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DEVELOPING HOT DRY ROCK RESERVOIRS WITH INFLATABLE OPEN HOLE PACKERS

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ABSTRACT

An open hole packer system was designed for high pressure injection operations in high temperature wells at the Fenton Hill, Hot Dry Rock (HDR) Geothermal Site. The packer runs were required to verify that the HDR reservoir fractures had been penetrated during the drilling of well EE-3A. They were also used to stimulate fractures connecting EE-3A to the reservoir and to conduct two massive hydraulic fracture treatments at the bottom of EE-3A. An attempt to use a modified packer design as a temporary well completion system was not successful but with modification the system may prove to be an important HDR completion technique. The eleven packer runs have demonstrated that formation testing, stimulation and HDR reservoir development can now be conducted with an open hole inflatable packer operating over large temperature ranges and high differential pressures.

INTRODUCTION

Open hole inflatable packer runs in wells EE-2 and EE-3 prior to 1982 failed at differential pressures which were much too low to conduct fracturing or reservoir stimulation in the Phase II HDR system. Subsequent review of these packer operations failed to identify a single failure mode. Oversized wellbore and insufficient self anchoring of the packer element were the most likely modes of failure (Carden et al., 1985).

Subsequently, large fracture systems were created in HDR wells EE-2 and EE-3 below 4-1/2" cemented-in-liners and below the 9-5/8" casing shoes as described in Carden et al., 1985.

All attempts to connect the EE-2 and EE-3 fracture systems by driving hydraulic fractures from one well to the other were not successful. (Dreesen and Nicholson, 1985; Dash et al., 1985). Sidetracking EE-3 and drilling a new wellbore, EE-3A, through the microseismic zone created in the Massive Hydraulic Fracture (MHF) from EE-2, was successful in establishing a connection between the wells and has subsequently served as a hydraulic heat extraction flow system.

The use of the improved open hole packer system during the course of drilling EE-3A allowed positive identification, location and stimulation of the active EE-2 MHF fractures (Fig. 1). The packers were also used to successfully fracture deep in EE-3A below the connecting fractures in an unsuccessful attempt to enlarge the heat extraction reservoir with new connections.

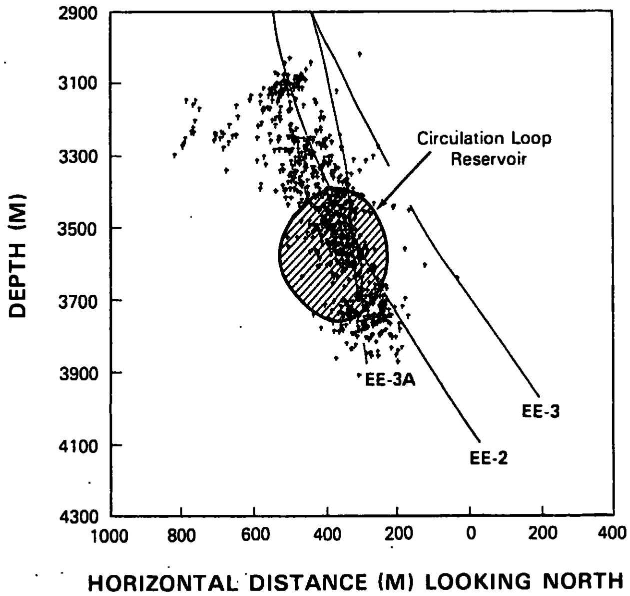

Figure 1. HDR wells, microseismic events, and active reservoir.

The procedures used to run, set, operate, release and retrieve the high temperature-high pressure open hole packer, are described in Dreesen and Miller, 1985. The procedures used to select packer seats and correlate wireline depths to drill pipe depths are discussed in Dreesen, et al., 1986. The function of the components and operation of the packer system are described in Dreesen, et al., 1986. A brief review of the packer and running gear shown in Fig. 2 and described in the papers cited above, the main components in the packer system are: (1) the expansion joint which mechanically decouples the packer from the drill string, (2) the inflate-release sub, with inflation port and

* References at end of text.

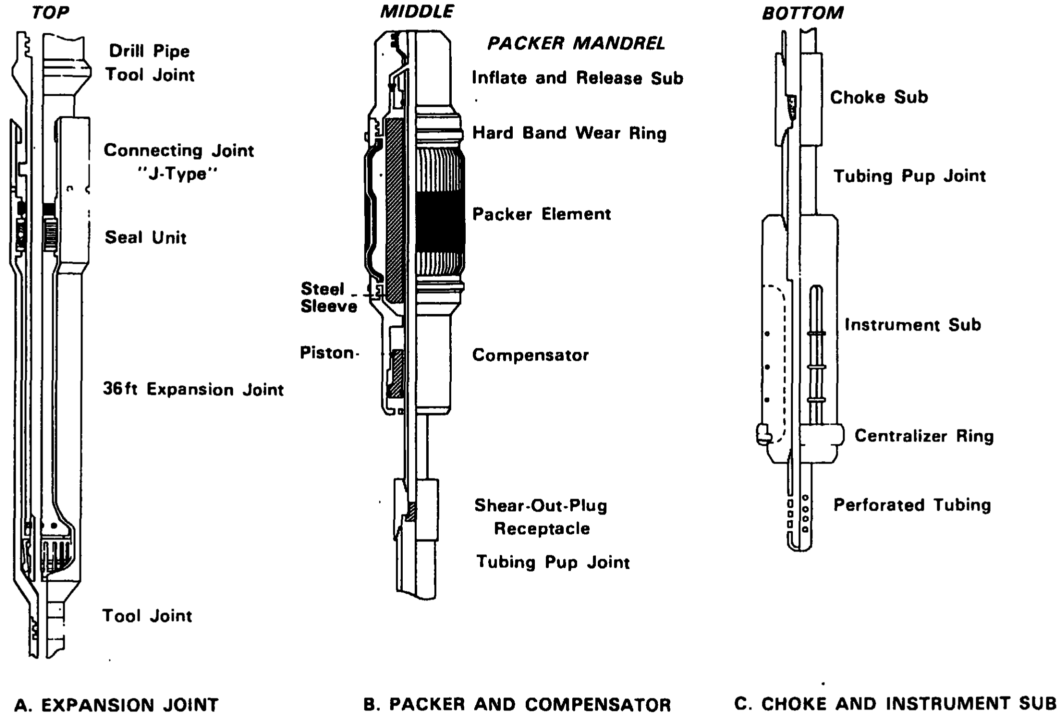

Figure 2. High temperature-high pressure open hole packer and running assembly.

TABLE I

Results of Open Hole Packer Runs in EE-3A

Run	Date	Depths (ft) Packer	Depths (ft) Injection	Maximum Injection Parameters Packer Temp. (°F)	Diff Pressure (psi)	Rate (BPM)	Injected Volume (1000 gals)
1	4/19/85	10829	10830-10875	405°-360°	4700	6.0	6
2	5/02/85	10841	10842-11615	405°-178°	4530	8.6	140
3	5/15/85	11537	11538-12203	460°-120°	Packer damaged during run-in-hole		
4	5/27/85	11537	11528-12203	460°-120°	4325	10.0	420
5	6/20/85	12585	12568-13180	468°-407°	Packer element set in oversized borehole and ruptured.		
6	6/29/85	12555	12556-13180	462°-135°	5050	10.5	1386
7	7/16/85	11976	11977-12550	406°-154°	4800	12.0	1512
8	1/10/86	12469	12469-12480	Packer element set in oversized borehole and ruptured.			
9	1/16/86	12563	12569-12840	Packer was probably damaged during a set down on ledge. Packer failed 20 seconds after shear plug released.			
10	1/30/86	12320	12320-12840	NA	5500	10.5	1008
Permanent Packer							
11	4/5/86	11610	11610 12250	460-300	4310	7.1	27
				First packer test after setting packer on drill string			
	4/6/86				3120	1.7	27
				Retest packer after installing tubing string. Packer leaked after pressure was increased above 3000psi.			

Table I. Summary of Early Packer runs.

check valve, rotates to the right to deflate and release the packer, (3) the packer mandrel, the main flow path through the packer, and (4) the compensator which prevents deflation of the packer element with fluid compression that occurs during pressure increases in the hot wellbore, (5) the choke sub which keeps the packer element inflate during a major cooldown of the wellbore, and (6) the packer element. The packer element is constructed with a high temperature rubber (EPDM) inter tube, a layer of over lapping steel reinforcing straps, and an outer EPDM rubber jacket on the straps which is located between exposed sections of straps. The exposed sections, after contacting a wellbore during element inflation serve as both the packer friction anchor surface and as barriers to prevent extrusion of the outer rubber jacket as differential pressure is applied to the packer element.

The use of a packer system to (1) complement the microearthquake location techniques in locating and defining the structure of the HDR reservoir and (2) to selectively stimulate the reservoir connecting fractures was critical in the development of the deep heat extraction system.

SUMMARY OF EARLY PACKER RUNS

Eleven EE-3A packer runs are listed on Table I. The objective of the first run was to conduct a downhole anchoring and equipment test in a very short unfractured injection interval. The packer was exposed to a high differential pressure, modest cool down from 207°C (405° F) at inflation, and performed well. The packer was deflated, released, removed and found to be in excellent condition. The packer system had shown that a minifrac stress measurement capability using retrievable equipment in a recently drilled smooth bore was now available.

During injection the second inflatable packer was exposed to sufficient pressure and cool down to deflate the packer. A fluid compensator prevents deflation of the element as the inflation fluid contracts with increased pressure and cooling (Dreesen et al,. (1986). As predicted, with additional cooling, the second packer element released and the packer moved up hole rapidly slamming closed the expansion joint. On subsequent packer runs in lieu of a larger compensator a choke was included in the tail pipe below the packer providing sufficient pressure during injection to charge the element through the inflation port and check valve above the choke. Using this system, packer anchoring and sealing was maintained through large cool downs on the remaining packer runs.

Well flow and an influx of carbon dioxide gas caused the third packer element to partially inflate and wear out during run in. The damaged element ruptured during inflation and was pulled in two when the packer removal was attempted. This resulted in an extended fishing operation. On the remaining packer runs a delayed (drill pipe) fill up schedule was used to prevent unintentional inflation.

On the fourth packer run a reservoir connection between EE-3A and EE-2 was demonstrated while injecting 420,000 gallons of water below the packer at 4300 psi differential pressure. This packer contained the combination compensator-choke system. This run demonstrated that this system is suitable for large volume injections which are needed to verify and evaluate flow connections between the wellbores.

The fifth packer was set in oversized hole (9-3/4" breakout in 8-1/2" bit drilled bore) and the element ruptured during inflation. The sixth packer operation was completed with no evidence of any leak around the packer. The packer continued to perform for another 32 hours after shut-in until the element finally ruptured due to heating of trapped fluid in the element after stroke out of the compensator.

From these first seven early packer runs it was determined that:

a. The existing compensator system was functional and necessary.
b. To supplement the small compensator, pressurization of the packer element could be maintained by a downhole choke.
c. The downhole choke plus small compensator worked well during injection.
d. During heat-up this system resulted in excessive pressure build-up in the element and ultimate failure.
e. The run in procedure is crucial with this design to avoid partial inflation and element damage during running the packer in the hole.
f. Packer seat selection and accurate placement are essential to successful installation.

RECENT PACKER RUNS

The eighth and ninth packer runs were both attempts to reset a packer in the packer seat at 12,550 - 12,600 ft depth used for packer runs 5 and 6. Both packer elements ruptured during inflation. This was a result of attempting to set the eighth packer in a wellbore breakout zone. This was caused by a drill string stand miscount. A high temperature combination gamma ray/caliper log was not available for formation drill string depth correlation.

An underreamed section was cut at 11,450 ft, drill string depth. This was used to obtain a direct drill pipe to caliper log tie-in for the ninth packer run.

The ninth packer was inflated but a drill string weight increase and a pressure drop occurred 20 seconds after the inflation was completed. The packer was recovered. The element was ruptured. Two possible causes for the rupture have been proposed: (1) A 30,000 lb setdown at 10,600 ft occurred during run in as the packer tagged a recently formed ledge. Visible damage to the packer body was evident. It is possible that a rock spall penetrated the packer's steel strap reinforcing during the setdown cutting and weakening the inter tube. (2) This was the fourth attempt to set a packer in the interval. The last caliper log showed deteriorating wellbore wall conditions occurring over much of the 2800 ft open hole section and severe deterioration was occurring just below and above the intended packer seat. The dynamic loads on the packer as the inflation plug in the tail pipe sheared established a differential across the packer which may have been sufficient to cause a formation failure. The packer element may have ruptured if the steel reinforcing straps parted as the rock shifted.

The eighth and ninth packer runs demonstrated, once again, the need for a high temperature combination gamma-ray/multi-independent arm caliper logging capability. A four independent arm caliper/gamma-ray tool is presently under development at Los Alamos to meet this need.

On the tenth packer run our objective of re-stimulating the deep open hole was modified. A potential packer seat at 12,320 ft was selected instead of a fifth attempt below 12,500 ft (where 3 settings had been unsuccessful.)

On this tenth run a 1.1 million gallons fresh water injection was completed in 53 hours. An 18,000 gallon polymer frac gel injection was conducted 42 hours into the pump because water injection had failed to develop the deep connection between EE-3A and EE-2. It was hoped a high viscosity injection would open new fractures in EE-3A which would connect with the reservoir developed during the EE-2 MHF.

We attempted to monitor the performance of the compensator choke (packer element inflation) system. A Kuster pressure gauge with a 15,000 psi element was connected to a port on the packer element with high pressure steel tubing. The effort to obtain instrumented data failed because the packer could not be released at the end of the frac shut-in. Fishing attempts were suspended before the packer and pressure bombs could be removed.

The performance of the open hole expansion joint ran just above the packer was closely monitored during the tenth packer run. Drill string weight was recorded throughout the pump. Bottom hole pressure was calculated from surface injection pressures and the predicted friction drop. The "piston effect" in the expansion joint was subtracted from the initial drill string weight to arrive at a theoretical string weight. This value, includes buoyancy but ignores the drag in the wellbore and friction in the pipe rams and expansion joint. The calculated string weight is compared with measured string weight on Fig. 3.

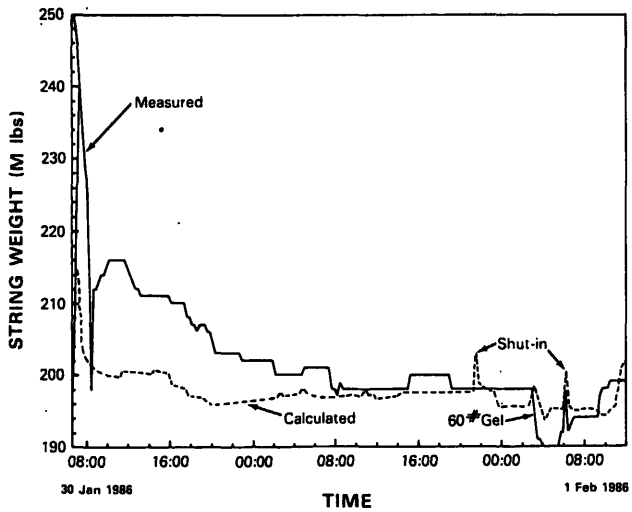

Figure 3. Calculated string weight vs measured string weight during 10th packer run.

Early in the pump a sudden loss in indicated string weight of 20,000 lbs. caused concern that the packer was moving up hole. It was more likely that friction in the rams or debris in the expansion joints or a bridge around the drill pipe released its grip on the pipe and the sudden release allowed some movement of the pipe. Comparison of the calculated weight to the measured weight provides evidence to suggest that the bridge or debris regained its grip on the drill pipe and further cooling and shortening of the drill string caused the 18,000 lbs. increase in weight observed over the next 3 hours. If this is the case the grip slowly deteriorated as the injection rate was increased over the next 12 hours. The drill string weight discrepancy was much larger than had been observed in the earlier packer runs. This is in agreement with caliper log results which showed a continuing enlargement and deterioration of the hole through wellbore breakouts and spalls.

At the end of the injection an instantaneous shut-in pressure (ISIP) of 5590 psi was recorded. The well was shut-in for 24 hours and had to be vented for 44 hours before the expansion joint was successfully closed. Attempts to rotate the packer mandrel open and deflate the packer failed. The expansion joint was separated, and the drill string removed. The outer expansion joint section was damaged or wedged to one side of the hole and wash-over runs failed. A jarring run failed to move the packer and a short barite plug was placed on the packer to establish a new plug back depth.

PERMANENT PACKER RUN

In planning for a 30 day flow test of the reservoir connection between EE-3A and EE-2 the use of a more "permanent" open hole packer was attempted. The packer was designed with the same basic functional parts as the retrievable packer and with the following modifications.

(1) The packer element had a longer seal section.
(2) The compensator was sized large enough to maintain packer inflation through a complete cool down, pressure and thermal recovery cycle.
(3) The choke was eliminated.
(4) A larger, heavy wall packer mandrel provided a through packer logging capability which did not exist in the retrievable packer and tail pipe choke assembly.
(5) A check valve backed up the packer inflation valve, and the packer had no deflation mechanism. The packer mandrel would be perforated to remove the packer.
(6) A tie back liner was installed between the packer and expansion joint. This placed the expansion joint in the 9-5/8" casing to prevent rock spalls and sand fill from jamming the expansion joint.

The packer-liner assembly was run and set in a short 20 ft-long packer seat using a through pipe gamma-ray/collar locator log to correlate drill pipe depth to a gamma-ray/caliper log (70 ft correction). The packer element was inflated to 4500 psi. The packer was tested by injecting 640 bbls of water a rates up to 7 BPM and a pressure of 4850 psi, (4310 psi ISIP). The drill string was then separated from the expansion joint, pulled out and laid down. The tubing string and seal assembly were run and sealed into the polished bore receptacle on top of the liner to form the expansion joint. A second packer test was run and communication to the annulus was observed as the differential pressure on the packer reached 3000 psi. A third packer flow test with temperature log was conducted to determine the location of the leak. Just as the temperature sensor was stationed at 2500 ft in the tubing, the packer anchor released and the packer liner assembly dropped down to the plug back depth. The assembly was successfully jarred loose after 5 days of unsuccessful back off attempts interspersed with jarring and rotation on the heavy wall packer mandrel. The rotation finally wore down the packer enough to allow its removal. Damage to the packer during fishing was sufficient to prevent diagnosis of the packer failure mode. No conclusive failure mode has been identified. Possibilities include:

(1) sticking of the compensator piston
(2) very slow leakage around the inflation check valve
(3) a very small rupture of the packer element occurred in a small breakout which opened up with each pressure cycle.

IMPROVING THE ODDS

The data in Table I and the summary in Table II shows that future packer operations in a Fenton Hill environment can be improved. Four of the five packer failures may have been prevented by setting the packers in good packer seats. The selection of seats and depth correlation would have been enhanced by better caliper logs and correlation to drill pipe depth.

TABLE II

Summary of Packer Operation

Run	Major Objectives Accomplished	Packer Removal
1	Y	Y-Released and removed
2	Y	Y-Removed
3	N	N-Ruptured and fished out
4	Y	Y-Ruptured and removed
5	N	Y-Ruptured and removed
6	Y	Y-Ruptured during shut-in and removed
7	Y	Y-Released and removed
8	N	Y-Ruptured and removed
9	N	Y-Ruptured and removed
10	Y	N-Unable to release or fish
11	N	N-Packer leaked, dropped down hole and fished out

Table II. Summary of Packer Operations.

The record in EE-3A, 6 successes out of 11 runs, could be improved to 5 of 7 if the packer runs between 12,500 and 12,600 ft are not included. The caliper logs runs showed that this interval was deteriorating with each thermal and pressure cycle of the wellbore. The deterioration of the EE-3A bore demonstrates that the number of packer runs for large volume injections in an hot uncased wellbore is limited. The retrievable packer running strategy should be planned carefully to achieve the require results before wellbore conditions deteriorate and make risks in running packers unacceptable.

The reinforcing strap design for the high temperature-high pressure open hole packer needs to be improved to allow the element to function in more rugged wellbores without a separation of the steel reinforcing straps occurring which allows the rubber inter tube to rupture. Design changes are also needed to facilitate fishing of the packer. Currently the limited use of this packer will preclude a major investment in packer element redesign and testing.

HDR DEVELOPMENT STRATEGY USING OPEN HOLE PACKERS

Lessons learned during the eleven packer runs combined with recent developments in microseismic data interpretation (Dreesen et al., 1987) now suggest a sound HDR reservoir development strategy. Upon completion of the first HDR well, an open hole liner with multiple, tandem permanent open hole packers and expansion joints would be used to provide a well completion suitable for multiple MHF operations to create the HDR reservoir in the rock surrounding the first well. Following the creation of the reservoir the second well would be drilled through the fractures mapped using microseismic techniques. Then the fractures would be located and stimulated using open hole packers. The use of packers in the first well is important because standard oil field technology using cemented-in-casings, casing packers and jet perforation to conduct multiple zone fractures is, as yet, untested in a HDR crystalline rock reservoir. The permanent open hole packer can provide open hole fracturing using cased hole flow distribution techniques.

Additionally, based on Fenton Hill experience, the use of retrievable open hole packers is clearly needed to:

(1) Conduct minifrac stress measurements to select the MHF injection zones and packer seats for the first well completion and fracture plan. This data would also be used for selecting casing setting depths.
(2) Provide the zone isolation needed to conduct selective stimulation in wells drilled into MHF reservoirs located using seismic techniques.

CONCLUSIONS

The experiences with open hole packer operations performed in the sidetracked wellbore EE-3A leads to the following conclusions:

1. Successful setting and anchoring require a packer seat which is:

a. Near drill diameter or only slightly larger.
b. Relatively "round" hole.
c. "Locatable" when the packer is run into the wellbore.

2. Volume compensators are required when the packer is required to operate over a large change in temperature. The volume compensator must be of a size to compensate for the volume change of the inflating fluid during the full temperature cycle.

3. Failure of the packer with a differential pressure (or resulting force from the drill string) across the element will cause packer movement. This packer movement upon failure results in a difficult fishing operation.

4. The open hole packer design and running procedure improvements made to date allow open hole packers to be used for HDR stimulation and reservoir testing work with confidence when:

   a. A packer seat can be located with the features listed in 1.
   b. The running procedures used allow the packer to be placed undamaged at the packer seat.
   c. A volume compensator can be used which is of adequate size, or is combined with a tail pipe choke.
   d. Movement in the event of a packer failure can be prevented.

5. Granitic wellbores tend to enlarge and/or become elliptical during injection of fluid. Potential packer seats are destroyed and only a limited number of successful packer runs can be expected in an open hole interval.

6. Additional development of permanent packers is necessary to assure their usefulness.

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