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LAWRENCE BERKELEY LABORATORY
Bldg.: Room: Ext.:

September 4, 1987

MEMORANDUM

TO: Interested Parties

FROM: Sally Benson Sally Benson
Lawrence Berkeley Laboratory

SUBJECT: East Mesa Well 8-1 Injection Testing

On June 13, 1987 we at LBL began preparations for a series of injection tests to be conducted in conjunction with GEO Operator Company at the East Mesa Geothermal Field. Well 8-1 was to be used as an injector for evaluating the applicability of injection testing techniques designed to improve our ability to track the migration of thermal fronts. At the same time, well 8-1 would serve as a temporary disposal well for geothermal brine produced from GEO's new production wells. This memorandum is intended to provide documentation of the events that led us to the conclusion that well 8-1 is in extremely poor condition, with both shallow casing leaks and a significant accumulation of scale on the walls of the bore.

We arrived at East Mesa on June 14 to begin a series of pre-injection wellbore surveys. On June 15 we ran a sinker bar into the well to determine if the wellbore was unrestricted to its reported depth of approximately 6000 ft. During the sinker bar run we encountered no restrictions in the upper portion of the wellbore. However, we detected fill at a depth of approximately 5810 ft, indicating that the bottom of the wellbore was filled with approximately 200 ft of unidentified material. On June 17 we left East Mesa, not expecting to return until GEO was prepared to begin the injection test.

On August 4 we arrived at East Mesa to run the first in a series of injection tests. GEO had produced approximately 2000 barrels of brine that could be injected into well 8-1. We planned to inject this brine during a 6 to 12 hour period in order to assess the injectivity of the well, and to obtain the first pressure transient injection data.

Before the injection test we obtained a temperature survey of the top 2550 feet of the well (Pruett ran a wireline temperature/pressure survey of the entire well several days earlier). A composite of the LBL and Pruett temperature logs is shown in Figure 1. At a depth of 2400 to 2500 feet the temperature gradient jumped from an average gradient of 8° C per 100 feet to approximately 22°C per 100 feet. Below 2550 feet the gradient is much lower, with an average value of 0.2° per 100 feet. The unusual jump in the temperature profile at a depth of 2400 feet, along with the nearly isothermal profile below 2550 feet suggest that geothermal brine is flowing up the wellbore from the slotted interval and exiting at a depth of 2400 to 2550 feet.

On the evening of August 5 we began the first injection test. At a wellhead pressures ranging from 125 to 150 psig, we injected at rates of 200 to 350 gpm. After several hours of injection, the rate stabilized at 200 gpm, with a wellhead pressure of 125 psig. After approximately 5 hours the well was shut in.

On the afternoon of August 6 we began a second injection test using canal water (several geochemists had recommended that GEO displace the high salinity fluid in the borehole with better quality fluid). Prior to running this test, while quickly lowering the pressure/temperature tool deeper into the borehole, we detected a slight thermal anomaly at a depth of approximately 2500 feet. Uncertain of the source and existence of the anomaly, we proceeded with the injection test with the idea that after the test we could obtain a detailed post-injection temperature profile. The result of this survey, obtained 15 hours after shutting in the well, is shown in Figure 2. As shown by the shape of the profile, the thermal recovery at a depth of 2500 feet was slower than in the rest of the borehole. This suggested a significant fraction of the injected fluid was leaving the borehole through a break in the casing located near the anomaly.

As a result of this information, we decided to conduct a third injection test, during which we would measure the temperature profile during injection. The result of this survey, shown in Figures 2 and 3, indicated that the thermal gradient in the top 2500 feet of the borehole was approximately 1/4 that in the lower part of the borehole. This again suggested a sizeable leak in the casing. Following this injection test, we conducted another post-injection temperature survey. This data, shown in Figure 2 (2.5 hours after injection), pinpointed the depth of the leak at 2550 feet.

In an attempt to measure the fraction of fluid leaving the casing at 2550 feet, a fourth injection test was conducted during which we attempted to run a downhole flowmeter. The downhole flowmeter functioned erratically, which as we later found out was caused by a large accumulation of scale in the inner workings of the flowmeter. Large pieces (1 to 2 cm^2) of black and grey scale, apparently knocked off the walls of the casing by the centralizer on the tool, were collected by the cone-piece and low-velocity funnel. In spite of the accumulation of scale, one reasonably successful survey was obtained in the top portion of the casing. This survey, shown in Figure 4, indicated that the impeller on the flowmeter stop rotating at a depth of 2560 feet, which confirms the depth of the leak as indicated by the temperature survey. However, we can not determine the fraction of fluid leaving the wellbore at or above this depth.

In an attempt to quantify the fraction of fluid leaving the casing at this depth we used a a computer code that models of the heat transfer between the formation and the wellbore fluid to simulate the temperature profile that we measured during the injection test. By first matching the data from the top 2550 feet of the well we were able to calibrate the model. Next, we attempted to match the temperature profile from the bottom of the well by varying the fraction of the total injection rate that continues to flow down the well past the leak. The best match we obtained (see Figure 5) indicates that approximately 50% of the injected fluid goes into the break in the casing and 50% goes into the slotted interval of the well. For comparison, the temperature profile we would expect to observe if 100% of the fluid went into the slotted interval is also shown in Figure 5.

The data obtained to date indicate that there is a break in the casing of well 8-1 at a depth of 2550 feet. The nature and extent of the break are not known, except that it allows a large fraction of the injected fluid to exit the wellbore at that depth. I recommend that a caliper survey be conducted to obtain additional information on the nature of the break. In its present condition, well 8-1 is not suitable for obtaining research-quality injection test data. For this reason, I recommend terminating the proposed research activities using this well unless the condition of the well is improved. One means of rehabilitating the well, that would make it satisfactory for conducting our current research program, is plugging the slotted interval of the well and perforating the casing from a depth of 2450 to 2950 feet. If necessary for adequate injectivity, additional perforations extending to a greater depth (not to exceed 3450 feet) may be satisfactory. We are also open for suggestions!

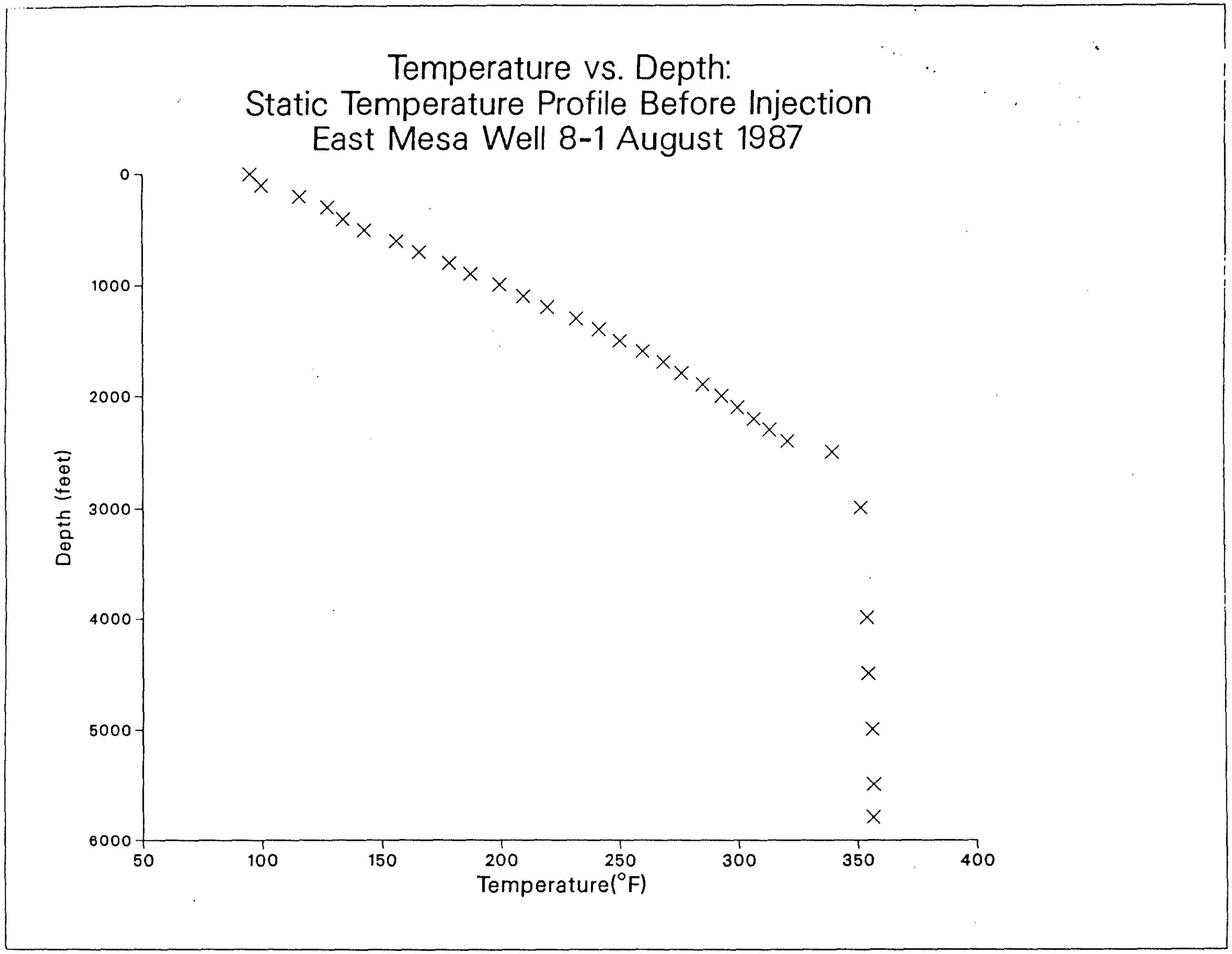

Figure 1. Temperature profile measured prior to injection.

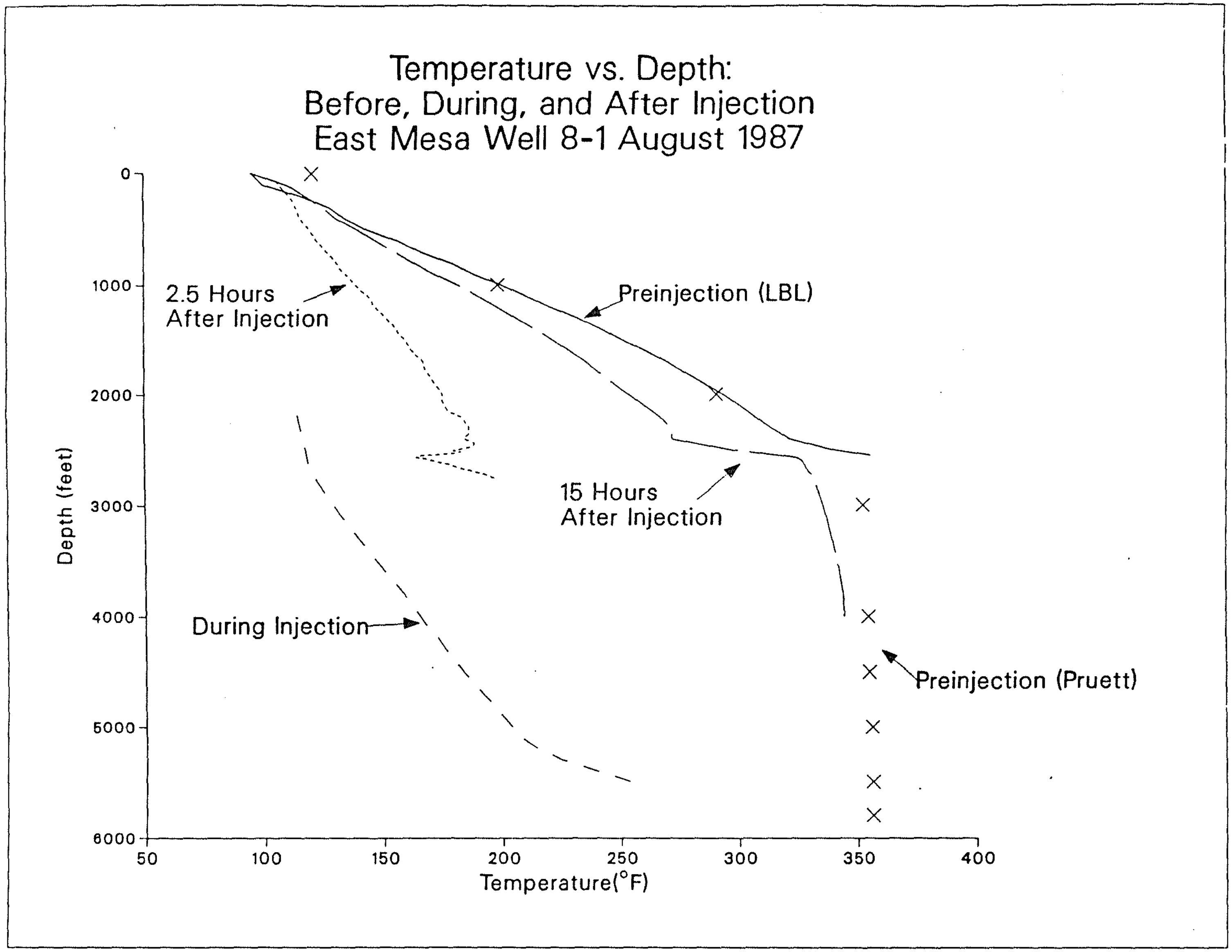

Figure 2. Temperature profiles measured before, during and after injection.

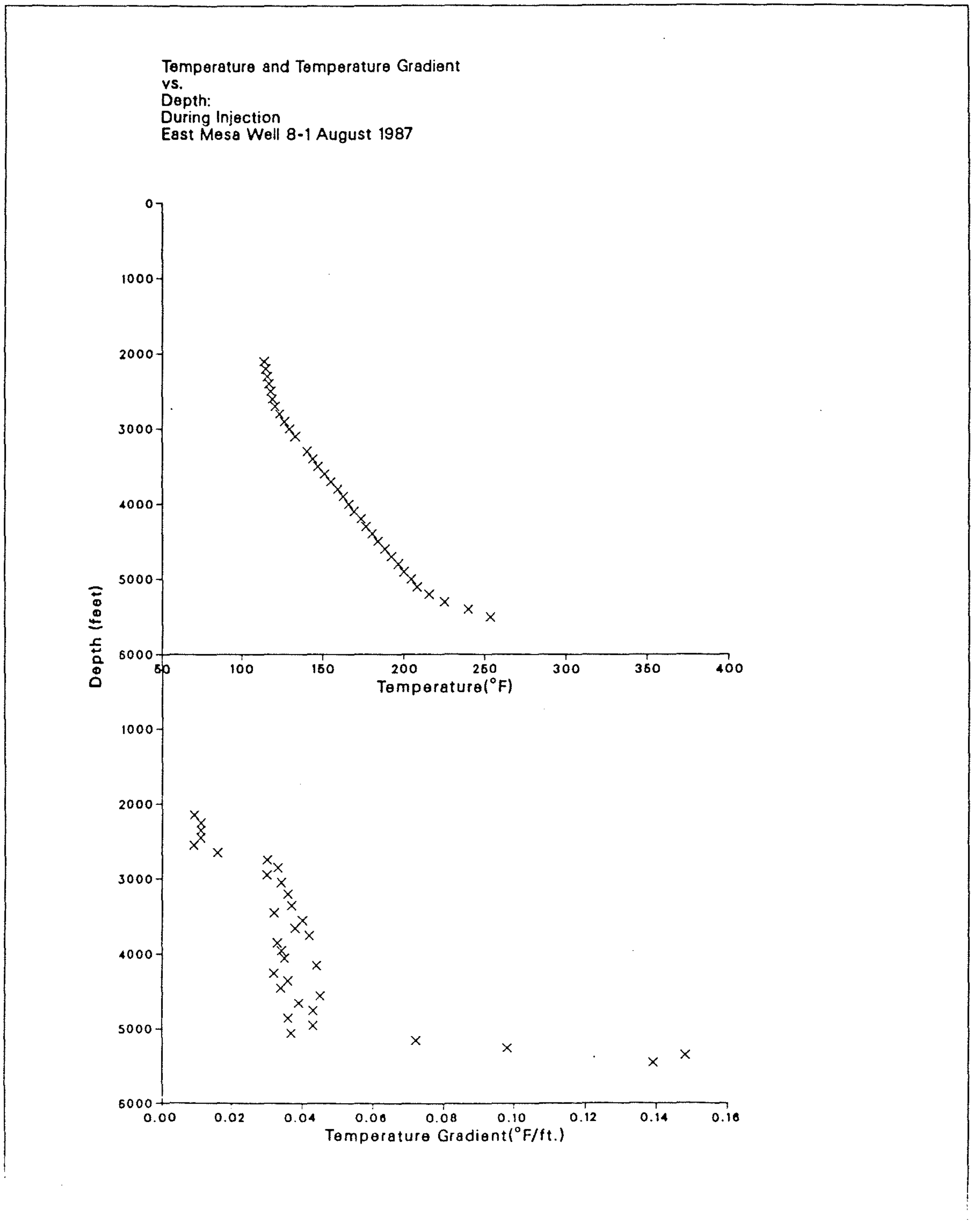

Figure 3. Temperature profile and temperature gradient measured during injection.

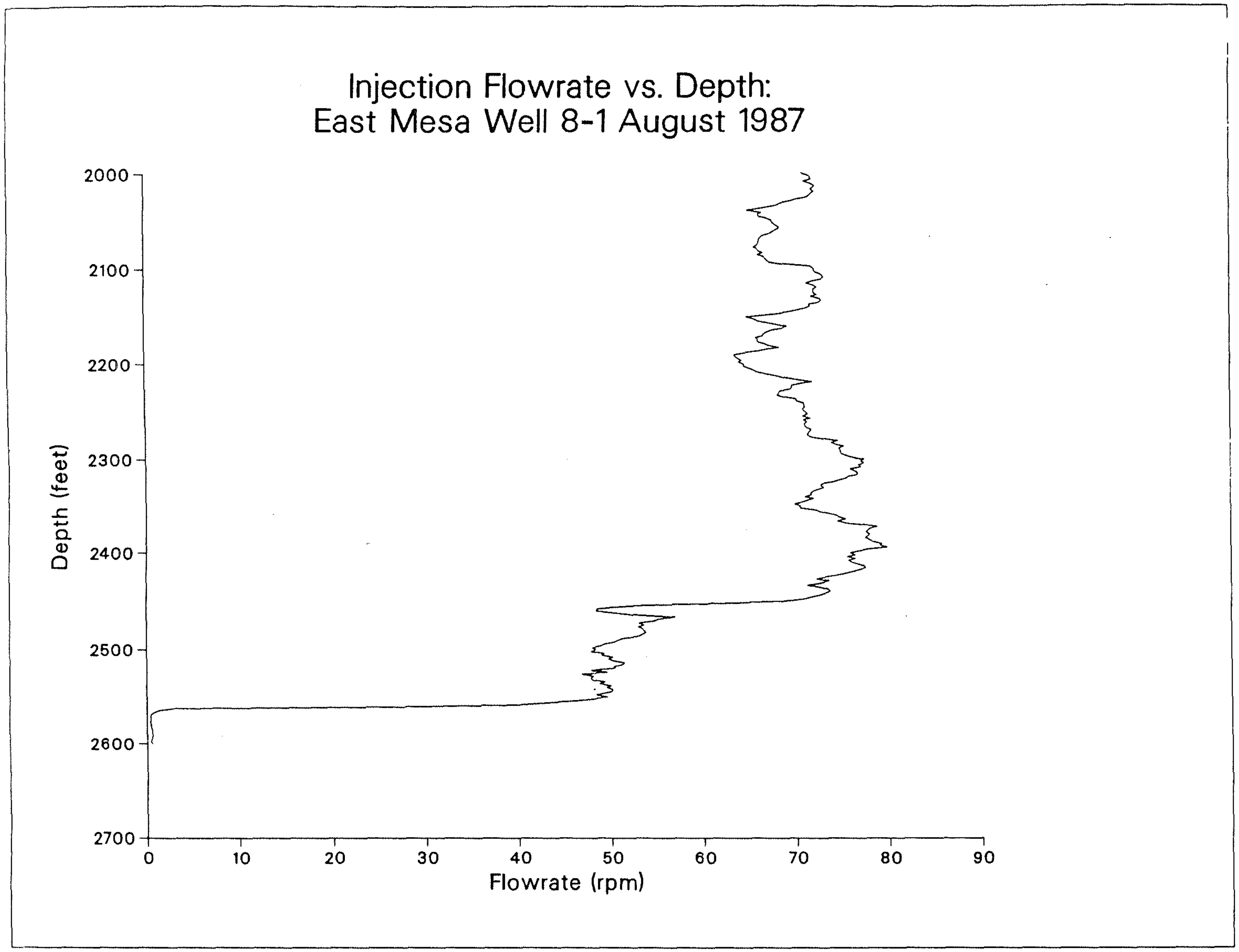

Figure 4. Downhole flowmeter survey measured during injection at approximately 200 gpm.

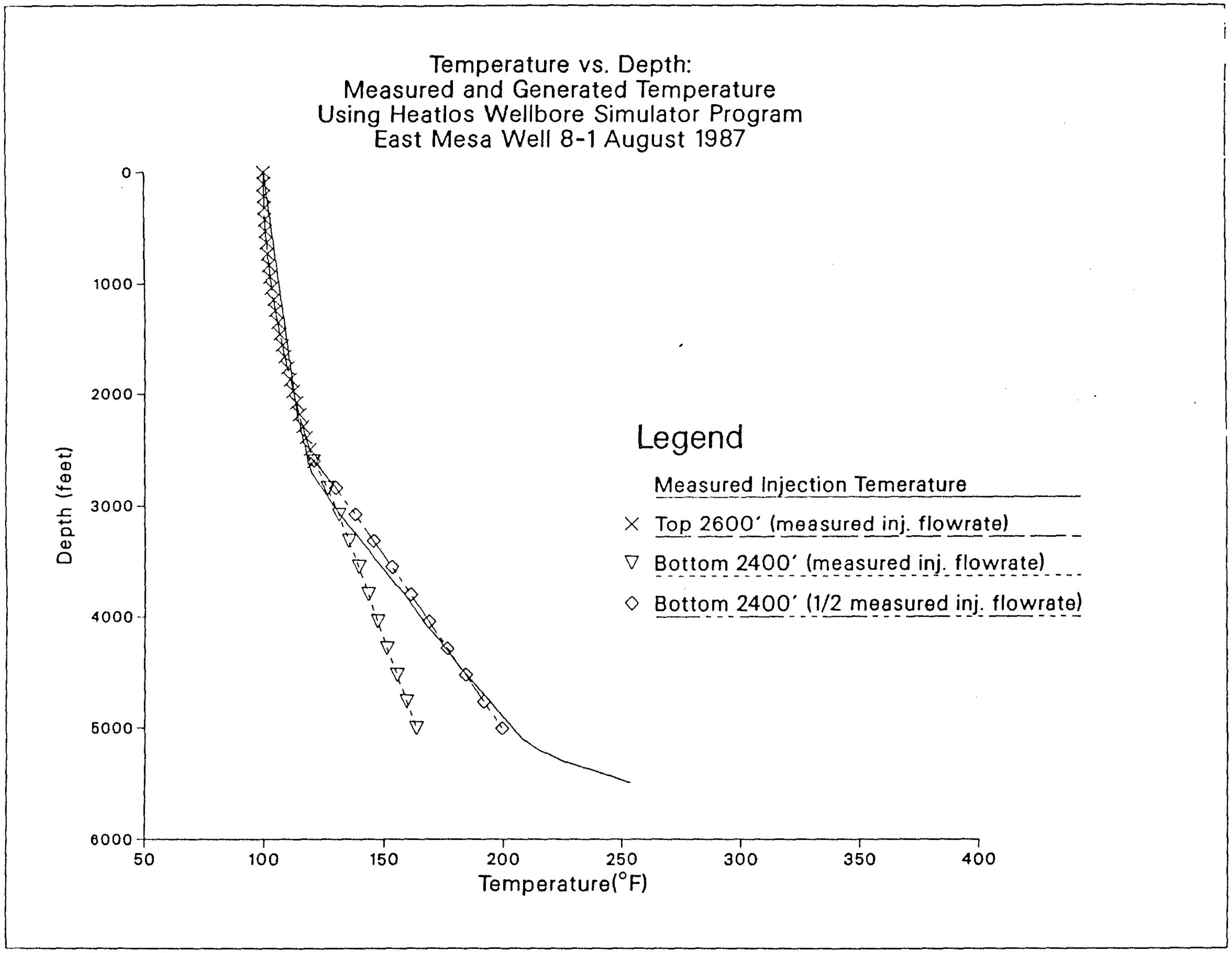

Figure 5. Measured and calculated temperature profile during injection.