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OPTIMIZATION OF THE ECONOMICS OF ELECTRIC POWER FROM ENHANCED GEOTHERMAL SYSTEMS

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ABSTRACT

Based on a review of the Enhanced Geothermal Systems (EGS) developed to date, numerical simulation of idealized EGS reservoirs, economic sensitivity analysis, and practical considerations of certain site characteristics, this paper shows that certain steps can be taken towards optimizing the economics of an EGS project: These steps, in decreasing order of their importance, are as follows: (a) reduce the operations and maintenance cost; (b) reduce the power plant cost; (c) choose the site with the highest possible vertical temperature gradient and for the thickest possible sedimentary cover on the basement; (d) choose the drilling depth that maximizes a well's power capacity per unit drilling cost rather than reaches the hottest resource; (e) create the largest possible stimulated volume per well; (f) improve stimulation effectiveness, and particularly, reduce the fracture spacing and heterogeneity in the hydraulic characteristics of the stimulated volume; (g) pump the production wells, if possible, taking advantage of the evolving advancements in pump technology; (h) develop multiple, contiguous EGS units to benefit from the economy of scale; and (i) through reservoir modeling optimize well spacing and injection rates that minimize the rate of decline in net generation with time.

INTRODUCTION

Enhanced Geothermal Systems ("EGS") are hydraulically tight reservoirs whose permeability has been enhanced by hydraulic stimulation. An EGS "unit" in this paper refers to an injection well and the neighboring production wells that derive fluid from it; for example, a doublet, triplet, five-spot, etc. The reservoir is assumed to be developed in the basement rock rather than in any sedimentary overburden. Most of the parameters in this exercise reflect the conditions encountered at the Desert Peak EGS project in the U.S. and the costs reflect 2006 U.S. dollars, but the conclusions reached here regarding optimization should be applicable, at least qualitatively, to any EGS project today.

Optimization of geothermal resource economics calls for minimizing the levelized cost of power (¢ per kilowatt-hour) over the project life. Minimizing the levelized cost, in turn, requires minimizing the capital cost of project development ($ per kilowatt-hour installed) as well as the operations-and-maintenance ("O&M") cost (¢ per kilowatt-hour generated). The approach taken here is as follows: (a) using numerical simulation of idealized EGS reservoirs to estimate power generation over time for various system configurations (number and spacing of wells, assumptions about stimulation effectiveness, etc.); (b) estimating the levelized power cost for each configuration, based on capital cost, O&M cost, cost of money and inflation rate; (c) determining the sensitivity of levelized cost to the cost components, interest and inflation rates, and resource characteristics (pumping rate, reservoir properties, depth to the reservoir, etc.); and (d) based on this sensitivity analysis and certain issues of site characteristics, identifying the practical steps that could be taken towards economic optimization.

LESSONS FROM RESERVOIR MODELING

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 and 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 is greater than for cases with higher throughputs. 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 also possible. Case histories of long-term injection into hydrothermal reservoirs do not show convincing or consistent evidence of progressive fracture enhancement with time, while degradation of the fracture characteristics due to scaling with time is 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 modified that model as needed for this analysis.

From the forecast of the production rate and temperature from the reservoir model, the net power generation versus time was calculated, for each well geometry, after subtracting the parasitic power needed by injection and production pumps. For each combination of assumed geometry, injector-producer spacing, stimulated thickness, enhancement level (fracture spacing and permeability) and production rate, three criteria of performance were computed: (a) net generation profile (net generation versus time over project life), (b) net power produced per unit injection rate, and (c) fraction of in-place heat energy recovered.

This numerical simulation study led to the following conclusions relevant to optimization of resource economics:

1. Cooling rate at production wells is not an adequate criterion for measuring the effectiveness of an EGS power project; net generation profile and reservoir heat recovery factor are more appropriate criteria.
2. Improving permeability, without improving the matrix-to-fracture heat transfer area (that is, reducing the fracture spacing), has little benefit in heat recovery or net generation.
3. The net generation profile can be improved (that is, the decline rate can be reduced) by curtailing the throughput without significantly affecting average generation over the project life.
4. Increasing the stimulated volume increases the generation level without significantly affecting the shape of the generation profile.
5. For a given state of stimulation (that is, fracture spacing and permeability) average net generation increases linearly with stimulated volume and is nearly independent of well geometry (Figure 1).

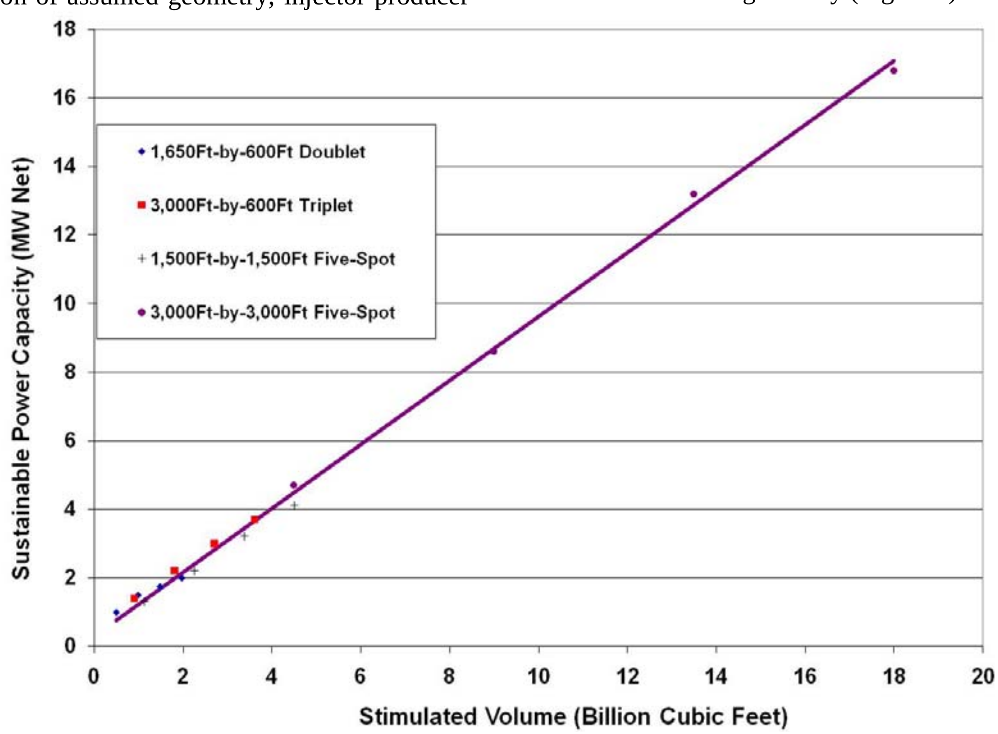

Figure.1: Sustainable power capacity versus stimulated volume

LESSONS FROM ECONOMIC MODELING

This analysis has utilized the economic model presented by Sanyal et al (2007a). We have estimated the drilling cost based on a statistical correlation with depth, and the stimulation cost based primarily on the experience of the European EGS project at Soultz-sous-Forêts and Geodynamics' EGS project at Cooper Basin, Australia. For the power plant and surface facilities cost and the O&M cost, we have used the typical range of values in the U.S. geothermal industry. The uncertain variables in this analysis (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 power cost. The capital cost was amortized over the project life at the interest rate, and O&M cost was increased at the inflation rate over the project life. The annual capital-plus-interest payment and O&M cost were discounted to their present value using the inflation rate. The mean levelized power cost versus stimulated volume per EGS unit was thus estimated for all configurations and stimulated volumes considered.

The economic analysis resulted in the following conclusions relevant to economic optimization:

1. Levelized power cost declines with increasing stimulated volume, and for any configuration, with the repeating of contiguous EGS units (Figure 2).
2. The lowest possible cost of power at Desert Peak was estimated at 5.43¢ per kWh (2006 $), ignoring certain uniquely site-specific and/or atypical costs of exploration, infrastructure development (such as roads and the transmission line), regulatory compliance, environmental impact mitigation, royalties, and taxes.
3. Levelized power cost is most sensitive to O&M cost, followed by power plant/surface facilities cost, drilling cost per well and interest/inflation rates, in that order (Figure 3). It is insensitive to stimulation cost but very sensitive to the effectiveness of stimulation (Figure 3).

Improvements in geothermal pump technology in the future could allow increasing the maximum practicable pumping rate from a well (currently 200 ℓ/s), thus reducing the levelized power cost; a plausible 50% improvement in the pumping rate can reduce the levelized cost to 5¢/kWh (Figure 4).

The effectiveness of stimulation in creating closely-spaced fractures and the desired reservoir characteristics (uniform, isotropic and sub-horizontal) reduces 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 as seen in Figure 5).

Reservoir depth determines drilling cost, energy reserves and well productivity, while the effectiveness of stimulation, which is dependent on the lithology and in-situ stress condition at the site, determines cooling. Therefore, the levelized cost can be very sensitive to site characteristics. Figure 6 shows the sensitivity of levelized power cost to well depth.

CONSIDERATION OF CERTAIN SITE CHARACTERISTICS

It is obvious that the higher the vertical temperature gradient, that is, the higher the heat flow rate at the surface, the more attractive the site should be. Sanyal and Butler (2004) presented an approach to estimating the EGS resource base using heat flow estimates at the surface. Using this approach, Figure 7presents estimates of potential EGS power capacity per square mile versus drilling depth for a range of surface heat flow values, assuming a minimum acceptable resource temperature of 250°F for power generation, a power plant rejection temperature of 72°F and a plant life of 30 years. As to be expected, the power capacity increases nearly exponentially with depth, and more steeply for higher heat flow rates (Figure 7). However, drilling cost also increases nearly exponentially with depth. Using the drilling cost versus depth correlation presented in Sanyal et al (2007a), we can estimate the reserves potentially secured per million dollar drilling cost for any drilling depth. Figure 8 presents the estimated potential reserves secured per million dollar drilling cost as a function of depth for various heat flow values, the other assumptions being the same as for Figure 7. This figure shows that the increase in the potential reserves per unit drilling cost does not go up exponentially with depth and tends to flatten out with depth, particularly for high heat flow rates. In other words, deeper drilling to secure a larger reserve base does not necessarily lead to economic optimization.

Site selection is often based on regional heat flow distribution and drilling of relatively shallow exploration wells. However, the temperature gradient measured at relatively shallow depths cannot be extrapolated downward indefinitely because of intervening geological issues such as the thickness of sediment cover on the basement, lithology changes, radioactive heat generation in the basement or the presence of natural convection cells. For example, Figures 9 and 10 show the effect of the thickness of sediment cover and radioactive heat generation, respectively, on the deep temperature gradient.

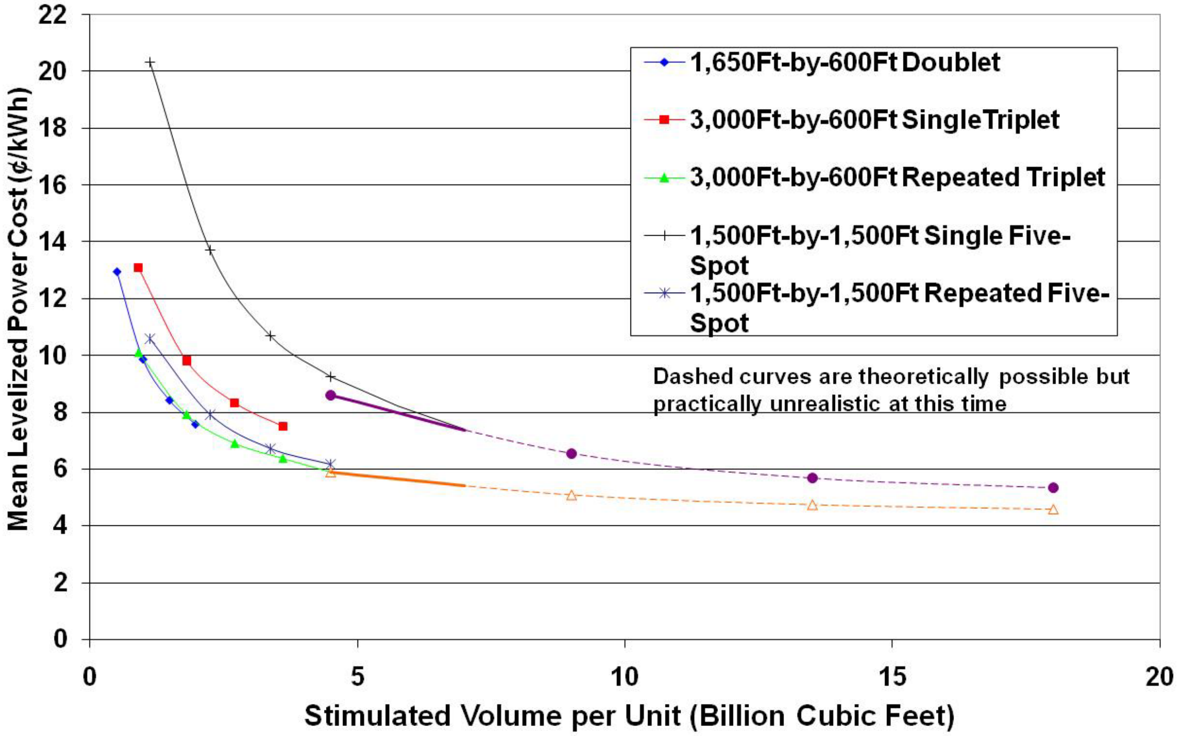

Figure.2: Mean levelized cost of EGS power versus stimulated volume

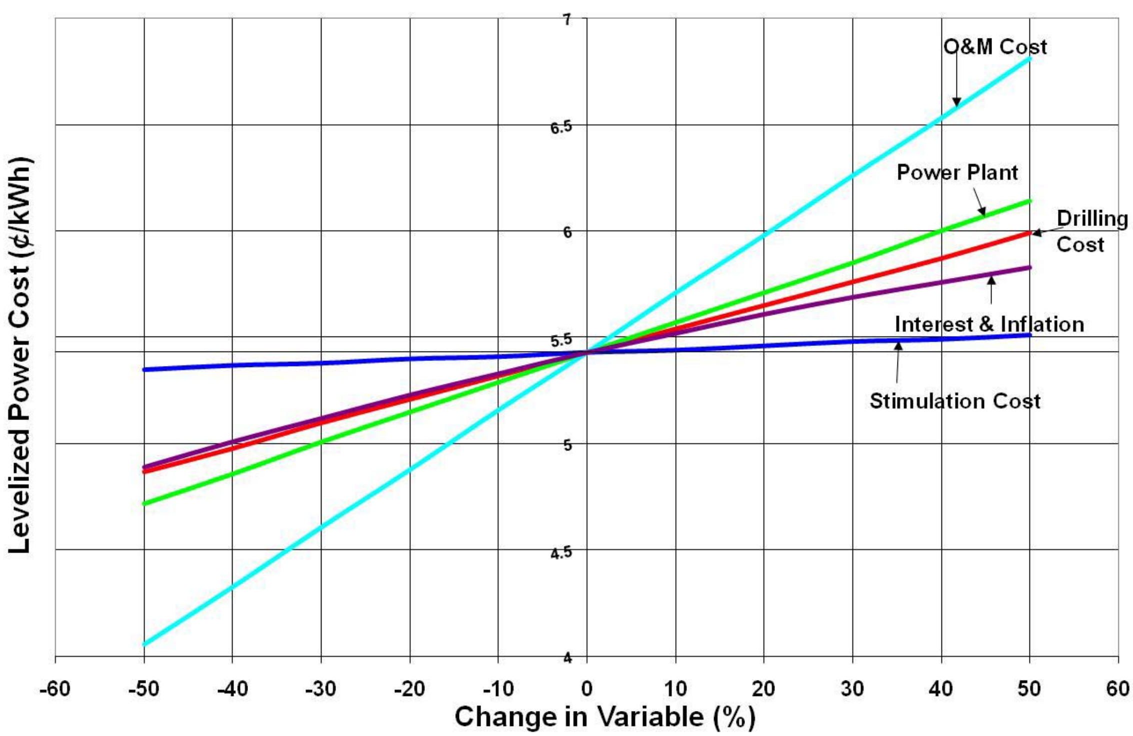

Figure.3: Sensitivity of levelized power cost

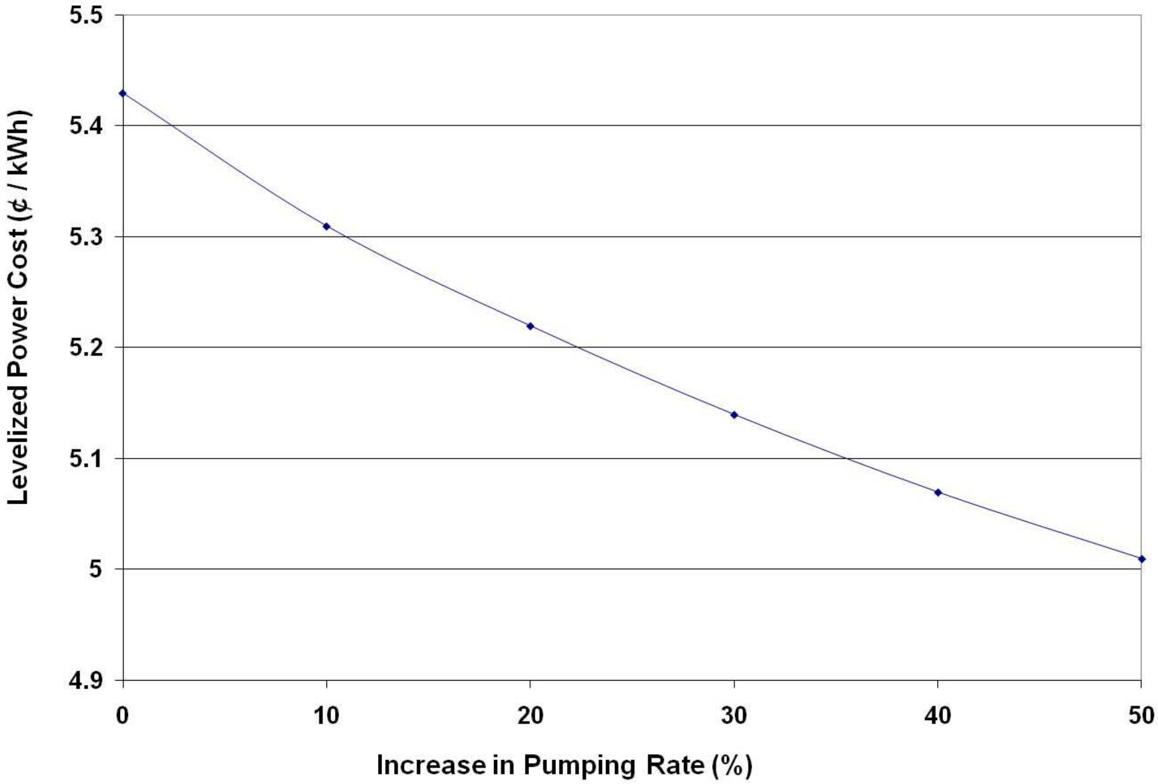

Figure.4: Levelized power cost versus increase in pumping rate

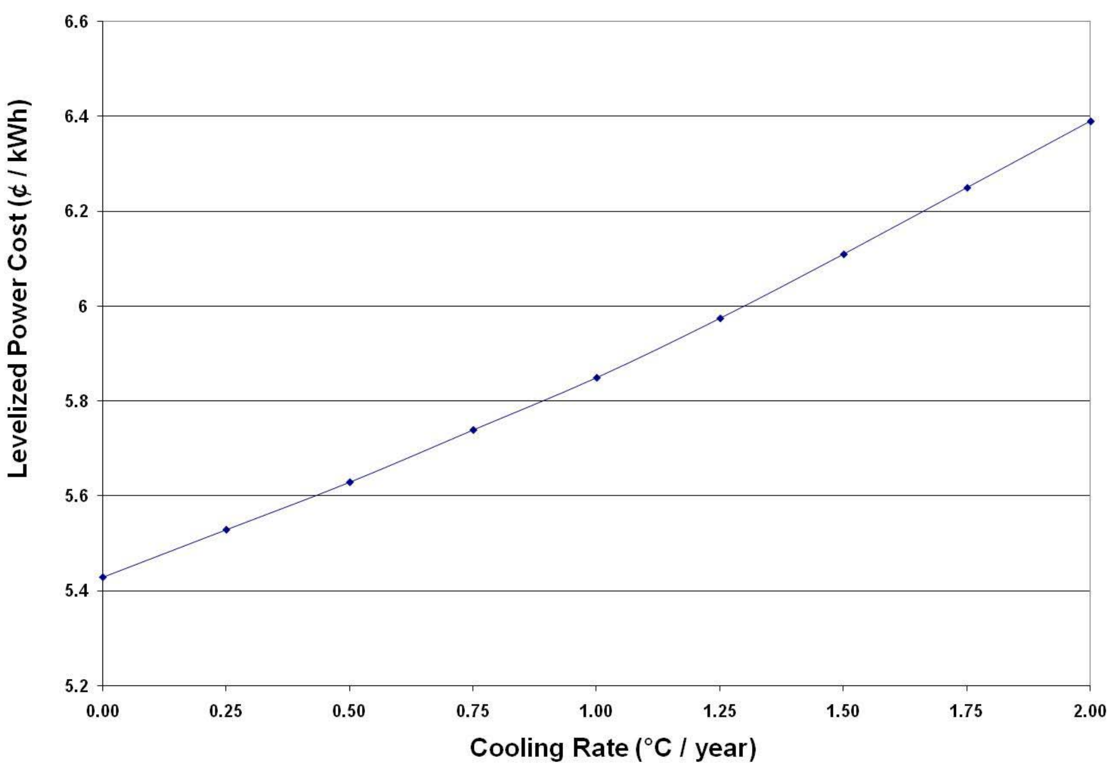

Figure.5: Levelized power cost versus cooling rate

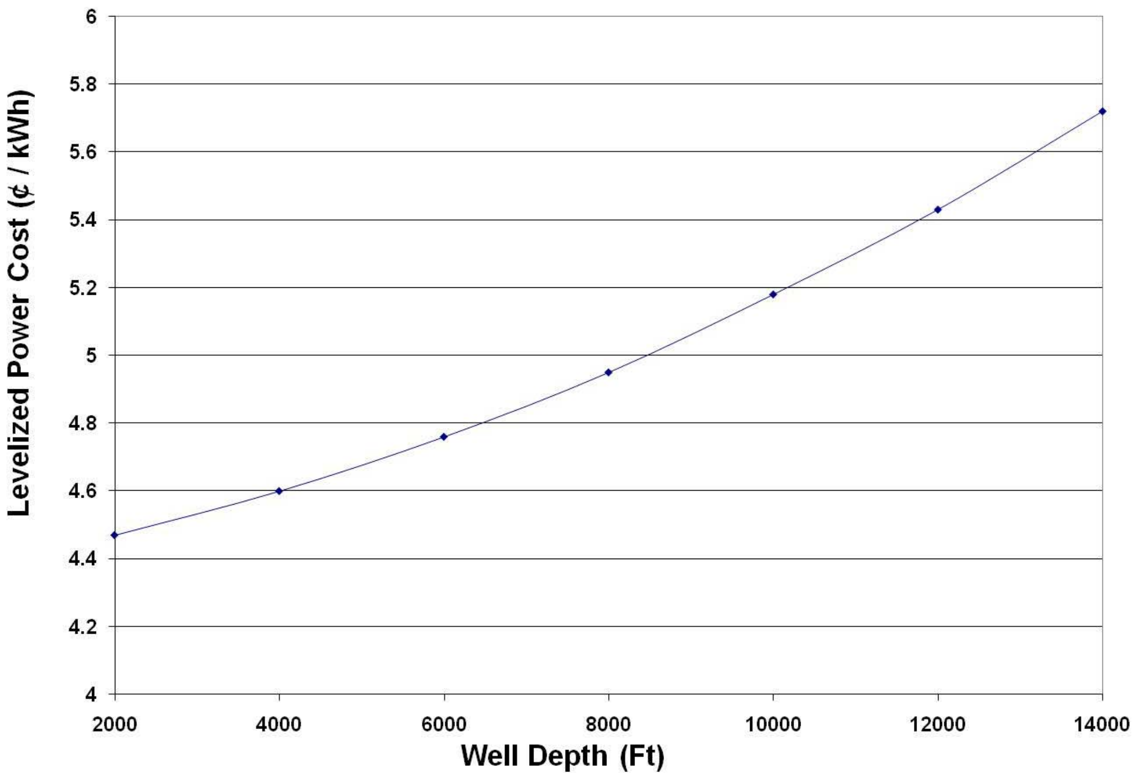

Figure.6: Levelized power cost versus well depth

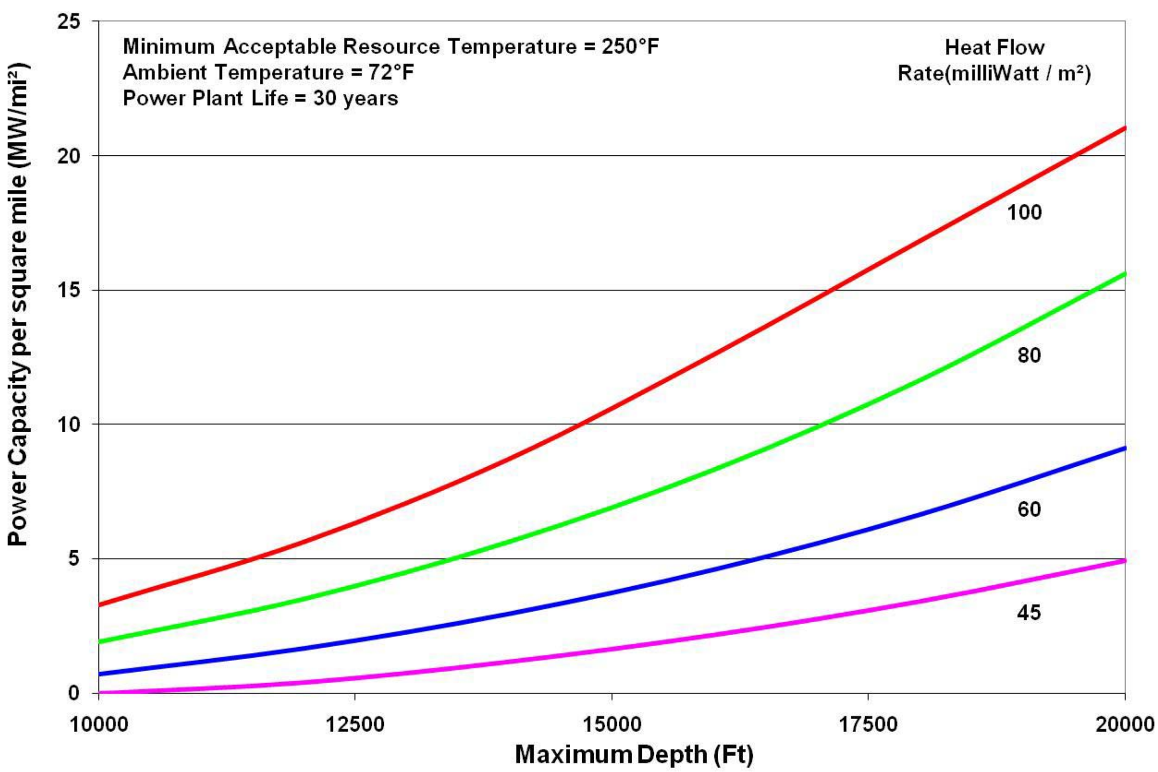

Figure.7: EGS resource base versus drilling depth

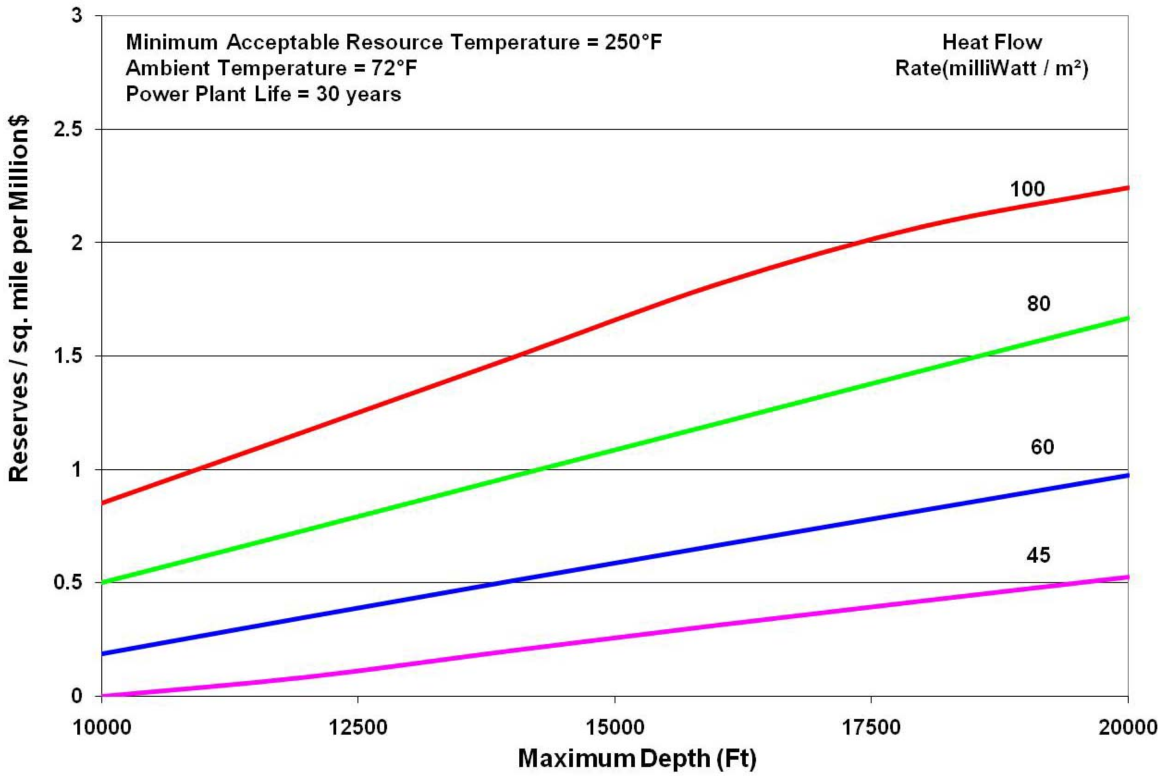

Figure.8: Reserve per square mile per million $ drilling cost

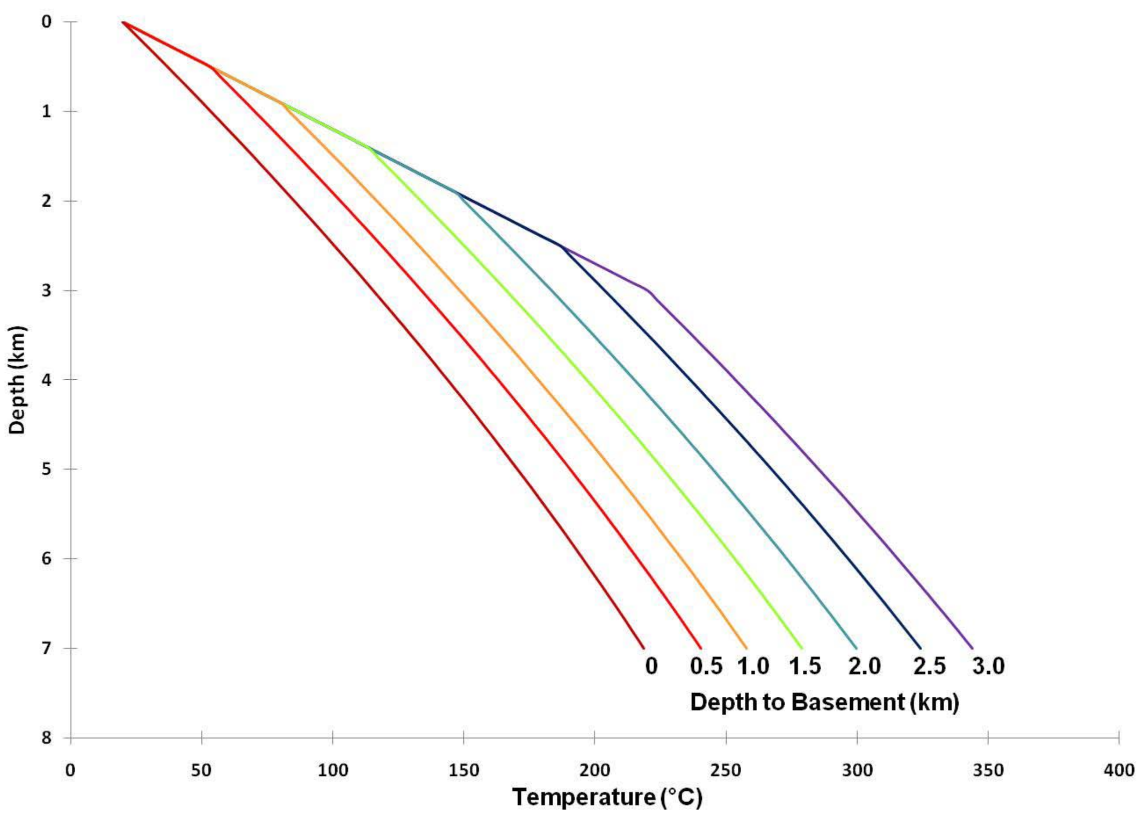

Figure.9: Effect of depth to basement on temperature profile

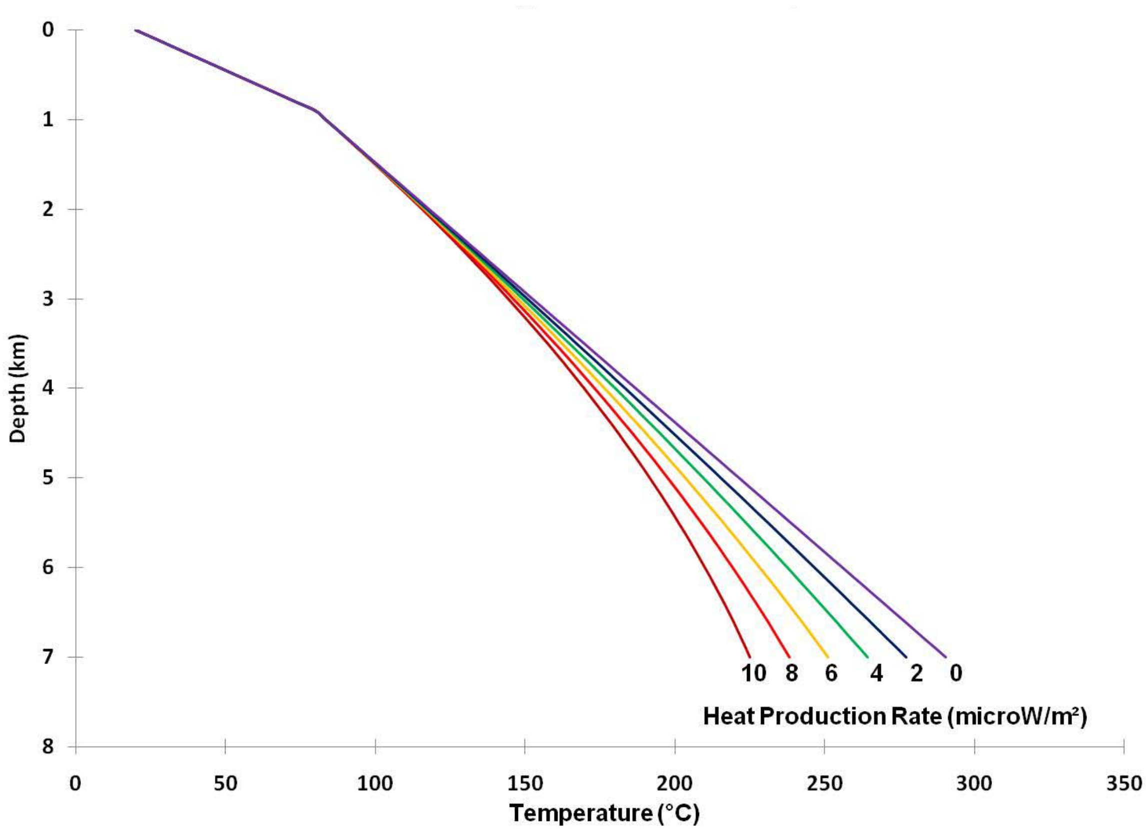

Figure.10: Effect of radioactive heat generation on temperature profile

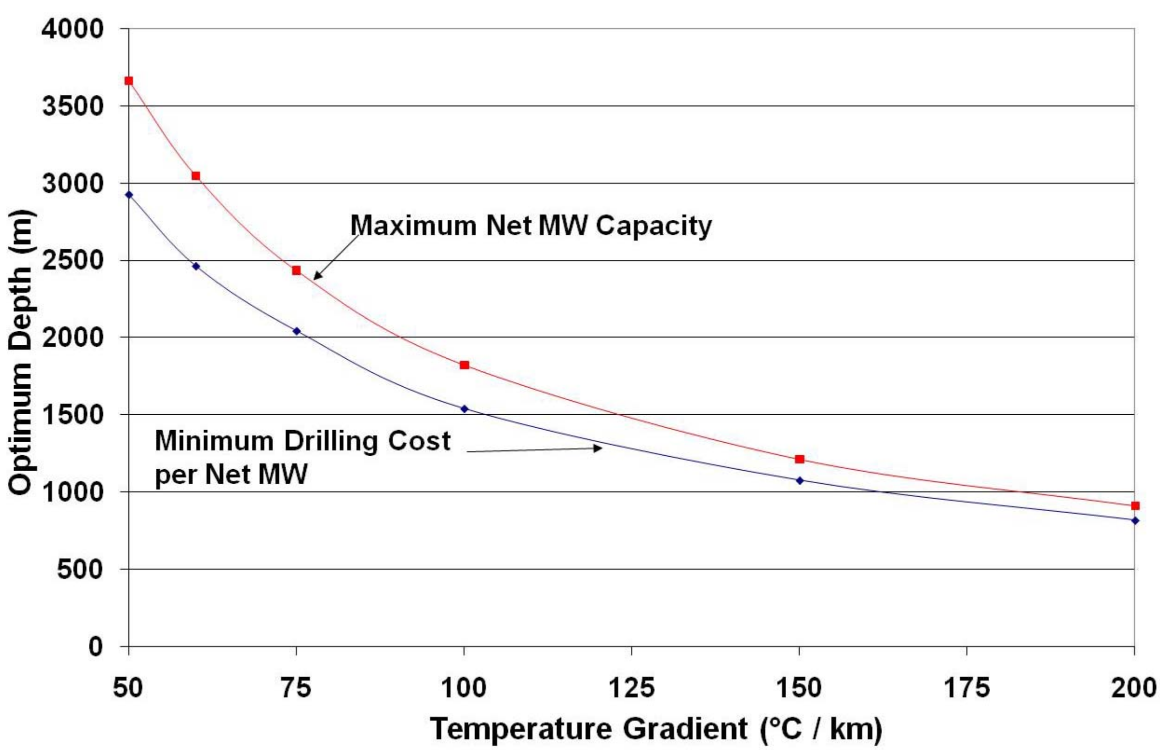

Figure.11: Optimum drilling depth of an EGS project versus temperature gradient

While energy reserves per unit area at any site increases with depth, net MW production capacity per well does not necessarily increase with depth (Sanyal et al, 2007b). This issue arises from the fact that up to the depth where the temperature reaches 190°C, which is generally the temperature limit for pumps available today, the capacity of a pumped well would increase with depth. Below this depth a well will have to be self-flowed and its capacity would actually be less; this would be true up to the depth where the temperature reaches about 220°C. Above this temperature level no generalization is possible about well capacity. Sanyal et al (2007b) showed that considering the well capacity and cost of drilling versus well depth, an optimum drilling depth may be defined at a site; this optimum drilling depth can be either the depth at which the well capacity is maximized or the drilling cost per MW well capacity minimized (Figure 11).

CONCLUSIONS

Based on numerical modeling of an idealized reservoir, economic analysis, and practical considerations of certain site characteristics, we conclude that the following steps can be taken towards optimizing the economics of an EGS project; the steps are presented below in decreasing order of their importance:

1. Reduce the operations and maintenance cost.
2. Reduce the power plant cost.
3. Choose the site with the highest possible vertical temperature gradient and/or the thickest possible sedimentary cover on the basement.
4. Choose the drilling depth that maximizes a well's power capacity per unit drilling cost rather than reaches the hottest resource.
5. Create the largest possible stimulated volume per well.
6. Improve stimulation effectiveness, and in particular, reduce the fracture spacing and heterogeneity in the hydraulic characteristics of the stimulated volume.
7. Pump the production wells, if possible, taking advantage of the evolving advancements in pump technology.
8. Develop multiple, contiguous EGS units to benefit from the economy of scale.
9. Through reservoir modeling optimize well spacing and injection rates that minimize the rate of decline in net generation with time.

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