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TITLE: FRACTURED GEOTHERMAL RESERVOIR GROWTH INDUCED BY HEAT EXTRACTION

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MASTER

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Fractured Geothermal Reservoir Growth Induced by Heat Extraction

ABSTRACT

Field testing of a hydraulically-stimulated, hot dry rock geothermal system at the Fenton Hill site in northern New Mexico has indicated that significant reservoir growth occurred as energy was extracted. Tracer, microseismic, and geochemical measurements provided the primary quantitative evidence for documenting the increases in accessible reservoir volume and fractured rock surface area that were observed during energy extraction operations which caused substantial thermal drawdown in portions of the reservoir. These temporal increases suggest that augmentation of reservoir heat production capacity in hot dry rock systems may be possible.

BACKGROUND

Commercial exploitation of hot dry rock in low permeability formations requires access to large rock surface areas and volumes. The concept consists of creating a labyrinth of flow paths with recirculated working fluids that are used to remove a portion of the thermal energy contained in the hot rock mass at depth. This process of heat mining has been achieved in a prototype field reservoir located in the Jemez Mountains of northern New Mexico. At the Fenton Hill site average gradients of 55°C/km are found in micro-darcy to nano-darcy (10^{-18} to 10^{-21} m²) permeability crystalline granitic rock. The active reservoir or Phase I system discussed in this paper was created by hydraulic fracturing over a depth interval from about 2.5 to 2.9 km (8000 to 10000 ft) where initial rock temperatures from 170 to 200°C are found. The main section of the fracture system is located in a body of biotite granodiorite consisting primarily of four major minerals: potassium feldspar (19%), plagioclase feldspar (37%), quartz (26%), and biotite (12%).

References and illustrations at end of paper.

The granodiorite section is texturally equigranular and non-foliated with frequent sealed joints or natural fractures. Earlier publications have described the geologic setting and reservoir characteristics in detail (Murphy et al (1981), Dash et al (1981), Zyvoloski (1981)).

SUMMARY OF FIELD TESTING

Initially, a small reservoir was created by hydraulically fracturing well EE-1 and sidetracking from well GT-2 to pass through the fractured region. At depths of 2.5 to 2.9 km, the minimum principal earth stress is horizontal, suggesting that induced or activated fractures would favor a vertical structure possibly along weakly-cemented joints. Testing of this system was conducted during Segments 2 and 3 of the Los Alamos program during 1979.

Later in 1979, a larger system was stimulated by fracturing from EE-1 after recementing the injection zone of the original reservoir at about 2.75 km. The injection region of enlarged system was deepened to 2.93 km, increasing the separation distance between the production zones in the sidetracked well GT-2B and the injection zone in EE-1 from about 100 m to 300 m. Testing of the enlarged system was carried out in Segments 4 and 5 from 1979 through 1981.

The systems were operated in a heat extraction mode during the Segments 2 through 5, with fluid injected under approximately instant injection and production pressure conditions of about 8.5 MPa (1200 psi) and 1.1 MPa (160 psi), respectively. Heat was removed from the recirculated fluid at the surface using air cooled, finned-tube heat exchangers. Makeup water was added as required to replace fluids permeating into the formation surrounding the pressurized active reservoir. Total thermal energy removal rates were calculated using measured downhole GT-2B production well temperatures at 2590 m and a constant 25°C surface reinjection temperature at

EE-1. Removal rates within the reservoir were based on estimated downwell injection temperatures obtained from a calibrated wellbore heat transmission model of EE-1.

Average thermal energy removal rates for the tests were as follows: Segment 1 - 3.1 MWt, Segment 2 - 2.1 MWt, Segment 4 - 2.8 MWt, and Segment 5 - 2.3 MWt. After 75 days of operation in Segment 2, the produced fluid temperature had dropped from 175 to 85°C. 23 more days of production during Segment 3 showed a ranged of 135 to 98.5°C, while temperatures during the 24-day Segment 4 test on the enlarged reservoir remained constant at 153°C. During extensive testing in Segment 5, production temperatures increased from 156°C to about 158°C after 60 days and then decreased to about 149°C after 286 days of operation.

In addition to these energy extraction tests, a unique experiment was conducted at the end of Segment 5 to release excessive reservoir stresses resulting from heat removal. This experiment is referred to as the Stress Unlocking Experiment or SUE. (See Murphy (1981) for details). The SUE test officially started after 281 days of energy extraction in Segment 5 when about 15 million kWh of thermal energy had been extracted from the Phase I reservoir. Relaxation of thermal stresses was accomplished by pumping water into EE-1 at pressures of about 15 MPa (2200 psi) with the production well GT-2B shut-in. With these higher injection pressures, the in situ normal and frictional stresses holding the fracture faces together during the energy extraction tests would be exceeded, resulting in shear slippage and microseismicity that could be monitored. Reservoir diagnostic tests were conducted before and after SUE to characterize any changes in reservoir geometry.

DIAGNOSTIC TESTS

Thermal hydraulic measurements

During all testing, surface and downhole temperature and flow measurements were made. A spinner/temperature logging tool was used for all downhole measurements. During extended production periods, the spinner/temperature tool was positioned in GT-2B inside the casing above all production zones. Periodically, logging was accomplished during production using a pressurized cable packoff system mounted in the GT-2B wellhead.

Tracer Tests

Throughout the testing periods, pulses of tracers were injected into the system and monitored in the produced fluid. Both Na-fluorescein dye and activated Br-82 tracers were used to map the flow and mixing patterns in the EE-1/GT-2B reservoirs. As described in earlier papers by Robinson and Tester (1984) and Murphy et al (1981), tracer tests provide a direct measure of accessible volume and dispersion levels within the active reservoir. Changes in reservoir mean ($\langle V \rangle$) or modal ($\hat{V}$) volume can be obtained easily from a pulse tracer test. The modal volume is simply the volume of fluid produced between the time the tracer pulse was injected into the reservoir and the time the peak tracer concen-

tration appears in the production well. This corresponds to the mode of the residence time distribution (RTD). The mean volume is integrated statistically over the entire RTD as

$$\langle V \rangle = \int_0^\infty V E(V) dV \quad (1)$$

where V = produced fluid volume
 $E(V) = C(V)/mp$ = RTD function
 $C(V)$ = measured tracer concentration at V
 mp = mass of tracer injected

Geochemical Monitoring

The water circulated in the system is diluted with relatively pure makeup fluid containing only 200 to 300 ppm total dissolved solids (TDS) compared to the steady state levels of approximately 2500 ppm TDS observed in the produced fluid. The concentrations of specific components in the fluid were monitored throughout the tests to quantify dynamic changes in an effort to understand important source and depletion mechanisms controlling the chemistry of the system. Dissolved silica (SiO_2), sodium (Na), potassium (K), lithium (Li), boron (B), carbonate (HCO_3^-/CO_3^{2-}), chloride (Cl^-), fluoride (F^-), and sulfate (SO_4) were the major species monitored along with radon (Rn) and various isotopic ratios. (Grigsby et al (1986), Zvoloski (1981) and Grigsby et al (1981)).

Passive and Active Microseismic Measurements

Both surface and downhole seismometer arrays were employed during all segments and SUE for both evaluation of potential seismic risks and to map microseismic event structures to infer reservoir geometry. Microseismic source mechanism theories suggest that pressurization of the reservoir with injected fluid will result in either tensile or shear failure depending on the alignment of the in situ horizontal principal stresses with the joint structure and on the level of anisotropy of the two principal horizontal stresses. Thus, by examining the spatial and temporal distribution of events, one can develop reservoir geometry models. Passive microseismic monitoring focuses on mapping events induced by pressurization during fracturing, heat extraction, overpressurization as during SUE (Dash et al (1981) and Murphy et al (1981)). There is some inherent uncertainty in locating microseismic events using single station downhole measurements and hodographic deconvolution techniques that must be kept in mind when viewing event maps.

Active techniques have also been used to examine reservoir structure. As described by Aki, Fehler et al (1982), detonator and piezo-electric acoustic sources were used in hole-to-hole transmission and reflection tests to study acoustic attenuation caused by the presence of water-filled fractures contained between wells.

FENTON HILL RESERVOIR STRUCTURE

The observed levels of fluid mixing and dispersion as illustrated in the tracer-determined RTD's of Fig. 1 are too large to be attributed to single fracture flow. (Robinson, Tester and Brown (1984)). Furthermore, downhole temperature/

spinner and gamma logging during radioactive tracer measurements using Br-82 verified the existence of three major production zones each with comparable levels of dispersion to the composite RTD. Borehole televiwers and spectral gamma logs consistently indicated the location of these zones.

Hydraulic pressurization to levels just slightly above the least principal horizontal confining stress (S_2) opens high injectivity fractures that run approximately vertically from EE-1 to GT-2B. There are apparently two sets of nearly orthogonal joints: a primary set aligned perpendicular to S_2 and a secondary set aligned perpendicular to S_1 . Br-82 and temperature logs demonstrated that as many as 9 fractures containing fluid intersect the GT-2B and EE-1 wells. The geophysical and flow data suggests that the major production and injection zones occur near the intersection of a series of en echelon secondary fractures with the wellbores. These secondary fractures permit lateral communication of fluid between the primary vertical joints, resulting in microscopic mixing between intersecting primary and secondary joints. This leads to the high level of fluid dispersion observed in each individual production zone (Robinson and Tester (1984)). A conceptual geometric model of the EE-1/GT-2B reservoir is depicted in Fig. 2.

EVIDENCE FOR RESERVOIR GROWTH

The interconnected joint set of Fig. 2 creates a low impedance, direct connection between EE-1 and GT-2B that is characterized by the short-residence time portion of the RTD surrounding the modal volume (see Fig. 3). The tail of the distribution can be largely attributed to flow in high impedance, secondary flow in a "matrix-like" path of long residence time. We feel this secondary flow path samples the reservoir's smaller scale porosity at larger distances from the interconnected primary joint set. The heat exchange mechanism for each region is also likely to be different: aeral sweep with 1-D and 2-D fluid convection linked to 1-D conduction through the fracture faces in the interconnected joint set versus 3-D volumetric sweep with heat removed by a displacement mechanism in the secondary path.

Geochemical monitoring during recirculation tests at Fenton Hill has indicated that the displacement of in situ pore fluids provides a source for observed levels of dissolved Cl, B, Na, K, and Li (Grigsby et al (1986)). Furthermore, quartz and Na-K-Ca geothermometry estimates of reservoir temperatures remain relatively constant at 185° to 190°C for quartz and 190°C to 200°C for Na-K-Ca throughout the energy extraction tests. In contrast to the produced fluid temperatures declined from 175° to 85°C for the original Phase I system and from 158°C to 149°C for the enlarged system. However, as shown by Grigsby and Tester (1985), the rate of quartz dissolution is much too slow and the residence time too short in the major joint system to account for the observed silica levels. A portion of the recirculated fluid must have sufficiently long residence times in a region of the reservoir that has not been thermally depleted so that the silica concentration can approach its quartz saturation value at the ex-

isting initial rock temperature levels of approximately 185°C to 195°C. This portion of fluid is then mixed with the fluid from the short residence time paths in the cooler regions of the reservoir.

The geochemical observations provide corroborating evidence of a secondary, long-residence-time flow path that is consistent with the tracer data. By assuming a pore fluid displacement mechanism for certain species, estimates of the fraction of flow in the primary and secondary paths can be made (see Grigsby and Tester (1986) for details). For example, if the secondary path produces a solution saturated in silica at 190°C, which assumes rapid dissolution kinetics and a high ratio of exposed rock surface area to circulated fluid volume, then about 30% of the flow must come from this hot source with the remaining 70% from the primary joints. This estimate is further supported by tracer experiments where roughly 70% of the tracer is recovered in the main peak of the RTD and the remainder in the tail of the distribution.

The modal volume of the reservoir can be regarded as a measure of the low impedance fracture connections. Heat is mined from this portion of the reservoir by convecting fluid over the fracture face removing thermal energy from the rock by transient conduction. Thus, a correlation between modal volume and reservoir heat transfer area might be anticipated. As shown in Fig. 4, such a correlation does exist for the Fenton Hill reservoir. In fact, it also agrees with data from the English HDR system at Rosemanowes (see Robinson and Tester (1984)).

The model used to estimate the effective heat transfer area assumes 1-D or 2-D steady flow in a planar fracture coupled to 1-D conduction in the rock perpendicular to the flow field. Thus, the rate of thermal drawdown will be controlled by the dera! rather than volumetric features of the rock exposed to the circulating fluid. Although simplistic, this model conveniently describes the thermal behavior of a fractured reservoir with a single adjustable parameter, the fracture area. Large-scale heterogeneities such as the superposition of flows in multiple joints undoubtedly exert great influence on heat transfer behavior, since the spatial positioning of these low impedance conduits effectively defines the accessible volume of rock. In many HDR systems studied to date, the onset and subsequent rate of thermal drawdown seems to be controlled by the surface area of the low impedance component of the reservoir.

A complete review of the tracer-test data from Segments 2 through 5 has revealed pertinent information regarding the growth of the reservoir due to heat extraction and pressurization effects. In the absence of thermal stress cracking, reservoir growth due to heat extraction is really a thermalcontraction effect -- as the rock surrounding the fractures shrinks, the fractures, and consequently, the measured volumes, expand. In addition, the interpretation of tracer volume changes could be used to develop improved methods of reservoir operation -- for example, remedial pressurization for stress relief such as SUE, or a huff-puff operation mode in contrast to our normal (stress-constrained) continuous mode of extracting heat.

Figure 5 is a linear plot of the modal volume

increase (ΔV) as a function of net thermal energy extracted from the reservoir (ΔE), excluding any energy contributions from the wellbores. Essentially identical linear behavior is observed for the low back-pressure experiment, Segment 2, of the original reservoir and the low backpressure experiment, Segment 5, of the enlarged system. In spite of the nonlinear coupled effects of thermal contraction, pore and fracture inflation due to sustained pressurization, and local irreversibilities resulting in fracture propagation, a simple correlation between ΔV and ΔE exists. Furthermore, this simple relationship persists even in the presence of the confining stresses surrounding the active reservoir, which induce a constrained behavior. The slope of the line for low back pressure is only about 10% of what would be expected for free thermal expansion

$[\Delta V = (\alpha_v / (\rho C_p)) \Delta E]$ in a stress-free environment.

Values of $\alpha_v = 24 \times 10^{-6} \text{ K}^{-1}$, $C_p = 1000 \text{ J/kgK}$ and $\rho = 2700 \text{ kg/m}^3$ were used to represent the granite matrix. For practical purposes, the region between the low-pressure data and the free thermal volume lines defines an envelope of reservoir operating conditions. As stresses are relieved, for example during SUE, or the high back-pressure test of the original reservoir (Segment 3), or the high-pressure, hydraulic-fracturing stage at the beginning of Segment 4, one moves away from the normally constrained condition toward the free thermal expansion line.

Figure 6 shows both the modal and mean volume increases that occurred during the Segment 5 test as a result of energy extraction. $\bar{V}$ is taken to represent the volume of the primary joint system, and $\langle V \rangle$ the total accessible reservoir volume including the secondary system. Thus the large increase in integral mean volume $\langle V \rangle$ during Segment 5 suggests that the opening of preexisting joints must have been occurring along with thermal contraction. Most of this fracture volume growth occurred in the high impedance secondary path, as evidenced by the much smaller increase in $\bar{V}$. The propensity of fluid to channel through a few low-impedance joints was dominant throughout the heat extraction test, although the shift of larger percentages of the injected fluid to secondary flow paths is evident from the systematic decline in tracer recovery during the 286 days of Segment 5.

To study the dynamics of reservoir changes induced by heat extraction, the stress unlocking experiment (SUE) was conducted on 12/8/80 (Murphy et al 1981). During this operation, both wellbores were pressurized simultaneously for about 8 hours. At the time of this experiment, the modal volume alone was used as a measure of the fracture system volume. Notice that $\bar{V}$ increased only slightly during Segment 5, much less than would be expected if the rock were contracting freely. The hypothesis, as explained in Murphy et al (1981), was that thermal stresses were partially "locked in" and not allowed to relieve themselves via a stress cracking mechanism during normal operation because of the large in situ confining stresses ranging from S_2 to S_3 imposed on the fracture system. Pressurization above S_3 was applied to allow the cooled and thermally stressed rock to redistribute stresses more

uniformly.

The result of the experiment was a substantial increase in the modal volume $\bar{V}$, as measured in two tracer experiments, one before and one after SUE. The new calculations of $\langle V \rangle$ suggest a slightly different, yet still optimistic interpretation of the stress unlocking experiment. Note that the total fracture volume $\langle V \rangle$ suggest a slightly different, yet still optimistic interpretation of the stress unlocking experiment. Note that the total fracture volume $\langle V \rangle$ was increasing at a rapid rate throughout Run Segment 5, even before SUE. Unfortunately, experimental difficulties during Experiment 217-A4 (directly preceding SUE) did not permit measurement of the tail of the RTD, thus making an accurate calculation of $\langle V \rangle$ impossible. Nonetheless, the dramatic jump in $\bar{V}$ caused by SUE does not seem to have been accompanied by a similar increase in $\langle V \rangle$.

The new finding of the present study is that the integral mean volume $\langle V \rangle$ was increasing throughout Segment 5 at a higher rate than can be explained by thermal contraction alone. Thermal stress cracking seems to have been occurring throughout the test, but with the new fractures accepting very little flow. This point is discussed in greater depth in the next section.

Because $\bar{V}$ corresponds only to low-impedance connections, it did not increase substantially. These facts suggest that SUE itself redistributed the primary flow among existing major fractures, rather than creating new fracture volume. Figure 7 compares tracer curves before and after SUE on the same scale. There appears to have been a redistribution of flow to a larger number of fractures, resulting in a larger modal volume and greater tracer spreading.

Microseismic measurements in the Phase I reservoir during hydraulic fracturing and energy extraction operations have been used to access induced seismic risks and to specify system geometry. Event maps during the early stages of fracturing to enlarge the active reservoir showed a distinct growth upward and outward from the injection region in EE-1 toward the production region in GT-2B (Zyvoloski et al (1981)). The events were characterized by large compressive and shear components indicating that both tensile fracturing and shear displacement along joints were occurring throughout the active reservoir. Using hodographic techniques to deconvolute single station measurements with a 3-axis downhole geophone array, the events observed during the hydraulic stimulation phase of initial pressurization are, in general, clustered about a north by northwest vertical plane ($\pm 20^\circ$) whose strike has remained remarkably constant. (Albright and Pearson (1982), and Dash et al (1981)). Although this planar feature is seismically active in the early period, continued pressurization with water permeation results in a general displacement of events away from the planar structure. During Segment 5, a spherical region of seismic events surrounded the injection-production region at distances greater than 500 m from the planar locus of events. The low impedance, primary fracture regions of the reservoir that were most severely thermally depleted during Segment 5 became aseismic while the high impedance secondary zone showed continued seismicity throughout the test. This level of

microseismic activity is consistent with the observed increase of $\langle V \rangle$ from the tracer tests. All of this data suggest that reservoir growth is occurring, but that the enlarged region is not being fully exploited for energy removal given the present wellbore geometry.

A model of this concept is shown in Fig. 8, where the vertical dimensions of two aseismic planar event zones extending from about 2820 to 2950 m and from about 2650 to 2750 m coincides with the location of the thermally-depleted regions depicted on the EE-1 temperature log. The lower depleted zone was caused primarily by Segment 5 testing of the enlarged system while the upper zone resulted from Segment 2 testing of the original system.

Pressurization of the reservoir during SUE resulted in significant seismic activity just outside and peripheral to the most active heat exchange regions. Figure 9 shows plan and elevation maps of events monitored during SUE. The aseismic region centered about the EE-1 injection zone has an effective diameter of about 100 m consistent with the size of the thermally-depleted fracture area. Apparently the high level of thermal contraction resulting from the large temperature change in the injection region has relieved the in situ stresses to such an extent that subsequent pressurization during SUE produced no further failure and microseismicity. A time sequence analysis of the event patterns during SUE has shown a clustering of microseismic activity in a series of step-outs from the most active heat transfer zones as the pressure field expands outward. (See Dash et al (1981) and Murphy et al (1981) for details).

The SUE test procedure may prove to be not only an effective means of mapping the progress of thermal depletion within an active HDR reservoir but it also may suggest a method of enlarging reservoir size.

Another measure of reservoir growth is provided by heat transfer modeling of the drawdown observed during Segments 2 and 3 with the original system and Segment 5 with the enlarged reservoir. In all cases the effective heat transfer area had to be increased substantially to accurately model the decrease in the drawdown rate estimate for a fixed area fracture system. Both 1-D convective modeling with multiple interacting fractures and 2-D convective modeling with thermally independent fractures showed similar results (Dash et al (1981)):

Segment 2 - 7500 to 15000 m²
 Segment 3 - 6000 to 12000 m²
 Segment 5 - 37000 to 45000 m²

Although this result is model dependent to a large degree, the volumetric growth observed in modal and mean reservoir volume is correlated to an increase in the heat production capacity of the reservoir.

MECHANISTIC INTERPRETATION

An optimistic analysis of reservoir growth as evidence by the increase in the active microseismic region and by increases in $\dot{V}$ and $\langle V \rangle$ attributes this to the creation of new fractures that may augment the reservoir's heat extraction capacity. An alternative hypothesis might interpret the volume increase to a simple separation of

fracture faces or increase in aperture as a result of thermal contraction. This alternative hypothesis is pessimistic because it says that over time, a short-circuiting fracture (or fractures) would transmit more and more flow. This type of "run-away" fracture would undoubtedly cool down very rapidly, since the majority of flow would sweep across a small surface area. The consequence would be premature thermal drawdown.

Since $\dot{V}$ and $\langle V \rangle$ are overall reservoir volume measurements, they alone cannot be used to distinguish between the thermal stress cracking and fracture face separation mechanism. Individual fracture zone RTD's suggest strongly that the fracture volume growth appears to be accompanied by a more uniform flow through more fractures, as opposed to more channeled flow through short-circuiting flow paths. Individual tracer response curves from various exit regions show that the permeability between fracture zones increased steadily during Segment 5, to the point where at the end of the experiment, two fracture zones which were initially independent appear to have merged into a single zone. (See Robinson and Tester (1984)). Also, flow fraction measurements in the GT-28 production well remained constant throughout the experiment, refuting the idea that the joint of lowest flow impedance will, over time, accept most of the injected fluid.

Thermally-induced stress could lead to the propagation of secondary cracks through a process known as thermal stress cracking. A first order theoretical analysis has been performed to provide a basis for evaluating this possible mechanism of reservoir growth.

It is assumed that the reservoir was formed by the hydraulic fracturing of previously unfractured, and impermeable, hot dry rock. For simplicity we assume a single vertically oriented hydraulic fracture. However, the following results are also appropriate for multiple fractures, so long as these are spaced far enough apart (tens of meters) so that there is minimal thermal interaction. The hydraulic fracture or fractures extend horizontally in the direction of S_2 , the maximum horizontal compressive earth stress. Thus initially, heat flows conductively from the surrounding rock in the direction orthogonal to S_2 , that is, coaxial with S_3 , the minimum horizontal compressive earth stress. The thermal gradients set up in the rock by this heat extraction process result in thermal stresses in the S_2 direction which eventually could produce thermal cracks that propagate in the S_3 direction.

The plane strain solution for the S_2 direction thermal stress induced in a homogeneous, linearly elastic rock mass which is contiguous to a large hydraulic fracture is

$$\sigma = E\alpha\Delta T/(1-\mu) \quad (2)$$

where

- σ = tensile stress
- E = Elastic modulus
- α = linear thermal expansion coefficient
- ΔT = the cooling of the rock
- μ = Poisson's ratio.

If it is assumed that the stress concentration at the tip of a crack is very large, or that the tensile strength of the rock is negligible, then cracking will occur when the induced tension just equals S_2 . For numerical examples data appropriate for the Fenton Hill site have been used. From flow experiments it has been estimated that S_2 is 38.6 bars (5600 psi). Estimates of E , α , and μ for granite are, respectively, 5×10^4 MPa (7×10^6 psi), 8×10^{-6} per $^{\circ}\text{C}$, and 0.22. thus, according to Eq. (2), cracking is expected when the rock is cooled by 75°C . When the rock surface next to the main hydraulic fracture is cooled in excess of 75°C , the crack penetrates and stays open to the point where the rock temperature is 75°C lower than its original temperature.

A estimate of the rock cooling can be obtained by solving the 1-D transient conduction problem with a fixed surface temperature boundary:

$$\Delta T = \Delta T_s \operatorname{erfc} \left[z / \sqrt{4\alpha t} \right] \quad (3)$$

ΔT = the rock cooling at any point
 ΔT_s = the rock cooling at the surface ($z = 0$)
 z = distance into the rock, measured parallel to S_2 , from the fracture surface
 α = thermal diffusivity of the rock
 t = time
 erfc = complimentary error function.

Thus, at the critical degree of cooling, $\Delta T_c = 75^{\circ}\text{C}$, the crack penetration distance, z_c , becomes

$$z_c = \sqrt{4\alpha t} \operatorname{erfc}^{-1} (\Delta T_c / \Delta T_s) \quad (4)$$

Maximum crack penetration occurs at the maximum ΔT_s which is estimated to be 135°C for a heat extraction experiments at Fenton Hill. No cracking at all occurs when $\Delta T_s < \Delta T_c = 75^{\circ}\text{C}$. If a value of $1.0 \times 10^{-6} \text{ m}^2/\text{s}$ is used for α , one observes for the first half year of operation that most thermal cracks penetrate no greater than two to three meters.

Having estimated the penetration of these cracks, we must next estimate the spacing of the cracks. This is a typical end effects problem, for which it is known that, as a first approximation, crack spacings and penetrations are roughly equal. This claim is supported by both calculations and observations of thermal stress cracking experiments performed on concrete slabs. Note that this suggests that at early time, the cracks in a reservoir will be closely spaced and of very shallow penetration, but as time goes on, fewer but deeper penetrating cracks will form as illustrated in Fig. 10. This process relieves the stress field around the shallow cracks.

If the aperture of the small stress-relieved cracks is ignored, then the maximum aperture, $\delta_{\max}$, of the largest cracks at anytime is

$$\delta_{\max} = \alpha \Delta T_s z_c \quad (5)$$

Furthermore, if the aperture is approximated as (this expression ensures smooth closure of the crack),

$$\delta = \delta_{\max} (1 - z/z_c)^2 \quad (6)$$

then the mean aperture, $\bar{\delta}$, is

$$\bar{\delta} = 1/z_c \int_0^{z_c} \delta dz = \delta_{\max}/3 \quad (7)$$

and if Eqs. (5) and (4) are substituted in Eq. (7), the result is

$$\bar{\delta} = \frac{2}{3} \alpha \Delta T_s \sqrt{\alpha t} \operatorname{erfc}^{-1} (\Delta T_c / \Delta T_s) \quad (8)$$

With representative thermal physical property values, during the first half year of operation, most cracks are less than a millimeter in aperture.

The heat transfer enhancement that may result from thermal stress cracking will depend on the flow properties of the secondary crack system. If the hydraulic fracture is pressure propped and buoyantly driven then a critical value of $\delta_c = 0.4 \text{ mm}$ is estimated at the point where flow in the secondary system becomes important. If main fracture is self-propped by roughness asperities on the surface of the fracture, then δ_c would be approximately 0.2 mm . In either case, one would expect to see significant thermal stress enhancement of heat transfer within a few months of operation. Furthermore, as fluid begins to flow in the larger thermal cracks, conductive heat transfer becomes 2-dimensional which causes even greater thermal contractions, leading to higher flow rates and higher heat extraction rates.

CONCLUSION

Using any criteria, the prototype hot dry rock reservoir at Fenton Hill grew in size as heat was extracted. The combined set of tracer, geochemical, microseismic, and thermal-hydraulic data strongly suggest that this growth augmented the heat production capacity and thus lifetime of the reservoir. Considerable evidence exists to support that fracture extension induced by thermal stresses and/or sustained hydraulic pressurization was the primary growth mechanism.

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- Fig. 1 Tracer-determined RTD curves for the Phase I reservoir at Fenton Hill. The total EE-1/GT2-B wellbore volume of 161m^3 is included in the horizontal scale (A-early/B-late)
- Fig. 2 Inferred system geometry of primary flow paths in the EE-1/GT-2B reservoir (from Tester et al (1982))
- Fig. 3 Conceptual geometric model for flow in a fractured hot dry rock system
- Fig. 4 Empirical correlation of tracer-determined modal volume and effective heat transfer surface area
- Fig. 5 Change in modal volume as a function of thermal energy extracted
- Fig. 6 Change in modal and mean volume as a function of thermal energy extracted during the Segment 5 test
- Fig. 7 Comparison of tracer response curves before and after the stress unlocking experiment (SUE)
- Fig. 8 Temperature survey in the EE-1 injection well after partial thermal recovery (7/10/81) showing correlation of the thermally-depleted regions with the microseismic planar event and aseismic regions
- Fig. 9 Elevation view (left) and plan view (right) of microseismic events located by the two station method during SUE. The aseismic region around the EE-1 injection zone is seen on a north-south plane in the elevation view
- Fig. 10 Idealized thermal stress cracking patterns

RTD FOR ZONE i

GEOMETRIC MODEL FOR ZONE i

CUTAWAY ELEVATION VIEW

ΔZ_i —spacing between zones

P—modal production one

I—modal injection region

PROJECTION PLANES USED
FOR THE PLOTS OF THE
HYPOCENTERS

GT-2B GEOPHONE
STATION
(2700m TVD)

EE-1 INJECTION SITE

ASEISMIC REGION

▼ = EE-2 GEOPHONE
STATION (2920m TVD)