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Economics of a 75-MW(e) Hot-Dry-Rock Geothermal Power Station Based upon the Design of the Phase II Reservoir at Fenton Hill

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DISCLAIMER

ECONOMICS OF A 75-MW(e) HOT-DRY-ROCK GEOTHERMAL POWER STATION BASED UPON THE DESIGN OF THE PHASE II RESERVOIR AT FENTON HILL

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ABSTRACT

Based upon EE-2 and EE-3 drilling costs and the proposed Fenton Hill Phase II reservoir conditions the break-even cost of producing electricity is 4.4 cents per kWh at the bus bar. This cost is based upon a 9-well, 12-reservoir hot dry rock (HDR) system producing 75 MW(e) for 10 yr with only 20% drawdown, and an assumed annual finance charge of 17%. Only one-third of the total, potentially available heat was utilized; potential reuse of wells as well as thermal stress cracking and augmentation of heat transfer was ignored. Nearly half the bus bar cost is due to drilling expenses, which prompted a review of past costs for wells GT-2, EE-1, EE-2, and EE-3. Based on comparable depth and completion times it is shown that significant cost improvements have been accomplished in the last seven years. Despite these improvements it was assumed for this study that no further advancements in drilling technology would occur, and that even in commercially mature HDR systems, drilling problems would continue nearly unabated.

I. INTRODUCTION

The Phase II reservoir, which will use the wells EE-2 and EE-3 recently completed at Fenton Hill, New Mexico, was used as a building-block reservoir for estimating electrical generating costs. This reservoir was used because it was in fact intended to serve as a preliminary demonstration of commercial viability, and because, with the completion of the two wells, we now possess cost data for deep, hot, inclined wells. Thus, unlike the pioneering studies of Tester et al.,[1] and Cummings and Morris,[2] which examined the economics of HDR systems with varying geothermal gradients, depths, and heat-to-electricity conversion cycles, this study is rather specific in nature. It examines in detail, in what is believed to be a realistic, up-to-date manner, a particular HDR system. Because the present study is based upon the Phase II reservoir design, which was not intended as a fully optimized, economic reservoir, the results of the study are not as optimistic as they could be. Nevertheless the study does illustrate the potential of HDR and indicates issues that require further study.

II. THE RESERVOIR

Although it is difficult to specify exact requirements for reservoir performance to assure commercial viability, performance goals were set in Refs. 1 and 2. These goals call for the production of a nominal thermal power level of 35 MW(t) with no more than 20% drawdown in 10 years. Temperature measurements in the first well completed, EE-2, indicate that the mean reservoir temperature will be 260°C (500°F). Over the 10-yr evaluation period, the average drawdown will be 10% so the mean outlet temperature during this period will be approximately 235°C. Wellbore heat transmission calculations show that over a 10-yr period, the loss in temperature as the water travels to the surface will average less than 5°C. Thus the time-mean temperature of the produced water at the surface will be 230°C. Currently the heat exchanger at Fenton Hill rejects heat so efficiently that the water extracted from the Phase I reservoir is reinjected at only 25°C. Assuming, however, that the increased flow rate intended for the Phase II reservoir results in lowered heat-rejection efficiencies, the Phase II reinjection temperature is conservatively taken as 50°C. The net change in the mean water temperature is thus 180°C, requiring a flow rate of 46 kg/s (730 gpm) to yield 35 MW(t) from the reservoir.

The effective heat-transfer area required to produce this thermal power can be estimated from one-dimensional heat conduction theory.[3] Using thermal

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The effective heat-transfer area required to produce this thermal power can be estimated from one-dimensional heat conduction theory.[3] Using thermal transport properties for Fenton Hill granites measured *in situ*,[4] it can be shown that an effective area of approximately 1 x 10^6 m^2 is required. This area represents one side of a fracture only. Thus, if a fracture were circular, with radius R, the area in question would be πR^2. This area requirement could be satisfied by one single fracture, or several parallel fractures. In the latter case the fractures would have to be far enough apart so that thermal interaction between the fractures, which would diminish performance, could be avoided over the time span of interest, or else more area would be required to offset the diminished performance. A single fracture would require, if circular, a radius of 580 m, which is beyond the fracturing technology so far demonstrated in HDR reservoirs. Thus, we have instead adopted the conservative philosophy that the Phase II fractures will not be much larger than the fracture that constitutes the second of our earlier Phase I reservoirs. This fracture, if judged by the inlet-to-outlet vertical separation distance of 300 m (1 000 ft), would have a total area, if circular, of 70 000 m^2, but due to inefficiencies of water sweep patterns within the fracture, the effective heat-transfer area is about 50 000 m^2, as established by its thermal-drawdown characteristics. Thus, the water sweep efficiency was 70%. This Phase I fracture was the result of a modest fracturing effort in which only 1 500 m^3 of water, without additives of any sort, was injected. Our fracturing capabilities will be expanded for the Phase II reservoir, but even so, we plan, conservatively, to create fractures with an inlet-to-outlet separation of 360 m, a modest 20% increase. Assuming the same water sweep efficiency as above, the estimated heat-transfer area of these new fractures will be 75 000 m^2 each, so that approximately 15 such fractures will be required for a total of 1 x 10^6 m^2.

Because the horizontal earth stresses at depth are usually considerably smaller than the vertical, or overburden stress, the fracture planes will be vertical. In order, then, to accommodate 15 fractures with reasonable horizontal separation distance between fractures, it was necessary to deviate the wells from the vertical direction in the hot downhole region, as shown in Fig. 1. While a perfectly horizontal well would be ideal for this purpose, and such wells have apparently been actually achieved in directional drilling practice, a well deviated too far from the vertical is impractical in our situation. If the angle from vertical exceeds 45° it becomes difficult to center and set casing, and even more difficult to run logging tools. As a compromise, therefore, an angle of 35° was chosen.

To avoid excessive heat-extraction deterioration because of thermal interaction between the fractures, they must be horizontally separated by approximately two times the thermal diffusion distance, $\sqrt{\kappa t}$, where κ is the rock thermal diffusivity and t is time. For 10 yr the required separation distance is 35 m, which for 15 fractures requires a total horizontal distance of about 500 m (1 600 ft). At a drilling angle of 35°C, 700 m of vertical height is required for the reservoir. For high-quality energy production purposes, reservoir temperatures in excess of 200°C are preferred, which, considering the geothermal gradients at Fenton Hill, corresponds to a depth of 3 km or more. Thus, as shown in Fig. 1, the plan was to drill vertically to about 2.5 km and then directionally drill until a deviation of 35° from vertical was attained.

This was in fact accomplished. After turning the wells to 35° from vertical, EE-2, the lower, or injection, well was completed to a total depth of 4.66 km (15 290 ft), a true vertical depth of 4.39 km (14 400 ft). Well EE-3 was completed to 4.25 km (13 930 ft) or a true vertical depth of 3.97 km (13 030 ft). The maximum horizontal distance for spacing fractures is the horizontal distance from the EE-2 casing shoe to the end of EE-3, 535 m (1 760 ft). The vertical distance between wells was maintained at 360 m as intended. The total heat energy in the temperature interval 50 to 260°C of such a cylinder of rock, 360 m in diameter and 535 m long, is 3.2×10^{16} J. Over a 10-yr period, with 100% water sweep efficiency, such an ideal volumetric source of heat could provide energy at the rate of 103 MW(t). If we assumed that all this stored energy in the cylinder of rock could be extracted at a constant rate by an idealized 100% efficient volumetric sweep technique, this would amount to a continuous supply at 103 MW(t) for 10 yr.

Results of more practical and detailed calculations that consider finite numbers of fracture, each with a water sweep efficiency of 70%, are presented in Table I and Fig. 2. These computations are based upon parallel, equidistant fractures and the thermal drawdown was limited to 20%. Potential thermal interactions between fractures are accounted for.[3] Table I and Fig. 2 present results not just for 10 yr, the reference case, but also for 15 and 20 yr.

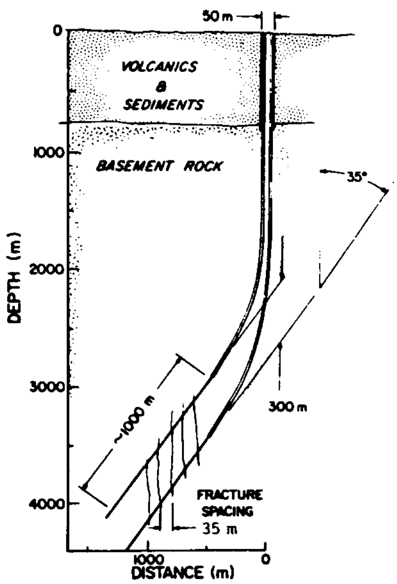

Fig. 1.
Phase II wellbore fracture system.

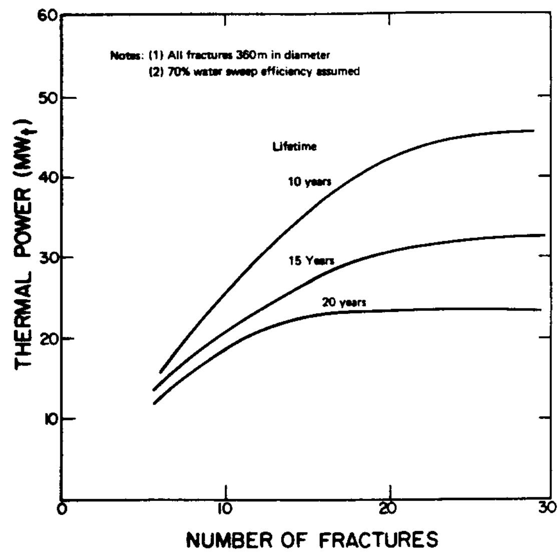

Fig. 2.
Effect of life-time and number of fractures on thermal power.

TABLE I

POWER PRODUCTION RATES FROM THE PHASE II BUILDING-BLOCK RESERVOIR
(Vertical Well Spacing = 360 m, Horizontal Length = 535 m)

Case	Number of Fractures	Reservoir Flow Rate m^3/s	Reservoir Flow Rate (GPM)	Average Power MW(t)
TEN YEAR LIFETIME				
1	9	0.029	461	23
2	16	0.047	728	37
3	25	0.056	889	45
FIFTEEN YEAR LIFETIME				
1	8	0.023	364	18
2	13	0.030	481	24
3	21	0.040	627	31
TWENTY YEAR LIFETIME				
1	7	0.018	279	14
2	12	0.026	410	21
3	18	0.029	461	23

Figure 2 illustrates an expected result: for a given number of fractures one can produce more power, i.e., rate of heat energy, if one reduces the expected lifetime. But unlike the theory for an ideal, volumetric source of heat, the conduction theory for a finite number of fractures does not result in a fixed, total energy. For example, for say 10 fractures, one can extract 25 MW for 10 yr, a total energy of 250 MW-yr, or one can extract 18 MW for 20 yr, a total energy of 360 MW-yr. In the second case the thermal boundary layers spreading into the rock from the fracture surface have propagated further, so that the effective reservoir volume is larger. These boundary layers propagate proportionately to the square root of time, so it is not surprising that the ratio of total energies for the two cases, 1.44, is very close to the square root of two, the ratio of the lifetimes. In the extreme of very many fractures, so that the spacing between them is small, the thermal boundary layer thickness quickly attains a value equal to the spacing between fractures. In this case the thermal interactions between fractures are severe, and in fact the energy per fracture is limited by the total energy of the volume of rock between fractures. In the limit of many fractures, the reservoir approaches the ideal volumetric source model. This is observed in Fig. 2; when the number of fractures exceeds 25, the thermal power no longer increases with number of fractures, and the maximum power for a 10-yr lifetime is exactly twice that of a 20-yr lifetime.

Turning now to Table I, we see that design choices can be selected -- a suitable heat production rate can be obtained by varying either the number of fractures or the lifetime. Focussing momentarily on the 10-yr results, it can be seen that for the first case of nine fractures, which completely avoids thermal interaction between adjacent fractures, a mean power level of 23 MW(t) could be extracted. For the next case, sixteen fractures, which results in a slight thermal interaction, 37 MW(t) could be extracted, in good agreement with the Phase II reservoir design goal [35 MW(t) with 15 fractures]. If one increases the number of fractures to approach the ideal volumetric heat source, more power can be produced, but at the expense of an ever-increasing number of fractures. For example, an increase of fractures from 16 to 25, a 50% increase, results in a power increase of only 20%. Fracturing costs are very uncertain, but it is apparent that increasing power by increasing the number of fractures soon runs counter to the law of diminishing returns. Consequently it was decided to keep the number of fractures in a reasonable range, say 10 to 20 fractures. Turning now to the question of lifetimes, let us compare two cases that have similar numbers of fractures, but quite different lifetimes: the case 2 with 10-yr life and 16 fractures; and the case 3 with 20-yr life and 18 fractures. In the first situation 37 MW(t) will be produced; whereas 23 MW(t), some 40% less, will be produced in the second situation. A clear trade-off of power-level vs lifetime is presented. For a fixed, total generating capacity the second situation will require 40% more reservoirs and, consequently 40% more wells. These wells are extremely expensive to drill, and at today's high interest rates it can be shown that the yearly cost of amortizing the extra wells in the second situation, i. e., a longer life, is more than amortizing, in the first situation, a lesser number of wells over a shorter period. In other words, at today's high inflation and interest rates, the value of <u>future</u> heat production is low.

In view of this discussion regarding number of fractures and wells it was decided to adhere closely to the original Phase II reservoir design, i.e., to consider a building-block reservoir of 16 fractures capable of providing 37 MW(t) over 10 yr. We note that this design is rather conservative because it disregards the beneficial effects of thermal stress cracking, which were demonstrated in Phase I,[5] and because, even without thermal stress cracking, the stated power, 37 MW(t) is only about one-third that potentially available from an ideal volumetric source.

We also note that reuse of the wells, for example, by deepening or sidetracking them into virgin rock, is not considered. In theory a new building-block reservoir, equal in production capacity to the first, could be produced by drilling an additional horizontal length of 535 m. At an angle of 35° from vertical this requires an additional drilling of 940 m (3 100 ft). However, as a consequence of the nearly exponential depth-cost relation discussed in Sect. IV, the cost of deepening a 4.5-km-deep well only 940 m is 70% of the cost of drilling a new well from the surface to approximately 4.5 km. While an economic argument could thus be made to deepen existing wells, rather than drill new ones, we nevertheless adopt the conservative view that the old wells may have suffered some damage over a 10-yr period, and assume that new wells will always be drilled. The situation with regard to sidetracking, or deviating, a well into laterally adjacent rock is more difficult to evaluate. Despite the great difficulty and expense experienced while sidetracking wells GT-2 and EE-3, one would assume that in a commercially mature HDR industry such costs could be significantly decreased; and a program of research in this area is recommended. However, the outcome of such a program cannot be anticipated here, so again, for this study we conservatively assume completely new wells are drilled from the surface after the reservoirs are drawn down by 20% at the end of 10 yr.

As shown in Sect. III, the net efficiency of converting thermal power to electrical power is low, and consequently the Phase II building-block reservoir will generate only 6.5 MW(e), so that 12 such reservoirs would be necessary for 78 MW(e). Preliminary studies indicate that commercially feasible plants need to have a capacity of at least 50 MW(e); we chose 78 MW(e) because this results in a convenient drilling and reservoir geometry, as described below. Later it will be found necessary to derate the system by 2 to 3 MW(e) to provide dry cooling, so for the remainder of this report we will refer to this system as a nominal 75 MW(e) system.

Figure 3 shows that twelve building-block reservoirs could be created by drilling nine wells in the "five-spot" pattern long familiar in the oil and gas industry. Note the economy of scale as the number of wells increases: For a single reservoir, two wells are necessary, an injection well and a production well, but for the 75 MW(e) system, 12 reservoirs are available with only nine wells. If the five-spot pattern was continued ad infinitum, eventually each well would result in two additional reservoirs. The astute reader

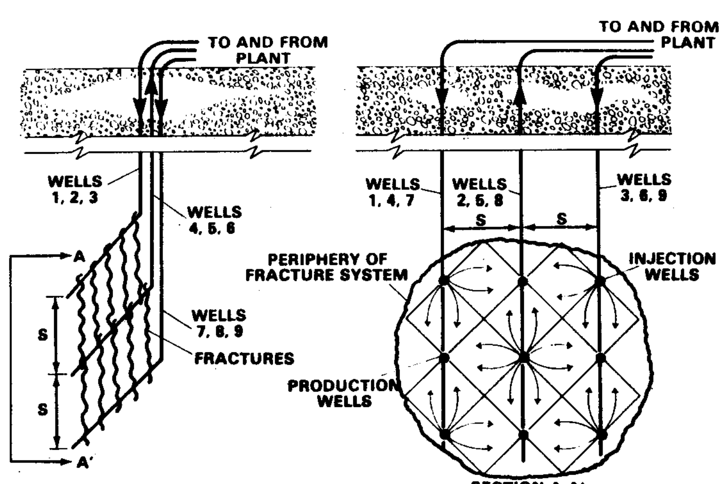

Fig. 3.
Conceptual nine-well HDR reservoir for 75 MW(e) generating plant.

will observe that each reservoir fracture is now a square, or if you like, a diamond slab of length $S/\sqrt{2}$ on each side and with a fracture opening in the third dimension, which is very small, typically 1 mm. The wells are now at opposite corners. In contrast the Phase II fractures will likely resemble circles of diameter S. The area of each circle is $\pi S^2/4$ whereas the area of a diamond is $S^2/2$, i.e., only 70% as large as the circle. Recall however that the water sweep efficiency of the circle is only 70%, so that, while the sweep efficiency of the diamond will not attain 100%, it certainly will be considerably greater than 70%. This follows because the wells are located at the extremes of each diamond, in the corners. Thus the effective heat-transfer areas of the circles and diamonds will not differ significantly.

III. THERMODYNAMICS

Let's first address the question of the ideal Carnot efficiency for converting heat to electricity. To examine the effect of a decreasing resource temperature, it's helpful to consider[6] an infinite number of infinitesimally small reversible heat engines each generating an infinitesimal amount of work δW and rejecting heat at the temperature T_0 as shown in Fig. 4. Integration over the temperature range T_{gf}^{in} to T_{gf}^{out} then yields the maximum work, or the change in availability, ΔB.

$$\Delta B = \Big[\Delta H - T_0 \Delta S\Big]_{T_{gf}^{in}}^{T_{gf}^{out}} \quad , \tag{1}$$

where ΔH and ΔS are the enthalpy and entropy changes. One can then develop[6] an approximate expression for the maximum Carnot cycle efficiency, η_c^{max}:

$$\eta_c^{max} \cong \frac{\Delta B}{\bar{\dot{m}}_{gf} C_p [T_{gf}^{in} - T_{gf}^{out}]} \cong \frac{T_{gf}^{in} - T_0 - T_0 \ln \frac{T_{gf}^{in}}{T_0}}{T_{gf}^{in} - T_{gf}^{out}} \tag{2}$$

where $\dot{m}_{gf}$ is the mass flow rate through the reservoirs and C_p is the specific heat capacity of the water. In this expression all temperatures must be expressed as absolute quantities. In the limit of a perfect power conversion process $T_{gf}^{out} = T_o$: therefore η_c^{max} reduces to:

$$\eta_c^{max} = 1 - \frac{T_o}{T_{gf}^{in} - T_o} \ln \frac{T_{gf}^{in}}{T_o} \qquad (3)$$

Thus, using an average temperature of 230°C for T_{gf}^{in} as stated earlier and a heat rejection temperature, T_o, equal to the Fenton Hill average ambient air temperature of 3°C (which is well documented by our own site meteorological data as well as that for the Union/PNM site at Baca) we can calculate that $\eta_c^{max} = 0.27$. Having found the ideal Carnot efficiency, we must next address the question of the proper utilization efficienty, η_u, to use to obtain the overall conversion efficiency, $\eta_u \cdot \eta_c^{max}$. There really are two questions here: first, what is the optimum thermodynamic efficiency one can expect for Fenton Hill conditions, and second, how close to this thermodynamic optimum should one operate for economically optimum conditions to prevail?

The thermodynamically optimum η_u depends on:

1. power cycle fluid choice
2. geothermal fluid temperatures
3. ambient temperatures,
4. mechanical efficiencies for the turbine and the power cycle feed pump, with the usual assumptions being $\eta_{turbine} = 0.85$ and $\eta_{pump} = 0.80$
5. approach temperatures in the primary heat exchanger and condenser system, (pinch point ΔT's).

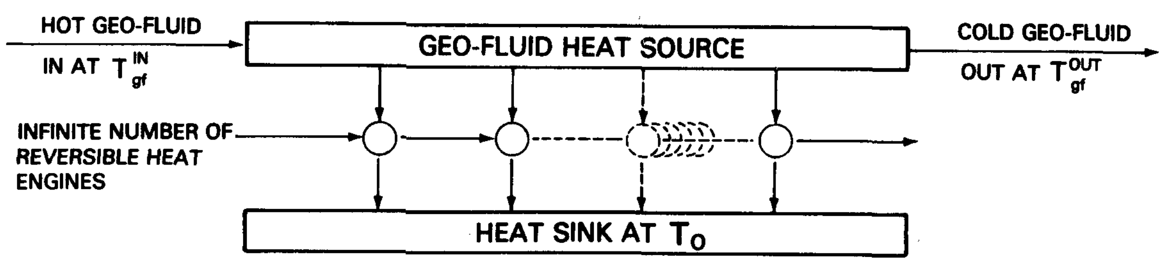

Fig 4.
Idealized heat engines.

It can be shown that a single fluid organic binary cycle is the best choice for Fenton Hill conditions, rather than, say, a direct flashing cycle, because: (1) water is a precious resource there, so water consumption should be minimized by avoiding flashing cycles, (2) to utilize the low ambient air temperature of 3°C, we should not use water as the working fluid in the power cycle, because of its low vapor density at temperatures below 35°C, compared to many organics. Water cannot be used effectively because the turbine exhaust end areas are too large.[6]

The results shown in Figs. 5 and 6 (for condensing temperatures of 26.7°C and 37.8°C, respectively) indicate that for reasonable ΔT's, in the range 10 to 15°C, maximum η_u's would range from 55 to 65% depending on the choice of working fluid.[7] For T_0 = 3°C, the η_u's would be somewhat lower, assuming that the condensing temperature remains at 26.7°C (Fig. 5) or 37.8°C (Fig. 6) in either case. However, by proper design of the condensing system, a floating condensing temperature could be utilized for seasonal and diurnal variations in T_0. The maximum temperature ever recorded at Fenton Hill is

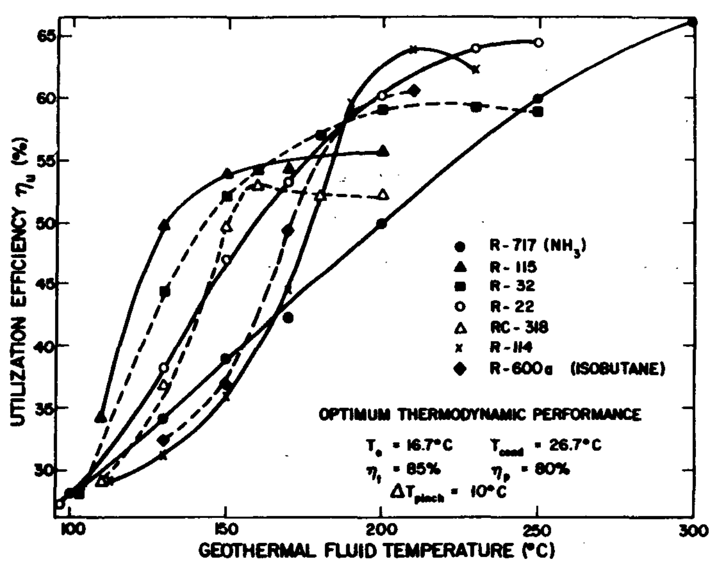

Fig. 5.
Geothermal utilization efficiency η_u as a function of geothermal fluid temperature for optimum thermodynamic operating conditions. A condensing temperature of 26.7°C was used with a 10°C approach to an average ambient temperature of 16.7°C. A 10°C minimum approach on the primary heating side was also used with an 85% turbine and 80% feed pump efficiency, (adapted from Milora and Tester).[6]

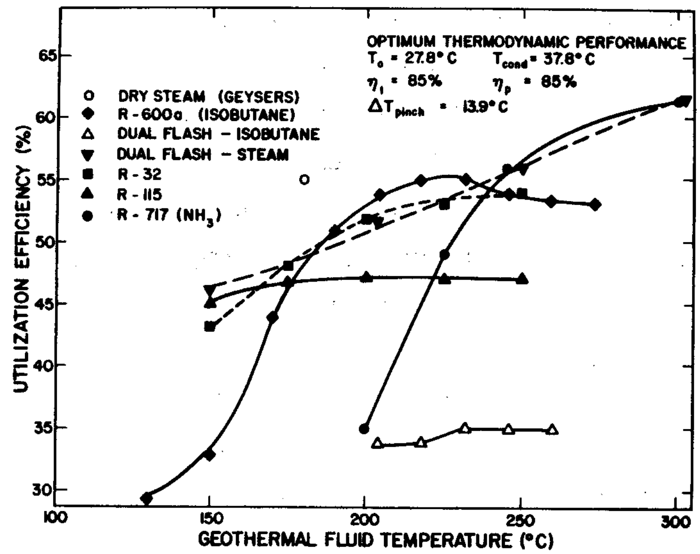

Fig. 6.
Utilization efficiency η_u as a function of geothermal fluid temperature, adapted from Milora and Tester[6] and Eskesen,[11] with optimum thermodynamic performance indicated.

29°C (85°F) and the minimum must be well below 0°F - so let's say that the daily average varies as $T_o = 3 \pm 15$°C.

Under optimal condensing conditions, T_o = -12°C, the actual condensing temperatures would be less than the design values of 26.7 or 37.8°C, but on hot days, T_o = +18°C, condensing temperatures would be higher than the design values. On average these conditions balance, so we should design the system for T_o = 3°C. Even if totally dry cooling was used for Fenton Hill, the absolutely worst case, we could still expect to approach 26.7°C (Fig. 5) in the condensing fluid on the average; the ΔT for the air-cooled condenser would be about 22°C (40°F). We have in fact actually achieved this condition using an R-114 fluid in the 60(e) Barber-Nichols generating unit operating at Fenton Hill.[8] Therefore, based on a T_o = 3°C, we estimate the maximum η_u's to be in the range of 48 to 56%. This range of η_u's has not only been documented in previous work,[6,7,9] but it also agrees with Pope et al.[10] and Eskesen[11] who give a range of 52 to 55% for 3 binary fluids (isobutane, isopentane, and propane), with similar assumptions regarding η_{pump}, and $\eta_{turbine}$.

The final question is the more controversial one. How close to this maximum η_u can we actually operate a real, economically feasible cycle? As pointed out by Milora and Tester[6] and Pope et al.,[10] the cost of producing the water (drilling wells, etc.), relative to the cost of converting the heat to electric power (heat exchangers, pumps, turbines, condensers, etc.) is critical in determing how close to this optimum one operates. Examining the extremes discussed in Appendix B of Ref. 6, one sees that very low ΔT's in the heat exchangers are required for high relative well costs whereas much larger ΔT's can be accommodated when well costs are low. As will be shown, the total reservoir development cost, including wells, fracturing, and site acquisition, in a "commercially mature" HDR reservoir system will be high relative to the total equipment cost, approximately 55%. Consequently, the maximum η_u's resulting with supercritical operation and ΔT's of 10-15°C would be near-optimal from an economic standpoint because of the premium placed on thermodynamically efficient use of the geothermal water by its high relative cost. This is in direct contrast to results shown by Pope et al.[10] who give, for a hydrothermal resource, an economic optimum range of η_u = 40 to 45% for situations where the ratio of well cost to total equipment cost is less than 50%. Conversion to HDR conditions would result in higher η_u's.

Based upon the above discussion we assume an operating economic η_u somewhere in the range of 48 to 56%, say 52% on average. Therefore, the net thermal conversion efficiency, $\eta_c^{max} \cdot \eta_u$, is 14%.

In the previous section, reservoir thermal power calculations were based upon an injection temperature of 50°C and a mean extraction temperature of 230°C, a temperature difference of 180°C. However, our thermodynamic calculations of η_c^{max} are based [Eq. (2)] upon a heat-rejection temperature, T_o, which has an annual mean value of 3°C. With this lower temperature, the heat-extraction temperature difference is increased from 180 to 227°C, an increase of 26%, and the reservoir thermal powers provided in Table I should be multiplied by 1.26 x 0.14, or 0.177, to convert to electric power. Thus, the design power for the Phase II reservoir, 37 MW(t), corresponds to an electrical capacity of 6.5 MW(e), and as discussed earlier, 12 such reservoirs are capable of generating a nominal 75 MW(e).

IV. ECONOMICS

The costs of generating electricity with a 75 MW(e) HDR system are broken down into: (1) operating and maintenance costs and, (2) fixed costs due to capital investment. In accordance with the previous section it is assumed that the reservoirs and wells have a useful life of 10 yr. Insofar as possible costs are stated on a 1981 basis, it assumes then that our hypothetical HDR station begins operation this year, and that, therefore, exploration and plant construction began several years ago. For these early costs, initial cost is compounded to 1981 as discussed below.

A. Operating and Maintenance Costs (O & M)

These costs are due to water charges, auxiliary power requirements for dry cooling, heat-exchanger fans, water circulation pumps, and other miscellaneous O & M costs such as revenue and property taxes, and labor. As will be developed, all O & M costs amount to only 10% of total HDR costs, so they are described rather briefly here.

1. Water Charges. Water is required for (1) makeup water losses due to permeation and leakage from the fracture system to the surrounding rock, and (2) evaporative water losses if wet cooling is used to reject the "waste" heat that was not converted to electricity. For simplicity and conservativeness, it was accepted that, due to the likely remote siting of HDR electrical stations, a beneficial, cost-recovering use of the 460 MW(t) of rejected or dissipated heat energy would not be found. During run segments 2 through 5 of the Phase I reservoir at Fenton Hill, we experienced water loss rates of approximately 10% of the circulated rate.[5] As would be expected, these rates were transient, being a maximum at the start of operation, and declining with time thereafter. The 10% rate stated above occurred near the end of run segment 5, which lasted 281 days. Over 10 yr of operation one would expect even smaller loss rates. Although the exact rate is obviously site-specific, we have been guided by the Fenton Hill experience and have accordingly assumed that the average rate of loss over the 10-yr lifetime will be approximately 5%. This amounts to 0.028 m^3/s (430 gpm or 770 acre-ft per year) for a 75 MW(e) system. Once again the cost of this water will be highly site-specific, but even if it assumed that such large usage does not permit commercial rates, so that the utility must pay rates similar to the typical home owner, $2 per 1000 gallons, the yearly cost will be only $450,000. To convert this to an equivalent cost per kilowatt hour, assume that the load factor is 85% (geothermal plants such as The Geysers are typically 90%; coal fired plants

are 80%). Thus a 75 MW(e) HDR plant would generate 5.6×10^8 kWh per year and the water cost would represent only 0.1 cents per kWh.

Robertson et al.[12] suggest in their Table 2-1 that the rejection of waste heat by means of a wet cooling tower at a site like Fenton Hill will require 60 acre-feet of water per year per MW(e) of capacity. A 75 MW(e) plant would thus require 4 500 acre-feet per year. In many areas of the country such amounts of water are available, but in the water-short western regions, where most electricity generating HDR reservoirs will likely be located because of the high geothermal gradients, water will probably be scarce. For this reason we assume that a dry cooling tower will be used, and to account for the large capital costs associated with such cooling, $100 per kW of capacity will be added below to the fixed capitalization costs.[13]

2. Auxiliary Power Requirements. The electrical power required to provide the forced air draft for dry cooling can be crudely estimated from our Fenton Hill heat-exchanger experience. These heat exchangers can reject 20 MW(t) to the atmosphere using fans with a nominal motor rating of 120 hp (90 kW). Our 75 MW(e) HDR system must reject 460 MW(t) of heat, so that if the same heat-exchange system was used again, 2.1 MW(e) would be required for air draft. No doubt a more efficient dry cooling system could be designed but even if one couldn't, our nominal 75 MW(e) plant need only be derated by 2 MW(e).

Each building-block reservoir requires 46 kg/s of water flow to generate 37 MW(t). Refering to Fig. 2 we see that, while one injection well, the center one, must service four reservoirs, the other four injection wells service only two reservoirs each. The four production wells service three reservoirs each. To ease the design of surface hardware such as pumps and valves, uneven pressures should be avoided. A rough balance of well pressure drops can be accomplished if the diameter of the center injection well is made 30% larger than the other wells -- a reasonable compromise is to case all wells with 9-5/8-in. casing (similar to EE-2 and EE-3) except for the center injector, which should be cased at 13-5/8 in. In this case the total pressure loss in the wells is 3 MPa (450 psi), 1 MPa each in the injectors, and 2 MPa each in the producers. Further calculations indicate negligible pressure losses in the surface equipment. Countering the pressure losses is the pressure gain due to buoyancy in the wells. On average the injection wells will be filled with 50°C water while the extraction wells will be filled with 230°C water. The density difference will be 315 kg/m^3, resulting in a buoyancy pressure drive of 12 MPa (1800 psi). Subtracting the wellbore pressure loss of 3 MPa leaves 9 MPa (1300 psi) for the fractures. Because the flow in each fracture is 0.0029 m^3/s (45 gpm), even a fracture impedance as high as 3 GPa s/m^3 (29 psi/gpm) could be withstood before pumping would be required. For comparison, the impedance measured during run segment 5 was 1.5 GPa s/m^3. In summary, it appears necessary to provide auxiliary power only for forced air draft, which requires 2 MW(e). Recalling that the actual rating was 78 MW(e), we retain the nominal rating of 75 MW(e), thus providing an additional 1 MW(e) for site power.

3. Other O & M Costs. Based upon 1979 taxes paid by Public Service Co. of New Mexico,[1] revenue taxes are taken as 2 1/2% of the bus bar price, which, as we will conclude, must be approximately 4.4 cents per kWh. The tax per kWh is thus 0.1 cents per kWh. Property taxes are based upon one-third of the undepreciated value of surface plant and improved land, and a tax rate of 0.026.[2] Land and plant values are discussed below. With these values property taxes amount to an average of 0.05 cents per kWh over the 10-yr lifetime. Insurance costs were taken as $4 per $1000 of surface equipment costs, or 0.05 cents per kWh. Other miscellaneous O & M costs, primarily for plant operators and maintenance, are taken from Ref. 1 and escalated to 1981 at 15% per year. These miscellaneous costs then amount to 0.2 cents per kWh.

A summary of all O & M costs is provided in Table II.

TABLE II
OPERATING AND MAINTENANCE COSTS FOR A 75 MW(e) HDR POWER STATION

Item	Cost, cents per kWh
Water losses	0.1
Dry Cooling (operating cost only)	Plant derated by 2 MW(e), to 75 MW(e)
Pumping	0.0
Revenue and Property Taxes, and Insurance	0.2
Miscellaneous	0.2
Total	0.5

B. Capital Costs

Capital costs consist of geophysical exploration and site acquisition costs, surface plant costs, well drilling and completion costs, and fracturing costs. These costs comprise 90% of total HDR costs, and of these, surface plant costs and well drilling and completion costs alone amount to 96% of all capital costs. Consequently, these two costs will bear the brunt of discussion below.

1. Geophysical Exploration and Site Development Costs. Geophysical exploration consists of the usual surveys (electrical, magnetic, seismic, and gravity), shallow wells for preliminary heat-flow studies, and deep evaluation drilling. Following Tester et al.,[1] total exploration costs are estimated at 2.9 million dollars in 1978. Escalating at 15% per year yields a 1981 cost of $\$4.4 \times 10^6$.

The total geothermal reservoir itself underlies only 100 acres. For conservativeness, assume that this land cannot be leased but must be purchased outright, and that an additional 100 acres are required for buffer purposes. Typical geothermal sites are rural in nature, hardly in the path of extensive development. Furthermore, HDR is so pervasive, unlike conventional geothermal resources, that little premium is attached to the land because of its HDR potential. Consequently a reasonable estimate of the value of the raw land would be $1 500 per acre, with an additional development cost of $1 000 per acre. Total land costs would then be $\$0.5 \times 10^6$.

The exploration and land costs above are the compounded costs -- should a plant be constructed at today's prices, the geophysical exploration would have been performed 8 to 10 yr ago and the land purchased 5 yr ago. The costs at those times would have been less than the 1981 costs estimated here, but the compounded cost, with the interest on debt, would be about the same, because interest and inflation rates have been roughly equal over the last 10 yr.

2. Surface Plant Costs. Again following Tester et al.,[1] the cost per kW of electrical power capacity, C_p, without dry cooling, is taken as

$$C_p = 977 - 2.15\, T_D \quad (1978\$)$$

where T_D is the design surface temperature. For T_D = 230°C, and escalating for inflation at 15% per year, the cost per kW(e) in 1981 dollars is $733. The 15% inflation factor is very conservative; inflation of fixed non-residential equipment has only been 7% for 1978 to 1981.[14] Add to this cost another $100 for dry cooling[13] and the total surface cost is $833 per kW(e). This surface plant cost is the total; it includes the purchase costs as well as engineering, installation, and contingencies. The credibility, in fact, the conservativeness of this total cost is established when one considers that the total capital cost of a coal-fired electrical station is about $975 per kW(e), only 17% greater than the HDR cost, even though the coal-fired station has expensive coal transporters, crushers, washers and dryers; boilers; super-heaters; pollution abatement equipment; and a myriad of other equipment. In view of this conservativeness, the $833 cost per kW is taken to be the compounded cost at the beginning of plant operation. In other words, the interest during construction, estimated to require 5 yr, is included.

3. <u>Drilling, Completion and Fracturing Costs.</u> The most uncontrolled cost in HDR power stations, as well as other geothermal power stations, is the cost of drilling. In this report we use actual Fenton Hill costs and are guided further by the average costs of onshore oil and gas wells drilled to comparable depths. Figure 7 presents average costs of onshore oil and gas wells drilled in the U.S. based upon 1979 data[15] of the Joint Association on Drilling Costs. Only costs for completed wells are presented in Fig. 7; dry holes were excluded. Well costs increase dramatically with depth; over the depth range of 1 to 4 km, the data in Fig. 7 can be fitted with a straight line, implying that costs increase exponentially with depth. Also shown for comparison are the actual, total costs of drilling the four deep geothermal wells at Fenton Hill: GT-2, EE-1, EE-2, and EE-3 as well as the "learning and disaster-free" costs which, as described below, are believed to be more representative of future, more commercially mature HDR drilling. All costs in Fig. 7 are presented in 1981 dollars. Following Carson and Lin[16] a 17% yearly escalation factor was taken for drilling costs, based upon the cost of U.S. oil and gas wells from 1972 through 1979. Whereas a drilling inflation of 17% per year sounds high, Garde-Hansen[17] indicates a rate of 15% per year from 1970 to 1979. This period includes three years of low inflation prior to the 1973 oil embargo.

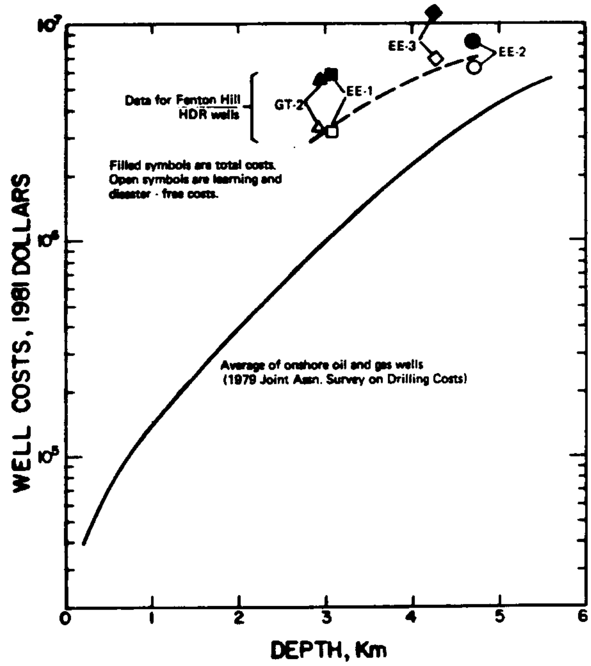

Fig. 7.
Well costs.

The cost data for HDR wells GT-2, EE-1, EE-2, and EE-3 are summarized in Table III. Both the costs at the time of completion, as well as restated 1981 costs, inflated at 17% again, are shown. A striking effect of 17% inflation is that the seemingly inexpensive costs of GT-2 and EE-1 at the times of their completions would triple or nearly triple at today's drilling costs. For each well we also present the cost, in 1981 dollars, for the average oil and gas well drilled to the same depth. These costs are taken from Fig. 7. A consequence of the nearly exponential cost-depth relationship, and 17% inflation, is that EE-2 and EE-3 were actually less expensive than GT-2 or EE-1 when compared on equivalent time and depth bases. To see this more clearly refer to the table heading, Ratio of 1981 Actual Cost to Oil/Gas Average. Wells GT-2 and EE-1 cost about five times the oil/gas average, whereas EE-3 cost four times the average, and EE-2 cost only two times the average. Thus, drilling has significantly improved at Fenton Hill, in the sense that HDR well costs are approaching those of oil/gas average costs. This fact is even more apparent when one recalls that GT-2 was drilled nearly vertically, with no directional drilling, and that EE-1 was directionally drilled only for the bottom 150 m (500 ft), at a maximum deviation of 4° from the vertical, and rather inaccurately at that. In contrast, EE-2 and EE-3 were directionally

TABLE III
DRILLING AND COMPLETION COSTS

Well	Drilling Time (Mos.)	Completion Date	Total Depth Along the Wellbore km	feet	Actual Cost, Millions of Dollars At Comp. Time	Escalated to 1981[+]	Oil/Gas Av. Cost*, Millions of 1981 Dollars	Ratio, 1981 Actual Cost To Oil/Gas Avg.	Learning- & Disaster-Free Cost, Millions of $ 1981	Ratio, Learning & Disaster Free Cost to Oil/Gas Average	Major Disaster Events
GT-2	8	10/74	2.93	9 620	1.9	5.7	0.94	6.1	3.3	3.5	"Stuck" drill pipe, Washover Required.
EE-1	5	10/75	3.06	10 050	2.3	5.9	1.1	5.4	3.2	2.9	Expts. at 6 500 ft, surveying expts.
EE-2	13	5/80	4.66	15 290	7.3	8.5	3.6	2.3	6.3	1.8	Collapsed casing.
EE-3	15	8/81	4.25	13 930	11.5	11.5	2.8	4.1	6.9	2.5	Major fish job, and sidetracking.
							Avg, All Wells =	4.5	Avg, All Wells =	2.7	
							Avg, EE-2 + EE-3 =	3.2	Avg, EE-2 + EE-3 =	2.2	

[+]Drilling Cost Escalation taken as 17% per year.

*Ref. 15

drilled, and accurately so, to an angle of 35° from the vertical for the bottom 2.3 to 2.7 km (7500 to 8800 ft).* This convergence of HDR and oil and gas well costs was foreseen in Ref. 18. For very deep wells HDR costs can actually be lower because use of expensive drilling muds and fluid additives can be avoided in hard crystalline rocks.

Carson and Lin[16] observed that geothermal wells cost two to four times that of oil and gas wells. The geothermal wells included in their survey were primarily in hydrothermal reservoirs -- they were drilled straight, and usually in softer formations. In contrast, wells EE-2 and EE-3 were directionally drilled in hard, dense crystalline rock, yet they cost only 2.3 and 4.1 times the oil and gas average wells drilled to the same depths.

Having shown that Fenton Hill drilling is nearly as inexpensive as other geothermal wells despite harder formations and directional drilling, and that Fenton Hill drilling is actually improving with experience, let us now consider improvements that may lie in the future. Refer again to Table III, this time to the column headed "Learning and Disaster Free Costs." These costs are the actual 1981 costs, from which are subtracted costs due to delays for experiments and "disasters." It is important to note that these are <u>not</u>

*This does not mean that direction-changing turbine drilling or motor-drills and sophisticated guidance tools (such as the "EYE") were used throughout this interval; we mean that the direction of the wells and their proximity were closely controlled, and changed when necessary, using a combination of conventional rotary drilling and turbine drilling, with the "EYE" when necessary.

the same as "trouble free" costs. We believe wells will always have the usual, unavoidable troubles, but in deriving costs to which HDR drillers might aspire we have subtracted costs due to the disasters as well as the experiments that one might reasonably expect to avoid as drilling matures and the number of wells in the reservoir increases. The costs of these disasters, and experiments that need not be repeated, were identified with the help of Don Brown and John Rowley, both of Los Alamos National Laboratory. As examples, for GT-2 we subtracted costs for the continuous coring experiments, and the stuck pipe and subsequent washover effort. For EE-1 we subtracted the cost of 26 days of experiments at 2 km, and the excessive time lost in locating the bottom of the hole in relationship to GT-2, an art which we seem to have mastered in EE-2 and EE-3. For EE-2 we subtracted the costs due to the casing collapse, which may have been caused by a simple miscount of casing joints. For EE-3 we removed the cost due to the prolonged fishing job and subsequent sidetracking. We did not subtract the costs of more typical troubles: losses of circulation, twistoffs and the more usual fishing jobs, breached casings, and directional drill motor and tool failures. Nor, of course, have we subtracted costs of reaming, cementing, circulating, inspection, logging, and casing.

The ratios of these "learning and disaster-free" costs to average oil/gas costs are presented in Table III. Wells GT-2 and EE-1 have ratios of 3.5 and 2.9, whereas EE-2 and EE-3 are 1.8 and 2.5, respectively. In view of, once again, the marked improvement with the last two wells, let's use their average ratios. The actual average cost ratio was 3.2, and the "learning and disaster free" average ratio was 2.2. We propose, for the purpose of estimating future costs, that the nine wells in a commercially mature, 75 MW(e) system can be drilled for 2.7 times the oil/gas average. This is exactly midway between the average actual and the "disaster free" ratios. In other words we are, rather conservatively, assuming that no further progress will be made in drilling technology; that only by dint of many repetitions, we can avoid one-half the disasters that befell us earlier.

The oil and gas equivalent costs of EE-2 and EE-3 in 1981 are \$6.4 x 10^6, per Table III. The factor 2.8 times this cost, \$17 x 10^6 (only 14% less than the actual total 1981 cost of EE-2 and EE-3), is the expected average cost of a HDR geothermal well pair. Consequently a nine-well, 75-MWe system will require \$77 x 10^6.

The final cost of concern is that of fracturing. Fractures will be made with ordinary water although it is possible that an inexpensive additive will be included to reduce friction losses in the injection well as well as to decrease permeation losses from the face of each fracture as it is propagated. Our experiences in the Fenton Hill granitic formations indicate that upon the cessation of pumping and fracturing, the fracture faces are "self-propped" due to asperity-to-asperity contacts on the fracture surfaces. Therefore proppants in the fracturing fluid are not required, resulting in considerable savings over the usual fracturing job, which typically requires hundreds of thousands of pounds of proppants, expensive fracture fluids, blending trucks, and pad and cleanup fluids. Experience during the hydraulic fracturing operations, Expts. 195 and 203, which created, in part, our current Phase I, 300-m fracture, showed that pumping rates of up to 0.05 m^3/s (750 gpm), pressures of 20 MPa (3000 psi), and total injection volumes of 1500 m^2 (400 000 gal) of water were used in creating the fractures. Costs of Expts. 195 and 203 were less than \$25 000 each. If the nearly 200 fractures required could be created this inexpensively, then the total fracturing cost would be \$4.8 x 10^6, or \$0.53 x 10^6 per well. However, it is possible that we may require expensive downhole isolation techniques, such as repeated packer runs and pressurizations, or the repeated setting of cement isolation packers, or perforated liners, in which case estimates have run as high as \$3 x 10^6 for the EE-2/EE-3 pair, or \$14 x 10^6 for the nine-well system. On the other hand there is ample justification for optimism. For example, the requirement for a total of 192 fractures stems from the assumption that the maximum fracture diameter is 360 m (300 m was established in the Phase I reservoir, rather easily it appears in hindsight). If the diameter could be doubled, then it can be seen by referring to Fig. 3 that the number of fractures could be reduced to 80. For this report we assume a total fracture cost of 10 million dollars. As was discussed, this cost is subject to a great deal of uncertainty, but it must be noted that the fracturing is only of the order of 10 to 15% of the drilling and completion costs, so that even such large uncertainties in fracturing costs are relatively unimportant.

Table IV summarizes the capital costs. HDR power stations are capital-intensive, requiring \$2 060 per kW(e) of installed capacity. Two items alone account for 91% of capital costs: drilling and well completions account for 50%, and surface plant costs account for 41%. In amortizing the capital costs,

TABLE IV

CAPITAL COSTS OF 75 MW(e) HDR POWER STATION, 1981 DOLLARS

Item	Total Cost (millions of $)	Cost per kW(e) $	Fraction of Cost
Geophysical Exploration	4.4	59	0.03
Site Acquisition & Development	0.5	7	--
Dry Cooling Heat Rejector	7.5	100	0.05
Other Surface Plant Costs	55.	733	0.36
Well Drilling and Completions	77.	1,030	0.50
Fracturing	10.	130	0.06
Total	154.	2,060	1.00

a distinction must be made between the wells and fracturing, which have a useful life of 10 yr, and the surface plant, site acquisition, and exploration costs. Typical surface plant equipment has a useful life of 30 yr, so the plant can be used for more than one HDR reservoir system. In fact, since the great advantage of HDR is its ability to exploit the earth's heat in nearly any type of formation, the second system should be developable immediately adjacent to the first system. Not only can the surface plant be reused, it need not even be moved, and furthermore one need not repeat geophysical exploration in such a proximate location. This being the case, the investment in wells and fracturing was amortized over 10 yr, and the other costs were amortized over 30 yr.

C. Break-even Bus Bar Costs of Electricity

In this section we estimate the price per kilowatt hour that an electric utility must charge to break even with a 75 MWe HDR power station. This is the selling price that covers debt service, operating and maintenance costs, and income taxes, and still provides a reasonable rate of return on invested capital. The actual cash flow resulting from operating any electric plant will vary over its lifetime. The capital expenditures will be made before production starts and then the interest payments, dividends, and return of capital to investors will take place over time in a manner depending on the particular method chosen for financial capital retirement. Likewise, operating and maintenance expenses may vary, inflation will alter absolute levels of costs and revenues, and tax payment schedules will be significantly changed by accelerated depreciation rules and exploitation of various tax incentives. So the actual yearly costs of electricity production will not be constant and, therefore, it becomes difficult to directly compare the costs of competing plants or technologies. The solution to this problem is to use the "levelized life-cycle cost" method as described for the electric utility industry in Electric Power Research Institute's (EPRI) Technology Assessment Guide.[19] This method reduces the bus bar cost of electricity to a single number, in constant dollars, so that plants based on different technologies, lifetimes, financing schemes, etc. can be directly compared by life-cycle cost. A particular format for implementing this method is found in BICYCLE - A Computer Code for Calculating Levelized Life-Cycle Costs.[20] The calculations in this report were based on this method, but due to the unique income tax features of geothermal development, modifications to the tax calculations of the code were made as required.

Table V lists the basic parameters that were used to calculate the levelized life-cycle costs for the 75 MW(e) HDR plant. The resultant base case cost was 4.4¢/kWh in 1981 dollars. In the following paragraphs we will discuss the selection of parameters and the changes in levelized cost which result from alternate parameter selections. The figures used for investments, operating and maintenance costs, plant lifetimes, and capacity have already been discussed in previous sections, so this section will deal primarily with the financial and tax parameters.

The most important financial parameter is the interest rate paid on capital. For the base case we have used a nominal 17% interest rate for both bonds and equity. This rate is reflective of current rates of return in the electric utility industry. Public utility bonds recently have been yielding 16 1/2% for AAA rated securities (the most secure rating), ranging up to 17% for A ratings and 17.3% for BAA (usually the least secure rating for marketing newly issued bonds to the public).[21] The 1981 range for the BAA bonds has been about 15-18%. So if public financing of HDR plant capital is contemplated, then even the riskiest, expected new bond rating would carry with it an interest rate near 17% at present. Likewise, recent returns on public utility common stock based on price earnings ratios of over 5.8 are also very close to 17%. The 1981 range on these equity return rates has been 14.7-18.2%.[22] As we shall see, the actual interest rate has a large effect on the

TABLE V

BASE CASE ECONOMIC PARAMETERS FOR A 75 MW(e) HDR STATION:
LEVELIZED LIFE-CYCLE COST CALCULATION IN 1981 DOLLARS

Result - Levelized Life-cycle Cost	4.4 ¢/kWh
Total Investment	$154 million
Drilling and Fracturing Investment	87 million
Electric Plant and Other Investment	67 million
Operating and Maintenance/year	2.33 million
Reservoir Lifetime	10 years
Electric Plant Lifetime	30 years
Plant Capacity	75 megawatts electric
Capacity Factor	85%
Nominal Interest Rate	17%
Equity Interest Rate	17%
Bond Interest Rate	17%
Fraction of Capital in Equity	.56
Fraction of Capital in Bonds	.44
Inflation Rate	6%
Real Interest Rate	10.4%
Federal Income Tax Rate	46%
State Income Tax Rate	5%
Gross Revenue Tax Rate	2.5%
Depreciation Method	Sum of Digits
Share of Drilling and Fracturing Costs Which are Intangible	75%
Depletion Allowance	15%
Share of Total Revenues to Which Depletion Allowance Applies	56%
Regular Investment Tax Credit	10%
Geothermal Investment Tax Credit	not taken

levelized life-cycle cost of electricity, so it is important to account for realistic rates of return on capital. For simplicity we will usually set both bond and equity rates equal to the same figure. There is good theoretical basis for using a single interest rate for evaluating a project.[23] The basic idea is that the project as a whole can be evaluated for its overall business risk and business return potential, which are independent of the particular financial instruments used to raise the investment funds. However, there is also a basis for expecting actual interest rates to differ between bonds and equity on the same project due to leveraging of financial risk and due to tax effects. We have separated out the tax effect problem by examining the effect on bus bar cost of changing the ratio of debt to equity while leaving interest rates unchanged.

We assumed that the fraction of capital financed by bonds is equal to 0.44, based on the assumption that bonds will finance the electric plant and other surface investments (44% of total capital), whereas riskier equity funds will pay for wells and fracturing. In the long run this is a conservative (i.e., pessimistic) assumption because mature utility industry debt fractions are higher, but is probably realistic during the early years of the industry. Because of the tax deductibility of bond interest, levelized costs would drop if a larger portion of capital was financed with borrowed funds. For example, if we simply reverse the debt to equity ratio so that debt finances 56% of capital, then levelized costs drop by 2.8 mills to about 4.1¢/kWh. If we want to be representative of a mature public utility industry we could use the current electric utility debt percentage which is 62.5%.[24] This changes our base case levelized bus bar cost to 4.0¢/kWh, but probably would be an unrealistically high debt ratio, at least initially, for an infant industry such as HDR.

The interest differences between bond and equity financing will be influenced by the debt fraction and by overall project risk. However, the weighted average interest rate (including tax effects) required by financial markets will depend only on real project business characteristics and risks. So by focusing on a single interest rate, and setting bond and equity rates equal to this project rate for simplicity, we do not lose any insight into total levelized bus bar cost.[23,*]

The interest rate which actually determines the "real" level of bus bar cost is the "real" (noninflationary, constant dollar) interest rate. The real returns to a project result from the productivity of capital and include a premium for risk, which depends on the uncertainty of business prospects. Observed market interest rates contain an additional component that is required to compensate lenders for the deflated value of the funds that are

*In fact, we have calculated bus bar costs where debt and equity rates are not equal in the mature industry case. This calculation is easily handled by the BICYCLE code (Ref. 20). A proper weighted average interest rate (including tax effects) yields identical results.

returned to them. The true cost of funds needed for a project depends only on the marginal productivity of capital in general, i. e., the going rate on funds for low-risk projects, plus the risk premium for the specific project. This true cost is independent of generalized changes in the value of money itself. To evaluate the real level of capital market costs, we need to concentrate on deflated interest rates. Thus, the nominal interest rate, i, which is actually observed in the financial markets will consist of a "real" component, r, the true return on invested capital, and an inflation premium, p, which compensates investors for the loss of purchasing power of the dollars they are paid back with, but does not provide any real income. The relation between these terms during discrete time periods is (1 + i) = (1 + r)(1 + p). So in our inflationary base case, today's nominal 17% interest rate reflects a somewhat lower "real" interest rate. The assumption about what inflation rate the financial markets are including in the nominal rate calculation is critical to knowing what the "real" interest rate is. We have assumed an inflation rate of 6%/year in all of our base calculations. With our base 17% nominal interest rate this implies a "real" rate of return of about 10.4%. It is this real rate which determines constant dollar bus bar costs. Figure 8 shows levelized bus bar costs as a function of real interest rates. The calculations upon which Fig. 8 is based were all made assuming a 6% inflation rate.

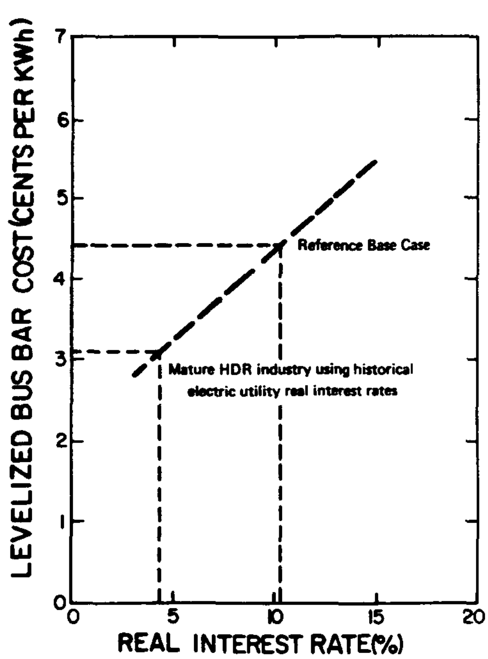

Fig. 8.
Levelized HDR electric plant bus bar cost as a function of real interest rate.

The nominal rates of interest used were 10.8, 14, 17, 20, and 25%. The reader may convert the real interest rates of Fig. 8 to normal market rates by using the formula previously listed, or approximately, by adding the assumed inflation rate to the real interest rate. We chose to use a 6% inflation rate because it has been approximately the average rate over the last 15 years, and it corresponds to currently predicted rates over the 1980's.[25] The actual inflation rate is unimportant to computing the constant dollar bus bar cost of electricity provided one is careful to recognize what "real" interest rate corresponds to nominal market rates. The reason for including the inflation rate in the calculation at all is that it does have tax effects which change final revenue requirements slightly. For our base case HDR plant, we found that holding real interest rates constant, zero inflation would reduce bus bar costs by only 0.6 mills/kWh, whereas raising inflation to 11% increased bus bar costs by only 0.6 mills/kWh.

The reader may make his own conclusions from Fig. 8 as to how fast and how far HDR electricity costs would drop as the maturing industry's financial and business strength and reliability result in less risk premium and lower real interest rates. A real interest rate of 4.5%, yielding a bus bar cost of 3.1¢/kWh, is highlighted in Fig. 8 because it represents an exact financial analog (including tax rates, debt equity ratio, depreciation method, etc.) to the figures for a mature coal and nuclear electric industry as recently studied in Hardie and Thayer.[26] The low weighted average interest rate used in the Hardie and Thayer study is based on the actual historical real rates of 2.5% on utility bonds and 7% on equity. Thus, should the financial markets perceive equal risks, our HDR plant would have bus bar costs essentially identical to new coal plants (at $25/ton for coal) or new nuclear plants (at $25 lb/$U_3O_8$), both of which have bus bar costs of about 3.2¢/kWh. However, it is unrealistic to believe that the young HDR electric industry could obtain such low financing rates, and therefore our base case nominal rate of 17% (real rate of 10.4%) provides a realistic risk premium for the near future. The conservativeness of our financial calculations, in conjunction with the realism of the drilling and other cost estimates previously discussed, should make it abundantly clear that a "mature" HDR electric industry should be highly competitive with current electric generation facilities.

Returning now to some of the other parameters in Table V, we used the new 46% Federal income tax rate; the normal 10% Federal investment tax credit;

a 5% state income tax rate, which is higher than average but is the New Mexico rate; and the fairly typical 2.5% gross revenue tax rate of New Mexico. The depreciation method used for tax purposes was the favorable sum of digits method, but no attempt was made to incorporate the upcoming new accelerated depreciation rules because the IRS has not yet defined how they are to be implemented. These new rules will probably have negligible additional benefit to our HDR system because we already have special tax benefits (including rapid expense writeoffs) of much more importance.

Our HDR electric plant receives special tax benefits as a result of the U.S. Energy Tax Act of 1978 in three forms: expensing intangible drilling costs, a depletion allowance, and a geothermal investment tax credit.[27,28] These tax features are very important to the economic feasibility of the system -- without any of them our base case bus bar cost rises to 5.2¢/kWh. Expensing the intangible drilling costs by itself saves about 0.4¢/kWh, and the depletion allowance is also worth another 0.4¢/kWh. Thus, together they reduce bus bar costs to the base case level of 4.4¢/kWh. We have not included the special 10% geothermal investment tax credit in our base case because it expires on December 31, 1982 and thus will not be representative of financing arrangements in the future. For a plant being built currently the effect of this credit would be to reduce bus bar cost in our base case to 4.1¢/kWh.

The option to expense intangible drilling costs follows basically the method used in oil and gas drilling. For our base case we assumed that 75% of drilling and fracturing costs would be intangible. This is based on figures for normal land-based oil and gas drilling and on expert opinion about variations expected in HDR drilling operations, published[29] and unpublished.* It is a conservative number as there is a possibility that the figure could go as high as 90% depending on HDR technological developments and is very unlikely to be less than 75%. Staff at Los Alamos National Laboratory estimated a tangible cost of $1 300 000 for our reservoir design including surface equipment, casing, and tubing strings in each well for possible removal and replacement in commercial operation, and flow control equipment in every other well.** This estimate still produces an intangible cost fraction of 85%

*Personal communications with Wally Tyner of Purdue University, Ron Miller and John Broderick of DOE Leasing Policy Office, Bob Kalter of Cornell University, and Ed Kaufman geothermal consultant, Los Alamos, October 1981.

**Personal communication with Don Dreesen, Los Alamos National Laboratory, October 1981.

(taxwise, more favorable than the 75% figure used for calculations). However, even if the ratio rises to 90%, our bus bar cost drops by only 0.6 mills/kWh from our base case using 75%, so our final costs are relatively insensitive to the exact intangible cost ratio.

In computing the tax effects of the geothermal depletion allowance we used the 15% rate which will be effective in 1984 and thereafter. Actually the rate is 20% in 1981, 18% in 1982, and 16% in 1983. But given the aims of our report it seemed fairest just to use the future rate for all years and to ignore the miniscule extra benefit that might accrue to a plant starting operations immediately. The depletion allowance technically applies only to the hot water sales value and not to final electricity sales. So a method of allocating the share of HDR water cost out of total bus bar cost has to be applied. We simply took the share of capital expenditures (56%) that the HDR production facility absorbed and used that percent of total revenue as being the hot water value. This method seems to provide a satisfactory approximation for our purposes, because our analysis shows that the percentage of HDR revenues can range from 39% to 73% of bus bar electricity price in order to cause only a 1.0 mill/kWh change in our 4.4¢/kWh levelized cost.

Our tax calculations depend on an institutional structure that makes it possible to truly realize all of the tax benefits, by having income to offset with deductions or ability to carry over into future years. This means that the project may have to be part of a larger corporate structure to fully utilize the tax credits, etc. This is not a restrictive assumption as ample evidence indicates routine methods of achieving these results in the real world.* Even in the speculative oil drilling business there are whole schemes of selling tax shelters, unitizing fields (already true of California geothermal steam wells), and other arrangements to fully exploit the tax incentives set up by the government. So we believe that our calculations are not only hypothetically correct, but actually realizable through normal management and organizational structures.

Our bus bar cost of 4.4¢/kWh is similar to the costs of HDR electricity reported in References 1 and 2, in spite of the significantly different reservoir design assumptions and the dynamic optimization methodologies used

*Personal communications with Wally Tyner of Purdue University, Ron Miller and John Broderick of DOE Leasing Policy Office, Bob Kalter of Cornell University, and Ed Kaufman geothermal consultant, Los Alamos, October 1981.

in those studies. In particular, in References 1 and 2 it was assumed that each reservoir required two wells, whereas here we used 9 wells for 12 reservoirs. Reference 1 assumed costs of 3.8 or 5.0¢/kWh (corrected to 1981 dollars) and then calculated profit levels depended upon various reservoir and technical parameters. Reference 2 found a cost of 3.3¢/kWh (corrected to 1981 dollars) for geothermal gradients similar to Fenton Hill but used drilling costs that were only about half the level of those used here. Thus the general magnitude of previously studied bus bar costs can be reconciled with our results, with our costs being more soundly based on recent research and cost data.

D. Comparison With Conventional Power Stations

Hot dry rock geothermal power production costs must be compared with the costs of other generating systems in order to evaluate their commercial feasibility. Table VI summarizes the most important cost characteristics of a number of typical generating stations. The calculations for these costs were all performed in the same way, using the method described earlier, so that the final levelized bus bar costs can be directly compared. The only exception is that our HDR base case assumes a much less favorable interest rate and capital

TABLE VI

COMPARISON OF ELECTRICITY GENERATING COSTS IN LEVELIZED, CONSTANT 1981 DOLLARS+

Type of Generating Station	Application	Capital Cost ($/kW of Capacity)	Fuel Cost	Levelized Bus Bar Cost (¢/kWh)
Hot Dry Rock Geothermal	Baseload	$2060	None	4.4* 3.1**
Coal Fired Steam	Baseload	975	$25/ton $40/ton	3.2 3.9
Oil Fired Steam	Baseload	645	$34/BBL $50/BBL	6.9 9.6
Nuclear LWR	Baseload	1335	$25/lb U_3O_8 $75/lb U_3O_8	3.2 3.6
Gas Turbine	Peaking	202	$2.72/mcf $5.00/mcf	4.2 7.2
Diesel Electric	Peaking	300	$34/BBL $50/BBL	8.4 11.9

+Method of calculation: Ref. 20.
*Base Case, 10.4% real interest rate.
**Using mature industry capital structure and interest rates to make plant-independent parameters identical to other generating stations listed.

Sources of input data: Refs. 19, 25, 26, 30, 31.

structure, as previously discussed. However, we have also shown in the table the calculation for our HDR system with a mature financial structure. This yields a 3.1¢/kWh final cost, which is insignificantly different from the present coal and nuclear costs calculated with identical plant-independent assumptions.

For each of the fuel burning plants we have first shown a final bus bar cost assuming that today's real fuel prices will remain unchanged. A second set of costs is also shown for a higher "real" (1981 dollars) fuel cost to give some indication as to how expected fuel price rises will affect the cost of electricity for these plants. For coal-fired steam stations, for example, we present results for a current cost of $25 per ton, but even today actual costs vary from a low of $15 per ton, which some Rocky Mountain stations still have access to, to a high of $50 per ton in New England states. The anticipated future typical cost was taken as $40 per ton, a price which many stations are paying already. To emphasize the importance of fuel costs it is noted that even at present costs, fuel costs are a significant, even the dominant, factor in bus bar prices. For example, at $25 per ton, the coal cost alone represents 1.1¢ per kWh, and at $34 per barrel the cost of oil represents 5.7¢ per kWh. In these calculations the heating value of coal was taken as 12 000 btu per lb, that of oil taken as 5.5×10^6 btu per barrel, and that of natural gas taken as 1 000 btu per scf.

We also performed levelized life cycle cost calculations assuming that today's real prices will rise at a 3%/year rate. The results are omitted from the table to avoid added clutter and because future price escalation rates are a matter of speculation. But the quantitative results for the generating plants are similar to the tabular final costs shown for a simple higher fuel price. The important point is that the HDR system costs do not depend on fuel prices, so that HDR's relative advantages can only grow in the face of rising real fuel costs for conventional power stations. The stability of the HDR cost is a dual benefit: to utilities in their capital financing, and to consumers in their use of the final product.

Looking at Table VI we can see that the HDR station is already much lower in cost than petroleum-using plants of any type: 4.4¢/kWh compared to 6.9¢ for oil fired steam, and 8.4¢/kWh diesel-electric. HDR is roughly competitive now with natural gas burning plants, 4.4¢/kWh compared to 4.2¢/kWh for a gas turbine peaking unit, and is expected to improve its position rapidly as gas deregulation results in dramatic gas price increases. So only coal and nuclear plants (both 3.2¢/kWh currently) remain as realistic competition to HDR baseload electricity. The reader may extrapolate his own fuel price increase expectations for these generating stations from the figures shown, and may consider the effects of probable drops in HDR costs as technological experience is gained. The life-cycle cost figures shown, based on actual capital and fuel prices in 1981 and calculated on a common basis, leave little doubt about the future comparative economic advantages of HDR power stations.

V. DISCUSSION AND CONCLUSIONS

We conclude that a 75 MW(e) HDR generating station can sell electricity at the bus bar for 4.4 cents per kWh and "break even", i.e., pay its debts and O & M costs, satisfy tax liabilities, and still return 17% per year to its investors. Should interest and investment return rates fall below 17%, significant cost decreases will result -- for example a decline from 17% to 14% results in a 15% decrease in levelized bus bar cost. This HDR bus bar cost is based on calculations assuming real rates of return of more than double historical electric utility levels. A mature HDR industry with rates of return at more normal levels would have a bus bar cost of only 3.1¢/kWh. This cost calculation is dominated by capital costs, which amount to 90% of the total cost. The capital cost, in turn, is dominated by just two items, surface plant equipment, and the drilling and completion of wells. The surface plant equipment, including dry cooling, comprises 41% of the capital cost and, accordingly, roughly 37% of the bus bar cost. The drilling and completion costs comprise 50% of capital and about 45% of the bus bar cost, consequently any percentage increase or decrease in drilling costs is immediately reflected as about one-half that percentage change in bus bar cost.

Because the surface plant and drilling costs are so important, amounting together to 81% of bus bar price, these costs were discussed in detail and justified in the text. To reiterate, the total surface plant equipment cost was taken as $833, 85% of the total capital cost of a coal-fired station, which includes expensive equipment for pollution abatement (tall stacks, precipitators, waste material handling, etc.), fuel preparation and combustion (crushers, washers, separators, boilers, superheaters), and auxiliary equipment (preheaters, feed water pumps, etc.).

Drilling costs were assumed to be similar to EE-2/EE-3 costs. Despite the expected commercial maturation of HDR drilling it was assumed that conventional rotary drilling would be used, with no further technical improvements, and that we could avoid only one-half the "disasters" that befell EE-2 and EE-3. This is an extremely stringent assumption -- in the comparison of HDR costs to coal- and oil-fired costs we make comparisons to technologies that have matured over 60 years. But deep, hard rock drilling is still in its infancy and much improvement can be expected even in rotary drilling. In the longer view, new means of drilling, for example impulse and thermal spallation methods, may offer even more significant cost savings. A halving of geothermal drilling costs, which would simply make them comparable to oil and gas drilling costs, would put the bus bar cost of HDR at only 3.3 cents per kWh while still including the substantial financial risk premium implied by a 10.4% real interest rate. This cost is in good agreement with the cost estimated in Ref. 26 for coal and nuclear plants in 1981. If, however, remaining skeptics insist that the total EE-2/EE-3 costs be used for all future wells, the bus bar cost would increase only by 8%, to 4.8 cents per kWh, with real interest rates still twice the normal electric utility levels.

HDR costs were also based in part upon reservoir heat extraction characteristics measured in Phase I experiments at Fenton Hill, New Mexico. On the one hand they are conservative in that it was assumed that future fractures are limited to a diameter no greater than 360 m, merely 20% greater than the one demonstrated in the Phase I reservoir; that only about one-third of the total heat of the reservoir volume would be extracted; and that the beneficial effects of thermal stress cracking were negligible. Furthermore it was assumed that even when this small fraction, one-third of the heat potentially available from a rock volume was extracted, the wells would be completely abandoned -- the possibility of mining heat from adjacent regions of rock by either deepening the wells or sidetracking was ignored. On the other hand the economic calculations assumed that the reservoir will be developed in the manner intended for the Phase II reservoir. Each building-block reservoir must have 16 fractures with the requisite heat-transfer area and flow capacity. This is clearly a formidable task, and represents one of the three most important technical tasks to be accomplished in the coming years. The other two tasks are conclusive demonstration of thermal stress cracking in large reservoirs, and significant reductions in drilling costs.

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