Hydraulic communication Tests at the Ogachi HDR site. Japan

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Abstract

Hydraulic communication tests between an injection wellbore and a production wellbore were conducted in 1992. 1993, and 1994 at the Ogachi Hot Dry Rock (HDR) site in Akita prefecture, Japan. This testing. conducted by the Abiko Research Laboratory of Central Research Institute of Electric Power Industry (CRIEPI). included injection testing of two fracture zones which spread out from two open hole intervals at depths of 720 m and 1000 m.

From the data obtained during hydraulic testing, reservoir parameters for Ogachi site (transmissivity and coefficient of storage) were calculated using an automatic inversion analysis based on the nonlinear least-squares method. However, to avoid the local minimum solutions, initial values for these two reservoir parameters were selected using t rial-and-error curve matching method.

For the upper fracture, derived in 1992, the resulting transmissivity and coefficient of storage were 2.97×10^{-5} m^2/s and 1.31×10^{-3}, respectively. For the combined fractures, derived in 1993, the transmissivity and coefficient of storage were 7.50×10^{-6} m^2/s and 1.01×10^{-4}, respectively. Those values that were derived after a stimulation to the production wellbore, in 1994, were 1.24×10^{-5} m^2/s and 7.05×10^{-5}, respectively.

Temperature profile changes of the production wellbore during the circulation period can be observed easily by using an optical fiber temperature measurement cable (Distributed Temperature Sensor. DTS). From these profile changes. the places where fracture zones had penetrated the production wellbore can be determined.

Introduction

Since 1990. Central Research Institute of Electric Power Industry (CRIEPI) has been conducting a research project to develop key technologies for Hot Dry Rock (HDR) geothermal power generation at the Ogachi site. At this site. there are two fracture zones between an injection wellbore and a production wellbore. Two fracture zones were produced by injecting pressurized water through two open hole intervals in the injection wellbore.

The lower fracture zone was created first. by the usual method. This zone was formed by injecting over 10.000 m^3 of water at the bottom of the injection wellbore. After this process, the hole was plagged back with sand to a depth of 860 m. In 1992. a 8 m-length window was cut out in the casing at depth of 720 m. This open hole was created by using the casing reamer. Then, the upper fracture was formed by injecting nearly 5,500 m^3 of water. This way of creating a fracture zone is called " The casing reamer and sand plug method (CRSP) ".

In spring, 1993, the first circulation test was conducted and a second one was conducted in the following autumn. The results derived from these tests were not satisfactory, especially the production flow rate. Then, in 1994, the production wellbore was stimulated conducted to increase the water recovery. After this stimulation, the reservoir parameters were improved. Also the recovery rate was improved, the value increasing to twice as much as the previous year's recovery rate,

Method of hydraulic communication analysis

During the communication test, pressure changes at the bottom of thr production wellbore couldn't be observed. So. a way of analysis to determine "Kh" value (strativity), derived from the relation between changes of flow rate and pressure at the bottom of the production wellbore, couldn't be used. In this study, the authors used a way of analysis to determine transmissivity and coefficient of storage that are defined in the following equations. Those parameters can be derived from the relation between changes of flow rate and water head that is ohtained from wellhead pressure.

In this analysis, we assume the followings:

1. Water flow is described by Darcy's law.
2. Flowing water isn't influenced by external factors except gravity.
3. Water flows radially and transiently through a homogeneous, isotropic, horizontally infinite, confined aquifer from the injection wellbore.
4. No temperature change occures in flowing water. And a general differential equation in cylindrical coordinate? is give as below [*].

$$\frac{\partial^2 H}{\partial r^2} + \frac{1}{r}\frac{\partial H}{\partial r} = \frac{S}{T}\frac{\partial H}{\partial t} \qquad (1)$$

where

T : transmissivity (m^2/s)

S : coefficient of storage(no dimension)

H : water head (m)

t : elapsed time (s)

r : radial distance from the center of the injection wellbore (m).

By using the following conditions

$t = 0, r \geq 0 : H = 0$

$t > 0, r = \infty : H = 0$

$t > 0, r = r_0 \cong 0 : q = -2\pi r T \frac{\partial H}{\partial r} = \text{constant}$

where

r_0 : radial distance from the center of the injection wellbore (m)

q : injection rate (m^3/s),

a solution of Equation (1) is

$$H = \frac{q}{4\pi T}\int_u^\infty \frac{e^{-u}}{u}du$$

$$u = \frac{r^2 S}{4Tt}$$

In order to deribe two reservoir parameters (T and S) from a result of a hydraulic communication test, an automatic inversion analysis based on the nonlinear least-squares method is used .... A normal equation for this analysis is

$$A^T(\Delta H - A\Delta P) = 0 \qquad (3)$$

where

A: sensitivity matrix

A^T: transposed matrix of A

ΔH: residual vector of water head between observed values and calculated values by Equation (2)

ΔP: correction vector of reservoir parameters

Equation (3) is solved by using of Marquardt's method

$$\Delta P = (A^TA + \lambda I)^{-1}A^T\Delta H \qquad (4)$$

where

I: unit matrix

λ: scalar multiplier ($\lambda \geq 0$) .

After some repetitions of calculations of Equations (2) and (4), converged reservoir parameters are obtained. In order to avoid the local minimum solutions, initial values for these parameters are given using a trial-and-error curve matching method.

Results at the single fracture zone in 1993

Figure 1 shows lime dependence of injection flow rate and pressure at the injecting wellhead during the test in 1992. The average flow rate and pressure were about 164 l/min and 16 MPa, respectively.

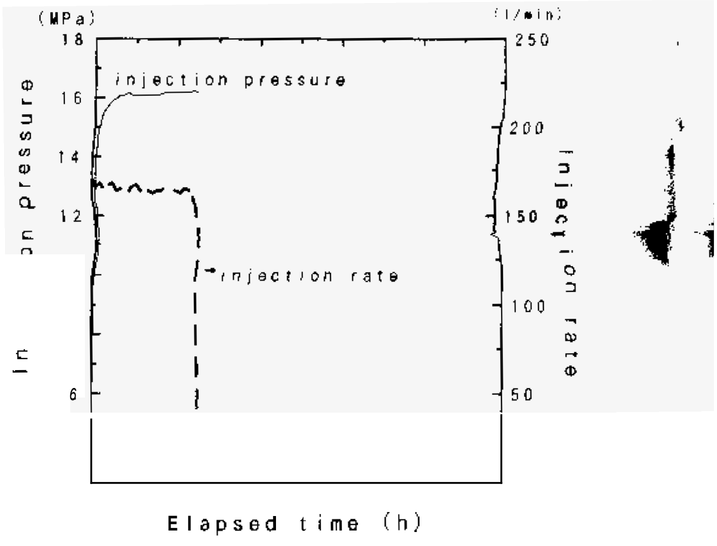

Fig. 1 Injecting condition in 1992

Figure 2 shows the time variation of the simplified injection rate used in this analysis and the water head (W.H.) at the production wellbore, and an analytical curve fitted tu the water head. In this test, the water level at the beginning of the test was taken as 0 m of water head, and also the same for the other tests.

The fitting curve was derived from the automatic inversion analysis.

In this analysis, which is applicable only to 1992, the distance between the injection wellbore and production wellbore was supposed to he 50 m.

The analyzed reservoir parameters, transmissivity and coefficient of storage, were 2.97×10^{-5} m^2/s and 1.31×10^{-3}, respectively.

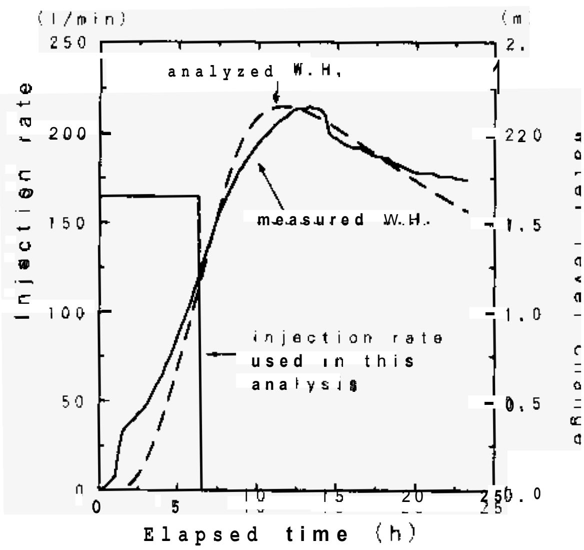

Fig. 2 Communication results in 1992

Results at the two fracture zones, in 1993

In this analysis, the distance between the injection wellbore and the production wellbore is supposed to be 80 m, because both wellbores aren't parallel and the distance is not constant with depth.

Before the analysis, there was a need to convert the production flow rate to water head, using a proportional coefficient. This proportional coefficient was derived from the relation between flow rate and shut-in pressure at the production wellhead. This relation is shown in Figure 3.

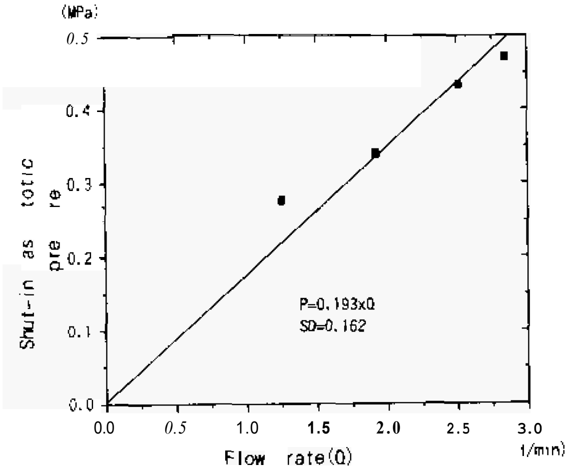

Fig. 3 Determine the proportional coefficient

Using this proportional coefficient, all flow rate data were converted into water head (W.H.). After this conversion, the data were smoothed by FFT digital low-pass filter.

Figure 4 shows the time dependence of injection rate, converted and smoothed water head, and analysed water head.

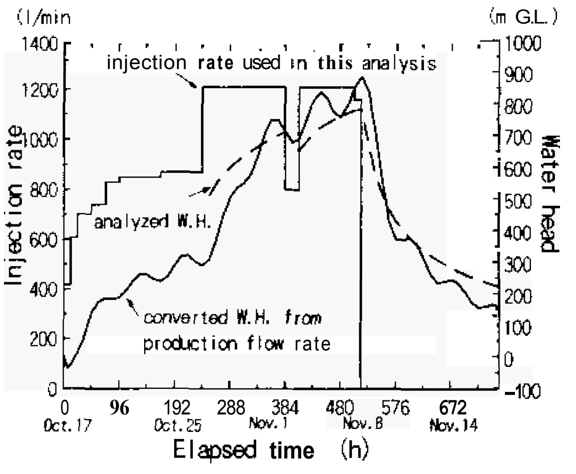

Fig. 4 Communication results in 1993

From this analysis, the derived transmissivity and coefficient of storage were 7.50×10^{-6} m^2/s and 1.01×10^{-4}, respectively. The measuring and analyzing conditions were not the same, so there is not a direct comparison between the results of 1992 and 1993.

Figure 5 gives plots of injecting flow rate and pressure at the injection wellbore head.

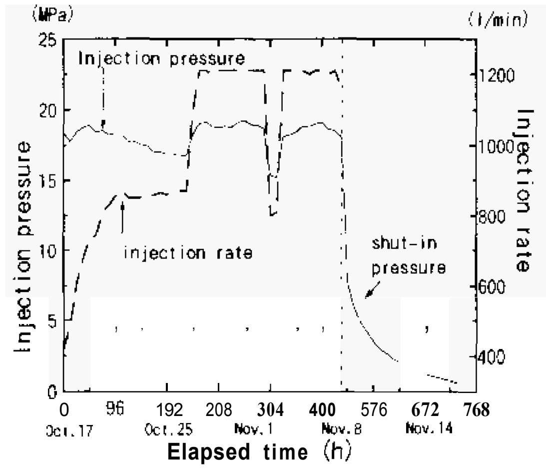

Fig. 5 Injecting condition in 1993

In this case, as shown in Figure 5, injection rate was boosted up substantially after 240 hours from the beginning of the injection. The data for injection rate and measured water head used in this analysis, was that obtained immediately following the boost in injection rate at 240 hours. Whenever time isn't limited, the residual sum of squares became rather bigger than that of the time limited case. This suggest that a small change occured in the production wellbore, like connecting a new fracture zone to the production wellbore. This phenomenon was observed in changes of production flow rate and temperature profiles of the production wellbore. From 240 h (Oct. 27) to 380 h (Nov. 2), there were two steps in flow rate change (see convened W.H. in Fig. 4). The first step occured on 240 h. injection rate was boosted up at this time, and the second step occured on 320 h (Oct. 31). The second step is thought to result from new fracture zones that dilated so as to become connected to the production wellbore. A sudden change of temperature profiles of the production wellbore was measured by an optical fiber temperature measurement cable (Distributed Temperature Sensor, DTS). In Figure 6, the four lines show changes of the wellbore condition. Only the data of Oct. 17 was measured by thermostat. On Oct. 27, injection rate was boosted up to 1,200 l/min from 800 l/min. There is a gradual change for 3 days till Oct. 30, and this change was about the same from the wellbore's bottom to the top. From comparison of Oct. 30 and Nov. 1 data, there was a clear difference in the upper part above G.L.-740 m. During that time, as shown in Figure 6, there was a second step up in production flow rate. As mentioned before, the flow rate increased on 320 h (Oct. 31).

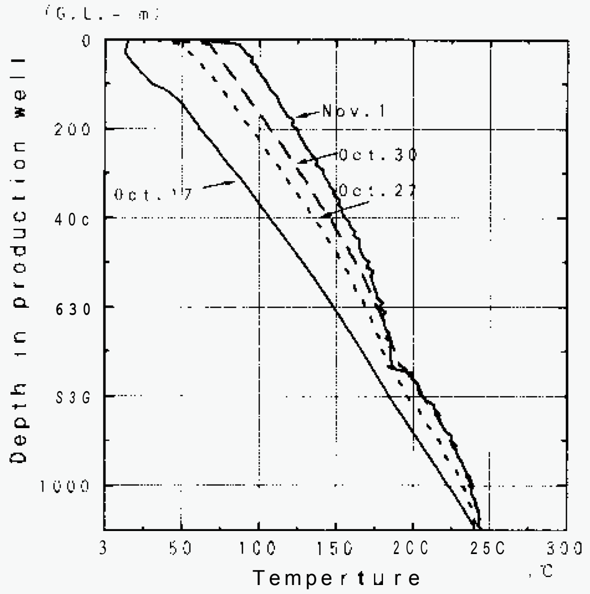

Fig. 6 Temperature profiles of the production wellbore

Results in 1994, after the wellbore stimulation

A stimulation to the production wellbore was done for 5 days in June, 1994. During this stimulation, pressurized water was injected in the production wellbore. Figure 7 gives an example plots of injecting tlow rare arid pressure at the production wellbore head.

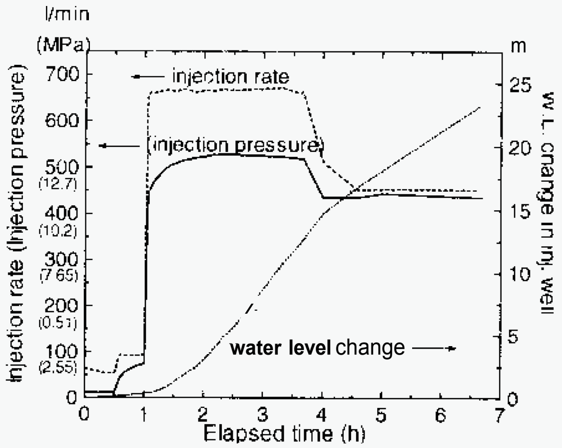

Fig.7 Production wellbore simulation in 1934

No down-hole tool war used in this stimulation. The full length of the borehole of the production well was pressurized.

After the first three days' stimulatoin, the hydraulic communication tcst was conducted by injecting water in the injection wellbore. The injection rate and injection pressure during this communication test is shown in Figure 8.

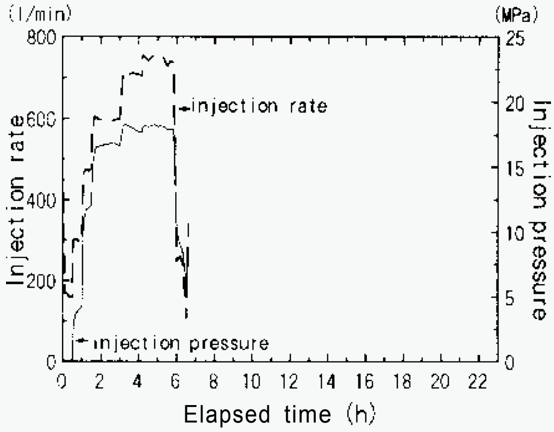

Fig. 8 Injecting condition in 1994

The results of this communication tests are shown in Figure 9. In this analysis. the distance hetween the injection wellbore and the production wellbore was supposed to be 80 m, the same as in the 1993 case.

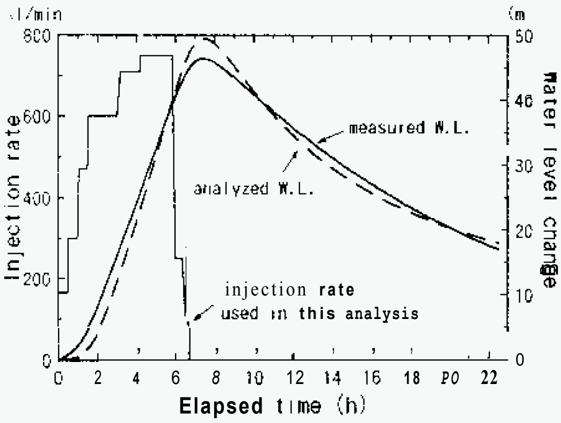

Fig. 9 Communication results in 1994

From this analysis, the derived transmissivity and coefficient of storage were 1.24×10^{-5} m^2/s and 7.05×10^{-5}, respectively. As compared with last year's results (7.50×10^{-6} m^2/s and 1.01×10^{-4}), the value of transmissivity increased by 65 % and the coefficient of storage reduced by 30 %. Figure 10 shows the difference between the results of circulation tests in 1993 and 1994, the relation of cumulative injected volume and production flow rate.

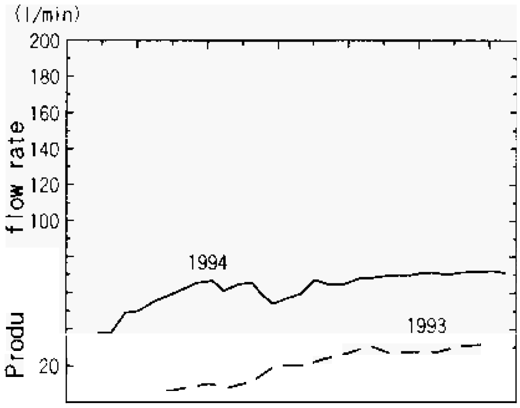

Fig. 10 Comparision of flow rate

As shown in Figure 10, the recovery flow rate increased by more than 100%. The effect of the improvement in the reservoir parameter could be seen in the results of water circulation. As the recovery flow rate increased, the temperature at the wellhead rose higher than last year. Temperature profiles of the production wellbore, measured by DTS, is shown in Figure 11.

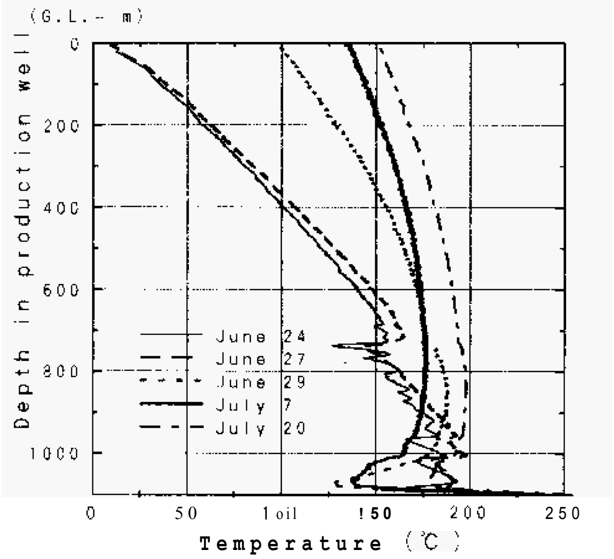

Fig. 11 Temperature in the production wellbore

The temperature profile logged on June 24 shows the influence of the production wellbore stimulation. The downward cusps in temperature show where the fracture zones are penetrating the production wellbore. These downward cusps showed recovery of temperature with time during the circulation period. This phenomenon can he interpreted as follows. During the stimulation period. cool injection water must have cooled the production wellbore and its surrounding areas in the fractures that connected the production wellbore. Then. at the circulation period, heated water flowed through these fractures by heating the cooled areas. Heating by the circulating water caused a recovery of temperature in the production wellbore.

A point near the bottom of the borehole was cooled with time till June 29. Afterwards, the temperature at this point increased gradually. During the stimulation period, the amount of water that penetrated through this point was much larger than any other points. Then the large surrounding area at this point, larger than any other area, was cooled From there results, this fracture zone might he more strongly connected to the production well than any other fracture zones

Conclusion

The results of hydraulic communication tests between the injection wellbore and the production well at the Ogachi HDR site are as below.

1. In 1992, using the single fracture zone, transmissivity and coefficient of storage were 2.97×10^{-5} m^2/s and 1.31×10^{-3}, respectively respectively.
2. In 1993. using the two fracture zones, transmissivity and coefficient of storage were 7.50×10^{-6} m^2/s and 1.01×10^{-4}, respectively.
3. In 1993, by measuring temperature profiles of the production wellbore by DTS, a change of temperature due to a new fracture connection to the wellbore was detected at G.L.-740 m.
4. In 1994, after a stimulation to the production wellbore, transmissivity and coefficient of storage were improved to 1.24×10^{-5} m^2/s and 7.05×10^{-5}, respectively. The production welbore stimulation, full borehole pressurizing, were effective to increase the recovery flow rate.
5. During circulation period in 1994, from the temperature profile changes of the production wellbore, returns of cold stimulation water from fracture zones were detected. Positions of fracture zones that are penetrating the wellbore were able to be determined by using DTS.

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