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DEVELOPMENT OF INJECTION CAPACITY FOR THE EXPANSION OF THE RIBEIRA GRANDE GEOTHERMAL PROJECT, SÃO MIGUEL, AÇORES, PORTUGAL

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ABSTRACT

This is a case history of injection capacity development for a 6.6 MW plant expansion at the Ribeira Grande geothermal field, where a 5 MW plant has operated since 1994. Of the four production wells available for the expanded power plant, one (CL-4) was unneeded and not used because of low productivity, so a 55 day injection and tracer test was conducted at this well. Injectivity of the well CL-4 increased steadily during the test, reaching 2.5 times the injectivity estimated at the start. The well can easily accept all of the wastewater from the expanded plant without pumping. Flowing temperature and pressure profiles and pressure fall-off behavior were recorded to further define well characteristics and hydrologic properties of the reservoir. A fluorescein dye tracer test at CL-4 showed no returns at the production wells, providing reassurance that injection into CL-4 would not adversely affect them. Silica saturation ratios under expected operating conditions indicate that the use of well CL-4 as an injector is unlikely to cause significant scaling in injection lines or in the well. Therefore, CL-4 has been dedicated as the injector for the plant expansion.

1. INTRODUCTION

The Sociedade Geotermica dos Açores, S.A. (SOGEO) operates the Ribeira Grande and Pico Vermelho geothermal power plants, both located at the Lagoa do Fogo (Agua de Pau) volcano in the central part of the island of São Miguel, Azores, Portugal (Figure 1). The two plants are supplied by separate wellfields that exploit different areas within a single extensive geothermal system on the northern slope of the volcano. Figure 2 is a schematic cross-section of the field in the NW-SE direction.

Exploration and development of the lower (northern) part of the field, where the Pico Vermelho plant is located, took place during the late 1970s and early 1980s, after a research core hole drilled in 1973 found temperatures above 200°C. Five deep wells (RG-1, RG-2, PV-1, PV-2 and SB-1) were drilled during 1978-1981, and the 3 MW Pico Vermelho plant began operation in 1981. Well damage and scaling problems left PV-1 as the only well available for use by the plant, and as a result the plant output has typically not exceeded 0.7 MW. Since 1990, the plant has operated with a high degree of availability at an average output of 0.5 to 0.6 MW. Mechanical removel and, more recently, chemical inhibition, have been used to manage calcite scaling in well PV-1.

During the late 1980s, exploration of the southern part of the field (higher elevations on the volcano) was undertaken in an effort to identify a geothermal resource of higher temperature and lower scaling potential. Well CL-1 was drilled in 1988-89 and wells CL-2, CL-3 and CL-4 during 1992-94. The production from these wells was more than sufficient to supply Phase A of the Ribeira Grande power plant (5 MW net) located in the upper part of the field. Constructed in 1993-94, this plant consists of two binary-cycle Ormat Energy Converters. Wells CL-1 and CL-2 serve as production wells for the plant, and residual fluids are discharged at the surface. The Ribeira Grande power plant has operated continuously at approximately 4.8 MW (net) since March 1994. All production wells are prone to calcite scaling, which is prevented by downhole injection of a scale inhibitor.

Phase B (6.6 MW) was installed at Ribeira Grande in 1997, bringing the total capacity of the plant to approximately 11.6 MW (net). Well CL-3 and the excess capacities of wells CL-1 and CL-2 are used to supply this facility. CL-4 has also been used intermittently; however, following the assessment described below, this well has been converted to injection and a new production well is being drilled to replace it.

2. AVAILABLE INJECTION OPTIONS

Before Phase B was completed, its total production requirement was available from wells CL-1, -2 and -3. Well CL-4 could produce another 1.6 MW; however, this well was unstable when produced near its maximum output and showed a large flowing pressure drawdown, making scale inhibition in the wellbore difficult. Therefore, it was not practical to produce routinely from well CL-4; this well could either be kept as a stand-by well or used as an injector. Because SOGEO planned to inject the Phase B wastewater, the availability of sites for a new injection well, the use for injection of non-commercial wells near the Pico Vermelho plant, and the possibility of injecting into well CL-4 were all investigated.

3. INJECTION AND TRACER TEST OF WELL CL-4

3.1 Test Sequence

Beginning on 16 January 1998, wastewater from the power plant was injected continuously into CL-4, which is downhill from the plant and accepts fluid without pumping. During the first week, injection rate steps of about 30, 60 and 147 t/hr were conducted to assess the well's response. Thereafter, the injection rate was maintained at 147-148 t/hr for about 6-1/2 weeks. Two more rate steps, each about 2 weeks long, were then conducted at injection rates of approximately 153 t/hr and 60-65 t/hr, before the well was shut in on 31 March 1998. Downhole pressure at 800 m was measured periodically while injecting, and a number of downhole temperature/pressure profiles were measured before and during the test. Pressure falloff in CL-4 was recorded after injection was stopped.

3.2 Injectivity Test of Well CL-4

The rate of injection into CL-4 was measured at approximately 2 hour intervals throughout the test. The histories of injection rate and wellhead pressure are shown on Figure 3. The depth of 800 m was selected for downhole pressure monitoring because it is an intermediate level between the several deduced permeable zones in the well; however, it does not coincide with any single major injection zone. As a result, measured downhole pressures were affected by changes in the density of the water in the wellbore during the first few days of the test, before thermal equilibration of the wellbore was reached (Figure 4). Thermal effects undoubtedly contribute to the apparent data scatter in the first few days of the test, and to a steep pressure decline during the second (60 t/hr) test step. Downhole temperature profiles measured before and during the test indicate that thermal equilibration of the well-bore was essentially complete by about January 20.

During the first rate steps (Figure 3), an initial rapid increase in measured downhole pressure was observed after each increase of injection rate, followed by a more gradual decrease (Figure 4). As noted, the pressure decrease during the first one or two steps may have been due to thermal effects; however, the pressure decrease later in the test was clearly due to a steady improvement of injectivity. Downhole pressures stabilized on or about 5 February 1998, after about 20 total days of injection and after 16 days of injection at the highest (147 t/hr) rate. After this point in the test, the injectivity of CL-4 probably did not change substantially over time. Because of the problem of thermal effects, the injectivity of CL-4 could not be estimated quantitatively using the data from the initial injection steps. The last several steps, however, were not affected significantly by thermal changes and so can be used to calculate an injectivity index, as discussed below.

The downhole temperature profiles measured in CL-4 while injecting show that the entire wellbore was cooled by the injected water, to the maximum depth that can be reached with downhole tools (about 1,140 m). Therefore, some, if not most, of the injected water exited the wellbore below 1,140 m, and it is likely that there are multiple injection zones in the well. Sequential pressure profiles confirm that the injectivity of the well improved over time during the course of the test. After 4 February 1998, there was no significant change in downhole pressures while injecting at a constant rate.

A complete downhole temperature/pressure profile was measured in CL-4 on 1 April 1998, one day after injection was stopped, and a partial profile was measured the following day. These profiles show that little heat-up took place in the deeper part of the well (below 900 m) during the first two days after shut-in, but rapid heating occurred within 24 hours at shallower depths, particularly in the interval from 500 to 700 m. This is consistent with previous observations in CL-4, which indicate the presence of a steam or two-phase zone in the upper part of the production interval. The steam zone heats up much more rapidly than liquid-dominated zones after injection of water, and the long-term injection carried out during the present test does not appear to have affected this behavior. The rapid heat-up, coupled with a buildup of gas pressure in the wellbore soon after shut-in, caused the well to flow briefly before injection could be re-initiated after the pressure fall-off measurement.

Wellhead pressure and temperature at CL-4 were monitored throughout the test (Figure 3). Beginning early in the second (60 t/hr) rate step, CL-4 developed a slight vacuum at the wellhead, which was maintained until injection was stopped on 31 March 1998. At no time did the well fill to the surface while injecting. This is consistent with the results of the measured downhole pressure profiles. Wellhead temperatures showed some fluctuation between 80 and 94°C during the first two weeks of the test, but then stabilized in the range of 92-95°C until the injection rate was decreased significantly on 20 March 1998.

Prior to shut-in for the pressure falloff test, the injection rate was approximately 61 t/hr. After shut-in, the pressure at 800 m dropped from 40.3 kscg to 34.3 kscg, indicating an injectivity index of 10.2 t/hr/ksc, or 2.98 l/s/bar. This injectivity is 2.5 times higher than was estimated for CL-4 from earlier testing in 1996. Such an improvement in injectivity upon prolonged injection is probably caused by a combination of fracture clean out and extension of micro-fractures that accompanies the injection of cool water into a hot formation.

Fluorescein dye (90 kg) was added to the injection stream on 23 January 1998. The produced fluids in wells CL-1, CL-2, CL-3 and PV-1 were then sampled daily for two weeks and at intervals of about four days thereafter. There was no detectable return of tracer at CL-3 before the well was shut in on 25 February (34 days after tracer injection), and no return at the other wells through 30 March (66 days after tracer injection; Figure 5). All measurements were below the detection limit of 0.1 ppb, except for a very small level of background contamination in all samples measured during the first day of the test (when the tracer was injected); this is discounted as tracer return because it affected all wells equally and it disappeared with clean-up and re-calibration. Similarly, samples from all four wells showed equivalent effects of subsequent minor instrument drift below the detection limit and of re-calibration (*e.g.*, on January 24-25, February 5-6 and March 16). The samples from well CL-2 always have a slightly higher background than the other wells (see Figure 5), which is a result of the systematic analytical procedures being used. The observed analytical results are consistent with an absence of any detectable returns of tracer dye in the production wells. To be sure that no longer-term breakthrough occurred, periodic sampling of the production wells continued through late May 1998; no tracer was detected.

3.3 Pressure Falloff Test of Well CL-4

Figure 6 is a log-log plot of the normalized (un-smoothed) pressure falloff data collected at the end of the injection period. The early data points define a 1/2-slope line, which indicates that the flow to the well is controlled by a fracture that intersects it. We have also matched, by trial-and-error, the smoothed falloff pressure data with calculated pressure (Figure 7). The calculation includes fluid flow in the reservoir, as well as the effects of wellbore storage and skin factor. A good match was achieved with a permeability-thickness product (kh) of 4,500 millidarcy-meters (md-m) and a skin factor of -1.2. The kh value is within the range of kh previously determined for the field. The negative skin factor indicates that the wellbore is currently in a stimulated condition, which is consistent with the observation that the injectivity of the well has improved during the course of injection.

3.4 Analysis of Silica Scaling Potential

The potential for injection scaling relates primarily to formation of amorphous silica which, under certain conditions, can form in injection pipelines and/or injection wells. A general scenario for this is illustrated by Figure 8, which shows the solubilities of quartz and amorphous silica as mg/kg (or ppm-wt) SiO_2, plotted with respect to the liquid saturation enthalpy of water in Joules/gm. Corresponding saturation temperatures and pressures are shown at the top of the figure. The illustrated scenario is conservative, because it does not include reservoir steam which dilutes the SiO_2 in total flow.

The SiO_2 content of produced water is estimated by assuming reservoir saturation by quartz at the static downhole temperature of the main production zone(s). Quartz saturation is commonly observed in high-temperature geothermal systems throughout the world. We estimate SiO_2 by this method because we do not have recent chemical analyses from the wells. Averages of samples collected during 1994 and 1995 indicate that SiO_2 at CL-1 is about 500 mg/kg, and SiO_2 at CL-2 is about 560 mg/kg (it is our understanding that these samples were collected after steam loss to atmospheric pressure, but this is not certain in all cases). These SiO_2 concentrations suggest that figure 8 accurately represents well CL-1, but underestimates the SiO_2 at CL-2 by about 10%. SiO_2 in the combined flow from all three wells is illustrated by a weighted average of 400 mg/kg. The uncertainty of this average is about ±5%.

We have assumed that the water and steam at each well are separated at 5 bar-a, because the separation pressure at CL-1 is currently about 4.8 bar-a, and the separation pressure at CL-2 is currently about 5.2 bar-a. At 5 bar-a, the combined water flow from all three wells will contain about 490 mg/kg of SiO_2. This would become saturated with amorphous silica if cooled to about 127°C. However, the hot brine is mixed with condensate upstream of the pre-heater, so the brine alone will not be cooled to this temperature.

When the separated water is re-combined with steam condensate, the combined flow represented in Figure 8 carries a maximum of 400 mg/kg (very slightly higher than the original total-flow concentration, because a small amount of steam is lost with the ejected non-condensible gases). In reality, because all three wells produce some reservoir steam, there will be excess condensate, and the SiO_2 concentration in the injection water will be lower than 400 mg/kg. The Phase B plant design specifications indicate a combined water flow of 317 t/h from CL-1, CL-2 and CL-3, and a combined steam flow of 87 t/h. This means that water with 490 mg/kg SiO_2 will be diluted to 384 mg/kg, or about 4% less than 400 mg/kg. Data for CL-1 and CL-2, combined with recent test results for CL-3 (85 t/h at 1400 J/g), also indicate that excess steam should dilute the SiO_2 by about 5%.

The 400 mg/kg level of SiO_2 will not saturate with amorphous silica until it is cooled to about 109°C, and water with about 380 mg/kg will not saturate until cooled to about 105°C. At the design temperature of 95°C, the 400 mg/kg flow will be oversaturated by about 60 mg/kg (Saturation Index 1.18), and 380 mg/kg flow will be oversaturated by about 40 mg/kg (Saturation Index 1.12). These levels of oversaturation will be reduced if the fluid pH is relatively high. For example, if pH(100°C) is 7.6, the solubility of amorphous silica is increased by about 5%; if pH(100°C) is 8.0, the solubility increases by about 10%. Data to calculate the expected pH are not available, but waters separated from steam at CL-1 and CL-2 tend to have a relatively high pH (above 7.5).

Experience with silica deposition in experimental and real-world settings has shown that these levels of saturation and temperature do not, generally, result in any significant level of scale deposition. It is probable that little scale will be found in 95°C injection lines and wells, even after several years. There are conditions under which slightly oversaturated water deposits silica as a result of nucleation on calcite scale particles, but this should be prevented by the calcite scale inhibition already being used. There are other conditions under which slightly oversaturated water deposits alumino-silicate scale, when pH is particularly high. This kind of scale is difficult to predict, but alumino-silicate scale is usually soft and easily removed by mechanical clean-out.

A secondary, indirect potential for scaling that is associated with injection relates to calcite. The inhibitor that prevents calcite scale in the production wells is still present in solution in the injected water. Although we do not know the long-term thermal stability of the inhibitor, it probably decomposes over time, and, since the scale-inhibited water still contains calcium but is stripped of gases, it has a higher pH than original reservoir water. When the scale-inhibited water is re-heated in the reservoir after injection, there is some potential for calcite deposition in the formation. This is a theoretical possibility that is very unlikely to have a measurable effect on the injection well(s), production wells, or the reservoir. We are not aware of any reservoir at which calcite inhibitor has had any impact of this kind that has been detected.

4. DISCUSSION AND CONCLUSIONS

The injection test of CL-4 provided important information about the injectivity of the well at high injection rates over an extended period of time. Injection rates up to about 160 t/hr were sustained for a period of more than 10 weeks, without filling the wellbore to the surface. The injectivity improved over time during the first several weeks; thereafter, well behavior was stable as injection continued. Stabilized data from the latter part of the test indicate that the injectivity of CL-4 is approximately 10.2 t/hr/ksc (10.4 t/hr/bar). This implies that the total injection rate could be increased to at least 400 t/hr before the wellbore is filled to the surface, based on the water level of about 300 m observed while injecting at a rate of 150-155 t/hr. Furthermore, because the elevation of CL-4 is low with respect to the power plant, the wellhead pressure while injecting could be increased by several bars without the use of an injection pump, thereby allowing the well to accept a still higher rate. From the above analysis, we conclude that well CL-4 is easily capable of accepting the 270 t/hr wastewater from the Phase B power plant.

The absence of observed tracer breakthrough in the production wells provides a strong indication that routine injection into CL-4 will not cause an enthalpy decline in any of the production wells over the short term (up to several years). Although a test of this duration cannot guarantee that thermal breakthrough will not occur during the lifetime of the power plant, we do not consider that the use of CL-4 as an injector poses a significant near-term risk.

Silica scale deposition is unlikely in either the injection lines or injection wells. It is not possible to totally discount all possibility of scale deposition, but the impact of such scale, if it forms, is not likely to exceed the impact of long-term routine maintenance of the injection lines and wells.

5. ACKNOWLEDGEMENTS

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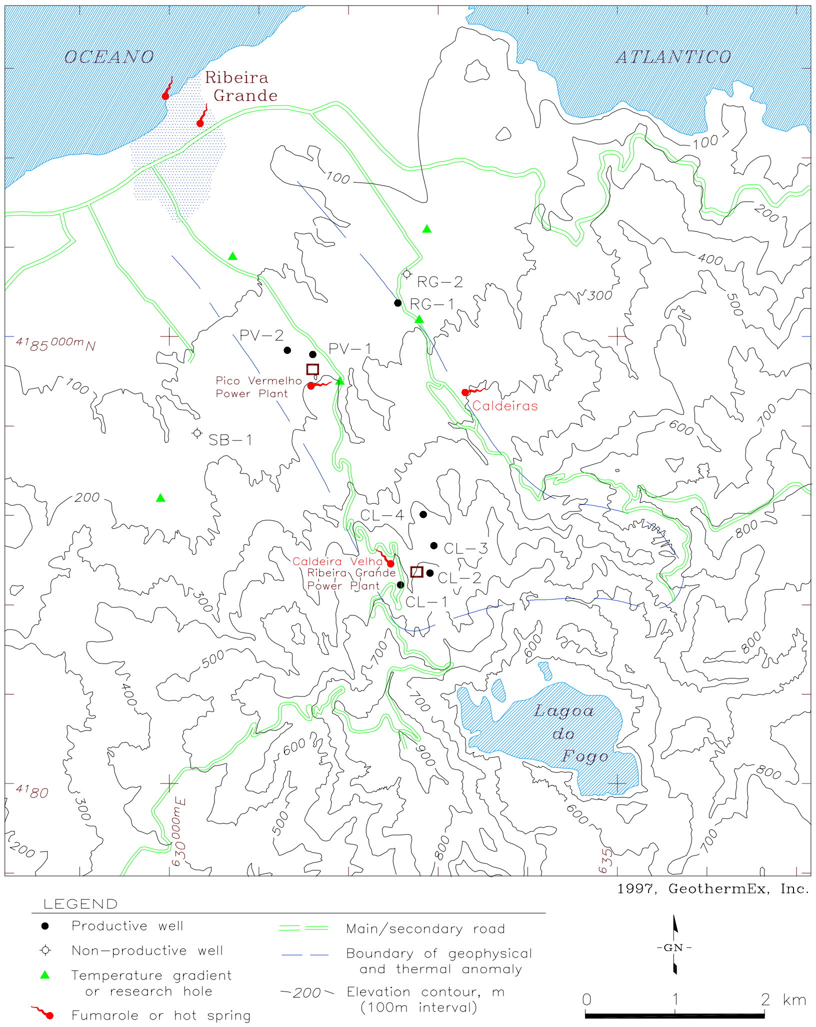

Figure 1. Map of geothermal field, Fogo volcano

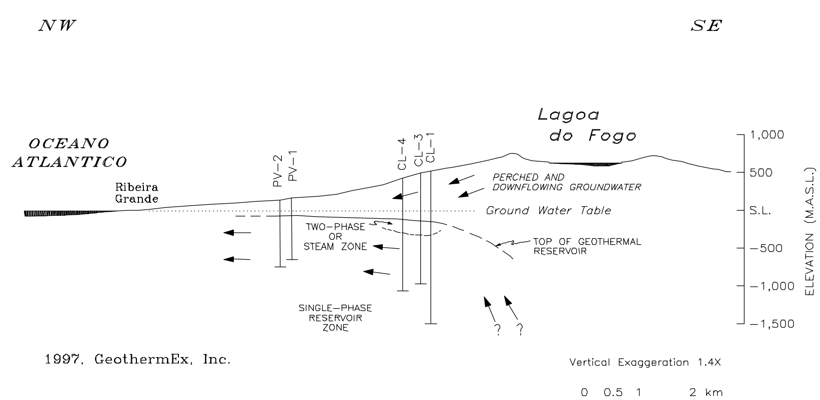

Figure 2. Schematic cross-section of the Fogo geothermal system

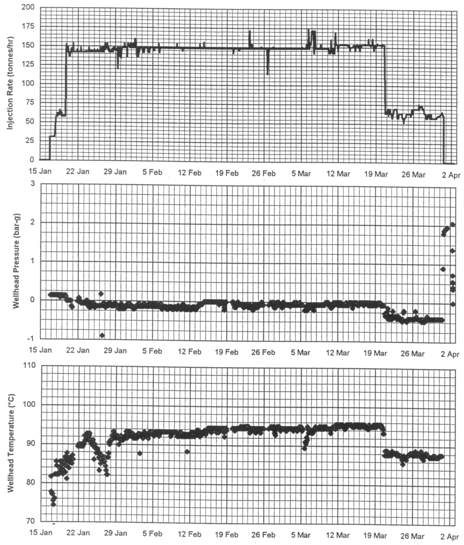

Figure 3. Wellhead pressure and temperature during injection, well CL-4

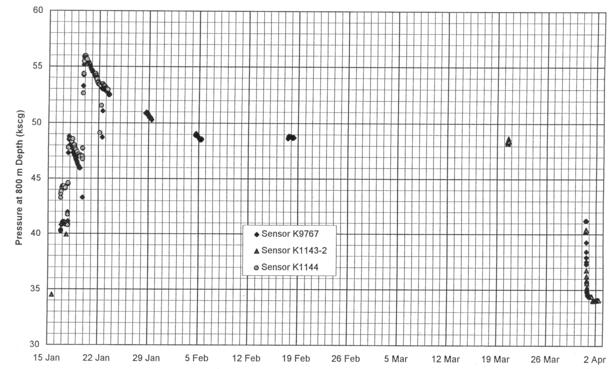

Figure 4. Downhole pressure monitoring, well CL-4

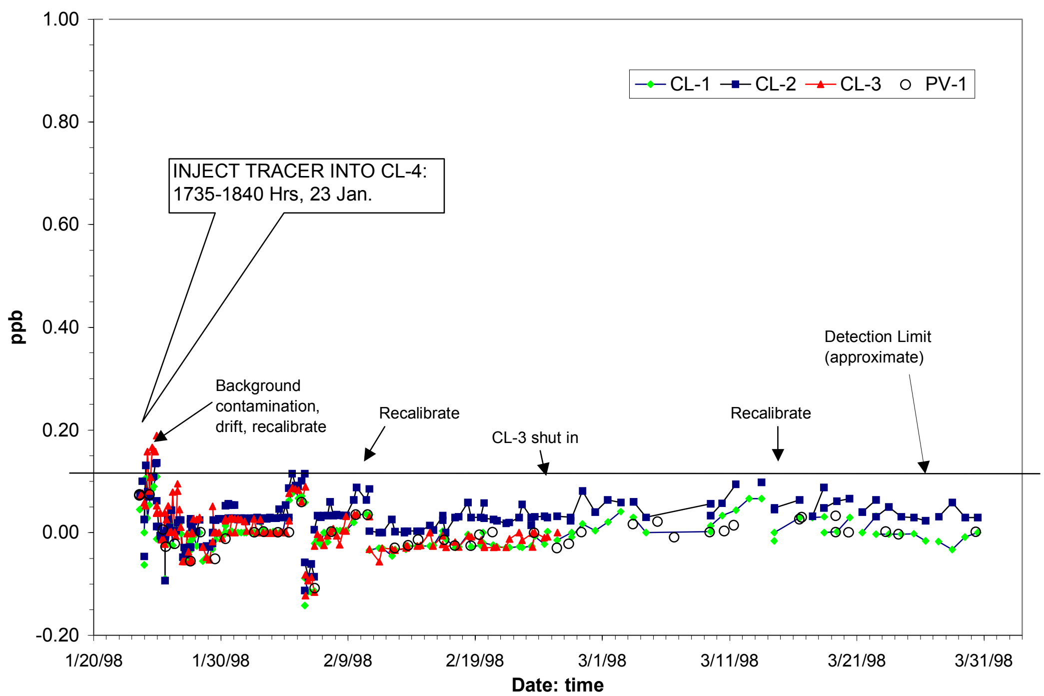

Figure 5. Fluorescein in production waters

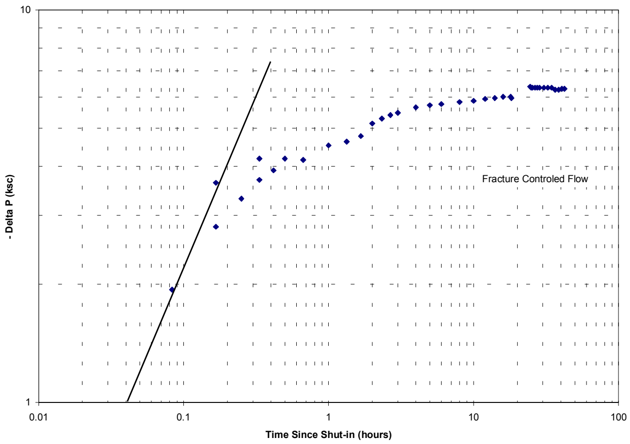

Figure 6. Pressure fall-off test, well CL-4

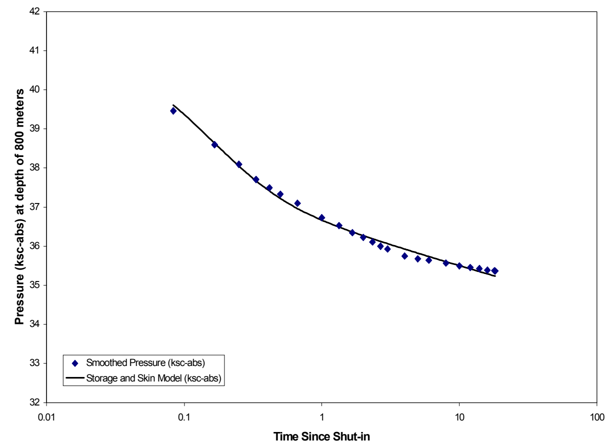

Figure 7. Matching pressure fall-off test, well CL-4

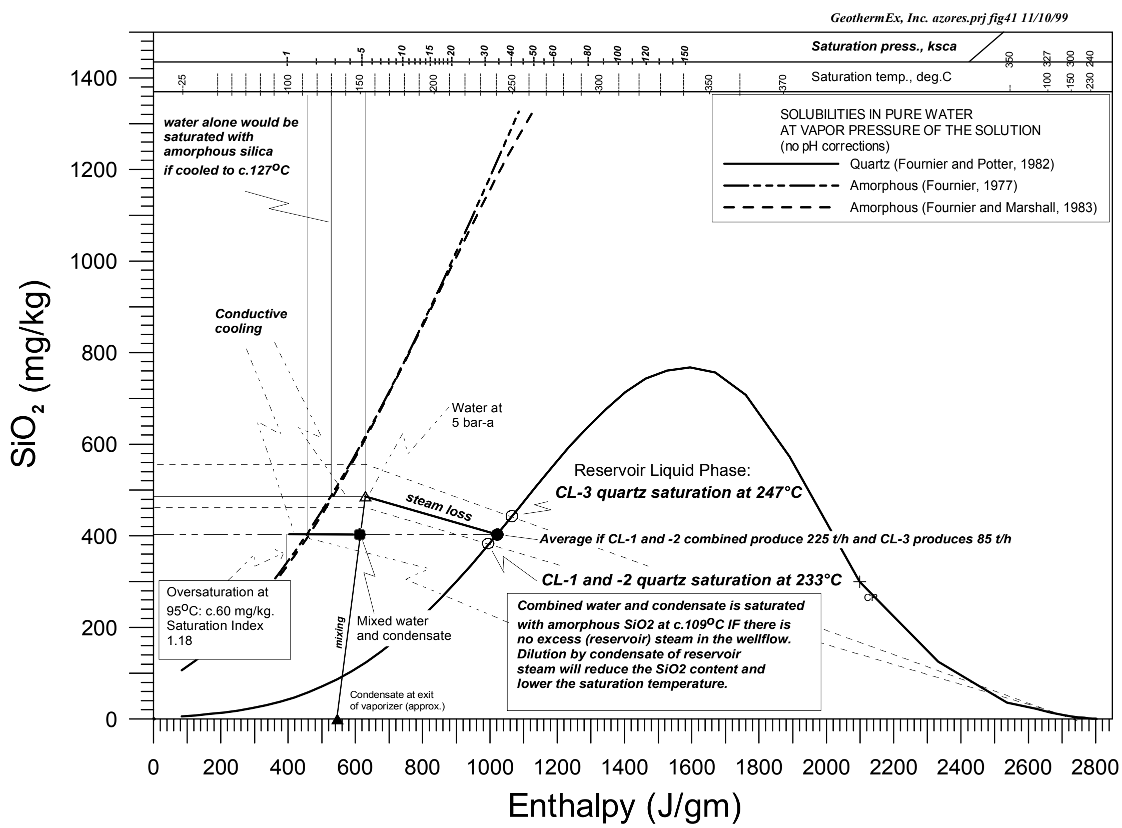

Figure 8. Dissolved silica vs. enthalpy