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HR. 1383

DOE/ET/27017-T2

POWER PRODUCED FROM HOT DRY ROCK GEOTHERMAL RESOURCES

A Case Study for the Imperial Valley, California

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MASTER

December 1979

Work Performed Under Contract No. AS04-79ET27017

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U. S. DEPARTMENT OF ENERGY

Geothermal Energy

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POWER PRODUCED FROM HOT DRY
ROCK GEOTHERMAL RESOURCES:
A Case Study for The Imperial Valley,
California

Report for DOE Contract No. DE-AS04-79ET27017

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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 California's Imperial Valley. The second case study* concerns a combined HDR system-power plant which is hypothetically located in the Fenton Hill area, New Mexico.

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 presented 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 used for analyzing the HDR system involves a two-stage process. In stage 1, the maximum amount that the electric plant can pay to an HDR system for geothermal fluids is calculated for alternative busbar prices of electricity received by the electric plant. In stage 2, costs for the HDR System are calculated under differing assumed risk environments and drilling conditions. These two sets of data may then be used to analyze the minimum busbar price of electricity -- which defines a maximum fuel bill that could be paid to the HDR system by

*Cummings, R. G., G. E. Morris, et.al, December, 1979(a).

the electric plant -- which could result in the HDR system's full recuperation of all production and drilling costs.

Major results from these analyses are as follows: with a real rate of return/interest combination of 6%/3%, the minimum busbar cost for electricity (in constant 1978 dollars) which could result in a commercially feasible HDR system is 25 mills/kwh, 27 mills/kwh and 32 mills/kwh under best, medium and worst drilling conditions, respectively. As real rate of return/interest combinations vary between 9%/6% and 15%/12%, this minimum busbar price for electricity varies between 31-41 mills/kwh and 45-60 mills/kwh depending on assumed drilling conditions.

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I. INTRODUCTION: THE HOT DRY ROCK GEOTHERMAL RESOURCE

A. The HDR Geothermal Resource. In June, 1977, scientists at the Los Alamos Scientific Laboratory successfully completed the world's first closed loop "hot dry rock" (HDR) geothermal system.* The HDR system involves a man-made geothermal reservoir which is a fracture system in hot granite. This fracture system, some two miles below the earth's surface with initial rock temperatures of 205 degrees centigrade (401 degrees fahrenheit), was created by massive hydraulic fracturing techniques which have been developed in the petroleum industry. Pressurized water was circulated down across the fracture system through an injection well, heated by the hot dry rock, and returned to the surface via a "production well". Such a system might then be used for the generation of electricity or for any of a number of process or space heat applications. Figure 1 depicts a combined HDR reservoir and electric power plant.

While the technology for making use of energy from HDR geothermal resources is still at an early stage of research and development, the fundamental features of this technology are sufficiently well understood for the system's critical engineering and economic parameters to be defined and analyzed. Engineering parameters and results from the experimental HDR system are described in detail in [Brown, et.al., 1979]. A general study of economic conditions under which HDR-produced electricity might be commercially feasible is given in [Cummings and Morris, Dec., 1979(b)]. This paper provides a more detailed, site-specific consideration of the economics and operating pattern of an HDR system which provides geothermal fluid for

*See Tester and Albright (1979).

FIGURE 1
HOT DRY ROCK GEOTHERMAL CONCEPT

an electric generating plant.

B. A Case Study. The purpose of this report is to provide a site-specific case study for an HDR system which provides geothermal fluid for an electric generating plant; the HDR system and the electric power plant are separate decision-making entities. In a companion study which focuses on an HDR system in Jemez Mountains of New Mexico*, the HDR facility and the electric power plant are operated by a single decision maker.

The site chosen for this case study is the Imperial Valley in southwestern California. The Imperial Valley is a well-known hydrothermal area; major drilling efforts to develop liquid dominated geothermal reservoirs began there in the late 1950's-early 1960's.** In terms of current electricity production from liquid dominated geothermal reservoirs in the area, a 10 MW pilot flash binary plant was constructed in the Salton Sea area in 1975. Several additional electric generating facilities, which will use geothermal resources, are currently under design or construction in the Imperial Valley: a 50 MW(e) plant in the Salton Sea; a 10 MW(e) plant in the Brawley area; a 48 MW(e) double flash plant and a 10 MW(e) binary plant in the East Mesa area; and a 50 MW(e) plant in the Herber area. The power potential from known reservoirs in the Valley is estimated at 6,000-7,000 MW(e).

The Imperial Valley may also be an attractive area for early applications of the HDR technology given the high geothermal gradients in the Valley. Geothermal gradients--the average increase in rock temperature below the earth's surface per kilometer of vertical depth--are estimated at some 60

*Cummings, Morris, et al. [December, 1979 (a)].

**Most of the following is drawn from Anderson (1979).

degrees centigrade per kilometer of vertical depth ($60^{\circ}\text{C}/\text{km}$) in the Imperial Valley. Given that the bulk of the costs for HDR reservoir systems is drilling costs, high geothermal gradients then imply lower drilling costs required to attain any given reservoir temperature. Unfortunately, crystalline rock, currently the most favored medium for HDR systems, lies under almost 3000 m. of sedimentary overburden in the Imperial Valley. The question, then, is whether an HDR/electric system is economically attractive under these circumstances.

In what follows, we posit the existence of a 50 MW (e) electric generating plant which makes use of a Rankine Binary Fluid Cycle technology. The plant is assumed to be designed for fluid temperatures of 205°C requiring a fluid flow rate of 503 kilograms per second (kg/sec). The plant's geothermal fluid requirements will be satisfied by reservoirs as described below. This set of reservoirs and any auxiliary structures and equipment are referred to as the HDR "system" to distinguish them from the electric plant which utilizes the HDR-produced fluids. The combined HDR system and electric plant is referred to as the HDR/electric facility.

C. The Commercial Feasibility of an HDR/Electric Facility. The major purpose of this case study is to assess the potential commercial feasibility of using HDR systems to provide hot geothermal fluids for use in electricity generation. Since the HDR system is essentially providing the fuel requirements for a generating plant, we wish to know if the system can do so at a cost which would be competitive with a coal-fired electric power plant.

Given the uncertainties that surround many of the key engineering and economic parameters which are of potential importance for an HDR

system, the issue of the "competitiveness" of an HDR/electric facility must then be analyzed using a range of values (high to low) for these parameters. Attention here will be focused on two particularly important economic variables which will be varied in the analyses that follow; these are:

(a) Drilling Costs. High, medium, and low estimates for drilling costs in the Imperial Valley have been prepared for the Los Alamos Scientific Laboratory by the Republic Geothermal Company (1979). The commercial feasibility of an HDR/electric facility in the Imperial Valley will be assessed using the high, medium, and low Republic estimates for drilling costs.

(b) Risk. An important element for the assessment of any new technology is the element of risk as it relates to technology adoption. Measures of relative risk are implicit in the rates of return and interest which a firm or investor requires above the normal rates before investing in a particular project. Of course, it is difficult to specify the future character of the risk environment relevant for HDR/electric facilities, as would be manifested by required rates of return on bonds and stocks sold by either the prospective HDR resource producer and/or the firm which operates the electric generating plant. Thus, the following real (inflation-free) rates of return were arbitrarily chosen for use in analyses; this range of values for interest rates is believed to cover a sufficiently broad range of possibilities to cover any reasonable scenario for risk conditions that might face potential operators of an HDR/electric facility.

<u>HDR Electric Plant</u>		<u>HDR System</u>
<u>Rates of Return on Stocks</u>	<u>Interest on* Bonds</u>	<u>Rates of Return on Stocks*</u>
6%	3%	6%
9%	6%	9%
12%	9%	12%
15%	12%	15%

D. Plan of the Report. In developing this analysis of the commercial feasibility of HDR-produced power, the arguments proceed in the following manner. In section II, revenues and cost items for the coal-fired power plant and for the HDR/electric facility are developed. Based on these analyses of costs and revenues, the question "could HDR-produced power be commercially feasible?" is addressed in section III. Analyses in this section seek to identify those electricity prices (at the busbar) or fuel costs under which HDR-produced electricity in the Imperial Valley might be a commercial alternative. Finally, concluding remarks are offered in section IV.

Before continuing, however, it is important for the reader to recognize that there is no pretense for the analyses presented here to be anything other than a "partial" analyses. In other words, there are many reservoir and economic parameters about which uncertainty exists at this stage of technology development and these parameters are held fixed at values based on best available estimates; only a small part of these parameters are varied in the analyses given here. The rationale for such a partial analysis is essentially two-fold. First, efforts for

*Given that the HDR system has little in the way of buildings and other physical assets--the bulk of HDR costs are for drilling and establishing wells--it is assumed here that all financing comes from the sale of stocks which command, of course, higher rates of return than do bonds. The HDR power plant itself is assumed to finance operations with 50% stocks and 50% bonds.

a more complete analyses of feasibility conditions wherein all (or a much larger number of) parameters are subjected to sensitivity analyses may result in such an overwhelming volume of data as to make difficult any meaningful focus on specific questions with policy content; an example of such a broader effort is found in [Cummings and Morris, Dec., 1979 (a)]. Second, both the broad study and earlier analyses [e.g., Cummings, et. al., 1978 and Feb., 1979] have demonstrated the relative insensitivity of feasibility measures for HDR/electric facilities to many of the parameters held constant here and the relative sensitivity of such measures to drilling costs, rates of return, and interest.* Thus, the focus here is on key elements in the HDR system which were found to be particularly critical in early assessments of the potential commercial feasibility for HDR/electric facilities. A list of values used for major parameters in characterizing the HDR electric generating plant and HDR system is given in Table 1.

*Feasibility measures for the HDR system are also shown to be particularly sensitive to the rate of temperature drawdown in HDR reservoirs. Thus, a relatively rapid rate of temperature drawdown is assumed in the analyses below, in which case drilling costs based on the analyses could be overstated; see [Cummings and Morris, Dec., 1979 (a), section IV].

TABLE 1
Parameter Values Used in Characterizing the
Power Plant and HDR System

Number of fractures	= 6
Fracture radius	= 300 m
Well-flow rate	= 108 kg/sec/well pair
Number of reservoirs	= 5
Geothermal gradient	= 60°C/km
Plant design temperature	= 205°C
Design flow rate	= 503 kg/sec.
Capacity factor	= .80
Plant capacity	= 50 MW(e)
System life	= 30 yrs.
Operation and maintenance	= 5 mills/kwh
Federal Income Tax	= 48% of taxable income
State Income Tax (deductable on federal tax)	= 9%
Effective Income Tax rate	= 52.68%

II. REVENUES AND COSTS FOR THE POWER PLANT AND THE HDR SYSTEM

A. Payment Capacity for Fuel By the Electric Plant. The HDR system and the electric plant it serves are separately owned and managed. Consequently, payments for fuel by the electric plant are revenues to the HDR system. Two approaches for estimating criterion levels of these payments-revenues are used here. The first approach is to simply argue that the cost of a 50 MW(e) coal-fired power plant would not be significantly different from the cost of a 50 MW(e) power plant using a binary fluid technology. In this case, a utility would not invest in an HDR electric plant unless it paid no more for HDR fuel power than a comparable coal-fired plant would pay for fuel. A 50 MW(e) coal-fired plant would use approximately 200,000 tons of coal per year, assuming an 80% capacity factor. Using a somewhat low delivered price/ton for coal of \$25.00 (1978 dollars), the upper bound for the annual amount that the electric plant would pay an HDR system for power would be \$5,000,000.

The second approach is a bit more complicated and involves the calculation of a "maximum fuel bill" which the binary generating plant could pay for HDR-produced fuel. This maximum fuel bill is the plant's annual capacity to pay for fuel after all other annual costs have been met. It is calculated in the following manner.

(a) Plant construction costs, including interest paid during a 5-year construction period, are calculated for a 50 MW(e) plant with a design temperature of 205°C, using the Rankine Binary Fluid Cycle technology. These costs, based on Milora and Tester's estimates [Milora and Tester,

1976, p. 112] are inflated for 1978 dollars; such costs are further inflated by 20% to account for high ambient temperatures in the Imperial Valley. The resulting estimate for plant costs is \$32.2 million.

(b) Annual purchase/lease costs for land are taken to be \$458.00 acre; annual property taxes are estimated at \$95,000.* Operation and maintenance costs are assumed to be \$.005/kwh; assuming an 80% capacity factor, annual power output would be 350.4 million kwh, and annual O&M costs would be 1.75 million dollars.

(c) California charges a 9% state income tax deductible on federal taxes. With a federal income tax of 48%, the effective income tax rate for the Imperial Valley becomes .5268, as computed by the following:

$$\begin{aligned}\text{Tax Bill} &= .09(\text{Taxable Income}) + .48(\text{Taxable Income} - .09(\text{Taxable Income})) \\ &= (.09 + .48 - .0432)\text{Taxable Income} \\ &= .5268 \text{ Taxable Income}\end{aligned}$$

Inasmuch as it is assumed that all revenue minus costs, net of taxes, is paid as a fuel cost to the HDR facility, taxes are paid only on profits which, in this case, are represented by equity payments to stockholders. If C is plant cost, half of which is financed by stocks, and r_2 is the appropriate rate of return on stocks, the annual tax bill is given by $r_2(\frac{C}{2})(.5268)$. A revenue tax of \$.0025/kwh is also charged as a cost.

(d) An annual cost for a sinking fund is charged. This annual cost is an amount which, along with compound interest and net of a 52.68% tax deduction on interest earned, will recover all capital costs C at the end of 30 years.

The maximum fuel bill for the electric generating plant is calculated as gross revenue minus the costs as described above. The maximum fuel bill

*Based on an average assessed value of \$1,074,000 and a milly levy of .26421 on 1/3 of assessed value.

for this 50 NM(e) plant is calculated for various busbar electricity prices and alternative rates of return and interest as demonstrated in Appendix A. The results of these calculations are given in Table 2. Thus, referring to Table 2, with debt and equity rates of return of 6% and 3% respectively, the maximum fuel bill would be approximately 4 million dollars with busbar prices of \$.03/kwh and .9 million dollars with busbar prices of \$.02/kwh.

Of course, the HDR system must be capable of providing the electric plant's fuel requirements at a cost that is no greater than the electric plant's capacity to pay for fuel (at any given busbar price for electricity) -- the "maximum fuel bill" given in Table 2. Thus, it is to an analysis of HDR system costs that attention is now turned.

B. Cost Components for the HDR System. Costs for the HDR system consist of drilling and re-drilling (well re-completion) costs, exploration/development and fluid distribution costs, operation/maintenance costs, land leasing costs, sinking fund and debt payment costs, and taxes. A discussion of each of these costs follows.

B.1 Drilling Costs. Initial drilling costs, as well as redrilling costs, depend upon the generating plant's requirements for fluid flow and temperature, as well as on the well-flow rate (the rate at which water is passed through an HDR reservoir) used for each HDR reservoir. Given the plant's design temperature, if the required or design flow rate for the plant is (as an example) 400 kg/sec, then this requirement could be met with one HDR reservoir (one pair of wells) using a well-flow rate of 400 kg/sec, two HDR reservoirs using a well flow-rate for each reservoir of 200 kg/sec, etc. Assuming there are no technical problems associated with attaining these high flow rates, one would seemingly wish to use one reservoir operated at 400 kg/sec, given the costs of drilling and establishing additional reservoirs.

TABLE 2

Maximum Fuel Bills for Alternative Busbar Prices of
Electricity and Interest Charges

<u>Busbar Price</u> (\$/kwh, 1978)	<u>Rate of Return/Rate of Interest Combination</u>			
	<u>6%/3%</u>	<u>9%/6%</u>	<u>12%/9%</u>	<u>15%/12%</u>
	(millions of 1978 dollars)			
.020	.9	*	*	*
.021	1.2	.2	*	*
.022	1.5	.5	*	*
.023	1.9	.8	*	*
.024	2.2	1.1	.01	*
.025	2.5	1.4	.3	*
.026	2.8	1.7	.6	*
.027	3.1	2.0	1.0	*
.028	3.4	2.4	1.3	.1
.029	3.7	2.7	1.6	.5
.030	4.0	3.0	1.9	.8
.031	4.4	3.3	2.2	1.1
.032	4.7	3.6	2.5	1.4
.033	5.0	3.9	2.8	1.7
.034	5.3	4.2	3.1	2.0
.035	5.6	4.5	3.4	2.3
.036	6.0	4.9	3.8	2.6
.037	6.2	5.2	4.1	3.0
.038	6.5	5.5	4.4	3.3
.039	6.9	5.8	4.7	3.6

*negative maximum fuel bills.

A problem arises, however, in that temperature drawdown -- the cooling of the hot granite -- increases with larger well-flow rates. Given a geothermal temperature gradient of $60^{\circ}\text{C}/\text{km}$ in the Imperial Valley, suppose that initial drilling is to four kilometers. With a crustal temperature of 15°C , initial reservoir temperature would be 255°C . As water is passed over the hot granite, reservoir temperature declines; when it declines to 205°C (the plant's design temperature), it is necessary to re-drill and establish "new" reservoirs (re-drilling is discussed in more detail below). The higher the well-flow rate, the more quickly reservoir temperatures will fall to 205°C , necessitating redrilling and its associated costs. This problem is addressed by comparing alternative ways of meeting the electric plants' fuel requirements under the alternative cost assumptions and selecting the minimum cost strategy.

As discussed above, three sets of drilling cost estimates for initial drilling and redrilling are drawn from the Republic Geothermal study of drilling costs for HDR reservoirs (Republic Geothermal Co., 1979). For initial drilling costs, one of the following is used. (D denotes depth of drilling in feet).

$$\text{Initial Drilling Costs 1} = (\$184.5)(D) + \$982708.4$$

$$\text{Initial Drilling Costs 2} = (\$303.3)(D) + \$548349.2$$

$$\text{Initial Drilling Costs 3} = (\$543.7)(D) + \$390978.0$$

Redrilling (or "well recompletion") may take one of two forms, as is exemplified in Figures 2A and 2B. "Side-tracking" involves entering the original bore holes for some distance, after which directional drilling techniques are used to drill obliquely to "new" areas of hot granite at approximately the same vertical depth as the original reservoir (Figure 2.A). The second technique for redrilling, referred to as "Extension Drilling", involves entering the

FIGURE 2.A
RECOMPLETION WITH PLUG BACK
AND SIDETRACK

original bore holes, closing off the original fracture, and drilling to deeper depths (Figure 2.B). Costs for each of these alternative redrilling operations are given as follows.

$$\text{Redrilling Costs (Side-Tracking) 1} = (48.4)(D) + 1106500.$$

$$\text{Redrilling Costs (Side-Tracking) 2} = (30)(D) + 1986000.$$

$$\text{Redrilling Costs (Side-Tracking) 3} = (52.9)(D) + 2407000.$$

$$\text{Redrilling Costs (Extension Drilling) 1} = (20.8)(D) + 797000.$$

$$\text{Redrilling Costs (Extension Drilling) 2} = (37.7)(D) + 892500.$$

$$\text{Redrilling Costs (Extension Drilling) 3} = (97.6)(D) + 591500.$$

All of the above drilling costs include rig mobilization costs (costs to get the drilling rigs on site).

Drilling beyond depths of 4.5 km is not considered in the analyses that follow. This restriction in drilling depths is imposed to reflect the uncertainties surrounding the technical feasibility of drilling in rock with temperatures in excess of some 300°C. Thus, with an average geothermal gradient of 60°C in the Imperial Valley, and assuming a 15°C crustal temperature, our restriction on drilling depths has the effect of restricting initial reservoir temperatures to less than 285°C.

Given a combination of drilling costs (e.g. Initial Drilling Cost 1 with redrilling via side-tracking), an assumed well-flow rate for each reservoir (e.g., 108 kg/sec), and the plant's design flow rate (503 kg/sec for a design temperature of 205°C), the required number of HDR reservoirs is defined and temperature drawdown in the HDR reservoirs can be traced through time for any given initial temperature. A range of initial temperatures between 205°C and 285°C are chosen and, for each initial temperature (which implies a drilling depth and therefore an initial drilling cost), temperature drawdown is estimated.

FIGURE 2.B
RECOMPLETION BY CEMENTING THE HEAT DEPLETED FRACTURE
SYSTEM, DEEPENING THE WELL AND CREATING
A NEW FRACTURE SYSTEM

At the point in time when reservoir temperature approaches 205°C, redrilling costs are required to re-establish reservoir temperatures.

This process is demonstrated in Figure 3 for a well-flow rate of 90 kg/sec, with initial reservoir temperatures of 160°C and 285°C. Costs here are based on initial drilling scheme 3 with Extension Drilling recompletion. With an initial reservoir temperature of 260°C, initial drilling depth is 4,080 meters and drilling costs are approximately \$38.5 million. Redrilling is required in years 6, 12, 18, and 24 and the present value of redrilling costs (using a 6% discount rate) is \$7.5 million, \$5.3 million, \$3.7 million, and \$2.6 million, respectively. The present value of all drilling costs, if an initial temperature of 260°C is chosen, is therefore \$57.6 million.

With an initial temperature of 285°C, initial drilling depth is 4333 meters. Initial drilling costs are \$42.6 million, and the present value of redrilling costs incurred in years 8, 16, and 24 is \$7.1 million, \$4.5 million, and \$2.1 million, respectively, for a total of \$56.3 million. Clearly, an initial drilling depth of 4333 meters (associated with the initial drilling cost of \$42.6 million) is the least cost alternative for providing the generating plant's power requirements in this example.

Similar comparisons were made for initial temperatures of 235°C, 260°C, and 285°C; for each initial temperature, the process is repeated using well-flow rates of 54, 60, 67.5, 77.1, 90, and 108 kg/sec. From these many alternatives (see Appendix B) the least cost combination of well flow rate and initial drilling depth is chosen.

A summary of least cost drilling costs used here is given in Table 3.

FIGURE 3
AN ILLUSTRATION OF TEMPERATURE
DRAWDOWN AND REDRILLING PERIODS*

* Based on Initial drilling function #3, Extension Drilling Recompletion,
and a well-flow-rate of 90 kg/sec,

TABLE 3

Least Cost Drilling Costs, Initial Reservoir Temperatures, and
Timing for Redrilling Associated with Alternative Estimates
for Drilling/Redrilling Costs

RECOMPLETION VIA SIDE-TRACKING

Function #	Discount Rate	Initial Reservoir Temperature	Timing for Recompletion (years)	Well-Flow Rate (kg/sec)	Present Value of all Drilling Costs (1978 dollars)
1.	6%	285 ^o	6	108	\$32,494,500
	9%	285 ^o	6	108	28,180,400
	12%	285 ^o	6	108	25,375,300
	15%	285 ^o	6	108	23,474,800
2.	6%	285 ^o	6	108	\$43,724,400
	9%	285 ^o	6	108	37,969,400
	12%	285 ^o	6	108	34,227,600
	15%	285 ^o	6	108	31,692,400
3.	6%	285 ^o	6	108	\$62,218,500
	9%	285 ^o	6	108	54,665,300
	12%	285 ^o	6	108	49,754,200
	15%	285 ^o	6	108	46,426,900

RECOMPLETION VIA EXTENSION DRILLING

1.	6%	285 ^o	6	108	\$26,491,600
	9%	285 ^o	6	108	23,875,900
	12%	285 ^o	6	108	22,175,000
	15%	285 ^o	6	108	21,022,700
2.	6%	285 ^o	6	108	\$35,517,200
	9%	285 ^o	6	108	32,084,200
	12%	285 ^o	6	108	29,852,100
	15%	285 ^o	6	108	28,339,800
3.	6%	285 ^o	6	108	\$52,536,400
	9%	285 ^o	6	108	47,722,500
	12%	285 ^o	6	108	44,592,500
	15%	285 ^o	6	108	42,471,800

B.2 Exploration/Development and Fluid Distribution Costs. Exploration and development costs required for establishing the HDR system are summarized in Table 4. Pipe costs for fluid gathering systems are based on the grid system shown in Figure 4. For the distribution of the gathered fluids to the generating plant, a pipe with diameter of 12 inches is required with a length of 5900 feet; costs for this gathering system are estimated to be \$329,443.

B.3 O&M and Land Costs. A conservative estimate of \$500,000/year is used here for the HDR's O&M costs.

We assume that the HDR facility is operated on private land and a royalty payment of approximately 15% of gross revenues is charged. This is a very conservative assumption in that a royalty rate of only 10% would be charged for operation on Federal lands.*

B.4 Taxes. An "ad velorum" or "local property-type" tax of 1% of the market value of property is charged. The market value of property can be as low as the tangible drilling costs of an HDR reservoir, or as high as all of the drilling costs, piping costs, and mineral value of the reservoir. One percent of the joint power producer-well operator's net profits is charged here as this "ad velorum" tax.

B.5 Sinking Fund Costs and Debt Repayment. Use of the cash-flow annualizing method used here requires that the HDR system acquire, via the sale of stock, all capital funds required for its 30-year lifetime at the beginning of operations. Thus, let DC_1 be the costs of exploration/

* For computational simplicity, the royalty payment is included in calculations for "Maximum Fuel Bills" (Table 2).

TABLE 4

EXPLORATION-DEVELOPMENT COSTS

<u>YEARS TO START OF PRODUCTION</u>	<u>TYPE OF ACTIVITY</u>	<u>COST (\$1978)</u>
9	Power plant site purchase	125,000
9	Leased well site (per pair of wells)	293,000
8	Geophysical surveys for site reconnaissance	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
		<hr/>
	Exploration Development Costs "EDC"	\$3,302,000

FIGURE 4

REPRESENTATION OF FLUID GATHERING GRID

development, pipes for distribution/gathering systems and total initial drilling costs; let $RD_1, RD_2, \dots$ be the present value of costs (adjusted for income taxes on the firm's rate of return) for the first, second, ... etc., required redrilling operation. If redrilling is required in n different periods, the HDR firm is then assumed to acquire stocks in the initial period in the amount $DC = DC_1 + \sum_{i=1}^n RD_i$.

As an aside, for the discussion of taxes in the following subsection it is useful to have a measure for the average nominal value of drilling costs which have been incurred at any point in time. If, for example, redrilling costs of \$10 million are incurred every ten years and initial drilling costs are \$50 million, incurred drilling costs are \$50 million for the first ten years, \$60 million in years 11-20, and \$70 million in years 21-30. A weighted (by time) average of incurred drilling costs is then the sum of \$50 million, \$10 million times $2/3$, and \$10 million times $1/3$, or \$60 million. This weighted average of incurred drilling costs is divided by 30 years--straight line depreciation--and the result is denoted AVDC; AVDC will be used in the following subsection.

Returning to the estimate used for capital costs -- DC as described above -- two annual charges are derived from this measure. The first is annual payments to holders of stocks; given r_2 as a competitive rate of return on stocks, this charge is given by $r_2(DC)$. The second charge is a sinking fund charge, the purpose for which is to recover, over the 30-year life of the system, all capital costs. This charge, denoted SF, is determined by the following relation, where $\hat{r}_2$ is the rate of return, r_2 , adjusted for income taxes paid on the firm's returns to capital.

$$SF = \frac{DC}{\sum_{t=1}^{30} (1+r_2)^{30-t}}$$

Thus, the HDR facility makes annual payments to the stockholders who financed the system and to a fund which will purchase their equity at the end of the system's life. Estimates for annual stock payments and sinking fund charges used for alternative drilling costs are given in Table 5.

B.6 Taxes. As mentioned above, the HDR system is assumed to pay 52.68% of taxable income in income taxes. To determine taxable income, we define E as gross annual revenue to the firm, and AVDC as the annual depreciation of the boreholes and their hardware (including pipe costs). Define A as the difference between annual revenues and the sum of AVDC and annual O & M costs, i.e.,

$$A = E - AVDC - O\&M$$

According to the current law, a depletion allowance, DA, may be claimed by the HDR system; the depletion allowance is calculated as follows:

$$DA = .15 (E) \quad \text{if} \quad .15 (E) < .5 (A)$$

$$DA = .5 (A) \quad \text{if} \quad .15 (E) \geq .5 (A)$$

Thus, if half of net income as given above by A exceeds 15% of gross revenue, the depletion allowance is 15% of gross revenue; if 15% of gross revenue exceeds half of A, the depletion allowance is half of A.

With a tax rate for state and federal income taxes of 52.68%, the annual tax bill for income taxes, TB, is .5268 times A - DA, i.e.,
 $TB = [A - DA] (.5268)$. In addition, however, the firm must pay a "minimum tax," MT, where MT is derived as follows:

TABLE 5

Estimates of Sinking Fund Charges and Stock Payments
for the HDR Facility with Alternative Interest Rates
and Drilling Costs

RECOMPLETION VIA SIDE-TRACKING

<u>Initial Drilling Function #</u>	<u>Rate of Return on Stocks</u>	<u>Stocks Payments</u>	<u>Sinking Fund Charges</u>
1.	6%	\$1,231,129.	\$442,643.
	9%	1,839,109.	348,878.
	12%	2,446,077.	272,793.
	15%	3,055,386.	211,864.
2.	6%	\$1,630,193.	\$593,314.
	9%	2,462,325.	467,102.
	12%	3,270,459.	364,730.
	15%	4,078,351.	282,798.
3.	6%	\$2,441,924.	\$877,975.
	9%	3,643,206.	691,114.
	12%	4,836,762.	539,409.
	15%	6,026,853.	417,910.

RECOMPLETION VIA DESIGN DRILLING

1.	6%	\$1,171,216.	\$421,101.
	9%	1,755,581.	333,033.
	12%	2,342,455.	261,237.
	15%	2,934,715.	203,497.
2.	6%	\$1,568,280.	\$563,863.
	9%	2,348,126.	445,438.
	12%	3,128,787.	348,931.
	15%	3,913,368.	271,358.
3.	6%	\$2,345,288.	\$843,230.
	9%	3,508,482.	665,557.
	12%	4,669,628.	520,769.
	15%	5,832,218.	404,414.

$$\begin{aligned}
 MT &= .15 \left[DA - \text{maximum of } \begin{Bmatrix} \$10,000 \\ TB \end{Bmatrix} \right] \\
 &= 0 \text{ if } \left[DA - \text{maximum of } \begin{Bmatrix} \$10,000 \\ TB \end{Bmatrix} \right] < 0
 \end{aligned}$$

C. Annual Net Returns for the HDR system. Given the annual cost components for the HDR system, we can now define annual "excess" returns, or excess income, which accrues to the system; a summary of notation introduced above and used here is given in Table 6.

$$\text{Annual Excess Returns (AER)} = E - r_2 DC - SF - (TB + MT) - O\&M$$

By "excess" returns we mean the following: Included in costs are competitive returns to all investors in the HDR production process as well as competitive returns to land, labor, management and capital. Thus when AER is zero a competitive return is being paid to all factors used in production. AER positive then implies above normal profits; AER negative implies that the system cannot cover all of its costs and is thus not commercially feasible. AER positive or zero then implies potential commercial feasibility. Measures for AER under various parameter values are given in Table 7.

D. Some Tax Considerations Relevant for AER Measures. Before continuing with an analysis of the data developed above, a number of observations concerning the treatment of taxes for the HDR facility may be of interest. First, the bulk of drilling costs incurred by the HDR firm would qualify as "intangible drilling costs" under the recent Energy Tax Act of 1978 (PL 95-618). According to this new tax law, such costs may either be expensed in the year that they are incurred or depreciated via straight-line depreciation; the latter method is used here. It is quite likely that

TABLE 6

SUMMARY OF NOTATION

DC:	Drilling Costs (meters)
RD_i :	Redrilling in period i (meters)
r_1 :	Interest rate on bonds
r_2 :	Rate of return on stocks
$\hat{r}_2$:	r_2 adjusted for income taxes
SF:	Sinking Fund Costs
E:	Annual gross revenues to the HDR System
AVDC:	Annual depreciation of boreholes and their hardware and pipe costs
A:	Difference between E and the sum of AVDC and O&M costs: taxable income prior to applying depletion allowances
DA:	Depletion allowance
TB:	Annual tax bill
MT:	Minimum tax
AER:	Annual "Excess" Revenues

TABLE 7

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MEASURES FOR ANNUAL EXCESS RETURNS TO THE HDR SYSTEM
WITH VARIOUS PARAMETER VALUES

Real Interest Rate for Bonds/Stocks (P is the busbar price of electricity received by the generating plant.)	Annual Excess Returns with Alternative Redrilling Techniques (ED = Extension Drilling, ST = Sidetracking) and Drilling Conditions (worst, medium and best)					
	<u>ED WORST</u>	<u>ST WORST</u>	<u>ED MED</u>	<u>ST MED</u>	<u>ED BEST</u>	<u>ST BEST</u>
A. 3%/6%						
P* = .023	-1830664.	-1962044.	-805457.	-885653.	-358762.	-373738.
.024	-1518458.	-1649838.	-586566.	-607041.	-151345.	-154847.
.025	-1249063.	-1337631.	-367675.	-388149.	35007.	53148.
.026	-1030172.	-1054327.	-178943.	-169259.	210483.	239499.
.027	-811281.	-835435.	7210.	32211.	382890.	418606.
.028	-600458.	-616545.	179616.	218562.	555296.	591012.
.029	-414106.	-397653.	352023.	400854.	727703.	763419.
.030	-227755.	-198495.	524429.	573261.	900109.	935825.
.031	-51119.	-12143.	696836.	745667.	1072516.	1108232.
.032	121287.	174208.	869242.	918074.	1244922.	1280638.
.033	293694.	351301.	1041649.	1090480.	1417329.	1453045.
.034	466100.	523707.	1214055.	1262887.	1589735.	1625451.
B. 6%/9%						
P* = .029	-2105054.	-2168651.	-915832.	-944540.	-355278.	-350183.
.030	-1886164.	-1939219.	-729481.	-729177.	-182872.	-165074.
.031	-1667272.	-1720328.	-551270.	-542825.	-10465.	7333.
.032	-1475094.	-1501437.	-378863.	-356473.	161941.	179739.
.033	-1288742.	-1288384.	-206457.	-182123.	334348.	352146.
.034	-1106105.	-1102032.	-34050.	-9717.	506754.	524552.
.035	-933699.	-915681.	138356.	162689.	679161.	696958.
.036	-761292.	-732585.	310763.	335096.	851567.	869365.
.037	-588886.	-560179.	483169.	507502.	1023974.	1041771.
.038	-416479.	-387772.	655576.	679909.	1196380.	1214178.
.039	-244073.	-215366.	827982.	852315.	1368787.	1386584.
.040	-71666.	-42959.	1000389.	1024722.	1541193.	1558991.
.041	100740.	129447.	1172795.	1197128.	1713600.	1731397.
.042	273147.	301854.	1345202.	1369535.	1886006.	1903804.

- continued -

MEASURES FOR ANNUAL EXCESS RETURNS TO THE HDR SYSTEM

WITH VARIOUS PARAMETER VALUES

Real Interest Rate for Bonds/Stocks (P is the busbar price of electricity received by the generating plant.)	Annual Excess Returns with Alternative Redrilling Techniques (ED = Extension Drilling, ST = Sidetracking) and Drilling Conditions (worst, medium and best)					
	<u>ED WORST</u>	<u>ST WORST</u>	<u>ED MED</u>	<u>ST MED</u>	<u>ED BEST</u>	<u>ST BEST</u>
C. 9%/12%						
P* = .037	-2209347.	-2234481.	-801596.	-798872.	-91716.	-89724.
.038	-2033449.	-2048129.	-629190.	-626466.	80691.	82683.
.039	-1861043.	-1861778.	-456783.	-454059.	253097.	255089.
.040	-1688636.	-1685422.	-284377.	-281653.	425504.	427496.
.041	-1516230.	-1513016.	-111970.	-109246.	597919.	599902.
.042	-1343823.	-1340609.	60436.	63161.	770317.	772309.
.043	-1171417.	-1168203.	232843.	235567.	942723.	944715.
.044	-999010.	-995796.	405250.	407974.	1115130.	1117122.
.045	-826604.	-823390.	577656.	580380.	1287536.	1289528.
.046	-654197.	-650984.	750062.	752786.	1459942.	1461934.
.047	-481791.	-478577.	922469.	925193.	1632349.	1634341.
.048	-309384.	-306171.	1094875.	1097599.	1804755.	1806747.
.049	-136978.	-133764.	1267282.	1270006.	1977162.	1979154.
.050	35429.	38642.	1439688.	1442412.	2149568.	2151560.
.051	207835.	211049.	1612095.	1614819.	2321975.	2323967.
D. 12%/15%						
P* = .044	-2657957.	-2677100.	-914472.	-930698.	-32103.	-43971.
.045	-2485551.	-2504694.	-742066.	-758292.	140304.	128435.
.046	-2313145.	-2332288.	-569660.	-585886.	312710.	300841.
.047	-2140738.	-2159881.	-397253.	-413479.	485117.	473248.
.048	-1968332.	-1987475.	-224847.	-241073.	657523.	645654.
.049	-1795925.	-1815068.	-52440.	-68666.	829930.	818061.
.050	-1623519.	-1642662.	119966.	103740.	1002336.	990468.
.051	-1451112.	-1470255.	292373.	276147.	1174743.	1162874.
.052	-1278706.	-1297849.	464779.	448553.	1347149.	1335281.
.053	-1106299.	-1125442.	637186.	620960.	1519556.	1507687.
.054	-933893.	-953036.	809592.	793366.	1691962.	1680094.
.055	-761486.	-780629.	981999.	965773.	1864369.	1852500.
.056	-589080.	-608223.	1154405.	1138179.	2036775.	2024907.
.057	-416674.	-435816.	1326812.	1310585.	2209181.	2197313.
.058	-244267.	-263409.	1499218.	1482992.	2381588.	2369720.
.059	-71861.	-91003.	1671625.	1655398.	2554995.	2542126.
.060	100546.	81404.	1844931.	1827805.	2726491.	2714533.
.061	272952.	253810.	2016438.	2000211.	2898807.	2886939.

HDR firms would find it advantageous to use the expensing approach, however. Similarly, neither regular nor special energy investment tax credits have been included for the HDR system or for the electric generation plant in these analyses. Both these choices with respect to taxes probably result in an understatement in the AER and hence in the competitive position of the HDR system.

III. COULD HDR-PRODUCED FUEL BE COMMERCIALY FEASIBLE?

We now turn to an analysis of the data developed in the preceeding section to the end of addressing the question: could HDR-produced power be commercially feasible under conditions found in California's Imperial Valley? In addressing this question we once again acknowledge that a definitive response must await further results from ongoing R&D efforts concerning such things as reservoir design and performance. This analysis of economic conditions under which HDR-produced power might be commercially feasible is valuable as an indication of the commercial potential for this technology and for responding to questions related to the sensitivity of an HDR system's economic potential under alternative estimates of drilling costs and required risk premiums.

A. A Point of Departure. As a point of departure, we begin our analyses with the case where returns on bonds and stocks are 3% and 6% respectively. Recalling that revenues to the HDR system are the maximum fuel bills which can be paid by the electric generating plant and that these, in turn, depend upon busbar prices for electricity, HDR-produced power is feasible with busbar prices on the order of 25 mills/kwh under "best" drilling conditions in the Imperial Valley (Table 7: annual excess revenues are positive for all busbar costs of 25 mills/kwh and higher);

feasibility obtains at $p = 25$ mills/kwh regardless of the re-drilling technology used -- extension drilling or sidetracking.

As drilling conditions worsen -- referring to medium and worst conditions in Table 7 -- higher busbar prices are required for the electric generating plant to provide the fuel payments which cover all costs for the HDR firm. Feasibility for the HDR firm obtains at busbar electricity prices of 27 mills/kwh and 32 mills/kwh under medium and worst drilling conditions, respectively. Thus, with real rates of return on bonds and stocks of 3% and 6%, respectively, HDR-produced fuel for an electric generating facility in the Imperial Valley might be commercially feasible under best to worst drilling conditions so long as busbar prices received by the generating plant are in the range of 25-32 mills/kwh.

Looking at the question of feasibility from the perspective of competing fuel sources, the annual fuel bill paid by the plant to the HDR system is somewhat less than the fuel bill required by a similar (in terms of cost structure) plant using coal under best and medium drilling conditions. Referring to Table 2, the busbar price required by the generating plant to cover \$5 million annual coal costs is some 28-29 mills/kwh -- somewhat higher than the 25-27 mill/kwh range required when "fuel" is purchased from the HDR system under best and medium drilling conditions. Under worst drilling conditions, the busbar price required for HDR-produced fuel -- 32 mills/kwh -- is higher than that for the coal option (28-29 mills/kwh).

B. Extensions Concerning Risk. It is likely to be the case that high risk premiums may be required in early stages of technology adoption for new technologies such as HDR. In an effort to capture the essence of such risk environments, feasibility data for bond/stock rates of 6%/9%, 9%/12% and 12%/15% are also given in Table 7 ; since these are real, inflation-free

rates of return, the implicit nominal rates of return are quite high. For example, if the expected rate of inflation is 8%, the 12% - 15% case corresponds to the case where nominal bond and stock rates are 20% and 23%, respectively.

Minimum busbar prices for electricity which yield revenues to the electric plant which are sufficient to purchase fuel from the HDR system increase from 31-41 mills/kwh to 45-60 mills/kwh as real rates of return rise from 6%/9% to 12%/15%, depending on drilling conditions encountered (Table 7). Thus, as one might anticipate, the commercial feasibility of the HDR operation is quite sensitive to conditions of risk as reflected by risk premiums in rates of return. At the high, 12%/15%, rates busbar electricity prices of 45 mills/kwh are required even under "best" drilling conditions; with "worst" conditions, busbar prices of 60 mills/kwh are required if the electric generating plant is to have income sufficient to cover fuel costs from the HDR firm.

Since the electric generating plant will have revenues sufficient to cover annual fuel costs from coal (\$5 million) at busbar prices of 28-29 mills/kwh (Table 2), the data in Table 7 suggest that HDR-produced power would be competitive with coal (given the structure of relative prices and costs used here) only under best and medium drilling conditions with 3%/6% real rates of return.

C. Observations Concerning Drilling Costs. The sensitivity of commercial feasibility for an HDR firm to estimates of drilling costs was raised earlier in this report as an issue of some considerable concern. Consider the increase in required busbar prices which result in a feasible HDR operation as drilling costs are evaluated under best to worst conditions. As between best and worst conditions, busbar prices are 28% higher with 3%/6% rates of return (Table 7), some 32% for 6%/9% and 9%/12%, and 33% higher

with 12%/15% rates of return. These data bring into sharp focus the sensitivity of any assessment concerning the potential commercial viability of HDR-produced power to estimated drilling costs.

IV. CONCLUDING REMARKS

The purposes of this study have been to assess some of the conditions under which HDR-produced power for use by an electric generating plant might be commercially feasible in California's Imperial Valley. Particular attention has been given to those conditions related to alternative estimates for drilling costs and drilling conditions that one might encounter in the Imperial Valley and to risk conditions as they might be reflected by rates of return paid on bonds and stocks by both the HDR firm and the electric generating plant.

The analyses described in this work suggest that HDR-produced fuel might be used by an electric generating plant so long as busbar prices for electricity are, at a minimum, in the range 25-60 mills/kwh (constant 1978 dollars); this range of prices reflects differing assessments of risk and drilling conditions. Whether or not this range is indicative of the potential commercial feasibility of HDR systems depends, of course, on minimum busbar costs required by electric generating plants that use other fuel sources. The crude estimate used here for coal-fired plants suggested a minimum busbar price for such plants of some 28 mills/kwh. Estimated 1985 busbar prices given in the National Energy Outlook (Federal Energy Administration, 1976, p. 244) range from 33-39 mills/kwh;* Hudson and Jorgenson (Jorgenson, 1976, p. 52) estimate average busbar prices for electricity at 26 mills/kwh in 1990 and 53 mills/kwh in 2,000 (current dollars), which translate into

* The range 26-31 mills/kwh is reported in the FEA document where such values are in constant, 1975 dollars. Average electricity prices increased some 27% between 1975 and 1978; thus, 33-39 mills/kwh reflects this inflation of FEA data to yield comparable 1978 measures.

21 mills/kwh and 20 mills/kwh in constant 1978 dollars. Based on these estimates, a "competitive" busbar price for electricity over the next two to three decades may lie in the range 20-39 mills/kwh.

With rate of return/interest combinations of 12%/9% (or less), the HDR system analyzed here would be competitive in the upper limits of the 20-39 mills/kwh range under most drilling conditions; to the extent that future busbar costs of electricity produced from alternative sources are viewed as approaching 39-40 mills/kwh (1978 dollars), the results analyzed here would provide some basis for cautious optimism concerning the future commercialization of HDR system in the Imperial Valley once a proven technology is well established.

A further comparison of the estimated busbar costs for HDR-produced electricity may be of interest. A site-specific study concerning HDR-produced electricity in the Fenton Hill, New Mexico area is reported in Cummings and Morris [1979a]. Assuming a rate of return/interest combination of 9%/6% and the "deeper drilling" technology for re-drilling*, a comparison of estimated busbar costs for HDR-produced electricity is as follows.

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

* This is referred to as the "extension drilling" technology in Cummings and Morris (1979a).

The higher estimated costs for HDR-produced electricity in the Imperial Valley is attributable to a number of factors. First, due to the higher ambient temperatures in the Imperial Valley, a more costly plant design is required (plant costs are \$23.6 million in the Fenton Hill study compared with \$32 million used here); also, a higher design temperature for the electric generating plant was used in the Fenton Hill study (235°C compared with 205°C used here). Second, given that crystalline rock may be under relatively large sedimentary overburden in the Imperial Valley, drilling costs used for the Imperial Valley study are about 43% higher than those used in the Fenton Hill study. Finally, taxes and royalty payments are higher in the Imperial Valley than in the Fenton Hill area; state income taxes in California are some 1% higher than in New Mexico and the 15% (of gross revenue) royalty payment imposed in the Imperial Valley study would most likely not be required in the Fenton Hill case.

The results discussed here obtain for an HDR system with characteristics described in Table 1 and, of course, as R&D efforts continue the system parameters used here may be found to be either too optimistic or too pessimistic. Future results from research at Los Alamos concerning reservoir design will be particularly important in terms of refining feasibility assessments of HDR-produced power given the importance of temperature drawdown in HDR reservoirs for drilling costs. If large surface areas for reservoirs are established such that temperature drawdown is reduced relative to those rates used here, initial drilling to shallower depths and fewer redrilling activities may well result. The associated reduction in fuel costs for the HDR system could be substantial -- as was demonstrated above in discussions of the sensitivity of system feasibility to drilling costs.

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APPENDIX A

MAXIMUM FUEL BILL CALCULATIONS FOR ALTERNATIVE BUSBAR PRICES
AND RATES OF RETURN

Design Temperature = 235°C

Busbar Price = .030 mills/kwh

	Debt/Equity Ratio	
	<u>3%/6%</u>	<u>6%/9%</u>
Annual Revenues	\$10,511,992.	\$10,511,992.
Sinking Fund Charge	695,041.	550,070.
Interest Payment on Bonds	483,282.	966,564.
Interest Payment on Stocks	966,564.	1,449,845.
Revenue Tax	875,999.	875,999.
Property Tax	94,584.	94,584.
Income Tax	509,186.	763,778.
O & M Costs	1,751,998.	1,751,998.
Land Costs*	<u>1,092,040.</u>	<u>1,081,297.</u>
Maximum Fuel Bill	\$ 4,043,298.	\$ 2,977,875.

* Includes cost of purchasing land for the well site, and a 1% "local property tax" charged on net revenues.

APPENDIX A (Continued)

Busbar Price = .050 mills/kwh

	Debt/Equity Ratio	
	<u>9%/12%</u>	<u>12%/15%</u>
Annual Revenues	\$17,519,987.	\$17,519,987.
Less: Sinking Fund Charge	431,175.	855,114.
Interest Payment on Bonds	1,449,845.	1,933,127.
Interest Payment on Stocks	1,933,127.	2,416,409.
Revenue Tax	875,999.	875,999.
Property Tax	94,584.	94,584.
Income Tax	1,018,371.	1,272,964.
O & M Costs	1,751,998.	1,751,998.
Land Costs	<u>1,834,127.</u>	<u>1,822,876.</u>
Maximum Fuel Bill	\$ 8,130,758.	\$ 7,016,914.

APPENDIX B

DRILLING FUNCTIONS AND DRILLING TIME ASSUMPTIONS

The time required to complete the drilling of an HDR well is a major determinant of drilling cost. Following the methodology developed by Republic Geothermal (1979), the time needed to drill straight sections of hole is given by:

$$DRT_i = (1 + f_i) \left(N(C_1 Da_i + C_2) + K_i C_1 \sum_{I=1}^N I + (Db_i - Da_i) / PR_i \right)$$

$$N = [(Da_i - Db_i) / (PR_i + BL_i)]$$

Where: DRT_i = drilling rig time in interval i
 f_i = contingency factor in interval i
 N = total number of bits used in interval i less one
 C_1 = tripping rate (hrs/1000 ft)
 C_2 = tripping time constant (hrs)
 K_i = footage for bits in interval i
 PR_i = penetration rate of bits in interval i
 BL_i = bit life in interval i
 Da_i = depth at the beginning of interval i
 Db_i = depth at the bottom of interval i
 and $[x]$ = represents the integer part of x

Assuming that the whipstock directional drilling technique will be used to drill the angle buildup section of hole, drilling time is given by:

$$\text{DRT} = 2(C_1 (\text{KOP} + \frac{1}{2}(\alpha/b)) + C_2) (\text{NT}) + (C_1 (\alpha/b) + C_2) + (\alpha/b)/\text{PR} + 26 \text{ NT}$$

$$\text{NT} = [(\alpha/b)/\text{WF}] + 1$$

where: WF = distance between whipstock runs
 KOP = distance to the kick-off point, the point at which directional drilling begins.
 α = Maximum hole angle, assumed to be 40°
 b = Rate of angle buildup ($^\circ/88$)
 NT = Number of trips in the angle buildup section of the well hole.

Drilling time depends not only on the length of each drilling interval ($D_a - D_b$), but also on the chosen penetration rates (PR), bit life (BL), tripping rates (C_1), tripping times (C_2), contingency factors (f), and distance between whipstock runs (WF). Fast penetration rates, long bit lifes, slow tripping rates, short tripping times, small contingency factors, and long distances between whipstock runs will result in short drilling times. On the other hand, slow penetration rates, short bit lifes, fast tripping rates, long tripping times, large contingency factors, and short distances between whipstock runs will lead to long drilling times.

In practice, the values for these parameters vary widely and are hard to predict. Rather than fix these values in our calculations, we chose to define three sets of drilling conditions and develop cost estimates relevant to each set. Table A shows the acceptable ranges for these variable values.

TABLE A
PRESENT RANGE OF VARIABLE VALUES
FOR HDR DRILLING TIME ESTIMATES

		<u>Variable Range</u>	<u>Possible Median</u>
Penetration Rate (Ft/Hr)			
Permeable Section	26" - 17½" bits	7 - 25	12 Ft/Hr
	12¼" - 8½" bits	12 - 30	15 Ft/Hr
Impermeable Section	All Sizes	5 - 15	8 Ft/Hr
Bit Life (Hrs)	26" - 17½" bits	40 - 80	50 hours
	24¼" - 8½" bits	50 - 150	75 hours
	6 1/8" bits	20 - 75	25 hours
Round Tripping Constants	C ₁ (Hours/1000ft)	½ - 1.5 .001	1 hour
	C ₂ (Hours)	½ - 3	1½ hours
Fraction of time spent for Miscellaneous Operations*	(Permeable Section) - 8% - 50% Median 20%		
	(Impermeable Section) - 5% - 15% Median 8%		

* Estimated from four Reports from several "relatively" trouble-free exploratory wells.
Source: Republic Geothermal (1979, p. 7).

The "best" case set of drilling conditions are defined as those that assumed the fastest penetration rates, longest bit lives, smallest tripping constants, and smallest contingency factors. The "median" case assumes that the median values of the accepted ranges for all these variables will be realized in drilling. The "worst" case assumes the slowest penetration rates, shortest bit lives, largest tripping constants, and largest contingency factors in those ranges. The table below relates each case of drilling conditions to the variable values it defines.

	Best Case Drilling Function #1	Median Case Drilling Function #2	Worst Case Drilling Function #3
<u>Penetration Rate (ft/hr)</u>			
Permeable Section			
26 " - 17½" bits	25	12	7
12¼" - 8½" bits	30	15	12
Impermeable Section			
all bits	15	8	5
<u>Bit Life (hrs)</u>			
26 " - 17½" bits	80	50	40
24¼" - 8½" bits	150	75	50
8 1/8" bits	75	25	20
<u>Tripping Constants</u>			
C ₁ (Hours/1000ft)	½	1½	1.5
C ₂ (hours)	½	1½	3
<u>Contingency Factor</u>			
Permeable Section	8%	20%	50%
Impermeable Section	5%	8%	15%
<u>Length of Whipstock Runs (ft)</u>	300	200	100