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WELLBORE INTERFERENCE IN FRACTURED MEDIA

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ABSTRACT

In order to bypass wellbore casing damage and reaccess productive reservoir regions, it was decided to sidetrack and redrill the bottom 600 m of production well EE-2 at the Hot Dry Rock (HDR) geothermal site at Fenton Hill, New Mexico. The most desirable new trajectory would maximize reservoir size and minimize water diversion to an older abandoned reservoir. Based on a simple model using Muskat's analysis it was determined that the new well should be drilled near the old one since water diversion considerations outweighed the advantages of a larger reservoir.

INTRODUCTION

An uncontrolled vent of production well EE-2 following a three-day, 21,200 m^3 injection into the Phase II HDR reservoir collapsed a portion of the well's casing. The ability to perform logging and stimulation experiments in the producing region of the well was lost. Thus, a sidetracking and redrilling operation was planned in order to bypass the damaged section of the well (Figure 1). While the plan included cement jobs designed to plug the producing region of the old well, only a small probability of success was anticipated due to the difficulty in cementing below the damaged casing.

Previous hydraulic fracturing experiments indicated that one or more fractures that hydraulically communicate with a shallow, now-abandoned reservoir have fracture opening pressures as low as 10 MPa. Thus, there existed the possibility that these low-pressure fractures in the old well would parasitically divert hot water from the newly-drilled well and reduce the energy extraction rate. The question arose as to whether water diversion would be minimized by drilling close to the old well, or farther away. A greater separation would result in the benefit of a larger reservoir, but would have to be balanced against an increase in intrinsic reservoir impedance.

A simple model of the problem was developed and is described below. It showed that while reservoir impedance did not significantly increase with the more distant trajectory, water diversion is minimized by drilling close to the old well.

MODEL ASSUMPTIONS

Because HDR reservoirs are normally operated in a steady-state mode, the model was based on Muskat's relationship between pressure and the log of distance, which assumes steady-state, two-dimensional Darcy flow in a homogeneous reservoir[1]. Since the reservoir at Fenton Hill is so extensively fractured, we treat the rock as a uniformly porous medium. It was assumed that all fluid injected would be recovered at the production well or else be diverted to the low pressure fractures. Also implicit in the analysis were the assumptions that near-wellbore impedance, or skin effect, is independent of wellbore pressure, and that the fractures connecting the abandoned reservoir to the old wellbore would continue to parasitically take water once their opening pressure was exceeded. Finally, as a conservative estimate it was assumed that the cementing operations which were planned to plug the low-pressure fractures would not succeed.

Most of these assumptions represent the worst-case scenario for fluid diversion. For example, if the cement jobs are even partially successful, then less flow will be diverted.

The only non-conservative assumption is that all fluid is either produced or diverted, since there are also losses to the surrounding rock during HDR production. From previous testing[2], we can assume that an average of 30% of the injected fluid will be lost to the field, so an "effective" injection flow rate (in our case, 70% of the actual injection flow rate) may be substituted.

RESULTS

Derivation of the working equations is presented in the appendix. The expression for intrinsic reservoir impedance, I_{RES}, is given by

$$I_{RES} = \frac{\mu}{\pi kh} \ln\left(\frac{d}{a_i}\right) \qquad (1)$$

where μ is the fluid viscosity, d is the interwell spacing, k is the average permeability, and a_i is the effective injection well radius.

If the new well were drilled a distance d_1 from the injection well, the new intrinsic reservoir impedance can be found from equation (1) by substituting d_1 for d. Presumably redrilling has no effect on k or h, so the ratio of new to old reservoir impedances is given by $\ln (d_1/a_i)/\ln (d/a_i)$. Results are given in Table I. Note that halving or doubling the well spacing has little effect on the intrinsic reservoir impedance. In other words, the reservoir impedance would stay nearly the same regardless of whether the new well was drilled near to or far from the existing well. Because reservoir impedance would be nearly unchanged, the only remaining concern about increasing the size of the reservoir was the amount of water diversion.

TABLE I

EFFECT OF INTERWELL DISTANCE UPON INTRINSIC RESERVOIR IMPEDANCE (a_i = 1.0 m)

Ratio of New to Old Inter-Well Spacing	Ratio of New to Old Impedance
0.5	0.86
1.0	1.00
2.0	1.14

In order to determine the well spacing needed to keep the pressure in the old well below the fracture opening pressure of 10 MPa, thereby avoiding a large water diversion to the low-pressure fractures, equation (A2) was employed for a situation with two production wells and one injection well. The distance from the injection well to the new production well is d_1, and a_i and a_p are respectively the effective injection radius and the effective radius of the new production well. The distances from the old well to the injection well and the new production well are given as r_i and r_p. If P_{old}, P_i, and P_p are the pressures at the old well, the injection well, and the new production well, then

$$P_{old} = C + \frac{\mu Q}{2\pi kh} \ln(r_p/r_i) \qquad (2)$$

$$P_i = C + \frac{\mu Q}{2\pi kh} \ln(d_1/a_i) \qquad (3)$$

$$P_p = C + \frac{\mu Q}{2\pi kh} \ln(a_p/d_1) \qquad (4)$$

Combining (2-4) results in

$$\frac{P_{old} - P_p}{P_i - P_p} = \frac{\ln\left(\frac{r_p}{r_i}\frac{d_1}{a_i}\right) + s_p}{2\ln\left(\frac{d_1}{a_i}\right) + s_p} \qquad (5)$$

where s_p is the skin factor at the new well. Notice that P_{old} increases with P_p, which illustrates the effect of high backpressure, and with s_p. When P_p and s_p both equal zero, which provides the most optimistic situation for minimizing P_{old},

$$P_{old} = P_i \frac{\ln\left(\frac{r_p}{r_i}\frac{d_1}{a_i}\right)}{2\ln\left(\frac{d_1}{a_i}\right)} \quad . \qquad (6)$$

Typically, P_i = 30 MPa, so for P_{old} to be less than or equal to 10 MPa in order to minimize fluid diversion to the abandoned reservoir, then

$$r_i/r_p \geq (d_1/a_i)^{1/3} \quad . \qquad (7)$$

This indicates that r_p must be considerably smaller than r_i. For example, if the new well is drilled near the old well so that d_1 is still 150 m, and if a_i can be taken to be 1 m, then the new well can be drilled no greater than 28 m from the old well if the latter's pressure is not to exceed 10 MPa. In other words, the only chance to maintain a pressure lower than 10 MPa at the old well, and thereby avoid a large fluid diversion to the low-pressure fractures, would be to drill quite near it.

However, this result assumes no skin effect around the new well, and no pressure on the new well while it produces. Since neither of these assumptions can be completely assured, some fluid diversion is inevitable. Equations (A9-A12) in the appendix describe how to estimate the of the diversion. The results are graphed in Figure 2, showing four families of curves, each of which assumes a different improvement in the near-production-wellbore impedance. The abscissa, Q_L/Q_i, is the ratio of the flow rate lost or diverted to the old well to the injected flow rate, and is shown as a function of the pressure at the new production well. All cases assume an injection pressure of 30 MPa. The curves labeled "far" simulate the case where the new production well is 100 m farther from the injection well than the old production well; the "near" curves add only 15 m to the distance between the injection and new production wells.

Two trends are immediately obvious. First, high backpressure experiments, where the production well is operated at high pressure, may result in a excessive water diversion to the old reservoir. Most high backpressure tests are run in order to stimulate the producing wellbore and to decrease the overall reservoir impedence. Calculations show, however, that the ratio of flow lost to the old reservoir to flow injected is 50% or more for backpressures above 19 MPa. Nearly all the flow will be diverted to the old well if a backpressure of 25 MPa or more is imposed on the new production well. While it may be possible for these experiments to stimulate the producing regions of the new well and decrease intrinsic reservoir impedance, they would come at a high cost in the form of fluid loss. Unless the old well can be sealed with cement, back-pressures greater than 19 MPa should be avoided.

Secondly, the graphs show that, as stated above, a "far" trajectory will result in some amount of fluid diversion regardless of production pressure, and that at normal producing pressures (i.e. 2.5 MPa), this diversion is greater than that which would result from a closer trajectory. This is due to the increased size of the reservoir which accompanies a more distant trajectory. The larger reservoir allows a higher pressure to exist near the old well, which results in more fluid flowing into the low-pressure fractures.

CONCLUSIONS

A model was developed based on a Muskat analysis which assumed steady-state, two-dimensional flow in a homogeneous reservoir. The model provides quantitative estimates of fluid diversion as a function of production pressure, and shows that for the reservoir at Fenton Hill, a more distant trajectory for a sidetracked well would not result in a very large increase in intrinsic reservoir impedance. However, the model predicts that the new well should be drilled relatively close to the old well in order to minimize water diversion.

POST SCRIPT

As this paper was being prepared, the new well was drilled along a trajectory which maintained a maximum distance of 30 m from the old production zone. Preliminary pump tests indicate that the cement jobs were at least partially, if not completely, successful. Thus, we are expecting only minimal water diversion to the old reservoir.

APPENDIX

Muskat[1] shows that for steady state, two-dimensional, Darcy flow in a homogeneous reservoir with multiple wells, the theory of superposition results in

$$P = C + \frac{\mu}{2\pi k} \Sigma\, q_j \ln(r_j) \qquad \text{(A1)}$$

where

P = pressure at any point in reservoir
C = arbitrary constant
μ = fluid viscosity
k = permeability
q_j = volumetric flow rate per unit height of reservoir produced from well j, (positive for production, negative for injection)
r_j = distance from well j to point where P is being evaluated.

For a reservoir of height h, q_j is Q_j/h, where Q_j is the total volumetric flow rate for well j. Hence (A1) becomes

$$P = C + \frac{\mu}{2\pi kh} \Sigma\, Q_j \ln(r_j) \ . \qquad \text{(A2)}$$

In a two well system in which the injection flow rate is -Q and the production flow rate is +Q, (A2) gives the pressure at a point which is a distance r_i from the injection well and r_p from the production well:

$$P = C + \frac{\mu Q}{2\pi kh} \ln(r_p/r_i) \ . \qquad \text{(A3)}$$

If (A3) is evaluated first at the injection well, where r_i then becomes the injection well bore radius a_i, and r_p is the separation distance between the wells d, then

$$P_i = C + \frac{\mu Q}{2\pi kh} \ln(d/a_i) \ . \qquad \text{(A4)}$$

Likewise, at the production well,

$$P_p = C + \frac{\mu Q}{2\pi kh} \ln(a_p/d) \qquad \text{(A5)}$$

where a_p is the production well radius.

If the production well is fully vented, (i.e. $P_p = 0$) then $C = -\frac{\mu Q}{2\pi kh} \ln(a_p/d)$, and substituting in (A4) yields the injection pressure:

$$P_i = \frac{\mu Q}{2\pi kh} \left[\ln\left(\frac{d}{a_i}\right) + \ln\left(\frac{d}{a_p}\right) \right]$$

or

$$P_i = \frac{\mu Q}{2\pi kh} \left[2\ln\left(\frac{d}{a_r}\right) + \ln\left(\frac{a_r}{a_i}\right) + \ln\left(\frac{a_r}{a_p}\right) \right] \qquad \text{(A6)}$$

where a_r is a reference wellbore radius which will be explained below. The second term in the brackets is the skin factor of the injection well s_i, and $\frac{\mu s_i}{2\pi kh}$ is the near-injection wellbore impedance. Likewise, the third term in the brackets is the production well skin factor s_p. Because it is pressurized, the fractures near the injection well are usually more open, so it is nearly always observed that $s_i = 0$. Hence, $a_r = a_i$ and

$$P_i = \frac{\mu Q}{2\pi kh}\left[2\ln\left(\frac{d}{a_i}\right) + \ln\left(\frac{a_i}{a_p}\right)\right] \quad \text{(A7)}$$

and the last term is the production well skin factor. Dividing (A7) by Q results in the familiar impedance concept, based on an electrical resistance analogy:

$$\frac{P_i}{Q} = \frac{\mu}{\pi kh}\ln\left(\frac{d}{a_i}\right) + \frac{\mu}{2\pi kh}\ln\left(\frac{a_i}{a_p}\right). \quad \text{(A8)}$$

The first term on the right hand side is the intrinsic reservoir impedance I_{RES}, and the second term is the near-production well impedance I_p.

A triplet of wells requires the superposition of yet another well and flow rate. P_i and Q_i will continue to indicate injection pressure and flow rate, P_p and Q_p indicate production well conditions, and now P_L and Q_L indicate the "leakage" quantities at the old well. Neglecting permeation losses to the rock surrounding the reservoir, $Q_i = Q_p + Q_L$. Letting $m = \mu/2\pi kh$, the pressures at all three wells are given as:

$$P_i = C + m[-Q_i\ln(a_i) + Q_L\ln(r_i) + Q_p\ln(d_1)] \quad \text{(A9)}$$

$$P_L = C + m[-Q_i\ln(r_i) + Q_L\ln(a_L) + Q_p\ln(r_p)] \quad \text{(A10)}$$

$$P_p = C + m[-Q_i\ln(d_1) + Q_L\ln(r_p) + Q_p\ln(a_p)] \quad \text{(A11)}$$

Combining (A9-A11) and recalling that $Q_i = Q_p + Q_L$, it can be shown that

$$\frac{Q_L}{Q_i} = \frac{\ln\left(\frac{d_1 r_p}{a_i r_i}\right) + s_p - P^*\left[2\ln\left(\frac{d_1}{a_i}\right) + s_p\right]}{2\ln\left(\frac{r_p}{a_i}\right) + s_L + s_p - P^*\left[\ln\left(\frac{r_p d_1}{r_i a_i}\right) + s_p\right]} \quad \text{(A12)}$$

where P^* is the pressure ratio $(P_L - P_p)/(P_i - P_p)$, and s_p and s_L are the skin factors at the new and old production wells, respectively.

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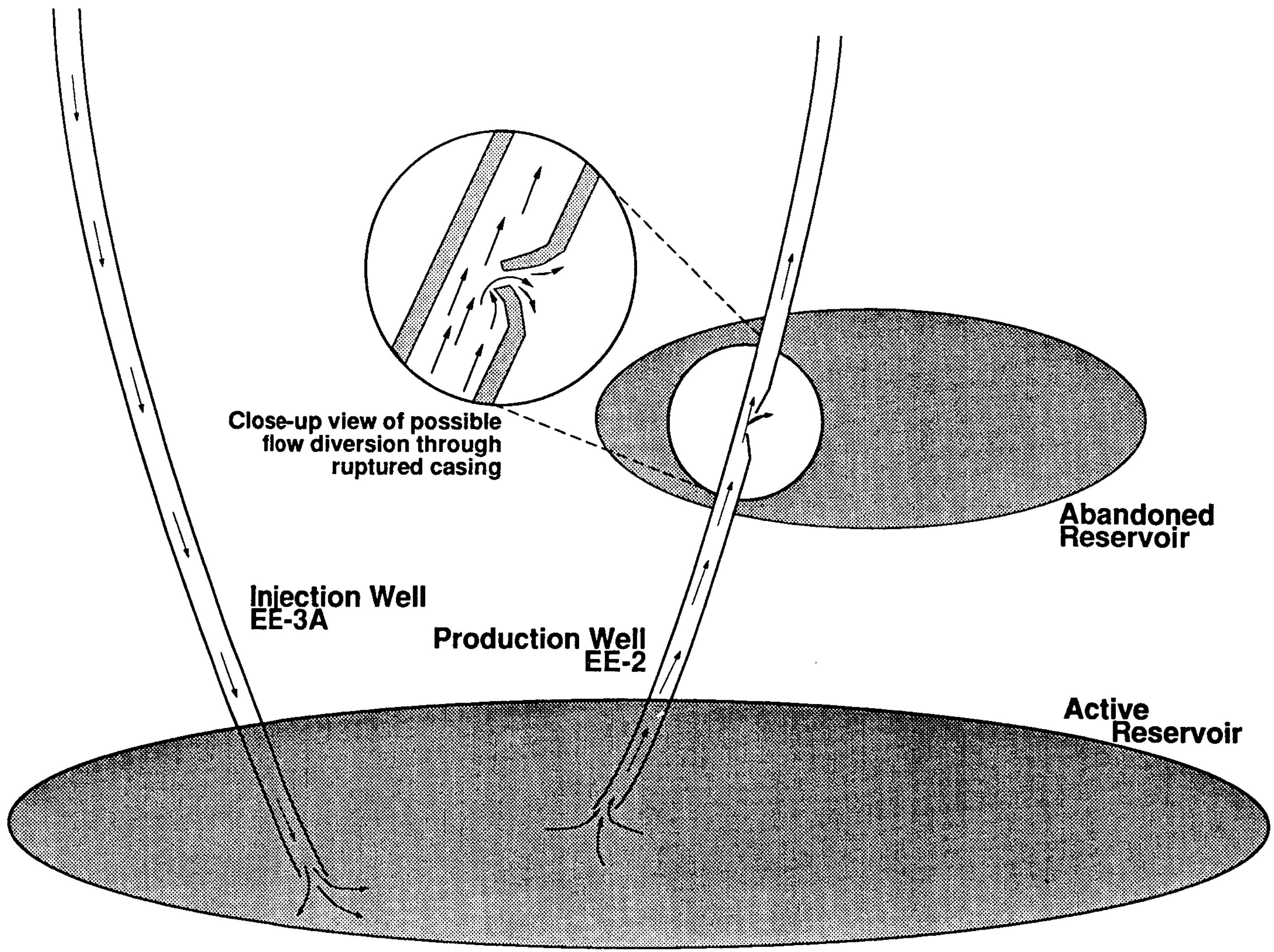

Figure 1: Idealized view of the two reservoirs (not to scale)

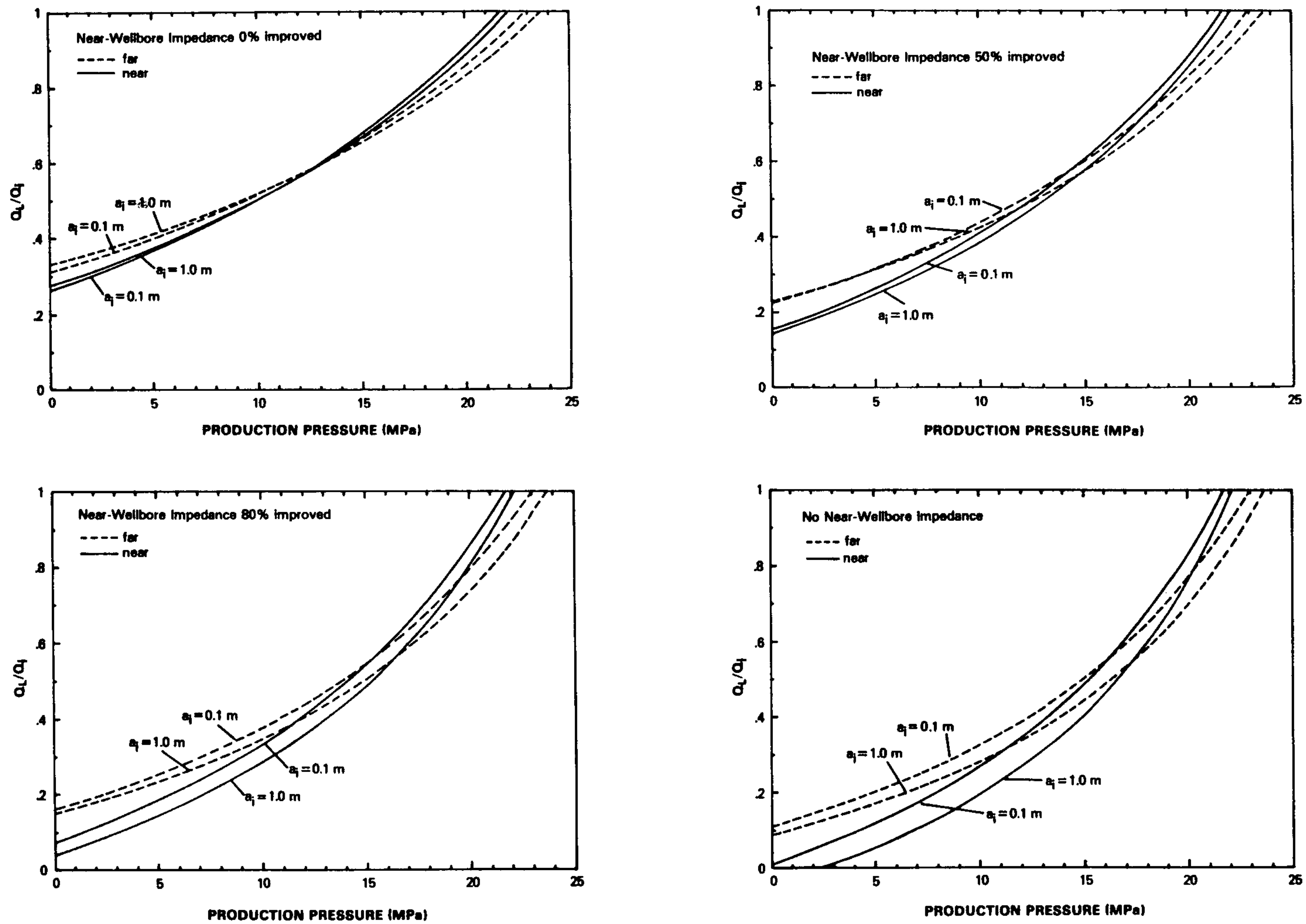

Figure 2: Flow rate diverted to the low pressure fracture, normalized by the injection flow rate, as a function of production pressure at the new well. The "near" curves assume that the producing region of the new well lies 15 m more distant from the injection well than does that of the old well; the "far" curves add 100 m in distance. Two values for a_i, the effective injection well radius, are given for each case. Each family of curves assumes a different degree of improvement in near-production-wellbore impedance, some amount of which is expected due to the regained ability to stimulate producing regions in the new well. The worst case would be 0% improvement; the ideal case would be to have no near-wellbore impedance. An improvement of 50%-80% is expected.