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Prospects for Universal Geothermal Energy from Heat Mining

J.W. Tester, H.J. Herzog, Z. Chen, R.M. Potter, and M.G. Frank

The extraction of heat or thermal energy from the Earth—heat mining—has the potential to play a major role as an energy supply technology for the 21st century. However, even if reservoir productivity goals are achieved, the role of heat mining with today's energy prices and development costs is limited to only a small fraction of the Earth's surface. A generalized multi-parameter economic model was developed for optimizing the design and performance of hot dry rock (HDR) geothermal systems. Key technical and institutional obstacles to universal heat mining are discussed in a more general context. Advanced concepts in drilling technology are reviewed in light of their potential impact on overcoming some of these obstacles to universal heat mining

FUNDAMENTAL REQUIREMENTS AND TRADEOFFS

Hot dry rock (HDR) geothermal energy or, more generally, heat mining is envisioned by some as an environmentally sustainable primary energy supply that could reduce our dependence on fossil and fissile fuels in the 21st century. In principle, thermal energy is extracted from accessible regions of hot rock using extended oil and gas drilling and stimulation technology to create reservoirs that in many ways emulate natural hydrothermal systems. At depths where sufficient temperature can be found (greater than three kilometers typically), the porosity and permeability of rocks are frequently too low to permit the storage and circulation of natural fluids. For such systems, a first step in heat mining is to create artificial permeability using hydraulic stimulation techniques to propagate and open joints or fractures. The resulting fracture network is connected to a set of injection and production wells where heat is removed by circulating water under pressure from the surface, down one well, through the fractured zone, and up a second well. Electricity and/or process

All authors are with the Energy Laboratory, Massachusetts Institute of Technology, Cambridge, Massachusetts.

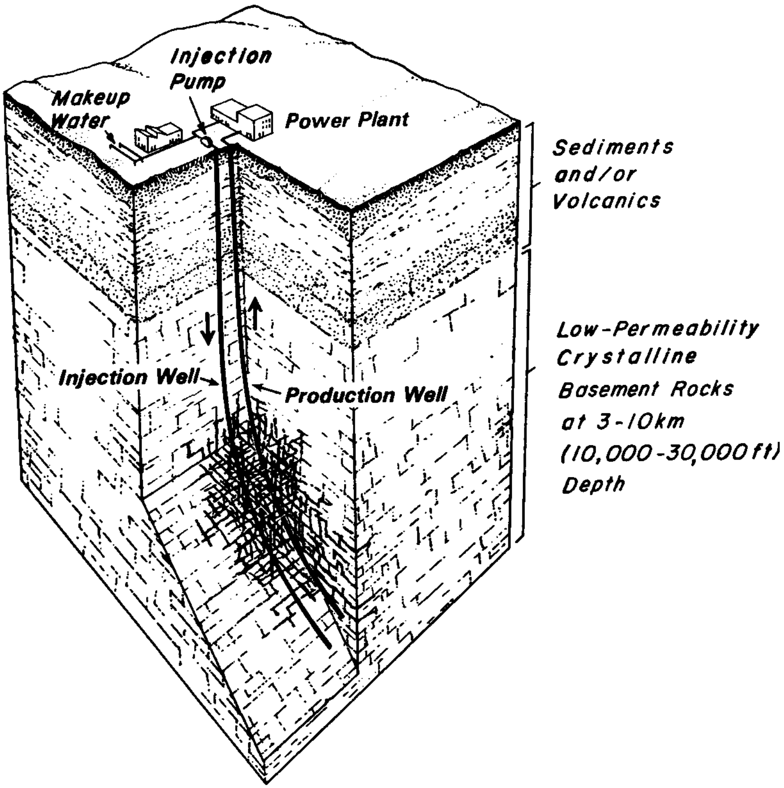


Figure 1: HDR reservoir concept (doublet system) for an interconnected network of fractures stimulated in a low-permeability formation (from Tester *et al.*, 1989).

steam could then be generated using the heated water in an appropriately designed power plant. This heat mining concept (see figure 1) is closed-loop so there are no emissions. This limits the environmental impact of the HDR "fuel cycle" to site preparation, well drilling, and other modest land use requirements. Consequently, heat mining would not contribute to local or regional air or water pollution, global-scale problems of greenhouse gas build-up, or air or water quality-related health concerns (Tester *et al.*, 1989). Even with these positive attributes, HDR has been categorized as a very long-term alternative, one that has been portrayed like other renewables as a "Cinderella Option" (see Grubb, 1990).

Many potential private developers of HDR regard its current state of development too immature. Major energy markets are currently driven by low oil and gas prices and the perception that new energy technology is inherently risky. Consequently, private investment in alternative energy systems in general and in heat mining specifically has been very small. Although some concerns about the risks of achieving successful heat mining are certainly understandable, they seem disproportionate relative to other new technologies. Much of the required technology has either already been demonstrated for HDR specifically in government-supported R&D programs or represents an extension of existing state-of-the-art techniques used for hydrocarbon or hydrothermal fluid extraction. Heat mining systems, like hydroelectric power plants, require a large, up-front capital investment that includes both the power conversion equipment and the "fuel" supply system. This should partially reduce the risk for HDR over fossil-fired plants that face potentially unstable fuel prices.

National and international R&D programs have focused heavily on engineering fractured systems in hot rock with low natural permeability (Batchelor, 1984a,b, 1987; Brown et al., 1991; and Armstead and Tester, 1987). In the last 10 years, however, most of these programs have suffered from underfunding in the face of plentiful and cheap oil and gas worldwide. With such subcritical support, technical milestones have not been fully realized and a few important development requirements still remain.

Over the past 20 years, studies of HDR technology and economics have assumed a certain set of reservoir performance levels and development costs for drilling, stimulation and power plant construction. Tester and Herzog (1990, 1991) reviewed seven HDR studies to evaluate these assumptions and provide revised economic predictions for heat mining. The studies reviewed were from Bechtel (1988); Cummings and Morris (1979); Murphy et al. (1982); Smolka and Kappelmeyer (1990); Shock (1986); Entingh (1987); and Hori et al. (1986). Later studies of HDR economics include those by RTZ consultants (1991) and Pierce and Livesay (1993). Recently, the U.S. Geological Survey (1993) published a report on the potential of HDR in the Eastern U.S.

Milora and Tester (1976) and Armstead and Tester (1987) introduced general economic modeling approaches for HDR systems to show the effect of resource grade, reservoir productivity, and reservoir depth or temperature. Earlier studies did not tackle the non-linear, multi-parameter optimization problem of simultaneously selecting well depth, reservoir structure (e.g., number and spacing of fractures), geofluid flow rate and redrilling management strategies. These design and operating choices are somewhat unique to heat mining systems. Figure 2 shows the tradeoffs between drilling/reservoir development and power plant costs that yield an optimal drilling depth (or initial rock temperature) for a specified HDR resource defined by its average geothermal gradient, ambient heat rejection conditions, and reservoir flow impedance. While power plant costs tend to decrease monotonically with temperature, well drilling costs tend to increase exponentially with initial

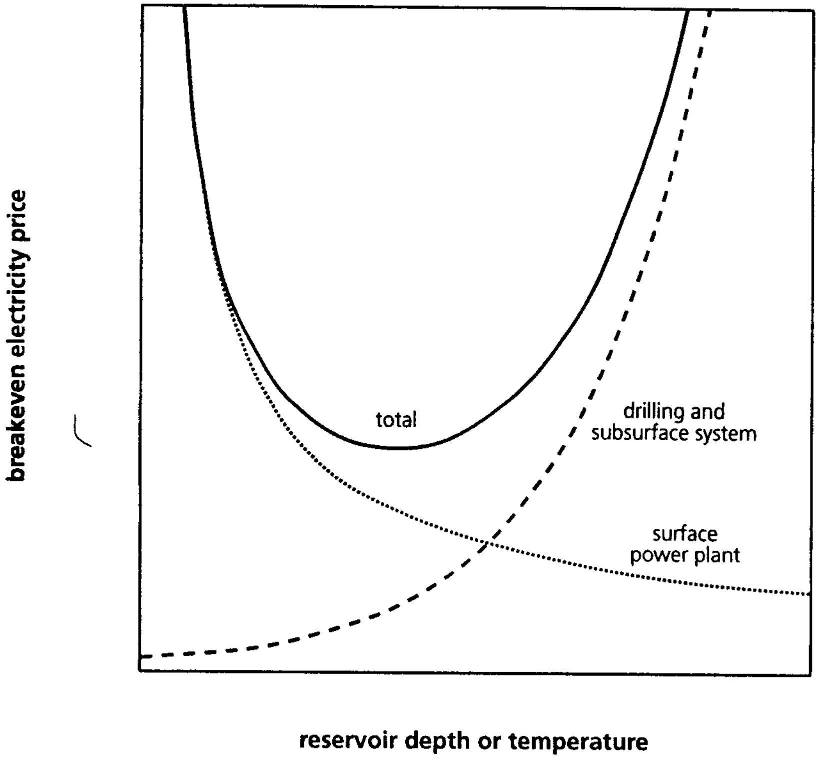


Figure 2: Conceptual tradeoffs in terms of breakeven electricity price between power plant and drilling-related costs as a function of depth or initial reservoir temperature for a fixed geothermal temperature gradient.

rock temperature (i.e., depth).

In real reservoirs with finite thermal lifetimes, temperature decline or drawdown will occur at different rates depending on the mass flow rate per unit of rock surface area or volume exposed to the circulating fluid. An optimal strategy to produce minimum costs requires a balanced state of utilization. The instantaneous power produced, $P(t)$, will scale as the product of the mass flow rate ($\dot{m}$) and the practical availability of the geofluid ($\eta_u \Delta B$) where η_u is the utilization efficiency of the power cycle and ΔB is the thermodynamic exergy or availability, that is the maximum power production potential (see Milora and Tester, 1976, and Tester, 1982, for details). Both η_u and ΔB are strong functions of the geofluid temperature, T, such that the instantaneous power per unit of effective reservoir size (<A>) is given by:

$$\frac{P(t)}{<A>} = \frac{\dot{m}(t)\,\eta_u(T)\,\Delta B(T)}{<A>}$$

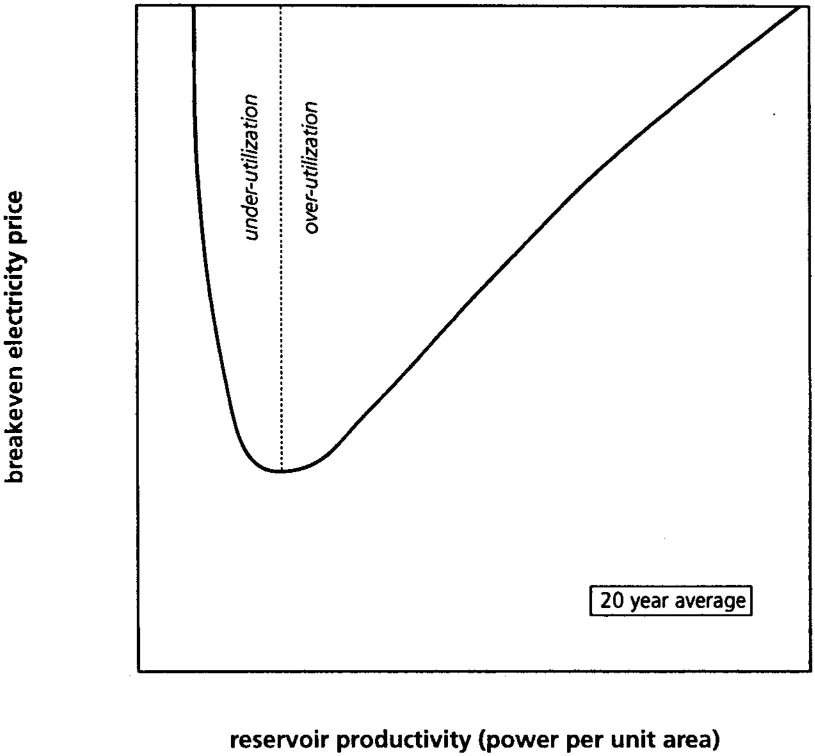


Figure 3: Qualitative relationship for a specified heat mining resource (known gradient, reservoir area and impedance, depth, initial temperature, etc.) between breakeven electricity price and reservoir production flow rate $\dot{m}$.

where $\Delta B \equiv \Delta H - T_o \Delta S$ over the interval from T to T_o; T_o = lowest heat rejection temperature; and ΔH and ΔS represent the change in specific enthalpy and entropy of pure geofluid from T to T_o, respectively.

The magnitude of $P(t)/<A>$ is a measure of reservoir quality in terms of its productivity. Thermal drawdown rates scale directly with $\dot{m}(t)/<A>$, while electric power production potential varies with $\eta_u(T)\Delta B(T)$. As $\dot{m}(t)$ is increased for a fixed reservoir size ($<A>$), T decreases faster and, since both $\eta_u(T)$ and $\Delta B(T)$ decrease rapidly as T declines, the overall productivity of the reservoir decreases and the resource is over-utilized as shown qualitatively in figure 3. As $\dot{m}(t)$is decreased below its optimal value, the temperature drawdown rate is reduced, but so is the productivity $P(t)/<A>$. This condition corresponds to an under-utilization of the reservoir.

ECONOMIC ASSESSMENT MODEL DEVELOPMENT

A generalized multi-parameter economic model was developed for optimizing the design and performance of geothermal heat mining systems. This was accomplished by enhancing the Massachusetts Institute of Technology Energy Laboratory's existing HDR economic model (see Tester and Herzog, 1990, 1991). The major modifications included:

- reformulating our simple HDR reservoir representation by introducing a multiple-parallel-fracture conceptual reservoir with a well deviation parameter;
- adapting the model to an optimization environment and interfacing this revised HDR system model to an SQP (Successive Quadratic Programming) optimization package;
- interfacing a levelized life-cycle cost (LLC) algorithm to the model;
- and updating costs to the most recent year for which cost data are available, in this case 1991.

As before, electricity production is calculated based on the geofluid (the term "geofluid" refers to the circulation of water under steady-state conditions where dissolved minerals are present) flow rate and temperature using a utilization efficiency correlation. The electrical production is then corrected to account for the parasetic pumping requirement caused by system pressure drops minus the buoyancy-driven pressure gain. The model can calculate the electricity breakeven price through a fixed charge rate or LLC approach. The LLC code, consistent with methodology used by the Electric Power Research Institute and developed by Los Alamos National Laboratory (Hardie, 1981), has been fully integrated into the revised HDR model. Results presented in this paper all use the LLC approach and are given in 1991 dollars. For simplicity, throughout the remainder of this paper we refer to this model as the HDR optimization model.

A proper understanding of the reservoir temperature drawdown rates is required to predict the geofluid temperature as a function of time. HDR reservoirs are made up of a complex network of interconnecting fractures that may result from the activation of a set of natural joints or weaker zones in the formation. To make the modeling effort more tractable, an idealized set of single or parallel fractures is assumed (see figure 4). This conceptual model was first

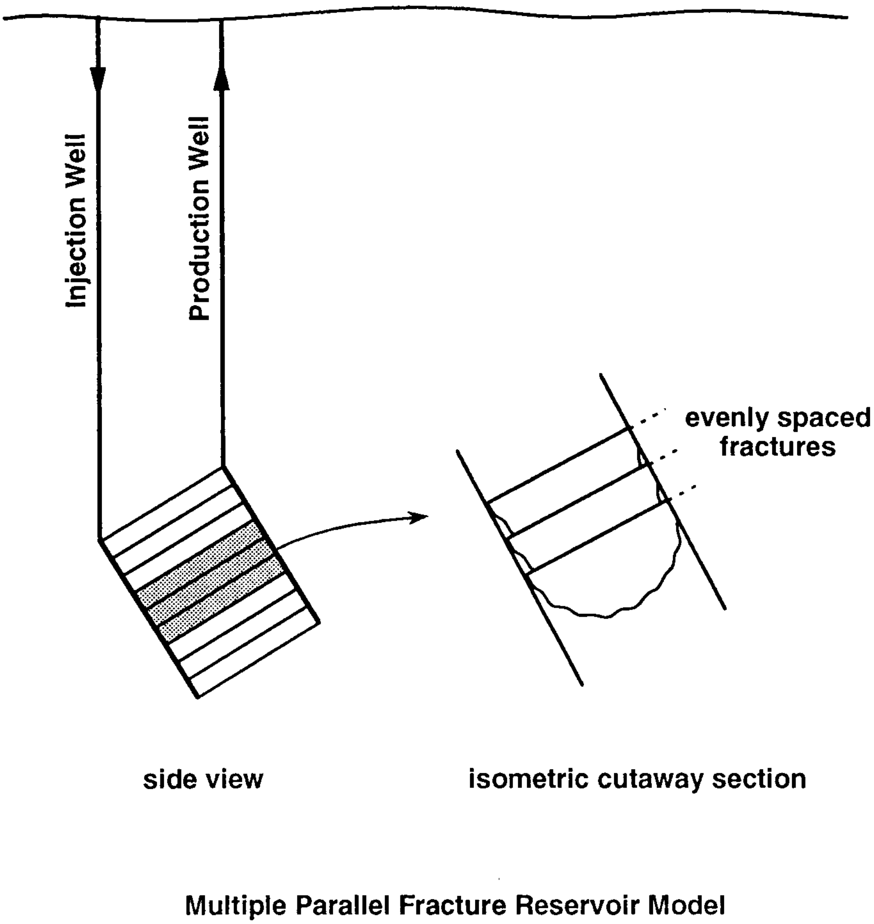


Figure 4: Schematic of the HDR reservoir conceptual model used for the base case of the HDR optimization model. (Multiple parallel fracture reservoir model)

to define the reservoir have exact physical meaning. As geofluid flows through these fractures, it extracts heat from the surrounding rock. The performance of the reservoir depends on the fracture pattern geometry and spacing and impedance, which affects the pressure drop through the reservoir and therefore may limit the geofluid flow rate. We also account for temperature changes as a function of depth along the length of the wells.

The model HDR system is composed of an injection and a production well which are drilled vertically to a certain depth and then deviate in paralle, linked by a finite number of equispaced fractures of uniform thickness, separated by blocks of homogeneous impermeable rock. These fractures are all linked by a finite number of equispaced fractures of uniform thickness, separated by blocks of homogeneous impermeable rock. These fractures are all assumed perpendicular to the injection and production wells. No heat flux is assumed across the reservoir boundary. Heat transfer in the rock mass is assumed normal to the fracture surfaces. Potential expansion due to thermal stress is ignored. Water is injected at the surface, passes through the fractures with evenly distributed flow, up the production well and eventually to the power plant. Five parameters are used to define the geometry of the reservoir: well depth, well deviation, effective area of an individual fracture, number of fractures, and fracture separation. The model predicts the well length, total effective heat transfer area, average reservoir depth and average initial rock temperature. The drawdown behavior of the reservoir is predicted with a differential equation set that couples one-dimensional rock conduction to one-dimensional convection flow in planar fractures of uniform aperture.

The HDR optimization model is comprised of a non-linear equation system that can be solved explicitly. The manipulated variables are restricted by upper and lower bounds. Some of the model parameters are also subject to linear or non-linear inequalities. For example, the geofluid pressure at the bottom of the reservoir should be less than or equal to the fracturing critical pressure so as to minimize water loss. This mathematical structure requires a constrained, non-linear optimization algorithm that solves small-scale, highly non-linear problems effectively. The objective is to minimize the levelized electricity price. Maximizing power generation, thermal output or geofluid availability can be specified as alternate objectives. In order to accelerate convergence and prevent the optimization from falling into local minima, the control parameters are scaled to a magnitude of unity. Other details concerning the model and sensitivity analysis can be found in an MIT Energy Laboratory report (Herzog et al., 1994).

In this study, the following parameters were designated as manipulated variables to be optimized:

- Drilling Depth. Given a geothermal gradient, optimal drilling depth is determined by balancing increased drilling costs (with depth) with the increased effectiveness in electric power production due to higher geofluid temperatures.

- Number of Fractures. With well separation and fracture spacing specified, the number of fractures is the parameter that determines the reservoir volume. Larger reservoir volumes result in lower temperature drawdown rates, but higher capital costs and somewhat lower initial geofluid temperatures. For computational convenience, the number of fractures was

Table 1: Parameter values for the base case.

Parameter	Value
Maximum geofluid temperature	330°C
Average surface temperature	15°C
Ambient heat rejection temperature	25°C
Temperature drop in production well	15°C
Impedance per fracture	2.57 GPa-s m^{-3}
Geofluid loss/total geofluid injected	5%
Rock density	2700 kg m^{-3}
Rock thermal conductivity	3.0 W $(m\text{-}K)^{-1}$
Rock heat capacity	1,050 J $(kg\text{-}K)^{-1}$
Well deviation from vertical	30°
Effective heat transfer area per fracture	100,000 m^2
Fracture separation distance (horizontal)	60 meters
Injection temperature	55°C
Geofluid circulation pump efficiency	80%
Plant life	20 years

treated as a continuous control parameter, although only whole numbers make practical sense.

- Geofluid Flow Rate. Larger geofluid flow rates increase the initial power generation while accelerating temperature drawdown.

Simulations were run using a range of average geothermal gradients varying from 20 to 100°C km^{-1}. Other parameters defining the base case are given in table 1. Using an approach described by Tester and Herzog (1991) and today's relatively high drilling and completion costs, a three-dimensional plot of breakeven electricity price against geofluid flow rate and the number of fractures is presented in figure 5 for the base case at a geothermal gradient of 50°C km^{-1}. Note the valley on the levelized electricity price surface from low

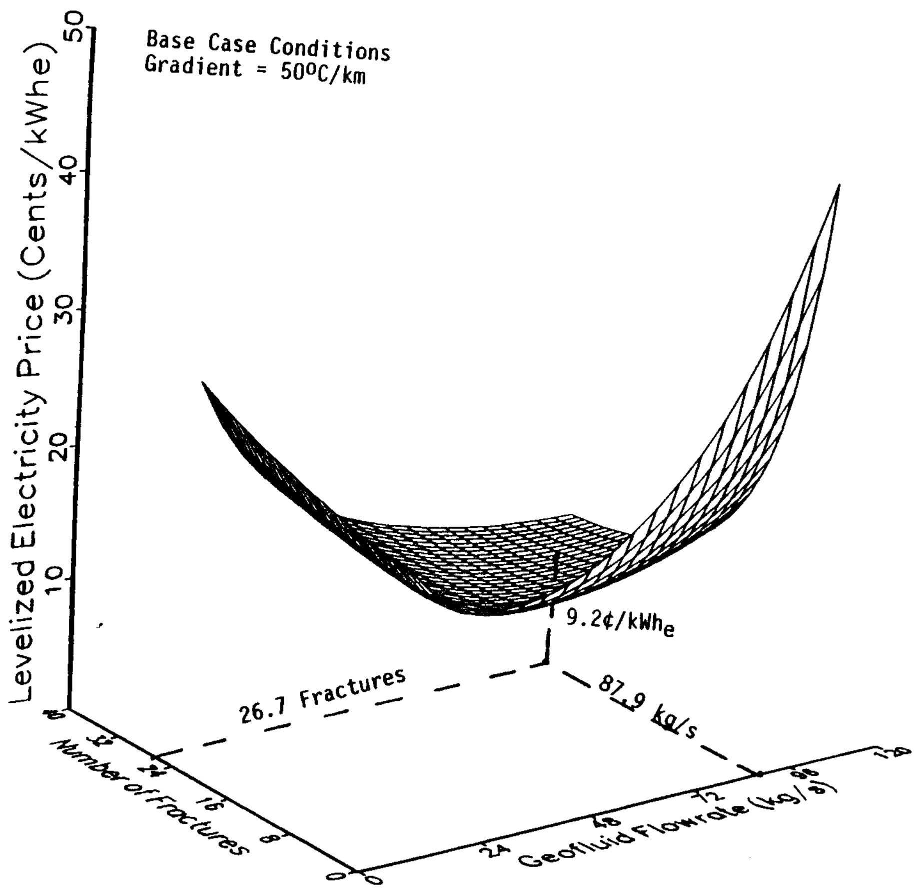


Figure 5: HDR Optimization model results for the base case and a geothermal gradient of 50°C km^{-1}. A plot of breakeven electricity prices are shown versus number of fractures and geofluid flow rate, with the optimal point indicated.

can be also seen that in a fairly large region the breakeven price surface is quite flat. The optimum occurs at a geofluid flow rate of 87.9 kg sec^{-1} and 26.7 fractures with a breakeven electricity price of 9.2¢ kWh$_e$$^{-1}$. The total temperature drawdown over the 20-year plant life is about 17.6 percent, that is $[T(t = 0 \text{ years}) - T(t = 20 \text{ years})] / [T(t = 0 \text{ years}) - T_o] = 0.176$, where $T(t)$ is the outlet fluid temperature at time t, and T_o is the ambient heat rejection temperature.

Figure 6 presents the contribution of each major cost component to the estimated breakeven electricity price. As the geothermal gradient decreases, drilling and completion costs comprise a larger share of the overall costs. To emphasize this point, consider a very low grade area (20°C km^{-1}) where a 50

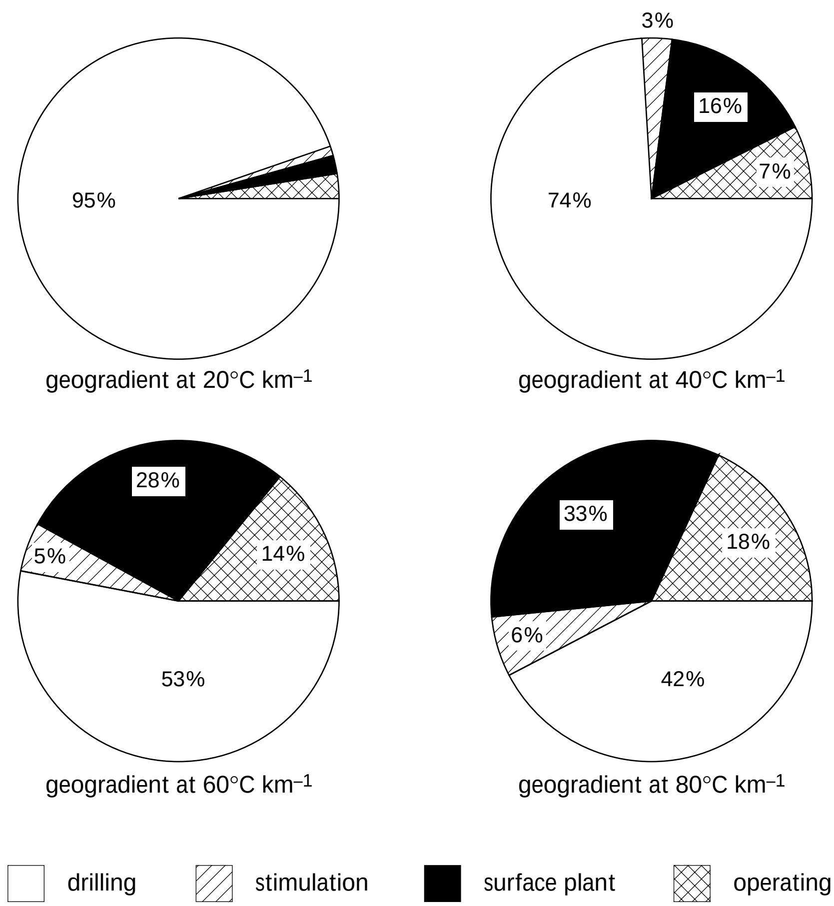


Figure 6: Breakdown of component costs (drilling, stimulation, plant, and operating) for the HDR optimization model base case conditions at a range of geothermal gradients using today's technology and drilling costs.

estimated breakeven electricity price. As the geothermal gradient decreases, drilling and completion costs comprise a larger share of the overall costs. To emphasize this point, consider a very low grade area (20°C km^{-1}) where a 50 MW_e system would require a total initial investment of $5.5 billion, mainly for the wells and reservoir system. As the grade improves, the required investment decreases markedly, for example, an 80°C km^{-1} resource requires $125 million for a 50 MW_e plant. This demonstrates why commercial opportunities for HDR are currently limited to mid- to high-grade (>50°C km^{-1}) areas. It also underscores the importance of reducing drilling costs if HDR is to become an important energy supply technology in the low gradient areas that cover most of the world.

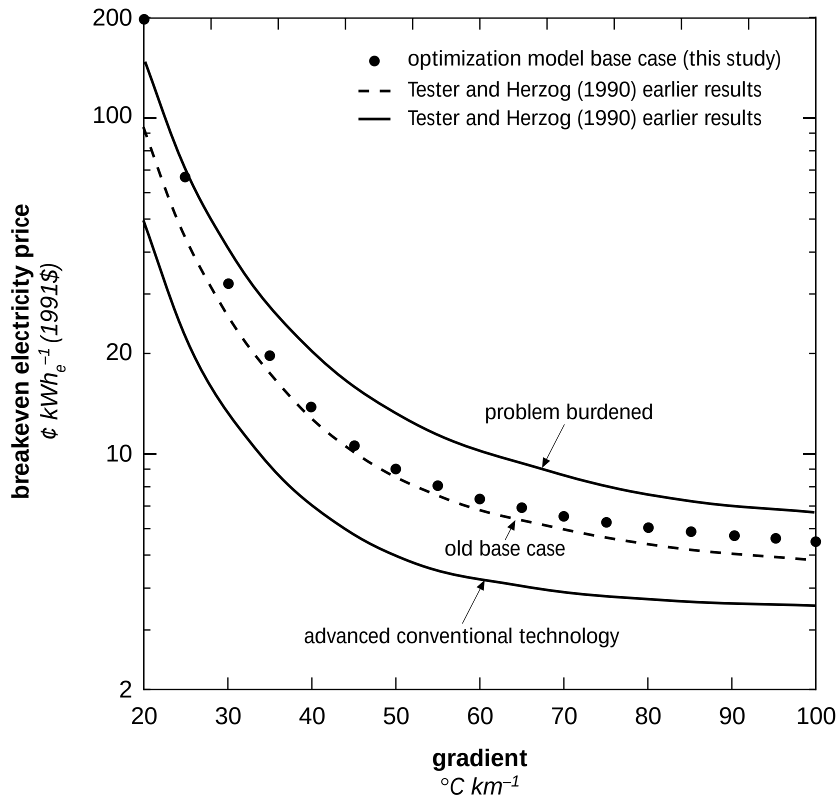


Figure 7: Comparison of HDR optimization model base case results to those reported earlier in Tester and Herzog (1990, 1991).

Figure 7 compares the HDR optimization model base case with the commercial base case from Tester and Herzog (1991). The levelized electricity prices predicted by the HDR optimization model are somewhat higher, partly because in this work redrilling/restimulation is not considered. While the breakeven electricity prices of the two models are comparable, the system designs are very different (see table 2) due to the introduction of the Gringarten et al. (1975) reservoir conceptual model, which leads to a very conservative design.

Figure 8 shows the sensitivities of the three manipulated variables along with three calculated variables. At an average geothermal gradient below 40°C km^{-1}, well depth is determined by balancing drilling and completion costs with geofluid temperature. However, above 40°C km^{-1} the drilling depth is always on the upper bound associated with maximum allowable geofluid temperature. In addition, for geothermal gradients above 40°C km^{-1} and a

Table 2: System design comparison for a single well pair, Old = Tester and Herzog (1991), New = this study.

Average gradient	20°C km^{-1}		40° C km^{-1}		60°C km^{-1}		80°C km^{-1}	
	old	new	old	new	old	new	old	new
Breakeven electricity price ¢ kWh_e^{-1}	85	205	11.9	14.0	6.6	7.6	5.3	6.2
Installed surface plant cost $\$ kW^{-1}$	1,900	1,900	1,000	1,100	1,000	1,000	1,000	1,000
Installed subsurface (wells/reservoir) system cost $\$ kW^{-1}$	31,000	107,000	3,500	5,600	1,300	2,300	800	1,500
Well depth *km*	9.15	9.15	7.13	7.74	4.75	5.25	3.56	3.94
Geofluid flow rate $kg\ s^{-1}$	75	46	75	92	75	81	75	66
Effective area $10^6\ m^2$	1.2	2.04	1.7	2.93	1.6	2.48	1.6	1.94
New power output MW_e	3.5	1.4	14.9	13.7	14.7	11.7	14.5	9.2

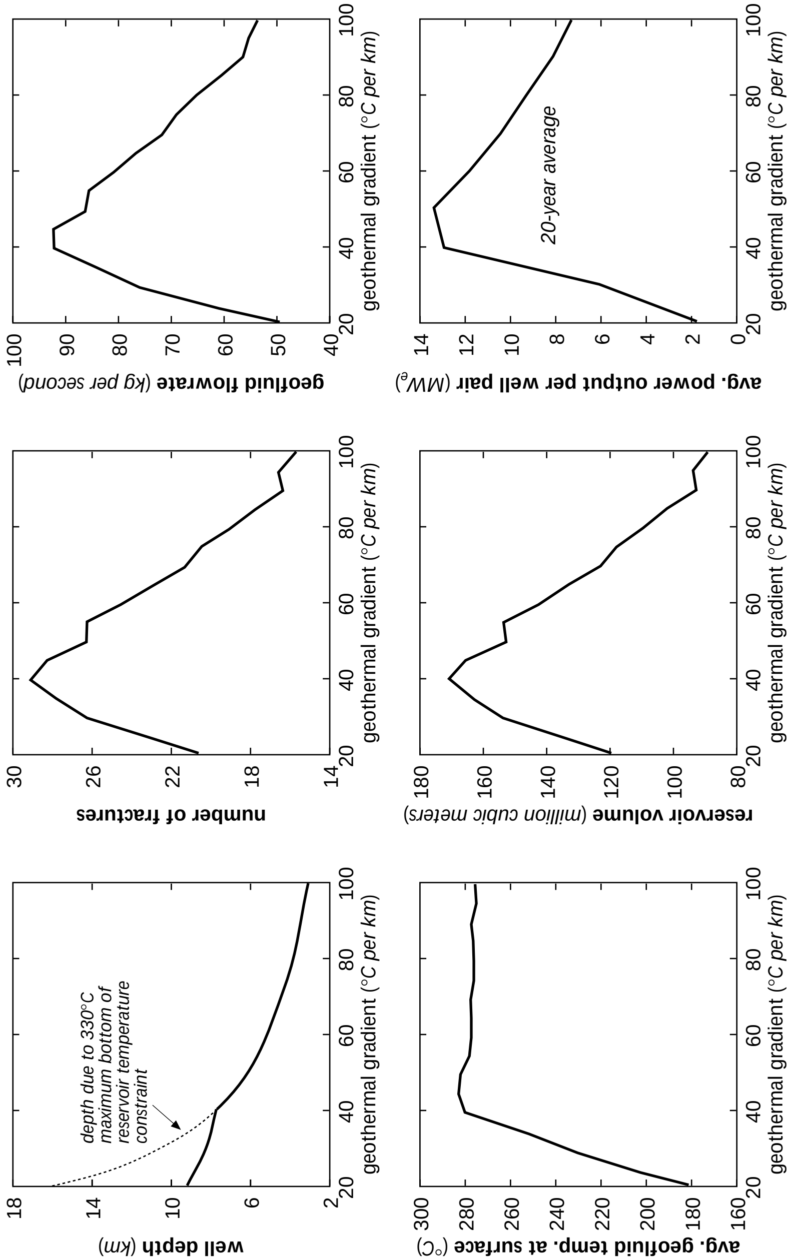


Figure 8: Estimated values for key design parameters as a function of geothermal gradient for the HDR optimization model base case.

specified reservoir geometry, the higher the geothermal gradient is, the greater the temperature drop will be through the reservoir. Thus, there is a clear reason to create smaller reservoirs in higher geothermal gradient areas, and larger reservoirs in lower geothermal gradient areas. Because of this reservoir size differential, the optimal geofluid flow rate for a low geothermal gradient resource will be higher than that for a high geothermal gradient resource. Furthermore, the average electricity production for a single well pair over the plant life of 20 years decreases considerably with increasing geothermal gradient because of the smaller reservoir sizes and lower geofluid flows associated with the higher geothermal gradients.

OBSTACLES TO UNIVERSAL HEAT MINING

The economic model simulation discussed in the previous section obviously contains a certain amount of speculation. For example, we have made a number of assumptions regarding anticipated levels of reservoir productivity that go beyond what has been achieved in field tests to date. In effect, we are dealing with the economic feasibility of heat mining somewhat retrospectively. In 1976, Milora and Tester assimilated data for commercial hydrothermal systems to establish a range of performance criteria as a goal for HDR. Later, Entingh (1987), various groups at Los Alamos (Cummings and Morris, 1979, and Murphy et al., 1982) and in the U.K. (Batchelor, 1984 a,b, 1987), Armstead and Tester (1987), and Tester and Herzog (1990, 1991) refined these criteria somewhat. We have been able to show that our initial assumptions for base case conditions reported earlier (Tester and Herzog, 1990, 1991) were consistent with the more rigorous model developed in this study that treated the non-linear multi-parameter optimization problem. Moreover, this means that the original assumptions for reservoir productivity used earlier are still at a higher level than has been demonstrated in the field.

For mid- to high-grade resources (>50°C km^{-1}) at assumed reservoir productivities of 45 to 100 kg sec^{-1}, 30 to 80 MW$_t$ per well pair and reservoir sizes large enough to ensure drawdown rates of five percent or less over five years of production, the HDR breakeven electricity price is 6 to 10¢ kWh$_e^{-1}$. This assumes current drilling costs, power plant construction costs, and modest exploration and site development costs.

To achieve this base case level of reservoir production at Fenton Hill (a high-grade reservoir in New Mexico operated by the Los Alamos National Laboratory for the U.S. Department of Energy), a 5 to 10-fold reduction of flow impedance from current levels is needed with acceptable water losses. Clearly, more fundamental engineering experience is needed before HDR reservoirs can be constructed in an optimal fashion. There are no insurmountable technical barriers, but more knowledge of how to create large fracture systems in low permeability rocks is required before low impedance systems of sufficiently high productivity can be routinely engineered. The key implication here is that more time, effort, and funds should be invested in field demonstrations of heat mining. This approach will build the engineering knowledge base, technical know-how, and human resources required to develop heat mining commercially. One can think of the goal of demonstrating HDR reservoir productivity on a commercial scale as the first crucial step in the evolution of universal heat mining.

A successful demonstration would virtually guarantee commercial development of our mid- to high-grade HDR resource as an alternative to fossil or fissile-fired electricity generation. To achieve truly universal heat mining, the ubiquitously distributed low- grade (20 to 40°C km^{-1}) resource must become economically accessible. This will require more revolutionary developments. As seen in figures 6 and 7, low gradient resources result in very high breakeven prices that are induced primarily by the high drilling cost component. At base case operating and design conditions for low-grade HDR, which includes reservoir productivities comparable to mid- and high-grade systems, electricity prices range from about 15 to 100¢ kWh_e^{-1} or a factor of 3 to 20 too high in today's marketplace. One can see from figure 6, that as the gradient decreases from 80 to 20°C km^{-1} the fraction of total costs due to drilling increases from 42 to 95 percent.

Even given the inherent speculative nature of these economic projections, it is still relatively safe to say that heat mining will not become universal until a fundamental change in drilling and/or reservoir formation costs occurs to significantly lower costs. Although one could hypothesize that the discovery of new methods of creating HDR systems could result in enormous increases in productivity per well pair, it seems more probable based on the limitation of current heat mining concepts that a breakthrough in drilling technology is more likely to give the desired result. Such a breakthrough would involve a shift away from the exponential well cost versus depth functionality that has been observed historically for essentially all U.S. oil and gas drilling experience and, although offset to higher costs, for U.S. geothermal drilling experience as well. Figure 9 shows some of these data. The base case/today's technology line represents average conditions for HDR-type well drilling using conventional rotary drilling technology. The problem-burdened and advanced conventional technology lines form the envelope of drilling costs used in our sensitivity analysis that essentially captures the range of all HDR well cost data and predictions, again for rotary drilling technology. Joint Association

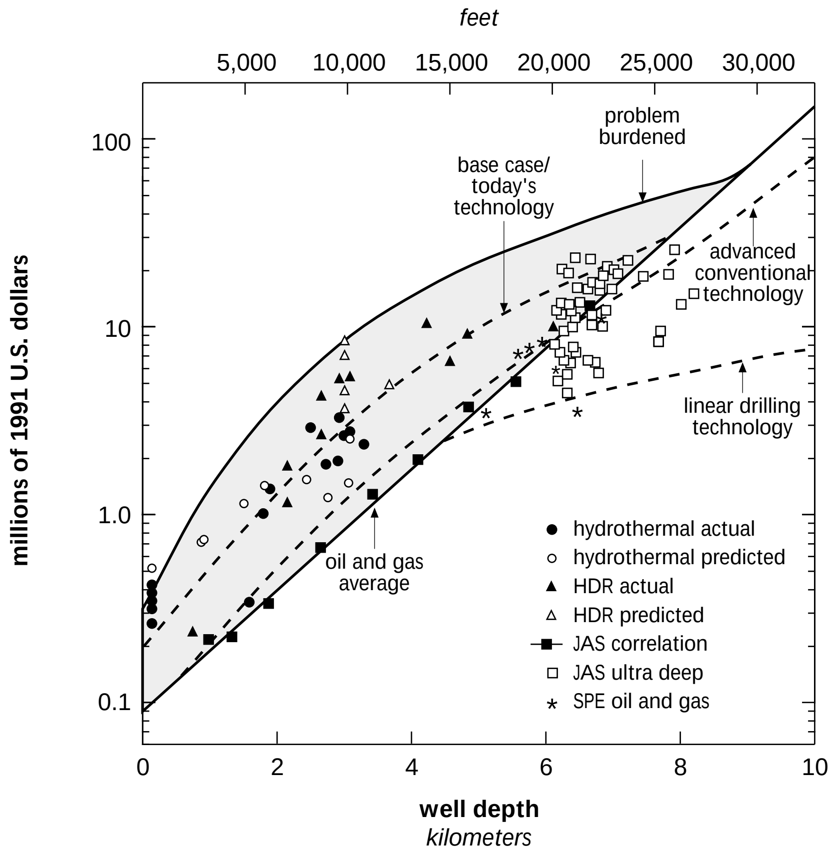


Figure 9: Drilling costs for different technology levels used in the HDR model simulations. Also plotted are historical drilling costs for HDR, hydrothermal, oil and gas, and ultra-deep wells. see Herzog et al. [1994] and Tester and Herzog [1990, 1991] for the sources of data that are plotted

Survey (JAS) (1978–1991) data are plotted for oil and gas wells average costs as well as for specific ultra-deep wells. Note the scatter in the costs for ultra-deep wells, caused primarily by variations in formation type and drilling programs.

Figure 9 also shows a line for what we have called "linear drilling," where drilling costs for wells deeper than about four kilometers become linear with depth. We believe that such behavior represents a lower boundary on drilling costs when advanced technologies, such as flame-jet thermal spallation or water-jet cavitation drilling methods, are employed in a fully integrated drilling system.

There have been significant advancements in conventional rotary drilling, using roller cone bits made of superior materials such as tungsten carbide and diamond composites. However, such improvements are inherently limited by the fact that the basic mechanism for such penetration still depends on a crushing and grinding mechanism which is prone to wear and eventual failure.

Geothermal reservoir rocks tend to be more difficult to drill as they are harder than most oil- and gas-bearing formations. In addition, heat mining from low-grade resources will require ultra-deep drilling to depths between four to eight kilometers where drill bit replacements are time-consuming. These factors make the cost of average geothermal wells two or three times higher than oil or gas wells of the same depth. Further advances in conventional rotary drilling technology could make heat mining drilling costs comparable to average oil and gas well drilling costs.

We believe that a fundamental change in the drilling mechanism that results in high penetration rates with significantly less wear than conventional rotary equipment could lead to a more linear dependence of cost on depth. For example, thermal flame-jet spallation penetrates by using high heat fluxes to create differential thermal stress and failure. Rock spalls are ejected from the surface and removed from the hole by high-velocity combustion product gases. In preliminary field tests, hard granitic formations have been drilled to depths of 1,000 meters at rates approximately 5 to 10 times faster than conventional methods with essentially no wear to the drilling apparatus. Similar improvements in performance have been achieved using water erosion and cavitation methods. Although it is too early to forecast universal gains for deep heat mining applications, research and development efforts are beginning to focus on ultra-deep drilling technology. For example, the German Continental Deep Drilling Program (KTB) near Windischeschenbach (operated by the German government) and Russian Kola deep hole on the Kola Peninsula (operated by the Russian government) have provided useful data. In addition, a national program on Advanced Drilling and Excavation Technologies (NADET) supported by the USDOE is scheduled to be launched in late 1994 to explore revolutionary drilling improvements (NADET, 1994).

Predicted heat mining development costs are shown in figures 10 and 11 for the base case conditions cited in table 1 but with linear rather than exponential drilling costs. Figure 10 shows the shift in the distribution of costs over what was found with conventional drilling technology shown in figure 6. For example, for a 20°C km^{-1} resource, only 51 percent (rather than 95 percent) of the total costs are due to drilling when a linear drilling model is applied.

In figure 11, the total U.S. heat mining resource is divided into five classes or grades, each corresponding to an average gradient between 80 and 20°C

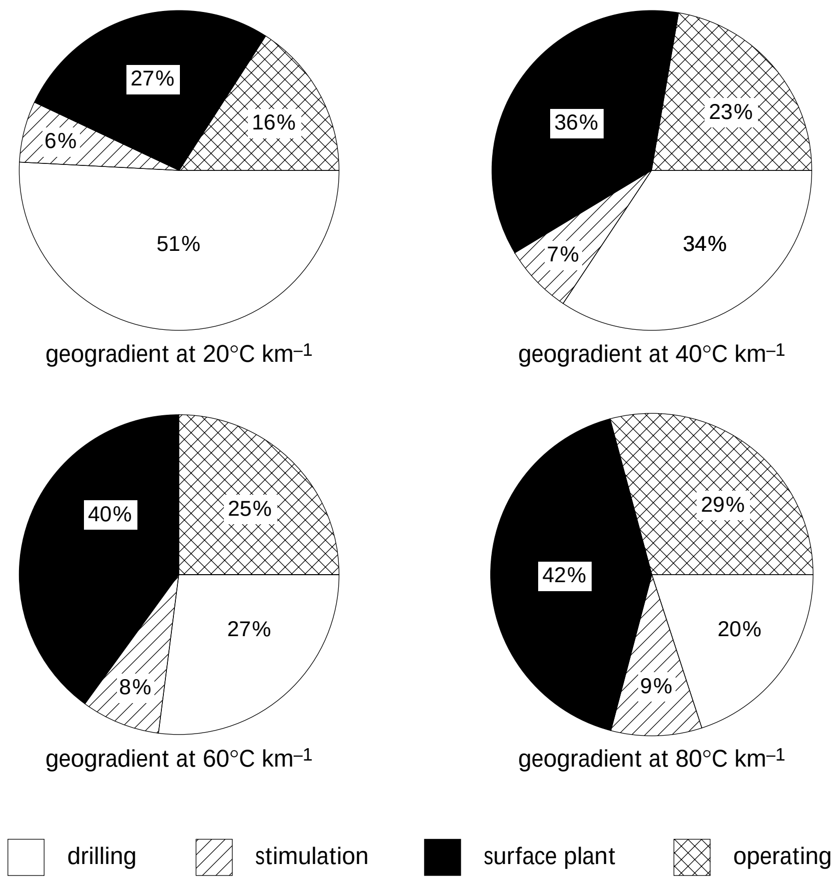
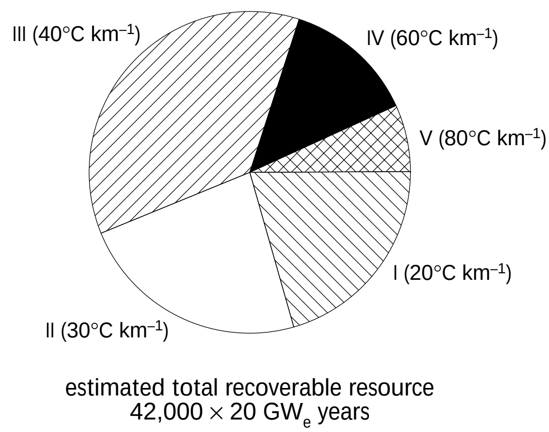


Figure 10: Breakdown of component costs (drilling, stimulation, plant, and operating) for the HDR optimization model base case conditions at a range of geothermal gradients using linear drilling technology and costs.

km^{-1}. (See map in Tester et al., 1989, for distribution of geothermal gradients in the U.S.) This amounts to a total supply of about 42,000 GW_e from heat mining for a 20-year period. (For reference, the current U.S. generating capacity is about 700 GW_e.) The bar graph in figure 11 compares the breakeven electricity price for each HDR grade using today's drilling costs to what would be possible with linear drilling technology. For the high-grade classes (60 to 80°C km^{-1}) the effect of this advanced drilling technology, while significant, is not as striking as for the lower HDR grades (20 to 40°C km^{-1}) where such technology leads to the economic feasibility of heat mining in current energy markets.



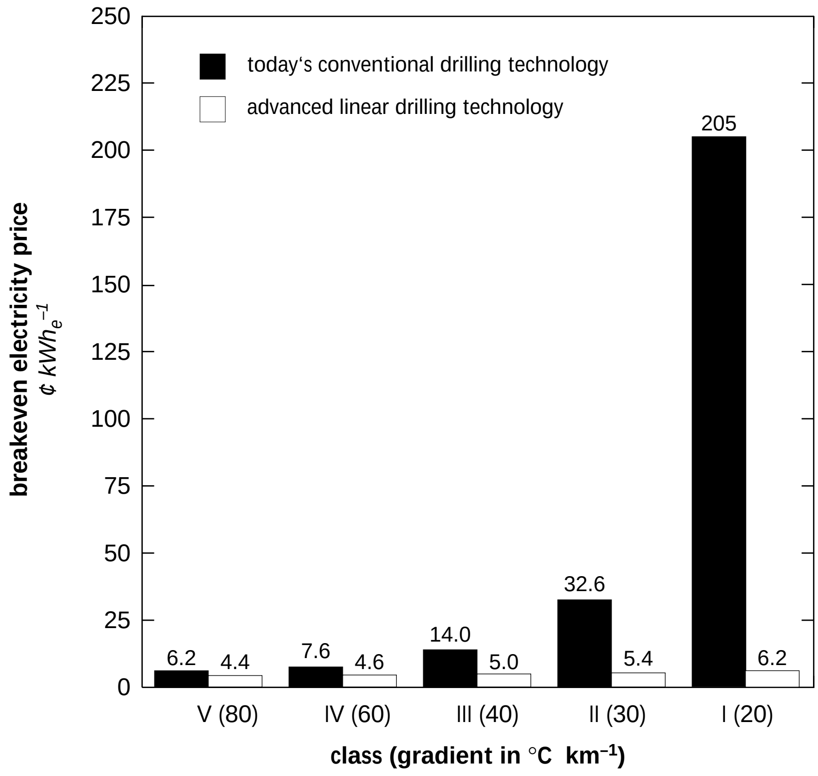


Figure 11: Heat mining resource base for the U.S. Two sets of costs for producing electricity from this resource are shown— one using today's conventional drilling technology and the other using advanced linear drilling technology.

CONCLUSIONS AND RECOMMENDATIONS

A multi-parameter optimization model has been developed to specify reservoir design (well depth and spacing, effective fracture size and location) and operating conditions (flow rate, pressure drop) to minimize breakeven electricity prices. The effects of finite reservoir thermal drawdown, wellbore heat losses, and parasetic losses due to fluid recirculation have been accounted for. Electricity price as a function of resource grade (nominally expressed by the average geothermal gradient) and important costs factors (such as individual well drilling costs as a function of depth) has been parametrically examined. However, this paper does not attempt to establish minimum costs for HDR-produced electricity.

Base case conditions for the model simulations were selected somewhat conservatively based primarily on today's technology and costs for developing commercial hydrothermal geothermal resources. A key assumption throughout is that heat mining reservoir productivity levels (e.g., flow rate and impedance) can, in practice, match those found in existing hydrothermal systems. Field results to date from prototype heat mining systems fall short of this goal. Based on current progress and potential, we strongly recommend continued field testing of heat mining concepts to achieve the reservoir productivity levels required for commercialization. For example, indications from recent testing of the high-grade Fenton Hill HDR system suggest that a sufficiently large reservoir system with acceptable water losses has been created; it only lacks proper hydraulic connections to fully utilize its heat mining capacity (Duchane, et al., 1991–1993).

For mid- to high-grade areas (>50°C km^{-1}), commercially competitive heat mining will require somewhat higher levels of reservoir productivity and/or lower drilling costs than have been achieved to date. Heat mining in low-grade areas will not be competitive until drilling costs approach a linear dependence with well depth. This will require revolutionary advances in drilling technology. We hope that the proposed national program on advanced drilling and excavation will provide such technology.

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Table 2: System design comparison for a single well pair,
Old = Tester and Herzog (1991), New = this study.

Average gradient	20˚C km^{-1}		40˚ C km^{-1}		60˚C km^{-1}		80^{o}C km^{-1}	
	old	new	old	new	old	new	old	new
Breakeven electricity price ¢ kWh$_e^{-1}$	85	205	11.9	14.0	6.6	7.6	5.3	6.2
Installed surface plant cost $ kW^{-1}	1,900	1,900	1,000	1,100	1,000	1,000	1,000	1,000
Installed subsurface (wells/reservoir) system cost $ kW^{-1}	31,000	107,000	3,500	5,600	1,300	2,300	800	1,500
Well depth km	9.15	9.15	7.13	7.74	4.75	5.25	3.56	3.94
Geofluid flow rate kg s^{-1}	75	46	75	92	75	81	75	66
Effective area 10^6 m^2	1.2	2.04	1.7	2.93	1.6	2.48	1.6	1.94
New power output MW$_e$	3.5	1.4	14.9	13.7	14.7	11.7	14.5	9.2