EXTERNAL CASING CORROSION IN NEW ZEALAND'S GEOTHERMAL FIELDS

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SUMMARY – Literature on external casing corrosion (ECC) in oil, gas and geothermal fields is reviewed. ECC in geothermal systems can be related to CO_2-rich or acid-sulphate waters. Several cases of ECC due to CO_2-rich fluid have been reported in geothermal fields within the Taupo Volcanic Zone (TVZ), including: Brodlands-Ohaaki, Rotokawa, Tauhara and Mokai. The main factors controlling the rate of ECC due to CO_2-rich fluid are the CO_2 content and the shallow horizontal permeability of the field. It is anticipated that in-field reinjection of mixed brine and condensates may aggravate casing corrosion by pushing CO_2-rich fluid towards casings. Solutions are given for the prevention and mitigating of ECC.

1. INTRODUCTION

External casing corrosion (ECC) can severely damage production wells that would require expensive repairs, drilling of replacement wells and substantial decrease in power generation.

ECC is common in oil and gas wells and has been reported in many fields world wide (Gordon et al., 1984; Crolet and Bonis, 1986; Rahman, 1989; Talabani et al., 2000). Gordon et al. (1984) found that there are two causes for ECC in oil and gas wells. In the upper 60 m of wells ECC is mainly caused by oxidation enhanced by the high chloride, sulphate and salt (e.g. *NaCl*) concentrations of the ground waters. Below 60 m ECC is associated with CO_2-rich (carbonic acid) solutions. Poor cementing jobs are often the main causes for ECC in oil and gas wells (Gordon et al. 1984; Talabani et al., 2000).

In andesitic geothermal systems, such as in the Philippines and some Indonesian geothermal systems like Karaha-Telaga (Moore et al, 2002), most cases of ECC are caused by acid-sulphate rich waters. These waters form from the oxidation of H_2S to form sulphuric acid, which can descend through highly permeable structures to as deep as 2500 m in the Philippines (Moore et al, 2002; Rosell and Ramos, 1998). Three wells at the BacMan field, Philippines (Rosell and Ramos, 1998) and several in Palinpinon (Zaide-Delfin, unpublished results, 1988) and Cerro Prieto, Mexico (Dominguez, 1980) suffered from penetration due to ECC by acid-sulphate fluids. A consequence of casing penetration is blockage of the well by anhydrite deposition due to mixing of acid-sulphate water with upflowing neutral chloride waters during discharge (also downflow of acid fluids while well is shut, mixes with reservoir chloride waters) (Zaide-Delfin, unpublished results, 1988; Rosell and Ramos, 1998; Sugiaman et al., 2004).

Acid-sulphate waters were also reported in young volcanic (sulphur-rich) areas (Ellis and Mahon, 1977). In the Tatun geothermal field in Taiwan, the average fluid pH (25 ^oC) ranges between 2 and 3.5. Liquid sulphur was encountered along with the hot water in some wells (Ellis and Mahon, 1977). Much of the casing corrosion in Tatun was initiated inside the well, resulting in total corrosion of the casing within hours of production and subsequent abandonment of field development (Christopher and Armstead, 1983). In Matsukawa, Japan acid-sulphate-rich waters with pH (25 ^oC) ranging from 3.7 to 5.5 also caused internal casing corrosion during early production. Similar casing corrosion was reported at Tiwi, Philippines where caustic injection is used to increase the pH (25 ^oC) from 3 to 5 (Sugiaman, 2004).

The hydrothermal minerals typically formed during interactions of rock with acid-sulphate fluids (cation-depleted) include: kaolinite, dickite, pyrophyllite, illite, sulphur, natroalunite, alunite, jarosite, anhydrite, andalusite, tourmaline, diaspore, pyrite, marcasite and enargite (Moore et al., 2002). Alteration minerals associated with neutral to slightly acidic CO_2-rich steam heated waters (asending CO_2 dissolves in perched water resulting in weak carbonic acid solution) include quartz, calcite, albite, pyrite, chlorite, goethite, hematite, illite and siderite.

It is common practice to grout a well once a hole is detected in the casing, to prevent blow-outs and to stop cold down flow through the casing-hole when the well is shut.

2. ECC IN NEW ZEALAND GEOTHERMAL SYSTEMS

All the reported cases of ECC in New Zealand are related to CO_2-rich fluid. One of the main features of the CO_2-rich fluid is that it is steam heated as it hardly contains any chloride (Hedenquist, 1990). No anhydrite deposits were reported in any of the wells penetrated by ECC (no acid-sulphate). Corrosion products mainly contain magnetite, which is consistent with CO_2-rich fluid attack (Driver and Wilson, 1984).

The CO_2 content in geothermal systems within the TVZ increases along the eastern boundary Giggenbach (1995). Kawerau, Broadlands-Ohaaki and Rotokawa have the highest CO_2 concentrations (1.5 ± 0.5 mmol/mol), typical of arc-type geothermal systems in the Taupo Volcanic Zone (Giggenbach, 1995). Significant amounts of metal sulphide scales were reported in the well heads and surface pipelines of these systems, consistent with arc-type systems of high gas content (Reyes et al. 2002). Geothermal systems to the western part of TVZ (rift type) are dominated by rhyolitic volcanism, which is characterised by lower CO_2 concentrations (0.12 ± 0.05 mmol/mol) (Giggenbach, 1995).

This could indicate that the risk of ECC is higher in geothermal systems in the eastern boundary of the TVZ than those in the west.

2.1 Broadlands-Ohaaki

The first case of ECC was identified in December, 1983 in Broadlands-Ohaaki (BR25) (Driver and Wilson, 1984). Hedenquist and Stewart (1985) reported minor to severe ECC in BR7, BR10, BR14, BR16 and BR24. Surveys in BR45, which was drilled in 1984, also indicated early stages of ECC soon after completion.

Recent surveys have shown that several other wells in Broadlands-Ohaaki suffer from some ECC at depths ranging from 60m to 600m below CHF. Depending on the casing configuration ECC might affect intermediate, anchor or production casings in different wells. The corrosion varies from quite minor to penetration of the casing in some wells. Contact Energy has a programme of casing condition monitoring in place and some wells have been grouted, due to ECC.

2.2 Rotokawa

The first case of ECC was reported in RK2 where full penetration of casing at 284 m took place in 1985. The well was grouted to the surface, due to the extent of the damage (Bixley and Wilson, 1985). Wells RK3 and RK4 also suffered from severe damage due to ECC and were also grouted in 1993/94 (Thain and Dunstall, 2000). Well RK9, drilled in 1997 (Thain and Dunstall, 2000), also suffered from casing damage and was taken out of service in 2002-3 (Bromley, 2003).

Apart from RK9 all the wells mentioned above (RK2, RK3 and RK4) were not in production when damage occurred, indicating that the corrosion was not production induced. However, it is possible that reinjected fluids have helped move and spread the CO_2-rich water close and past RK9. This resulted in damage of RK9 (to only six years after completion) and possibly will lead to a similar fate for RK5, especially since the distance between the reinjection pad (RK1, RK11 and RK12) and the production wells (RK5 and RK9) is about 550 m (Reyes et al., 2002).

The extent of ECC in the wells (RK6 and RK8) (Reyes et al., 2002) drilled on the northern bank of the Waikato River is unknown. It is anticipated that the risk of ECC is lower than those at the southern bank, due to the drop in gas content (Giggenbach, 1995) and the distance from reinjection pad.

2.3 Kawerau

The CO_2 content in Kawerau is similar to that of Broadlands-Ohaaki and Rotokawa (Hedenquist, 1990; Giggenbach, 1995) and shallow CO_2-rich condensate has been reported in the Onepu area (Christenson, 1987). Nevertheless, there is no ECC taking place in any well at Kawerau although some of those wells were drilled in the early 1950’s (private communication, Mr. Alastair Maxwell). It is anticipated that the possibility of ECC increase towards the eastern boundary of the field also known as Putauaki (Wood et al., 2001), which is closer to the eastern boundary of the TVZ. There is also surface discharge of gas (CO_2) in this area, which is consistent with the presence of vapour and vapour condensate in the shallow aquifer (Christenson, 1987). However, acid sulphate alteration extends to deeper levels in the eastern portion of the field (Putauaki) than the main bore field of Kawerau (Christenson, 1987). This results in extension of the low lateral permeability to deeper formations and reduces the risk of ECC in wells in this part of the field.

2.4 Wairakei

Wairakei is a low gas field (Giggenbach, 1995) and the first to be developed in New Zealand. More than 170 wells were drilled in the field since the early fifties. Bixley and Wilson (1985) reported no serious ECC in Wairakei although mechanical damage due to subsidence is common in some parts of the field.

2.5 Tauhara

Four deep wells were drilled in Tauhara in the mid-1960's and although their CO_2 content is similar to Wairakei, TH1 suffered from complete ECC 16 years after drilling and was sleeved with a 6 5/8" from 325m to CHF (Bixley and Wilson, 1985).

2.6 Mokai

Mokai is one of the low gas fields located close to the western boundary of TVZ (Giggenbach, 1995). Significant external casing thinning in MK3 and MK5 (drilled in 1982-83 respectively) has been related to ECC attack by CO_2-rich fluid (private communication, Mr. Pat Brown). It is not clear whether the ECC is post or past production, since there is no reported background record of casing conditions. There is no information on casing conditions of other wells.

2.7 Ngawha

Ngawha is the only high temperature field outside the TVZ with an average moderate enthalpy of 1000 kJ/kg. It has high CO_2 content, similar to Broadlands (Hedenquist and Henley, 1985). Fifteen investigation wells were drilled in Ngawha between 1964 and 1982 (Karmon, 1999). All wells showed a conductive temperature profile through the shallow reservoir/cap rock (down to 400-500 m), which indicates no presence of a shallow steam condensate. It is anticipated that the low permeability of the cap rock (Karmon, 1999), will reduce the risk of ECC. However, areas with localised high permeability can trap CO_2-rich water, but this will be relatively close to the ground surface. There is no reported case of ECC in Ngawha (private communication, Mr. Roger DeBray).

There is no information on the casing conditions in investigation wells in other fields in New Zealand, but the occurrence of ECC in other geothermal systems is fairly possible (Hedenquist and Stewart, 1985). Two investigation wells have been cemented in Te Kopia and another seven in Waiotapu for unknown reasons (private communication, PRL Browne) possibly ECC. There is also no information on casing conditions of the four deep investigation wells drilled in Ngatamariki, the four wells drilled in Orakeikorako.

On average it takes 12 to 16 years for full penetration of single (cemented) casing to take place by CO_2-rich waters. The rate of ECC increases with the increase in CO_2 content (CO_2partial pressure) of the field. ECC can affect several casing strings at multiple depths. ECC due to CO_2-rich fluid commonly takes place between 200m to 450m deep, with a maximum reported depth of 600m.

Pressure drawdown due to production may result in the formation of steam condensate at deeper levels with time. This can result in the channelling of the CO_2-rich fluid to deeper levels down faults, permeable formations and possibly well annulus.

Reservoir modelling using the water- CO_2 module along with fluid-rock interaction could be a useful tool in understanding and predicting the extent of the corrosive zone. However, this can only be useful once a detailed and well calibrated model of the field is established.

3. REINJECTION AND EXTERNAL CASING CORROSION

The chemistry of the reinjected water is strongly affected by the choice of the power station's condenser (Glover and Mroczek, 1993). In Rotokawa the pH of condensate is estimated to be 5 (Glover and Mroczek, 1993), while the measured mixed brine and condensate has a pH of 5.7 (19 ^oC) (Reyes et al., 2002). In Mokai, on the other hand, the pH of condensate is estimated to be 4 (Glover and Mroczek, 1993) from simple calculation of separator pressure of 17 bar abs (Thain and Dunstall, 2000) it is estimated that the pH of reinjected mix is around 5.5. Therefore it is anticipated that corrosion effects from reinjected water at Mokai due to the use of binary plant to be higher than the other fields (Ohaaki, Rotokawa and Tauhara) (Glover and Mroczek, 1993). The chemistry of reinjected fluid should be considered in future reservoir modelling of fields with low mixed brine and condensate pH.

The impact of external casing corrosion on reinjection wells is less significant as the reinjection is normally taking place close to the CO_2-rich aquifer (in shallow reinjection) and any hole in the casing due to ECC will in fact improve the injectivity. It is also possible that the reinjected water with neutral pH prevents the corrosive fluids from reaching the casing at some depths. However, ECC will present a challenge for deep targeted reinjection wells, as it results in increasing well costs.

Monitoring ground-water wells and discharge of natural features can provide early warning by measuring any increase in temperature, water level and change in chemistry (Bromley, 2003). Also micro-gravity measurements can identify areas with positive anomaly, which will indicate mass gain in the reinjection area (Stefansson, 1997). This can indicate whether the reinjected water is travelling toward the production wells.

Using a binary plant heat exchanger generally reduces the gas discharged to the atmosphere, since the concentration of dissolved gases are in proportion to the gas partial pressure, which is higher than direct contact condensers (Glover and Mroczek, 1993). This makes cold reinjection returns (breakthrough) difficult to detect by monitoring chloride concentration, due to the small difference in concentration between produced and reinjected fluids (Stefansson, 1997).

ECC is another reason to consider outfield reinjection, especially in geothermal systems with high CO_2 content and a reasonably permeable shallow reservoir. Even when infield reinjection is abandoned for outfield reinjection, the shallow aquifer created by the reinjected fluid will continue to trap gases ascending through the system, creating a large CO_2-rich aquifer threatening the integrity of well casings. The possibility of reinjection enhanced ECC is higher when the reinjected brine includes condensates from the turbine.

4. CORROSION PREVENTION

Detection of the alteration minerals associated with acid-sulphate/CO_2-rich fluid and the presence of a highly permeable shallow aquifer (circulation loss and well kicks) during drilling gives the first indication for the potential of ECC in a new field.

Several methods have been considered to prevent and mitigate the damage from external casing corrosion. This includes the use of corrosion resistant cement, multiple lining within the corrosive zone, corrosion resistant casing material and cathodic protection.

4.1 Corrosion resistant cement

Cementing has been the first method used to protect geothermal wells casing from corrosive fluids (Wahl, 1977). Pore solution in Portland cement class-A (commonly used in New Zealand and world wide), contains a high fraction of $CaOH_2$ (pH>10), thus providing the casing with a passive protecting film against corrosion. When the cement matrix is exposed to the CO_2-rich fluid, the pore solution will be neutralized resulting in the formation of calcium carbonate ($CaCO_3$) scale (Hedenquist and Stewart, 1985). This scale breaks down the passive film and leaves the casing pipe exposed to the corrosive environment (Rahman, 1989). Portland cement class-G with 40 % silica flour and activated pozzolan or perlite has been used in similar corrosive conditions in Cerro Prieto (Dominguez, 1980). It should be noted that corrosion resistant cement was developed by the oil industry. Thermal stresses due to heating and cooling of casing in geothermal environment can cause fracturing of cement, which will allow fluid to be in direct contact with the casing. Petty et al. (2003) reported the development of a foamed thermal resistant cement (TRC), which is also resistant to CO_2-rich fluid.

Using a liner-tieback casing programme can insure a better cementing job compared with a single string casing especially in deep wells. This will reduce the risk of ECC from having un-cemented parts of the casing directly exposed to CO_2-rich fluid.

4.2 Multiple lining

The use of multiple casing strings through the corrosive zone is common in oil and gas wells especially in a marine environment. Along with the added cost of additional liners and cementing, the disadvantage of using multiple casing strings through the corrosive zone in geothermal wells is that the possible damage from trapped water during cementing (poor cementing job) will be more significant, because of the reduced annulus area. Compared with standard casing design, there will be less cross sectional area when a water pocket flashes, which will lead to more lateral extension of the damage zone.

4.3 Corrosion resistant casing material

Stainless steels or alloy steels with chrome content are not advised due to stress corrosion cracking. At the Salton Sea grade 12 titanium and *Ti-Pb* alloys are used which can resist chloride crevice corrosion and pitting attack (Thomas, 2003), however, this comes at a very high cost.

4.4 Cathodic protection

In oil wells cathodic protection is designed to protect from ECC. However the suitability of cathodic protection differs from one field to the other (Gordon et al., 1984). No information is available on the use or success of cathodic protection in deep geothermal wells. However, cathodic protection has been used with success in down-hole heat exchangers.

5. MITIGATION

Once damage takes place in a casing, bore fluid will form a steam thief zone around the well in the affected area, resulting in reduced output and drop in wellhead pressure. The plan of action will be dictated by: the size of hole, rate/extent of corrosion damage, the depth at which casing damage takes place and the permeability of the surrounding formations.

If the casing damage is not significant enough to affect the integrity of the well (no risk of blow-out) the well can be sleeved with a smaller liner. BR25 was run with 6 5/8” extremeline liner and cemented back to surface with a net loss of 20 % of production mass output (Driver and Wilson, 1984; Bixley and Wilson, 1985), no significant corrosion has been reported in the 6-5/8” liner since installed in 1984. Possibly a significant amount of cement was squeezed through the casing hole and prevented further corrosion (multiple cement squeezing is a common solution to ECC in oil wells). TH1 was also run with a 6-5/8” liner in 1986. However, there is no information on the current casing conditions.

If the well cannot be sleeved and the casing damage is close to the surface, which can present a risk of blow-out. The well should be properly abandoned; in this case the well is grouted to the surface. The well may also be grouted if there is significant down flow of cold shallow water through the casing hole into the main production zone especially when the well is shut.

If the well cannot be abandoned properly due to major casing collapse, which can prevent access below the casing hole, a relief well may be needed to reduce the pressure from the damaged well before intervention in the damaged well. The relief well is normally drilled alongside the damaged well within a distance of about 50m from the main production zone.

In the worst case scenario of a blow-out, the relief well may be used as a “killer well” to inject cement into the production zone of the damaged well. In this case the cost of abandoning the well will include the cost of the relief/production well, which will be significantly high.

It should be mentioned that quenching a hot production well with a significant ECC problem should be progressed with more caution to prevent further damage to the casing due to thermal stresses. At Cerro Prieto two production wells with reported ECC where lost due to quenching (Dominguez, 1980).

Possibly the simplest well completion precaution to the suspected occurrence of ECC in any field is to extend the anchor casing to farther depth (> 600 m) and to use class-G cement with 40% silica flour for cementing the production casing.

ECC can be detected using electromagnetic casing corrosion detector (Bixley and Wilson, 1985) also known as the Hot Hole Casing Corrosion (HHCC) tool (Stevens, 2000). It is based on measuring magnetic flux leakage and eddy currents (Talabani et al, 2000). The tool can measure external casing thinning through two casing strings (production and anchor casings) (Stevens, 2000).

It is a good practice to include the HHCC log in the completion programme of new wells. This is to identify casing thinning due to drill string rubbing against casing especially in directional wells. The first survey will form the baseline for comparison with future logs taken every 2-4 years (Bixley and Wilson, 1985). This will help identify the occurrence and rate of ECC during the life of the well. Cement bond logs are also used to ensure the quality of the cementing job in the cased part of the well prior to production (Gordon et al., 1984).

6. CONCLUSIONS

ECC is under reported in geothermal systems in the TVZ. It will remain a problem for existing and future wells in systems with high CO_2 contents and high shallow horizontal permeability (Ohaaki and Rotokawa). It is also a problem in low gas fields with high shallow permeability and fluid of low pH.

Infield reinjection is likely to be responsible for aggravating/enhancing ECC, by spreading the CO_2-rich water and possibly adding corrosive fluid to the shallow aquifers. Shallow infield reinjection also helps create an aquifer, which traps CO_2 even after reinjection is halted.

Binary power schemes with total reinjection of mixed brine and condensate, have a weaker chemical signature (chemical front) of reinjected fluid compared with plants with condensing turbine and with separate injection of brine and condensates (e.g. Ohaaki).

Monitoring casing conditions and using cement bond log are usefull methods of prdicting casing penetration and the need for expensive workover or possible loss of a well.

The worst case scenario of a blow-out risk and the need for a killer well, justifies the added investment in the prevention/minimisation of ECC during drilling using extended lining and corrosion resistant cement.

Further work is required to better prepare for the occurrence of ECC.

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