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INJECTION, INJECTIVITY AND INJECTABILITY IN GEOTHERMAL OPERATIONS

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ABSTRACT

The present reinjection of heat-depleted brine is still hampered by numerous problems. No refined and readily useable technology for reinjection exists. DOE/DGE has undertaken major efforts to solve the reinjection problems. Studies are under way to define and solve the main problems. In this paper, we describe the major reinjection problems and some of the work suggested to find solutions.

INTRODUCTION

Reinjection in geothermal operations is a worldwide problem, more so in the U.S. than in other countries because of the added environmental restrictions. The geothermal industry will never reach its full potential in the U.S. unless the major injection problems are solved. The geothermal reinjection technology is in desperate need of development. No refined and readily useable technology for reinjection seems to exist. The complexity of the injection problems cannot be overemphasized and is not limited to injector-wellbore plugging as frequently assumed.

The U.S. Energy Department, Division of Geothermal Energy realizes these problems and is undertaking major efforts to conduct elaborate theoretical, laboratory and field studies to overcome the presently encountered injection problems. Top priority is given to the problems listed in Table 1.

MAGNITUDE OF INJECTION RATES CAUSES SPECIAL PROBLEMS

One of the main difficulties in evaluating and solving reinjection problems is caused by the huge amounts of liquid to be reinjected. For example, a "small" geothermal power plant of 150 MW may require a reinjection of 1.3×10^8 liter per day. A single geothermal injection well may take liquid on the order of 400,000 liter/hr (60,000 BWD), whereas injection wells in the oil field may have to take only a maximum of 40,000 liter/hr. Table 2 illustrates the magnitude of geothermal reinjection rates. Fairly small individual effects per liter of reinjected geothermal brine can easily grow to gigantic dimensions within a relatively short time due to the cumulative effect. This cumulative effect causes the need for studying even minor phenomena in geothermal reinjection systems. Such an effort is not required in other types of injections, e.g., in oilfield operations. In addition, an injected oilfield brine is relatively cool and thermodynamically stable, whereas the opposite is true for reinjected geothermal brines. The elevated geothermal temperatures and this thermodynamic instability require the careful study of individual effects not found in the oilfield.

SUSPENDED PARTICLES AND THEIR EFFECTS ON INJECTABILITY AND INJECTIVITY

Suspended particles are one of the major reasons for the presently encountered injection problems. They can be categorized by (a) origin, (b) type and/or degree of damaging effects, (c) chemical composition or (d) physical parameters such as size, shape, consistency, etc. Table 3 lists some of the frequently found particles categorized by origin.

Major efforts are undertaken to analyze and remove these particles (or prevent their formation) before the heat-depleted brine is reinjected. Proper methods for instantaneous measurements of particles, their size, size distribution, etc. as functions of thermodynamic and kinetic conditions must be developed. Methods for a constant brine quality control in the field are required. Millipore filter tests as commonly done in oilfields are almost useless and can lead to totally false conclusions. Particles not only fill up or plug wellbores and the sandface, but can also penetrate into the reservoir, thus causing deep penetration damages. Effects of the particles on the permeability of actual core materials should be re-evaluated using newly developed experimental procedures. The data from particle measurements and core flood tests should be used to develop proper correlations between particle and reservoir parameters. These correlations must consider the permeability variations with depth in the wellbore and with distance from the sandface. The goal is to develop mathematical models to explain and document the various correlations.

The use of chemicals to aid the removal of suspended particles should be studied in more detail to obtain the required minimum standards of brine injectability. Adding of additives to various brines should be done in a technically and scientifically correct manner. Previous "shot-gun" approaches are too expensive and time-consuming. These approaches may lead to discarding many potentially useful chemicals because they do not allow the proper study of the complex and critical "concentration-time-composition" correlations.

The use of mechanical clarification processes such as reactor clarifyer and Wemco units should be studied in more detail. Preliminary results in the Niland area were very encouraging. These experiments should be extended to different geographical areas. These new experiments should include the use of chemicals (flocculants) and proper monitoring instrumentation. The monitoring techniques should include instantaneous determinations of all critical particle parameters (size, size distribution, shape, etc.). Special attention should be paid to the quick changes of the particle geometry (caused by the thermodynamic brine instability) and the effects of these changes on injectability and injectivity.

SCALE FORMATION IN INJECTION WELLS

Much of the present scale formation in geothermal injection systems could be avoided by handling the problem with either chemical additives or pressure and temperature manipulations in the field. Dissemination of already available information to the operators is still a problem. Each scale-forming compound acts differently as a function of pressure and temperature changes. Proper modeling of the thermodynamic behavior of each of these classes of chemicals must be done at the earliest possible time to allow the operator to understand his site-specific problems. Present scale models are too complicated and costly to run. They ignore the critical pressure effects and/or lead to false predictions. Preliminary modeling of sulfate scales using a more realistic and complete data base and a more effective and less time-consuming code has shown that the proper modeling can be done. These new thermodynamic models can easily be expanded to the other three classes of scale (carbonates, sulfides and silica).

A more complicated problem is caused by combining a workable scale prediction model with reservoir modeling. This would allow us to predict the effects of scale formation not only for the injection wells but also for the entire reservoir including the production side.

The required scale prevention is not limited to flash cycles as commonly assumed. Binary systems can also exhibit severe scale problems in the injection wells. It is presently assumed that carbonate and sulfate scales can be avoided even under the most severe scaling conditions. More research is required to combat silica scale experienced during the reinjection of brine produced from high temperature reservoirs.

Chemical additives used to prevent the formation of scale and wellbore plugging by suspended particles should be studied. Emphasis should be placed not only on the preventive effects of these additives, but also on the negative side effects of these chemicals. Precise solubility measurements of scale and particle-forming solids must be performed under simulated thermodynamic reservoir conditions.

INJECTION WELL DRILLING AND COMPLETION TECHNOLOGY

Drilling and completing of geothermal injection wells follow the technology established in the oil and gas fields. This practice may have led to some damage of the injection wells in geothermal fields. Geothermal injection wells may require a different drilling and completion technology due to the specific set of conditions typical for this reinjection. The temperature of the injection interval and the water injection rate will be much higher than that of a "typical" injection well in oil and gas fields. The higher temperatures require a definite thermal stability of the drilling and completion fluids. Any decomposition products of these fluids formed by the high temperature effects must not cause formation damage and must be easily removable. Conventially used and newly developed muds should be thoroughly tested as to their damage forming characteristics.

Slotted liners are frequently used in the completion of geothermal injection wells. These liners work well unless stimulation jobs must be performed. In case a well must be stimulated, the liners become a tremendous obstacle for even a well designed and conducted work-over job. The critical placement of the stimulation fluids becomes an impossible task. Newly drilled injection wells should not be completed with slotted liners until the present geothermal injection technology is sufficiently improved. Presently, only cemented and perforated liners should be used.

WELL STIMULATION TECHNIQUES

The techniques used for improving the well injectivity depend upon the type of wellbore or formation damage. Basically, the low injectivity of some wells can have either one of two causes: (a) undamaged wells having an originally low injectivity and/or (b) decreased injectivity due to the formation of wellbore and reservoir damages. The stimulation technique to be used will depend upon whether the well is damaged or not and also upon the size and depth of the injection interval. For example, if the size of the injection interval is on the order of 1000 feet and the damage reaches three feet into the reservoir, chemicals required for a stimulation job may not be affordable. If the brine is reinjected into the producing reservoir, fracturing may not be a valid stimulation method, whereas hydraulic fracturing may offer a viable solution if the brine is injected into an horizon different from that of the producing reservoir.

Various acids (HCl and mixtures of HCl/HF), bases (e.g., NaOH) and chelating agents (EDTA, NTA, etc.) have a good potential for stimulation of injectors if scale or suspended particles have caused wellbore damage. The thermodynamics and kinetics of the dissolution reactions with the various stimulation fluids should be reevaluated even though an extensive number of literature references are available. Recent field experience has shown that the thermodynamics and kinetics of the dissolution reactions at the high temperatures are more complicated than described in the literature. Lab studies of this problem are suggested. Field studies on the stimulation of injection wells are also planned. The lab data (see above) should be applied to design a limited number of injector stimulation jobs.

Of high interest are also the effects of various stimulation fluids on naturally low permeability (reservoir rock components) and damaging materials formed during drilling and completing the wells. The spent fluids after each stimulation job should be produced back and analyzed for their precise chemical composition to evaluate all downhole reactions and the effectiveness of all additives used in the jobs. This includes the efficiency of all stimulation fluids used for removing the wellbore damage as well as the effectiveness of the corrosion inhibitors used.

RESERVOIR PRESSURE MAINTENANCE AND EFFECTIVE SWEEP EFFICIENCY MUST BE EVALUATED

Geothermal reinjection may require injection of the heat-depleted brine back into the producing reservoir for at least three different reasons: (a) to maintain the formation pressure (b) to improve the recoverable heat reserves by applying a sweep and (c) to prevent subsidence. Even if all the heat-depleted brine is reinjected into the producing reservoir, there may still develop a liquid deficiency in the reservoir after some producing time. This liquid deficiency is mainly caused by the water losses during the cooling process. To avoid all sweep and subsidence problems, these losses should be made up through supplementary water injection, i.e., through imported water. This means, optimum heat-mining and, at the same time, prevention of subsidence should be attempted by importing injection water to the field.

The large disadvantage of this method of importing injection waters would be the problems generated by chemical compatibility problems. The chemical compatibility problems can also be caused by reinjection of produced water into the identical reservoir from which it originally came. Thermodynamic conditions during production can drastically change the composition of the produced water. Preliminary lab and field studies have shown that even extreme compatibility problems may be handled in an economically and technically feasible way. However, this method, its pros and cons, should be studied more carefully to avoid future reservoir and production problems in various geothermal areas.

Methods and preliminary models of the chemical compatibility problems are already available. Comparatively small efforts are required to "debug" the present models and extend them to a wider range of applicability. The major problem is to combine the new chemical models with more conventional reservoir models. This combination is feasible and should be attempted immediately.

NEED FOR NEW TRACER TECHNOLOGY IS STRONGLY INDICATED

If water is injected into the producing reservoir, a new tracer technology must be developed to monitor the unpredictable advance of a cool temperature front from the injectors toward the producer before severe temperature damage occurs in the producing reservoir of wells. Conventional reservoir engineering through rate, pressure and/or temperature test work and analysis is not sufficient for the required surveillance and reservoir verification due to the uncertainties regarding the reservoir heterogeneities. Conventional reservoir engineering should be supplemented by this tracer technology. Every new injection project in the field should involve these tracers from the start of brine reinjection. Using the tracer techniques as a prewarning system will allow the operators to stop reinjection and to take proper steps to redesign his injection system before irreparable damage occurs.

Tracers suitable for the high temperatures in geothermal reservoirs are limited to a small number. Tritium in the form of tritiated water seems to be the most suitable tracer. However, additional tracers must be found to evaluate the wide range of reservoir problems. All potential tracers must be evaluated in laboratory studies for their suitability in geothermal reservoirs. The high temperature behavior of tracers, particularly their hydrothermal stability and adsorption isotherms, must be determined in great detail. These hydrothermal and adsorption/desorption characteristics of potential tracers must be studied in the laboratory prior to field applications.

Tracer chromatography methods should be evaluated for geothermal reservoir applications. This new method will allow an optimized reservoir management. This may turn out to be of utmost importance for the most economical exploitation of our sometimes marginal reservoirs.

Sophisticated and field oriented mathematical modeling of the observed tracer effluent profiles is also required. Preliminary studies have indicated that this goal can be achieved within a fairly short time. This modeling cannot be performed without conducting a laboratory study on the adsorption/desorption characteristics of all suggested tracers.

TABLE 1

TOP PRIORITY PROBLEMS FOR GEOTHERMAL REINJECTION

1) SUSPENDED PARTICLES

   A) EFFECTS ON BRINE INJECTIBILITY
   B) EFFECTS ON WELLBORE AND RESERVOIR INJECTIVITY

2) SCALE FORMATION

3) INJECTION WELL DRILLING AND COMPLETION TECHNOLOGY

4) WELL STIMULATION TECHNIQUES

   A) FOR DAMAGED WELLS (ORIGINALLY HIGH INJECTIVITY)
   B) FOR UNDAMAGED WELLS (ORIGINALLY LOW INJECTIVITY)

5) NEW TRACER TECHNOLOGY TO VERIFY RESERVOIR PRESSURE MAINTENANCE AND EFFECTIVE HEAT SWEEP EFFICIENCY

TABLE 2

FLOW RATES OF SUSPENDED AND DISSOLVED SOLIDS

	APPROXIMATELY METRIC TONS (PER YEAR)	POUNDS (PER DAY)
1) MISSISSIPPI RIVER	1.13×10^8	6.82×10^8
2) 1,000 MWE* (GEOTHERMAL)	9.77×10^7	6.15×10^8
3) 3,000 MWE** (GEOTHERMAL); PROJECTED FOR 1985	2.93×10^8	1.85×10^9
4) 20,000 MWE** PROJECTED FOR 2000	1.95×10^9	1.23×10^{10}

* ASSUMING: 1.86×10^9 LITERS OF BRINE PER DAY; 150,000 MG/L TDS

** ASSUMING: DOE/DGE ESTIMATION IN 1977

TABLE 3

SUSPENDED PARTICLES IN GEOTHERMAL BRINES (CATEGORIZED BY ORIGIN)

1) PARTICLES CAUSED BY THERMODYNAMIC INSTABILITY OF BRINE; PRECIPITATIONS DUE TO TEMPERATURE AND PRESSURE DROPS (E.G., SILICA, SILICATES, CARBONATES)

2) PARTICLES NATIVE TO PRODUCING RESERVOIR AND DISLODGED BY THERMAL AND/OR MECHANICAL STRESSES (E.G. SAND, CLAY)

3) PARTICLES CAUSED BY MIXING OF INCOMPATIBLE WATERS (E.G., SULFATES, CARBONATES)

4) PARTICLES FORMED BY ADDITION OF CHEMICAL ADDITIVES (E.G., PHOSPHONATES, POLYACRYLATES, CaF_2)

5) PARTICLES GENERATED THROUGH CORROSION (E.G., IRON SULFIDES AND IRON HYDROXIDES)

6) PARTICLES CAUSED BY OXYGEN CONTAMINATION (E.G., IRON HYDROXY-OXIDES, ELEMENTAL SULFUR)

7) PARTICLES FORMED THROUGH BACTERIAL ACTIONS (E.G., SLIMES)

8) PARTICLES DUE TO LACK OF CLEANLINESS (E.G., DIRT, MUD)

9) PARTICLES CAUSED BY IMPROPER DRILLING AND COMPLETION OF PRODUCING AND INJECTION WELLS (E.G., MUD FINES, FORMATION CUTTINGS, DECOMPOSITION PRODUCTS OF DRILLING AND COMPLETION FLUIDS)