

# Material Challenges for Deep Superhot Geothermal Wells

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## Keywords

*Geothermal Wells, Casings, Corrosion, Mechanical Properties, IDDP*

## ABSTRACT

Several challenges are encountered in the design, construction, and production of deep superhot geothermal wells. These include stresses and strain exceeding the yield strength and plastic strain limits of materials used for well casings due to thermal cycling. Additionally, due to high temperatures (>300°C) and corrosiveness of the geothermal fluid, increased corrosion and erosion-corrosion can be expected. In this study, lessons learned from drilling, construction and production of superhot geothermal wells are reviewed, with the IDDP wells used as an example. The main material challenges are described and discussed. Carbon steel casing materials start losing their strength at elevated temperatures thus less stress due to thermal cycling is needed for failure. Also, carbon steel casings commonly used in these projects are not corrosion resistant and susceptible to various corrosion forms such as hydrogen embrittlement, sulfide stress corrosion cracking and micro-cracking caused by high temperature hydrogen attack. Thus, materials that have higher corrosion resistance and better resistance against thermal cycling effects are needed to achieve structural integrity of superhot wells. Potential candidates could include the newly developed titanium alloy Ti-745 (Ti-0.4Ni-3.6Mo-0.75Zr), the nickel alloys SM2245 and SM2550 and self-healing and heat-and acid resistant cement casing blends.

## 1. Introduction

For the last two decades, interest has increased in utilizing geothermal energy from superhot or supercritical geothermal resources which has led to the initiation of several projects in this field around the world, e.g. the Iceland Deep Drilling project (IDDP) in Iceland, the Newberry Deep Drilling Project (NDDP) in the USA, Japan Beyond Brittle Project (JBBP) in Japan and GeoMex in Mexico (Reinsch et al., 2017). In most of these projects this means drilling deeper than conventional geothermal wells (>3 km, >340°C) to obtain superhot geothermal fluid and consequentially highly corrosive fluids. The common driver of these projects is the goal to obtain higher power output per well, higher than traditional high temperature wells (3 -10 MW<sub>e</sub>). This is

due to the increased enthalpy, lower density and viscosity of supercritical fluids that will allow much higher flow rates, and increased productivity (Friðleifsson et al. 2005, 2014a, b).

Several challenges have been encountered in this approach, i.e., in the design, construction, and fluid production of deep and/or superhot geothermal wells. These challenges occur both during the drilling as well as in completion. Kruszewski and Wittig (2018) reported a study based on literature search on failure modes of 20 wells from different high-enthalpy geothermal fields around the world (with temperatures greater than the critical point of pure water) where they gave an overview of areas of improvements and potential solutions regarding the drilling and well completion technology. The main findings were that in most cases failures of the wells, where the failure modes were known, were caused by excessive high thermally induced stresses on the casing strings and couplings during operations such as well quenching or production kick-off causing connections rupture or casing collapse. Bad cementing (lacking cement/bond) job was also reported to promote casing collapses. Scaling, corrosion, and erosion due to high flow rates of corrosive and in many cases hypersaline geothermal brines were also noted as serious issues, particularly during well testing and fluid production (Kruszewski and Wittig, 2018).

As pointed out by Gruben et al. (2021) the main issue encountered in the construction and production of superhot geothermal wells is regarding the well integrity. Well integrity issues are closely connected to the well materials, specifically the steel and cement casing materials. For example, the commonly used API K55 carbon steel casing material is vulnerable to thermal cycling which causes permanent plastic deformation due to excess strains resulting in casing fracture. Carbon steel casing materials also start losing their strength (yield and tensile strength) at temperatures above 200°C thus less load is needed for causing plastic strains and exceeding the yield and tensile strength of the material and fracturing it (Maruyama et al., 1990). Additionally, due to high temperatures (>300°C) and corrosiveness of the geothermal fluid expected in superhot geothermal wells, increased corrosion and erosion-corrosion can be expected (Karlsdottir et al., 2014, 2015). Carbon steel and low alloyed steel (LAS) are not corrosion resistant and are susceptible to various corrosion forms such as hydrogen embrittlement, sulfide stress corrosion cracking (SSC) and micro-cracking and fissuring due to High Temperature Hydrogen Attack (HTHA) (Karlsdottir et al. 2018; Karlsdottir et al., 2022). Thus, materials that have higher corrosion resistance and better resistance against thermal cycling effects are needed. The structural integrity of the cement casing is also very important as well as the cementing job to be successful as will be pointed out in the following sections, such as in lessons learned from IDDP wells.

In this study the key material challenges are described and discussed and recent results from relevant high temperature and corrosion testing is reviewed. The potential application of corrosion resistant alloys instead of standard API carbon steel casing material is reviewed. Information regarding well cement and potential candidates for the next generation of cement and metal casing materials for deep and superhot geothermal wells are also discussed.

## **2. Lessons Learned from IDDP Wells**

The aim of the Iceland Deep Drilling Project (IDDP) is to test whether it is feasible to extract energy from hydrothermal systems at supercritical conditions. In 2005, the consortium initially proposed a plan for the first IDDP well. The plan was to deepen an existing geothermal well, RN-17, located in the Reykjanes geothermal field to a depth of 4-5 km to make certain that it

reached supercritical conditions. The unique properties of the Reykjanes geothermal field were the main reason for this selection. Because this field is located on a narrow peninsula, seawater recharges its reservoir and is the medium of pressure regulation. However, due to a collapse during flow testing the uncased 3 km well collapsed and the deepening attempts of this geothermal well failed. The IDDP project then moved to the Krafla caldera in northeast Iceland to drill the first IDDP well, IDDP-1 in 2008-2009. Given the geothermal gradients known to depths of ~2 km at Krafla, supercritical conditions should exist at 4-5km depths. This attempt at drilling to supercritical in the IDDP-1 was unsuccessful as the borehole penetrated a nearly aphyric rhyolite magma at >900°C, at only 2100 m depth, but with fluid pressure well below the critical point of the low salinity meteoric water-sourced fluids (Friðleifsson et al. 2020). During drilling, between 2000 - 2100 m depth the drill bit got stuck twice and it was cut loose. In the third drilling attempt the drillers decided not to attempt retrieving the drill string but remained in magma with full circulation (70 L/s of cold water) for 28 hours. Once retrieval was attempted the drill string was loose but the lowest 9 m of the open borehole was filled with chilled volcanic glass. Drilling was terminated and the hole was completed as a production well, cased down to 2072 m (Kaldal Skúlason 2019). The IDDP-1 was then completed with a slotted production liner set above the rhyolite magma, with good permeability. Figure 1 summarizes the planned well design dimensions, materials, and connection types and compares them to the actual design parameters used in the IDDP-1 well.

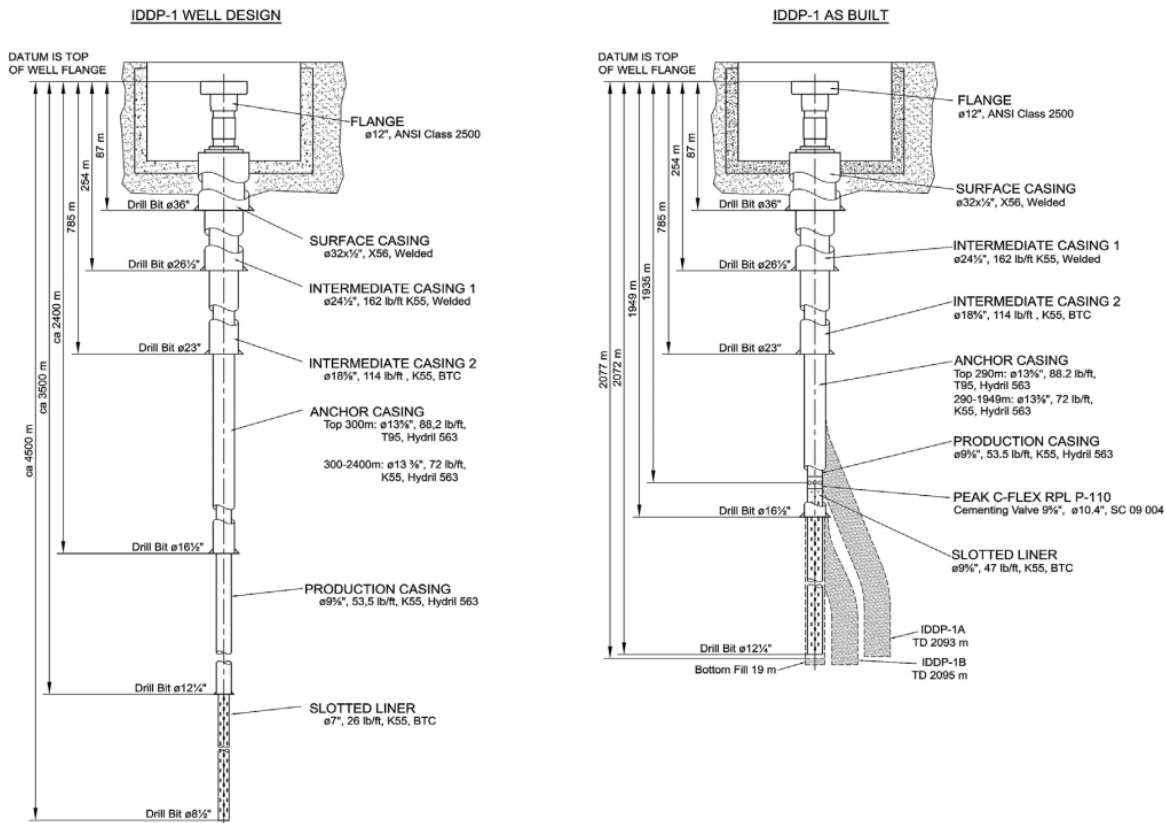


Figure 1. IDDP-1 well design versus IDDP-1 as built (Thorhallsson et al. 2010).

After construction of the well, periods of heating up the well followed, and subsequent discharge of saturated geothermal fluid, black colored steam, indicating active corrosion of the well casing and liner down-hole due to acidic conditions. But subsequent to long-term flow tests, the IDDP-1 well produced superheated steam with a wellhead temperature of 452°C at a flow rate and enthalpy sufficient to generate about 30 MWe. The superheated steam from the IDDP-1 well reached 450°C and 140 bar at the wellhead and contained gases (HCl, CO<sub>2</sub>, HF, H<sub>2</sub>S) that are highly corrosive upon condensation. When flowing, IDDP-1 was the world's hottest production well, but, after two years of production tests, repair of the surface equipment became necessary, resulting in the need to quench the well. Both master valves (10" expanding gate type valves) at the wellhead failed during a critical leakage in the wellhead. Inspection of the valves revealed that the connection between the stem and the gate had been lost because the stem head had broken. This was believed to be caused by high stresses and hydrogen embrittlement of the stem material, 17-4 PH stainless steel (SAE Type 630 stainless steel/UNS S17400). The 17-4 PH is not recommended for use in components that experience high pressure loads in wet H<sub>2</sub>S environment due to danger of sulfide stress corrosion cracking and hydrogen damages according to the NACE MR0175/ISO15156 standard (NACE MR0175/ISO 15156 standard). The subsequent quenching of the well caused collapse of the well casing due to the strain build up in each thermal cycle., i.e., the production casing in IDDP-1 failed, fractured in multiple places when the well was quenched, and ultimately the well had to be abandoned (Friðleifsson et al. 2020). Figure 2 shows results from a finite element modelling study by Kaldal Skulason et al. of the IDDP-1 well. The model was used to demonstrate the effects of thermal cycling on the production casing. It can be seen that in each phase, there is a change in the temperature (cooling and heating), which causes plastic strain to build up, which eventually leads to casing failures (Kaldal Skulason (2016)).

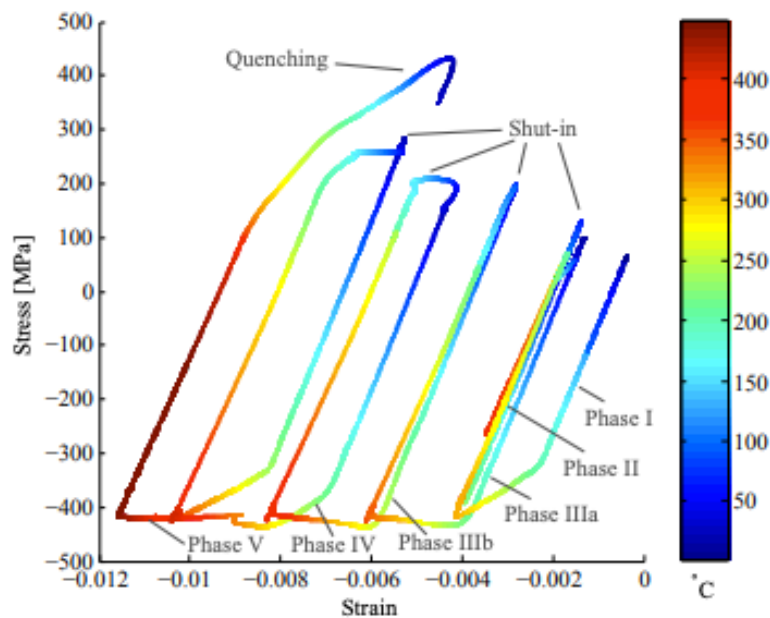


Figure 2. Stress-strain diagram from FEM analysis showing the effects of thermal cycling in the production casing of IDDP-1 causing plastic strain build up (Kaldal Skúlason, 2016).

Analysis of the top 6 m of the IDDP-1 well steel and cement casing were done after small steel samples were retrieved from the well that had experienced cracking caused by hydrogen effects due to the chemical composition of the steam ( $H_2S$ ,  $HCl$ ). The effects on the carbon steel casing material (K55, T95) was examined with microstructural and chemical composition analysis which showed that the K55 was particularly damaged in the top part of the well, with micro-cracks and corrosion damage caused most likely by High Temperature Hydrogen Attack (HTHA) (Karlsdóttir et al., NACE 2018, Karlsdóttir et al 2022). The examination of the deterioration process of the cement was also performed with mechanical testing and microstructural and chemical composition analysis (Wallevik et al., 2022). Well cement fragments were recovered for each cement casing from the IDDP-1 well, both from an excavated segment of the top part of the well and from a depth of around 600m. Samples were obtained from four cement casings contained within the surface casing. Changes in texture, structure, chemical composition, density, compressive strength, and other properties were studied and compared to laboratory fabricated reference samples. All well cement casing samples exhibited de-calcification. The Ca/Si ratio in the cement casing samples was lower than the ratio in the reference samples. No portlandite was found in the well cement samples, indicating dihydroxylation of the portlandite present in the originally mixed cement grout. Samples from the innermost and outermost cement casing, collected close to the wellhead, had low compressive strength due to a direct interaction with geothermal fluid during well operation. This was reflected in porous texture, leached Ca from the CSH phase ( $CaO-SiO_2-H_2O$ ) and carbonate formation. The two cement casings located between the outermost and innermost cement casings showed physical and mechanical properties comparable to the reference samples. (Wallevik et al., 2022).

The second IDDP well was drilled at the Reykjanes geothermal field. The drilling of IDDP-2 was completed in the beginning of 2017. Similar to the IDDP-1 well, the plan was to use an existing well (RN-15) as a base for IDDP-2. The RN-15 well was 2500 m deep and when the drilling was completed the IDDP-2 well reached 4650 m deep. The measured bottom hole temperature of this well was  $427^\circ C$  and pressure was 340 bar. The bottom of the IDDP-2 well reached fluid at supercritical conditions and became the deepest geothermal well in Iceland (Karlsdottir et al. 2019). But problems were encountered during the drilling, such as problems with hole stability that required frequent reaming, and the drilling assembly becoming stuck several times. Each of these issues was solved successfully. However, the major problem that was not solved was a complete loss of circulation returns to the surface encountered at depths just below the production casing shoe. The circulation loss could not be cured with lost circulation materials, nor by 12 successive attempts to seal the loss zone with cement. Therefore, drilling had to continue with only intermittent cutting returns between 3000 and 3180 m depth and no return of drill cuttings from deeper than 3180 m (Friðleifsson et al. 2020).

Damage was discovered in the IDDP-2 casing at 2300m depth. In late 2017 a problem within the production casing was detected. Deploying logging tools were prevented by a constriction in the  $9\ 5/8''$  production casing between 2307 and 2380 m depth (Friðleifsson et al. 2020). During the drilling phase there were problems in well cementing and information were obtained from cement bond logging that part of the cement was not present or well bonded to the casing in part of the well, falling in the range where casing damage was discovered. This suggests that the decrease in strength of the cement or non-existence of the cement behind the production casing caused increased stress on the production casing, leading to a failure.

After drilling and construction of the well was completed a 3.5” carbon steel (API 5DP PSL1 grade G-105) injection drill string was implemented to the bottom of the well to ensure cold water and improved stimulation into the deepest part of the well in effort to obtain self-flowing of steam from the well. When the injection drill string was retrieved from the well, extensive corrosion damages were discovered on the lowest part of the injection string. Multiple axial cracks were also observed on multiple tool joint boxes in a 600-meter interval of the pipe, from 4659 m up to 4000 m depth. At this location interval the injection drill string is placed inside a perforated liner of the IDDP-2 well. Failure analysis of the damaged parts of the injection pipe with visual inspection and microscopic examination revealed extensive uniform and pitting corrosion. The analyses indicate that the high temperature and relatively high oxygen content in the cold water used for injection and contact with corrosive reservoir fluid caused the severe corrosion. The analysis of the cracks and hardness measurements of the joints indicate that sulfide stress corrosion cracking (SSC) is the most likely cause of failure due to combined effects of thermal stresses, corrosive environment, and susceptible material (Karlsdottir et al. 2019).

Conclusions were made based on the experience and information from the injection test with cold water for stimulation of the well that any fluid travelling up the IDDP-2 well would most likely disappear into the opening (loss zone) in the formation at this location and thus prevented pressure build up and discharge of the well (Friðleifsson et al. 2020) (Karlsdottir et al. 2019). The IDDP-2 well could not be stimulated for the production of steam and is thus now unutilized.

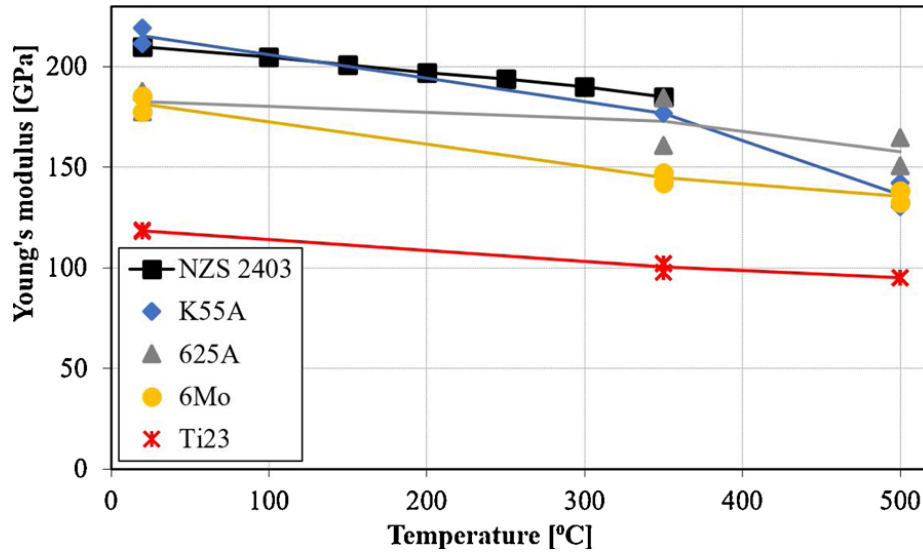
### **3. Well Integrity and Material Challenges**

Based on literature review and experience from IDDP wells the main material challenges that have been identified in construction and design of superhot geothermal wells are: (1) stresses and strain exceeding the yield strength and plastic strain limits of materials used for well casings due to thermal cycling and loss in strength of materials at temperatures exceeding 200°C, (2) corrosion of casing materials due to high temperatures (>300°C) and corrosiveness of the geothermal fluid and (3) degradation of cement casing materials due to high temperatures and poor cementing job. These factors will thus be discussed in the following subsections.

#### ***3.1 Mechanical Properties at High Temperatures***

At elevated temperature the mechanical properties such as the elastic modulus (E), yield strength ( $\sigma_y$ ) and the ultimate tensile strength ( $\sigma_{UT}$ ) decreases of carbon steel casing materials such as API K55 commonly used in high temperature geothermal wells. Thus, less load is needed for causing plastic strains and exceeding the yield and tensile strength of the casing material during the lifetime of the well (Maruyama et al. 1990). The main design code for geothermal wells, NZS 2403:2015 (New Zealand Standard, 2015), provides only mechanical properties data for casing materials for temperatures up to 350°C. But recently a study done by Gruber et al. (2021) extend the data set listed in NZS 2403:2015 by providing data for higher temperatures from mechanical testing several carbon steel casing material and corrosion resistant alloys. This was done in effort to enable design of collapse- and tensile capacity for geothermal casings exposed to temperatures up to 500-550°C. It was reported that the carbon steels followed the same near linear decay in strength as the NZS 2403:2015 curves up to 350°C, but then experience a large drop in tensile strength at higher temperatures. This was particularly true for the lower strength steels. The

alloys with high nickel content work hardening at high temperatures and retained their strength at temperatures above 350 °C. Also, in contrast to the tested nickel alloys, the titanium alloy tested did not display dynamic strain ageing and showed high yield strength and low work-hardening at 500°C (Gruben et al. (2021)). Figure 3 shows a graph from the study by Gruben et al. showing the decrease in Young's modulus for selected materials with increasing temperature and comparison to data from NZS 2403:2015 (Gruben et al. (2021)).



**Fig. 3.** Graph from a study by Gruben et al. showing the decrease in Young's modulus for selected materials with increasing temperature and comparison to data from NZS 2403:2015 (Gruben et al. (2021)).

After the drilling and construction phase of a geothermal well, it heats up after being in a cold state from the cooling fluid (drilling mud) during drilling. This gives rise to compressive stresses due to the thermal expansion of the metal casing material (Kaldal et al., 2016), which can result in elastic Euler buckling or local plastic buckling of the casing if some parts of the metal casing is not supported by the cement (Rechard and Schuler, (1983)). There can also be a risk of casing collapse due to high pressure on the outside of the casing, but the casing collapse capacity is linked strongly to the yield strength of the metal casing material (Gruben et al., (2021)). The thermal cycling can occur as demonstrated in Figure 1 if the well is needed to be cooled after the initial heat up phase (which is common in geothermal wells due to maintenance or inspection). The casing is constrained and upon cooling the metal casing contracts and causes tensile stress, and upon heating compressive stresses are again generated. This can be seen in Figure 1 that for each cooling and heating phase, plastic strain builds up, which eventually leads to casing failures (Kaldal Skulason, 2016)). The tensile stresses caused by fast cooling has also been reported to create the potential for tensile failure, and a buildup of residual tensile stress causing the casing to be more susceptible to biaxial collapse failure (Maruyama et al., 1990).

### 3.2 Corrosion in Superhot Geothermal Environment

In vapor dominated geothermal systems ( $T > 300^{\circ}\text{C}$ ) hydrogen chloride (HCl) is often present in wells with superheated geothermal steam. This occurs for example at the Geyser in the USA, Tatum in Taiwan, Larderello in Italy, Tiwi in the Philippines and in Krafla in Iceland (KG-12

and IDDP-1). The presence of HCl in superheated geothermal steam has caused severe corrosion problems which have led to major operating difficulties. Carbon-steel casings corrode at accelerated rates upon the condensation of the super-heated steam with HCl gas. This is because below the dew point the droplets formed are highly acidic due to the partitioning of the HCl into the liquid present which causes an acid solution to be formed. HCl is only transported in superheated steam since below 300°C it becomes very soluble in neutral liquid and would have been washed away; removed from the vapor if the condensate was present. The origin of the HCl in vapor dominated systems has been proposed to be due to high temperature reactions, complete evaporation (boiling) of near neutral NaCl or reactions of halite with silicates (Haizlip et al., 1988; Hirtz et al., 1991; Viviani et al., 1995; Nogara et al., 2014). For example, HCl is present in the steam produced from the deep wells of the geothermal area Larderello in Italy. The steam produced is very aggressive, due to the presence of high contents of acid chloride, up to hundreds of ppm by weight (Lazzarotto et al., 2005). The greatest danger of corrosion exists where the superheat is lost (at the dewpoint); this can be in the casings, at the wellhead or steam pipeline system as experienced in Lardarallo. Only a few ppm of HCl is needed in the geothermal steam to cause severe corrosion failures; steam with only 1-10 ppm HCl caused corrosion cracking and etching of turbine components at Lardello (Viviani et al., 1995).

At the Geysers geothermal field, as in Larderello, the HCl in the superheated steam is closely related to the existence of high-temperature zones below the main vapor-dominated reservoir (Gallup & Farison, 1998, Haizlip et al., 1988). In most wells at the Geysers the danger of rapid corrosion damage occurs at the wellhead where first condensation of the HCl containing superheated steam happens (Hirtz et al., 1991). The internal corrosion rates in carbon steel pipes at the Geysers with high HCl content steam (50-100 ppm) and acid-dewpoint corrosion can exceed 25 mm/year. Over the years the steam chemistry at the Geysers has changed towards becoming more corrosive. The high corrosiveness of the north Geysers HCl rich steam has produced steam leakages several times since early 2011, when the wells were put in service, due to an upset in the operation of the corrosion mitigation facility (Farison et al., 2017, Gallup & Farison, 1998). The location of the corrosion damages in the wells at the Geysers is dependent on the location of the acid dew-point conditions, which can arise down-hole in casings and liners, at the wellhead, and in pipelines (Hirtz et al., 1991).

In the geothermal area Krafla in Iceland the presence of HCl in wells producing dry superheated steam has caused severe corrosion of a wellhead, pipelines and turbine materials due to condensation and re-boiling that causes localized enrichment of the hydrochloric acid (Eliasson et al., 1982). The Krafla geothermal field has drilled 12 wells that have shown acidic characteristics which are all categorized as deep wells (>1800 m). It is now considered that in most parts of the Krafla geothermal system acid conditions prevail at a depth interval below 2200 m. The acid HCl steam from deep aquifers has corroded the liners and caused scaling and blockage of the acid wells in Krafla. This has mainly been attributed to mixing of superheated steam with HCl from the deep reservoirs with wet aquifers at shallower depth causing acidic conditions at the mixing point. The amount of HCl measured in the superheated wells produced in Krafla is in the range of 20-100 ppm with a pH ranging from 2.5-4.0. These wells also produce H<sub>2</sub>S and CO<sub>2</sub> gases which are corrosive substances and exist in all high temperature geothermal wells in Iceland (Einarsson et al., 2010).

The presence of HCl in the superheated steam of the IDDP-1 well in Krafla was encountered which caused difficulties in utilizing the superheated steam for production (Karlsdottir et al. 2014, 2015). Extensive material testing was done in early 2012 on site in the IDDP-1 well geothermal steam before the well had to be quenched to stop discharging (Karlsdottir et al. 2014, 2015). These included experiments for the erosion corrosion, heat exchanger simulation and corrosion coupon in-situ tests were conducted with the IDDP-1 steam. During this time the IDDP-1 well was discharging dry superheated steam from the wellhead with high temperature (450°C) and pressure (140 bar). For all the test units temperature decreased to about 350°C and pressure to 12-13 bars, except for in the heat exchanger experiment the pressure was decreased to 52-60 bar and temperature to around 260-270°C to obtain some steam saturation. The steam was supersaturated with silica and when the temperature and pressure was dropped it caused silica deposition from the steam. Materials tested in the IDDP-1 steam were of four types; low alloy carbon steels, stainless steels, nickel based alloys and titanium alloys. The test results showed that all samples tested, including the carbon steels; S235JR, K02100, K55, TN95, austenitic stainless steels; S30403, S31603, S31254, Ni-based alloys; N06255 and N06625 and titanium alloys; R50400 and R52400 had very low corrosion rates (< 0.01 mm/year) but all the samples were prone to localized corrosion damages, i.e. cracking, pitting or both (Karlsdottir et al., 2014, 2015). Furthermore, all samples tested had silica scaling covering the surfaces, which likely affected the corrosion behaviour of the samples tested. It was concluded that silica scaling on the test sample surface had likely provided a protective effect resulting in a low corrosion rate but might have also promoted some localized corrosion damage in the test samples due to under deposit corrosion (Karlsdottir et al., 2015).

Following this, research led by Karlsdottir and Thorhallson was conducted to answer questions that arose about whether the same corrosion behaviour would result if the carbon steels or the corrosion-resistant alloys would be exposed to a similar dry superheated geothermal fluid but without any silica scaling. Due to several corrosive species present in the geothermal fluid of IDDP-1, it was not evident which chemical species or environmental factors were the sources of the localized corrosion damages observed in all the carbon steel and corrosion-resistant alloys tested (Thorhallson, 2022). The research involved a corrosion behaviour study of carbon steel and several corrosion-resistant alloys (CRAs) tested in contact with synthetic geothermal fluids at high temperatures in a novel flow-through reactor corrosion testing facility. Corrosion tests were carried out using superheated steam ( $T = 350\text{ }^{\circ}\text{C}$  and  $P = 10\text{ barG}$ ) containing  $\text{H}_2\text{S}$ ,  $\text{CO}_2$  and HCl. The materials tested were carbon steel, stainless steel, nickel-based alloys, titanium alloys, high-entropy alloys (Thorhallsson et al., 2020). Some of the materials were further tested after silica ( $\text{SiO}_2$ ) had been deposited on the surfaces, and under boiling and condensing conditions at lower temperatures (Thorhallsson et al., 2022). In superheated fluid, carbon steel and Cu added high entropy alloys (HEAs) were prone to corrosion damage but negligible damages were observed in the corrosion-resistant alloys tested including the newly developed titanium alloy Ti-745 (Ti-0.4Ni-3.6Mo-0.75Zr), and the nickel alloys SM2245 and SM2550 (UNS N06255). The carbon steel was prone to more severe corrosion damage in the boiling and condensing conditions in comparison with the superheated test fluid, hence, the corrosion behaviour of carbon steel can be associated with the physical condition and temperature of the corrosive fluid (Thorhallsson et al., 2020, 2021a, 2021b). The extent of corrosion damage of Cu added high-entropy alloys (HEAs) in the superheated fluid is associated with increased Cu content and Cu-rich intermetallics (Thorhallsson et al., 2021b). From the results, it can be concluded that the corrosion-resistant alloys Ti-745 (Ti-0.4Ni-3.6Mo-0.75Zr), and the nickel alloys SM2245 and

SM2550 are immune to corrosion damage in high-enthalpy superheated geothermal fluid containing H<sub>2</sub>S, CO<sub>2</sub> and HCl and should be selected in preference to carbon steels and Cu added HEAs in such environments (Thorhallsson et al., 2022).

### ***3.3 Cement Casing Integrity***

The structural integrity of the cement, as well as good quality cementing job, are important success factors as pointed out in the lessons learned from IDDP-2. In the Hengill area in Iceland, 75% of drilled geothermal wells encountered circulation loss and wellbore collapse (Sveinbjornsson and Thorhallsson, 2014). Such problems can lead to poor cement jobs that endanger the well integrity. Vice versa, selection of appropriate well cement mixture is crucial for good cementing jobs to maintain well integrity. A study of over 380,000 wells worldwide found that nearly 7% of wells experience wellbore failure (Davies et al., 2014) with one of the main reasons being the high temperature (up to 400 °C), thermal cycles, and chemically corrosive (typically hypersaline, CO<sub>2</sub> and H<sub>2</sub>S rich) environments (Kiran et al., 2017). Failure of the wellbore cement can be due to a combination of chemical degradation, fracturing, and debonding from the host rock or well casing. Standard API well cement does not exhibit autonomous healing at either bulk cement or cement-steel interface based on permeability analysis. For instance, Rod et al. (2020) tested novel polymer-cement composites that bring self-healing and re-adhering (to steel casing) properties in contrast to conventional wellbore cement. This was particularly evident by the filling of fractures and interstitial gaps, demonstrated by tomography and permeability results. The development of self-healing materials could potentially be a solution for prolonging lifetime of well cement casings.

Wellbore cementing is essentially the process of placing cement in the annular space between the well casing and the geological formation surrounding the wellbore to provide zonal isolation, or between two strings of casing. The main objectives of well cementing are: providing axial and collapse support to the casing, protecting well casings from corrosion, reducing the risk of groundwater contamination by oil, gas or saltwater, preventing crossflow (exchange of gas or fluids among different geological formations) (Teodoriu et al., 2018). Cementing plays an important role in terms of well stability, three mechanical issues affecting wellbore integrity, or cement failure types have been identified; (1) as radial cracks, (2) de-bonding cracks, and (3) shear failure (Teodoriu et al., 2013, 2018). To decrease the likelihood of steel casing failure over the lifetime of a geothermal well the cement casing needs to be intact and properly bonded. In production phase of a geothermal well, where completion components are installed on, the casing's role becomes more critical, since it may lead to the vibration at the surface and even blowouts due to expansion of the fluid/steam flow. The cement stability at high temperatures leads to well integrity problems over the well life cycle. Temperature is the most imperative element because of a robust impact on cement slurry setting time and its impacts on cement strength over the well's lifetime. There are numerous studies in the literature referring to cement behavior in different well conditions, however just a couple have discussed the geothermal high-temperature conditions and cement behavior in such harsh environment (Elbakhshwan et al 2020). Some of the cement compositions may show sufficient strength at the early stages of setting but will lose their strength after a while due to continuous exposure to high temperatures. Allahvirzideh (2020) recently reviewed well cementing studies and performance of different types of mixes, which have in common to be designed to be acid and high temperature resistant.

#### 4. Conclusion

The main issue that has been encountered in the construction of superhot geothermal wells are regarding the well integrity due to problems connected to the well materials, specifically steel and cement casing materials. The commonly used API K55 carbon steel casing material is not vulnerable to thermal cycling which causes permanent plastic deformation due to excess strains resulting in casing fracture. The relatively high thermal expansion coefficient of carbon steel and the subsequent contraction and expansion of the cemented steel casing causes high stresses and plastic deformation of the steel casing material that leads to fracture of the casing. Carbon steel casing materials start losing their strength (yield and tensile strength) at elevated temperatures above thus less stress due to thermal cycling is needed for exceeding the tensile strength of the material and fracturing it. Also, carbon steel and low alloyed steel (LAS) are not corrosion resistant and susceptible to various corrosion form such as hydrogen embrittlement, sulfide stress corrosion and micro-cracking due to HTHA. Thus, materials that have higher corrosion resistance and better resistance against thermal cycling effects are needed to achieve structural integrity of superhot wells. Potential candidates could include the newly developed titanium alloy Ti-745 (Ti-0.4Ni-3.6Mo-0.75Zr), the nickel alloys SM2245 and SM2550 and self-healing and heat-and acid resistant cement casing blends.

#### Acknowledgement

The authors would like to thank the Icelandic Research Fund (RANNSÍÐ) for funding the project that this work was done within called “Material Research and Modeling for High Temperature and Deep Geothermal Wells,” no. 2113356-0611.

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