A Feasibility Study of the Potential Benefits of Low-Rate Water Injection In Superheated Steam Production Wells

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Keywords

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ABSTRACT

This paper investigates the technical feasibility of improving the productivity of superheated steam production wells by low-rate water injection downhole. A combined numerical simulation model of the reservoir and wellbore was developed to analyze the physical and thermodynamic processes associated with such downhole injection. The model consisted of a geometrically-increasing radial grid with 12 horizontal layers, the vertical stack of the central gridblocks representing the wellbore. The model was calibrated against the temperature and pressure profiles from two flowing wells at The Geysers steam field in California. The modeling of low-rate downhole injection (through a tubing) so far indicates that up to a third of a megawatt (MW) of additional power can be easily gained by injection at 7,500 feet (ft) in a superheated steam well. Of this additional steam, about half results from de-superheating of steam and the rest from extraction of heat from the formation surrounding the wellbore. In addition to increasing the power capacity, downhole injection allows neutralization of acidic steam through the addition of caustic soda to the injection water, scrubbing of chloride, and dilution of the non-condensable gases in the produced steam.

Field testing of low-rate water injection downhole was conducted using capillary tubing. The preliminary results indicate that heat was extracted from the formation. However, long-term tests are required to verify this process. To successfully conduct a long-term field tests, a new design of the downhole spray assembly is needed to prevent plugging of check valves due to scale buildup .

Introduction

In portions of The Geysers steam field in California, Calpine Corporation has been injecting "scrub water" (a solution of caustic soda in water) into the produced steam just downstream of the wellhead (*i.e.*, in the surface piping at the scrubwater spool) for corrosion control and "de-superheating." Downstream of the scrub water spool is a moisture separator, where chloride and other undesirable water-soluble species as well (as the moisture) are removed from the steam. The process prevents operational problems usually associated with superheated steam further downstream, such as corrosion and silica scaling in pipelines and power plant components.

The potential benefits of downhole injection are:

- An increase in steam flow rate (and therefore in electric power generation) as the result of more complete and efficient de-superheating of steam by downhole injection rather than by surface scrubbing.
- A decrease in specific enthalpy of the downhole steam, leading to heat transfer from the reservoir rock and/or reduced heat loss from the wellbore to the formation, thereby also increasing the net output of the well.
- Improved acid neutralization and scrubbing of chloride and dilution of the non-condensable gases (NCG). By injecting the caustic solution downhole, the casing can be protected from chloride attack. The injected condensate, which will be nearly NCG-free, will reduce the concentration of NCG in the steam by dilution.

The most important objective of this continuing study is to investigate whether the performance of a superheated steam production well can be enhanced economically by injecting water downhole through a tubing string, to determine the requirements of the process and to determine the optimum operating parameters.

Modeling Approach

It is clear that the location and rate of downhole water injection must be carefully controlled to avoid "watering out" the production well; that is, initiating two-phase "slug flow" or "plug flow," which would result in a sharp decrease in steam produc-

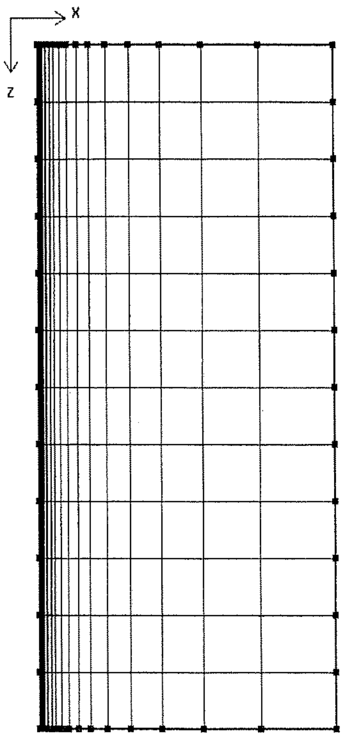

Figure 1. Radial grid system used in the reservoir-wellbore model.

tion and would require the installation of a separator to remove the unflashed water. To analyze the fluid flow and heat transfer associated with downhole injection in a steam production well, a combined finite-difference numerical model of the reservoir and wellbore was developed.

This numerical model consists of a stack (12 layers) of horizontal concentric radial elements as shown in Figure 1. The upper 4 layers (which cover the interval of 0 to 4,000 ft depth) represent the cap rock, and the remaining 8 layers represent the reservoir down to a depth of 12,000 ft. In the radial direction, the block lengths increase geometrically (1.00 ft, 1.35 ft, 1.82 ft, 2.46 ft, 3.32 ft, ···) out to a radius of about one mile (5,176 ft). The wellbore is represented by the innermost radial elements in the top 8 layers. Heat transfer from the reservoir elements to the wellbore elements is allowed in each layer, but fluid flow in the radial direction is only allowed in the bottom 3 wellbore elements, which represent the open interval in the well.

At very low injection rates, the injected water will flash to steam. As the injection rate is increased, there is a point at which the excess available heat in the well (both steam superheat and wellbore heat) is used up and the flow becomes two-phase. Increasing the injection rate above this point results in steam quenching. Thus, the heat recovery can be optimized only within a narrow range of injection rates.

To theoretically optimize the injection rate and depth before attempting field trial, a source of water was introduced into the element(s) in the model that represented the open section of the wellbore in the reservoir-wellbore model. This method of introducing water into the model did not take into account the heating of the injection water as it flows down the tubing by the steam flowing up the wellbore. This simplification does not alter the overall heat balance but will have a minor effect on the temperature gradient in the wellbore. A trial-and-error process was then utilized, in which the depth and flow rate of the injected water were varied, and the enthalpy and flow rate at the top most wellbore element were monitored until the maximum rate of single-phase steam production was achieved at the wellhead.

Numerical Testing of Feasibility

Two wells at The Geysers field were selected as candidates for field-testing of the feasibility of downhole injection for improving well productivity. The first well, 68G-21, is in the Calistoga well field, and the second well, DV-13, is in the Socrates well field. 68G-21 is a multi-leg well and is about 2250 ft deeper than DV-13, which is a single-leg well.

Using the numerical reservoir-wellbore model, a flowing pressure and temperature (PTS) survey of well 68G-21 was matched by trial-and-error as shown in Figure 2. Overall, the

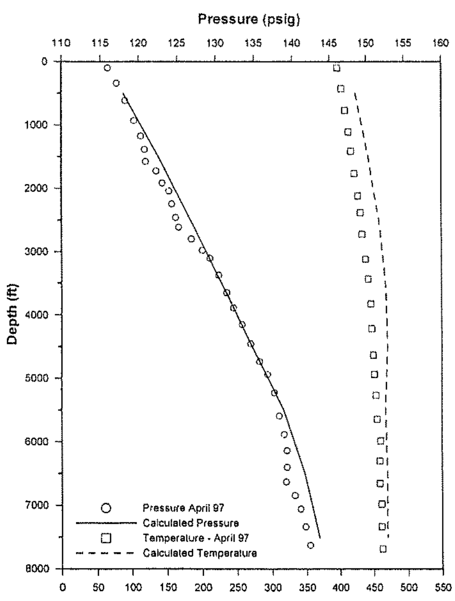

Figure 2. Match to flowing pressure and temperature survey, Well 68G-21.

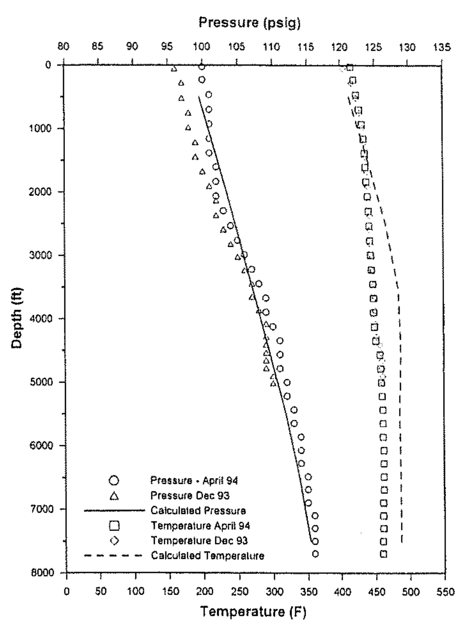

Figure 3. Match to flowing pressure and temperature survey, Well DV-13.

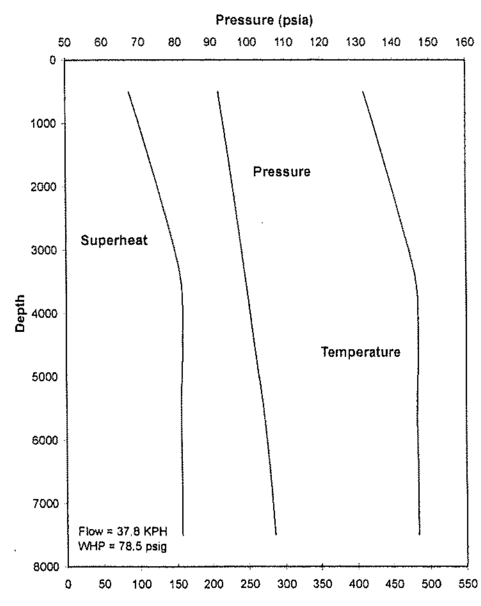

Figure 4. Calculated flowing profiles (adjusted to DV-13's average Dec 2000-May 2001 wellhead conditions).

model closely matches the observed downhole flowing pressures and temperatures. One minor difference is that observed temperatures above the depth of 4,800 ft are lower than the calculated temperatures. This is probably due to a higher rate of heat transfer from the wellbore in the cap rock and near-surface regions.

Data from two flowing pressure and temperature surveys in well DV-13 were also matched using this model as shown in Figure 3. Overall, the model matches the downhole flowing pressures; however, the observed downhole temperatures are about 20 degrees Fahrenheit lower than the temperatures calculated by the model. This result indicates that the formation temperatures in the DV-13 area maybe slightly below the values used in this generalized reservoir-wellbore model.

Since the purpose of the field test is to demonstrate the effectiveness and to fine-tune the methodology of downhole injection in production wells, well DV-13, which has a simpler completion, was deemed more suitable for the first field test. The model was therefore revised to more closely represent the current flowing conditions of well DV-13. Using this revised model, downhole flowing pressure, temperature, and superheat values were recalculated as shown in Figure 4.

The model was then used to calculate the reduction in steam enthalpy as a result of downhole injection of water. Modeling results after 30 days of injection at rates up to 5,000 pounds per hour (10 gallons per minute) and at various injection depths are shown in Figure 5. The model indicated that as the injection rate was increased, the enthalpy of the steam at the wellhead was reduced. Once the enthalpy dropped below the value for saturated steam, a two-phase (wet steam) system developed. Injecting water at rates exceeding those required to obtain saturated steam at the wellhead resulted in quenching of some of the steam. In practice, dropping the enthalpy below the saturation point is sometimes desirable since the liquid phase "washes" some of impurities from the superheated steam.

The modeling results indicated that slightly more than 5,200 pounds per hour of additional steam (equivalent to about a third of a MW) can be obtained by injecting water at a depth of 7,500 ft in well DV-13. Of this additional steam, 2,750 pounds per hour (that is, slightly more than half) resulted from de-superheating, as shown by the results for near-surface injection (at a depth of 500 ft). Therefore, the additional steam flow resulting from extraction of heat from the surrounding formation was 2,450 pounds per hour.

Shallower injection resulted in less heat extraction and less additional steam, as shown in Figure 5. However, the modeling results for injection at 4,500 ft are more similar to the results for injection at 7,500 ft than expected. Apparently, a large portion of the extracted heat in the modeling runs came from the upper portion of the reservoir and the lower portion of the cap rock. This is encouraging because shallower injection would reduce the cost of equipment installation and maintenance.

Downhole flowing conditions predicted by the model for injection rates of 4,000 and 5,000 pounds per hour at a depth of 7,500 ft are shown in Figure 6. By lowering the downhole flowing temperature, a temperature gradient between the wellbore and the formation is created, resulting in the flow of heat from the higher-temperature formation into the cooler wellbore. A plot of the formation temperature at 3,500 ft versus radial distance from the wellbore, is shown in Figure 7, for the case of injecting 5,000 pounds per hour at 7,500 ft for 30, 300, and 3,000 days. A similar plot of temperature verses radial distance at 7,500 ft is shown in Figure 8. These results support the conclusion stated earlier, that a large portion of the extracted heat in the modeling runs is coming from the upper portion of the reservoir and the lower portion of the cap rock.

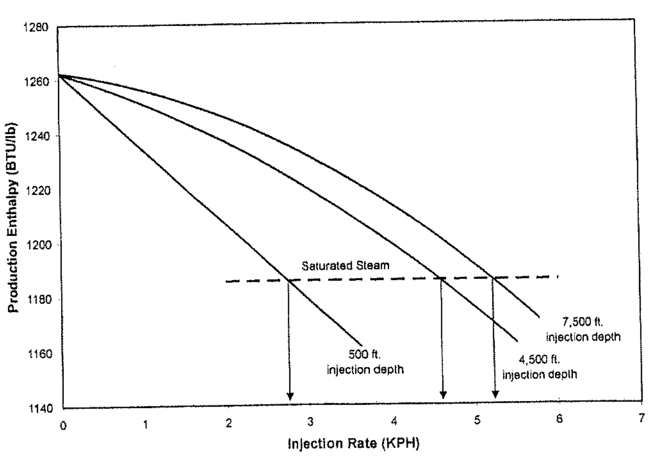

Figure 5. Injection rate and projected wellhead enthalpy.

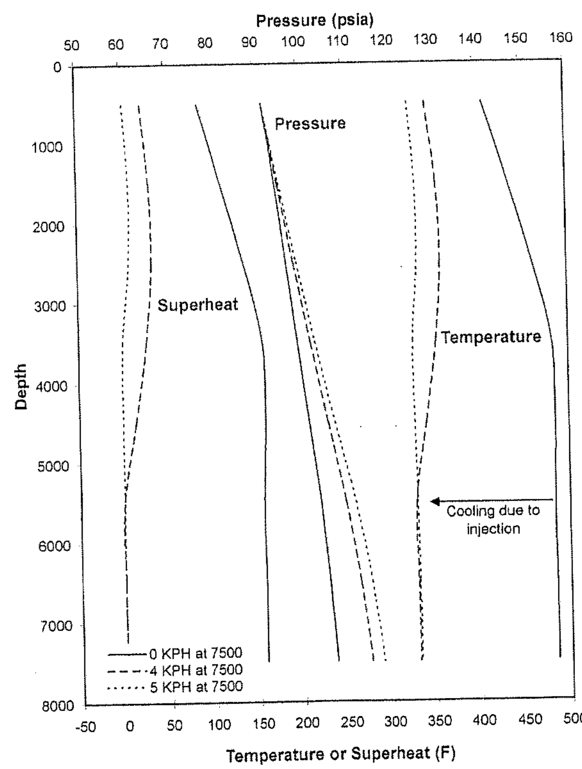

Figure 6. Calculated flowing profiles (injection into DV-13 at 7,500′ after 30 days.

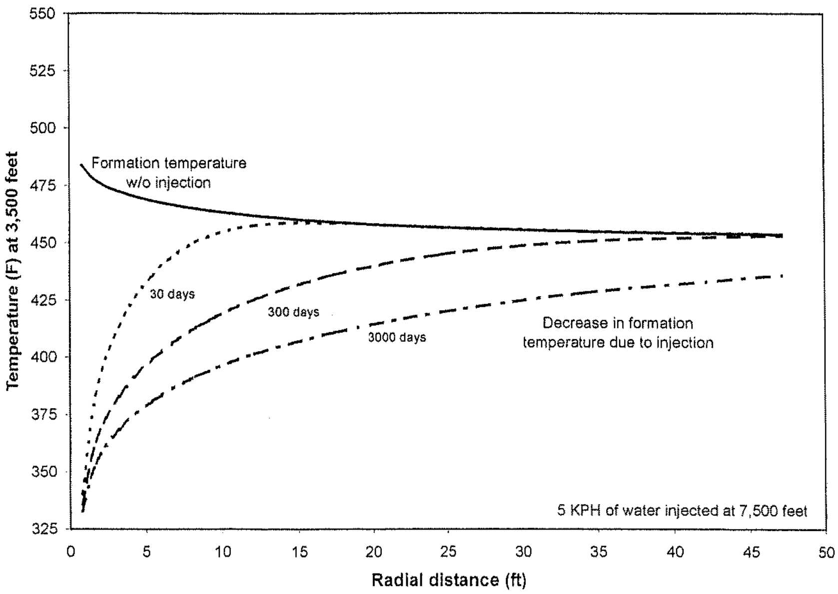

Figure 7. Heat recovery from the formation at 3,500 ft.

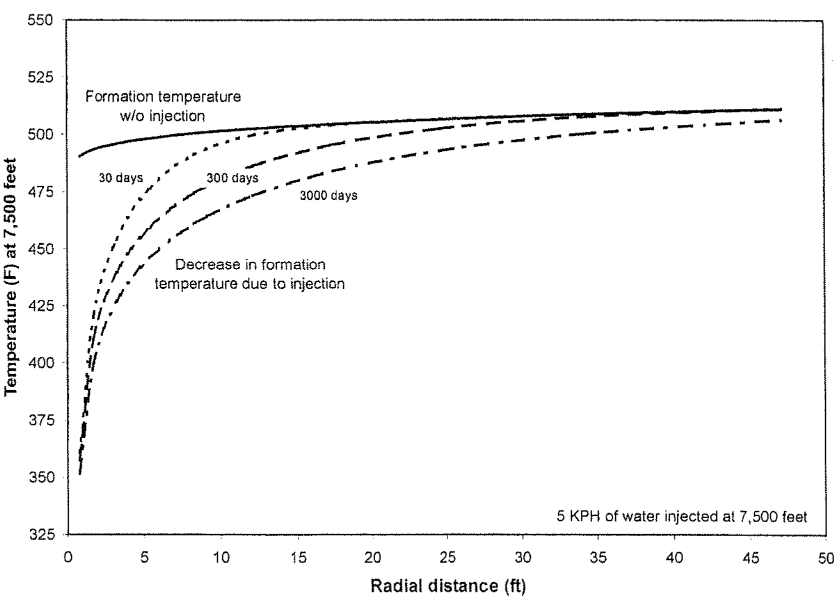

Figure 8. Heat recovery from the formation at 7,500 ft.

Field Testing of Feasibility

To verify the numerical modeling results, a field test of low-rate injection into well DV-13 was conducted using coiled tubing. A total of three attempts were made at a depth of 8,000 ft. The first attempt on November 8, 2001, was not successful in installing the coiled tubing at 8,000 ft because the seals in check valves failed, and steam appeared at the coiled tubing reel. Limited data collected during this first attempt showed that at least 75% of the injected water was converted into steam due to de-superheating of steam and heat transfer from rocks at an injection rate of 4 to 5 gallons per minute.

The second attempt to install coiled tubing was made on February 6, 2002, using seals and packing materials rated for high temperature. This attempt failed because the check valves plugged due to scale buildup. New coiled tubing and a centralizer with larger inside diameter were used in the third attempt on March 6, 2002. The downhole check valves plugged again, though the amount of scale was significantly smaller than in the second attempt. The chemical analysis of the scale suggested it to be magnetite. The scaling appeared to be related to corrosion of the coiled tubing, since the amount of iron in the injection water was less than 0.5 ppm.

Conclusions

Numerical modeling has shown that improving the productivity of superheated steam production wells by low-rate water injection downhole is technically feasible. For well DV-13, which is a typical well at The Geysers field, modeling indicated that slightly more than 5,200 pounds per hour of additional steam (equivalent to about a third of a MW) could be obtained by injecting water at a depth of 7,500 ft. Of this additional steam, slightly more than half resulted from de-superheating of steam and the rest from heat transfer from the surrounding formation.

Data collected during field-testing at well DV-13 confirmed the concept that additional heat can be recovered by low-rate injection. Further testing, in which injection rates can be controlled and the resulting steam enthalpies accurately measured, is needed to confirm long-term viability of such injection. To successfully conduct a long-term test, a new design of the downhole spray assembly is required, to prevent plugging of check valves due to scale buildup.

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