REINJECTION PROBLEMS IN OVERPRESSURED GEOTHERMAL RESERVOIRS

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ABSTRACT

In this study, high injection pressure problems in geothermal reservoirs with pressure gradients higher than hydrostatic are examined. For this reason, mechanisms controlling injection pressures are identified and investigated. Two geothermal field cases (Kizildere and Salavatli) with overpressured reservoirs from Turkey are presented. The reasons for high injection pressures in those geothermal fields are presented, solutions to overcome those problems are investigated and the results are reported.

INTRODUCTION

Reinjection of waste hot water has always been the most challenging issue for the exploitation of geothermal fields since early 70’s. Most of the experimental work and research on this subject have been directed to cooling effect of relatively cold disposal water on the geothermal reservoir (Horne, 1982), which has been a real concern from the power production point of view. Horne, (1985) investigated reinjection effects on production in fractured geothermal fields, and concluded that it carries the danger of production damage due to premature thermal breakthrough. He also stated that locating reinjection wells to a safe distance is desirable, but underground flow paths are complex and a safe distance above ground is not necessarily a safe distance below ground.

Another concern was the injectivity changes during the exploitation of the fields. In some cases injectivity of individual wells declined as stated by Bixley and Grant, (1979) and Itoi et al., (1989), while it increased in other cases (Bixley and Grant, 1979 and Dobbie and Menzies, 1979). Declining injectivity has usually been attributed to silica deposition. While some of declining cases were identified as silica deposition by well testing and well documented (Bixley and Grant, 1979), some others are presumed. In some cases, silica deposition within the reservoir was alleviated either by separating at higher pressures (Hibara et al., 1989) or preventing air exposure, or injecting the water as quickly as possible (Horne, 1985).

In most of the cases, injectivity has been reportedly found to increase with time (Bixley and Grant, 1979, Horne et al., 1982 and Horne, 1985). The cause has been attributed to either inflation of fractures under injection pressure, or thermal contraction of rock causing opening of fissures (Horne, 1985). Sometimes the disposal water is injected into two phase zone causing condensation with resulting pressure decline.

Geothermal fields are located in highly fractured areas of the earth crust and formation pressures encountered in those areas are generally abnormally low due to pressure gradients below hydrostatic. Sometimes, pressure gradients change within the same field depending on the location of well is found whether in upflow or peripheral zone. Sometimes topography creates favorable position from the reinjection point of view since water table remains below the wellhead. In those cases, reinjection is said to be carried out by gravity. Reinjection of disposal waters into geothermal reservoirs with below hydrostatic gradient is not problematic, provided that no cooling effect and silica deposition occurs. Water levels are sometimes well below the surface, and therefore, reinjection operation is conducted by taking advantage of adding water column head to the existing hydrostatic head in the wellbore. In fact, this creates an extra hydraulic head just like pumping without using power in the surface. Sometimes, separation pressure is also used to help to overcome small wellhead pressures built. Downhole pressure surveys taken in AH-5 during the reinjection test conducted (Einarsson et al., 1974) indicated such an extra head around 17.5 bars. Much bigger hydraulic heads are created in some other fields.

Above hydrostatic gradients are originally found in some unexploited geothermal fields, such as
Wairakei (Donaldson et al., 1983) and Kizildere (Serpen, 2000). Table 1 lists the excess pressure gradients observed in some geothermal fields around the world. Reinjection tests conducted roughly 30 years after the exploitation began in Wairakei. At that point, reservoir pressures must have been substantially declined; therefore, no problem related high wellhead pressures are reported. Partial reinjectionoperation in Kizildere started after roughly 20 years of exploitation due to pressure decline (more than 10 bars) occurred and has been proceeding smoothly in the last 2 years.

Table 1. Excess Gradients Observed in Some Geothermal Fields (Donaldson, et al., 1983, Serpen, 2000)

<table>
<thead>
<tr>
<th>Fields</th>
<th>Excess Gradient, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kizildere</td>
<td>18</td>
</tr>
<tr>
<td>Wairakei</td>
<td>7</td>
</tr>
<tr>
<td>Broadlands</td>
<td>15</td>
</tr>
<tr>
<td>Broadlands</td>
<td>9</td>
</tr>
<tr>
<td>Baca</td>
<td>4</td>
</tr>
<tr>
<td>Tongonan</td>
<td>6</td>
</tr>
<tr>
<td>Ngawha</td>
<td>2</td>
</tr>
<tr>
<td>Kawerau</td>
<td>7</td>
</tr>
<tr>
<td>Yellowstone</td>
<td>10-40</td>
</tr>
</tbody>
</table>

Some overpressured geothermal fields have been discovered in Turkey. Difficulties of reinjection have been initially observed in this type of the geothermal fields due to high wellhead pressures required. These might create serious operational, economic and environmental problems to solve. Therefore, in this study, reinjection problems related to overpressures encountered in some geothermal fields will be investigated.

MECHANISMS CONTROLLING INJECTION PRESSURE

The following mechanisms are identified to change the injection pressure in a reinjection system:

- **Injection Well Performance into a Liquid Filled Reservoir**

In the injection system design of injection field cases, the most important issue is the estimation of the injection well performance. Darcy’s law for steady state flow of single-phase fluids in a well centered in a circular reservoir is used:

\[
q = \frac{k_w h (p_{nf} - p_{wf})}{18.665 B_w \mu_w [\ln(\frac{r_e}{r_w}) + s]} \tag{1}
\]

where, “r_e” is the radius extending from wellbore to the front of the cool water bank, i.e., the interface of injected cool water and the hot reservoir water, \(p_e\) is the reservoir pressure at this front, and “\(p_{nf}\)” is the bottom hole injection pressure.

As can be observed from Eq. 1, increasing \(r_e\) value with rising injection volume will reduce injection rate \(q\) with time, provided that the other parameters are not changed. Although a negative skin factor value will initially increase injection rate, as will be seen later the same declining injection rate trend will follow.

Numerical study conducted by Ahmed et al., (1979) indicated similar results, that is, increasing wellhead pressures if the same injection rate is maintained. Reinjection tests in Bulalo geothermal field indicated the same declining trend of the injection rate in some wells (Messer, 1979).

- **Mobility Ratio**

Mobility ratio, \(M\) in geothermal reinjection involves mobilities of cold injection bank and hot water reservoir. Assuming that the permeability is the same in both banks, mobility ratio will be reduced to the ratio of viscosities of both banks.

Assuming a line drive reinjection scheme, for a piston like flow, injection rate can be expressed as follows:

\[
q = \frac{\pi \lambda h (p_{nf} - p_{wf})}{\left(\frac{1}{M} - 1\right) \ln \left(\frac{r_f}{r_w}\right) + \ln \frac{a}{r_w} + 1.571 \frac{d}{a} - 1.927} \tag{2}
\]

Considering hot and cold bank viscosities, mobility ratio for geothermal injection will be less than 1, which will in turn reduce injection rate in Eq. 2. This will increase the injection pressure for the same rate. Ariki and Akabayashi, (2001) obtained similar results in their numerical study, in which injection pressures increase for horizontal flow during the injection with low temperatures. They also indicated that if injection fluid temperature is the same as the reservoir fluid temperature, pressures do not change in neither downward vertical nor horizontal flow.

On the other hand, Willhite, (1969) cautions that the effects of mobility ratio on injection rates can be observed in early injection. Thus, injection rates based on short pilot tests or early injection performance can be misleading when projected to entire injection operation. In fact, Kun, (2003) observed wellhead pressure increases during a short run pilot reinjection test, but reinjection reportedly proceeded smoothly without any pumping effort during the exploitation period.

- **Skin Effect due to Partial Penetration**

In case of limited entry or partial penetration, the well communicates with only a fraction of producing
zone thickness. Partial penetration corresponds to a reduction of the surface of contact between the well and the reservoir. In fractured wells, skin due to partial penetration is not normally expected since fractures increase this contact. But, in geothermal wells where horizontal flow dominates with no vertical fractures around, partial penetration might occur if the whole production zone is not exposed. Partial penetration has been observed in some geothermal wells (Serpen, 2001).

Bourdet, (2002) studied several scenarios for partial penetration well, and concluded that even with a small penetration ratio, geometrical skin is seldom larger than 30 or 50. On the other hand, he stated that on limited entry wells wellbore damage is amplified and total skin can reach values of several hundreds. This could be a real concern for geothermal wells drilled with mud, and increasing skin will cause pressure increase and injection rate decline.

- Non-darcy Flow

Non-darcy flow effects have been observed during production tests in some geothermal wells (Satman et al., 2001 and Onur, 2004). High rate injections in this sort of wells might cause non-darcy flow in the bottomhole of the wells that will in turn increase the injection pressures.

- Gravity Effects

The effect of gravity in vertical flow can be expressed based on the following equation:

\[ m = -\frac{\rho k}{\mu} (\Delta p + \rho g) \]  

(3)

where: \( m \) is mass-flux.

It is evident from the Eq. 3 that injection capacity of a geothermal reservoir with vertically oriented fractures is enhanced with increasing gravity term \( \rho^2 g k /\mu \). Ariki and Akabayashi, (2001) concluded that the injection capacity drastically improves when the low temperature water is injected into shallow part of a geothermal reservoir with vertically oriented fractures.

- Permeability Enhancement

Permeability improvement due to cold water injection into geothermal fields has been observed in several geothermal fields (Horne, 1985, Bixley and Grant, 1979 and Dobbie and Menzies, 1979). It is believed that permeability is enhanced due to hot rock contraction, creating new fractures around the cooled zones, increasing fracture aperture and increasing storativity that cause pressure decline. It is clear that permeability improvement in Eq. 1 will increase the injection rate. Ariki and Akabayashi, (2001) in their study also found permeability enhancement of especially vertically oriented fractures with downward injection fluid flow.

- Constrains in Well Flowing Diameter

The 9 5/8” dia. casing is regularly used in either production or reinjection wells. Sometimes larger diameter casings are used in some reinjection wells to alleviate frictional pressure drops. The frictional pressure drop through 700 m long 9 5/8” casing at moderate injection rates (250 t/h) is negligible, but it is becoming substantial (approx. 5 bars) when the injection rates rise to 500 t/h. If disposal water collected from several production wells is desired to inject in one well, then constrain on casing diameter becomes important. In that case, wells with larger diameters should be planned for reinjection purpose.

REINJECTION TESTING EXPERIMENTS IN OVERPRESSURED RESERVOIRS

In this section, two reinjection testing experiments conducted in Kizildere and Salavatli geothermal fields are examined.

Kizildere Geothermal Field

This field originally was an overpressured reservoir as seen in Fig. 1. The pressure gradients over hydrostatic encountered in geothermal fields of Turkey are generally caused by partial pressure of CO2, which makes 60%-75% of total reservoir pressures in deep thermal and hot water reservoirs of Kizildere geothermal system, respectively.

![Reservoir pressures of Kizildere geothermal field.](image)

The first reinjection test in Kizildere was conducted in 20/9/1971. In well KD-1, a maximum reinjection rate of 125 t/h and a minimum reinjection rate of 27.5 t/h were obtained at wellhead pressures of 13.8 bars and 4.7 bars, respectively (Serpen, 2000). Similar
trend (increasing wellhead pressures with rising injection flow) was obtained in another well, KD-9.

Fig. 2. Variation of wellhead pressure and injection rate with time for the injection well KD-1A.

In 1975-1976, a long term re-injection test was carried out in a nearby well KD-1A, which took 29 weeks (Kasap, 1976). During the 29-week long injection operation the average injection rate was approximately 83 tons per hour, and the injection water temperature varied between 30°C and 42°C. The results of the test are illustrated in the Fig. 2 and Fig. 3. The behavior of wellhead pressure and injection rates, recorded at well KD-1A can be seen in Fig. 2. The well KD-1, 68 meters away from the injector, was the observation well and its down-hole temperatures, at the depths of 500 and 530 meters, and bottom-hole pressures were monitored as seen in Fig. 3. For the first 5 weeks, the injection rate increases from 75 t/h to 90 t/h, and the wellhead pressure follows a similar trend by increasing from 7 bars to 9 bars. In the following two weeks the pressure remains constant, although injection rate increases slightly. As seen in Fig. 3, in the mean time, both the temperature and the bottomhole pressure in the observation well KD-1 remain constant with some minor fluctuations.

From 7th to 12th weeks, the injector wellhead pressure drops down to 8 bars, while the injection rate fluctuates around 90 tons/hr. In the observation well, however, both the pressure and temperature at the depth of 530 m drop 2 bars and 5°C, respectively. The cooling effect is felt at the observer 6 weeks after the start of injection.

It is known that two long term production tests of hot water reservoir conducted earlier caused a small reservoir pressure decline and the subsequent formation of a free gas phase, consisting of essentially carbon dioxide and some water vapor, into the hot water reservoir in Kizildere geothermal system (Serpen, 2000). After the arrival of injected water at the observation well, on the 6th week of operation, it is more likely that the further injection is filling up the reservoir while compressing the free gas phase. The sharp increase in bottom-hole pressure, shown in between the solid arrows in Fig. 3, may be attributed to the dispersion of free gas phase in liquid water upon compression. Simultaneously the decline in injection rate is lessened (Fig. 2) as the volume of dispersed gas phase is replaced by slowly increasing volume of water (Mihcakan et al., 2005).

After the 12th week, the injection rate drops to 75 tons/hr, until the 15th week. In the mean time, the wellhead pressure increases to 11 bars. As expected, the pressure at the observer follows the same trend and increases to 59 bars, indicating a good hydraulic communication in between the two wells. The temperature at KD-1 increases about 2°C due to conductive heating of the rock, since the delivery of cooler water toward the observation well is mitigated with the rapidly decreasing injection rate. Based on these facts, the actual reason for the rapid drop in injection rate is thought to be the filling up of the reservoir with the cumulative water injected by that time. Thus, the attempt of forcing more water into the already filled up reservoir back pressured the reinjection well (Satman et al., 2000).

As seen in Fig. 2, the injection rate suddenly increases and reaches 85 t/h level, as the wellhead pressure remains constant, between the 15th and 16th weeks. Such behavior is likely to be the initiation of hydraulic fracturing of the rock of a pressured up formation. It is well known fact that once the formation is broken down, it does not take much pressure to progress the fracture. Thus, the injection pressure in Fig. 2 starts increasing up to 13 bars until the 17th week, and then remains constant for six weeks. Injection rate also remains constant for six weeks. Another evidence for the probable fracture enhancement may be deduced from the pressure behavior at the observation well in Fig. 3. The
observation well begins to sense the slow progressing fracturing action at the 17th week. The pressure at the observer begins to a sharp drop at 19th week (255000 tons of water is injected) and the fracture progress is completed. Steady increase of the temperature at the depth of 530 m in the observation well indicates that the fracture was not enhanced at that direction and depth.

Kizildere field is situated in a graben, and near vertical fractures are very characteristic of such structures. Fracture enhancement in the above test after 15 weeks, during which horizontal flow dominated, probably occurred through vertically oriented fractures downward as Ariki and Akabayashi, 2001 study indicated.

On the other hand, a deep well, R-1 (2300 m) was completed in 1997 for reinjection purpose, and struck a hotter horizon at depth. Injection attempts to this well ended with negative results. But, well R-1 with permeability thickness of 6.5-7.5 d-m and higher temperatures (205°C vs. 240°C) resulted in a good producer. Though permeability thickness of this well can be considered as reasonable, injection into this well was not possible because of excessive wellhead pressures.

Ongur, (2005) states that near vertical fractures in graben structures tend to close to horizontal at depth. Horizontal flow might be dominating at deeper levels due to the scarcity or lack of vertically oriented fractures, and for that reason, injection pressures may be increasing as Ariki and Akabayashi, (2001) study explained.

**Salavatli Geothermal Field**

Salavatli is a newly developing big geothermal field with relatively moderate temperatures of 170°C and relatively high static wellhead pressures of 7 to 12 bar (Serpen and Tufekcioglu, 2003). The field is also situated on the same graben structure (B. Menderes) as Kizildere, and is evidently overpressured as pressure measurements indicate due to also relatively high CO₂ content. Three wells have been drilled so far, 2 for production and 1 for the reinjection. A forth well is being drilled for reinjection. The first 2 wells (AS-1 and AS-2) were drilled 20 years ago, and they are now being considered for production. They are producing at flow rates varying between 250 t/h and 300 t/h from the depths of 800 m-900 m. The injection capacities of these wells are limited to their production level at wellhead pressures of approx. 20 bars. The first reinjection well ASR-1, drilled to 1420 m approx. 1.5 km away and at a lower elevation resulted to be a good producer with a flow rate of 550 t/h. The permeability thickness of this well is estimated as 17 d-m by both build-up and injection tests.

Injectivity indexes of the wells AS-1, AS-2 and ASR-1 are 2.45 lt/s-bar, 4 lt/s-bar and 1.55 lt/s-bar, respectively (Table 2). On the other hand, productivity index of the well ASR-1 is 22 lt/s-bar, which is substantially higher than the injectivity index. This seems to be characteristic of the geothermal fields with pressure gradients over hydrostatic. The production rate of ASR-1 is as much as the sum of the other wells (AS-1 and AS-2), although the injectivity indexes of the wells AS-1 and AS-2 are higher than the injectivity index of ASR-1. As expected the deeper the wells get, the difficulties in injection increases. This could also be due to normal permeability decline with depth. As seen in Kizildere case beforehand, there is also difficulty for reinjection in Salavatli field. High wellhead pressures are needed to inject the disposal fluids.

<table>
<thead>
<tr>
<th>Wells</th>
<th>Well Depths, (m)</th>
<th>Injectivity Index, (t/h-bar)</th>
<th>Productivity Index, (t/h-bar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AS-1</td>
<td>1500</td>
<td>2.5</td>
<td>36</td>
</tr>
<tr>
<td>AS-2</td>
<td>900</td>
<td>4</td>
<td>26.5</td>
</tr>
<tr>
<td>ASR-1</td>
<td>1430</td>
<td>1.5</td>
<td>22</td>
</tr>
</tbody>
</table>

In our opinion, injection tests conducted in Salavatli geothermal field are very short and inconclusive. Injectivity index of ASR-1 well has improved in three consecutive injection tests. Remembering Willhite, (1969) warning against short run pilot tests, long term injection performance of the well ASR-1 was studied using infinite reservoir model. To obtain injection rates and volume, the following Eq. 4 and Eq. 5 are utilized coupled with reservoir parameters obtained through the wells tests conducted in well ASR-1.

\[
q = \frac{1}{18.66} \mu \frac{\Delta p}{\ln \left( \frac{V_w}{(\pi \phi h r_w^2)} \right)}
\]

\[
t = \frac{18.66 \mu \frac{V_w}{h}}{kh \Delta p} \left[ \ln \left( \frac{1}{r_w} \sqrt{\frac{V_w}{(\pi \phi h)}} \right) - \frac{1}{2} \right]
\]

where: \( V_w \) is injected volume and \( \Delta p = p_{wf} - p_e \)

Fig. 4 and Fig. 5 illustrate reinjection performance results. Fig. 4 shows injection rate change with the injected volume, with and without skin factor. Actually, ASR-1 well has a negative skin factor of 6. As can be observed in Fig. 4, although initial injection rates are higher, decline in those injection rates with increased injection volume are much
pronounced with respect to no skin. Fig. 5 shows the change of the injection time with injection volume; and it can be noted that the elapsed time between the cases with or without skin widens as injection volume increases and pressure differential decreases.

Salavatli geothermal field is situated in the northern flank of B. Menderes graben, which is a big 200 km long, important structure. Several small scale grabens and horsts are formed through stepwise faulting within the B. Menderes graben where Salavatli field is sited. Four belts of alternating production and reinjection wells are planned to locate along these faulting zones, excepting that more permeable structures are developed along these faults. Conductivity between the production and reinjection belts is thought to be weaker, since there no direct contact was unearthed so far. Therefore, injection is not expected to influence the production wells in short run, which are approx. 650 m away. This sequence of production and reinjection wells resembles a line-drive system used in oil field waterflooding operations.

A long term injection performance study for the Salavatli filed was conducted using line drive solution (Eq. 2), and the results are shown in Fig. 6. As seen from the Fig. 6, there is a sharp initial injection rate drop, as predicted by Willhite, (1969), and afterwards, injection rate decline is gradual.

ALTERNATIVE SOLUTIONS

Since there were reinjection problems because of overpressured reservoir when the Kizildere geothermal power plant started power production in 1984, a laboratory study (Tolun et al., 1985) was conducted with the aim of eliminating boron from Kizildere waste water using boron selective resin Amberlite IRA 743. Single and double stage regenerations of resin were found feasible. A preliminary economic evaluation resulted in extra cost of 1 cent/kWh for boron removal (Recepoglu and Beker, 1991). Although this extra cost could be affordable, for 1500 t/h geothermal water production rate, the process would have yearly produced 125000 m³ of alkaline, 100000 m³ of acidic solutions and 400000 m³ of contaminated washing water to dispose (5% of total disposal water). Salavatli geothermal water has boron content twice that of Kizildere. Therefore, more by-product disposal water might be produced.

Tolun et al., (1985) also proposed the reverse osmosis process as an alternative for boron removal, which could eliminate all TDS in the waste water, producing also substantial amount of fresh water to be used elsewhere. The first Salavatli geothermal power plant is being manufactured with air cooling system, which loses roughly 1 MWₑ of power with respect to the water cooling. In the next enlargement of power production, this fresh water could be also used for cooling purpose. They stated that according to their information, the cost of such process would be around 1 cent/kwh. Twenty years after this estimation, it is expected that new technologies could provide more economical solutions.

Even if the above solutions were implemented, depletion of the reservoir should be controlled. After
some pressure drop in the reservoir, reinjection operation should certainly be initiated. Since dissolved CO_2 provide driving energy for the geothermal reservoir just like a depletion drive oil reservoir, it would be advisable to keep reservoir pressure over bubble point pressure. The natural recharge of the Salavatli field is not known yet. The planned production rate of the first binary power plant could be partly or fully met by the natural recharge, thus no pressure decline could be also observed with the planned production rate. Therefore, a comprehensive reservoir engineering study is needed as the numbers of wells are increasing and the testing data are accumulated.

On the other hand, our economic evaluations indicate that reinjection operation would roughly cost 0.5 cent/kWh, and it is still cheaper and more attractive than the above alternative solutions. Though modeling studies show otherwise, permeability enhancement during injection could occur as happened elsewhere. In that case, the injection rate would increase in long run.

**SUMMARY**

The following subjects are investigated in this study:

- Mechanisms controlling injection pressures are investigated.
- Injection experiments in two overpressured reservoirs of Turkey are examined and the behavior of those fields under injection is explained.
- Possible alternative solutions are presented.

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**REFERENCES**


