# INJECTION - RELATED PROBLEMS ENCOUNTERED IN GEOTHERMAL PROJECTS AND THEIR MITIGATION: THE UNITED STATES EXPERIENCE

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## ABSTRACT

Underground fluid injection is important to a geothermal project for a number of reasons: (i) to avoid any environmental impact arising from surface disposal, (ii) to provide pressure support to the reservoir, (iii) to scavenge heat from the rock matrix, and (iv) to avoid any ground subsidence.

A survey of some 70 commercial geothermal projects in the United States shows that the following problems have been encountered or suspected in connection with the injection of waste geothermal fluids: (i) lack of suitable injection sites, (ii) cooling of the produced fluid, (iii) excessive injection pressure, (iv) loss of productivity of steam wells, (v) ground water contamination, (vii) ground heaving, (viii) leakage of the injection fluid to the surface, (ix) adverse impact on the chemistry of the produced fluid, and (x) induced seismic activity. About 20% of the projects have experienced such problems. However, typically no more than one of these problems has affected a single project.

Most of these problems, except for the first one noted above, can be avoided by means of careful siting of injection wells based on exploration, well testing and conceptual modeling of the reservoir, and through proper well design and prudent field operation. Experience has shown that such problems can be mitigated even if they occur unexpectedly. Tracer testing and numerical modeling of the reservoir can help in developing an optimum injection strategy. Cooling due to injection can be fully reversed if mitigation measures are taken promptly; the mitigation plan ideally should be based on a numerical model of the reservoir calibrated against the cooling history. The mitigation plan typically calls for re-completing or relocating production or injection wells.

## 1. INTRODUCTION

An important aspect of geothermal field development and operation is fluid injection. The types of fluids requiring injection in connection with a geothermal project include: unflashed geothermal fluid from the separator, condensate from a steam turbine, heat-depleted water from a binary turbine, cooling tower blowdown, waste drilling fluid, etc.

Underground fluid injection is important to a geothermal project for a number of reasons:

- to avoid any environmental impact due to surface disposal,
- to provide pressure support to the reservoir,
- to scavenge heat from the rock matrix, and
- to avoid any ground subsidence.

In the early days of commercial geothermal development in the United States, indeed as recently as in the mid-1980s, proving production capacity was given the primary priority by the developers. In fact, injection wells were often not drilled until most of the required production capacity was on hand. Little attempt was made towards answering questions fundamental to an "injection strategy", such as, whether the project needed "peripheral" injection or "in-fill" injection or both, how many injection wells would be optimum for the project, where the wells should be sited, how deep the injection level should be, etc. It was a common practice to merely convert disappointing producers to injectors. This lack of serious planning for injection early in the development phase sometimes caused delays in putting power on line or reaching the planned generation level, and in a few extreme cases, necessitated a permanent reduction in the generation level after the power plant has already been constructed.

An important lesson has been learned from these negative experiences: planning for injection should begin as early in the field development stage as possible. Ideally, at least a preliminary injection strategy should be developed as soon as the first few exploration and production wells have been drilled and tested, and a reasonably satisfactory conceptual model of the reservoir has been developed.

Injection underground does not necessarily require injection into the geothermal reservoir from which production is derived. The waste fluid may be injected into an aquifer other than the geothermal reservoir simply to avoid any environmental impact due to surface disposal. In such a case, obviously, reservoir pressure support, heat scavenging or mitigation of ground subsidence cannot be expected; instead, the wellhead injection pressure may become impractically high over time because of injection into an aquifer not subject to depletion. In fact, the injection pressure may become so high as to create seismic activity, ground heaving or leakage of the injection fluid to the surface. Even groundwater contamination is a possibility. Such problems have occurred or been suspected to have occurred in some commercial projects in the United States. Some developers still prefer to inject outside the reservoir from which production is derived in order to eliminate any possibility of cooling the production wells. Moreover, injection in an aquifer shallower than the producing reservoir saves drilling cost.

Injection into the reservoir from which production is derived has all the benefits listed above, but carries with it the risks of potential cooling of the production wells and possible adverse impact on the chemistry of the produced fluid.

Of some 70 commercial geothermal projects developed in the United States to date, all but 2 include injection. About 20% of these projects have encountered problems related to injection. With a few exceptions, no more than one of these problems has affected a single project. In most cases the problems have been solved eventually. The purpose of this paper is to point out the vexing problems associated with injection and their solutions, with examples from a number of commercial geothermal projects in the United States. Because of the proprietary nature of the associated data, names of wells or fields are not given for some examples.

In our experience, the following problems have been either actually encountered or suspected in connection with the injection of waste geothermal fluids:

- lack of suitable injection sites,
- cooling of the produced fluid,
- excessive injection pressure,
- loss of productivity of steam wells,
- ground water contamination,
- ground heaving,
- leakage of the injection fluid to the surface,
- adverse impact on the chemistry of the produced fluid, and
- induced seismic activity.

## 2. LACK OF SUITABLE INJECTION SITES

This problem has become a serious issue in several geothermal projects in the United States that are dependent, for production, on a single fault zone in an otherwise unfractured system. Obviously, production and injection within the same fault zone can cause serious cooling. On the other hand, sufficient injectivity may not be discovered outside the fault zone, because the only commercial flow capacity in such a system occurs within the fault zone. In such systems, the developer has the following choices:

- Injecting in shallow ground water aquifers, if the geothermal fluid is environmentally benign.
- Injecting within the fault zone, but at a level significantly deeper than the production level. The expectation is that the cooler, and hence relatively dense, injected water will not readily move up to the production level until it has heated up.
- Discharging the fluid on the surface, if it is environmentally benign. This has been practiced only at the Amedee geothermal field in California and Wabusca in Nevada (during the first few years of its history).

In a geothermal field in Nevada, locating sufficient flow capacity outside the fault zone from which production was derived proved impossible. Surface disposal was not possible because of the relatively high boron content of the geothermal fluid. Attempts were made to inject in the shallower parts of the fault zone, at a location nearly a kilometer away from the production wells. This proved to be a temporary solution as gradual cooling of the produced fluid started shortly after production/injection started. The developer finally decided to inject within the fault zone several thousand feet below the production level.

Sometimes the lack of injection sites may be related to the constraints of the area dedicated to the project. We have been involved in several projects where suitable injection sites could not be found within the dedicated area, but there were reasons to believe that such sites could be found if the dedicated area could be expanded appropriately.

Sometimes surface constraints (such as topography, location of roads or other surface obstacles to running injection lines, etc.) may prevent the utilization of potentially optimal sites for injection. In at least 2 projects, the presence of a major highway forced injection wells to be located on less than optimal sites.

The lack of suitable injection sites has limited field development in several geothermal projects. In some projects, this problem has been avoided by adopting surface disposal of the waste water. In one such case of surface disposal in the United States, as in the case of the Tiwi field in the Philippines, the reservoir suffered such an excessive pressure drawdown that cool ground water eventually infiltrated into the reservoir and caused a steep decline in the enthalpy of the produced fluid.

## 3. COOLING OF THE PRODUCED FLUID

"Cooling" of the produced fluid implies declining temperature of the produced fluid if it is hot water, or declining enthalpy of the produced fluid if it is a steam/water mixture (even though the temperature of the produced fluid may remain the same). Cooling due to injection appears to be the most common problem actually experienced or feared in the geothermal industry. In general, there are 2 causes for injection-induced cooling:

- unduly close spacing of production and injection wells, and
- "short-circuiting" of the injected fluid to the production wells through a fault or fracture zone even though the spacing between the production and injection wells appears reasonable for a relatively uniform reservoir.

Cooling caused by unduly close proximity of the production and injection wells--on the order of 100 meters--has been experienced in at least 4 geothermal projects in the United States. The closeness of the spacing in such cases typically reflected an overly optimistic development plan. Even without any reservoir modeling, the unduly close spacing of the wells in these cases should have been apparent.

Cooling due to injection has taken place in at least a dozen geothermal projects worldwide mostly for the second reason cited above. The potential short-circuiting has been overlooked by the developer either due to inadequate exploration and well testing, or due to their reliance on an inadequate conceptual model of the system. In several of these systems a properly conducted tracer test program could have alerted the developer to the potential cooling problem.

In a few projects where an injected tracer returned to production wells, particularly when the return took place in a matter of days and a significant cumulative recovery of the tracer was reported, the production fluid showed cooling in a matter of weeks to months.

It should be noted that a tracer test is not a panacea; the mere breakthrough of an injected tracer in a production well does not imply any premature cooling problem. In a project in Nevada, no cooling has been observed in the production wells for over 3 years even though a tracer test had shown tracer breakthrough in production wells in only 5 days. While the tracer return curves at production wells can be matched by relatively simple tracer flow models, the match is usually non-unique. Forecasts of any cooling of the produced fluid based on tracer flow modeling is questionable unless the model is calibrated against the actual cooling history of the wells. Therefore, where no cooling has been observed at the production wells, even though a tracer test has indicated definite communication between the production and injection wells, any quantitative forecast of cooling can be highly non-unique. On the other hand, a lack of tracer returns in production wells during a tracer test conducted over a few weeks or months does not guaranty that the tracer would not return if the test were continued longer. Therefore, a negative result from tracer testing is usually inconclusive.

Fortunately, any cooling due to injection water breakthrough is reversible if the offending injector is shut down, or recompleted in a zone other than the production zone. In a project in Nevada, the produced fluid cooled down by nearly 40°C in a few months, but upon careful modification of the injection strategy, the fluid temperature increased by 20°C in less than a year and recovered nearly completely in about 3 years. In a project in California, where precipitous (over 10°C per year) cooling occurred from the inception of the project, the cooling rate was lowered sharply upon cementing of the upper injection intervals in the injection wells and redirecting injection to levels deeper than the production zones. This stable injection behavior has lasted for nearly 3 years to date with the temperature declining at the rate of 0.5°C to 1°C per year. In another project in California, in spite of many workovers and some make-up well drilling, persistent but gradual cooling at the rate of about 1°C per year has accompanied production since the plant came on line several years ago.

If there is a significant cooling history, a detailed numerical model of the system, calibrated against the cooling history, can be used to forecast recovery of the produced fluid temperature upon relocating injection. We have relied on such modeling to solve the cooling problem in at least 4 fields in California and Nevada.

## 4. EXCESSIVE INJECTION PRESSURE

Several geothermal projects in the United States have been plagued by excessive increases in injection pressure over time. Such increased pressures can be due to one or more of the following causes:

- low flow capacity around the injection well,
- lack of communication between the production and injection wells,
- gradual plugging of the injection wells or pipeline due to scaling or deposition of particulate matter, and
- gradual collapse or full-up of the injection well, particularly if it has not been lined.

The first 2 causes have plagued several projects in Nevada. Plugging or fill-up of injection wells by particulates is a significant problem in the sedimentary, intergranular fields, such as Heber and East Mesa, both in California. Silica scaling has been the cause of a gradual loss of injectivity in many high temperature geothermal fields in the world. Deposition of rock debris or chemical scale in the surface piping has been experienced in several projects. Partial collapse of unlined injection wells has been encountered in some argillite-rich parts of The Geysers field. The Heber geothermal reservoir in California had experienced excessive injection pressure build-up. A 50 MW binary project at Heber was abandoned in part due to this problem; the wellhead injection pressure exceeded 50 bars. An excessive increase in the injection pressure may make the pumping of the injection fluid uneconomic, or operationally infeasible, if the injection pressure exceeds the pressure limit of the surface equipment. In extreme cases, excessive injection pressures may cause inadvertent hydraulic fracturing underground.

Some of the causes of injection pressure buildup are preventable. For example, proper chemical treatment and/or filtering of the injection fluid can prevent scaling and/or plugging of injection wells. The use of finer filters, more frequent changing of filters, and back-flushing and occasional acidizing of injection wells have proven effective in controlling injection pressure build-up in the Imperial Valley fields in California. Accumulation of rock debris or scale can be minimized by sizing the injection lines such that the injection fluid velocity is high enough to prevent the settling of suspended solids. The pipeline can be kept open by routine clearing of the debris by on-line "pigging". These steps have proven valuable in maintaining the injection systems in the Imperial Valley, where production of fine sand and/or scaling tend to reduce injection efficiency with time. Proper design and completion of injection wells can prevent fill-up or collapse. Locating injection wells in low flow capacity areas can be avoided by careful planning based on transient well testing and geologic interpretation. A lack of communication between the production and injection wells can be avoided by siting injection wells based on interference testing and proper conceptual modeling. However, a lack of communication between the production and injection wells has the benefit of reducing the risk of cooling or adverse chemical changes at the production wells.

## 5. LOSS OF PRODUCTIVITY OF STEAM WELLS

Excessive injection into a steam reservoir, or into the "steam cap" of a 2-phase reservoir, has been known to cause a collapse of the steam saturation and consequent sudden loss of productivity of the steam wells. This situation has been experienced in parts of The Geysers in California and Tiwi in the Philippines. In 2-phase reservoirs, this problem can be avoided by injecting primarily in the low-steam saturation parts of the reservoir. In a steam reservoir, the problem can be avoided by distributing the injection as widely as possible throughout the reservoir. Numerical modeling of the reservoir is the only quantitative means of optimizing the injection strategy in such situations.

## 6. GROUNDWATER CONTAMINATION

At least one case of alleged groundwater contamination by the injected geothermal waste fluid has been reported in the United States. Assuming that the waste fluid is injected in the geothermal reservoir and not in the ground water aquifer, such contamination can be caused by either of the following factors:

- upflow of the injected water to the groundwater aquifer through a fault, and
- leakage of the injected fluid behind the casing due to poor cement bond or through the casing damaged due to corrosion or mechanical causes.

The second mechanism mentioned above has been responsible for the cooling of production wells in at least 2 geothermal fields in California. Although the presence of the first mechanism has been suspected in some cases, no convincing proof exists.

The first cause can be avoided by locating injection wells based on careful geologic modeling. The second cause can be eliminated by proper casing design and cementing. The first cause can be mitigated by relocating injection through workover or drilling, and the second cause can be mitigated by proper well workover.

The allegation of groundwater contamination due to geothermal fluid injection referred to earlier proved false. In this case, the communities near the geothermal project site, located in Nevada, had complained that the arsenic level in some local water wells had increased due to geothermal fluid injection.

After a careful study of the historical data base on the chemistry of the water from various water wells over time in the area, the developer was able to convince the local authorities that the relative increase in the arsenic level in groundwater was caused by a long-term chemical cycle, related to the local precipitation and irrigation cycles, and not due to geothermal fluid injection.

## 7. GROUND HEAVING

Ground heaving is possible if too much injection is concentrated over too small an area. Such heaving (up to a few inches) has been noted in a part of the Imperial Valley in California. Normally such small amounts of heaving is not a problem because geothermal project sites are often remote and/or rugged. In the Imperial Valley in California, however, even a few inches of heaving or subsidence of the ground surface can be important because of the extensively cultivated nature of this flat valley lying below the sea level.

The only resolution to the problem is to re-distribute the total amount of injection over a larger area, by either increasing the spacing between the injection wells or increasing the number of injection wells and thereby reducing the injection rate per well.

## 8. LEAKAGE OF INJECTION FLUID TO THE SURFACE

In a few instances of injection in very shallow geothermal reservoirs (a few hundred meters), the injected fluid has found its way to the surface. In one project in Nevada, a marshland resulted from injection in a shallow geothermal system. In another field in Nevada, the injected geothermal fluid re-activated some old hot springs through leakage. Therefore, injection in very shallow geothermal reservoirs must be planned with caution. If this problem occurs, injection should be diverted to a level deeper than the production level as far as possible.

## 9. ADVERSE IMPACT ON THE CHEMISTRY OF THE PRODUCED FLUID

If the injection fluid finds its way back to production wells the chemistry of the produced fluid may be affected adversely in one of several ways:

- the salinity of the produced fluid may increase, because the injection fluid becomes concentrated after the flashing of steam,
- the pH of the fluid or the solubility of various solids in the fluid may change, triggering corrosion or scaling, and
- the gas content in the produced fluid may increase if some of the produced gases are injected along with the water.

At the Coso geothermal field in California, where the produced gases are injected along with the liquid, an increase in the gas content of the produced fluid had caused problems in one part of the field. Scaling and/or corrosion at the production wells due to the breakthrough of the injection fluid has been noted in a few fields, such as The Geysers in California.

## 10. INDUCED SEISMIC ACTIVITY

Prolonged, high pressure injection may induce seismic activity at a geothermal site, particularly if the fluid pressure is increased beyond the original pore pressure and if there are subsurface zones of weakness or active faults near the injection area. While the occurrence of microearthquakes near injection sites have been documented in several geothermal fields, such as The Geysers in California, no major earthquakes due to injection in a geothermal field has yet been reported. It should be noted that a few cases of major earthquakes induced by injection have been reported from the petroleum and waste injection industries. For example, water injection in petroleum reservoirs has caused major earthquakes (over Richter magnitude 6) in Rangely, Colorado. Nuclear waste injection at the Rocky Mountain Arsenal in Colorado has caused magnitude 6+ earthquakes. Therefore, caution should be exercised in conducting geothermal fluid injection at a high pressure. Injection wells should be located away from known active faults, and the injection pressure should not be allowed to exceed the original pore pressure of the system.

## 11. CONCLUDING REMARKS

Nine types of injection related problems have been identified based primarily on the experience from some 70 geothermal projects in the United States. With careful siting of injection wells based on exploration, well testing and conceptual modeling of the reservoir, and with proper well design and prudent field operation, most of these problems can be avoided. Tracer testing and numerical modeling of the reservoir can help in developing an optimum injection strategy.

Such problems, with the possible exception of the lack of injection sites, can be mitigated if they occur unexpectedly. Cooling due to injection, which is the most common problem, can be fully reversed if mitigation measures are taken promptly. The mitigation plan should be based on a numerical model of the reservoir calibrated against the cooling history and the results of a properly designed tracer test.