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FRACTURING OPERATIONS IN A DRY GEOTHERMAL RESERVOIR

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ABSTRACT

Fracturing and completing deep wells in hot, non-porous crystalline basement rock challenges conventional equipment use, procedures, and techniques common in oil and gas and normal geothermal completions. Fracturing operations at the Fenton Hill, New Mexico, Hot Dry Rock (HDR) Geothermal Test Site initiated unique developments necessary to solve problems caused by an extremely harsh downhole environment.

Two deep wells were drilled to approximately 15,000 ft (4.6 km); formation temperatures are in excess of 600°F (315°C). The wells were drilled during 1979-1981, inclined at 35 degrees, one above the other, and directionally drilled in an azimuthal direction orthogonal to the least principal in-situ crustal stress field. The pair of wells form the injection and production wells of an energy extraction system which will be unique in reservoir development.

The test site is located near the flank of a young silicic composite volcano, the Valles Caldera, in the Jemez Mountains of northern New Mexico. The deeper well was planned as the cold water injection hole; as such, it may be cooled from the static, conduction geothermal gradient to as low as 80°F (25°C). The upper, production well will be heated to over 500°F (260°C) along its entire length. The well pair has been designed to be a closed loop, heat-extraction system formed with hydraulic fracture connections between the 1200 ft (370 m) vertically-spaced wells. These production conditions, and the in-situ formation temperatures, strongly constrain all completion hardware, cementing formulations and procedures, and fracturing operations.

Hydraulic fracturing experiments to connect the two wells have used openhole packers, hydraulic jet notching of the borehole wall, cemented-in isolation liners and casing packers. Problems were encountered with hole drag, high fracture gradients, H₂S in vent back fluids, stress corrosion cracking of tubulars, and the complex nature of three-dimensional fracture

growth that requires very large volumes of injected water. Two fractured zones have been formed by hydraulic fracturing and defined by close-in, borehole deployed, microseismic detectors. Initial operations were focused in the injection wellbore near total depth, where water injection treatments totalling 51,000 bbls (8,100 m³) were accomplished by pumping through a cemented-in 4-1/2-in. liner/PBR assembly. Retrievable casing packers were used to inject 26,000 bbls (4,100 m³) in the upper section of the open hole. Surface injection pressures (ISIP) varied from 4,000 to 5,900 psi (27 to 41 MPa) and the fracture gradient ranged from 0.7 to 0.96 psi/ft.

INTRODUCTION

Natural, or hydrothermal, geothermal reservoirs form where water has contacted rocks heated by shallow heat sources within the crust. In a few places, large circulating convection systems exist within porous, fractured reservoirs. These natural systems, capped by an impervious layer, are characterized by high heat flux at the surface and are sometimes associated with leakage of fluids, via hot springs, geysers, and fumaroles. Natural hydrothermal reservoirs are rather rare, but are excellent resources when exploited. World-wide development of such high-grade hydrothermal reservoirs is at an installed electrical capacity of about 3200 MW(e) in 13 nations, from about 3000 wells. Increasing exploration activities have seen wells drilled into some 147 hydrothermal reservoirs located in 43 countries. The current worldwide growth rate of installed geothermal electric power generating capacity is approximately 15% per year.

Several HDR projects have been initiated around the world, with those in the United States, United Kingdom, Germany, France, and Japan being the most advanced. Pursuit of research and development projects for innovative geothermal energy extraction systems has been motivated by the recognition that exploration and development wells often do not produce fluids. The ratio of dry to producing wells in hydrothermal exploration averages somewhat greater than 3 to 1. The majority of the dry holes are hot -- penetrating into dry rock that lacks sufficient fluids and

References and illustrations at end of paper.

natural permeability. Developmental drilling of natural hydrothermal reservoirs thus often produce dry, but usable, hot wells that are excellent prospects for stimulation², or for possible development as HDR energy extraction systems. The latent energy in HDR is immense, and its successful development offers a promising answer to the world's increasing energy demands.

PROJECT STATUS

Production of heat energy by the HDR technique involves creation of in-situ permeability in hot rock formations by hydraulic fracturing. A two-well HDR reservoir system, drilled into hot crystalline rock, and the circulation of water through fractures produced between the wellbores has evaluated and demonstrated the basic feasibility of the concept (See Appendix A, Geology and Rock Properties). The artificial geothermal reservoir project was initiated at the Fenton Hill experimental site in 1974 (Fig. 1). Two wells were drilled to about 10,000 ft (3 km) depth, at a bottom hole temperature of 400°F (200°C), and were fractured in 1975-1977, creating the first reservoir. Extensive circulation and heat extraction experiments during 1978-1980, along with reservoir simulations³ of the vertical planar heat transfer fracture zone, capable of producing power at a 3 to 5 MW (thermal) level for about one year, motivated the present study and development of a larger and hotter HDR geothermal reservoir.

This paper reviews the initial phases of experimental hydraulic fracturing efforts in the second pair of deeper, 35° inclined wells, configured so that a multi-fracture, parallel reservoir concept could be attempted (Fig. 2). The drilling of the deeper well pair^{4,5} was finished in August 1981. The wells were drilled with open hole reservoir sections of 8-3/4-in drilled diameters. The deeper injection well (EE-2) was drilled to a measured depth of 15,298 ft (4.65 km) at a bottom hole static temperature of 608°F (320°C). The production well (EE-3) reached a measured depth of 13,933 ft (4.25 km), at a BHST of 580°F (280°C). High precision directional drilling located the production well EE-3 at 1200 ± 50 ft (370 ± 15 m) above and with relatively close lateral location tolerances, 100 ft (±30 m) to EE-2, to maximize the possibilities for connection during fracturing operations. Figures 3a and 3b summarize the wellbore trajectories for the EE-2/EE-3 well pair.

Completion operations began in November 1981 with the mobilization of a small workover rig over EE-2 to clean the wellbore (See Appendix B for details). The fracturing operations commenced in 1982 with the mobilization of a large workover rig over the EE-2 injection well. The initial phases of these operations are still underway (July 1983).

OPERATIONAL PLAN

Prior to the mobilization of the workover rig, a sequence of fracturing experiments was planned, with these major objectives:

- a. Select equipment, hardware, and methods required for fracturing in crystalline granitic rock at depths below 11,000 ft (3.4 km).

- b. Create at least two fractures near the bottom of the injection well EE-2, connecting to the production well EE-3.
- c. Measure the initial flow impedance of the fractures.
- d. Map the fractures between the two wellbores using microseismic techniques.

These experimental plans focused on three zone isolation methods:

- high-temperature, open hole packers,
- cemented-in liners with sand plugs below, and
- casing packers with sand plugs below.

The planning and strategy of the fracturing operations were based upon the decision to start initial fracture-connection attempts near the total depth of the EE-2 injection well below 14,000 ft (4.3 km) and in static formation temperatures greater than 580°F (275°C).

If a hydraulic connection could be achieved from this zone, then circulation of flow through this lower, hotter region, with heat extraction by surface heat exchangers, would permit cooling of the openhole reservoir section of EE-2, thus simplifying subsequent fracture-connection operations. Many of the anticipated problems were similar to those detailed in Ref. 6 in that long strings of large diameter pipe would be used, with large cooldown contractions, downhole stack-off force uncertainties, tubular buckling conditions, and precise force and movement control of frac-string required at the surface. Wellbore friction was also anticipated to be a major problem.

PREPARATION FOR FRACTURING

The drilling of the wells required the use of a lubricity additive that, upon thermal decomposition, formed a heavy black coating on downhole hardware and could foul the fluid injection process. Consequently, the EE-3 well was cleaned prior to and following final casing installation; EE-2 required a workover cleanout operation that was accomplished in December 1981.

Workover Rig and Equipment

The experience gained from drilling and cleaning of EE-2 indicated that significant hole drag and torque would be experienced during run-in and pull-out of the hardware for the fracture operations. Specifications of the workover rig used for these operations were:

Derrick and Substructure:	136 ft International 800,000 lb GNC, rated for 600,000 lbs hook load with 12 lines, 22 ft substructure clearance.
Drawworks:	National 610, Parmac 281 hydromatic brake, 1-1/8-in. drilling line.
Rig Pumps:	Two - 8P80 800 HP Triplex pumps.
Rig Floor:	Racking capacity for 16,000 ft of 3-1/2-in. O.D. drill pipe.

Blow-out Preventors: 12-in. 3000 lb WP single and double 12-in. rams, and 3000 lb Hydril.

Workstring: 9000 ft, 3-1/2-in. Grade E, and 7000 ft, 3-1/2-in. Grade S; 13.3 lb/ft, API premium.

A 4-1/2-in. O.D. frac string (buttress casing) N-80 and P-110, 15.1 and 11.6 lb/ft, was also available.

Brinkerhoff-Signal Drilling Co. (Denver, CO) Rig #78 was mobilized to the Fenton Hill HDR test site on April 4, 1982. The personnel, with this equipment, had previously drilled a considerable number of wells at the Union Oil Co., Baca, NM, hydrothermal reservoir located only 4 miles from Fenton Hill. This previous hot-hole experience was judged to be a significant advantage to the project. The sequence of operations described was accomplished using this workover equipment and personnel.

Preliminary Pressurization

Both open wellbore reservoir sections were pressured to determine the formation tightness. The injection well, EE-2, was extremely tight. Pressurization to 2200 psi surface pressure did not produce breakdown nor was any significant water injected into the formation. Worn spots in the 9-5/8-in. casing precluded higher pumping pressures. The production well, EE-3, took water at about 1500 psi surface pressure. A lost circulation zone that extended for about 240 ft (73 m) along the wellbore was found just below the 9-5/8-in. casing shoe.

Hole Conditioning for Drag Problems

The effect of hole drag on both the drill string and wireline tools was a continuing problem, that required a hole conditioning treatment prior to the start of fracturing operations. A detergent and a sepiolite mud mixture were both tried (described in detail in Appendix C), with sepiolite being the most successful.

Notching Experiments for Fracture Initiation

The creation of a notch near the bottom of well EE-2 prior to fracturing was considered important to: (1) create a fracture initiation point, (2) reduce the tendency of a created fracture to grow up the wellbore around the packer, and (3) penetrate the wellbore stress cage (if such existed). The desired notch configuration was a radial groove which would not cause hole sloughing and would allow passage of all bottom hole assemblies and wireline tools.

Three methods of notching were considered: (1) explosives, (2) underreaming, and (3) hydro-jetting. Attempts to use explosives run on electric wireline were thwarted by hole conditions which stopped the dummy test explosive tool at approximately 14,100 ft (4298 m) depth. Underreaming was considered to be a very difficult operation due to the high torque required to rotate 15,000 ft (4.6 km) of drill pipe in the deviated hard rock hole.

Two problems were anticipated using the hydro-jetting technique. Anchoring of the nozzles required either an open-hole, sidewall anchoring device or a stinger to space the nozzles off the bottom. Keeping

sand and formation cuttings suspended required careful attention to the hydraulic design. A description of the hardware and pumping chronology is included in Appendix D. A notch was apparently created, but had no observable effect on fracture initiation.

FRACTURE OPERATIONS

Operations in EE-2

The sequence of fracture-connection operations is recorded in Table 1. Experiment numbers are referenced to the wellbore and zone isolation configurations in Fig. 4. The first two fracture attempts used a high temperature open-hole, single packer system (Lynes, Inc., Houston, TX). After circulating and cleaning EE-2, a sand-barite plug was set with top at 15,145 ft (4616 m), back-filled from the 15,298 ft (4663 m) drilled depth. This was done both to cover a lost gamma tool on bottom, and to place the isolated zone of open EE-2 wellbore vertically below the bottom of the EE-3 wellbore. The EE-3 TD had been stopped short of its target depth by about two bit runs, i.e. ~600 ft (200 m).

Both Lynes packers were run and set as planned. However, selection of the packer seating depths were made without benefit of a caliper log. The selections were based upon cuttings, core, and drilling records data. These two fracture tests were based on the supposition that downhole breakdown and injection pressures might be as low as 7000 psi (a fracture gradient of 0.5 psi/ft.). The packer limitations were p of 5,000 psi and 500°F (260°C) as established by laboratory tests. To possibly decrease the breakdown and injection pressures, a notch was made in the isolated zone for the first test (Fig. 4). The first packer was set and pressure tested at 2250 psi Δp. However, it failed when a loss in pressurization occurred and possibly unseated and ruptured the packer prior to injection. Extensive circulation at a flow rate of 30 bpm for 14 hours was performed prior to the second Lynes packer test in an attempt to cool the hole and create thermal stress fractures in the wellbore wall. The second Lynes packer test run went as planned; a total weight of 125,000 lb was stacked-out after a pressure check to 4200 psi. A backside (annulus) pressurization to 2000 psi was established. However, the packer failed at a flow injection volume of only 12 bbls at a maximum surface pressure of 4400 psi; and no breakdown nor any true injection rates were observed. This result demonstrated that the fracture gradient was at least greater than 0.7 psi/ft., as confirmed by the subsequent fracture and injection experiments.

After the failure of the packers, a 310-ft-long (94 m) liner/PBR assembly was run in and cemented at 14,698 ft (4480 m), see Appendices E and F.

Two successful large fracture and injection treatments were performed at surface injection pressures of 6600 and 6750 psi with flow rates of 30 and 35 bpm, Table 1. The downhole injection pressures of 5300 and 5400 psi, indicate fracture gradients of about 0.7 psi/ft. The total injection volume was 2.1×10^6 gals. These results, and the subsequent fracturing results are tabulated in Table 2. The first major treatment (0.8×10^6 bbls) ended on schedule, but had an indication of liner by-pass flow to the annulus. This flow could be controlled to less than 1-1/2 bpm by pressurizing the backside to 2000 psi and by the

addition of silica flour to the fracture water. The flow and pressure histories for these two treatments are shown in Figs. 5 and 6. A friction reducer of approximately 10 lb/1000 gals was used.

These first attempts at connection of the wellbores were discontinued after Experiment 2016 when the on-line seismic fracture mapping data showed that the microseismic "cloud" was missing the EE-3 wellbore, Fig. 7, and also that a pressure rise had not occurred at the EE-3 wellhead. Post test analysis of the annulus flow and pressure behavior showed that the PBR seals had held, that no micro-annulus between the cement and liner had occurred, and that fracture permeability immediately adjacent to the cemented-in interval did not contribute to the by-pass, but that a complex fracture path through the formation was responsible. The combined evaluations indicated that further fracture experiments below the liner/PBR would be fruitless without extensive remedial work. However, these two massive volume injections confirmed the effectiveness of a cemented-in liner as a completion technology for HDR zone isolation. Although the cementing of the liner was apparently successful, further evaluation of the cement is required to determine its durability.

Following the failure to make a connection at the 15,000 ft (4.6 km) depth, the injection wellbore was sanded back to a depth of 12,060 ft (3676 m) as shown in Fig. 4 with approximately 430 ft (131 m) interval of open wellbore exposed. The plan was to use a high temperature permanent casing packer system near and above the casing shoe. Several attempts to set and use such a system failed due to the hole condition, equipment problems and setting tool inadequacies. A high temperature retrievable casing packer (by Otis Engineering, Dallas, TX) was successfully run for three fracture operations (Fig. 4). Such a packer system has been successfully used in other geothermal stimulation projects⁷; and is based upon a newly developed EPDM Y267 elastomer formulation.

This upper interval was subjected to three fracture treatments, with the results summarized in Tables 1 and 2; denoted as Experiments 2018, 2019, and 2020. The total injection volume of 1.084×10^6 gal was achieved at flow rates up to 34 bpm. The microseismic fracture mapping results, Fig. 8, indicate that significant number of events approached the EE-3 production wellbore. The last of these three injections, for which the flow and pressure histories are recorded in Fig. 9, required a surface pressure of 7000 psi, an ISIP of 5900 psi with an implied fracture gradient of 0.9 psi/ft. These fracturing operations were all terminated because of failures of the frac-string due to stress corrosion cracking, caused by CO_2 and H_2S released from the large fracture surfaces produced by the massive treatments performed previously (see below). A temperature survey indicated the presence of three injection points with temperature depressions, but a hydraulic connection to the other well was not made by this sequence of treatments.

Operations in EE-3

Following this sequence of fracture-connection attempts the rig was skidded to the EE-3 wellhead to test and seal off the lost circulation zone below the casing and to attempt to fracture below that zone. These operations were intended to create a fractured zone around EE-3, which would be a target for later

EE-2 fracture experiments, and to produce additional microseismic data system evaluations. A sand plug and cemented-in PBR/liner were installed as illustrated in Fig. 4, and described in Appendix F. One injection treatment (Expt. 2025) of 150,000 gals was achieved, but was terminated by a fracture string failure requiring a fishing job to retrieve the string and PBR seal mandrel. The injection pressure and flow history are shown in Fig. 10.

This sequence of field operations was concluded at the end of Experiment 2025 with the decision that new work and fracture strings would be required before any fracturing operations could be continued. The workover rig was furloughed on-site until these hardware items could be procured.

GEOCHEMISTRY PROBLEMS

The clear (no solids) water drilling fluid program for EE-2 and EE-3 minimized possible contamination of the reservoir. The crystalline rock formations are essentially insensitive to such a fluid system. The pH was controlled by caustic additions and the drill string corrosion was controlled with an oxygen scavenger sulfite additive.⁸ Towards the end of the drilling of the wells, H_2S was detected, but was found to be generated in the large circulating mud pits ($\sim 15,000$ bbls) used to cool the drilling fluid and drop the extremely fine cuttings.

The large fracture areas created in the crystalline rocks by the attempts to connect the wells released significant amounts of H_2S and CO_2 gases during venting operations. Typical gas analyses are shown in Table 3. The gases tended to aggregate downhole and were released as bubbles, or kicks at the surface, when vent back of the massive fracture treatment volumes occurred.

The CO_2 and H_2S contents were sufficient to induce embrittlement cracking of the S-135 Grade 3-1/2-in drill pipe work string and the P-110, 4-1/2-in. fracture string. Although a number of gases (H_2 , O_2 , He, CO , H_2S , Ar, and hydrocarbons) were at times present in small quantities, the major constituent is CO_2 at 90 to 99%. H_2S is present occasionally as high as 60 ppm.

The emission of these gases presents problems in that: (a) personnel safety is endangered because of kicks during workover operations and the toxicity of H_2S ; (b) CO_2 , O_2 , and H_2S cause severe corrosion of the steels used in well completion; and (c) it may be necessary to remove these gases from the circulating water heat extraction flow once a circulating loop is established.

During four attempts to hydraulically fracture EE-2 and EE-3, the frac-strings failed six times (Table 4). These failures were examined visually and using a scanning electron microscope. The cracks in the drill pipe were 2 to 3 ft. long and generally along the axis. The cracks in the casing couplings were also axial. All cracks originated at indentations resulting from handling the pipe with the elevators, tongs, and slips. All of the failures occurred in steels that were of a tempered martensite structure. Microscopical examination of the cracks revealed a branching pattern indicating failure along prior austenite grain boundaries.

The CO₂ content also caused rapid deterioration of the rubber seals in the rams and the annulus preventor. Replacement time and costs for the items in the BOP stack were significant.

DATA ANALYSIS

Microseismic data acquisition and data analysis, detailed evaluation of the microearthquake data⁹ and fracture-injection data¹⁰ have been performed. The use of on-site, downhole deployed, seismic sensor packages coupled to real-time processing of the microearthquake signals (Fig. 8) during the massive treatments reported here, provide insights into the location, orientation, growth and size of fracture systems being created. Quick decisions were possible with respect to ongoing as well as planned subsequent operations. The review and evaluation¹⁰ of the Fenton Hill fracture flow and pressure data, together with that from four other HDR sites in Japan, United Kingdom, Germany and France, correlated hypocenter maps with fracture injection volumes and formation permeability. In contrast to their volumetric appearance and "cloud-like" extents, the correlations suggest interpretations that induced fractures are essentially planar and possibly propagate aseismically. That is, the growth of these primary fracture crack tips or edges is not recorded. The "cloud-like" appearance of the hypocenters is a result of water diffusion along the natural joint system with consequent increase in pore pressure away from the fracture surface. These joints, inclined to the minimum and maximum earth stress axes, are stimulated by the pore pressure increase and experience shear-slips, and thus produce the observed microseismicity¹¹. These shear events would not be expected to open significant porosity or permeability compared to that in the planar hydraulic fractures.

The planar fractures created in the injection treatments described above are thought to be controlled by the usual fracture relationships and the ISIP data. Figure 11 reflects the high fracture gradient due to the existing minimum horizontal stress in the granitic crystalline rock of the reservoir. The 45° dip indicated for the fractures (Fig. 8) generated below the liner/PBR may be a result of the suspected unusual state of stress¹² near the Quaternary volcanic center that is the heat source for the Fenton Hill HDR geothermal resource.

FUTURE PLANS

Much is yet to be learned about fracturing treatments in high temperature, granitic rocks. The information gained so far will be used to modify future fracture treatments in the effort to connect the EE-2 and EE-3 wellbores. Several distinct changes have been made in the fracture plans and these are discussed below.

Higher Frac Rates

The rate of fracture growth is one of the most important parameters to consider. By using higher flow rates, a planar fracture will have a higher radial growth rate. This is important for several reasons. First, better fluid efficiencies are obtained with higher rates and more fracture growth is achieved. At low flow rates, most of the fracturing fluid leaks off via natural fractures. Moreover, fluid cooling causes rock shrinkage, creating more

permeability and porosity in the rock adjoining the main planar fractures. Second, the low flow rate fracturing treatments performed earlier appear to give thick, disc-like fractures instead of narrower fractures so that larger volumes of fluid were required for fracture extension.

A higher upward fracture growth rate is necessary to complete the connection between wells. Surface horsepower can be increased to give higher injection rates, or a larger diameter frac-string can be used. Because of limited space on site for additional horsepower, it was decided to use a 5-1/2-in. fracture-string to increase the injection rate (up to 60 BPM) using the same horsepower level previously employed.

Larger Volume Treatments

Larger volume treatments will be required in the future. To supply the fluid required for such treatments, a 5-million gallon (119,000 bbl., 19,000 m³) pond is now available for fracture treatments. This fluid will be used to extend fractures the full distance between wells (1200 ft or 366 m). The isolated openhole section can fracture in more than one zone traversing the reservoir volume between injection well (EE-2) and producing well (EE-3). Each of the multiple fractures requires a large amount of water to keep it expanding outward and upward toward the EE-3 well. Thus far no effective method has been considered to limit the fracture growth exclusively to only one fracture (unless a short zone isolation is used).

Real-Time Fracture Growth Analysis

During the next fracturing operations, on-line microseismic data will be used to monitor fracture extension, and to test the various theories relating fracture radius, injected fluid volume, leak-off, and fracture growth rate. This may enable us to predict when the connection will be made as well as identify the required water volume to make the connection. Both the Geertsma¹³ and Perkins¹⁴ models, and others,^{15, 16} for radial fracture growth will be compared using the microseismic data. Other more complicated three-dimensional models may be required to adequately describe complex fracture mechanics. The successful development of this technique is important not only for future geothermal projects but also in oil and gas fracture treatments. However, as yet, no positive correlation has been established between the microseismic data and low impedance fractures.

Steel Metallurgy

A new, larger diameter fracture string has been ordered so that higher flow rates could be achieved. However, other steel-related problems in past operations showed the importance of using a controlled hardness grade of steel. A string of 4-1/2-in. diameter 15.6 lb/ft, L-80 tubing with V and premium connections; and a string of 5-1/2-in. diameter 20 lb/ft, RY-90 tubing with Hydril TAC-I connections was ordered. Its Rockwell "C" hardness was restricted to between 18 and 24.2. With this hardness level, the tubing will not be affected by the H₂S. Higher fracture gradients generate higher internal tubing pressure; therefore, a higher grade of steel was needed to have an adequate burst strength rating. Also, since directional wells have higher tension requirements,

premium tubing was specified for the new fracture-string.

CONCLUSIONS

From these initial fracturing operations conducted in 1982, several conclusions can be made:

- Significant fracturing fluid volumes can be injected into the massive, non-porous intra-wellbore reservoir rock.
- No significant fluid loss zones have been detected within the reservoir volume. The small low-pressure leak-off zone in EE-3 has been bypassed with the cemented-in liner.
- Our current interpretation of the micro-seismic data indicates that the fractures are essentially planar and are formed perpendicular to the least minimum principal stress. The fracture planes generally strike normal to the plane of the wellbores thus confirming the azimuthal directional drilling decision made on the basis of the original reservoir and heat-extraction system created at 10,000 ft (3.0 km).
- The technology of on-line fracture mapping has been developed to an advanced stage. Placement of sensors is still critical and confirmation of quantitative results is needed.

Although a hydraulic connection between the wellbores has yet to be achieved, some important operational factors have been defined.

- High-temperature cemented-in liner/PBR zone isolation systems have been developed that can be used in future fracturing operations.
- The CO₂ and H₂S gas contents encountered within the backflow fluids require major improvements in downhole hardware, and especially an up-grading of fracture-string metallurgy.
- The large fluid injection volumes required to provide interwell connections place extreme reliability requirements on all pumping and related equipment.
- More extensive use of fluid loss additives would reduce water volume requirements.
- The belief that planar fractures are formed in jointed rock masses indicates that short zone isolation intervals should be used; reduced from the present 400 to 450 ft (122 to 137 m) to a 20 to 40 ft (6 to 12 m) zone.
- The high fracture gradients encountered dictate high-strength downhole hardware designs for all future operations.

Given these operational conclusions, zone isolation and related items are in need of improvement as follows:

- (1) Experience with advanced, high-temperature, very durable cement systems.

- (2) A practical openhole high-temperature straddle packer system.

- (3) Related to (2), a high-temperature, independent arm, caliper tool should be available.

APPENDIX A

GEOLOGY AND ROCK PROPERTIES

The geology of the rock at Fenton Hill has been described in detail¹⁷ and consists essentially of approximately 500 ft (152 m) of welded volcanic tuff, erupted from the Valles volcano one million years ago, overlaying about 800 ft (244 m) of Permian-age redbeds (shales and sandstones), and 1100 ft (335 m) of Pennsylvania-age clays, shales, and limestones. These formations are an insulating blanket on top of the 4 x 6 mile (6 x 8 km) block of Precambrian-age crystalline basement rocks of extremely low permeability that make up the reservoir rock below 2400 ft (730 m) depth at the Fenton Hill site. The temperature at the top of the Precambrian rock is 212°F (100°C), the geothermal gradient in the crystalline rock results from a local heat flux of 250 mW/m (or about 5 times the global average). This yields a static geothermal gradient of 30°F/1000 ft (55°C/km) in the upper part of the reservoir, and increases to a gradient of 50°F/1000 ft (89°C/km) at 15,000 ft (4.6 km) depth.

The basement crystalline rock has a compressive strength of more than 40,000 psi (280 MPa), porosity <0.1% and is very abrasive as determined from measurements conducted on cores. Much of the reservoir section is gneissic in nature, with no observable large-scale layering. The crystalline rock ages vary from 1.3 to 1.7 billion years. Several large intruded bodies of granodiorite are found within the gneiss, with numerous, narrow zones of "altered" materials that contain chlorite, pyrite, and considerable amounts of calcite. A significant amount of chemical alteration occurs in these zones. They appear to be fracture zones or sheared-zones, possibly caused by the later forceful injection of volatiles and intrusive magmatic material into the host gneissic rock. Variations in drilling rate and unexpected directional drilling problems confirm the presence of fault structures or altered zones in the wellbores. The lithology presented in Fig. 12 was established below 10,000 ft (3 km) from a few cores and cuttings analyses without the benefit of confirmation from appropriate geophysical logs.

APPENDIX B

EE-2 WELLBORE CLEANING

Residue left in the EE-2 wellbore after the drilling rig had moved consisted of a "black gunk" on the sides of the hole below about 5,000 ft (1525 m). This gummy substance, which coated and clogged logging tools, was apparently composed of degradation products from Torq-Trim (a lubricity agent used extensively during drilling to prevent high torque of the drilling string), from ground-up rubber drill pipe protectors, rock cuttings and metal filings. Besides being troublesome for logging and fishing operations, it was feared the gunk would interfere with upcoming fracturing operations and wellbore characterization work.

A cleaning rig was mobilized on site on November 29, 1981, under a contract with CRC-Colorado Well

Service, Inc., of Rangely, Colorado. The rig was a mobile unit (CRC No. 68), with a 112 ft. (34 m) 175,000 lb derrick. A workstring of 10,000 ft (3050 m) of 2-7/8-in., 10.4 ppf, Grade E; and 6,000 ft (1830 m) of Grade S-135 American Openhole pipe was used. The pipe was run in to 15,146 ft (4616 m) and a 2% solution of a commercial detergent (Calgon Big Cat) was circulated in the hole for two days. The pull required to lift the pipe string decreased from an initial 182,000 lbs to 144,000 lbs as the detergent was circulated. After circulation, the pipe string was pulled out; a thin deposit of gunk still coated the pipe between the 3,000 ft to 9,000 ft (915 m to 2745 m) depths. A second circulation period of 12 hours was completed, with the pH of the detergent solution adjusted to 12. After the pipe was pulled out, a wireline sampling tool was run in and the hole was determined to be clean. A hydrojet washing tool was run in to the bottom and the hole volume displaced with fresh water. The pull-out weight on the final trip out was 250,000 lbs. The CRC rig was released after 21 days of operation.

APPENDIX C

HOLE CONDITIONING

The earlier cleanout operations in well EE-2 had clearly indicated that the subsequent fracturing and completion procedures would be complicated by the considerable hole drag experienced. The wellbore diagrams in Fig. 2 indicate the casing programs and the openhole reservoir sections. The detailed trajectories of the two wells is illustrated in Figs. 3a and 3b as derived from the single shot and gyro survey data.

It was anticipated that all tubular operations in the wells would experience very high axial and torque drag and friction forces. The temperature levels were very high, the wells had penetrated an excellent HDR resource, as shown in Fig. 12. Therefore, severe problems with space-out distance and stack-off of weight on packer settings and PBR seals could be anticipated. From a stabilized static condition to a pressurized and flowing condition there were probable changes of 7000 psi (48 MPa) and 520°F (270°C). Initial calculations indicated fracturing string contractions of ~35 feet (11 m). To provide for force and contraction control, a fracturing head was designed and fabricated (Fig. 13). This hardware was stored in the derrick and used with both the 4-1/2-in. OD P-110/N-80 frac-string and 3-1/2-in. OD S-135 work string (drill pipe).

Detergent Solution

Before adding any detergent to the fluid in the rig system, measurements of the drag (both up and down), and torque were made. The string in the hole consisted of 15,000 ft (4572 m) of 3-1/2-in., 13.3 lb/ft drill pipe, with a 3-1/2-in mule shoe on bottom, for a total string weight of 200,000 lbs. The initial up and down loads were 250,000 lbs and 165,000 lbs respectively.

Approximately two hours after initiating the circulation of a 1% solution of Calgon Big Cat liquid detergent (at 4 bbls/hr), drag and torque measurements were begun. Readings were taken at 30 minute intervals for the first four hours, then recorded every hour for more than 15 hours. Drag readings were

taken as the pipe was pulled up a full joint and then lowered the same distance. Torque was measured as the pipe was turned at least 20 revolutions, which assured that the turns were down to the bottom of the string.

The liquid detergent became effective after the first 3 hours of circulating; at this point the concentration in the hole was just under 0.5%. For the next 3 hours, both the drag up and the torque were reduced, with the turning torque being reduced an hour before the drag up showed any decrease. After about 7 hours, both drag and torque increased. Torque and drag began increasing within 3 hours after the addition of soap was stopped, as the lubricating properties degraded under the existing hole temperatures of 525°F (275°C) or greater.

Sepiolite Hole Conditioning Mud

The initial sepiolite mixture circulated downhole consisted of:

Sepiolite - 5 lbs per bbl
Bentonite - 1 lb per bbl
Caustic - 0.2 lb per bbl

The drill pipe was reciprocated up and down every 15 minutes. The drill string weighed 200,000 lbs, and the initial up and down loads were 260,000 lbs and 165,000 lbs respectively. The drag actually increased to 295,000 lbs up, and 155,000 lbs down with the initial sepiolite mud system. This increased drag was attributed to continued cleaning of the hole wall of the "gunk"; however, because of the difficulty in getting the sepiolite mixture to "yield", the sepiolite may have initially caused increased wall friction.

As the initial mud funnel viscosity was only 30 secs, the solids were increased to:

Sepiolite - 12 lb per barrel
Bentonite - 1 lb per barrel
Caustic - 0.2 lb per barrel

After 8 hrs circulation at 6 BPM and 4000 psi (average), the mud properties were:

Funnel viscosity - 33 secs
PV - 5 cp
YP - 0 lb/100 ft²
Gels - 1/5 lb/100 ft²
Filtrate - 52 sec
pH - 7.5
CL - 250 ppm

The up and down hole drag were 240,000 lbs and 175,000 lbs respectively. Also, the torque was less (i.e. there was less torque trapped after rotation of the drill string).

On April 19, 1982 the sepiolite mud was stored for use later in the program. After displacement of mud system with fresh water, the drag increased to 285,000 lbs up and 165,000 lbs down.

The following conclusions are drawn from the limited use of this simple mud system:

- 1) It was difficult to get the sepiolite to "yield."

- 2) The mud retained good flow properties after exposure to between 500°F and 575°F (260°C and 300°C) for extended periods.
- 3) The mud, after yielding, significantly reduced drag in the well.

APPENDIX D

HYDROJETTING

Method Used

A hydrojet tool consisting of a bottom hole circulating sub with a ball seat and nozzle port above the ball seat was constructed out of drill collar stock (Fig. 14). The nozzle port was intended to allow part of the jetting fluid to exit near the bottom of the stinger and keep sand from settling around the stinger during notching operations.

Two joints of 5-in. drill pipe were used to space the notching sub above the circulating sub. The notching sub consisted of an 8-1/2-in. OD fluted centralizer with two nozzle ports recessed to keep the nozzle exits flush with the OD. The sub had a 12-in.-long, 4-3/4-in. OD fishing neck above the centralizer.

Hydraulics

The selection of nozzle sizes was based on hydraulic calculations and the following assumptions: (1) Nozzles smaller than 3/16 in. diameter were not feasible due to the high probability of plugging. (2) The pumping pressure was limited to 5000 psi to keep hydraulic horsepower costs in the lowest unit price range and minimize the probability of tool joint washouts. (3) An annular velocity of 50 ft/min around the 5-in. stinger and 100 ft/min behind the 3-1/2-in. drill pipe was desirable to minimize the possibility of sanding-in the hydrojet assembly.

Calculations using the properties of water at normal temperatures showed that a 3/16-in. jet on the notching sub would require 700 HHP to pump at 5-1/2 BPM at 5000 psi surface pressure. (1/4-in. ID jets were used). The hydraulic horsepower at the notching nozzle would be 370 HHP. The calculated annular velocity at bottom hole conditions at the stinger was 29 ft/min and 92 ft/min above the notching sub.

Nitrogen was added to the jetting fluid at 200 SCF/bbl to increase the notching penetration rate, and increase the stinger velocity to 34 ft/min. Running sand at 2 lbs per gallon increased the stinger velocity to 37 ft/min.

Pumping Chronology

A blender and two high-pressure pumpers were used to inject into the 3-1/2-in., 13.3 lb/ft IF drill pipe. Three notching operations of 30 minutes each were accomplished, each followed by a flush to circulate the sand-laden fluid 800 ft (244 m) above the notching assembly prior to a scheduled, temporary shut down. During the shut down, the pumping head was removed and 1/3 round of right hand torque was turned into the drill pipe. The drill pipe was then reciprocated 20 ft (6 m) to work the torque to bottom and achieve a 15° to 20° rotation between the three pumping sequences. Notching operations were suspended

after nitrogen returns were circulated to surface, unloading the 9-5/8-in. casing and 8-3/4-in. openhole wellbore. For these operations, 184U bois or mud, 22,500 lbs 20/40 sand and 58,000 SCF of nitrogen were injected.

An analysis of the cuttings circulated out during and after notching indicated signs of formation in the sample. A junk basket run during subsequent pumping recovered 50% grandiorite schist, 40% crushed frac sand, 10% thin brown flakes (possibly carbonate scale) and a small amount of iron. When the wellbore was subsequently pressured to 2000 psig, no change in leak-off rate was evident as a result of the notching operation.

APPENDIX E

CEMENT TEST¹⁸

The use of a cemented-in permanent scab liner/PBR assembly, set at about the 15,000 ft (4.6 km) depth in EE-2 for zone isolation for hydraulic fracturing below it, was decided in December 1981. At that time, investigations were also started to determine suitable cement mixes, elastomeric seals and wiper plugs, and an appropriate method to adequately test them. In January 1982, a cement test procedure was designed to test the proposed slurry under downhole conditions at the depth, temperature, and pressure that the scab liner would encounter in EE-2. Concurrently, the Dowell Research Laboratory in Tulsa, Oklahoma started conducting tests on these three proposed slurries and downhole conditions:

- A. Cement Type and Silica Content
 1. Class H cement, with 40% silica
 2. Class H cement, with 60% silica
 3. Class J cement, with 60% silica equivalent
- B. Properties:

48 hour compressive strength = >4000 psi
Slurry density = >15.0 ppg
- C. Placement Conditions:

BHCT = 525°F (275°C)
Pumping time: 4 hours
Depth: 14,500 ft (4420 m)
Pipe: 3-1/2-in. drill pipe, 13.3 lb/ft
Fluid in the hole: water
- D. Contaminants in the Hole:

Big Cat commercial detergent: 2% solution

By the end of March, laboratory testing was completed on the three mixes. The cement systems had a thickening time of 4 to 5 hours at a BHCT of 525°F (275°C), and a minimum compressive strength of 4000 psi in 48 hours at 600°F (315°C). Cement testing was accomplished by standard API procedures, except that the heat-up times were accelerated to more closely simulate downhole placement times.

Laboratory Test Results

The final formulation of the chosen cement system was:

Amarillo Class H cement
40% D66 (silica flour)
5.5% Retarder/Dispersant (XE67565)*
0.2% D46 (defoamer)

*The XE67565 additive is an experimental Dowell retarder/dispersant that was premixed in the mix water.

Cement Properties

Density ppg	Yield cu ft/sk	Mix Water gal/sk	Thickening Time hrs:min
16.6	1.44	5.03	4:10

Compressive Strengths, PSI

Temp °F	48 Hours	48 hours Contaminated*
600	4805	4099

*The samples were contaminated with 2% by volume of Calgon Big Cat detergent.

Dowell wiper plugs (made of EPDM Y267,¹⁹ formulated by L'Garde, Inc.) and Brown Oil Tool (BOT) darts were statically tested at 572°F (300°C) and 4400 psi in the Los Alamos autoclave. BOT molyglass chevron seals for the scab liner/PBR assembly were also statically and dynamically tested at 572°F (300°C), withstanding 3300 psi differential pressure before failure, in the Los Alamos autoclave. (Only one seal set was dynamically tested, whereas several seal sets were used in the actual downhole assembly.)

Downhole Placement

The bottom-hole assembly (BHA) for the downhole cement test is shown schematically in Figure 15. Basically, this BHA consisted of 742 ft (226 m) of 2-7/8-in. tubing, containing a dart catcher sub, and a pressure and temperature (Kuster) gauge holder.

Run-in of the cement test assembly was completed on April 18, with the pressure and temperature gauge sub being located at a depth of 14,580 ft (4444 m), where the in-situ rock temperature is 580°F (305°C). As the design thickening time temperature of the cement mix was 525°F (275°C), the hole was cooled by circulating through the BHA for 3 hours with the rig pumps at 5.4 bbls/min. Pumping pressure of the cement slurry was 500 psi; after the lower dart bumped into the dart catcher, the pressure raised to 1500 psi. The pressure was held without leakage for 5 minutes; then the cementing head was rigged down, and the pipe string pulled up one stand. During the 48-hr waiting period for the cement to set, the pipe string was reciprocated for 15 ft (5 m) at 30 minute intervals for the first six hours. Later, during the waiting period, the reciprocating interval was increased to 60 minutes and then to 90 minutes.

On May 20, the cement test assembly was started out of the hole, after having set at depth for 48 hours. The Kuster temperature gauge leaked, giving no data after 24 hours. A maximum reading thermometer, also included in the Kuster package, indicated 558°F (293°C) at 14,580 ft (4444 m). Figure 16 shows the occurrence of the cement in the cement test assembly. Approximately 1.23 bbl of cement remained in the pipe, leaving 0.53 bbl unaccounted for, presumably leaking by the plug in the dart catcher. However, there was

no indication of cement in the bottom of the hole when it was later cleaned out to bottom. The top plug, expected to be recovered at the top of the cement column, was actually found 105 ft (32 m) down from the top of the cement. Compressive strength of the hardened cement retrieved from the tubing was 5270 psi (36 MPa).

APPENDIX F

PLACEMENT OF CEMENTED-IN LINER²⁰ IN EE-2

After the successful laboratory and downhole cement and hardware testing, a short liner with a polished bore receptacle (PBR) was run in and cemented. The liner was 300-ft-(91 m) long, 4-1/2-in. OD with the top of the liner at 14,400 ft (4389 m) and the re-entry guide shoe at 14,698 ft (4480 m) (Fig. 16).

The liner (as designed by Brown Oil Tool) was intended to create the following wellbore conditions:

- Provide 400 ft (121 m) of uncased wellbore below the liner for the first fracture attempt.
- Provide a 300-ft-long (91 m) annulus seal.
- Maintain 3000 ft (915 m) of openhole above the liner and below the 9-5/8-in. casing shoe for future fracturing and completion operations.
- Provide the PBR for sealing into (and later retrieving) with the fracturing string (4-1/2-in. casing, 11.6 lb/ft, N&P grades).
- Provide a means for experimenting with perforations for fracturing in sections of the liner.
- Provide a means of controlling flow into both the openhole and the perforated sections by use of the x-nipples.
- Provide a 40-ft (12.2 m)-long polished bore, to allow frac string movement during fracturing or injection of cold water.
- Provide easy retrieval of the frac-string.

The liner shoe was planned to be set at 14,800 ft (4511 m) on a sand plug; however, during installation the liner could not be worked deeper than 14,698 ft (4480 m). It was successfully cemented at a temperature of 525°F (275°C).

The cement slurry formulation and properties used were:

Amarillo Class H cement
40% D66 (silica flour)
5.5% (XE 67565) Retarder/Dispersant
0.2% D46, Defoamer
Density - 16.6 ppg
Water Content - 5.03 gal/sk
Thickening Time - 4 hrs and 10 mins
Compressive Strength - 4805 psi (600°F), at
48 hrs, as measured in the laboratory.

The liner/PBR was cemented in place with 37 bbls of cement slurry as described above. The slurry was batch mixed for two hours, and displaced with calculated volumes, as the liner wiper plug did not seat. After cement displacement, the liner setting tool was "un-jayed" and the seals picked up about 5 ft above the PBR and the excess cement reversed out.

A major problem developed when entry into the liner/PBR was attempted with a 3-3/4-in. mill. Two clean-out runs resulted in twist-offs of the 2-3/8-in. drill pipe. The re-entry problem was solved by (1) use of a Baker off-set jet, flat-bottomed mill, 1000 ft of 2-3/8-in. Wilson flush joint drill pipe and 2000 ft of 2-7/8-in. American openhole drill pipe below the 3-1/2-in. drill pipe; (2) use of a 120-ton power swivel to control torque, and (3) reducing the drag in the wellbore by "mudding-up" with the sepiolite-bentonite fluid containing Baroid Torq Trim. The surface torque was reduced with this fluid from over 10,000 ft-lbs to 4500 ft-lbs. The cleanout of the liner and washing out of sand to 15,155 ft were accomplished without further problems.

There was considerable concern regarding destruction of the molyglass seals while running the seal assembly over 3000 ft of rough crystalline rock. A seal cover protector sleeve was developed jointly by Los Alamos and Brown Oil Tool; this cover fully protected the seals during run-in.

PLACEMENT OF CEMENTED-IN LINER IN EE-3

The zone starting about 20 ft below the 9-5/8-in. casing shoe in EE-3 for some 200 ±ft, the geological conditions are such that the wellbore accepted water at gravity head. When pressurized and pumped, the injection at 16 to 19 gpm and a wellhead pressure of 1480 psi, and the flow-pressure data characteristics indicated that the injection was occurring at an estimated minimum horizontal earth stress ranging from 5290 to 5940 psi, some 1245 to 1900 psi above local hydrostatic. Flowing temperature surveys indicated no flow up behind the casing, but that this pre-existing fracture zone accepts fluid for about 240 ft along the EE-3 wellbore.

Following the pressurized flow tests, a seal-off operation was attempted using lost circulation additions. A mixture of clays (sepiolite and bentonite) with finely ground (200 mesh) barite was placed with open-ended pipe at the leak-off zone. Pressurized pumping then injected the leading LCZ pill, and was followed with a flow slug consisting of mica flakes, teflon beads, and the clay mixture as a carrier. This plug-off attempt apparently temporarily sealed the zone but when the hole was cleaned with a bit-scraper run and circulated out, the zone again accepted fluid.

Well EE-3 was backfilled with sand to a depth of 11,770 ft (3588 m), and a liner/PBR assembly was installed across the lost circulation zone (Fig. 17). It was successfully cemented at a BHCT of 300°F (150°C) using the following slurry formulation:

Amarillo Class H cement
40% D66 (silica flour)
1.7% D121 Retarder/Dispersant
0.2% D46 Defoamer
Density - 15.5 ppg
Water content - 5.32 gal/sk
thickening time - 6 hrs

Compressive strength - 9269 psi (420°F) at 48 hours, as measured in the laboratory.

The cement was drilled out without the problems encountered in previous clean-out operations.

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Reference to any specific company, product name, or service does not imply approval or recommendation of these products or services by the University of California (Los Alamos National Laboratory) or the U.S. Department of Energy to the exclusion of others that might be suitable. The Los Alamos HDR geothermal program is jointly funded by the U.S. DOE, Division of Geothermal and Hydropower Technology, and the governments of West Germany and Japan.

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TABLE 1
SUMMARY OF HYDRAULIC FRACTURING OPERATIONS - 1982

Exp. No.	Well	Date	Zone Isolation Method	Depth ^a & Interval (ft)	Surface Injection Data		
					Injected Vol. (bbls)	Max. Pressure (psi)	Max. Rate (bpm)
Lynes I	EE-2	5-2-82	Lynes Packer (Open Hole)	14,981 164 (TD) ^b	3	2200	--
Lynes II	EE-2	5-6-82	Lynes Packer (Open Hole)	14,989 156	12	4400	3
2011	EE-2	5-30-82	Cemented Liner/PBR & Sand Plug	14,698 447	3,300	7000	6.5
2012	EE-2	6-4-82	Cemented Liner/PBR & Sand Plug	14,698 447	20,000	6600	30
2016	EE-2	6-20-82	Cemented Liner/PBR & Sand Plug	14,698 447	31,000	6750	35
2018	EE-2	7-19-82	Otis Packer (9-5/8-in. Casing) & Sand Plug	11,587 473	5,700	6900	14
2019	EE-2	7-24-82	Otis Packer (9-5/8-in. Casing) & Sand Plug	11,587 473	247	5800	5
2020	EE-2	10-6-82	Otis Packer (9-5/8-in. Casing) & Sand Plug	11,587 473	20,000	7000	34
2023	EE-3	11-8-82	Open Hole	11,589 3559 (TD)	930	2020	6.5
2025	EE-3	12-14-82	Cemented Liner/PBR & Sand Plug	11,389 381	3650	6670	25

^aMeasured depth along wellbore.

^bSanded up from 15,298 drilled depth.

TABLE 2
SUMMARY OF PUMPING DATA AND FRACTURING RESULTS - 1982

Exp. No. and Date	Zone Isolation Method	True Vertical Depth (ft)	ISIP (psi)	Volume (gals)	Fracture Gradient (psi/ft)	Remarks
Lynes I 5-2-82	Open Hole Packer	EE-2 14,000	--	126	--	Packer failure
Lynes II 5-6-82	Open Hole Packer	EE-2 14,010	4100(?)	504	0.7	Packer failure
2011 5-30-82	Liner/PBR & Sand Plug	EE-2 13,950	5300	0.14×10^6	0.7	Pumping equipment failure
2012 6-4-82	Liner/PBR & Sand Plug	EE-2 13,950	5400	0.840×10^6	0.7	Scheduled shut down No connection
2016 6-20-82	Liner/PBR & Sand Plug	EE-2 13,950	5200	1.302×10^6	0.8	Fracture string failure
2018 7-19-82	Casing Packer & Sand Plug	EE-2 11,200	--	0.24×10^6	0.8	Fracture string failure
2019 7-24-82	Casing Packer & Sand Plug	EE-2 11,200	--	10,400	--	Fracture string failure
2020 10-6-82	Casing Packer & Sand Plug	EE-2 11,200	5900	0.84×10^6	0.96	Fracture string failure No connection
2023 11-8-82	Open Hole to T.D.	EE-3 (11,300)	2200	39,000	--	Lost zone N240 ft long, below casing shoe
2025 12-14-82	Liner/PBR Sand Plug	EE-3 11,000	--	0.153×10^6	--	Fracture string failure No connection

TABLE 3
TYPICAL^a EE-2 FRACTURE VENT-BACK GAS ANALYSES, VOL. %

<u>Sample Date</u>	<u>CO₂</u>	<u>O₂</u>	<u>N₂</u>	<u>CH₄</u>	<u>H₂S^b</u>	<u>H₂</u>	<u>H₂O</u>
31 May 1982	78.1	3.8	17.9	0.2	-0-	-0-	-0-
7 June 1982	90.0	0.47	7.4	0.17	0.08	0.55	-0-
12 Oct 1982	45.3	10.7	41.6	-0-	-0-	-0-	1.3

^a During a back-bent flow or kick, approximately 1:1 ratio of liquid to gas volume at STP was collected.

^b H₂S was detected in about 1/5 of the samples.

TABLE 4
SUMMARY OF TUBULAR FAILURES

<u>Date</u>	<u>String and location</u>	<u>Tubular Grade</u>	<u>Approximate Depth of failure</u>
7-9-82	3.5 in. drill pipe, near box end	S-135	1000 ft
7-24-82	3.5 in. drill pipe, near box end	S-135	2542 ft
7-27-82	3.5 in. drill pipe, in slips area	S-135	5549 ft
10-4-82	4.5 in. casing coupling	P-110	9247 ft
10-10-82	4.5 in. casing coupling	P-110	9300 ft
12-17-82	4.5 in. drill pipe, 7 ft below box end	S-135	1774 ft

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Schematic of Fenton Hill HDR Wells

Notching Sub

SIDE VIEW

Circulating Sub

Recessed 3/16"
circulating nozzle

EE-2 Wellbore Configuration for Fracturing