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THERMAL ENERGY RECOVERY FROM ENHANCED GEOTHERMAL SYSTEMS – EVALUATING THE POTENTIAL FROM DEEP, HIGH-TEMPERATURE RESOURCES

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ABSTRACT

A variety of mechanical, chemical and thermal approaches to reservoir stimulation have been proposed and tested over more than three decades of research on Enhanced Geothermal Systems (EGS) technology, with the primary focus at present on enhancing fracture permeability by elevating fluid pressure sufficiently to induce shear failure along pre-existing natural fractures. A critical issue in assessing the potential EGS resource is quantifying R_g, the geothermal recovery factor, which is defined as the ratio of produced thermal energy to the thermal energy contained in the fractured volume comprising the reservoir. One approach to EGS resource assessments incorporates the assumption that a constant amount of thermal energy is recovered during the life of a project, regardless of the temperature of the reservoir, thereby concluding that there is a decrease in R_g with increasing reservoir temperature and a reduced potential associated with deep, higher temperature resources. By contrast, production experience and simulations of thermal energy recovery from naturally fractured geothermal reservoirs indicate that R_g, which typically falls in the range from 0.05 to 0.2, is primarily a function of internal reservoir structure, not temperature. Because the thermal energy content of the crust increases linearly with increasing temperature, if the characteristics of R_g for naturally fractured reservoirs apply to EGS reservoirs, proportionally greater resource potential is associated with the deeper, hotter portions of the Earth's crust, despite the costs and challenges associated with creating and exploiting reservoirs at greater depths and higher temperatures. However, other aspects of production from deep, hot EGS reservoirs need further evaluation, such as the relative effects on productivity of declining fluid viscosity with increasing temperature, fracture closure at higher levels of effective stress, and the increased rates of mineral precipitation and dissolution at higher temperatures. These aspects may limit the viability of deep EGS resources.

INTRODUCTION

Conventional geothermal resources depend upon hydrothermal fluid circulation that results from the convergence of high temperatures and high permeability, typically fracture permeability produced as a result of recent or active faulting. Enhanced Geothermal Systems (EGS) are geothermal resources that require some form of engineering to develop the permeability necessary for the circulation of hot water or steam and the recovery of heat for commercial applications (DOE, 2008). Because exploitation of EGS resources incorporates the augmentation or creation of permeability in situ, the presence of elevated temperatures at drillable depths is the dominant factor controlling the quality of the resource.

Under the assumption of successful implementation of EGS technology, provisional estimates of EGS electric power resource potential in the western United States, where high crustal heat flow is most favorable for EGS development (Figure 1), were included in the recent USGS geothermal resource assessment (Williams, et al., 2008a). In this assessment, models for the extension of geothermal thermal energy recovery techniques into regions of hot but low permeability crust down to a depth of 6km yield an estimated mean electric power resource on private and accessible public land of approximately 520,000 MWe. This is nearly half of the current installed electric power generating capacity in the United States and an order of magnitude larger than the conventional geothermal resource.

Another recent EGS resource assessment was produced by a panel of experts convened by the Massachusetts Institute of Technology (MIT) under Department of Energy (DOE) sponsorship (Tester et al., 2006). In their report, Tester and others estimate the EGS potential for entire continental United States to a depth of 10km. The portion of this assessment covering the same western states as the USGS assessment and over approximately the same 6km depth range varies between 200,000 and 2,000,000 MWe, depending on the assumptions applied for the recoverability of heat from the Earth's crust. Although the mean USGS estimate lies within the range of values produced by the MIT panel, the wide variation highlights significant uncertainties in the potential recovery of useful heat from the Earth's upper crust. Understanding and reducing these uncertainties is of critical importance to the successful development of the EGS resource.

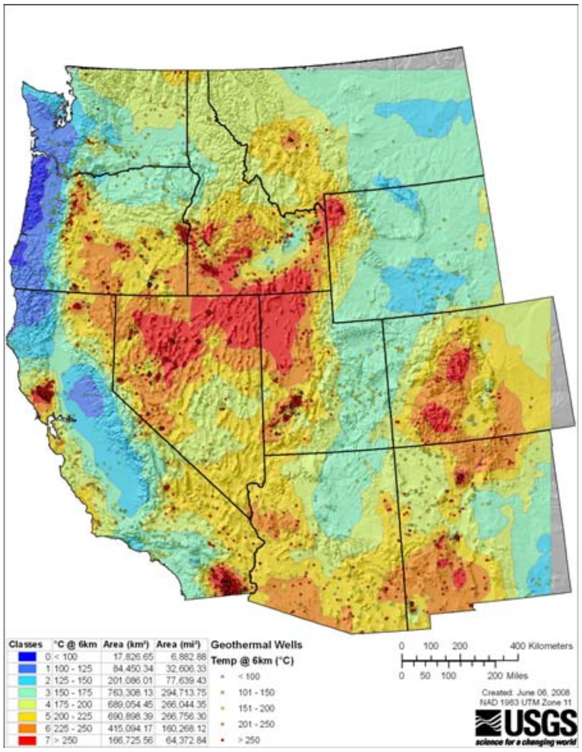


Figure 1: Map showing an estimated distribution of temperature at a depth of 6km in the western United States.

THE RECOVERY OF HEAT FROM GEOTHERMAL RESERVOIRS

The potential energy recovery from a geothermal reservoir depends on the thermal energy, q_R, present in the reservoir, the amount of thermal energy that can be extracted from the reservoir at the wellhead, q_{WH}, and the efficiency with which that wellhead thermal energy can be converted to electric power. Once the reservoir fluid is available at the wellhead, the thermodynamic and economic constraints on conversion to electric power are well known (for example, DiPippo, 2005). The challenge in geothermal resource assessment lies in quantifying the size and thermal energy of a reservoir as well as the constraints on extracting that thermal energy. In the approach applied in USGS assessments, the reservoir thermal energy is calculated as

$$q_R = \rho C V (T_R - T_0) \qquad (1)$$

where ρC is the volumetric specific heat of the reservoir rock, V is the volume of the reservoir, T_R is the characteristic reservoir temperature, and T_0 is a reference, or dead-state, temperature. The thermal energy that can be extracted at the wellhead is given by

$$q_{WH} = m_{WH}(h_{WH} - h_0) \qquad (2)$$

where m_{WH} is the extractable mass, h_{WH} is the enthalpy of the produced fluid, and h_0 is the enthalpy at some reference temperature (typically 15°C). The wellhead thermal energy is then related to the reservoir thermal energy by the recovery factor, R_g, which is defined as

$$R_g = q_{WH} / q_R \qquad (3)$$

Inherent in these equations is a geometrical concept of the reservoir that allows calculation of a volume and an estimate of the ability to extract hot fluid from the volume. In ideal cases values for R_g as large as 0.5 to 0.6 have been derived from analytical and numerical models of heat extraction from a geothermal reservoirs through a "cold sweep" process, in which the hot reservoir water is gradually replaced by colder water through natural recharge and/or artificial injection (e.g., Nathenson, 1975; Muffler and Cataldi, 1978; Muffler, 1979; Sanyal and Butler, 2004). Analyses of production data from naturally fractured reservoirs indicate that R_g typically varies between 0.05 and 0.2 (e.g., Lovekin, 2004; Williams, 2004). These lower values for R_g reflect the thermal effects of heterogeneities in the spatial distribution and flow characteristics of permeable fractures in the reservoirs (Bodvarsson and Tsang, 1982; Pruess and Bodvarsson, 1984; Williams, et al., 2007, 2008b).

From estimates of R_g and measurements of reservoir volume and properties, the exergy, E, (DiPippo, 2005) for a geothermal reservoir can be determined as

$$E = m_{WH}[h_{WH} - h_0 - T_0(s_{WH} - s_0)] \qquad (4)$$

where s_{WH} is the entropy of the produced fluid and s_0 is the entropy at the reference temperature. The electric energy, $\dot{W}_e$, for a given period of time (typically 30 years) is then determined through multiplying the exergy over the same period of time by a utilization efficiency, η_u, which is generally well-constrained for a reservoir of a specified fluid state and temperature (Muffler and others, 1979; DiPippo, 2005; Williams et al., 2007, 2008), as

$$\dot{W}_e = \dot{E}\eta_u \tag{5}$$

The 2008 USGS geothermal resource assessment applied this approach for both naturally-occurring geothermal reservoirs (both identified and undiscovered) and Enhanced Geothermal Systems. The resource estimate for EGS incorporated three significant changes relative to natural geothermal systems. First, the potential EGS reservoir volume in the western United States for electric power generation was assumed to be the portion of the Earth's crust above 6km depth in which the temperature exceeds 150^{o}C (Figure 1), reduced by the area occupied by public lands closed for geothermal development, such as national parks. Second, the available reservoir volume was reduced by a factor ranging from 6 to 12 to allow for the fraction of rock in situ that would either be lithologically unsuitable for EGS development or left unfractured for the lifetimes of first generation reservoirs in order to preserve low permeability barriers between zones of contrasting temperature and/or pressure. Third, the average value of R_g was set to 0.05, at the low end of the observed range for naturally-fractured geothermal reservoirs. This value reflects the observation that, for EGS experiments conducted to date, the stimulated volume indicated by microseismicity during reservoir development is significantly larger than the effective reservoir dimensions under production (e.g., Williams et al., 2008b).

The analysis applied in the 2006 MIT report follows a somewhat different approach in the definition of terms and analysis of power potential, but the basic concepts are similar. For example, the recovery factor was given as

$$F_R = \frac{q_{rec}}{q_{tot}} = \frac{V_{act}(T_R - T_a)}{V_{tot}(T_R - T_{ref})} \tag{6}$$

Where F_R is the recovery factor, q_{rec} is the recovered thermal energy, q_{tot} is the total thermal energy in the reservoir, V_{act} is the volume of the active, or producing portion of the reservoir, V_{tot} is the total reservoir volume and T_a is the average reservoir temperature at abandonment (Tester et al., 2006). For quantitative estimates, equation (6) was simplified to

$$F_R = \phi_{eff}\left(\frac{10°C}{T_R - T_{ref}}\right) \quad (7),$$

in which φ_{eff} was specified to be either 0.02 or 0.2. In this formulation φ_{eff} is equivalent to the volume fraction estimate applied separately in the USGS EGS assessment, and the temperature ratio to the right of φ_{eff} represents the true thermal recovery factor within the active reservoir.

Despite the overall similarities, there are two important questions regarding potential differences between the recovery factors defined in the two assessments. First, how does the average reservoir temperature relate to the temperature of the water produced at the wellhead? Second, in the USGS and other assessments for both natural and EGS reservoirs, R_g has a range of values independent of temperature (Williams et al., 2008b), whereas the value of F_R from the MIT assessment decreases with increasing reservoir temperature, resulting in a constant amount of heat recovered at all temperatures (Tester et al., 2006). Which approach is more likely to be representative of EGS reservoir performance? The section below investigates the significance of these contrasting approaches through analysis of a simple reservoir model.

ANALYSIS OF A DOUBLET RESERVOIR MODEL

The basic characteristics of thermal energy recovery in geothermal reservoirs can be illustrated with an idealized reservoir model. Figure 2 shows the evolution of temperature within a circular EGS reservoir 150m in diameter that is exploited by a single production and injection well doublet, with the two wells separated by 100m. At the early time of 2.5 years (left side of Figure 2), temperature at the production well is undisturbed from the initial 200°C even though the cold water injection front has affected a relatively large portion of the reservoir. By the later time of 7.5 years (right side of Figure 2), thermal breakthrough has resulted in a significant temperature decline at the production well.

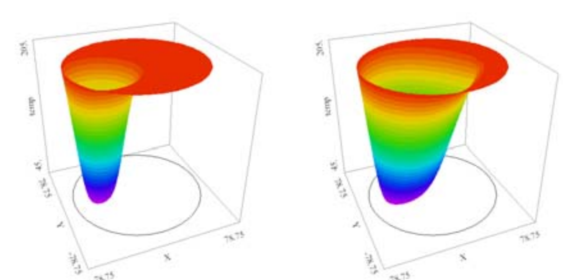


Figure 2: Contour plot showing propagation of a thermal front in a circular reservoir from an injection well to a production well located 100 m away after 2.5 years (left) and 7.5 years (right). Colors range from 50°C (violet) to 200°C (red).

Figure 3 shows the thermal recovery factor for the modeled reservoir from a series of simulations with a constant well spacing of 100m but increasing reservoir diameter from 150m to 400m. The thermal recovery factor decreases with increasing reservoir diameter as a progressively larger fraction of the reservoir is left untapped. These results are similar to the production histories for naturally fractured reservoirs in which fast paths between injection and production wells can limit recovery and lead to premature temperature declines.

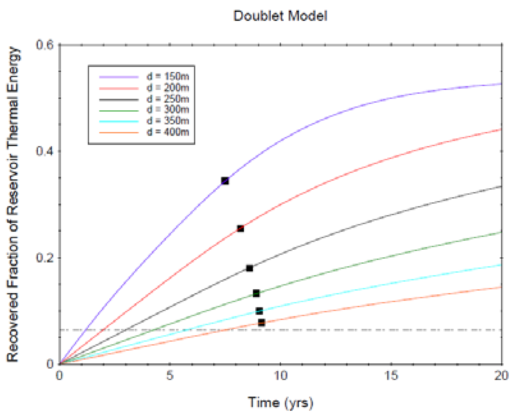
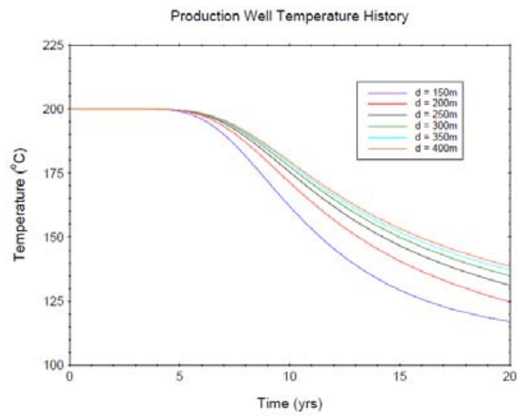


Figure 3: Recovered thermal energy over time from the modeled reservoir for diameters ranging from 150 to 400m. Black squares represent recovery at the time of thermal breakthrough as defined in the text. The dashed gray line represents the recovery factor for this reservoir as defined by equation (7).

Detailed histories of the temperature at the production well and the average temperature in the reservoir are shown in Figure 4 for the same set of reservoir parameters. The basic features of the thermal histories are consistent, even though the amplitudes of the responses vary with increasing reservoir size. At the production well temperatures are relatively constant for approximately 5 years, at which point a decline begins (Figure 4a). The initial timing of this decline is controlled by the 100m spacing between the injection and production wells. With increasing reservoir size a progressively larger fraction of the flow between the wells follows longer paths around the margin of the reservoir, carrying additional heat to the production well and reducing the rate at which production temperature decreases. If thermal breakthrough is defined as occurring when the temperature difference between the production well and the injection well declines to 0.9 times its initial value, then the breakthrough time varies from 7.5 years for a 150m diameter reservoir to 9.15 years for a 400m diameter reservoir (Figure 3).

By contrast, the average temperature in the reservoir starts declining almost immediately as the cold water plume propagates out from the injection well (Figure 4b). One consequence of this is that for all but the largest reservoir diameters, the average temperature in the reservoir drops by more than 10°C before a measurable decline begins at the production well.

(a)



(b)

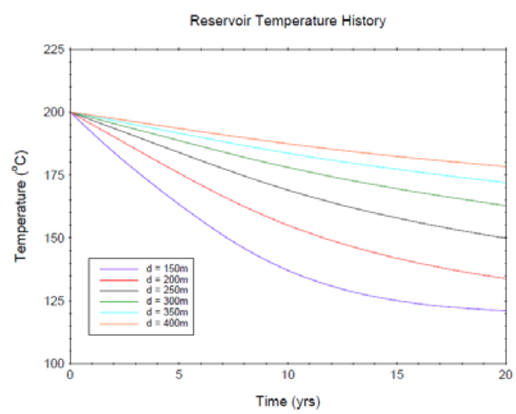


Figure 4: (a) Production well temperatures and (b) average reservoir temperatures over time for varying reservoir diameter.

Figure 5 illustrates the relationship between production well and average reservoir temperatures for these simulations. In those cases for which the reservoir diameter is close to the well spacing and the thermal recovery factor is high, the production well temperature remains above the average reservoir temperature until times long after thermal breakthrough has occurred. As the reservoir diameter increases and the recovery factor declines to values more representative of those likely to be encountered in fractured reservoirs with high permeability "fast paths", the production well temperature is equal to or less than the average reservoir temperature for a longer period of time. In these cases the recovery factor defined by a specified reservoir temperature, as in the MIT assessment, is relatively close to the recovery factor defined by thermal breakthrough, as in the USGS assessment.

Although this analysis explains the approximate consistency of these two approaches, there still remains the question of whether recovery factor should vary as a function of temperature. This question cannot be addressed solely from an earth science or reservoir engineering perspective, since the decision to abandon a geothermal reservoir depends in part on economic factors, such as the cost of adapting power plant operations to lower inlet temperatures. As a general rule, there is greater engineering flexibility at higher temperatures, which is consistent with a constant recovery factor. However, there are also important aspects of reservoir stimulation and exploitation to consider, particularly when higher reservoir temperatures are associated with greater depth, as they are for most of the Earth's crust in the western United States.

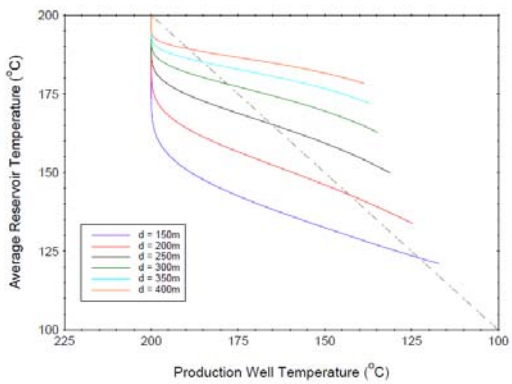


Figure 5: Reservoir versus production well temperature for the specified range of reservoir diameters plotted along with a line (dashed grey) representing the points at which the production well temperature equals the average reservoir temperature.

FACTORS INFLUENCING DEEP, HIGH TEMPERATURE EGS RESOURCES

Because of the increase of temperature with depth due to the conductive geothermal gradient, exploiting most of the higher temperature EGS resource involves drilling to greater depth. Consequently, a definitive evaluation of EGS potential should include the full range of thermal, mechanical, hydraulic, and chemical processes that can alter both natural and induced fracture permeability at elevated temperature and stress. In addition, the propagation of a cool thermal front the vicinity of injection wells will influence fracture permeability of the reservoir through the effects of thermal contraction and the role of temperature in mineral precipitation and dissolution reactions (e.g., Taron et al., 2009; Taron and Elsworth, 2009).

The key parameter in evaluating potential stress and temperature sensitivity of reservoir flow rates is the hydraulic conductivity, K, which is defined as

$$K = \frac{k\rho g}{\mu} \tag{8}$$

where k is the permeability, ρ the fluid density, g the acceleration due to gravity and μ the viscosity. In general, natural fracture permeability decreases with increasing effective normal stress on the fractures (e.g., Walsh, 1981), and this is also true for the permeability of shear fractures induced through hydraulic stimulation (Raman et al., 2002). For these shear fractures, the relationship between permeability and effective normal stress is generally given as

$$\left(k\right)^{1/3} \propto a = \frac{a_0 + U\tan(\phi_{dil})}{1 + 9\sigma' / \sigma'_{nref}} \tag{9}$$

where a is the fracture aperture, a_0 is the aperture at some reference state, U is the shear displacement, φ_{dil} is the dilation angle, σ´ is the effective stress, and σ'_{nref} is a reference effective normal stress (Willis-Richards et al., 1996).

For this analysis, two possible permeability scenarios are considered for EGS systems developed in the depth and temperature range from 150°C and 3km to 300°C and 6km (Figure 6). One represents a relatively compliant fracture system in which the parameters in equation (9) are set so that k_1(z=6km) is equal to 0.2 k_1(z=3km), and the other represents a relatively noncompliant fracture system with k_2(z=6km) equal to 0.5k_2(z=3km). The depth dependence of k_1 is approximately equal to the predictions of Willis-Richards et al. (1996) for the EGS sites at Fenton Hill and Rosemanowes. The density of water over this temperature and pressure range is derived from tables for pure water under hydrostatic pressure conditions, and the viscosity is determined from the equation

$$\mu(T,P) = A_0\left(\frac{P}{F}+1\right)^{2(1-\frac{T_0}{T})} \exp\left(\frac{B_0}{T}\right) \tag{10}$$

in which P is fluid pressure, T is temperature (in degrees Kelvin) and A_0, B_0, F and T_0 are reference coefficients (Wakasugi, 1990). Over this depth and temperature range the effect of the decrease in both density and viscosity with increasing depth and temperature partially compensates for the decrease in permeability, so that the values are K_1(T=300°C, z=6km) ~ 0.3K_1(T=150°C, z=3km), and K_2(T=300°C, z=6km) ~ 0.7K_2(T=150°C, z=3km).

The potential decrease in reservoir K with depth and temperature could be moderated to some degree by fracture opening due to contraction cooling of the reservoir rock in the vicinity of the injection well and by accelerated mineral dissolution reactions. The full set of couple mechanical, thermal, hydraulic, and chemical processes is being addressed within the geothermal community through sophisticated numerical modeling (e.g. Taron et al., 2009; Taron and Elsworth, 2009). However, with existing modeling results limited to a narrow range of reservoir conditions and rock properties and the absence of long-term EGS field experience, the most that can be stated at this point is that decrease of permeability with depth could hamper efforts to extend EGS technology to depths beyond the deepest existing natural geothermal reservoirs, which have yet to be exploited below approximately 6km (Kobayashi, 2000).

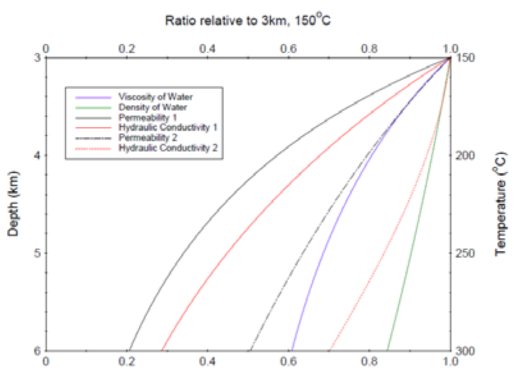


Figure 7: Two possible hydraulic conductivity profiles for EGS reservoirs based on modeled profiles for permeability, water viscosity and water density over the depth and temperature interval from 3km and 150°C to 6km and 300°C.

SUMMARY

Field observations and modeling studies indicate that values for the geothermal recovery factor, R_g, less than 0.1 are likely to be representative of EGS reservoir performance. Although both constant and temperature-dependent formulations for R_g can yield consistent results in specific cases, significant temperature-dependence for R_g has yet to be established and could underestimate the potential from higher temperature resources. R_g is more likely to decline with increasing effective stress, and to the extent that the increase in effective stress with depth corresponds with increasing temperature in the Earth's crust, the exploitation of deep, high-temperature EGS resources may be limited.

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