



On-site erosion–corrosion testing in superheated geothermal steam



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ABSTRACT

Erosion and erosion–corrosion of stainless steel, carbon steel and ceramic lined carbon steel are investigated in a superheated geothermal steam at a high velocity (98–118 m/s) and at a lower velocity (48 m/s) for comparison. Erosion–corrosion caused the high velocity carbon steel test pipe to leak after only 14 days. Furthermore, evidence of erosion is seen in all pipe bends. Interestingly, cracks and pits were formed in the N08028 and S32707 stainless steels, but not in the S31254 stainless steel. The dry superheated steam is supersaturated with silica causing the test unit to clog after only 24 days of testing.

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1. Introduction

Materials in high temperature geothermal wells and equipment connected to them can be subjected to corrosion and erosion due to the high temperature and the chemical composition of the geothermal steam. Geothermal steam contains corrosive agents such as dissolved carbon dioxide (CO₂), hydrogen sulfide (H₂S), hydrogen (H₂), ammonium (NH₃) gases, and sulfate and chloride ions (Bridges and Hobbs, 1987; Conover et al., 1980; Banás et al., 2007). The source of the chloride ions (Cl⁻) can be salt brine in geothermal areas close to the ocean or volatile chloride transported as hydrogen chloride (HCl) gas from the volcanic system (Eliasson and Einarsson, 1982; Viviani et al., 1995). If HCl gas exists in the system there is an increased danger of corrosion because a localized enrichment of hydrochloric acid can occur due to condensation and/or re-boiling which can cause severe corrosion of the materials in the system (Eliasson and Einarsson, 1982; Viviani et al., 1995). Corrosion in geothermal equipment and wells is also dependent on operational factors such as the pressure, flow rate and the pH level of the geothermal fluid. There can be a significant variation of these

parameters between geothermal systems and even within the same geothermal system (Karlsdottir, 2012). Furthermore, geothermal steam contains dissolved minerals that can precipitate from the liquid and deposit onto the surface of equipment and in geothermal well casings. This is called scaling and it occurs due to a change in temperature, pressure or pH value of the geothermal fluid disturbing the equilibrium of the system (Ocampo-Díaz et al., 2005; Thorhallsson, 2005; Pátzay et al., 2003). When scaling occurs in geothermal equipment and well casings, it can create major problems in the geothermal power production. The scaling can result in clogging of the wells and the geothermal equipment, inhibiting production and incurring expensive cleaning costs as well as causing erosion of equipment such as the steam turbines (Corsi, 1986; Gallup, 2009; Mazur et al., 2009; Gunnarsson and Arnorsson, 2005). Unfortunately, at some fields both scaling and corrosion problems are encountered at the same time which results in high costs associated with maintenance, materials and production efficiency of wells.

In recent years there has been increased interest in exploring the deep roots of geothermal systems by drilling deeper to find out whether it is economically feasible to extract energy and chemicals from hydrothermal systems at supercritical conditions (Fridleifsson et al., 2010a,b). On this basis the Icelandic Deep Drilling Project (IDDP) was formed in the year 2000 as a

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geothermal exploration and technology development program. The first well was called IDDP-1 and was drilled in 2008–2009 in Iceland. One of the objectives of the IDDP group is to determine whether utilization of heat from geothermal resource at supercritical conditions would lead to increased productivity of wells at a competitive cost. The flow test of IDDP-1 began in March 2010 and the well was found to be capable of steam flow rate of 50 kg/s which corresponds to at least 30 MW of electricity (Markusson, 2012). For high temperature geothermal wells the power output is commonly on the order of 3–4 MW per well. Thus there is considerable gain involved if the steam can be utilized.

The geothermal steam from the IDDP-1 well is superheated with a temperature of 450 °C and a pressure of about 140 bar at the well-head. The superheated steam contains acid gases (HCl and HF) and is thus highly corrosive when it condenses. Due to a number of problems in the flow tests in 2010 and 2011, including mechanical issues and decrease in the wall thickness of the pipe bends, the well was put in a restricted flow mode in 2011 with an 8–12 kg/s superheated steam flow. When the decrease in wall thickness of the pipe bends was detected the velocity of the steam flow was measured to be 85 m/s. The rate of reduction in the wall thickness seemed to level off with time during the first 50 days of operation when the steam was heating up. The temperature in that period was below 320 °C. Then the temperature rose rather sharply above 320 °C and the rate of reduction in the wall thickness simultaneously increased again.

Erosion or erosion–corrosion in steel pipes is generally not considered a problem in clean dry steam. On the other hand, if the steam is wet or if it contains solid particles erosion or erosion–corrosion may become a problem at high flow rates and temperatures (Rajahram et al., 2009; Bala et al., 2011; Hou et al., 2004). The rate of erosion–corrosion of API J-55 low carbon steel in wet geothermal steam at 70–100 m/s was found to increase sharply if the pH of the geothermal brine fell below about 4.5 showing the importance of the corrosive conditions in the erosion–corrosion process (Sanada et al., 2000). The initial decrease in the wall thickness of the pipe in the IDDP-1 steam (below 320 °C) was considered to be due to combined effect of erosion and corrosion due to solid particles in the steam and acid liquid droplets formed while the well was being heated up. The second rise, on the other hand, was not clear. Thus to investigate this further and as a part of a pilot plant study for exploring the possibilities of utilizing the IDDP-1 steam, an erosion–corrosion experiment was started in 2012 at the IDDP-1 site, which is the topic of this paper.

2. The IDDP-1 well

2.1. The IDDP-1 well construction

The IDDP-1 project started in 2008 with the aim of drilling a 4.5 km deep geothermal well in the Krafla area in north-east Iceland. It was supposed to be completed late summer of 2009 but was terminated unexpectedly in June 2009 at 2.1 km depth when the drill penetrated molten rock. This became evident when quenched magma (glass) was found when the drill was pulled out and inspected at the surface. The glass plugged the lowest 20 m of the hole but fortunately the well had been cased down to 1958 m depth and thus could be completed at that point with a slotted liner (perforated steel pipe) down to 2080 m depth (Fridleifsson et al., 2010a,b).

2.2. IDDP-1 steam composition

The chemical composition of the geothermal steam from IDDP-1 has been analyzed (Armansson, 2014; Hauksson et al., 2014). In a sample, taken before the erosion–corrosion test was conducted, the

CO₂ was 732 mg/kg and the H₂S 339 mg/kg which is relatively small compared to the other geothermal wells in the area. For example a well nearby has a 14,270 mg/kg of CO₂ and 2327 mg/kg of H₂S in the steam. The concentration of H₂ was also relatively low at 10 mg/kg in the steam. The concentration of Cl⁻ was 93 mg/kg and F⁻ 5.0 mg/kg, which is a high concentration for geothermal steam. The HCl and HF gases in the steam make the condensate acidic with low pH level ranging from of 2.6 to 3.5 (Armansson, 2014; Hauksson et al., 2014). The presence of HCl and HF in the IDDP-1 steam is regarded to originate from magmatic gases in the geothermal system (Armansson, 2010). Concentration of other mineral constituents was low, apart from iron (Fe) with concentration of 8.4 mg/kg most likely resulting from corrosion of the casings in the well during heating up. Boron (B) concentration was measured to be 1.0 mg/kg and NH₃ concentration was only 0.14 mg/kg (Hauksson et al., 2014). Because of the low concentration of NH₃ it does not have much influence on the acidic properties of the steam unlike in the case of the Geysers geothermal field in USA where the concentration of NH₃ is in excess of the chloride concentration (Hirtz et al., 1991). The IDDP-1 steam was reported by Hauksson et al. (2014) to contain both silica (SiO₂) dust and dissolved silica which was effectively washed from the steam with wet scrubbing. The condensate analyzed after wet scrubbing contained 94 mg/l of suspended matter which was analyzed with SEM and XEDS as solid elemental sulfur (S) and SiO₂ particles. The origin of S was not determined by Hauksson et al. (2014) but they stated that it must have been in gaseous form in the saturated steam and sparingly soluble in water and possibly in the form of disulfide (HS₂H) or polysulfide (HS_nH) gas. The sulfides could not be identified in the steam in the wet scrubbing experiment and more research was claimed to be needed to explain the occurrence and characteristics of S in the IDDP-1 steam (Hauksson et al., 2014).

3. Experimental procedures

3.1. Experimental setup for on-site erosion–corrosion testing

The erosion–corrosion testing was done at the Krafla high temperature geothermal field in north-east Iceland where the IDDP-1 well is located. Fig. 1(a) shows the experimental setup for the erosion–corrosion test. It was decided to perform the test with straight pipes and bends that were arranged in a loop so they were connected in series, as can be seen from Figs. 1 and 2. Three types of stainless steel pipes, one type of a carbon steel pipe and a ceramic lined carbon steel pipe were tested. The inner diameter of the pipes ranged from 26.6 mm to 27.9 mm to give a steam velocity of 99–118 m/s. One additional carbon steel pipe was included with an inner diameter of 38.1 mm for a steam velocity of 48 m/s for comparison. Initially, it was planned to use steam taken directly from the wellhead for the erosion–corrosion test. But the pressure at the wellhead had risen from the originally planned 90 bar to about 140 bar which was considered too high for the test unit. Therefore, the steam pressure was reduced and the test was performed at 13–14 bar. The temperature at the inlet of the test unit was between 320 and 350 °C. The unit was not insulated but the steam was still superheated at the exit. This can be seen from Fig. 1(b) where the steam coming from the outlet pipe is transparent, i.e. superheated. When the steam mixes with the atmosphere it cools down and becomes white. The testing time was 24 days for all the pipes, except for the carbon steel pipe at a higher velocity (109 m/s) that started to leak after 14 days of testing. Table 1 summarizes the chemical composition of the IDDP-1 steam, i.e. the environment that the materials were tested in Hauksson et al. (2014).

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