61
410	57
435	54

Referring back to Figure 7 then, we can see that a well drilled to obtain an initial reservoir temperature of 335° would draw down to

235° (70% of 335°) in 6 years with a well flow rate of 108 kg/sec (μ = 5000), or in 9 years with a well flow rate of 90 kg/sec.

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