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Surface analysis of metal alloys exposed to geothermal fluids with high non-condensable gas content

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ABSTRACT

Nine types of carbon steels and corrosion resistant alloys (CRA) were exposed to high enthalpy geothermal fluid with high non-condensable gas content (NCG). Surface evaluation showed that Carbon steel sustained relatively high corrosion rates (> 0.15 mm/y). Scales completely covered the surface of most of the other coupons and consisted of 33–35 μm thick micro-crystalline iron sulfides outer layer and iron oxides, sulfides and silica inner layer. CRA's were immune to uniform corrosion. However, the duplex stainless steel 2205, Alloy 825 and Alloy 59 suffered crevice corrosion. Thin (~4 μm) scales were observed in most of the CRA's with high concentration of chromium and nickel.

1. Introduction

Geothermal fluids containing high concentration of non-condensable gas (NCG) have been encountered in many geothermal fields worldwide (Kaya and Zarrouk, 2017). The deep reservoir of Kizildere geothermal field, Turkey (Haizlip and Tut, 2011; Haizlip et al., 2012) Ngawha, Broadlands-Ohaaki and Kawerau geothermal fields, New Zealand (McKibbin and Pruess, 1988; Lichti and Julian, 2005) Aidlin geothermal project in The Geysers (Klein and Chase, 1995) and Bagnore geothermal field in Italy (McKibbin and Pruess, 1988; Kaya and Zarrouk, 2017) are a few examples. The NCG content for these high gas fields ranges from 2.5% to 5.4% (by weight) but may in rare locations spikes from 10% to 80% (McKibbin and Pruess, 1988; Haizlip and Tut, 2011). Normally, the constraint with high gas geothermal fluids used for power generation is in energy conversion efficiency (Tajima and Nomura, 1982; Zarrouk and Moon, 2014; Kaya and Zarrouk, 2017) rather than corrosion. High gas content also requires the installation of complex gas extraction systems at high cost. Alternatively, a binary plant may be used to avoid the requirement for gas extraction as at the Ngawha field (New Zealand).

Corrosion of carbon and stainless steels caused by high NCG geothermal fluids has been studied in the Broadlands-Ohaaki field, New Zealand (Braithwaite and Lichti, 1980). The estimated NCG level of the geothermal fluids in this field is about 2.1% by weight (Lichti and Wilson, 1999). Anticipating that other fields within New Zealand may yield geothermal fluids with much higher gas content, a corrosion study was conducted by Lichti and Julian (2005) wherein they simulated a geothermal fluid with high-NCG of about 25% (by weight) for the mixing test of fluids from wells BR3 and BR22 in Broadlands-Ohaaki. Results from this test showed that among the materials exposed to the high NCG content at a temperature of 160 °C, carbon steel (AISI 1018) did experience substantial pitting but the pits were shallow. These pits produced low corrosion rates as calculated using the mass-loss coupon exposure method. Low-alloy steel (4140), grey cast iron and Ni-resist Type 1 cast iron experienced pitting mainly in the crevices formed by PTFE insulating spacers. Results of the 25% NCG corrosion test using corrosion coupons and Corrosometer™ probes indicate an acceptable corrosion rate between 51.9–67.2 μm/y for carbon steel exposed to the high gas two-phase fluid at 185 °C for 5.7 weeks. It was also reported that stainless steel 316 exposed to the same condition produced negligible corrosion rates in terms of mass-loss. However, pitting rate equivalent to < A1 based on ASTM G46—2005 was observed for this stainless steel. Pyrrhotite ($Fe_{1+x}S$) and mackinawite ($FeS_{(1-x)}$) together with silica were observed as corrosion products adhering to the surface of both carbon steel and stainless steel.

NGC's are a natural part of the geothermal fluid it is composed mainly of carbon dioxide (CO_2) and hydrogen sulfide (H_2S). Other gases such as ammonia, methane, hydrogen, nitrogen, and argon contribute but rarely exceed 10% in the dry gas composition (Wood, 1973). Geothermal fluids are normally oxygen-free (Wood, 1973; Shannon, 1977). Carbon dioxide and hydrogen sulfide constitute about 90% of the total dry gas component (Marshall and Braithwaite, 1973).

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Fig. 1. Photo of the back-pressure orifice plate installed at well XH-01. The orifice plate is 10.16 cm (4 in.) in diameter. Right photo shows the enlarged view of the damage near the drain orifice.

Fig. 2. CL900 RTJ Flange (left) where the corrosion rack (right) was installed.

Table 1
Steam condensate composition from well XH-01.

DATE (d/m/y)	WHP (barg)	h (kJ/kg)	MF (t/h)	SPP (bar g)	TA (°C)	pH	Cl mg/L	SO_4 mg/L	HCO_3 mg/L	NH_3 mg/L
4/08/2014	73.8	2745	2 (est.)	0.2	21	5.97	0.04	1.5	766	no analysis

Table 2
Gas composition (mmol/100 mol H_2O) of steam sample collected from well XH-01 collected from the pipeline.

Date	Sample Type	WHP (bar)	h (kJ/kg)	MF (t/h)	SPP (bar)	CO_2	H_2S	NH_3	H_2	CH_4	N_2
4/08/2014	Web. separated steam	73.8	2745	2.0 (est.)	0.2	5481	271	21	191	181	31

Experience in the oil and gas industry shows that these two gases are corrosive to carbon steel and other metals and alloys used in well bore and pipeline construction (CO_2 corrosion causes metal dissolution and tubing perforation while H_2S corrosion causes sudden cracking of tubing and casings in high H_2S gas fields (Crolet, 1983). CO_2 corrosion of steels is much localized, and appear in the form of pits, gutters, or damaged areas of various sizes. Localized corrosion occurs with a much higher penetration rate of several millimetres per year (Carlson, 1948). Zarrouk (2004) reported CO_2 corrosion causing external casing corrosion (ECC) damage in a number of wells within the TVZ. Normally, apart from the affected areas, the dissolution rate of the metal is not substantial. The transition from an affected to an unaffected area is most often very abrupt (Greenwell, 1952).

Cracking of steel and other alloys in the presence of H_2S can be divided into two distinct problems: (1) sulfide stress cracking (SSC) which occurs at all temperatures and concerns the upper parts of oil and