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**Preliminary Evaluation of the
Second Hot Dry Rock Geothermal Energy Reservoir:
Results of Phase I, Run Segment 4**

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H. D. Murphy	C. O. Grigsby
R. L. Aamodt	R. H. Hendron
J. N. Albright	C. Pearson
N. Becker	R. M. Potter
D. W. Brown	J. W. Tester
R. Butler	P. E. Trujillo
D. Counce	G. Zyvoloski
H. Fisher	

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PRELIMINARY EVALUATION OF THE SECOND HOT DRY ROCK GEOTHERMAL ENERGY RESERVOIR:
RESULTS OF PHASE I, RUN SEGMENT 4

by

H. D. Murphy (ed.), R. L. Aamodt, J. N. Albright, N. Becker, D. W. Brown,
R. Butler, D. Counce, H. Fisher, C. O. Grigsby, R. H. Hendron, C. Pearson,
R. M. Potter, J. W. Tester, P. E. Trujillo, and G. Zyvoloski

ABSTRACT

Results of the preliminary assessment of the second hot dry rock reservoir at the Fenton Hill field site are presented. This second reservoir was created by fracturing a deeper interval of granitic rock located at a depth of 2.93 km (9620 ft) in the same wellbore pair used in the creation of the first reservoir; no additional redrilling was required. The new fracture system has a vertical extent of at least 320 m (1050 ft), suggesting that the combined heat-transfer area of the old and new fracture systems is 11 times that of the old system. The virgin rock temperature at the bottom of the deeper interval was 197°C (386°F). Water at a flow rate of 6 l/s (100 gpm) was circulated through the reservoir for a period of 23 days. Downhole measurements of the water temperature at the reservoir outlet, as well as temperatures inferred from geothermometry, showed that the thermal drawdown of the reservoir was negligible and preliminary estimates indicate that the minimum effective heat-transfer area of the new reservoir is 45 000 m² (480 000 ft²), which is six times larger than the first reservoir. Thermal energy was extracted at a rate of 3 MW. Reservoir residence time studies with sodium fluorescein dye tracers indicate that the volume of the second reservoir is nine times larger than that of the first reservoir. Near the end of the assessment period the rate of water loss permeated to the rock surrounding the fracture system was 1.3 l/s (20 gpm). Despite the six- to eleven-times larger fracture size, this loss rate was only twice that of the first reservoir after an equivalent period of time. The flow impedance, a measure of the resistance to circulating flow through the reservoir, was 14 bar s/l (13 psi/gpm) under low back-pressure conditions. It was observed that the impedance is both flow rate- and pressure-dependent. Geochemical monitoring indicated that the produced reservoir fluid was low in total dissolved solids and no scaling or corrosion of pumps, heat exchangers, or pipes was observed. Downhole seismic monitoring indicated that low level reservoir seismicity was

detected only during the high back-pressure stage of the test, when the possibility of additional slow fracture extension existed. This seismic activity occurred at distances as great as 700 m (2300 ft) from the fracture system; microseismic magnitudes were in all cases less than -1.5 on the extrapolated Richter scale. During the normal closed-loop heat-extraction stage of the experiment, no seismic activity in excess of magnitude -3 was detected. These new results are particularly encouraging for future commercial-sized hot dry rock geothermal systems; not only do they show that larger fractures can be created, but they prove that multiple fractures can be created with the same pair of drilled wellbores, offering the possibility of substantially reducing costs to achieve the total fracture area required.

1. HISTORICAL BACKGROUND

The concept of extracting geothermal energy from hot dry rock (HDR) has been described by Smith et al.¹ Basically it was proposed that manmade geothermal energy reservoirs can be formed by drilling into low permeability basement rock to a depth where the temperature is high enough to be useful, creating a reservoir by hydraulic fracturing, and then completing the circulation loop by drilling a second hole to intersect the hydraulically fractured region. Thermal power would be extracted from this system by injecting cold water down the first hole, forcing the water to sweep by the freshly exposed hot rock surface in the reservoir-fracture system, and then returning the hot water to the surface where the thermal energy would be converted to electrical energy or used for other purposes. System pressures would be maintained so only one phase, (liquid) water, would be present in the reservoir and the drilled holes.

The first series of reservoirs is being investigated at Fenton Hill, located on the west flank of a dormant volcanic complex, the Valles Caldera, in the Jemez Mountains of northern New Mexico. The first deep borehole, Geothermal Test-2 (GT-2), was drilled in granitic rock to a depth of 2.929 km (9609 ft) where the temperature was 197°C (386°F). Following a series of hydraulic fracturing experiments in GT-2, a second borehole, Energy Extraction-1, (EE-1) was then drilled towards the largest of the GT-2 fractures to complete a circulating heat-extraction system. Due to survey errors during the directional drilling, the EE-1 borehole missed the GT-2 fracture by 6 m (20 ft), as determined by subsequent gyrosurveys, as well as magnetic and acoustic ranging.

Despite such close proximity, the intervening rock was so impermeable that the impedance to water flow was too high to permit a viable heat-extraction experiment. As described in Ref. 2, various attempts to improve flow communication between the boreholes proved unsuccessful. One of these attempts was the hydraulic fracturing of EE-1. The resulting fractures did not result in the required reduction in impedance, presumably because the fractures in both wells were parallel and did not intersect.

The EE-1 well was then cased to 2.93 km (9600 ft). However, subsequent temperature and cement bond logs showed that the casing cement from 2.74 to 2.93 km (9000 to 9600 ft) deteriorated with time because of the high indigenous-rock temperatures as well as the thermal cycling caused by numerous flow and pressurization experiments conducted after setting the casing and cement. This deterioration resulted in the formation of a water flow path in the annulus between the rock and casing. Eventually a large vertical hydraulic fracture was formed behind the casing in EE-1 at a depth interval centered at about 2.75 km (9020 ft). A heat-extraction reservoir was completed by deviating (side tracking) GT-2 at 2.5 km and redrilling it towards the top of the 2.75-km fracture in EE-1. The intent was to achieve an inlet-to-outlet spacing within the fracture to maximize the effective heat-transfer area and to achieve simultaneously low resistance to through-flow. In this manner significant rates of water flow and heat extraction could be achieved at pressure levels less than those that would result in additional fracture extension during heat-extraction operations. Such additional fracture growth could result in increased downhole water losses without significantly increasing the effective heat-transfer area. Two attempts were required. The first redrilling path may have passed over the top of the fractured region; however, some flow testing results indicate that this first path may in fact have intersected the fracture, but the resulting flow impedance was too high. The second path, drilled to intersect the fracture closer to its origination point, also may have failed to intersect the fracture directly but did penetrate several major joints or natural fractures that communicated with the hydraulic fracture so that the impedance to flow circulation was low enough to proceed with a heat-extraction test. Again, however, there is some evidence that this path also intersected the fracture, but the connection obtained was of very high flow impedance except under high back-pressure (HBP) conditions. The combination

of the original GT-2 wellbore and the second redrilling path is referred to as the GT-2B wellbore.

Reservoir performance was first evaluated by a 75-day period of closed-loop operation from January 28 to April 13, 1978. Hot water from the production well, GT-2B, was directed to the water-to-air heat exchanger where the water was cooled to approximately 25°C before reinjection. The relatively low power produced did not economically justify the conversion of the geoheat to electricity, so the heat was simply dissipated into the atmosphere by the heat exchanger. The cooled water, in addition to the make-up water that was required to replace downhole losses to the rock surrounding the fractured region, was then pumped down the injection well, EE-1, and then through the fracture system. Heat was transferred to the water by means of conduction within the nearly impervious rock contiguous to the fracture walls, and the heated water was withdrawn by means of the production well. In subsequent discussions this testing period is referred to as the Phase I, run segment 2. The term, Phase I, denotes all reservoirs created from the EE-1 and GT-2B wellbore pair.

Phase II wellbores, in which the goal is to create many, large multiple parallel fractures as the first step towards achieving commercialization, are currently being drilled or planned at Fenton Hill. The first hole of this second pair, designated EE-2 and located about 60 m (80 ft) from EE-1, is nearing completion. Drilling of EE-3, to parallel EE-2, will start when the drill rig can be moved to the new location about 50 m (150 ft) from EE-2. This larger reservoir will be developed at depths from 4 to 5 km (12 000 to 15 000 ft) with initial rock temperatures ranging from 120 to 275°C (430 to 530°F).

The assessment of the first reservoir in EE-1 and GT-2 is referred to as "run segment 2," or the "75-day test." (Run segment 1 consisted of a short precursor experiment conducted in September 1977.) The average thermal power extracted during run segment 2 was 4 MW. The flow impedance, initially 17 bar s/l (15 psi/gpm), decreased by a factor of five as thermal contraction and continued pressurization resulted in the opening of natural joints that provided additional communication with the producing well. Water losses to the rock surrounding the fracture steadily diminished and eventually this loss rate was less than 1% of the injected rate. The geochemistry of the produced fluid was benign and the seismic effects associated with heat extraction were immeasurably small. However, the relatively rapid thermal drawdown of the

produced water, from 175 to 85°C (345 to 185°F), indicated that the effective heat-transfer area was small, about 8000 m² (86 000 ft²) and essentially confined in a fractured region between the main injection and production zones in the EE-1 and GT-2B wells. Details are found in Refs. 3 through 5.

During a subsequent operation, run segment 3 or the "HBP" experiment, which was designed to elucidate flow impedance behavior under conditions of high mean fracture pressures, it was found that the condition of the cement behind the EE-1 casing had deteriorated even further, and that water injected in EE-1 was flowing in the annulus to depths as shallow as 700 m (2500 ft) with the potential danger of entering ground-water aquifers. To correct this condition, which would have resulted in very large water losses, and also to investigate the feasibility of creating a larger fracture from the same wellbores, the EE-1 casing was recemented near its casing bottom at 2.93 km (9600 ft), thus eliminating most of the flow communication with the old main EE-1 fracture situated at 2.75 km (9020 ft). A new reservoir was then formed by extending a hydraulic fracture from an initiation depth of 2.93 km (9620 ft) in EE-1. Fracture extension was performed with two massive hydraulic fracturing (MHF) treatments conducted in mid-March of 1979. In the first of these, Expt. 203, 603 m³ (168 000 gal) of water were injected while 755 m³ (200 000 gal) were injected during the following Expt. 195. In both cases only ordinary water was used as the fracturing fluid, with no viscosity-increasing or loss-of-fluid additives, and the downhole fracturing pressure was raised about 200 bars (3000 psi) above hydrostatic in both operations (1 bar is 0.1 MPa or 14.5 psi). An extensive series of seismic measurements of the fracturing process was made with downhole geophones, and these, as well as other results, are reported in Ref. 6. The resulting large fracture (described in Sec. 3) propagated upward to at least 2.6 km (8600 ft). Thus, the new fracture appeared to have a minimum inlet-to-outlet spacing of 320 m (1050 ft), more than three times that of the first fracture, which suggested that the effective heat-transfer area might be significantly greater than the first reservoir. Evaluation of the new reservoir was accomplished during a 23-day heat-extraction and reservoir-assessment experiment that began October 23, 1979. This segment of operation with the EE-1/GT-2B well pair is run segment 4, or Expt. 215 and is the main topic of this report. To conserve time and resources, several facets of reservoir operation were examined during the short test period, rather than conduct separate experiments. For example, an early period of additional

fracture extension was incorporated, and the reservoir was operated under both HBP and low back-pressure (LBP) conditions to assess these effects upon flow impedance. Test procedures, a discussion of the inferred reservoir geometry, and our preliminary conclusions regarding major reservoir characteristics are presented in the following sections.

2. OPERATIONAL PLAN

The plan for Phase I, run segment 4, was to inject water into borehole EE-1 and extract the geothermally heated fluid from borehole GT-2B. The heated water was to be cooled with an air-cooled heat exchanger and then re-circulated, using a variety of injection and pressurization modes. Surface equipment including centrifugal pumps (with the exception of the rented positive displacement pumps mentioned below), heat exchangers, and control and data acquisition systems are described in Ref. 3. Four stages of operation were planned.

- (1) An early period of additional fracture extension with controlled injection flow rates for specific time intervals. (The purpose of this additional fracture extension was to achieve a lower flow impedance than that obtained during the earlier MHF treatments, Expts. 203 and 195.)
- (2) An LBP flow test--a 36-hr test with 124 bars (1800 psi) injection pressure at the EE-1 wellhead and 11 bars (160 psi) back pressure at the GT-2B wellhead.*
- (3) An HBP flow test with two steps--first with 62 bars (900 psi) and second with 117 bars (1700 psi) GT-2B back pressure, in conjunction with 124 bars (1800 psi) injection pressure in EE-1.
- (4) An LBP heat-extraction stage--14 days at 96 bars (1400 psi) injection and 11 bars (160 psi) GT-2 back pressure.

Operating pressures were selected after considering estimated rock stresses in the reservoir and existing pumping and piping capabilities. Maximum flow desired during the fracture extension stage was 26.5 ℓ /s (420 gpm). In addition to measuring the flow-related data to control and record the above operations, downhole surveys were conducted, and geochemical and seismic results were monitored. These included (1) dye tracer studies of fluid mixing and residence time in the geothermal reservoir, (2) downhole temperature surveys in GT-2B,

* Unless specifically noted to the contrary, all pressures in this report are surface wellhead pressures. At the low flow rates of run segment 4 the friction losses in the wells are negligible so the downhole reservoir pressures are equal to the wellhead pressures plus the hydrostatic pressure corresponding to the depth in question. The mean geothermal reservoir depth is approximately 2.8 km (9100 ft) so the additive hydrostatic pressure is about 270 bars (4000 psi).

(3) downhole flow rate (spinner) surveys in GT-2B to measure the relative flow contributions of the natural joints conducting water from the hydraulic fractures to the production well, and (4) downhole seismic measurements with geophones in EE-2, as well as the existing surface seismic nets that were continuously monitored throughout.

2.1. Operational Sequence

The experiment began with the fracture extension stage. Because the high injection rates and pressure levels required for this stage were beyond the capacity of the presently installed pumps at Fenton Hill, commercial pumping equipment was rented for this phase of operation. The initial plumbing connection to EE-1 resulted in a greater than expected flow restriction at the wellhead, so that the desired fracture extension pressure could not be attained. This first aborted attempt at stage 1 is referred to as stage 1A. The rented pump equipment was then replumbed to provide a more direct connection to the EE-1 wellhead. With this accomplished and an increased water supply assured, water was pumped into EE-1 at 200 bars (2900 psi) and a flow rate of 29.1 ℓ/s (462 gpm) was attained until a total of 755 m^3 (200 000 gal) had been injected. This was accomplished while maintaining a low, 11 bar (160 psi), back pressure at GT-2 and an outflow rate which increased from 2 to 6 ℓ/s (15 to 100 gpm). This is referred to as stage 1. Because of the information gained in this stage and to save time, the planned intermediate HBP step at 62 bars (900 psi) was eliminated. The back pressure was instead held at 11 bars (160 psi) for another day (stage 2) and then increased to approximately 100 bars (1450 psi) for 3 days (stage 3). The injection pressure was held at approximately 170 bars (2500 psi) for both stages 2 and 3. During this initial period, the fluid produced at GT-2B was not immediately reinjected but was released initially to the GT-2 pond and later to the EE-1 pond through the heat exchangers. This "open-loop" circulation was required while the rented pumps were used, because there was no provision in the rented equipment for handling pressures as high as 10 bars (150 psi) at the pump inlet. The open-loop operation also served to flush solid particles from the fracture system and from the surface piping before "closed-loop" or complete recirculation was established. At the end of the seventh day, stage 4 was initiated by phasing in the Los Alamos Scientific Laboratory's (LASL) circulating pumps to provide an EE-1 wellhead pressure of approximately 95 bars (1400 psi), while maintaining 11 bars (160 psi) back pressure in GT-2B. A comparatively steady period

of flow and heat extraction followed for the remainder of the test. During this last stage, the system was operated with complete recirculation of the geothermal fluid with water from the reserve pit added to make up the fluid lost by permeation in fractures and rock pores. Eventually this make-up water loss rate decreased to the point that the Fenton Hill fresh water well could supply the entire make-up requirements and the make-up system was then switched from the reserve pit to the fresh water well. Short interruptions occurred to conduct planned temperature and flow rate surveys and to inject dye tracers; three shutdowns were required for valve repairs and a local power outage occurred due to failure of air-conditioning equipment. In addition a 1-h shut-in occurred on the fourteenth day in an attempt to locate impedances and check buoyancy factors.

3. RESERVOIR GEOMETRY AND FLOW PATHS

Figure 3-1 shows the inferred geometry of the present recemented EE-1/GT-2B system based on data from earlier experiments and run segments, as well as run segment 4. The first fracture with origin at 2.75 km (9020 ft) in EE-1 is shown as the small vertical fracture and the new fracture is shown to the left as the larger one. Both fractures are shown to be nearly vertical because the planes of hydraulic fractures are normally orthogonal to the minimum (least compressive) component of the tectonic Earth stress. In tectonically relaxed geological settings this stress is expected to be a horizontal one at depths greater than about 1 km and, in fact, in Ref. 2 it was shown that the minimum horizontal stress was only one-half the vertical overburden stress at 2.75 km. The size and shape of the fractures are not precisely known, but based upon the dye tracer and heat-extraction data, as well as the vertical distance separating the fracture initiation depth in EE-1 and the

Fig. 3-1.
Inferred reservoir geometry, recemented EE-1/GT-2B system.

fracture outlets that communicate with GT-2B, the new fracture is believed to be roughly circular, with a diameter of about 300 m (1000 ft). In comparison, the diameter of the old fracture, also believed to be roughly circular, is only about 100 m (300 ft). The possibility that the new fracture is connected to the original fracture and thence to GT-2B, rather than directly connected to GT-2B, has been discounted due to the behavior of the recovery temperature surveys in EE-1 taken at the end of run segment 4. These surveys do not show the temperature changes that should accompany a major flow of heated water through the older fracture.

Whereas the flow path on the injection side of the new fracture, i.e., from EE-1 into its single connection with the fracture, is easy to describe, the manner in which the new fracture is connected with GT-2B is far more complex and was studied with temperature drawdown and recovery measurements, well-bore flow-rate measurements, dye- and radioactive-tracer measurements, and other logging methods. This connectivity apparently consists of a set of non-vertical natural fractures or joints with a dip of approximately 60° (30° from vertical), which intersects both the vertical fractures and the GT-2B open hole. These joints appear to be the same ones that also formed the connections between the old fracture and GT-2B. The temperatures and velocities of the water in the connecting joints were measured at the joint/well intersection with a combined thermistor probe and flow rate (spinner) tool, which was used to determine temperature and flow rate profiles in the open-hole region of GT-2B.

3.1. Flow Velocity Measurements

The measurement of the flow distribution in GT-2B was obtained in several ways. In the stationary mode, the flow-rate tool was located at several depths and average rates were obtained by measuring over 3-min periods. However, this method was time consuming and was used primarily as a check on the results obtained from continuous logging. The continuous logging mode consisted of using the results of several different logs such as those shown in Fig. 3-2, each run at a different but constant speed. Plotting the spinner revolution rate against logging speed gave very linear relations whose intercepts represented the spinner rate due to fluid flow alone. Figure 3-3 is a typical example of this method. The zero velocity point was actually obtained from a stationary measurement. Note the excellent agreement of this measured value with the value obtained by extrapolation to zero logging speed. To obtain flow

Fig. 3-2.
Flow rate (spinner) surveys run at differing logging velocities in GT-2B,
November 9, 1979.

Fig. 3-3.
Spinner rate--logging velocity relationship over depth interval 2676-2688 m
(8780-8820 ft).

rates the effective area of the borehole must be known. Figure 3-2 shows the effect on the flow velocity resulting from residual cement in the wellbore. The cement was used to bond the casing to the surrounding rock. A caliper log of the same region, shown in Fig. 3-4, shows a severe reduction in diameter caused by the failure to displace all the cement from the well into the annulus shown between the casing and the rock. The effect of the finite area of the tool itself, A_T , and the area of the wellbore, A_H , on the velocity was obtained from the slope of the frequency, f , vs logging velocity, V , plots over regions of known borehole diameter. Figure 3-5 is a plot of k , the calibration coefficient relating revolution rate and velocity as a function of borehole area. The hyperbola shown is fit by choosing a value of A_T which gives a minimum standard deviation. This value, about 0.0064 m^2 (9.9 in.^2) is approximately 50% greater than the geometric cross section of the tool at the location of the spinner. To obtain a flow rate, the fluid velocity is obtained from the relation $f = kV$ using the zero logging speed spinner resolution and the k value corresponding to the borehole area. The flow rate is then the fluid velocity times the effective area ($A_H - 0.0064$).

The flow distributions for both HBP and LBP conditions are shown in Fig. 3-6. There is no significant shift in flow distribution to the lower openings with HBP as was observed in run segments 2 and 3. The following table shows the excellent agreement, better than 2%, between the value of flow rate obtained when the tool was positioned just below the casing bottom and that measured at the surface with a venturi flow meter.

<u>Date</u>	<u>Flow (l/s) in GT-2B</u>		<u>Mode of Operation</u>
	<u>Downhole</u>	<u>Surface</u>	
October 29	8.14	8.26	HBP
November 9	6.69	6.62	LBP

3.2. Temperature Surveys

The location of the fluid entry points in GT-2B were determined from both the flow rate and temperature surveys. Several wellbore joint intersections had flow-rate changes distinct enough to provide an accurate location with the flow-rate survey alone but the majority were located with the aid of temperature surveys. Figure 3-7 shows the temperature surveys run during both HBP and LBP conditions. These surveys show both the minor changes in

Fig. 3-4.
GT-2B caliper log showing diameter changes due to the casing and residual cement in well.

Fig. 3-5.
Calibration coefficient, k , for flow rate surveys.

Fig. 3-6.
Flow rate distributions in GT-2B for low and high back pressure. Step changes in flow rate result from fluid influx at joint-wellbore intersections.

Fig. 3-7.
Temperature surveys in GT-2B during low and high back pressure. Major temperature changes occur at joint-wellbore intersections.

temperature that occurred over a 1-wk period and the location of the major flow entrances at 64 m (210 ft) and 95 m (310 ft) below the casing. The expanded temperature scale used shows a complex structure. Below 2.64 km (8660 ft), the temperature profile consists of a series of steps with long isothermal regions. Above 2.64 km (8660 ft) the temperature rises in a ramp-like fashion. The lower region is characterized by well-defined flow entrances; the upper by poorly defined entrances. This difference may be due to tortuous exit paths through the cement collar. Measurements of both the temperature and flow rate at each of the openings allows a calculation of the temperature of the entering fluid by means of a simple heat balance for the typical wellbore-joint intersection depicted below.

In this sketch the quantities C , $\dot{Q}$, and T represent the volumetric heat capacity, volumetric flow rates, and temperatures, respectively. The temperature, T_2 , of the water flowing from the joint is

$$T_2 = \frac{\dot{Q}_1(T_3 - T_1) + \dot{Q}_2 T_3}{\dot{Q}_2} .$$

Using this equation the temperature of the water entering the wellbore at each joint connection can be calculated. Figure 3-8 shows these temperatures as a function of the connection depth for both HBP and LBP in GT-2B. Both temperature distributions can be fitted to the same smooth function except for the two values centered near 2635 m (8650 ft). The flows associated with these anomalous temperatures are very low (≤ 3 gpm) so that the uncertainties in the calculated temperature are high. They do, however, probably

indicate a flow path originating from a higher temperature region than that for the rest of the flows. As was the case with the flow rate surveys, little difference can be noted between the computed joint temperatures for LBP and HBP, and yet, as will be discussed, flow impedances were significantly affected by back-pressure conditions.

Fig. 3-8.
Temperature of fluid entering GT-2B at various fracture openings.

4. WATER LOSSES

Figure 4-1 summarizes the injection and production wellhead pressures throughout the duration of run segment 4. Figure 4-2 summarizes the injected and produced water flow rates. The aborted fracture extension stage is stage 1A; its successful repetition is stage 1; the period of LBP in GT-2B is stage 2 while injecting at a pressure of approximately 170 bars (2500 psi) in EE-1; the HBP period is stage 3 while still injecting at 170 bars; and finally stage 4 consisted of LBP operation while injecting at a lower pressure, about 95 bars (1400 psi).

The water loss rate, i.e., the rate at which water permeates the rock formation surrounding the fracture system, is the difference between the injection rate and the circulated, or recovered, rate at GT-2B. The actual measurement of the volumetric rate of water loss was performed with the make-up water flow meter except for short periods when this data was not available and then the actual difference between the EE-1 and GT-2 wellhead flow rate was used. Because the make-up pump provides the difference between the injection rate and the produced flow rate (after the latter is cooled by the heat exchanger), this measurement eliminates nearly all of the small error that would be caused by temperature-induced density differences.

The resulting water loss rate is plotted in Fig. 4-3 and its integral, the volume remaining in the system, is plotted in Fig. 4-4. The start-ups for both stage 1A and its repetition, stage 1, actually consisted of step flow increases. This was done to obtain information on the pressure and flow dependence of the flow properties of the system. The data sets for each stage are discussed below under the appropriate stage; however, because the flow steps of the aborted stage 1A were similar to the repeated stage 1, discussion of the flow steps themselves is deferred to the stage 1 subsection.

4.1. Stage 1A

EE-1 was pressurized on October 23, 1979, at 16:10 in steps to approximately 120 bars (1700 psi) and then maintained at 120 bars for one day. By adjusting the injection flow rate, the GT-2B pressure during this time was held at 14 bars (200 psi). This pressurization was followed by a GT-2B vent and approximately one day of down time. The plot of wellhead pressures throughout this stage, shown in Fig. 4-5, indicates the degree to which they were held constant. The time scale of Fig. 4-5 precludes the showing of the flow steps that began stage 1A. The resulting rates of EE-1 flow, GT-2 flow,

Fig. 4-1.
Wellhead pressures for the duration of run segment 4.

Fig. 4-2.
Injection and production flow rates for the duration of run segment 4.

Fig. 4-3.
Water loss rates for the duration of run segment 4.

Fig. 4-4.
Integrated water loss for the duration of run segment 4.

and water loss are plotted in Fig. 4-6. The irregularities in the flow rates can be correlated with the changes of pressure in EE-1. The general decrease of the water loss rate is typical of diffusion systems under the influence of a constant pressure.

4.2. Stages 1 and 2

At 18:30 on October 25, 1979, EE-1 was again pressurized during stage 1, in steps, to a maximum pressure of 200 bars (2900 psi). After 770 m³ (200 000 gal) of water were injected, the EE-1 pressure was reduced to about 170 bars (2500 psi) for stage 2 and maintained at this level while in a pressure control mode of operation. The GT-2 pressure was controlled at 11 bars. The water loss rate during these stages is identified as 1 and 2 on Fig. 4-3. The large spike is the transient response to the 200-bar peak in the EE-1 pressure during stage 1. The loss rate during the constant pressure part, stage 2, shows only a slow gradual decrease. Plots of the five flow steps that initiated the extension stage are shown in Fig. 4-7 with the resulting pressure response in Fig. 4-8. Large transients are obvious in the flow rates in Fig. 4-7. Approximate values of the receptivity have been extracted from the first, third, fourth, and fifth flow steps. The receptivity, α , is $A\sqrt{\kappa\beta/\beta_0}$, where A is the diffusing permeation area, κ is permeability, β is the compressibility at elevated pressure, $\beta_0 = 2.7 \times 10^{-6} \text{ bars}^{-1}$ is the reference value of the reservoir rock compressibility at hydrostatic pressure. In Fig. 4-9, these values are compared with those obtained during MHF Expt. 195.

4.3. Stage 3

At 16:00 on October 27, 1979, the GT-2 flow was throttled to bring the GT-2B pressure up to 100 bars (1450 psi) while the EE-1 pressure was held constant. This HBP stage lasted approximately 3 days. The water loss rate during this stage (stage 3 on Fig. 4-3) is also characterized by a large transient spike resulting from the transient in the GT-2 pressure (stage 3 on Fig. 4-1). The loss rate during the constant pressure part of this stage shows an atypical and rapid increase, possibly because the combination of high pressures at both wells was sufficient to result in additional hydraulic fracturing.

4.4. Stage 4

Beginning at 06:28 on October 30, 1979 the following sequence of events was initiated to reduce the EE-1 and GT-2B pressures: (1) at 06:28 the EE-1 flow rate was reduced to approximately 2.1 l/s (33 gpm); (2) at 08:50 the

Fig. 4-5.
Wellhead pressures during stage 1A.

Fig. 4-6.
Well flow rates and water loss rate during stage 1A.

Fig. 4-7.
Injection flow rate steps, stage 1.

Fig. 4-8.
Injection pressures for flow rate steps in stage 1.

GT-2B flow rate was increased to reduce GT-2B pressure; (3) at 11:40 EE-1 was vented; and (4) at 16:00 EE-1 was shut-in. On the following day: (1) at 08:10 pumping into EE-1 started at 7-6 μ /s (120 gpm); and (2) at 12:00 the EE-1 pressure was stabilized at 95 bars and GT-2 at 11 bars. The EE-1 and GT-2 pressures were held constant (Fig. 4-1, stage 4) until 11:50 on November 15, 1979, when both wells were shut-in.

The water-loss rates during stage 4 are plotted on Fig. 4-10. Both the data for the make-up pump meter and the data for the difference of the EE-1 and GT-2B flow rates are shown. The two sets of data agree fairly well. Except during transients caused by operational shut-ins, the loss rate remained nearly constant during the 14 days despite almost constant pressure operation. The operational transients introduced during the first three stages of the experiment prevent ready extrapolation to a long-term water loss rate. However, the nearly constant rate of about 1.3 μ /s (20 gpm) during the constant pressure stage 4 is a reasonable upper bound to the long-term loss rate. We emphasize that this is indeed an upper bound; the long-term loss rate would be expected to decrease as it did during the 75-day test, run segment 2. Furthermore, the loss rate is a function of pressure levels and time, not circulation rates. Thus, if the rate of circulation could be increased in the future by further impedance reductions, then the loss rate, expressed as a percentage of circulated rate, would be substantially reduced from the 20% observed at the end of run segment 4. In run segment 2 the percentage was eventually reduced to 1%.

The loss rate at the end of the 23 days of operation of run segment 4 was 1.3 μ /s (20 gpm). This rate is twice the loss rate experienced with the first reservoir after an equivalent period of time in run segment 2. However, as shown in Secs. 7 and 8, the present reservoir has an effective area 6 to 11 times that of the first reservoir, so it appears that, on a unit area basis, the present reservoir has one-third to one-fifth the water-loss potential.

Fig. 4-9.
Receptivity, α , as a function of injection wellhead pressure--comparison of run segment 4 (Expt. 215) with MHF Expt. 195.

Fig. 4-10.
Water-loss rate during constant pressure stage, stage 4.

5. FLOW IMPEDANCE

The entrance to the new fracture is at a depth of 2.93 km (9620 ft) in the EE-1 wellbore. A fracture in this region was first inflated on October 14, 1975, but, as indicated by temperature surveys, it did not play a major part in subsequent experiments until the EE-1 casing was recemented on January 14, 1979. Following the recementing, the 2.93-km fracture became the main entrance to the EE-1/GT-2B circulation system. Before the massive hydraulic fracture treatments described in Ref. 6, the impedance was measured as 142 bar s/ ℓ (130 psi/gpm) during Expt. 194 in February 1979. The hydraulic fracture treatments, designed to increase the fracture size and decrease the impedance were carried out during Expts. 203 and 195 in March 1979. Subsequently, it was found in a separate experiment conducted just before run segment 4 that the impedance was approximately 8 bar s/ ℓ (7 psi/gpm), at conditions of low pressure, 0 to 14 bars (0 to 200 psi), and flow rates of 1 to 2 ℓ /s (10 to 30 gpm). This low-flow-rate value of impedance will be compared to the run segment 4 values in Sec. 5.4.

Measurements of impedance for the entire duration of run segment 4 are shown in Fig. 5-1, both uncorrected and with buoyancy corrections. The overall flow impedance shown is believed to be the sum of several components such as impedances associated with restricted flow paths at wellbore-fracture intersections and flow resistances distributed along the main fractures. The uncorrected impedance is simply the difference between the injection and production wellhead pressures divided by the circulated through-flow rate measured at the GT-2B wellhead. The corrected impedance accounts for the fact that the water in the injection well was colder than in the production well so an additional pressure difference existed due to density variations. The calculated pressure correction due to these density variations is shown in Fig. 5-2. Wellbore temperatures were estimated with a transient heat transmission code.⁷ Generally, uncorrected impedances are 20% lower than corrected values. In reviewing the overall impedance behavior shown in Fig. 5-1, it may be helpful to refer back to Figs. 4-1 and 4-2, which show wellhead pressures and flow rates for the same period of time. The impedance behavior during the various stages is discussed below.

5.1. Stages 1A and 1

Figure 5-1 indicates that the impedance calculated for stages 1A and 1 is a rapidly varying function of time. During early periods of injection most

Fig. 5-1.
Flow impedance behavior for the duration of run segment 4.

Fig. 5-2.
Calculated buoyancy pressure correction.

of the water is due to permeation losses in the surrounding rock. The small fraction that does circulate to GT-2B during these short stages increases with time so that the computed impedance behavior is strongly transient. It is not until the longer stages, stages 2, 3, and 4, that reasonably steady impedances were obtained.

5.2. Stages 2 and 3, Effect of HBP

To increase the GT-2B pressure for stage 3, the valve controlling GT-2B flow was partially closed. When the desired back pressure was reached and the valve position was adjusted, the uncorrected impedance decreased from about 22 bar s/l (20 psi/gpm) to 8 bar s/l (7 psi/gpm) as shown in Fig. 5-1 on day 5. Figure 5-3 shows the GT-2B pressure and flow rate for the 2 days just preceding, and for 2 days that immediately follow this back-pressure change. The EE-1 injection pressure during this time did not vary significantly, being about 169 bars (2450 psi). Near the end of the 2-day flow intervals the GT-2B flow rate was essentially constant for both the LBP and HBP flow conditions as shown in Fig. 5-3. The flow and pressure data averaged over the final 8 h for each 2-day period are summarized in Table 5-I. The impedances tabulated are not corrected for buoyancy, they would be approximately 20% higher with such a correction. The imposition of HBP, despite its attendant reduction in the net pressure differential across the fracture system, resulted in 12% increased flow rate and a 64% reduction in flow impedance. This increased flow rate and decreased impedance is probably due to a net reduction in the effective fracture system closure stress in the vicinity of GT-2B, resulting in increased fracture apertures. The impedance reduction caused by HBP operation in run segment 4 is substantially less than that observed previously. During run segment 3 the old fracture system impedance was observed to decrease by 90% when a similar level of back pressure was imposed. The LBP and HBP comparisons that led to this factor of 10 impedance reduction in run segment 3 were performed under conditions of similar reservoir temperatures and flow rates, so that only the impedance dependence upon pressure is illustrated. During run segment 3, it is believed that a significant fraction of flow occurred through a near-vertical fracture path that intersected GT-2B directly rather than via the slanting natural joints. As alluded to in Sec. 2, this fracture path resulted in too high an LBP impedance and was activated only during the HBP operations of run segment 3. The flow properties of this path would be controlled by the minimum Earth stress and would be more sensitive to HBP

TABLE 5-1

COMPARISON OF LBP AND HBP FLOW DATA

GT-2B Pressure Condition	Time Interval	GT-2B Outflow l/s (gpm)	GT-2B Pressure bars (psi)	EE-1 Pressure bars (psi)	Flow Impedance ^a bar s/l (psi/gpm)
LBP (Stage 2)	10/27 0800-1600 h	7.3 (116)	11 (160)	169 (2450)	22 (20)
HBP (Stage 3)	10/30 0000-0800 h	8.1 (129)	102 (1480)	167 (2420)	8.0 (7.3)

^aNot corrected for buoyancy effects.

Fig. 5-3.

GT-2B outlet conditions just preceding and following imposition of high back pressure.

operation than the new fracture system of the recemented EE-1/GT-2B reservoir. As shown in Sec. 5.6, much of the impedance of the new fracture system is due to the flow paths via the slanting (60° dip) joints, upon which a significant component ($\cos 60^\circ = 0.5$) of the twice-as-large vertical stress² acts as a closure stress.

5.3. Stage 4, Change From HBP Back to LBP

As the transient phase of recovery from stage 3 operation was almost completed on day 10, there was a loss of flow due to a power outage. The EE-1 pressure dropped more rapidly than the GT-2B flow, giving an apparent impedance decrease as seen in Fig. 5-1. Following these transients, the GT-2B flow rate remained essentially constant at $6.0 \text{ m}^3/\text{s}$ (95 gpm) $\pm 3\%$. The GT-2B fracture outlet temperature, pressure, and impedance were also constant during the last 12 days of stage 4. Table 5-II compares operating conditions at LBP before and after the intervening period of HBP operation. As above, the relatively steady period from 08:00 to 16:00 on October 27 was used to characterize stage 2 conditions. The second period of LBP operation resulted in only a 18% decrease in circulated flow, despite a reduction of 40% in the injection well pressure and fracture differential pressure. The net flow impedance during the second LBP period was only 14 bar s/m³ (13 psi/gpm) compared to 22 bar s/m³ (20 psi/gpm) for the first LBP period. One explanation for this behavior is that the intervening operation at HBP resulted in an irreversible decrease in flow impedance, caused perhaps by fracture movement and a fracture

TABLE 5-II
COMPARISON OF LBP OPERATIONS
BEFORE AND AFTER INTERVENING HBP STAGE 3

Time Interval	GT-2B Flow Rate m ³ /s (gpm)	GT-2B Pressure bars (psi)	EE-1 Pressure bars (psi)	Flow Impedance ^a bar s/m ³ (psi/gpm)	
10/27 (stage 2) 0800-1600 h	7.3 (116)	11 (160)	169 (2450)	22	(20)
11/3-11/15 (stage 4)	6.0 (95)	11 (160)	95 (1400)	14	(13)

^aNot corrected for buoyancy effects.

aperture increase. This conclusion is subject to some qualification, however, as follows. During stage 4, GT-2B was shut in several times for operational purposes and consequently pressurized to nearly 95 bars. However, after the shut-in transients died out, the flow and impedance returned to their previous values. This would tend to indicate that pressure cycling GT-2 between 11 and 95 bars has no apparent effect in changing the flow impedance, but that pressurization to 102 bars, as during HBP operation, does have a significant effect. This suggests that the fracture closure stress, equivalent to the minimum compressive tectonic stress, lies between 95 and 102 bars above hydrostatic. In comparison, values between 92 and 102 bars were determined by measuring pressures required to extend the first fracture system.²

5.4. Discussion of Stage 4 Impedance

Referring to Table 5-II, the impedance corresponding to the LBP conditions of stage 4 (95 bars injection pressure, circulation rate of 6.0 ℓ/s) is 14 bar s/ ℓ . This value is nearly twice that determined for an experiment conducted at LBP, just before run segment 4, at injection pressures of 0 to 14 bars and flow rates of 1 to 2 ℓ/s . We believe the increased impedance in the present experiment is due to a flow rate-dependent impedance. Such a dependence has been previously noted⁸ and is indicative of Forcheimer flow in which viscous pressure losses in rough-walled fractures are related not just linearly to flow rate and velocity, as is the case for Darcy flow, but also to an additional quadratic term involving flow rate or velocity. Additional nonlinearities occur near the fracture inlet and outlets, where pressure losses can be nearly completely related to quadratic terms.^{9,10}

5.5. System Decoupling

An overall assessment of the reservoir flow performance during run segment 4 indicates an apparent decoupling between the fracture inlet and outlet responses to flow and pressure variations. This insensitivity contrasts with the much more responsive fracture system inlet-to-outlet coupling observed for the old fracture reservoir during run segments 2 and 3. Figure 5-4 illustrates the insensitivity of the EE-1 fracture inlet flow rate to the changes in the GT-2 back pressure that mark the beginning of stage 3. During this time the EE-1 pressure was held constant at 169 bars (2450 psi) by adjusting the injection flow rate. The flow rate increased linearly at a rate of about 3 $\ell/s/day$ (50 gpm/day), which may be indicative of additional, gradual extension of the new fracture. At 18:00 on October 27, the GT-2 back pressure was

Fig. 5-4.
Variation of injection flow rate after imposition of high back pressure.

Fig. 5-5.
Hypothesized fracture system impedance model.

Fig. 5-6.
Pressure histories in EE-1 during shut-in of EE-1 on October 30, 1979.

Fig. 5-7.
Pressure history in EE-1 during shut-in of both wells on November 6, 1979.

rapidly increased from 11 bars (160 psi) to 100 bars (1450 psi), and then maintained at this higher pressure for the next 2 days. However, as can be seen from Fig. 5-4, there is no significant change in the rate of increase of the fracture inlet flow rate as a result of this 89 bar increase in the GT-2 back pressure.

5.6. Distribution of Impedance in the Circulation System

Figure 5-5 illustrates a network of flow impedances postulated for the fracture geometry discussed in Sec. 3, as well as the observed flow and pressurization behavior of this section. P_A is the pressure in the EE-1 wellbore at the fracture entrance and P_B is the pressure inside the new fracture near its entrance. P_b is defined specifically as the sum of the hydrostatic pressure at that depth and pressure derived by extrapolating the curves in the insets of Figs. 5-6 and 5-7 to zero time. These figures are discussed below. P_C is similarly the pressure in the new fracture near its fracture exit, derived by extrapolating the curve in the inset of Fig. 5-8 to zero time and again adding the hydrostatic pressure of the water in the GT-2B wellbore. P_D is the pressure in the GT-2 wellbore at the depth corresponding to the mean depth of intersection of GT-2B with the major joints communicating with the new fracture. The impedances Z_4 and Z_5 indicate that the old fracture system, through which flow passed in the previous run segment 2, 75-day flow test, is still connected to the GT-2 wellbore and to the new fracture and flow along these paths is again possible depending upon the magnitudes of Z_4 and Z_5 .

As described in Sec. 7, the temperature of the old fracture following thermal recovery from the 75-day test is estimated to be in the range of 130 to 150°C as shown in Fig. 7-1. The observed water temperature near the bottom of the GT-2 wellbore (Fig. 3-7) is reasonably consistent with this estimate and from Fig. 3-6, flow through this path is about one-fourth of the total flow. In the following analysis this flow will be neglected, with the understanding that the impedances Z_4 and Z_5 are lumped with Z_1 , Z_2 , and Z_3 , as in electrical circuit theory. Figures 5-6, 5-7, and 5-8 show transient pressures in EE-1 and GT-2B during shut-ins of EE-1 (Fig. 5-6) and shut-ins of both EE-1 and GT-2B (Figs. 5-7 and 5-8). Backward-time extrapolations of the curves are shown in insets, which show that each curve may be fitted by an expression of the form $\ln(P - P_r) = K - t/\lambda$ where P_r , K , and λ are constants and t represents time. The pressure appears to start from a value $P = P_r + e^K = P_0$ at $t = 0$, and approaches $P = P_r$ asymptotically. The extrapolated end points P_r

Fig. 5-8.

Pressure history in GT-2B during shut-in of both wells on November 6, 1979.

are assumed to represent the surface pressures when flow in the fracture has ceased.

5.6.1. EE-1 Entrance Impedance. For the shut in of October 30 (Fig. 5-6), P_o is 148.9 bars (2160 psi) and P_r is 108.9 bars (1580 psi). The difference between the actual shut-in pressure of 166 bars (2410 psi) and P_o is thought to represent the pressure drop across Z_1 at the flow rate of 24.6 l/s (390 gpm). This gives a value for Z_1 of 0.7 bar s/l (0.64 psi/gpm) at the shut-in pressure. The point inside the fracture at which P_o is measured is not well defined--it must be a region with sufficient area at a pressure near P_o so that the pressure is maintained after shut-in by a return flow of pore fluid that had previously permeated the nearby rock. In Fig. 5-7 a similar analysis gives $Z_1 = 1.06$ bar s/l (1 psi/gpm) at a lower inlet shut-in pressure, 96.2 bars (1396 psi), and lower flow rate, 7.89 l/s (125 gpm). In this case the increase in impedance due to the decreased pressure level outweighs the decrease due to lower flow rate.

5.6.2. Other Localized Impedances. If Z_2 in Fig. 5-5 was small, it would be expected that the rise in GT-2B pressure and the drop in EE-1 pressure to the average fracture pressure would be prompt and nearly equal. The time constants λ for EE-1 and GT-2B in Figs. 5-7 and 5-8 are 13 and 17.7 minutes, respectively. During steady flow the main circulating flow path is through Z_1 , Z_2 , and Z_3 . Let $\dot{Q}_1$ be the EE-1 flow rate, $\dot{Q}_2$ that from GT-2B, $\bar{\rho}_1$ the mean density on the EE-1 side and $\bar{\rho}_2$ that on the GT-2B side; then with the notation of Fig. 5-5 for the pressures at specific locations, we may write:

$$P_A = P_1 + \bar{\rho}_1 g h_1$$

$$P_B = P_A - Z_1 \dot{Q}_1 ,$$

where g is the gravitational constant. Let the mean flow inside the fracture be $(\dot{Q}_1 + \dot{Q}_2)/2$; then

$$P_C = P_B - \frac{\dot{Q}_1 + \dot{Q}_2}{2} Z_2 - \bar{\rho}_2 g(h_1 - h_2)$$

$$P_D = P_C - \dot{Q}_2 Z_3$$

$$P_2 = P_D - \bar{\rho}_2 g h_2 .$$

Finally, noting that the pressure correction due to buoyancy is $\bar{\rho}_1 g h_1 - \bar{\rho}_2 g h_2$, we have the expression

$$P_1 + \bar{\rho}_1 g h_1 - P_2 - \bar{\rho}_2 g h_2 = \dot{Q}_1 Z_1 + \frac{\dot{Q}_1 + \dot{Q}_2}{2} Z_2 + \dot{Q}_2 Z_3 .$$

Using this simple analysis and the extrapolated end points P_r , in Figs. 5-7 and 5-8, to represent the values that P_1 and P_2 would assume in the absence of flow, then, from the above equation with $\dot{Q}_1 = \dot{Q}_2 = 0$:

$$P_2 - P_1 = \bar{\rho}_1 g h_1 - \bar{\rho}_2 g h_2 = \text{buoyancy pressure correction} .$$

From Fig. 5-2 the calculated buoyancy pressure correction at shut-in is 20.2 bars (293 psi). The difference between the extrapolated points, P_r , in Figs. 5-7 and 5-8 is 15.8 bars (230 psi), in reasonably good agreement with the calculated buoyancy.

The sum of left-side terms of the next to last equation may be evaluated from the known P_1 and P_2 at shut-in and calculated buoyancy, as 102.9 bars (1493 psi). The changes in pressure when flow is zero in EE-1 and GT-2 are 8.4 bars and 65.5 bars, respectively, which may be assigned to the drops across Z_1 and Z_3 . This leaves 29 bars (421 psi) across Z_2 . With $\dot{Q}_1 = 7.9$ ℓ/s (125 gpm) and $Q_2 = 6.0 \ell/s$ (95 gpm) the final values of impedance are

IMPEDANCE	LOCATION	VALUE	
		bar s/ ℓ	(psi/gpm)
Z_1	EE-1 entrance region	1.1	(1.0)
Z_2	Across main fracture	4.0	(3.7)
Z_3	GT-2B exit region	10.0	(9.2)

The sum of these, 15 bar s/ ℓ (14 psi/gpm), is only 7% higher than the total impedance measured during stage 4, see Table 5-II. The large magnitude of Z_3 indicates that most of the system impedance is associated with the natural joints that connect the hydraulic fractures with the GT-2B wellbore. As sketched in Fig. 3-1, these joints are not vertical, so an additional component of the vertical overburden stress, which is estimated to be twice the horizontal stress,² would act to keep these joints more tightly closed than the vertical hydraulic fractures.

The absence of transient effects that the old fracture system would be expected to exhibit deserves further discussion. When GT-2B was temporarily shut-in during stage 4 the GT-2B pressure increased very rapidly to 70 bars (1000 psi) above hydrostatic pressure in only 1.5 minutes, and, from Fig. 5-8 the transient phase in the pressure rise died away in ~5 minutes. The dilemma in the model is sketched as follows. The impedance Z_4 in Fig. 5-5 is low, as is the flow through it. Thus, under LBP conditions the old fracture system should be at near-hydrostatic pressure. It was found previously that this old fracture had a median volume of about 30 m³ (8000 gal).³ Just before to the shut-in the flow rate into GT-2 was 6.0 ℓ/s (95 gpm). Therefore, upon actual shut-in, the flow rate shunted into the old fracture could be at most 6.0 ℓ/s ,

and yet, after 1.5 minutes of this flow, a total of only 540 ℓ (140 gal), was apparently capable of raising its pressure by 70 bars.

5.7. Comparison of First and Second Reservoir Impedances

During the run segment 2 evaluation of the first Fenton Hill reservoir, the overall impedance declined from a high of 17 bar s/ ℓ (15 psi/gpm) to a low of 3 bar s/ ℓ (3 psi/gpm). Operating conditions consisted of LBP in GT-2B, injection pressure of 60 to 90 bars (900 to 1300 psi) in EE-1, and circulating flow rates of 7.6 to 15.1 ℓ /s (120 to 240 gpm). Thus, with the exception of the flow rate, which was 1.2 to 2.4 times higher, the operating conditions were quite comparable to stage 4 of run segment 4, in which the impedance was shown in Table 5-II to be 14 bar s/ ℓ (13 psi/gpm). During run segment 2 the temperature of the produced fluid declined from 185 to 85°C, and a linear correlation of the impedance with temperature suggests that the observed impedance reduction was caused largely by the thermal drawdown, perhaps as the result of thermal-contraction-widening of the fracture aperture or the formation of secondary thermal cracks. In the present experiment there was essentially no thermal drawdown, so presumably there would be no change in impedance for the constant pressure and flow rate conditions of stage 4, and in fact, the impedance did remain constant. It appears then that the present value of 14 bar s/ ℓ should be compared with the initial segment 2 value of 17 bar s/ ℓ . Further, this initial value was obtained at an EE-1 pressure of 90 bars and a circulating flow rate of 7.6 ℓ /s, very close to run segment 4, stage 4 conditions. This rough equivalence of impedances for the two systems results despite the fact that by all indications the flow path lengths in the new fracture are several times that of the old fracture--the distance between inlet and outlets is a factor of 3 larger and the heat-transfer area and fracture volume are 6 to 11 times larger. So once again the evidence suggests that the impedance of vertical, self-propped, hydraulic fractures is small; most of the impedance is caused by the natural joints at the outlet. The favorable conclusion then is that larger fractures can be created without unduly large flow impedances.

6. GEOCHEMISTRY

Samples of the geothermal fluid were collected at regular intervals from the GT-2B wellhead, the EE-1 wellhead, and at the make-up pump, which provided the water from reserve pits to replace the downhole water loss. Samples of the dissolved gases were collected at less frequent intervals. The samples were of two types: ordinary gas samples and radon samples. Details of the sampling procedures and the types of samples collected are provided in the App. Fluid samples were analyzed for pH, Eh (oxidation-reduction potential), conductivity, SiO_2 , Na^+ , K^+ , Li^+ , Ca^{++} , Mg^{++} , Sr^{++} , Mn^{++} , Fe^{+2} and $+3$, B, $\text{SO}_4^{=}$, Cl^- , HCO_3^- , F^- and total suspended solids (TSS). Dissolved gas samples were analyzed for H_2 , N_2 , O_2 , CO_2 , CH_4 and H_2S . Analytical procedures for the fluid and gas samples are detailed in the Appendix.

6.1. Variation in Concentrations with Time

The results of the fluid analyses from the GT-2B wellhead are presented in Table 6-I. Gas analyses are in Table 6-II, and radon analyses are shown in Table 6-III. The results from these tables plus the results for EE-1 and make-up fluid analyses are plotted vs time for several major elements in Figs. 6-1 through 6-7. Plots for other species are included in the Appendix. Several interesting features relate directly to the method of operation of the system.

- A dilution effect is observed up to the eighth day for most species due to open-loop operation (described in Sec. 2). This effect appears as a decline in the concentration as low concentration (make-up) fluid displaces more concentrated fluid from the fracture system (Fig. 6-1).
- Closed-loop operation began at the end of the seventh day, as a consequence the dilution effect diminished and the concentrations began to increase to a "steady-state" level.
- Steady-state-like behavior is observed for many of the dissolved species soon after closed-loop circulation was established.

Other features of interest are:

- At early times (0-3 days) the Ca^{++} and $\text{SO}_4^{=}$ (see the Appendix) were more concentrated in the injected fluid than in the produced fluid due to chemicals added to the make-up reserve pit, which was concurrently being used as a mud pit for drilling of EE-2 in

TABLE 6-I

RESULTS OF ANALYSIS OF PRODUCED FLUID FROM GT-2B
(All concentrations in ppm)

S/N	Date & Time	pH	Eh-mv	Cond. μ mho/cm	SiO ₂	TDS ^a	TSS ^b	Na	K	Li	Ca	Mg	Sr	Mn	Fe	Al	B	SO ₄ ⁼	Cl ⁻	HCO ₃ ⁻	F ⁻
1G	00:00 24 Oct	6.62	216	5700	233	3856	nd ^c	1058	85.5	21.3	56.4	1.0	2.7	0.08	3.4	nd ^c	41.6	377	1508	361	8.01
2G	02:58 24 Oct	6.60	246	6300	245	3923	nd ^c	1072	84.5	20.9	51.0	1.1	2.4	0.06	1.4	nd ^c	41.6	520	1502	373	8.57
3G	06:10 24 Oct	6.67	354	5750	232	3523	nd ^c	922	80.5	18.4	61.6	1.2	2.6	0.06	1.3	nd ^c	37.2	548	1273	335	9.77
4G	07:00 24 Oct	6.78	323	5800	230	3568	19.5	967	79.0	18.3	68.4	1.3	2.6	0.07	2.1	0.05	34.4	622	1192	343	9.17
5G	13:00 24 Oct	7.36	335	5650	219	3967	17.0	980	80.5	16.7	84.6	1.5	3.1	0.14	1.8	0.07	28.0	1245	980	318	7.58
6G	15:00 26 Oct	7.82	332	5400	188	4490	15.5	1010	76.0	11.9	99.4	1.0	4.0	0.17	0.5	0.05	10.5	2380	418	279	12.28
7G	11:30 29 Oct	7.34	107	3200	174	2458	2.1	555	44.0	5.7	37.6	0.2	1.3	0.11	0.4	0.03	4.5	1166	190	268	11.37
8G	11:30 30 Oct	7.32	145	2750	177	1906	12.4	380	37.8	5.6	31.0	0.2	1.3	0.07	0.1	0.06	4.4	834	167	257	11.30
9G	11:30 31 Oct	6.52	189	3600	226	2620	3.5	605	48.0	8.0	49.0	0.6	1.9	0.16	0.9	0.08	10.9	928	390	340	11.85
10G	11:30 1 Nov	6.43	172	3900	233	2939	2.5	652	51.5	9.9	54.3	0.9	2.2	0.16	0.9	0.06	13.0	1061	482	368	10.00
11G	11:40 2 Nov	6.36	203	4100	238	3127	7.7	767	65.0	10.4	68.0	0.9	2.2	0.18	1.7	0.07	14.6	1035	533	381	10.17
12G	11:30 3 Nov	6.39	104	4050	232	2952	3.7	700	52.8	10.5	52.3	0.9	2.1	0.12	0.8	0.07	15.3	917	572	384	11.80
13G	11:30 4 Nov	6.37	114	4050	229	2958	3.0	742	53.5	10.8	55.0	0.9	2.1	0.13	0.9	0.08	16.3	852	586	397	12.00
14G	11:30 5 Nov	6.36	200	3950	234	3073	2.4	687	58.5	10.7	52.3	0.9	1.9	0.16	0.9	0.05	16.4	1009	589	400	11.56
15G	11:40 6 Nov	6.32	61	4000	237	3001	2.8	697	58.0	10.6	54.3	0.9	1.9	0.14	1.3	0.08	16.7	914	596	403	9.81
16G	11:30 7 Nov	6.30	96	4000	235	2946	3.4	667	56.5	11.0	49.0	1.0	1.9	0.15	0.7	0.11	16.4	877	615	405	10.16
17G	11:40 8 Nov	6.36	68	4000	231	2784	2.2	715	60.0	11.0	48.5	0.9	1.9	0.14	0.7	0.11	16.1	671	608	409	9.73
18G	11:30 9 Nov	6.20	226	4050	236	2914	4.8	677	60.0	10.9	51.5	1.0	2.0	0.12	2.0	nd ^c	16.0	830	612	405	10.27
19G	12:30 10 Nov	6.33	254	4000	236	2922	2.9	690	59.3	10.9	47.7	0.9	1.9	0.11	1.0	0.08	16.2	820	613	415	10.00
20G	10:45 11 Nov	6.36	305	3950	234	3169	5.7	680	57.7	10.7	44.5	0.9	1.9	0.12	0.7	0.11	16.2	1079	612	420	10.27
21G	12:00 12 Nov	6.43	291	3900	255	2914	4.3	650	58.8	10.6	44.0	0.8	1.8	0.00	0.7	0.10	16.1	845	601	419	10.04
22G	12:40 13 Nov	6.31	237	3800	234	2852	3.5	670	56.7	10.4	42.8	0.8	1.8	0.10	0.6	0.12	15.7	798	596	414	10.42
23G	11:30 14 Nov	6.31	260	3750	226		4.0	790		10.4		0.8	1.8	0.11	0.6	0.12	15.6	745	591	415	10.34
24G	10:00 15 Nov	6.34	73	3700	226		3.1	780		10.1		0.8	1.8	0.11	0.7	0.11	15.6	744	584	409	10.74

^aTDS - total dissolved solids.^bTSS - total suspended solids^cNot determined.

TABLE 6-II

COMPOSITION OF GAS SAMPLES EXPRESSED AS PERCENT OF TOTAL GAS COMPOSITION

	<u>Date and Time</u>	<u>CO₂</u>	<u>O₂</u>	<u>N₂</u>	<u>H₂</u>
GT-2B	24 October	54.9	2.4	27.9	13.3
	29 October	55.8	3.9	37.1	1.7
	31 October	39.3	9.2	51.5	--
	1 November	57.1	4.0	38.9	--
	2 November	53.6	5.0	41.4	--
EE-1	25 October	2.3	21.3	74.6	0.8
Air	Ambient	0.3	21.0	79.0	

TABLE 6-III

CONCENTRATION OF RADON IN SAMPLES OF PRODUCED AND MAKE-UP FLUID

	<u>Date and Time</u>		<u>Rn (nCi/l)</u>
GT-2B	24 October	0700	3.68 ± 0.188
	24 October	1350	13.798 ± 0.712
	29 October	1020	1.074 ± 0.057
	30 October	1130	0.562 ± 0.030
	31 October	1145	1.253 ± 0.071
	5 November	1355	1.052 ± 0.057
Make-up	31 October	1230	0.113 ± 0.031

Fig. 6-1.
Variation in silica concentrations.

Fig. 6-2.
Variation in sodium concentrations.

Fig. 6-3.
Variation in potassium concentrations.

Fig. 6-4.
Variation in chloride concentrations.

Fig. 6-5.
Variation in boron concentrations.

Fig. 6-6.
Variation in gas compositions.

Fig. 6-7.
Comparison of radon concentrations for run segments 2 and 4.

preparation for Phase II reservoirs. This possibly caused precipitation of a calcium sulfate mineral in the reservoir.

- The Mg and Fe concentrations in the injected fluid are higher than in the produced fluid indicating removal of these ions from solution within the reservoir (see the Appendix).
- The gas compositions are quite different from atmospheric composition. The fluid is highly enriched in CO_2 and somewhat depleted in oxygen relative to nitrogen. The presence of hydrogen in the early samples is probably due to dissociation of water in contact with hot metal or metal sulfides (Fig. 6-6).
- The graph of radon concentration vs time (Fig. 6-7) is similar to the graphs of other dissolved species.

6.2. Rock-Water Equilibria

Two downhole sources for the dissolved species in the geothermal fluid are dissolution of rock and addition of indigenous pore fluid. There are a large number of minerals that could be dissolving or precipitating to produce or remove aqueous species. To sort out these dissolution/alteration/precipitation reactions, the results of the water analyses were specified in a computer program, SOLMNEQ,¹¹ which was used to calculate rock-water equilibria from solution analyses. With SOLMNEQ the change in the Gibbs free energy is calculated for a standard set of minerals for which thermodynamic data are available. The output indicates those minerals that are close to saturation, undersaturated, or supersaturated in the solution; however, this cannot be taken as an absolute indication that a particular mineral is dissolving or precipitating. Favorable kinetic rates might allow the precipitation of a thermodynamically less-stable species at the expense of a more thermodynamically favored species that has an unfavorable kinetic rate.

The number of minerals to be examined is very large, and this discussion will be limited to ten: the primary phases--albite, anorthite, and microcline; the vein filling minerals--calcite and fluorite; possible alteration or secondary minerals--Ca-montmorillonite, wollastonite, kaolinite, and phillipsite; and, because of the high sulfate concentration in the make-up water during the early part of the experiment, gypsum. The solution equilibria were calculated for temperatures of 50, 100, 154, 175, and 190°C; this range provided estimates of the effect of temperature on mineral solubilities. The calculated Gibbs free energy changes, ΔG 's, are plotted vs temperature for

several minerals in Fig. 6-8. As the temperature increases the feldspar minerals, albite, anorthite, and microcline become more soluble, hence the ΔG 's for microcline and albite drop with increasing temperature. The low ΔG for anorthite could be due to the rapid precipitation of a Ca-rich phase, such as phillipsite, which shifts the equilibrium to greater undersaturation. Phillipsite, which has been observed as an alteration product on plagioclase in the experiments of Charles,¹² appears to be supersaturated at temperatures less than 200°C and is probably depositing within the reservoir. Calcite could be dissolving at any temperature shown, but it appears to be more soluble at low temperatures, which is consistent with the observed retrograde solubility at lower temperatures. Plots of ΔG vs time for the temperature of 190°C are shown in Fig. 6-9 for several minerals. It is apparent that the feldspars are all undersaturated and that phillipsite is supersaturated at 190°C. The clay minerals kaolinite and Ca-montmorillonite are even more undersaturated than the feldspars. The rock alteration probably produces zeolites in preference to clay minerals under the conditions of temperature, pressure, and fluid composition encountered in this experiment.

Although most major species in solution can be traced to reaction between water and rock, several cannot. In particular, the Cl^- and B are not likely to be the products of dissolution of any known mineral in the system. The ratio of boron to chloride in the fluid is very nearly constant throughout the experiment, which suggests an influx of pore fluid, as will be discussed further in Sec. 6.3.2.

6.2.1. Geothermometry. The maximum temperature of the rock surface exposed to circulating fluid can be estimated from concentrations of dissolved species--notably Na^+ , K^+ , and Ca^{++} as well as aqueous silica $[SiO_2(aq)]$ --which results from interactions between the fluid and certain minerals in the rock. When the fluid and rock are in chemical equilibrium, the ratios of Na^+ , K^+ , and Ca^{++} in solution are fixed according to the empirical Na-K-Ca geothermometer of Fournier and Truesdale:¹³

$$\log (Na/K) + \beta \log (\sqrt{Ca}/Na) = \frac{1647}{273 + T} - 2.24 \quad ,$$

Fig. 6-8.
Variation of Gibbs free energy changes with temperature for several minerals.

Fig. 6-9.
Variation in Gibbs free energy changes with time for several minerals.

where the concentrations are expressed in molality (g moles/kg of H_2O), $\bar{T}$ is expressed in $^{\circ}C$, and $\beta = 1/3$ for water temperature above $100^{\circ}C$.

The quartz geothermometer¹⁴ provides an indication of the temperature at which quartz was last in equilibrium with the fluid. The relationship, based upon laboratory measurements of the solubility of quartz as a function of temperature, is

$$-\log [SiO_2(aq)] = \frac{1309}{273 + \bar{T}} - 5.19 ,$$

where again $\bar{T}$ is expressed in $^{\circ}C$ but the aqueous silica concentration, $[SiO_2(aq)]$ is expressed in ppm. The quartz geothermometer and the Na-Ca-K geothermometer temperatures have been calculated for the fluid produced at GT-2B. Plots of these geothermometer temperatures as well as the actual fluid temperature measured downhole are shown in Fig. 6-10. Although there are some variations in the chemical geothermometers, the temperature predicted by both

Fig. 6-10.

Comparison of quartz and Na-K-Ca geothermometers with downhole measured temperature.

thermometers is $\sim 190^{\circ}\text{C}$ ($\pm 5^{\circ}$) for the closed-loop portion of the experiment. The initial drop in geothermometer temperatures is due to the dilution effect associated with the period of open-loop operation.

6.2.2. Dissolved Gases. Although calculations of the effects of dissolved gases mineral equilibria in the reservoir have not been performed, several qualitative observations of the dissolved gas composition can be made. If it is assumed that dissolved nitrogen is not adsorbed or removed by reaction with water or rock, then the nitrogen can be treated as an internal standard for comparison with other gas concentrations. In this experiment the CO_2 concentration in the produced fluid was very high relative to the amount of CO_2 that was injected into the system via the make-up water. The likely source for this CO_2 is the dissolution of calcite within the reservoir. The dissolution rate of calcite is sufficient to completely saturate the make-up fluid fraction so that the produced fluid is always saturated with respect to calcite. Rough calculations of calcite solubility for the old reservoir, from run segment 2,³ indicate equilibrium of calcite with water in the coldest regions of that reservoir after ~ 65 days of circulation. Similar behavior is expected for this reservoir and run segment.

The depletion of oxygen relative to nitrogen could be an indication of oxidation taking place within the reservoir. This is supported by the fact that the Eh, a measure of the oxidation potential, of the produced fluid is lower than that of the make-up and injected waters. What is being oxidized cannot be ascertained. Likewise, the presence of free hydrogen in the early samples has not been satisfactorily explained.

6.2.3. Radon. The concentration of radon in the geothermal fluid behaves in a manner similar to the other dissolved species (Fig. 6-7). There was a high initial concentration of Rn followed by a rapid drop in concentration due to dilution of the fluid in the reservoir during the open-loop operation. After the closed-loop operation commenced, the radon returned to a slightly higher steady-state level. It is important to note that the lowest concentration of Rn in the produced fluid is close to the Rn concentration of the make-up fluid. The highest Rn level observed in run segment 4 is somewhat higher than the level predicted by Kruger et al.,¹⁵ from radon measurements during run segment 2. The similarity in shape between the graphs of the dissolved radon and other species in solution could indicate a common source (i.e., indigenous pore fluid).

6.3. Geochemical Behavior of the Reservoir

After closed-loop operation of the geothermal system was established the silica concentration in the produced fluid rose to a value of 230 ± 8 ppm. This concentration level corresponds to an equilibrium temperature of 190°C according to the quartz geothermometer, and this temperature is close to the initial rock temperature, 197°C , at the EE-1 wellbore-fracture connection at 2.93 km (9620 ft) and even closer to the mean indigenous fracture temperature of 188°C (see Sec. 7). If the temperature predicted by the quartz geothermometer had dropped during the rest of the experiment, this would have been taken as evidence of thermal drawdown of the reservoir. The addition of about 20% make-up water flow rate throughout the closed-loop operation would have slowly diluted the fluid, lowering the apparent geothermometer temperatures. Instead, the fluid produced at GT-2 maintained high, unchanged silica concentrations, indicating that the fluid attained a temperature of about 190°C during its residence in the reservoir. It is unlikely that the mixing of fluids from two zones would occur in such a fashion as to always produce an average silica concentration of 230 ppm when the temperatures and the flow fractions of such zones would no doubt be variable. It seems more likely that the entire fluid volume approached thermal equilibrium and silica saturation with respect to quartz at 190°C . If the fluid did indeed achieve a temperature of 190°C , a significant amount of cooling took place along subsequent paths in the reservoir since the mixed mean temperature measured at 8050 ft in GT-2B was $\sim 153^{\circ}\text{C}$. Further discussion is deferred to Sec. 7.

6.3.1. Quartz Dissolution Kinetics. If all the fluid came to thermal equilibrium with the rock at 190°C , how long did it take for the fluid to become quartz saturated? The dissolution of quartz can be described by a first order rate equation³

$$\frac{d\bar{C}}{dt} = k a^* [C^{\text{sat}} - \bar{C}] , \quad (6-1)$$

where $\bar{C}$ is the mean silica concentration observed at GT-2B, C^{sat} is the saturation concentration at 190°C , k is the specific rate constant, and a^* is the interfacial rock reservoir area to fluid volume ratio. The temperature

dependence of the rate constant for the forward (dissolution) reaction is described by the Arrhenius equation

$$k = \alpha \exp [-E/RT] \quad , \quad (6-2)$$

where α is the pre-exponential factor, E is the activation energy, R is the universal gas constant, and T is absolute temperature. For the quartz-water system, $E \approx 17.3$ kcal/mol and $\alpha \approx 3.981 \times 10^5$ m/s as computed from the data compiled from the literature by Apps.¹⁶ Equation (6-1) can be rewritten as

$$\frac{d\bar{C}}{dt} = \alpha \exp [-E/RT] a^* [C^{\text{sat}} - \bar{C}] \quad . \quad (6-3)$$

Integrating from the limits $\bar{C} = C_1$ at time t and $\bar{C} = C_0$ at time zero yields

$$At = \frac{-V \ln[(C^{\text{sat}} - C_1)/(C^{\text{sat}} - C_0)]}{\alpha \exp [-E/RT]} \quad , \quad (6-4)$$

where A is the surface area of quartz exposed to circulating fluid and V is the total system volume, fractures and wellbores. If we define $(C^{\text{sat}} - C_1)/(C^{\text{sat}} - C_0) \equiv 1 - C_\theta$, it can be shown that for a constant temperature of 190°C and a total volume of 340.7 m³ (90 000 gal), consisting of 189.3 m³ (50 000 gal) in the reservoir, as determined from the dye tracer experiments, plus 151.4 m³ (40 000 gal) in the wellbores, then

$$At = 1.2545 \times 10^5 \ln (1 - C_\theta) \quad . \quad (6-5)$$

Since quartz composes about one-third the bulk volume of the rock, the true fracture area A_f is

$$A_f t \approx 3.7695 \times 10^5 \ln (1 - C_\theta) \quad . \quad (6-6)$$

Fig. 6-11.

Total fracture area A_F , required to achieve different saturation levels in a specified time.

A plot of A_f vs time is shown in Fig. 6-11 for various values of C . For fluid entering the fracture with composition C_0 , it would take a fracture area of about 1000 m^2 for the fluid to attain 99% of saturation in about one-half hour. The dye tracer studies discussed later indicate that the mean residence time of this system is about 8.3 h, from which the fracture system volume cited above is derived. Apparently, the dissolution rate is sufficient to allow the incoming fluid to achieve saturation if a relatively small area of the reservoir is maintained at 190°C . The available area of rock present at an initial temperature of 190°C for 24 days is at least $30\,000 \text{ m}^2$ (see Sec. 7). There is sufficient area, temperature, and time for the produced fluid to be saturated with respect to quartz at 190°C during the experiment.

6.3.2. Pore Fluid. Certain of the species in solution cannot be accounted for by dissolution of minerals known to be present in the rock. Such species as the chloride and the boron are not derived from rock-water chemical interaction with the circulating fluid, but are present in the interstitial pore fluid. When a flow experiment is initiated in a new fracture, some of this fluid is displaced immediately. Long-term circulation will eventually sweep this fluid from the rock pores and microcracks that are connected to the main flow system. One mechanism for accomplishing this displacement of pore fluid into the fracture system is illustrated in the following sketch.

*PORE FLUID DISPLACEMENT
IN MATRIX/MICROCRACK FLOW PATHS*

The concentration of impedance at the intersections between high-angle joints and the main fracture could cause sufficient pressure gradient in the connected pore matrix to allow a small volume of fluid to be displaced into the old fracture. In the absence of reactions between the aqueous species in the pore fluid and the rock or aqueous species in the make-up water, the dissolved ions in the pore fluid will maintain a constant ratio in the fluid produced at the surface when the effects of addition of different species concentrations in the make-up water are accounted for. These ratios in the pore fluid are most easily seen if the nondimensional concentration $\langle C \rangle$ is defined as

$$\langle C \rangle = \frac{C^\infty - \bar{C}}{C^\infty - C_m},$$

where C^∞ is the concentration of a given species in the pore fluid, C_m is the concentration in the make-up fluid, and $\bar{C}$ is the concentration of that species in the produced fluid at time t . Plots of $\langle C \rangle$ vs time for sodium, potassium, chloride, and boron are shown in Fig. 6-12. Values for C^∞ and C_m for each of these curves are given in Table 6-IV. For the Cl^- , B, and K^+ the values indicated for C^∞ are very close to the concentrations of these species in the earliest samples. The value of C^∞ for Na^+ is much higher than the Na^+ concentration in the first sample. This difference is probably due to the

high initial concentration in the make-up as well as reactions involving Na^+ . The similarity of curve shapes exhibited in Fig. 6-12 is an indication that the Na^+ and K^+ observed in the produced fluid are not derived by rapid dissolution of plagioclase but are added to the system from the pore fluid.

6.4. Comparison with the 75-Day Test, Run Segment 2

Many of the geochemistry results could have been foreseen from the run segment 2 test. The major difference is that essentially all of the fluid in the present test flowed through a series of paths connecting the old and new fractures, whereas in the 75-day test the flow was split in parallel paths--a small portion (5%) of the flow rate apparently followed a tortuous path along which little thermal drawdown occurred and a high fraction flowed through a region that experienced rapid thermal drawdown (see Fig. 7-1). The flow displacement of pore fluid and dissolution reactions along the hot, tortuous path contributed most of the dissolved species in run segment 2; in run segment 4 the displacement of pore fluid and dissolution effects were apparent much earlier in the experiment. The major conclusions to be drawn from the results of this experiment concerning fluid geochemistry are as follows.

- Saturation levels of SiO_2 observed in the circulating fluid indicate a quartz geothermometer reservoir temperature of 190°C . Exposure times and available rock surface at temperatures of $\sim 190^\circ\text{C}$ are sufficient to allow approach to saturation by active dissolution of the quartz component of the reservoir rock.
- Displacement of pore fluid into the circulating system is the major contributor of many dissolved species in the fluid.
- The concentrations of species contributed by addition of pore fluid leveled off early in the closed-loop operation, and with continued make up, these levels would have declined.
- The worst fluid encountered will occur in the early portion of a HDR reservoir's lifetime; rock-water interaction will set the ultimate concentration levels (lower than the pore fluid) to be encountered (less than 5000 ppm TDS in the Fenton Hill reservoirs).

TABLE 6-IV

VALUES FOR CONSTANTS USED IN NONDIMENSIONALIZING
CONCENTRATIONS OF Cl^- , B, Na^+ , AND K^+

Species	C^∞ (ppm)	C_m (ppm)
Cl^-	1600	30
B	41.6	0
Na^+	1600	130
K^+	95	35

Fig. 6-12.
Dimensionless concentrations for several dissolved species, of potential pore fluid origin, vs time showing similar behavior.

7. HEAT EXTRACTION

A combined temperature (thermistor) and flow meter (spinner) tool was positioned in the GT-2B production well throughout most of run segment 4. When not actually conducting surveys the tool was stationed at 2.6 km (8500 ft), just above the slanting producing joints that intersect GT-2B. In this fashion the mixed mean temperature of the fluid flows converging upon GT-2B was nearly continuously monitored. This temperature was compared with the geothermometer temperature indications in Fig. 6-10. It is emphasized that the geothermometer temperatures are maximum reservoir temperatures, averaged with respect to flow rate, i.e., the geotemperatures reflect the average of maximum temperature along all the flow streamlines, whereas the mean temperature measured with the thermistor corresponds to the flow rate-averaged outlet temperature. Although one might expect the geotemperatures and the outlet temperature to be the same if only a single new fracture was being operated, this is not the case when two fractures, each at different temperatures at the beginning of the test, are involved. In Sec. 3 it was shown that the same joints and natural fractures that conveyed flow to the production well were in operation for both the old and new fractures. This suggests that the old fracture that was thermally depleted during run segment 2 had to be an active participant in the run segment 4 heat-exchange system also. Using linear heat diffusion techniques¹⁷ it can be estimated that after thermal recovery the temperature of this old fracture was approximately 150-155°C at the beginning of run segment 4. Based upon temperature surveys taken soon after the initial drilling of EE-1, the equilibrium or undisturbed temperature near the bottom of the new fracture at its intersection with EE-1 at 2.93 km (9620 ft) is estimated as 197°C (386°F). The geothermal gradient is 0.055°C/m, so the mean-equilibrium temperature of the new fracture over its 320-m vertical length was 188°C (370°F). Figure 7-1 shows the inferred reservoir model of Figure 3-1 with a superimposed temperature field which qualitatively portrays thermal conditions just before the beginning of run segment 4. The left fracture is the new one; the right one is the old fracture. The figure illustrates how the water passing through the new large fracture would be heated and then subsequently cooled as it traversed the region cooled by the old fracture.

In Fig. 6-10 the silica geothermometer temperature is essentially constant at 190°C, quite close to the mean equilibrium temperature of the new

Fig. 7-1.

Inferred fracture system model with qualitative indication of thermal field at the beginning of run segment 4.

fracture, and the outlet temperature is also nearly constant, but at a lower temperature, 153°C, corresponding to the estimated average recovery temperature of the rock surfaces surrounding the old fracture. The relatively sharp change that occurs in the thermistor temperature during the first two days is attributed to the difference between thermal recoveries in a fracture and a wellbore. In the interim since run segments 2 and 3, it is estimated from radial heat diffusion theory that the GT-2B wellbore recovered more rapidly, to 172°C. Thus the transient change observed in the thermistor temperature of Fig. 6-10 is due to the time required for the fluid exiting the old fracture to impress its temperature upon the rock surrounding the wellbore. The decline in geotemperatures during the first seven days was due to make-up water dilution effects during open-loop operation. The subsequent nearly constant measured outlet and geo-temperatures suggest that for the low flow rates and operating times of run segment 4, both fractures were large enough

so that the flowing water attained the equilibrium temperature values for each fracture. Rough estimates of the size of each fracture can be obtained from coupled one-dimensional convection--one-dimensional heat diffusion theory, in which it is assumed that each fracture can be idealized as a rectangle with uniform flow.⁴ It was also assumed that the fractures are in series, so that all the flow exiting the new fracture entered the old fracture. Based upon wellbore heat transmission calculations,⁷ the injected water heated approximately 20 to 30°C in its transit down EE-1; it was thus assumed that the fracture system entry temperature averaged 55°C during run segment 4. More detailed two- and three-dimensional numerical analyses are currently under way, but for the moment the simple theory gives reasonable estimates of the minimum fracture areas. It is found that the new fracture must have an area of at least 30 000 m² and that the old fracture must have an effective area of about 15 000 m². Both areas represent only one side of the fracture, i.e., if a fracture were circular with radius R, then the areas quoted are πR^2 .

The area of the old fracture found here is nearly double the area determined from the analysis⁴ of the thermal drawdown in run segment 2. Possibly the more detailed numerical treatment will resolve this difference, but another explanation may be as follows. The highly jointed nature of the reservoir in the vicinity of the production well was already discussed in connection with the flow rate and temperature surveys in GT-2B. During run segment 2, repeated temperature surveys indicated that many of these joints were opened by thermal stress cracking and pressurization. Thus, portions of the upper fracture may, in terms of heat transfer during run segment 4, be acting more as a volumetric source of heat in which joints provide more intimate access to the reservoir rock, rather than as a planar source of heat in which the water is confined to a single fracture and all heat must be transferred, even from the rock far from the fracture, by means of conduction alone. Assuming for a moment a well-mixed water-rubblized rock volume model from which the heat is extracted by one-dimensional convection, it can be shown that the volume in question must be at least 20 000 m³. Thus, an area of 8000 m², as inferred from run segment 2, would require a rubblized region of 1 or 2 m on each side of the fracture. The drawdown immediately following run segment 2 was nearly 100°C. Previous results¹⁸ indicate that thermal stress cracks would have penetrated the rock adjoining the main hydraulic fracture to a distance of 1 m, in reasonable agreement with the estimate given above.

The combined fracture area, estimated here to be at least $45\,000\text{ m}^2$, is six times greater than the original area estimate obtained for the first fracture. In Sec. 8, it is shown that this ratio of fracture areas is in reasonable agreement with the ratio, about nine, of measured median fracture volumes. As indicated in Refs. 3 and 4, when impedances exceed 5 bar s/l the effects of buoyant density differences between the cold water entering a fracture and the hotter water leaving it do not significantly affect fracture flow patterns. The streamlines instead follow a potential flow solution in which they first fan out from the inlet and then converge upon the outlet. There is no tendency for the inlet fluid to first flow downward before flowing up towards the outlet, as occurs when buoyancy effects are large. For potential flow it is found that the effective heat-transfer area swept by the streamlines is approximately the same as a circle with a diameter corresponding to the inlet-to-outlet spacing. Roughly speaking then, the expected area for the new fracture would be about $80\,000\text{ m}^2$, so that the total for the two fractures would be about $90\,000\text{ m}^2$. This total area represents an area ratio of 11 times the original area estimate⁴ for the first fracture. From the simple theory described earlier it was found that the lowest bound estimate from the analysis of the transient reservoir temperatures was six, whereas the area ratio based upon mean volume estimates was nine. Thus, there is a reasonable consistency among the three independent estimates of reservoir size.

The thermal power extraction rate for the duration of run segment 4 is presented in Fig. 7-2. The average extracted thermal power was 3 MW and as indicated on the figure, the integrated energy was $5.6 \times 10^{12}\text{ J}$ (65 MW-days). The average power extracted from the old reservoir was approximately 4 MW(t); this was obtained at nearly double the circulating flow rate but was accompanied by 100°C of drawdown, thus accounting for the near equivalence of thermal powers produced by the two reservoirs.

Fig. 7-2.
Extracted thermal power.

8. DYE FLOW DISTRIBUTION STUDIES

Four experiments using Na-Fluorescein tracers were conducted during run segment 4. Flow conditions and results for these tests are given in Table 8-I. The first dye study was conducted at LBP conditions during stage 2 using an injection of 380 μ (100 gal) of water containing 300 ppm of Na-Fluorescein. The second test was run during stage 3 at HBP using a 300 ppm--380 μ injection also. The last two tests were conducted during stage 4 at LBP conditions using a more concentrated feed solution and the dye injector system at EE-1. In tests 3 and 4, a small amount (4 to 8 μ) of very concentrated solution was loaded into the dye injection system; it would be equivalent to a 1200 ppm--380 μ (100 gal) injection. Other experimental procedure details can be found in Ref. 5. In the discussion below these tracer tests are referred to as 215-1 through 215-4, where 215 indicates Expt. 215, or run segment 4, and the number following the hyphen indicates the sequential order of the tracer experiment.

Table 8-I also provides a summary of flow conditions and results from other tracer tests conducted on the first reservoir during run segments 2 and 3 which are indexed as I-1, ..., I-6 to refer to specific tracer experiments. The integral mean $\langle V \rangle$, mode $\overset{\circ}{V}$, median $[V]$, and 90% trimmed mean $|V|$ volumes shown are defined as follows:

$$\langle V \rangle = \frac{\int_0^{\infty} VC_i dV}{\int_0^{\infty} C_i dV} .$$

$[V]$ occurs when

$$\frac{\int_0^{[V]} C_i dV}{\int_0^{\infty} C_i dV} = 0.5 .$$

$\overset{\circ}{V}$ occurs when $C_i = f(V_i)$ is a maximum; and

$$|V| = \frac{\int_0^{V^*} VC_i dV}{\int_0^{V^*} C_i dV} ,$$

TABLE 8-I

SUMMARY OF DYE TRACER EXPERIMENTS EE-1/GT-2B FRACTURE SYSTEMS

Experiment	EE-1 Injection Pressure bar	GT-2B Production Pressure bar	GT-2B Production Flow Rate ℓ/min	Average Fluid Production Temp. °C	Mean <V> ℓ	Median [V] ℓ	90% Trimmed Mean V ℓ	Mode V ℓ	Variance σ^2_{θ}	Variance σ^2_{θ} (90%)	Pe ^{a-1}
First Reservoir LBP (75 day) ^b											
1-1 (2/9/78)	88	11	435	150	34405	25563	29254	11400	0.65	0.44	0.591
1-2 (3/1/78)	85	11	787	110	37472	28936	30889	17000	0.62	0.43	0.942
1-3 (3/23/78)	66	11	833	95	54684	45062	46250	22700	0.51	0.42	0.944
1-4 (4/7/78)	59	11	927	90	56232	48400	49203	26500	0.47	0.39	1.120
First Reservoir HBP (28 day) ^c											
1-5 (9/28/78)	93	97	462	111	33094	24730	26615	3800	0.75	0.56	0.358
1-6 (10/13/78)	93	97	560	98	56485	46477	48143	11400	0.45	0.36	0.306
1-7 (10/26/78)	93	17	939	~98	49612	40549	41843	20800	0.49	0.38	0.347
Second Reservoir (23 day)											
2-1 (10/26/79)	172	11	386	153	206781	192268	184455	136300	0.26	0.22	0.195
2-2 (10/29/79)	172	103	488	154	229695	210908	209416	143800	0.17	0.12	0.360
2-3 (11/2/79)	93	11	394	153	262098	216083	242565	115100	0.38	0.34	0.281
2-4 (11/12/79)	93	11	382	153	282630	236036	263378	128700	0.32	0.28	0.310

^aPe^{a-1} = D/UR = inverse dispersional Peclet number for single one-dimensional zone fit.

^bLBP = low back pressure.

^cHBP = high back pressure.

where $\{0, V^*\}$ defines the trimmed distribution of tracer concentration C_i and measured volume V . In Table 8-I results are shown for a truncated distribution after 90% recovery. This effectively reduces the influence of the long tail of the tracer curves. The concentrations shown later in Figs. 8-2, 8-3, and 8-5 are normalized with respect to the pulse strength and the fraction recovered as

$$C_{\theta}^* = \left[C_i / \int_0^{\infty} C_i dV \right] 10\,000 \quad .$$

Another procedure is used for Fig. 8-4 where the tracer concentration is normalized with respect to integral mean volume and fraction recovered as:

$$C_{\theta} = \left[C_i / \frac{1}{\langle V \rangle} \int_0^{\infty} C_i dV \right] \quad .$$

This is done to ensure that the integral of C_{θ} from $\theta \equiv \frac{V}{\langle V \rangle} = 0$ to ∞ is equal to one for all experiments. The spread of the distribution is proportional to the degree of dispersion and can be represented by the statistical variance σ_{θ}^2 where

$$\sigma_{\theta}^2 = \left[\int_0^{\infty} V^2 C_i dV / \langle V \rangle^2 \int_0^{\infty} C_i dV \right] - 1 \quad .$$

Another measure of this comes from the inverse Peclet number that results from a one dimensional fit to the data (see Ref. 5).

As can be seen in Table 8-I and Figs. 8-1 and 8-2, the new fracture system has an effective flow-through volume that is larger than the old system measured in run segments 2 and 3. Comparing the LBP results of run segment 2 with the LBP results of run segment 4, one finds a factor of 8.8 increase in the median fracture volume, $[V]$. The volumes are compared at those times within these stages where they were closest in terms of operating pressures and temperatures (EE-1 88 to 93 bars, GT-2 11 bars, $T = 150$ to 153°C). This

volume increase is just another verification of the increased heat-transfer area that resulted from the activation and extension of the lower fracture in EE-1 after recementing. Even a rudimentary model would suggest that flow-through volume would scale with area for a constant "self-propped" aperture. Assuming a similar fracture aperture profile for the upper and lower fracture systems, the 8.8-fold increase in volume agrees reasonably well with the lower bound ratio of heat-transfer areas ($45\,000\text{ m}^2/8000\text{ m}^2 = 5.6$) and an area ratio of 11 based upon the spacing between inlet and outlet.

The next feature of these studies concerns the degree of mixing and distribution of residence times. Although the analysis is far from complete, several generalizations can be made at this time. Figures 8-2 and 8-3 compare averaged (smoothed) and actual tracer curves for run segments 2, 3, and 4. After normalization with respect to integral average volume as described in Ref. 5, the degree of dispersion can be represented by the variance of the normalized distribution (σ_θ^2) and the inverse Peclet number (Pe^{*-1}) that results from a one-dimensional single zone best fit to the data. These characteristic numbers are cited in Table 8-I while representative normalized distributions for segments 2, 3, and 4 are compared in Fig. 8-4. Both σ_θ^2 and Pe^{*-1} are smaller for the run segment 4 indicating a somewhat smaller degree of dispersion. As a result, the spread of the normalized ($C_\theta - \bar{C}_\theta$) distribution in Fig. 8-4 during run segment 4 is less than the earlier case. One tentative explanation may explain this effect, in that the flow now occurs over a larger main fracture volume with the superposition effects caused by the connecting joints reduced. In the earlier Phase I tests (run segments 2 and 3), the GT-2B joint spacing relative to the separation distance between a particular joint and the main injection point at 2.75 km (9020 ft) in EE-1 was large in comparison to the new injection point at 2.93 km (9620 ft). Consequently, the net differences in volume or average residence times for the jointed fracture system would be expected to be smaller, resulting in a narrow effective spread of the superimposed distribution. Two-dimensional, dispersional type-curve analyses are currently being conducted and will be reported later.

Because the dye tracer results express a continuous residence time distribution (RTD) they can be viewed as a probability distribution function. Consequently, a statistical analysis may enhance our understanding of the system. In light of this, calculations were done to provide medians, modes, integrated and trimmed means of the observed RTD's as presented in Table 8-I.

Fig. 8-1.

Apparent fracture system volumes for the run segments 2, 3, and 4 tests of the old and new EE-1/GT-2B reservoirs.

Fig. 8-2.

Smoothed residence time distribution curves of normalized concentrations (C_0^*) vs apparent fracture system volume at constant injection rates. Results are all from representative Na-fluorescein tracer tests conducted during run segments 2, 3, and 4 on the EE-1/GT-2B fracture systems.

Fig. 8-3.

Na-fluorescein tracer residence time distribution results. Normalized dye concentration (C_0^*) as a function of apparent fracture system volume.

Fig. 8-4.

Normalized tracer concentration as a function of normalized fracture system volume for the EE-1/GT-2B reservoir.

Integrations of the distribution are required to produce means and medians and are biased toward large volumes or residence times because of the long tails observed in the distributions. The mode, on the other hand, eliminates this dependence and may be a more accurate estimate of the central tendency of the distribution. Using values of the mode as representing the main flow-through volume, average fracture apertures can be estimated from the heat-transfer areas. For the three segments listed in Table 8-I the following average apertures result:

Test	Reservoir Condition	Heat-Transfer Area (m ²)	Average Volume Mode (m ³)	Average Aperture (mm)
Run Segment 2 (75 day) I-1	LBP	8000	11.4	1.4
Run Segment 3 (28 day) I-6	HBP	8000	11.4	1.4
Run Segment 4 (23 day) 215-3 and 4	LBP	~90 000 ^a	122	~1.4

^aBased upon separation distance between inlet and outlet.

One rather interesting perturbation occurred during the first run segment 4 dye study when the pressure in GT-2B was increased to initiate the HBP stage. As seen in Fig. 8-5, a large pulse (double-peaked) of dye entered GT-2B at a time that corresponded exactly to the back-pressure increase. The possible explanation for this behavior is that partial entrapment of fluid occurred in the old fracture system and increased back pressure opened a tensile fracture near the bottom of GT-2B. However, the flow-rate survey results do not directly support this theory because they do not indicate an increase in flow fraction from the bottom near-vertical connection in GT-2B. Results from the HBP test (run segment 3) would suggest that a larger fraction of flow should have been observed during the HBP stage of run segment 4. However, a nonpressure dependent high-impedance connection between the new fracture in EE-1 and the bottom of GT-2B could explain the apparent equality of flow during LBP and HBP phases of run segment 4 and still account for the observed

Fig. 8-5.

Normalized tracer concentration as a function of apparent fracture volume for the 215-1 test showing the dye entrapment effect under low and high back-pressure conditions.

entrapment. For example, a small fraction of the concentrated (300 ppm) dye pulse flowing into a microannulus between the casing and the cement in EE-1, or a small volume flow path near EE-1 could eventually work its way up into the GT-2B joint system with a negligible amount of mixing or dilution. A careful analysis of the previously presented flow-rate survey results before, during, and after the HBP stages of run segment 4 suggests that significant and apparently permanent activation of the upper joints in GT-2B occurred by pressurization. Thus, when the pressure was increased in GT-2B, a flow path for this trapped concentrated dye could be created. Later radioactive Br^{82} tracer tests with logging in GT-2B may resolve this uncertainty. Dye recovery levels during run segment 4 were much lower than for earlier tests; entrapment may explain a part of this, but adsorption of dye on the rock surfaces presents a potential problem because of the higher feed concentration and longer residence times. Some recent tests also suggest the possibility of thermal decomposition. This would be analogous to a radioactive tracer with a short half-life isotope. Another effect that may be important is that dispersion effects are difficult to measure in this larger system because the dye concentrations at late times are very close to background levels. Other tracers,

including tritiated water, trace metal chlorides, concentrated KCl and $\text{NH}_4\text{Br}^{82}$, will be tried in future tests to determine the relative importance of entrapment, adsorption, and/or decomposition.

9. SEISMICITY

Reservoir seismicity was monitored with a surface seismometer array and a geophone package that was positioned downhole in EE-2 in the reservoir vicinity. The surface array consisted of seven stations within 750 m (1/2 mile) of the site, two 125-m deep borehole stations located at 1 and 3 km, and the LASL regional net--the nearest of which is located at 10 km. The sensitivity of this surface array extended to Richter earthquake magnitudes of 0 to -1 and is limited by the nearly 3 km of vertical separation and the large seismic attenuation of the near-surface sediments and volcanics. The downhole geophone package consisted of nine geophones, three each in the x- y-, and z-direction axes. The sensitivity of the downhole package extends to magnitudes as low as -4. During those periods when the geophones were in place, the drilling rig had to be idled, therefore, the downhole geophones were used only during selected periods. Previously, seismic measurements had been made during periods of active fracture propagation and extension during Expts. 195 and 203; these measurements are described below. For this reason geophone measurements were not attempted during stages 1A and 1 of the present experiment; instead these measurements were confined to stage 3, the HBP stage, and stage 4, the LBP recirculating heat-extraction stage. The first downhole measurement occurred on October 30, 1979 and encompassed a period that included the final 4 h of stage 3 and an additional 2 h of shut-in. At the beginning of this measurement approximately 7800 m^3 (2.1 million gal) of water had been injected into the reservoir of which 2800 m^3 (740 000 gal) had been recirculated. Throughout the first 4 h, wellbore pressures at EE-1 and GT-2B were maintained at 170 bars (2500 psi) and 100 bars (1450 psi), respectively. During the shut-in period the GT-2B wellbore pressure decreased by 1 bar while the EE-1 pressure dropped to 128 bars (1850 psi). The second measurement was made near the completion of stage 4 on November 14. At that time roughly $18\,200 \text{ m}^3$ (4.8 million gal) of water had been injected and $12\,100 \text{ m}^3$ (3.2 million gal) circulated. Wellhead pressures were nearly constant at EE-1 and GT-2B, 95 bars and 11 bars (1400 and 160 psi), respectively.

During both measurements the triaxial geophone package was positioned at 2885 m (9465 ft) estimated true vertical depth in EE-2, a location 180 m (590 ft) N5°E of the injection point in EE-1. At this depth EE-2 drifts 11° from vertical. The orientation of the reference horizontal geophone axis was determined using records from a Sperry-Sun multishot magnetic survey. Borehole

drift and direction obtained from each record agreed to within the measurement error ($\pm 0.5^\circ$ and $\pm 1^\circ$, respectively) with that obtained in earlier independent surveys of the well by Eastman Whipstock. A schematic of the geophone package is given in Fig. 9-1. We use the Cartesian convention to identify the geophone axis as related to the geophone package. The axis of the vertical geophones, z, corresponds with the long axis of the geophone package. The horizontal geophone axis, y, is in line with the locking arm and is used as the reference for magnetic surveys. While in position in EE-2 during both measurements, the z and y axis were inclined at roughly 10° to true vertical and to true horizontal, respectively. Records obtained using the z-oriented geophone show an anomalous harmonic distortion, which to date has precluded determinations of the inclination of microseismic foci in the coordinate system of the geophone package.

9.1. Results

The rate of occurrence of identifiable seismic events during the stage 3 measurements is shown in Fig. 9-2 along with rates observed during the earlier massive hydraulic fracture treatments (Expts. 195 and 203) which formed the circulating system in March 1979. In comparison with the earlier measurements the present rate of event occurrence is low and constant and did not perceptibly change on shut-in of the system. At the termination of stage 4, however, seismicity of the nature observed previously,^{19,20} characterized by clear shear-wave arrivals, was virtually nonexistent. Only very few events (perhaps 10) were identified during the entire 6-h period of the stage 4 measurements.

The general character of microseismic signals detected in stage 3 is shown in Fig. 9-3. The signals processed for interpretation showed clear compression (P) and shear (S) wave arrivals. For the P-waves the first-cycle amplitude-to-noise ratios were in excess of 10 and the polarization eccentricity was greater than 4. The largest event detected had a local magnitude of -1.5, estimated on the basis of a coda length assignment in the local earthquake magnitude scales by extrapolation to the microseismic range. Based on the delay time between P- and S-wave arrivals and the propagation velocities of the respective phases, rock failure occurred at distances as close as 75 m and as far as 600 m from the geophone package, the latter being 250 m greater than any events previously detected.

Fig. 9-1.
LASL geophone package tool 400B

Fig. 9-2.
Microseismic occurrence rate vs time.

Fig. 9-3.
Microseismic signal detected by geophone sonde in EE-2.

Source parameters, i.e., the dimension of the rupture r , the seismic moment M_0 , and the amount of shear stress relieved during the event $\Delta\sigma$ were calculated from the amplitude displacement spectra for a sample of 17 events from segment 4 using the equations proposed by Brune.²¹ The source dimension, r , is a measure of the distance over which the rock fails or undergoes renewed slippage (if the event is caused by sliding on a pre-existing fracture). It is believed that failure, or slippage, occurs as discrete local events, so that r would be much smaller than the total radial extent of a fracture. The calculated values of these parameters are very similar to those obtained for events recorded during the March 14 and 21 MHF experiments as shown in Table 9-I. The mean S-corner frequency for the events in run segment 4 is somewhat higher than it was for the two previous experiments (674 Hz vs 597 Hz for the March 14 and 21 experiments). This is somewhat surprising since the events in run segment 4 traveled a greater distance before reaching the geophone, and it suggests that attenuation of high-frequency S-waves is not a problem for spectral analysis even for events as distant as 600 m. The fact that high-frequency shear waves can be transmitted through the reservoir implies that the Q for the rock along the ray paths traversed in this experiment is comparable to that of competent, unfractured granite. The parameter Q is a measure of the transmission of seismic waves through rock. The mean stress drop was 4.8 bars. This value is slightly higher than the mean of the high-stress drop events that occurred during MHF Expt. 203. The latter events are believed to have arisen through rupture of virgin rock.

TABLE 9-I

MICROSEISMIC EVENT SOURCE PARAMETERS

Experiment	Rupture Dimension (m)	Seismic Moment, M_0 ($\times 10^{13}$ dyne-cm)	Stress Drop, $\Delta\sigma$ (bars)
MHF Expt. 203 (March 14, 1979)	2.7	10	1.2
MHF Expt. 195 (March 21, 1979)	2.0	7	1.5
Run Segment 4 (October 1979)	2.1	22	4.8

Figure 9-4 gives radial distances to microseismic event foci in terms of geographic coordinates centered at the geophone package in EE-2 and the azimuth of geophone first motion on P-wave arrival. Assuming that the rate of microseismic occurrence observed during the latter part of stage 3 of run segment 4 applies to the entire high-pressure stage and ignoring any seismicity that may have occurred in stage 4, we estimate that the mapped events represent less than 1% of the events that took place during the entire period encompassing stages 2 and 3. The small number of mapped events results primarily from the combination of the limited downhole monitoring time and the low percentage of detected signals of sufficient quality for analysis. Two additional factors contribute to the lack of resolution in the map. First, the loss of vertical control due to the failure of the vertical geophones means that foci otherwise spatially close will separate in projection. Second, in using EE-2 as a vantage point to view the reservoir, signals from certain directions will be highly attenuated and may not be amenable to analysis. For example, as will be seen, signals from events in the southwest quadrant arriving at EE-2 must pass through the fracture zone created during March 1979. Resolution of activity in the southwest quadrant is thereby reduced.

True locations cannot be given in any projection because of the lack of control on signal inclination due to the vertical geophone failure. Consequently we discuss only the limiting case in which it is assumed that all events occurred on the horizontal plane containing the geophone package. Further, the mapped events are subject to a simple two-fold ambiguity in direction, centrosymmetric with the geophone sonde location. This ambiguity, which is present in all locations determined from analysis of the signal detected using only a single station, means two directions 180° apart are equally likely directions to the event source. Our practice is to plot events based on geophone first motion only, ignoring the question of first motion at the microseismic source location. A result of this procedure in the past, as in the present case, has been that the seismicity so mapped locates the activity in the possible position closest to the injection well.

In Fig. 9-4 a vague definition appears of one to perhaps three west-northwest striking zones of seismicity within a rectangular volume of rocks as large as 400×800 m on a side. The relationship of these zones to those previously excited in the reservoir is shown in Fig. 9-5. The data, system conditions, geophone location, and injection well during each measurement are

Fig. 9-4.
Direction and radial distance to microseismic foci, plan view.

Fig. 9-5.
Comparison of run segment 4 event locations in Fig. 9-4 with locations from Expts. 195 and 203 (March 1979) and earlier experiments during October 1975 and June 1976.

given in Table 9-II. During experiments in October 1975 and March 1979 essentially vertical north-northwestern striking zones were detected. These experiments represent the first instances in which substantial amounts of water were injected into zones that had been hydraulically fractured to enlarge the respective fracture surface areas. An experiment in June 1976 resulted in the detection, based on meager data, of a west-northwest striking seismic zone. The extent and distance from the injection points of the zones detected before 1979 are not surprising considering the small volume of water injected into the reservoir at that time, never being greater than 30% of the smallest of the 1979 injections. Rock failure has not been detected seismically at any time within 25 m of the geophone location in any of the measurements. In addition, analysis⁶ of the spatial distribution of events detected during the March 1979 injections has shown that the events occurred in vertical zones having widths normal to the strikes that exceeded 100 m.

TABLE 9-II

OPERATING CONDITIONS DURING WHICH MICROSEISMIC EVENTS WERE DETECTED

Measurement Date	Volume/Injected and Injection Well (m ³)	Injection Rate (l/s)	Pressures EE-1/GT-2 (bars)	Seismic Zone Strike
10 October 1975	44/GT-2	25	0/142 ^{a,c}	N26°W
29 June 1976	189/EE-1	31	116/72 ^b	N62°W
14 March 1979	603/EE-1	27	195/55 ^d	N15°W
21 March 1979	755/EE-1	42	207/103 ^d	N20°W
30 October 1979	5000/EE-1 ^e	25	170/100 ^d	N75°W

^aThe production well was shut in throughout the monitoring period.

^bInjection through EE-1 into the EE-1/GT-2 system.

^cInjection through GT-2 into the EE-1/GT-2 system.

^dInjection through EE-1 into the EE-1/GT-2B system.

^eUnrecirculated.

Why was the run segment 4 seismicity excited along the west-northwest striking zones rather than the north-northwest zone which accounted for almost all of the activity in March 1979? The only apparent difference between injection during the run segment 4 test and Expts. 195 and 203 of March 1979 is the larger accumulation of unrecovered water during run segment 4. In the March 1979 experiments GT-2B was shut-in and total volumes of 603 and 755 m³ were injected into EE-1 and thence into the reservoir. In run segment 4 GT-2B was throttled to allow recirculation but the test was longer, so at the end of stage 3 seismic monitoring the cumulative difference between inflow and outflow, representing the net amount injected into the reservoir, was 5000 m³ (1.3 x 10⁶ gal), 6.6 times the highest volume of the March injections. If it is assumed that the west-northwest striking fracture is continuously connected and lenticular in shape, then the fractured surface area must be over 500 000 m² in surface area. Over 80% of this was created during and subsequent to March 1979. This surface area is ten times the lower bound estimated from the heat extraction data. However, the value cited here represents the total area of rock through which the injected water could be infiltrated. It includes all the manmade as well as natural fractures and joints and all the tortuous paths in the reservoir vicinity into which the water could be squeezed when the production well was shut-in. When the production well is vented for heat extraction, only a fraction of these same flow paths would conduct significant rates of flow, so it is expected that the effective heat-transfer area would be substantially less than the seismic area.

The attempt to detect seismicity during the low back pressure stage of run segment 4, stage 4, was to establish whether or not rock failure accompanies active heat extraction. Little seismicity of the scale and nature that occurred in stage 3 was observed; thus it appears that reservoir heat extraction, to the extent we have thus far witnessed, does not cause microseismicity.

The picture that emerges indicates that the north-northwest striking fracture system created in March was extended in the predominately easterly striking direction during run segment 4. As shown in Fig. 9-5 the easterly striking fracture permeability is not connected along its strike directly to the production well. Because of the large distances to the microseismic foci, and the relatively short period that the system was pressurized, there is no reason to suppose that the fracture permeability created in run segment 4 is

hydraulically isolated from the EE-1/GT-2 flow-through system. Further, because two prominent directions of enhanced permeability are not apparent, neither predominant fracture direction necessarily results from tensile fracturing normal to the least confining stress. An equally plausible explanation is the conventional idea in seismology that fluid pressures have decreased the normal stress along weakly permeable zones and consequently have caused the release of pre-existing tectonic stresses. Because of the close lateral proximity of the EE-1 injection point and the production zone in GT-2B, fluid velocities in the extremities of the north-northwest striking fracture and throughout the west-northwest fracture system will be negligible. The capability for through-put however, appears to exist and a well penetrating anywhere in the seismically active zones laterally displaced from the injection point at greater distances, might result in a significant enlargement of the available heat-extraction area.

9.2. Temperature Measurements

Both before and following the seismic measurements in stage 3, a temperature survey was run in EE-2 for the purpose of detecting flow that may have originated if hydraulic communication was present between EE-2 and the GT-2B/EE-1 circulating system. Figure 9-6 shows the results of the surveys in the depth interval 2.5 to 3.0 km. The surveys taken 30 h apart give no indication of flow in EE-2. The fractures which were created in the vicinity of EE-2 during stage 3 then necessarily either did not intersect the well even though the geophone package was located rather centrally in the band of seismicity or resulted in extremely low or dispersed flow in EE-2.

Fig. 9-6.
EE-2 temperature surveys, high back-pressure stage.

10. CONCLUSIONS

A new and deeper hot dry rock geothermal reservoir was created by hydraulically fracturing granitic rock at a depth of 2.93 km (9620 ft) where the virgin rock temperature was 197°C. The new reservoir is the second reservoir created between the EE-1 and GT-2B wellbores and supports the contention that large multiply-fractured reservoirs can be formed with a single well-pair, thus minimizing costs. The inlet-to-outlet spacing of the new fracture is three times that of the old one, and on the basis of potential flow theory the effective heat-transfer area of both fracture systems would be expected to be 11 times that of the old fracture, a total area of about 90 000 m². Measured median volume ratios suggest an area ratio of nine, and analysis of the thermal drawdown (actually the lack of it) provides a ratio of five or six at the very least, so estimates of reservoir size are in reasonable agreement. The seismic area ranged as high as 500 000 m², but this area includes those low flow rate paths provided by all the natural joints in the reservoir vicinity--only a fraction of these paths could be exploited with the present wells. Assuming that the effective heat-transfer area of just the new fracture is 70 000 m², as suggested by the average of the indications provided by measured median volume and the inlet-to-outlet spacing, only six or seven fractures of similar size are required for near-commercial size, Phase II, reservoirs in which 20 to 50 MW of thermal power would be produced for 20 years.

Despite the 6 to 11 times larger area the permeation water losses with the new fracture system were only twice the losses experienced with the old fracture after an equivalent period of time. These losses should diminish with time as the porosity of the surrounding rock is satisfied. The upper bound estimate obtained after 23 days of operation was 1.3 l/s (20 gpm). Fracture flow impedances were found to be pressure and flow-rate dependent. Following the HBP stage of the experiment, which resulted in an impedance reduction by a factor of two, the impedance was steady at 14 bar s/l (13 psi/gpm). This value is nearly equal to the initial value obtained with the old fracture, despite the fact that the inlet-to-outlet spacing, and therefore the flow path lengths, are three times that of the old fracture. Unlike the old fracture, a decrease of impedance with time was not observed, presumably because of the lack of thermal drawdown.

Geochemical monitoring established that the thermal drawdown of the new fracture, as measured by geothermometry techniques, was immeasurable during the 23 days of heat extraction. The concentrations of dissolved chemicals in the produced water was low and the pH was near neutral so that the produced water was of good quality--nearly of potable standards. No chemical corrosion or scaling of the surface pumps, heat exchangers, or piping was observed. Seismic monitoring indicated that the largest microseismic event detected had a local magnitude of -1.5. This magnitude occurred during stage 3, the HBP stage, when the fracture was possibly being slowly extended. The energy release of a -1.5 microseismic event is roughly equivalent to that of a 1-m-diam lead sphere dropped 3 m. During stage 4, the sustained low-pressure heat-extraction stage, no microseismic activity having a magnitude exceeding -3 was detected, suggesting that the seismic hazard associated with recirculating hot dry rock geothermal reservoirs should be negligible.

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APPENDIX

ADDITIONAL GEOCHEMISTRY DETAILS

1. SAMPLING PROCEDURES

1.1. Fluid Samples. Each fluid sample consisted of:

- 1 μ l of unfiltered water for analysis of total suspended solids,
- 1 μ l of filtered water for anion analyses,
- 1 μ l of filtered water which was acidified to pH<3 with $\sim$ 1.0 μ l of concentrated HNO_3 for cation analysis,
- 500 μ l of filtered water that was immediately treated according to the procedure of Barnes¹ (modified by P. Trujillo) for the extraction of monomeric aluminum. The samples and standards were treated to remove iron interferences,
- 50 μ l of filtered water for Sr isotope analysis,
- 1 μ l of filtered water for trace element analysis, and
- 125 μ l of unfiltered water for oxygen and hydrogen isotope analysis.

The samples in the first six categories were collected in new Nalgene bottles, which were rinsed at least twice with the geothermal fluid immediately before sample collection. The samples for oxygen isotope analysis were collected in flint glass bottles, which were filled brimful and immediately sealed with Polyseal caps. The filtered samples were filtered through 0.45 μ m Gelman filters, which were connected directly to the sample ports. The filters were changed as needed before each sample was collected.

1.2. Dissolved Gas Samples. A schematic of the gas sampling apparatus is shown in Fig. A-1. This apparatus consists of a 4- μ l high-pressure stainless steel flask fitted with a 1/4-in. stainless steel tubing, which was drilled with 15 1/8-in. holes to act as a spray separator. A 1- μ l high-pressure stainless steel flask immersed in an ice bath acts as a cold trap. The gas and liquid were separated by flashing hot fluid to just above atmospheric pressure within the 4- μ l stainless-steel flask and a sample of the gas was collected from the cold trap.

1.3. Radon Samples. Samples for radon analysis were collected and analyzed according to the procedure of Stoker and Kruger² with minor changes.

An additional ascarite trap was placed in the system to remove the excess amounts of CO_2 which had interfered with the radon analyses during the high back-pressure experiment, segment 3. A drawing of the modified system is shown in Fig. A-2.

2. FLUID SAMPLE ANALYSIS PROCEDURES

2.1. Total Suspended Solids. Gelman 0.45 μm filter papers were dried to constant weight at low ($\sim 30^\circ\text{C}$) temperature and individually weighed to the nearest 0.1 mg. A filter paper of known initial weight was placed in the high-pressure filter holder and 1.0 μl of fluid was placed in the liquid chamber. The entire 1- μl sample was forced through the filter paper with laboratory air pressure (5 bars). The filter paper was again dried to constant weight and weighed to the nearest 0.1 mg.

2.2. Anion Analyses. Analysis of the unidentified sample for pH, Eh, and HCO_3^- were performed as soon as possible after the bottles were opened. A 100 $\text{m}\mu\text{l}$ aliquot of the sample was placed in a small beaker and the pH and Eh electrodes were inserted. The sample was stirred slowly with a Teflon coated stirring bar (both pH and Eh electrodes were standardized in stirred solutions). Measurements of pH and Eh were made with standard electrodes as soon as the meter stopped drifting (5-10 min). The samples were immediately titrated to pH 4.5 (measured with the electrode) with 1.5 N standard H_2SO_4 with a Hach digital titrator. A 100- $\text{m}\mu\text{l}$ sample was titrated for Cl^- with 2.247N standard $\text{Hg}(\text{NO}_3)_2$ solution using Diphenylcarbazone indicator from Hach. Fluoride analyses were performed on 20- $\text{m}\mu\text{l}$ samples using an Orion solid-state fluoride selective electrode and Hach fluoride buffer. The conductivity of the unacidified fluid was measured with a Hach conductivity meter. Sulfate was determined by measuring turbidity of the solution after the addition of BaCl_2 to the geothermal fluid.

2.3. Cation Analyses. Silica analyses were performed on the filtered unacidified sample by the silicomolybdate spectrophotometric technique. Boron analyses were performed spectrophotometrically using the procedure of Meglen.³ All cations were analyzed by atomic absorption spectrophotometry using either air-acetylene or nitrous oxide-acetylene flames or the graphite furnace. Samples and standards which were analyzed by flame were diluted with $\text{CsCl} + \text{HNO}_3$ solution so that all samples and standards contained 1000 ppm Cs and were 1% by volume HNO_3 to eliminate ionization interferences and to acid

Fig. A-1.
Gas sampling apparatus.

Fig. A-2.
Radon collection and extraction equipment.

match the samples and standards. Standards were prepared from commercially available standard solutions.

2.4. Isotopic and Trace Element Analyses. These samples have not yet been analyzed.

3. GAS SAMPLES

Gas samples were analyzed on a Carle automatic gas chromatograph using a thermal conductivity detector. The gas chromatograph was calibrated daily with mixtures of pure gases. The sample loop was thoroughly flushed before the analysis cycle was started. Peak areas and retention times were measured using a Spectraphysics Minigrator. Helium was used as the carrier gas for the main columns and nitrogen was used for the hydrogen transfer tube.

3.1. Radon Samples. Radon samples were collected in Lucas cells and the Lucas cells were counted with a photomultiplier using a Ludlum high-voltage power supply-scaler-timer.

4. CONCENTRATION-TIME CURVES

Concentration vs time curves for many of the important species were presented in the main body of the text. Here in Figs. A-3 through A-12 are presented the concentration curves for pH, Eh, Ca, Li, Mg, Fe, Sr, HCO_3^- , SO_4^{2-} , and F^- .

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Fig. A-3.
Variation of pH.

Fig. A-4.
Variation of Eh.

Fig. A-5.
Variation of calcium concentration.

Fig. A-6.
Variation of lithium concentration.

Fig. A-7.
Variation of magnesium concentration.

Fig. A-8.
Variation of iron concentration.

Fig. A-9.
Variation of strontium concentration.

Fig. A-10.
Variation of bicarbonate concentration.

Fig. A-11.
Variation of sulfate concentration.

Fig. A-12.
Variation of fluoride concentration.

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