COST OF ELECTRICITY FROM ENHANCED GEOTHERMAL SYSTEMS

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ABSTRACT

This paper presents the results of an analysis of the cost of electric power from Enhanced Geothermal Systems (EGS), specifically, reservoirs with sub-commercial permeability enhanced by hydraulic stimulation. The parameters in this exercise reflect the conditions encountered at the Desert Peak EGS project in Nevada, but the results should be applicable, at least qualitatively, to any EGS project.

Several types of injection/production well configuration are considered (doublet, triplet, etc.). For each geometry, numerical simulation of energy recovery versus time was conducted for a range of injector-producer spacing, stimulated thickness, and enhancement level (fracture spacing and permeability). From this exercise, the optimized sustainable net power capacity for 30 years as a function of the stimulated volume was estimated for each case. Then the levelized cost of net power was estimated for each case based on capital cost (exploration and drilling cost, stimulation cost and surface facilities cost), operations-and-maintenance cost, cost of money and inflation rate. The uncertainty in the estimated levelized cost was assessed through Monte Carlo sampling of the uncertain variables. Levelized cost was shown to be a function of stimulated volume and well configuration. The lowest possible levelized cost was estimated at 5.43¢/kWh for a repeated pattern and a stimulated volume of 7 billion cubic feet.

A sensitivity analysis was then conducted to assess the impact of changes in the various capital cost components on the levelized power cost. In addition, the impact of changes in certain variables implicit in this exercise on the levelized power cost was also evaluated; the implicit variables considered were the maximum practical pumping rate, reservoir characteristics, and the depth to the reservoir at the site. The impact of any adverse reservoir characteristics was assumed to be manifested in cooling of the produced fluid.

One of the goals of this study was to forecast what the levelized cost of EGS power might be by 2050. For this forecast, the most likely values of the U.S. prime interest rate and the inflation rate were defined based on the economic trend over the last 40 years. The possible values of the other explicit and implicit variables were then estimated for 2050 using certain assumptions about the market forces and the technology improvements to be achieved by then. The results of this study confirm that EGS power is a strategic resource rather than a commercial resource today. With adequate research, development and demonstration over the next decade or two, EGS power should become commercially competitive by 2050.

INTRODUCTION

To mine heat in an Enhanced Geothermal System (EGS), an artificial heat exchanger of significant volume must be developed in the subsurface. Hydraulic stimulation is the main mechanism used to create the subsurface heat exchanger; by increasing pore pressures, permeability is enhanced in suitable rock formations with high temperatures but sub-commercial natural permeability. In this way, a stimulated rock volume is created. The orientation and spacing of the created fractures and size of the stimulated volume will vary with geologic setting, *in-situ* stress conditions, pressure increase during stimulation, and the volume of fluid injected during the stimulation. It is envisaged that a volume of rock will be stimulated from each well, and monitoring and testing techniques will allow the volume, shape and hydraulic characteristics of the stimulated zone to be determined. By drilling and stimulating a number of wells, a significantly large stimulated reservoir will be created. Water will be injected in a well and produced from one or more production wells to recover thermal energy from the created reservoir. Each injection well and its neighboring production wells will form a unit, such as, a doublet, a triplet, a five-spot, etc. A commercial EGS development will consist of a number of contiguous such units. The above scenario and the specific characteristics of the

Desert Peak Site form the background of the cost analysis presented in this paper.

VARIABLES CONTROLLING POWER COST

The critical variables that control the levelized cost of EGS power are the sustainable generation capacity per injector and its neighboring production wells (referred to here as an EGS "unit"), capital cost, operations-and-maintenance (O&M) cost, interest rate and inflation rate.

Performance of EGS systems is typically judged by the cooling trend of the produced water, with faster cooling rates representing less attractive performance. However, from a practical viewpoint, we believe that the net electric power capacity available from such a system versus time, defined in Sanyal and Butler (2005) as the "net generation profile," is the most appropriate and comprehensive criterion of performance. Numerical simulation shows that, for any fracture spacing, fracture permeability or production/injection well configuration, reducing the throughput (that is, injection and projection rates) reduces the temperature decline rate and lowers parasitic losses, thus resulting in a more commercially attractive net generation profile (that is, one with a lower variance). Heat recovery is less for a lower production rate, but due to reduced parasitic loads and a longer producing life, the net MW-hours supplied by the same is higher. One can arrive at an optimized net generation profile through numerical reservoir simulation by trial-and-error adjustment to the throughput.

In numerical simulation, we have assumed that after stimulation, the fracture characteristics will remain unchanged over the project life. While enhancement of fractures with time due to thermal contraction of rock is possible, gradual closing of fractures or degradation of fractures due to scaling is equally possible. Case histories of long-term injection into hydrothermal reservoirs do not show convincing or consistent evidence of progressive fracture enhancement with time, while fracture degradation due to scaling with time is not uncommon. Therefore, a fracture system that is invariant with time was considered a reasonable compromise for this exercise. To study the performance of a hypothetical EGS project similar to the Desert Peak project, we had developed earlier a three-dimensional, double-porosity numerical model (Sanyal and Butler, 2005); we have used that model here.

Figure 1 presents a plot of the net sustainable MW capacity versus stimulated volume for all the cases considered. This figure shows that the sustainable net MW capacity for the Desert Peak EGS is a linear function of stimulated volume: for each billion cubic feet of stimulated volume, the net MW capacity achieved is about one MW. The conclusion that such a correlation is essentially linear, and for all practical purposes, independent of the specific well configuration used, had been noted in Sanyal and Butler (2005). For the purposes of this project, we have used Figure 1 to estimate the net sustainable MW capacity for each considered case of well configuration and stimulated volume.
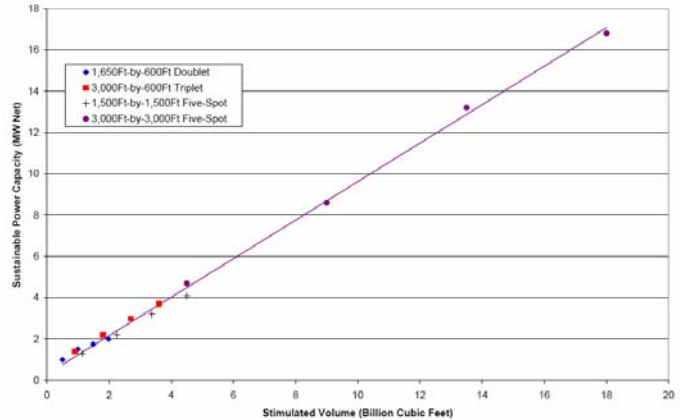

Figure 1: Sustainable Power Capacity vs. Stimulated Volume

The three basic components of the capital cost of EGS power are:
  a) drilling cost (including exploration cost, which would be a small fraction of drilling cost);
  b) stimulation cost (including costs of design, execution, monitoring and assessment of results); and
  c) power plant, gathering system and other surface facilities cost.

Table 1 presents the estimates of all basic cost components as well as other important parameters used in this study. We have assumed that the cost of the production or injection pump, if required, is included in the drilling cost.

We have estimated the drilling cost for the conditions at Desert Peak, and the stimulation cost based on the experience at the continuing EGS developments at Soultz (Europe) and Cooper Basin (Australia).

For the power plant/surface facilities cost and the O&M cost, we have used the range of values typically seen in the geothermal industry. However, we believe the unit O&M cost of an EGS project should be somewhat less than that of a conventional geothermal project because of the more controlled and optimized production/injection operation, absence of make-up well drilling, and relatively small number of well workovers expected in an EGS operation. These cost advantages would tend to mitigate the higher capital cost of an EGS project

compared to that of a conventional geothermal project.

Table 1: Assumptions Common to all Cases Considered

Power plant life:	30 years
Plant availability factor:	0.95
Annual operations & maintenance cost:	2.0 to 3.5¢/kWh (with equal probability)
Drilling cost per well (either production or injection well):	$5.0 Million minimum
	$5.5 Million most likely
	$6.0 Million maximum
Stimulation cost per well:	$0.5 Million minimum
	$0.75 Million most likely
	$1.0 Million maximum
Power plant and other surface facilities cost:	$1,800/kW minimum
	$2,000/kW most likely
	$2,200/kW maximum
Annual interest rate:	9%
Annual inflation rate:	4%

For the cases of the doublet, repeated triplet and repeated five-spot, the drilling and stimulation costs have been assumed to be twice that for a single well. If an EGS unit configuration is repeated infinitely, the effective number of production wells per unit will approach a value of two, irrespective of whether it is a doublet, triplet or five-spot. For a single triplet and a single five-spot, drilling and stimulation costs are (respectively) three times and five times that of a single well.

Figure 2 presents the most likely capital cost per kW installed versus stimulated volume for all the cases considered. In Figure 2, dashed curves have been used for stimulated volumes exceeding 7 billion cubic feet (sufficient for about 7 MW net capacity) because a production well for the conditions at Desert Peak cannot yield significantly more than 7 MW (net). In fact, given the existing pump technology, 7 MW (net) is essentially the limit of well capacity in any field unless the resource temperature exceeds 215°C (Sanyal et al., 2007). Given that the unit capital cost today for conventional geothermal projects is on the order of $3,500 per kW installed, nearly all the cases except the case of repeated 3,000 foot by 3,000 foot five-spots in Figure 2 can be considered uneconomic.
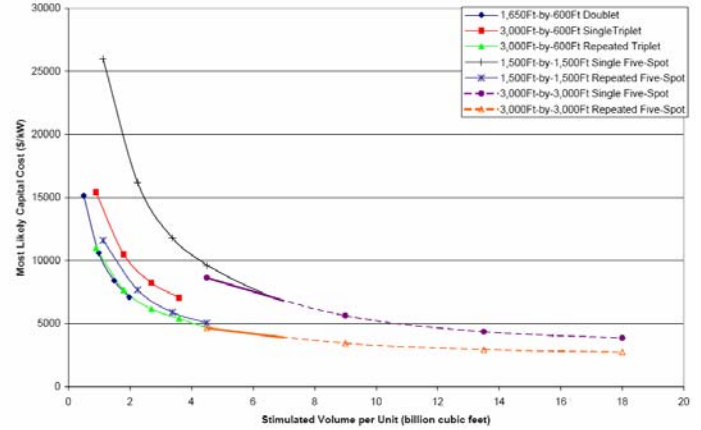

Figure 2: Most Likely Capital Cost per EGS Unit vs. Stimulated Volume

Development of repeated contiguous units benefits from the economy of scale, and therefore, reduces the capital cost. However as discussed later, the cases of repeated configurations are theoretically possible but would be unrealistic unless large-scale commercial generation of EGS power becomes feasible. Although the EGS power is a strategic resource base for the U.S., as indicated in the study by MIT (2006), it cannot be commercial today. Commercialization of EGS power will require reduction in the unit capital cost. Figure 2 shows that the unit capital cost drops rapidly as a function of increased stimulated volume; therefore, increasing the stimulated volume per well is a key to reducing the capital cost of EGS power.

ESTIMATION OF LEVELIZED POWER COST

The uncertain variables (capital costs of drilling, stimulation, power plant and surface facilities, O&M cost, interest rate and inflation rate) were subjected to Monte Carlo sampling and used in a probabilistic assessment of the levelized cost of power over the project life. The capital cost was amortized over the project life using the assumed interest rate, and O&M cost was increased at the inflation rate over the project life. The annual costs of capital-plus-interest payment and O&M cost were discounted to their present value using the assumed inflation rate. The levelized power cost was then calculated as the sum of net present worth of the future annual costs and dividing the sum by the total electrical energy generated over the project life at the net installed power capacity with a 95% plant availability factor.

Figure 3 compares the mean levelized power cost versus stimulated volume per EGS unit for all configurations and stimulated volumes considered.
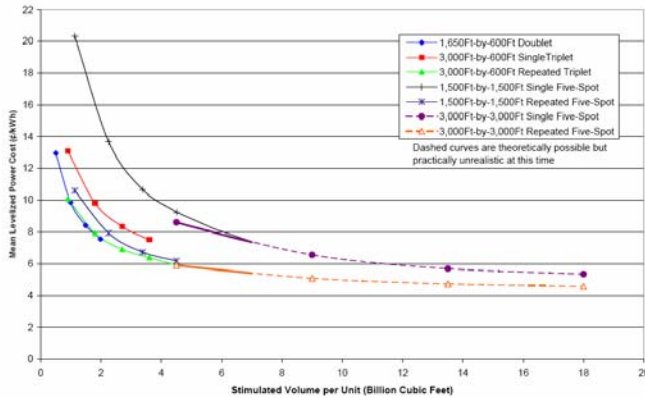
Figure 3: Mean Levelized Cost of EGS Power vs. Stimulated Volume

Figure 3 demonstrates that the key to reducing the levelized cost of EGS power is increasing the stimulated volume per unit and the number of contiguous units. These figures show that, for stimulated volumes exceeding about 10 billion cubic feet per unit, both the mean and maximum levelized costs become insensitive to the stimulated volume. The stimulated volume achieved at Rosemanowes (U.K.) and in Phase II of the Fenton Hill (New Mexico) project was apparently about 35 billion cubic feet, while at Soultz (Europe) and Cooper Basin (Australia) the stimulated volume achieved, or planned to be achieved, was nearly 90 billion cubic feet (MIT, 2006). Therefore, achieving a minimum levelized cost of 5.5¢/kWh at Desert Peak is possible, in theory at least, if the following conditions are satisfied:

a) the stimulated volume is on the order of at least 5 billion cubic feet per unit;
b) the stimulated volume is reasonably homogeneous and isotropic, as has been assumed in our numerical simulation of reservoir performance;
c) the reservoir is sub-horizontal, which represents the geometry of our the numerical model, rather than steeply-dipping;
d) the cost of creating a stimulated volume of several billion cubic feet is not substantially higher than the cost experienced at the Soultz and Cooper Basin projects; and
e) the development consists of a large number of repeated contiguous units.

If any of the above conditions is not satisfied, the levelized power cost will be higher than that estimated here. Given that all of the conditions above are unlikely to be achieved in any single project, the mean levelized cost estimates arrived at here should be considered the lower limit of what can be achieved today.

The lowest possible cost of EGS power today (estimated at 5.5¢/kWh) ignores certain uniquely site-specific and/or atypical costs (*e.g.*, for infrastructure, regulatory compliance, environmental impact mitigation, transmission line construction, royalties, taxes and tax credits). Considering the ignored cost items and the typically expected rate of return on investment in natural resource projects, the commercial break-even price for EGS power should be 30% to 50% higher than the levelized cost estimated here. Given today's typical power price level of 6 to 7¢/kWh, levelized cost of EGS power should be lower than 5¢/kWh. Figure 3 indicates that, under the right circumstances, the levelized cost of EGS power can come close to the current cost threshold for commercial power but is unlikely to fall below it. Levelized cost of EGS power could drop down to this threshold within the foreseeable future if adequate research, development and demonstration are conducted to identify appropriate subsurface stress conditions for effective stimulation, to increase the volume stimulated per well, to minimize heterogeneity in the stimulated volume, etc., and the shallowest sites with the most attractive temperature and stress conditions are chosen for development.

SENSITIVITY ANALYSIS

In this section we consider the sensitivity of levelized power cost, as estimated in the previous section, to various technical and economic variables. We first consider those variables explicitly relied upon earlier in arriving at the value of the levelized power cost (capital cost components, O&M cost, interest rate and inflation rate). Then we consider certain important variables implicitly assumed in the previous section in estimating levelized power cost (practical generation capacity of wells, reservoir characteristics and reservoir depth).

The Base Case

We have considered the sensitivity of the levelized power cost with respect to a "base case". Since the ultimate purpose of this study is to assess the prospects of commercial EGS power development in the future, we have chosen as the base case the most extensive of the development schemes considered earlier. In other words, the base case does not represent an experimental development or a demonstration project consisting of a single EGS unit, but a repeated five-spot development. The base case represents one such unit in a repeated development. It should be noted that at Cooper Basin (Australia), repeated star-shaped units ("six-spots") are planned to be developed (de Graaf, 2006).

Figure 1 shows that up to 16.8 MW (net) could be generated per unit 3,000 foot-by-3,000 foot five-spot, the required stimulated volume being 18 billion cubic feet. This required stimulated volume is achievable, given the range of 35 to 90 billion cubic feet reported from the various EGS projects to date (MIT, 2006). Therefore, in theory, up to 16.8 MW (net) can be

generated in the base case. However, as mentioned before, considering the productivity of commercial wells, the maximum practical limit of generation from such a unit would be about 7 MW (net). In other words, the base-case unit will not be reserves-limited but productivity-limited. Figure 1 indicates that this 7 MW (net) development per unit will require about 7 billion cubic feet of stimulated volume, which is relatively small compared to that achieved to date elsewhere. It should be noted that so long as the units are repeated infinitely, the economics will be essentially the same for a doublet or triplet or even a six-spot configuration.

Table 2 presents the relevant parameters assumed for the base case. The cost parameters for the base case represent mid-range values from Table 1. The interest rate assumed for the base case is the same as in Table 1 but the inflation rate has been assumed to be 3.6% based on the fact that the inflation rate is most likely to be about 40% of the interest rate as discussed below. The remaining parameters for the base case are the same as in Table 1. With these assumptions, we estimate the levelized cost of EGS power in the base case to be 5.43¢/kWh. It can be shown that this levelized cost is comprised of three components: 2.75¢/kWh of O&M cost, 1.51¢/kWh of capital cost and 1.71¢/kWh for the cost of money.

Table 2: Parameters Assumed for the Base Case

Development scheme:	Repeated five-spot, triplet or doublet
Well requirement per unit:	2
Net generation per unit:	7 MW
Stimulated volume:	7 billion cubic feet
Power plant life:	30 years
Power plant availability factor:	0.95
Annual operations and maintenance cost:	2.75 ¢/kW hour
Drilling cost per well:	$5.5 million
Stimulation cost per well:	$0.75 million
Power plant and other surface facilities cost:	$2,000 per kW ($3,786 per unit)
Annual inflation rate:	9%
Annual inflation rate:	3.6%

Sensitivity to Explicit Variables

Two important variables in the estimation of the levelized power cost presented earlier were the rates of interest and inflation. Figure 4 is a histogram of the U.S. prime interest rate over the last four decades; this figure shows that a prime interest rate of 8.25% per year had the highest frequency of occurrence;

therefore, we have assumed an interest rate of 8.25% in forecasting the levelized power cost in year 2050. Figure 5 presents a histogram of the ratio of the annual inflation rate to annual interest rate over the last four decades; a value of 0.4 for this ratio shows the highest frequency of occurrence. We have used this ratio in our sensitivity analysis as well as in forecasting the possible range of levelized power costs by the year 2050.
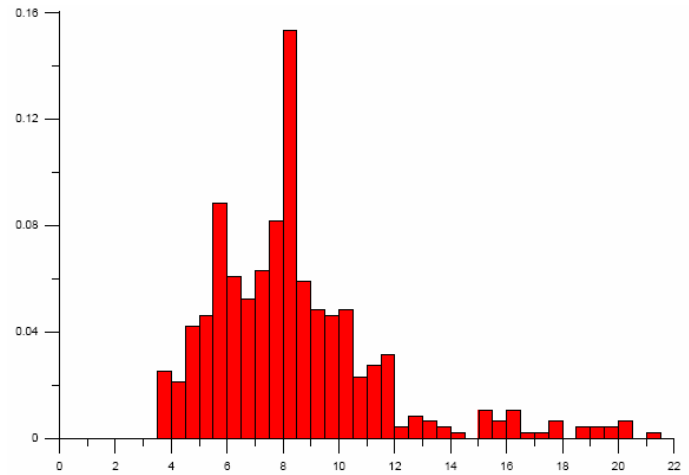

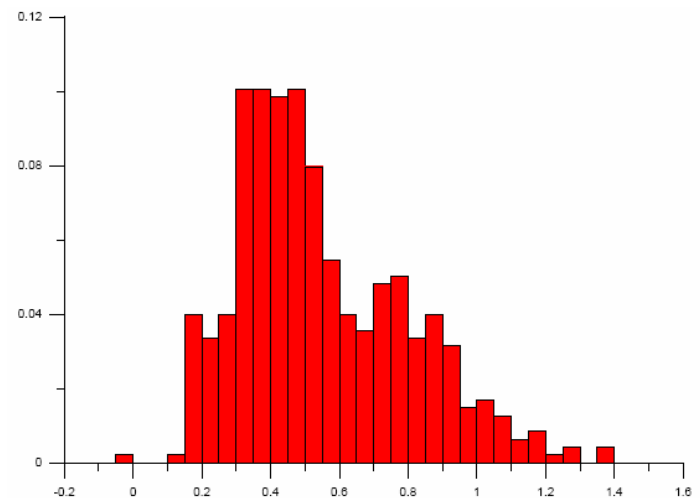*Figure 4: Histogram of Prime Rate (1967-present)*

Figure 5: Histogram of Inflation Rate / Prime Rate Ratio (1967-present)

In this sensitivity analysis we have varied the explicit variables (capital cost components, O&M cost, interest and inflation rate combination) by -50% to +50% and estimated the sensitivity of levelized power cost to this variation. Figure 6 presents the estimated value of levelized power cost as a function of the percentage changes in each of the explicit variables, the base case value of levelized cost being 5.43¢/kWh. Figure 6 shows that levelized power cost is most sensitive to O&M cost, followed by power plant cost, drilling cost per well, and interest/inflation rates; it is insensitive to stimulation cost.
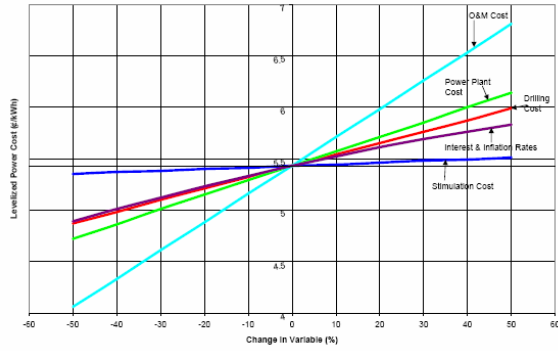
Figure 6: Sensitivity of Levelized Power Cost

Sensitivity to Implicit Variables

In addition to the explicit variables considered above, the levelized cost estimated earlier involved certain implicit variables, the foremost being the practical limit in generation capacity per well, reservoir heterogeneity and reservoir depth.

The maximum capacity of 7 MW (net) per well was assumed based on the present limitation of the flow rate of a commercial geothermal pump to about 2,500 gallons per minute (gpm); this flow rate can be available from a 12-inch diameter pump which can be set in a conventional 13-3/8-inch casing. However, if a larger pump could be used (in a larger diameter casing) the flow rate could be increased, and subsequently, levelized power cost could be lowered. Although these larger capacity pumps are not available commercially for geothermal use, they are available for pumping cooler waters. There appears to be no major technological barrier to developing such pumps. If the pumping capacity could be increased, so can the generation capacity per EGS unit. Figure 7 shows the estimated decrease in levelized power cost if the pumping rate could be increased. For example, if the pumping rate could be increased by 50% (to 3,750 gpm), which we believe to be possible, the levelized power cost could be lowered from 5.43 to 5.00¢/kWh.

The net generation levels estimated before assumed that the created reservoir a sub-horizontal slab and uniform and isotropic in its hydrological properties. If the reality proves very different from this idealization, the sustainable generation capacity per EGS unit and the levelized power cost would be higher. The most important impact of any adverse reservoir characteristics would be to increase the cooling rate of the produced fluid with time. The net generation capacity was optimized assuming a variance of less than 15% in net generation from the EGS unit over the project life. Given the various
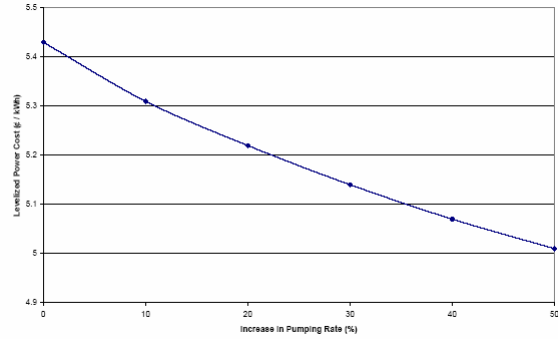

Figure 7: Levelized Power Cost vs. Increase in Pumping Rate

idealizations inherent in this exercise, the net sustainable capacity estimated before implicitly assumed negligible cooling of the produced water over the project life. In the conventional geothermal projects operating in the U.S., the cooling rate of the produced water typically ranges from nearly zero to 1°C per year. No EGS project has ever operated long enough to demonstrate a long-term cooling trend; but numerical modeling of the EGS projects under development indicate that the cooling rate would be in the 0° to 1°C per year. We have assessed the impact of cooling by up to 2°C per year on levelized power cost estimated earlier. Figure 8 presents the calculated increase in levelized power cost as a function of the cooling rate; this figure indicates that levelized power cost is quite sensitive to the cooling rate (approximately 0.5¢/kWh increase per °C/year cooling).
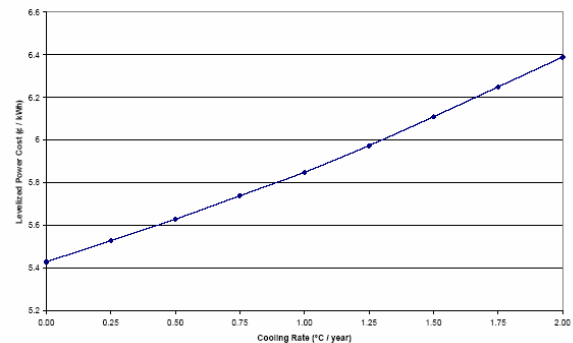

Figure 8: Levelized Power Cost vs. Cooling Rate

The temperature gradient at Desert Peak is approximately 80°C per km. Since the temperature gradient within the U.S. varies widely, from less than 30°C/km to greater than 500°C/km, the fluid temperature of 200°C available from the Desert Peak reservoir at about 8,000 feet can be available at a shallower or greater depth elsewhere depending on the temperature gradient at the chosen project site. Since reservoir depth largely determines the drilling cost, levelized cost of EGS power will depend not only on the reservoir temperature, *in-situ* stress conditions and the characteristics of the created reservoir, but also on the depth to the created reservoir. Figure 9 compares two correlations of

drilling cost of a well against well depth: one from GeothermEx (2004), with costs escalated from 2003 to 2004 according to the U.S. Producer Price Index for drilling, and one from MIT (2006), which reported 2004 drilling costs. Figure 9 shows that both correlations are quite close up to depths of 10,000 feet; little empirical data exist from deeper geothermal wells. Based on the GeothermEx (2004) correlation, Figure 10 shows a plot of the calculated levelized power cost versus the well depth at which a reservoir temperature similar to that at Desert Peak is reached. It is clear from Figure 10 that well depth has a large impact on levelized power cost. In other words, levelized power cost is very sensitive to site selection.
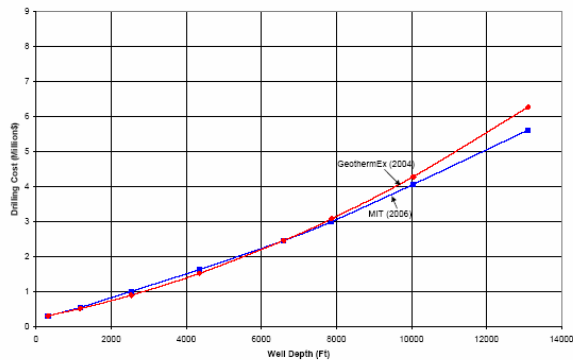

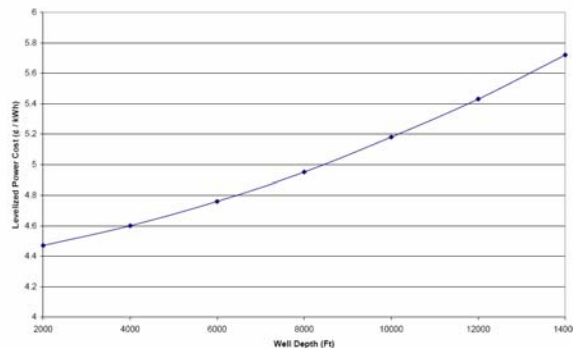*Figure 9: Drilling Cost vs. Well Depth*

Figure 10: Levelized Power Cost vs. Well Depth

COMMERCIAL PROSPECTS FOR EGS POWER BY THE YEAR 2050

Possible Power Price Level in 2050

In order to assess the commercial prospects for EGS power by the year 2050, one needs to forecast the cost of EGS power, the level of power price as well as the interest and inflation rates more than four decades from now. We have made the necessary speculations on future costs, power price and the economic climate based on the results presented earlier, GeothermEx's long involvement in the commercialization of conventional geothermal power in many countries, and historical trends in power price and relevant costs in the U.S.

Given the sharply rising trend in the price of electricity in the U.S. over the last few years, it is tempting to speculate that this trend by itself could render EGS power commercial in the foreseeable future. However, given the state of EGS technology today, we believe that free-market pricing cannot make EGS power commercial; it has to be subsidized by the government. On the other hand, based on the above sensitivity study, we believe EGS power can become commercial if its cost is reduced through research, development and demonstration over the next decade or two. While such cost reduction can be achieved, the required research, development and demonstration can only happen through the financial support of the U.S. DOE and other government agencies. The power producers would be unwilling to make such investments until the commercial feasibility of EGS power generation comes closer to reality, and the commercial feasibility of EGS power generation cannot be brought any closure to reality without such investments; this is a conundrum that can only be resolved through government support.

Figure 11 shows the historical trends in the city-average CPI for electricity and the overall CPI in the U.S. over the past 90 years. Between the two World Wars, electricity price declined steadily as the installed power capacity increased. Then in the four decades following the Second World War, power price increased at the prevailing inflation rate. Then, starting in 1986, the escalation rate in power price lagged behind the rate of inflation for nearly a decade because of the plentiful supply of cheap oil and natural gas and a sluggish rate of growth in power demand. Finally, over the last three years, electricity price has been escalating at a rate much faster than inflation because of the increasing prices of oil and natural gas and a shortfall in the required generation capacity to meet demand.
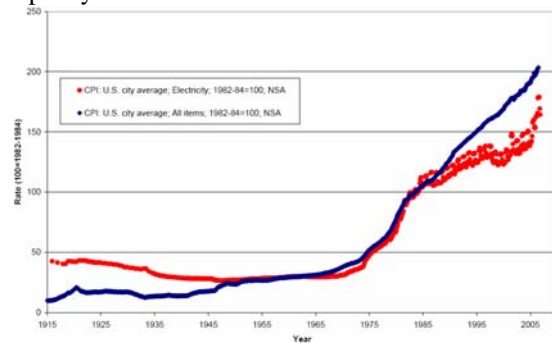

Figure 11: City Average Consumer Price Index vs. Electricity Price

It would be unreasonable to expect this unprecedented rapid escalation in power price to continue for decades; no commodity can indefinitely go up in price at a rate faster than the overall inflation rate. The escalation rate in power price and the rate of inflation should eventually converge, as had been observed over most of the post-war decades. For this reason we believe, in terms of constant 2006 dollars,

the price of electricity by 2050 is unlikely to be much higher than the current price level of 6 to 7¢/kWh.

Possible Reduction in EGS Cost Components

As indicated before, at the levelized cost of EGS power today, the power price needs to be significantly higher than the 6 to 7¢/kWh level to make EGS power commercial. As such, commercialization of EGS power will depend on reduction in the cost of its cost; of course, any government subsidies can only ease this challenge of commercialization. Our sensitivity study shows that this cost reduction can be achieved by reducing a combination of a number of tangible cost components.

The operation of an EGS project should be less challenging than that of a conventional geothermal project. Once the wells are drilled and the reservoir is created and adequately tested, operating an EGS is less subject to the vagaries of nature than a conventional geothermal system for the following reason. Operating a conventional geothermal project must deal with the uncertainties about hot water recharge, groundwater influx, increases in fluid acidity or gas content, success rate in make-up well drilling, and so on; these uncertainties all too often lead to "surprises" over the project life. Case histories of such surprises, and their cost consequences, can be found in the geothermal literature. An EGS project would be spared most of these uncertainties because an EGS reservoir is an "engineered" rather than entirely natural system, and as such, its behavior would be more predictable over the project life than that of a hydrothermal reservoir. Commercial geothermal plants have been operated for more than four decades; as such, it is unlikely that the learning-curve effect will lead to any major reduction in O&M cost of EGS over the next four decades. Nevertheless, some reduction in O&M cost could be realized by minimizing cooling. If generation from an EGS project declines due to cooling, the O&M cost for the project would not decline proportionally; in fact, it may decline little because a large portion of O&M cost represents overhead and other fixed costs that are insensitive to any shortfall in generation. Therefore, cooling would result in increasing losses of revenue as well as an increasing unit cost of O&M (in terms of ¢/kWh). Figure 8 illustrates the significant impact of cooling on the levelized power cost, which is in part due to increases in the unit cost of O&M. One can hope that through research, development and demonstration over the next decade or two, this cooling risk would be minimized, and the unit O&M cost can be reduced by some modest amount; we have arbitrarily assumed a 10% reduction (in constant dollars) in the fixed O&M cost by 2050.

Of the three components of capital cost per installed kilowatt capacity, cost of power plant and surface facilities per installed kW is essentially independent of the project size or configuration. On the other hand, the drilling and stimulation cost components, in terms of $ per kW installed, are highly variable, being dependent on the project size and configuration. Of these two highly variable components, stimulation cost is a small fraction of the overall capital cost, and as such, has little impact on the economics. No major breakthrough in technology is on the horizon that could substantially reduce the cost of power plant and surface facilities; we have arbitrarily assumed a modest (10%) reduction in this cost component by 2050. As regards stimulation cost, we have not considered any reduction by 2050. However, we have assumed that significant improvements in stimulation technology would be achieved by 2050 through research, development and demonstration such that heterogeneity and anisotropy in the stimulated volume would become minimal. This improvement would minimize cooling and increase the sustainable generation level. Therefore, drilling cost is the only component of capital cost that needs further review.

Figure 12, from MIT (2006), shows a drilling cost index (MIT Composite Drilling Index) as well as crude oil and natural gas prices as a function of time since 1972.
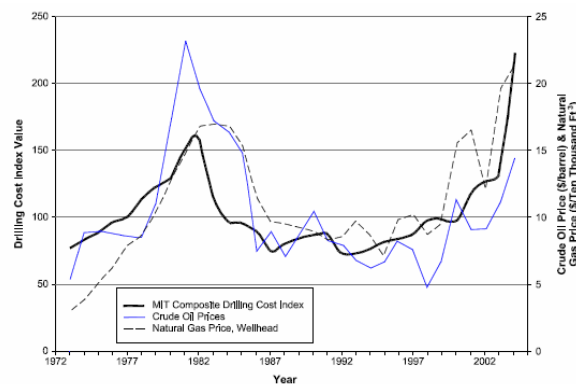

Figure 12: Crude Oil and Natural Gas Prices, Adjusted for Inflation (Energy Information Administration, 2005) Compared to MIT Composite Drilling Index (from MIT, 2006)

This figure indicates that the recent rapid increase in drilling cost mimics the rapid rise of oil and gas prices over this period; this correspondence is mainly due to the increased demand in the petroleum industry for drilling equipment and personnel. Figure 12 shows a similar episode of rapidly rising drilling cost in the late 1970s through early 1980s caused by the "oil crisis" of the time. Yet, Figure 12 shows that in the two intervening decades between these episodes, drilling cost remained nearly constant, and actually declined in real terms if one accounts for inflation. Given this overwhelming impact of

petroleum prices on drilling cost, it is futile to speculate on how much reduction in drilling cost might be expected by 2050, for we are in no position to predict what the petroleum prices might be four decades from now.

While one would expect improvements in drilling technology between now and 2050, these improvements may not necessarily reduce the drilling costs at that time. Figure 12 shows that drilling costs have risen by nearly 50% in the last 3 years; no amount of improvements in drilling technology could have mitigated this increase. The increasing petroleum prices and the need for ever deeper drilling in the petroleum industry have accelerated drilling research and development in the petroleum industry. The level of drilling activity and the budget for drilling research and development potentially available in the geothermal industry are minuscule compared to those in the petroleum industry. Therefore, notwithstanding potential advances in drilling technology to be achieved in the geothermal industry, it is unpredictable as to if and by how much geothermal drilling cost might decline by 2050; in fact, it is quite possible that drilling cost then would be higher in constant dollars than it is today.

We believe that the rapidly rising trend in drilling cost would ease in the foreseeable future, for no commodity can maintain indefinitely a cost escalation much faster than inflation. As seen from Figure 11, drilling cost declined by some 40% following the cost run-up in the late seventies and early eighties. Assuming that the current episode in drilling price escalation would come to an end in the foreseeable future, can we expect a similar decline in drilling cost? We believe not, because, unlike the two decades following the previous run-up in drilling cost, in the next few decades there is little likelihood of any improvement in the supply-to-demand ratio for petroleum, given that a third of the world's population (mainly in China and India) is poised for major improvement in living standards. We have arbitrarily considered a possible decline of 10% as well as a possible increase of 20% in drilling cost by 2050.

As indicated for the base case, 1.71¢/kWh of the levelized cost of 5.43¢/kWh (*i.e.*, nearly one third) represents the cost of money. Therefore, any changes in interest and inflation rates will have a substantial impact on levelized cost in the future. As Figure 6 indicates, this impact may rival the impact of any changes in drilling cost. Given the trends in interest and inflation rates over the last four decades (Figures 4 and 5), we have assumed a most likely interest rate of 8.25% per year in 2050, and a ratio of 0.4 between inflation and interest rates.

It is quite reasonable to expect that the technology of pumping geothermal fluids will improve significantly

by 2050. Given the incentive of a large enough market or adequate subsidies, pump manufacturers should be able to increase the pumping rate of geothermal water, by perhaps as much as 50%. We have optimistically assumed that an improvement in pumping capacity by 50% could be feasible by 2050, but it is also possible that this improvement may not come about by then due to the small size of the geothermal market and/or lack of subsidies. As regards the cooling rate, we assume research, development and demonstration would minimize the risk of cooling.

Possible Range of Levelized Cost in 2050

Given the discussion above we have considered an optimistic as well as a pessimistic scenario in assessing the potential cost of EGS power by 2050. In the optimistic scenario, we have assumed a 10% reduction in O&M cost, exploration and drilling cost, and power plant and surface facilities cost. We have not assumed any change in stimulation cost and have implicitly assumed that the stimulation technology will have essentially eliminated any cooling risk for a properly designed EGS. With these assumptions, we estimate a levelized cost of 4.42¢/kWh (in 2006 dollars) for EGS power under the optimistic scenario. Assuming a 30% to 50% margin required above this levelized cost for any commercial development, the optimistic scenario indicates that EGS power can be competitive with conventional geothermal power, and indeed, with most other power sources by 2050.

In the pessimistic scenario, we have assumed no improvements in technology and a 20% increase in drilling cost per well (in 2006 dollars). This scenario gives a levelized power cost of 5.51¢/kWh (in 2006 dollars) by 2050. This levelized cost will likely prevent EGS power from becoming commercial.

CONCLUSIONS

1) The total capital cost (exploration and drilling cost, stimulation cost, and power plant and surface facilities cost) for all sizes and configurations of hypothetical EGS projects concerned are higher that $4,000 per kilowatt installed capacity, compared to a typical value of $3,500 per kilowatt for conventional geothermal projects.

2) Capital cost decreases with increasing stimulated volume, and reaches its lowest possible level of $4,000 per kilowatt for a stimulated volume of 7 billion cubic feet and a repeated contiguous unit pattern.

3) Capital cost for any isolated single EGS unit is prohibitively high for a commercial project but with a large number of contiguous repeated units, capital cost could be as low as $4,000 kW per kW.

4) For reservoir temperatures less than 215°C, the maximum net generation level per EGS unit is about 7 MW and well requirement will vary depending on the injection/production well configuration. The well requirement (injector plus producers) per EGS unit declines to 2 for any configuration if a sufficient number of contiguous units are repeated.

5) The levelized cost of EGS power declines with increasing stimulated volume, and for any configuration repeating of contiguous EGS units.

6) The lowest possible cost of EGS power today is estimated at 5.43¢ per kilowatt hour, ignoring certain uniquely site-specific and/or atypical costs, of infrastructure (such as roads), regulatory compliance, environmental impact mitigation, transmission line construction, royalties, taxes and tax credits.

7) The estimated minimum levelized cost of 5.43¢/kWh is comprised of 2.75¢ of O&M cost, 1.51 ¢/kWh of capital cost and 1.7¢/kWh for the cost of money.

8) Considering the ignored cost items and the typically expected rate of return on investment in natural resource projects, the commercial break-even price for EGS power should be 30% to 50% higher than the levelized cost estimated here.

9) Given today's typical power price level of 6 to 7¢/kWh, the levelized cost of EGS power should be lower than 5¢/kWh.

10) The minimum levelized cost of 5.43¢/kWh is achievable at Desert Peak only if the following conditions are satisfied:
  a) The stimulated volume is on the order of at least 5 billion cubic feet;
  b) The stimulated volume is reasonably homogeneous and isotropic;
  c) The reservoir is sub-horizontal rather than steeply-dipping;
  d) The cost of creating a stimulated volume of several billion cubic feet is not substantially higher that the costs experienced at Soultz (Europe) and Cooper Basin (Australia); and
  e) A project of several hundred MW capacity based on contiguous repeated EGS units can be developed as being designed at Cooper Basin (Australia).
If any of the above conditions is not satisfied, levelized cost will be higher.

11) The levelized cost of EGS power is most sensitive to operations-and-maintenance cost, followed by power plant/surface facilities cost, drilling cost per well and interest/inflation rates, in that order. It is insensitive to stimulation cost but very sensitive to the effectiveness of stimulation.

12) Improvements in geothermal pump technology that would allow increasing the maximum pumping rate from a well from the current level of 2,500 gallons per minute can reduce levelized cost to as low as 5¢/kWh.

13) The effectiveness of stimulation in creating the desired reservoir characteristics (uniform, isotropic and subhorizontal) minimizes the risk of cooling of the produced fluid. The levelized power cost is sensitive to cooling rate (approximately 0.5¢/kWh increase per °C cooling per year).

14) The depth of the EGS reservoir determines drilling cost and has a large impact on levelized power cost; in other words, levelized cost is very sensitive to site selection.

15) At the levelized cost of EGS power today, the price level needs to be significantly higher than the current price level of 6 to 7¢/kWh to make EGS power more commercial. The price of power in year 2050, in terms of 2006 dollars, is unlikely to be much higher than this level. Therefore, commercialization of EGS power by 2050 will depend on the reduction in the cost of EGS power. Of course, any government subsides can only ease this challenge of commercialization.

16) Reduction in the cost of EGS power by 2050 can be achieved by reducing any combination of a number of tangible cost components (such as O&M and surface equipment costs), increasing the maximum pumping rate from wells, and reducing drilling costs by selecting the shallowest possible site for a given temperature and *in-situ* stress condition.

17) It is possible to reduce the levelized cost of EGS power to as low as 4.4¢/kWh (in 2006 dollars), which would readily make EGS commercial, if reasonable reductions in all cost components and increases in pumping rate can be achieved by 2050 through research development and demonstration under U.S. DOE's support.

18) In the absence of further technological advancements through research, development and demonstration in, potential increases in drilling cost due to market forces may undermine the prospects for commercialization of EGS power by 2050.

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