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PRELIMINARY RESERVOIR DESIGN AND SCREENING FOR A COMMERCIAL HOT DRY ROCK GEOTHERMAL PROSPECT

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ABSTRACT

A preliminary commercial reservoir design was completed for a promising hot dry rock (HDR) prospect in central Utah. The conceptual design included well-trajectory plans, well designs, and a novel completions approach for creating the multilevel subsurface reservoir.

Modeling results obtained early in the study emphasized the economic importance of creating a large heat-transfer area per well pair and maximizing the target temperature consistent with technical constraints. The investigation adhered to the following ground rules concerning technology: (1) Currently available geological, geophysical, and reservoir-production data were used; no additional geotechnical field work was performed, and (2) Current technology or reasonable extensions were used for well and reservoir designs. These ground rules limited the technology base to the current state of the art so that commercial development can proceed if the project economics are favorable and the technical risks are acceptable. In addition, use of these ground rules emphasized some important technology gaps for which additional HDR data are needed before expected project performance and economics can be adequately evaluated.

INTRODUCTION

The Roosevelt Hot Springs, Utah was evaluated as the potential location of a 50 MWe HDR power-generating facility. Using the current HDR concept of creating a fracture network in hot, impermeable rock through which water is circulated to heat mine the rock, the design goal for the heat-transfer reservoir was to provide a 30-year output of 50 MWe salable power (ie., power delivered to the transmission grid). The additional power required to sustain flow through the subsurface system was taken into account in all calculations. This work was part of the scope of a venture risks investigation that is discussed in detail by Cochrane, et al. (this volume).

Because of the high cost of well drilling and reservoir completion, it was imperative to economically optimize the reservoir and power plant combination to define a technically feasible, commercially competitive design. In central Utah, HDR must be competitive with the cost of new coal-fired power. Consistent with this objective, the subsurface system design involved the following steps in an iterative fashion to screen for an economically viable facility:

- Reservoir thermal performance modeling was used to identify the ranges of reasonably anticipated thermal drawdown.

- Cost estimates for well drilling and completion were developed.

- Thermal-performance modeling results, which included the effects of reservoir depletion, water loss, and the pumping power needed to sustain flow through the subsurface system, were combined with the expected power plant perform-ance to produce an estimate of salable power output as a function of time.

- For each case considered, a well/reservoir cost estimate, the corresponding projection of salable power output, and appropriate estimates for power plant costs were merged to estimate the levelized cost of electricity.

- Minimum levelized cost of electricity was used to define an optimum reservoir/power plant combination. To be economically viable, the levelized energy cost from HDR must be competitive with energy from more conventional generating sources, such as coal-fired plants.

RESERVOIR HEAT EXTRACTION MODELING

Several existing models that describe the extraction of heat by the flow of water through fractures in hot granitic rock were considered. The model selected for use is the multiple, parallel fractures model developed by Gringarten, Witherspoon, and Ohnishi (1975). The semi-analytic formulation of the Gringarten model minimizes computing costs thus permitting a large number of parametric-sensitivity studies to be evaluated. In addition, data input requirements are compatible with reasonable extrapolations of available information. Finally, the geometry of flow through multiple fractures used in the Gringarten model agrees favorably with the expected reservoir fracture pattern. The Gringarten model is flexible enough to allow the effects of alternative designs and reservoir performance assumptions to be evaluated by examining upper and lower limits of expected thermal behavior. Numerical formulations, such as a buoyancy-drive model (McFarland 1975) and a jointed-fracture model (Murphy, et al., 1980), were not justified for screening purposes considering the uncertainties in the subsurface and the greater computational costs. The model of heat extraction by flow through intensely fractured media (Wunder and Murphy 1978) was modified for use in examining the potential contribution of extreme thermal stress cracking in the narrow zone immediately surrounding the hydraulic fractures. The base case thermal performance was checked against a time-dependent numerical model and showed good agreement (Ferguson and Tester, personal communication).

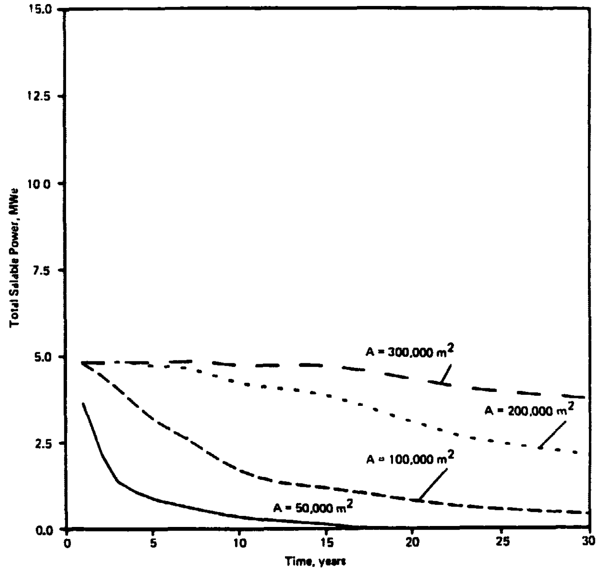
The Gringarten model assumes that the hydraulically created fractures are parallel, equidistant, of uniform aperture, and of equal surface area. The reservoir rock mass is assumed to have constant thermal conductivity and a constant product of density and heat capacity. Initial temperature in the rock mass is treated as an average, uniform midfield value calculated from the thermal gradient. Flow of water in the fractures is assumed to be laminar and constant. Heat transfer in the rock is treated as conduction normal to the fracture surfaces. Large rectangular fractures were assumed with uniform one-dimensional flow across the fracture faces as an idealized but convenient method for quantitatively introducing finite thermal drawdown into the model.

Table 1 summarizes the general model assumptions and the ranges of assumptions that were made regarding site-specific and design-specific conditions.

Figure 1 shows the strong dependence of salable power on fracture area, and it illustrates the desirability of maximizing the effective fracture area per well pair.

CONCEPTUAL WELL-PAIR DESIGN

The conceptual injection/production well pair is shown in Figure 2, and the economically optimized well pair depletion rate is shown in Figure 3. Based on this performance, four initial injection/production well pairs are needed to supply 50 MWe salable output. These initial well pairs will be supplemented by eight additional well pairs as needed to maintain 50 MWe output for 30 years. Each well pair consists of an



Model conditions: 1 well pair
8 parallel fractures at 50 m (164 ft) spacing
Fractures inclined at 30° to vertical
300°C (572°F) bottomhole temperature
6 l/s (95 gpm, 2.3 bpm) flow rate per fracture
No restimulation, no fracture growth
Areas are the average per fracture

Figure 1: Effect of Fracture Area on Salable Power Output

Table 1: Site-Specific and Design-Specific Model Input Information

DESCRIPTION	VALUE	JUSTIFICATION
Rock characteristics:		
Thermal gradient	55°C/km (0.03°F/ft)	Temperature logs of Wells 9-1 and 1-26 measured in conductive basement rock
Maximum bottomhole temp.	300°C, 250°C (572°F, 482°F)	
Rock thermal conductivity	6.2x10E-3 cal/cm-s-°C (1.5 Btu/ft-hr-°F)	Published values for granitic rocks (Clark, 1966)
Rock density	2.65 g/cc (165 lb/cu ft)	
Rock specific heat	0.25 cal/g-°C (0.25 Btu/lb-ft)	
Wells:		
Maximum deviation angle	20°-25°	Based on Fenton Hill and Rosemanowes
Injection wellbore cased ID	7 in	Injector well cased to lower risk of multilevel hydraulic frac installation
Production wellbore, uncased	8.5 in	
Fractures:		
Aperture	1mm (0.04 in)	Fenton Hill and Rosemanowes models
Heat transfer area per frac	50,000-300,000 sq m (0.54-3.2x10E6 sq ft)	GDK frac design and Fenton Hill and Rosemanowes data
Packer spacing	25-100 m (80-330 ft)	Fracture pressure control, site-specific joint spacing
Average frac inclination	vertical, 30°	Fenton Hill and Rosemanowes data
No. fracs per well pair	3-32	Well depth, site-specific geology
Reservoir thermal growth	0, 2X	Fenton Hill and Rosemanowes data
System Operation:		
Water loss per cycle	10%	Fenton Hill and Rosemanowes data
Power plant return temperature	115°C,66°C (239°F,151°F)	Double-flash and binary plants
Make-up water temperature	15°C (59°F)	Assumed aquifer temperature
Flow rate per fracture	2-30 l/s (32-475 gpm, 1,080-16,270 bpd)	Fenton Hill and Rosemanowes data

injector well, a producer well, and a multilevel, hydraulically fractured network that connects the two wells. While it is anticipated that higher ratios of producer:injector wells will substantially improve the project economics, these reservoir development schemes have not yet been tried in an HDR application.

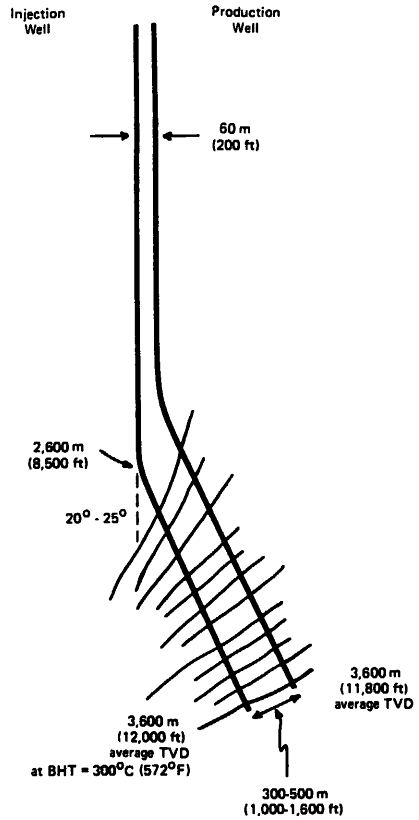


Figure 2: Depth and Spacing of Injection-Production Well Pair

Results obtained early in the study emphasized the economic importance of creating large heat transfer area (fracture surface) per well pair and maximizing the target temperature consistent with technical constraints and cost considerations. This led to a novel concept for installing multiple, discretely created fractures illustrated in Figure 2 using the following sequence at Roosevelt Hot Springs:

- Drill an injection well to the depth corresponding to the target temperature of 300°C. Deviate the bore 20 to 25 degrees below 2,590 m (8,500 ft).
- Case to the bottom of the injection well.
- Extend the depth of the injection well by 20 to 60 m (66 to 200 ft).
- Run 7 in. tubing from the surface to the top of the 7 in. liner that cases the deviated portion. Hydraulically fracture the open-hole interval. The water used for hydraulic fracturing cools the wellbore for subsequent logging and perforating. During the hydraulic fracturing operation, use microseismic monitors to map the subsurface fractures.
- Allow the wellhead pressure to decay to 3,000 psi (20 MPa). Do not flow back the fracture fluid.
- Set a cast iron, casing cement retainer ring as a casing packer near the bottom of the 7 in. liner.
- Perforate 10 to 25 m (30 to 80 ft) of the wellbore for the second fracture interval.
- Hydraulically fracture the second interval while using microseismic monitors to map the fractures.
- Repeat the four steps above, setting the packers at approximately 75-m (250-ft) spacings, until 12 fracture intervals have been created in the injection well.
- Drill a production well approximately parallel to the injection well targeting the fracture zones with the deviated portion 250 to 500 m (820 to 1,640 ft) above the deviated section of the injection well.

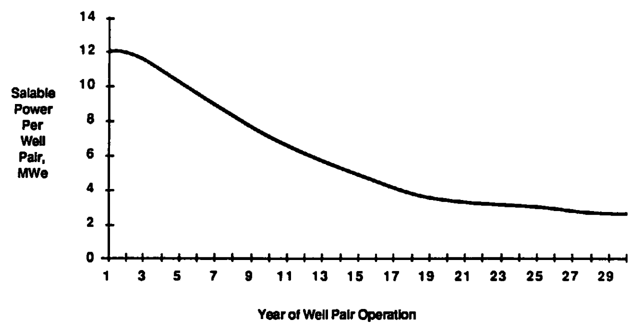


Figure 3: Optimized Well-Pair Depletion Rate

Although this is an aggressive hydraulic fracturing program, present-day equipment and techniques are used throughout. Installing a continuous, strong cement bond between the casing and formation is a key requirement. The casing throughout the fracture length is designed to withstand fracturing pressures from both the inside and the outside. Major advantages of this approach compared to that used at Fenton Hill and Rosemanowes are:

- Damage to the wellbore from thermal cycling is minimized by using a single episode of wellbore cooling.
- More reliable casing packers (retainer rings) are used instead of open-hole packers.
- Hydraulic horsepower and surface safety hazard are minimized by low friction loss through relatively large-diameter fracture tubing.
- Time-consuming flow back of the fracture fluid is not required.

- The production well is targeted through the fractured zones using the microseismically defined fracture locations.

Maximizing the amount of heat transfer area exposed by each fracture is crucial to HDR well productivity and longevity. Based on preliminary information from the Los Alamos Fenton Hill project and the Camborne School of Mines Rosemanowes project (Armstead and Tester, 1987; Tester, et al., 1986; Dash, et al., 1986), the following estimates of the initial heat transfer area and growth after the onset of production appear reasonable and conservative:

- 100,000 m^2 (1,080,000 ft^2) effective heat transfer area per fracture interval initially
- Doubling of the effective heat transfer area within the first year of plant operation.

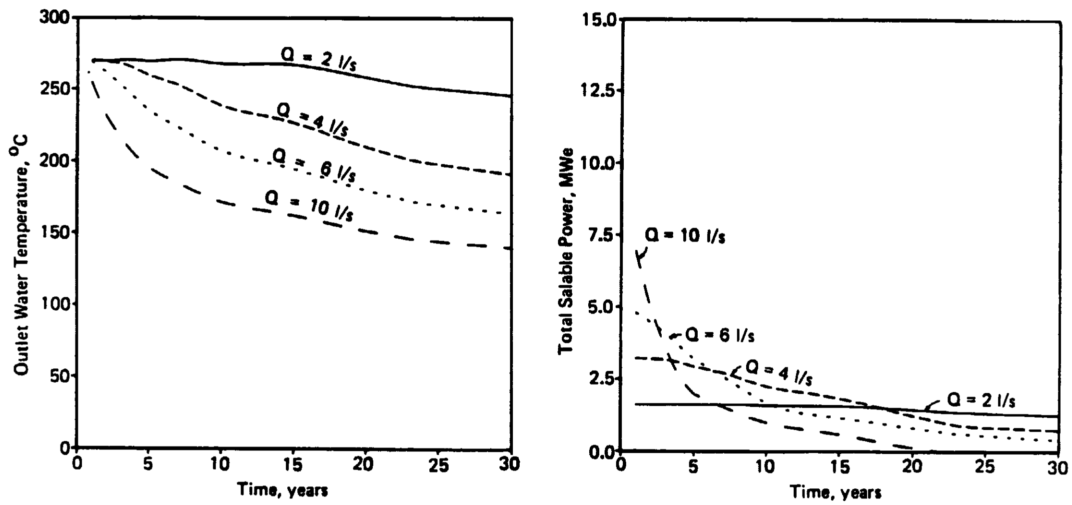
Because multiple fractures in one fracture interval were observed at both Fenton Hill and Rosemanowes, effective heat transfer areas significantly larger than 100,000 m^2 (1,080,000 ft^2) with greater productivity may be feasible with suitable fracture-fluid volumes, fluid delivery rates, sufficiently high fracture-propagation pressures, and proper targeting of the production well. However, it is emphasized that the maximum feasible size of the effective heat transfer area that can be accessed in each fracture interval has not been demonstrated. Because the initial size of the heat transfer area and the rate and magnitude of fracture growth after beginning operation are crucial to reservoir performance and project economics, they must be satisfactorily demonstrated by long-term flow tests before a commercial facility can be committed.

The proposed approach for coping with well-pair depletion is the addition of new well pairs throughout the life of the plant. Restimulation by fracturing additional intervals in existing wells may not be feasible due to lower temperatures in the remaining upper wellbore intervals and aging of downhole components. However, as the size and location of the fractures become better understood and more reliably located, other restimulation methods, such as drilling additional production wells, may be identified as cost-effective ways to maintain production.

Two important site-specific operating characteristics were assumed because data specific to Roosevelt Hot Springs are not available at present: First, the steady-state reservoir leakage was assumed to be 10 percent of the circulation rate; this was experienced during one of the longest test runs at Fenton Hill and approached by the longest test at Rosemanowes. Second, the pressure at the injection wellhead was assumed to be 1,500 psi (10 MPa); this pressure was used for much of the testing at Fenton Hill and Rosemanowes.

ECONOMIC OPTIMIZATION

Low flow rates during plant operation promise excellent thermal drawdown performance with temperatures remaining approximately constant over 30 years, but the power output is low (Figure 4). At low flow rates, a large number of well pairs would be required at considerable cost. Conversely, high flow rates project high initial power output but deplete the reservoir rapidly (Figure 4), indicating that frequent addition of new fractures or new well pairs would be required over the lifetime of the planned facility. The flow rate for the base case well pair was selected by optimizing the economics to yield the lowest levelized



A. Thermal Drawdown

B. Salable Power Outlet

Model conditions: 1 well pair
8 parallel fractures at 50 m (164 ft) spacing
Fractures inclined at 30° to vertical
100,000 m^2 (1.1 x 10^6 ft^2) area per fracture
270°C (518°F) midfield temperature corresponding
to 300°C (572°F) bottomhole temperature

Figure 4: Effect of Flow Rate on Thermal Drawdown

revenue requirements of the power plant/reservoir combination.

The following characteristics were used as the average values for a base case injection/production well pair for the economic analysis:

- 300°C (572°F) target bottomhole temperature
- 12 fracture intervals
- 100,000 m^2 (1,080,000 ft^2) effective heat transfer area per fracture interval
- Doubling of the heat transfer area within the first year of well-pair production
- 10 l/s (160 gpm) production flow rate per fracture interval
- 12 MWe initial salable power per well pair declining to 2 MWe after 30 years
- For 50 MWe of salable power
  - 4 injection/production well pairs initially
  - 8 additional well pairs over 30-year plant life

Table 2 summarizes the estimated costs for an HDR injection/production well pair drilled to 3,660 m (12,000 ft) at Roosevelt Hot Springs. For comparison, average costs for oil and gas wells drilled to 12,000 ft (3,660 m) in Utah are about $1 million and $2 million, respectively, in 1987 dollars.

WELLFIELD LAYOUT

The wellfield design is specific to the geologic setting of the Roosevelt Hot Springs along the western flanks of the Mineral Mountains in the basin-and-range province. In addition to the regional geologic setting, information pertaining to the fault history and subsurface state of stress, three-dimensional variation in thermal gradient, lithology/permeability, drilling characteristics, the potential for induced seismicity, and water availability figured prominently in the well, reservoir, and wellfield designs. The conceptual wellfield layout shown in Figure 5 is consistent with site structural geology, lithology, and the shallowest depths to potentially commercial HDR temperatures.

CONCLUSIONS

The Roosevelt Hot Springs area appears to be well suited for the installation and operation of an HDR power facility with the most promising region lying directly to the west of the Opal Mound horst and south of the Hot Springs fault. The shallowest possible occurrence of commercial HDR temperatures is in the eastern portionof this region.

Although a wealth of surface and near-surface data were available for this study, major issues that are important to technical risk mitigation and cost estimates remain unanswered. These concern the following rock properties in the deep subsurface HDR target zone:

- Persistence of faults at HDR reservoir depth
- Orientations of faults at depth

Table 2: Average Cost Per HDR Injection-Production Well Pair

SUMMARY OF COSTS FOR DRILLING AND COMPLETING ONE WELL PAIR
12 Fracture Intervals
($1987)

Fracture Fluid/Interval	2 Million Gallons			3 Million Gallons		
Pumping Rate	40 bpm	60 bpm	80 bpm	40 bpm	60 bpm	80 bpm
Pumping Services	1,474,000	1,544,000	1,744,000	2,096,000	2,216,000	2,517,000
Wireline Services	184,000	170,000	176,000	194,000	180,000	184,000
Subtotal	1,658,000	1,714,000	1,920,000	2,290,000	2,396,000	2,701,000
15% Contingency	249,000	257,000	288,000	344,000	359,000	405,000
Subtotal	1,907,000	1,971,000	2,208,000	2,634,000	2,755,000	3,106,000
Drilling and Casing (Two wells)	6,718,000	6,718,000	6,718,000	6,718,000	6,718,000	6,718,000
Microseismic Mapping	119,000	119,000	119,000	119,000	119,000	119,000
Subtotal	8,744,000	8,808,000	9,045,000	9,471,000	9,592,000	9,943,000
Management Fee	437,000	440,000	452,000	474,000	480,000	497,000
Total	9,181,000	9,248,000	9,497,000	9,945,000	10,072,000	10,440,000

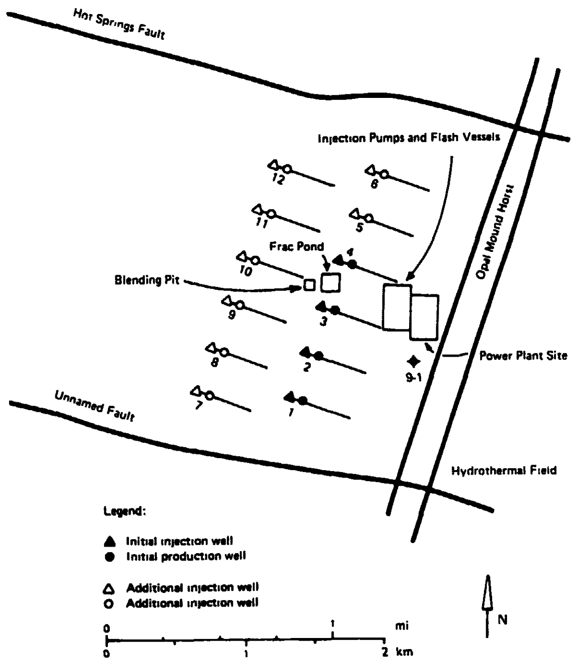


Figure 5: Conceptual Wellfield Layout

- Orientation of the principal stresses at depth
- Magnitude of closure stress that must be exceeded to stimulate hydraulic fracture growth
- Spacing and orientation of deep subsurface joint sets that may affect hydraulic fracture orientations, hydraulic fracture size, and the rate of water loss
- Temperatures at depths near 12,000 ft
- Confirmation that pressures needed to drive fluid circulation are low enough to control water loss and pumping costs

To examine the economic consequences of technical risks, potential cost impacts were investigated for the prominent performance characteristics that cannot be confidently predicted with the HDR data that are currently available. Figure 6 summarizes the cost sensitivity to performance estimates. For these analyses, variations were selected arbitrarily to test sensitivity; they are not estimates of uncertainty. Well-pair initial productivity and long-term thermal drawdown at commercial flow rates have pronounced effects on project economics. HDR testing that develops solid data for evaluating productivity and depletion rate is imperative before a commercial project can be initiated.

Multiplying Factors for Technical Risk Analysis

	Base Case	Better Performance	Poorer Performance
Productivity	1	2	1/2
Depletion Rate	1	1/2	2
Reservoir Leakage	1	1/2	2
Injection Pressure	1	2/3	4/3

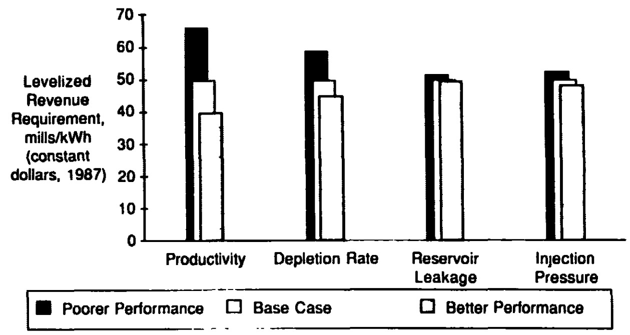


Figure 6: Required-Revenue Sensitivity to Technical Risks

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