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COMMON PROBLEMS FACED IN GEOTHERMAL GENERATION AND HOW TO DEAL WITH THEM

Sverrir Thorhallsson

ISOR - Iceland GeoSurvey
Grensásvegur 9, 108 Reykjavík
ICELAND
sverrir.thorhallsson@isor.is

ABSTRACT

High-temperature resources are found in the upper 1-3 km of the earth's crust in volcanic regions. These have been successfully exploited, mainly for power generation for almost a century. The geology, reservoir conditions and chemical compositions are quite varied and this influences every project but in different ways. Certain things are, however, common and this paper gives a review of how the chemical problems, that are found to a lesser or greater degree at every site, have been dealt with. First an overview is presented, but then a guided tour is made by following the fluid from the production wells through the surface plant and back to the reservoir. The main problems are mentioned and solutions that have been applied to manage them. The geothermal conditions are continually changing and successful management of the risks are important for the long-term operation of a geothermal plant. The paper is an overview written with the non-specialist person in mind who wants to gain some understanding of geothermal generation and its potential.

1. INTRODUCTION

The core of the earth is molten and heat is conducted to the surface at different rates depending on the thickness of the crust and some local variations. The temperature increases by 25-30°C/km as you go down, but in places this can be two to three times this value and even higher close to where there has been volcanic activity. Volcanic activity is strong along the plate boundaries of the globe. As these volcanic areas are where there is much tectonic activity and fracturing, it opens the way for water to travel more freely than in old continental crust. The high thermal gradient and the relative ease of fluid flow leads to the creation of high temperature geothermal areas.

The volcanologists of the world wanted to prove that their field of science was not purely academic and for public safety but could also be of economic significance. Thus the investigations of “volcano power” for the generation of electricity started early in the last century. The investigations into the high temperature resources grew in time out of the volcanological and geological institutes and the geothermal industry was born in many countries just over half a century ago. Many of the pioneer geothermists are thus still with us today and the geothermal fraternity is still a relatively small one. As the industry became more established, other scientific and engineering disciplines entered to contribute to the geothermal power projects.

The industry has now come of age and some geothermal plants are reaching “middle age” or have

even been retired. A wealth of knowledge and practical experience has thus been accumulated though the years. Although the national geothermal associations and international organizations have done an exemplary job of knowledge transfer, especially in the sciences, the practical knowledge gained during the operation of the geothermal fields and running of the plants has not been as widely covered, especially where there have been problems.

Very many of these problems have to do with the chemical composition of the geothermal fluids, corrosion and scaling. This paper is meant for the non-technical person and attempts to shed some light on the reason for these chemical and operational problems and give examples of what methods or “tricks” have been successfully applied. While it is stressed that no two geothermal fields are alike, there are still enough similarities so that good experience gained from one geothermal project can be transferred or modified for another one.

2. TYPES OF HIGH TEMPERATURE RESERVOIRS

High-temperature reservoirs extend over large areas but the target of most wells is to intersect fractures or layers with good permeability. These are zones with good flow that can draw in fluids far away from the well. There are three main types of high temperature reservoirs that have quite distinct characteristics, a) water dominated, b) boiling reservoirs, and c) steam dominated reservoirs.

Many reservoirs are liquid dominated, which means that there is only geothermal liquid in the reservoir and most of the well. In a flowing well the liquid starts to boil at a depth which depends mainly on the temperature of the liquid but also on the wellhead pressure and the well productivity. The higher the temperature the deeper will be the onset of boiling, and the higher the wellhead pressure the shallower will be the onset of boiling. Above the boiling point the fluid is transported in two-phase flow, steam and water together. If the well is not very productive or the temperature high in relation to depth, boiling can move out into the reservoir and over time turn it into a boiling reservoir. Then there will be a reduction in water flow but the stem flow will be less affected, as the liquid travels slower in the rock than the vapour and is left behind. Thus the average heat content of the produced fluid, measured as enthalpy (kJ/kg), increases. As far as steam production is concerned this can be beneficial.

Finally, there are vapour dominated reservoirs where there is only vapour present in the reservoir, except at great depths in the system. In many liquid dominated reservoirs a boiling reservoir can be formed, sometimes referred to as a steam cap, after considerable pressure decline due to production. Such steam caps will form in the upper parts of the reservoir, below the “cap rock”, where the water has drained away. Wells producing from such relatively shallow wells are popular with plant operators as they produce steam only and disposal of the wastewater is not a problem.

Just how high the maximum temperature can be in a boiling reservoir is controlled by the so-called Boiling Point Depth curve. The weight of the water column from surface exerts a certain pressure and the water can reach the temperature of boiling for the respective pressure at that depth. The temperature and pressure profiles of reservoirs are quite different and will change over time due to fluid withdrawal for power generation. The main changes are in the pressure, referred to as drawdown, but the temperature can be quite stable in comparison.

Mathematical modelling allows rather precise predictions on future reservoir behaviour for different rates of production, once there is enough historic data available of these changes. The field of reservoir engineering is important in managing the geothermal fields and predicting changes in pressure, enthalpy and temperature resulting from production and reinjection. Modelling of chemical changes over time is, however, more difficult and not nearly as precise.

Due to the above-mentioned changes over time it is important to monitor the geothermal fields,

bearing in mind that most changes are very slow and thus the accuracy of measurements needs to be very good but the frequency of measurements can in many cases be reduced from the current practice. Annual down-hole measurements and chemical sampling from each well is sufficient in many cases, but more frequent monitoring of drawdown by logging or by continuous means is very desirable, e.g. in observation wells. Continuous recording of flow and wellhead pressure for each well is a vital part of field monitoring and this is backed up by intermittent manual measurements.

Good understanding of such changes is vital for the proper design of a geothermal power plant for a particular site so that it can operate efficiently over its expected life. The wellhead pressure may go down over time, enthalpy either goes up or down and the same is true for the amount of gas (so called non-condensable gases) in the steam. Most of these changes are the inevitable effects of production, and not very much that can be done to affect these changes. It is thus important to be ready to accept them and take countermeasures in time. These factors affect such things as the inlet pressure to the turbine, size of gas extraction system and process design of the waste water system. The scaling problems will also change or even disappear, as happened in a field in Iceland where calcite scaling in wells stopped as a result of degassing caused by the formation of a steam cap.

Geothermal wells have proven to be a very reliable source of energy that can be expected to last 20-40 years but some decline in mass flow is common. An often overlooked fact is that the reinjection wells may limit how much power can be generated, as surface disposal of waste fluids is often not possible or allowed. The reinjection wells are known to clog with time requiring workovers, acid cleaning or stimulation to regain the capacity to accept the waste fluid. Makeup wells have in places not been drilled as required, and thus there are geothermal plants around the world that are not producing at full capacity.

It is the complex interplay of these factors that calls for the many science and engineering disciplines to be engaged long after the geothermal plants have gone on-line. This is not normally the case for conventional power plants so the power companies need to be educated in why this extra effort is so important and what benefits it can bring.

3. GEOTHERMAL FLUIDS

The term geothermal fluid refers to geothermal liquid, steam and gas separately or together. Just what state the fluid is in, liquid or vapour, depends on the temperature and pressure. When the fluid travels as a mixture of liquid and vapour (gas and steam), it is referred to as two-phase flow. The dissolved minerals, silica and salts, are practically only found in the liquid phase. Another component of geothermal fluids is gas, mainly carbon dioxide, which is dissolved in the liquid phase until the water starts to boil. Other gases are hydrogen sulphide, hydrogen, nitrogen and methane. Upon boiling the gases are rapidly transferred to the steam phase, as the gas molecules prefer to reside in the steam rather than the water.

Geothermal fluids carry quite different concentrations of dissolved minerals and gases. The study of these is the domain of the geochemists who have now identified more than 20 chemical species and chemical ratios governed by temperature. Such temperature indicators are called geothermometers are a valuable tool in exploration as by chemical analysis of fluids alone it is possible to predict the reservoir temperature and deduct a wealth of other valuable information of what is happening in the reservoir. This is because the geothermal fluid has been in the reservoir for ages and thus reached equilibrium with the minerals in the reservoir rock.

Most minerals are more soluble in hot water than cold, e.g. silica, and thus simply knowing the silica concentration in the water can tell us what the temperature in the reservoir is or has been. As the fluid is saturated at the reservoir temperature, any cooling will cause supersaturation leading the excess concentration to eventually precipitate. Mineral deposits so formed are known to attach themselves to

pipes and other surfaces. A few minerals on the other hand are less soluble in water at higher temperature, e.g. calcite and calcium sulphate, and this is an advantage because it limits the formation of such deposits when the fluid is exploited and cools down. Equally strong an influence on the chemical evolution of the geothermal fluids upon changes in temperature and pressure are changes in the pH value. This is because the dissolved carbon dioxide and hydrogen sulphide gases are weak acids. Once boiling is initiated the acid gases leave the liquid to the steam phase, and the liquid becomes more basic (higher pH). Most mineral equilibria are affected by changes in the pH so the net effect of cooling and steam separation is quite complex and computer chemical modelling is required to keep track of the changes that occur.

With information on the chemical activity and concentrations of the chemical species, the solubility product for select minerals can be calculated to see whether the fluid is supersaturated with respect to these minerals and can thus be expected to form scale. These calculations all assume equilibrium to be reached, and although it happens quite rapidly for many minerals there are minerals, however, that take time to equilibrate. The slow rates can sometimes be taken advantage of by making the fluid travel very rapidly through the equipment. Knowledge of the rate of the precipitation reaction is thus of importance in the design of the fluid handling system. Changing the pH of the fluid by acid or caustic addition is used for example to affect the precipitation rate of silica. When you add acid the precipitation is slowed down so that a highly supersaturated solution can be handled. Conversely if you want to separate the silica out from a highly supersaturated solution that has been acidified you may add caustic, which will then cause rapid precipitation.

4. GEOTHERMAL SCALES

Two of the most common geothermal scales are silica (SiO_2) and calcite (CaCO_3). Both these scales are white coloured and not easy to tell apart visually. The silica scales often appear grey or black due to small amounts of iron sulphide, a corrosion product found inside all geothermal pipelines. A quick method to distinguish these is to put a drop of hydrochloric acid on a piece and if bubbles are formed it is calcite. Scale analysis is otherwise a tedious process where X-ray diffraction (XRD) for identification of crystalline substances and electron microscopy (SEM) for distributive and qualitative analysis, are used together with wet chemistry analytical methods.

Silica scales are found to some extent in all geothermal installations but by maintaining the temperature above the solubility level for amorphous silica (the non-crystalline form of silica), the scaling rate is very low and thus this is one of the design criteria for most geothermal plants. In the reservoir, the silica concentration is usually in equilibrium with quartz, the crystalline form of silica. Once the water starts to boil and cool down, the silica concentration in the water increases. The water immediately becomes quartz supersaturated but no quartz precipitates are formed because of the slow formation of quartz crystals. Silica scales are first formed when the amorphous silica solubility curve is passed (Figure 1). Looking at these two curves it is clear where the “window of opportunity” lies for operating the geothermal plants without silica scaling. It is the temperature vs. concentration area between the quartz and amorphous curves that is “safe” from scaling. This means in practice that only some 25% of the water can be converted into steam without the danger of silica scales, almost independently of the temperature of the resource. A silica “rule of thumb” may say that it is only possible to cool the water by some 100°C without scaling. Reservoir water of 240°C has thus to be separated above 140°C to avoid scaling and conversely a reservoir of 290°C separated above 190°C . For this reason it is not of greatest importance that the reservoir temperature be as high as possible. The higher the reservoir temperature the higher the temperature of reinjected water needs to be!

Calcium carbonate scales (in the crystalline forms Calcite or Aragonite) are common in wells with reservoirs of $140\text{--}240^\circ\text{C}$, and are primarily found where the water starts to boil in the well. This scaling is due to the degassing of CO_2 and the resulting increase in pH. Calcite has retrograde solubility (“reverse”), is more soluble at lower temperatures, and thus upon further flashing as the

water and steam travels up the well, the calcite stops rather suddenly to form scales. Calcite scales are thus primarily found over a 200-300 m long section in the well above where flashing occurs (flashing= rapid conversion of water into steam), but are not found below or above that section. This makes the management of calcite scales easier and they can be predicted rather accurately by chemical modelling. A certain amount of super saturation needs to be achieved in order for calcite scaling to become pronounced, so there is a small “window of opportunity” in this case, as practically all geothermal water is at equilibrium (is saturated) with respect to calcite in the reservoir. At higher reservoir temperature the quantity of dissolved calcite in the water will be less and therefore the calcite scaling is usually not a problem in wells that produce from reservoirs with higher temperature than 260 °C. At temperatures above 300°C, especially in highly saline water, more complex minerals can form scales, mainly metal sulphides, silicates and oxides.

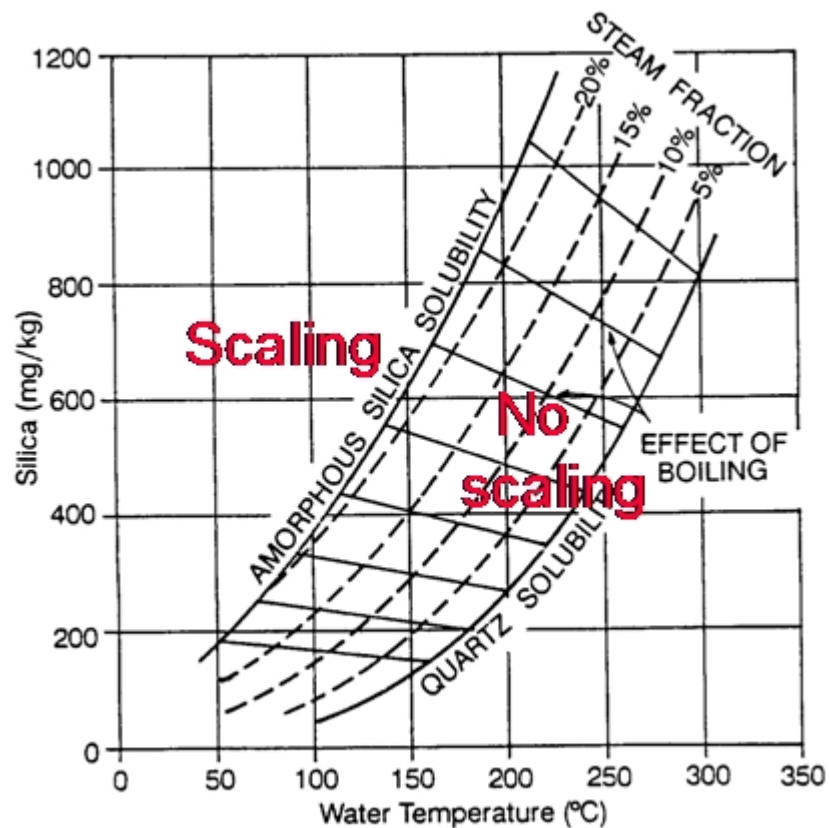


FIGURE 1: Solubility of silica in water. Scaling occurs above the amorphous silica solubility curve.

5. PILOT PLANT STUDIES AND MODELING CALCULATIONS

The engineering approach for studying scaling characteristics is to conduct studies under controlled conditions on a small scale, either by so called bench scale studies or pilot plant studies. This is preferable to full scale studies as it allows more precise studies to be carried out and at a lower cost. The nature of such studies has changed over time as the understanding and theory has advanced. Nowadays studies are more targeted, done on a smaller scale and take shorter time. By applying precise data logging and highly accurate chemical analysis, together with modelling calculations, it is possible to improve the predictions and to evaluate alternative designs. It is preferable to carry these studies out in the field with the fluids in question but in some cases the studies can be done in a laboratory away from site. The study of equilibrium is done in autoclaves where small samples are removed for analysis to monitor changes over time. Scaling rates and types of scales deposited are studied either on coupons inserted into pipes operated at different temperatures and pressures, this equipment being close to the wellhead. Operating a heat exchanger under controlled conditions is also used to determine the effects of scaling on the decline in heat transfer, and how the different fluid treatment options affect it. Other studies, for example, may involve the effect of “aging tanks” for water to be reinjected, to allow the silica to polymerize and become less scaling.

It is necessary to use chemical modelling calculations as knowledge of the concentrations of the various species is not enough. The solubility product as a function of temperature is known for a great

variety of minerals. In order to calculate the state of saturation from the concentrations you need to multiply the concentration by the activity coefficient to take into account the effect of other components in the fluid. This activity coefficient often varies between 0.4-1.0, depending on the mineralization of the fluid. Speciation programmes WATCH, SOLVEQ, EQ3/6, FERREQ and others are used. Among the results is the solubility index for the various minerals (SI). If the $SI > 0$ there is potential scaling (super-saturation), but when the $SI < 0$ there should be no scaling (under-saturation). These programmes require total chemical composition of the fluid to be known. Therefore this takes time and is somewhat costly to set up such models. These studies are often not carried out until a few years after a geothermal plant has gone on line, when people realize that the knowledge base is not solid and questions arise such as; how far into the scaling region can you operate, e.g. by installing bottoming units or binary units, or which fluid treatment option to apply to minimize scaling problems in reinjection wells.

6. SCALE MITIGATION MEASURES

It is simply not enough to know what the equilibrium concentrations of the scaling minerals are, as information on how quickly equilibrium is reached is of paramount importance. Many scales form almost instantaneously (e.g. calcite, sulphides) once the fluid becomes supersaturated, whereas silica and metal silicates for example take some time to equilibrate and the reactions are strongly influenced by pH, temperature and salinity. Low pH, temperature and salinity slow down the scaling rate of silica and this is often taken advantage of in process design. An example of this is the acidification of silica supersaturated solutions to lower the pH sufficiently (appr. pH 4.5-5.5) to slow down the scale formation, for example in heat exchangers of binary units for the generation of electricity. This may increase the corrosion rate of pipework. It is relatively simple to apply as sulphuric acid or hydrochloric acid which is simply injected by means of a chemical metering pump into the brine pipeline.

By rapidly dropping the brine temperature on the second flash separator for example by the use of vacuum, scaling is much reduced. That way the second flash steam can be used and the waste brine leaves the process equipment without clogging it. Saline solutions will precipitate the silica more quickly than dilute ones, due to higher reaction rate. It has thus been shown to be possible to take advantage of the slow scaling rate in dilute geothermal water and operate heat exchangers and binary units within the scaling regime, which would not be possible for brines.

The water chemistry can be modified by adding chemicals but the sheer volume of fluid that needs to be treated means that only chemicals that can be used in very small concentrations can be considered for cost reasons. One class of chemicals are the so called "scale inhibitors". Their main function is usually to affect the surface chemistry rather than a particular chemical reaction. Scale inhibitors have been used successfully to stop the precipitation of calcite in wells with low treatment levels, a few milligrams per litre. One such inhibitor contains polyacrylates, a polar high molecular weight chain that by surface charge attaches itself immediately to the small calcite crystals as they are formed and prevents them from sticking together and developing a scale. For this to work the inhibitor needs to be pumped down into the well through a capillary tube (a small diameter pipe suspended inside the well) deep enough (e.g. 500-800 m) to be mixed with the water before the onset of boiling.

High degree of turbulence enhances scale formation for example by the liner hanger in wells and just downstream of orifices or valves that are used to throttle the flow. Where the flow is saturated steam with some impurities there may be a "drying out" effect from the sudden loss of pressure that causes scale build-up, as the steam becomes superheated. Geothermal scales usually form a very rough surface and rippled deposits that have peaks that lean against the flow inside pipes. The effect of these deposits can be quite pronounced in spite of being only a few millimetres thick inside a good size pipeline. The reason is that the pressure drop becomes much greater than in a smooth pipe and thus reduces the flow capacity up to half compared to the design for a clean pipe. The design of reinjection

pipelines must take this into account and be provided with means to remove or to smooth the roughness by periodically running plugs through the pipelines, so called pigs.

The scaling conditions are thus constantly changing as the geothermal fluid travels from the wells and through the pipelines and back to the reservoir. This makes scaling prediction somewhat uncertain but by coupling chemical modelling calculations, pilot studies and practical experience it has usually been possible to come up with solutions that will overcome the most serious scaling problems. What most geothermal plants are, however, left with are maintenance problems of various dimensions. To monitor the scaling or corrosion at various locations in the pipelines it is possible to install retractable coupons that can be removed for periodic inspection without affecting the flow or operation of the plant.

7. A GUIDED TOUR THROUGH THE PIPELINES

In order to explain where and how various problems show up in the field and plant equipment a “guided tour” will now be conducted through the fluid network (Figure 2). Some of the solutions to overcome these will be mentioned as we move along.

7.1 The reservoir and well

Fluid in the reservoir has often been there for thousands of years and the fluid interactions with the rock are clearly noticeable. In the rocks the minerals have been altered in composition and crystal structure and secondary minerals have filled voids and fractures. Some fluid is even trapped inside crystals as they are formed and geologists and geochemists have been able to reconstruct the volcanic and reservoir history from such evidence, old and new. New fractures have opened fluid paths and these are now the main conduits for the fluid moving towards the wells. The cumulative voids of these fractures becomes large in the reservoir away from the well so any new precipitation is not likely to clog the reservoir, except near the well where the volume becomes smaller. The smallest volume that the fluid passes through is the well itself, and therefore that is the spot where any scaling is most detrimental.

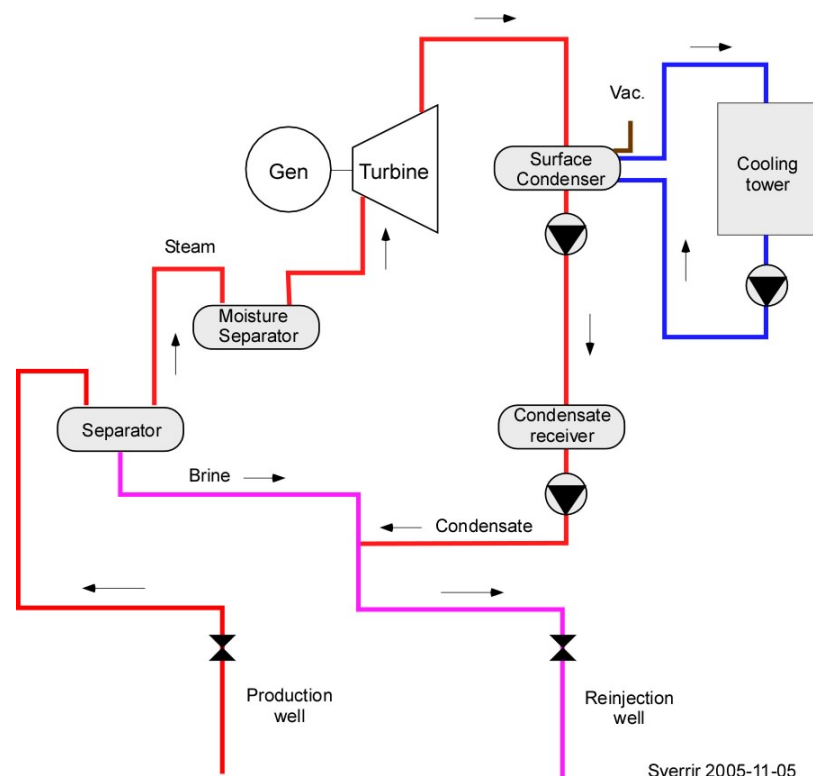


FIGURE 2: Sketch of the fluid path of a conventional geothermal power plant with a surface condenser

If the rock has stood up well during drilling and no collapses noticed, it is now becoming more common to have the section within the reservoir without a liner. The liner is meant to keep the well open, but the slots can become clogged. For this and cost reasons “barefoot” wells are becoming more common, where there is no slotted liner. Inside the liner or casing the fluid starts to lose gas and soon thereafter, a little higher up in the well, it starts to boil. This is a time of intensive chemical activity as

the non-condensable gases are “stripped” from the water and the pH value goes up, affecting the chemical balance in many ways. Calcite scaling appears at this point and some silicates and sulphides as well but in smaller quantities. The calcite will continue to precipitate until the water has cooled sufficiently, as then the water becomes under-saturated. As the steam is formed it starts to dominate the volume and thus the density of the two-phase fluid decreases, and keeps on decreasing as the fluid rises to the surface.

The temperature and pressure profile up the well can be calculated rather accurately and actual measurements are also made inside the wells while they are flowing. The temperature inside the well is usually kept high enough for the silica to stay within the safe “No scaling” area as far as scaling is concerned (fig. 1). The exception to this is for wells that have very poor inflow or are fully opened for maximum flow. In this case the restriction to flow will cause a large pressure loss and consequent temperature drop. The temperature may fall within the scaling region and that is to be avoided. The way to overcome this silica scaling problem is to partly close the valve on the wellhead, or throttle the flow by other means, and thus by reducing the flow the pressure at the wellhead is maintained high enough.

7.2 The wellhead

The only moving part of the well is the gate segment in the master valve and in other valves on the wellhead. Small scaling deposits are always found at the wellhead, and in order for the master valve to shut tightly, a valve of a special design is commonly used. This valve of the “expanding gate type” has a split gate that wedges against the valve seats in both the open and closed position that constantly protects and blocks scale build-up on the seats. Other valves on the wellhead may not have this feature, but then you do not depend on them for complete shut-off. For valves facing the well it is normal to design for redundancy, to have two valves in series. To avoid operating the well in the silica scaling region an orifice or a throttle valve is used to maintain the wellhead pressure at 8-25 bar, while the downstream pressure can be 6-12 bar.

The wellhead valves are either operated manually, electrically or hydraulically. This way the flow can be adjusted to meet the plants demand. Anywhere where there is a leak, such as at the valve glands, scaling will build up immediately as the water simply evaporates, leaving the dissolved solids behind. It is thus important to insure that the glands are properly packed and any leak whatsoever on the wellhead and expansion spool sealed immediately. There is a special injection tool for this, to force the sealing compound into place. The master valve usually lasts at least for at least 10 years without it having to be replaced. To replace the wellhead valves or sealing leaks below the master valve it is preferable to use a special packer to plug the well, called hot wellhead replacement. The master valve is removed with the well itself still under pressure, rather than to kill the well with cold water or mud. Geothermal wells may produce uninterrupted for years without any maintenance, except for that of the wellhead as mentioned above.

The only major overhaul has to do with removing down-hole scales. The scales most commonly removed by a drilling rig are calcite scales. They are drilled out with a common drill bit to a depth just below the start of boiling. Other scale types are similarly removed, and methods are available to do this during well discharge. The cuttings are removed from the well with the water and steam and the well can be on-line a couple of days later. The benefit of that method is also that the casing is not thermally stressed to the same extent as when wells are killed by water and cooled down. The main scale mitigation measures for geothermal wells is thus to maintain a certain wellhead pressure to be “safe” from silica scaling. Scale inhibitors are sometimes used for calcite.

The worst type of corrosion on a well is outside corrosion of the wellhead just below the soil or cellar floor that occurs during stand-by when the casing is allowed to cool. For this reason it is best for long life of wells to always keep them hot, either by production or bleeding to a small silencer. Corrosion problems can also be found in fluid disposal systems, e.g. condensate collection system or in

reinjection lines when the pH is low. The condensate collection system is typically made from stainless steel but to treat condensate corrosion in reinjection pipelines and wells of mild steel, adding soda ash to elevate the pH to 5 or to mix it with waste brine is required. Such pH control has also been found to be necessary in a few very acidic production wells. Then the caustic is injected through capillary tubing deep into the well.

7.3 Steam-water gathering system

The two-phase flow is usually piped to a central station where steam/water separators for several wells are situated. Older designs had the separators by each well. Because of the difficulty of running the flow uphill due to slugging and flow instability, the separators are usually sited below the elevation of the well pads and the pipes made to slope downward. This can be difficult to achieve for some wells as the geothermal fields are on the slopes of volcanoes and in rough terrain. Inside the pipes the velocity is up to 40 m/s with the water flowing at the bottom of the pipe, sometimes leaving a thin trail of scale deposits covering about 1/3 of the circumference.

7.4 Separators

The water needs to be separated from the steam to minimize scaling in the steam consuming equipment. This is done after the steam has been “flashed” to the selected pressure in several stages. The steam-water separators do this very efficiently where the steam comes out at the top and water out at the bottom. The minimum temperature for operation with respect to silica scaling is usually the factor that decides the pressure at which to operate the separators (fig 1.). Separation at a lower pressure will invite silica scaling.

The steam separators are of two main types, vertical with tangential inlet to the drum, or horizontal with a top inlet. The water droplets are removed by gravity for both types, the vertical separator with the assistance of centrifugal forces and the horizontal separator with wire mesh or chevron mist eliminators. The separators can be overloaded by too much flow which will cause carry-over and loss of efficiency. Experience has also shown that a long steam pipeline from the separator centre to the plant of say 400 m is very effective in cleaning the steam. Then the fine mist adheres to the pipe walls and is finally removed in condensate pots along the steam pipeline. Occasionally steam scrubbing is employed where condensate is sprayed into the steam, especially if the steam originates in “dry steam” wells.

Although the separation efficiency can be quite good a final separator, called mist eliminator, is installed close to the power plant. The mist eliminator has a wire mesh filters, but most of what it removes is condensate that has formed in the steam pipeline. The geothermal steam is usually of very high purity, almost like distilled water, with the percent separation efficiency having four or five nines (99.99-99.999%). The steam purity is checked for two things: mineral content and gas content. The best indicator is usually the sodium concentration and chloride in the steam and the non-condensable gases (CO₂, H₂S) are absorbed in a caustic solution in an evacuated flask and determined by titration. Another method, less precise, is measuring the volume of liquid and gas flow individually coming from a cooling coil. Regular monitoring of the steam quality is important as any impurities will over time clog the turbine inlet nozzles. An increase in the gas concentration affects the gas extraction system and if overloaded causes a reduction in the condenser vacuum, and hence a reduction in the turbine output.

The maintenance of the separators is mainly on the level control valves that have a tendency to stick but in general the separators need inspection and cleaning about once a year. Proper inspection openings and clean-outs manholes are therefore required. Most of the cleaning is by high-pressure washing. Control valves with oversize actuators, routine exercising of the valve (open/close) and irrigation of the valve gland with condensate are all known to help.

7.5 Turbine

Geothermal steam turbines are for the most part similar to conventional steam turbines with modifications to suit the geothermal conditions. The most common type is a single flash turbine, but dual flash units were also popular. Slightly more power could be generated in the dual flash units from liquid dominated reservoirs. There were two drawbacks to this. The low pressure stage was frequently in the silica scaling region so reinjection wells lasted a shorter time, and also with time the enthalpy of the reservoir fluid would change and thus the ratio of high- and low pressure steam drifted from the design condition. Some units have double flow, this is when the steam enters at the centre of the turbine and flows equally to both ends, thus balancing any axial forces on the rotor that otherwise have to be dealt with. Now axial turbines are gaining popularity.

The turbine blades are of two main forms, impulse and reaction. The impulse blades have a larger pressure drop over each stage and thus such turbine rotors have fewer stages. The reaction blades have become more popular as the seals between the turbine stages are not as important. These labyrinth seals are one of the things that wear out and need maintenance work during major overhaul.

The turbine is a rather simple piece of equipment, consisting of a rotor with several stages of blades on the rotor and an equal number of stator blade stages in the turbine shell. The turbine speed is maintained constant by a governor that acts on the turbine control valve. The steam is equally distributed over the whole turbine circumference from the steam chest through the first stator stage (non-rotating). It is on the back side of these steam inlet nozzles (stationary blades) that scaling accumulates. In time the scale build-up starts to restrict the steam flow, increasing the steam chest pressure and eventually lowering of the generator output.

A commonly applied method to clean salt/silica deposits in turbines is to do "turbine washing" by injecting a steady stream of condensate into the steam line just in front to the turbine. The moisture in the steam is brought up to about 5% and after a few hours of washing much of the turbine output is recovered. This may perhaps be done twice a year and should not be done frequently as it does cause some erosion damage.

Once the steam starts to do work it condenses partially (10-15%) as it passes through the turbine. Thus appreciable scaling is not found on the rotor blades or stators, except for the first stage. The last two rotor stages frequently have Stellite (cobalt-chromium alloy) wear protection (plates brazed on the leading edges of the turbine blades) against water droplet erosion from moisture increases and the very high tip velocities of the blades. Compared to conventional turbines, more moisture has to be removed through drains in the shell of geothermal turbines and other design modifications are to minimize droplet erosion. The amount of electric power generated per kg/s of steam depends greatly on the vacuum level in the condenser. It is not always appreciated that the amount of electric power generated is doubled by the 100 mbar vacuum in the condenser compared to turbines without a condenser (so called back-pressure units). Steam at such low pressure is very voluminous and thus the large pipe leading to the condenser.

7.6 Turbine condensers

The condensers are of two main types, direct contact and surface condenser. The direct contact condenser has water spray nozzles and is sometimes referred to as a spray condenser. The surface condenser has a bundle of tubes like a heat exchanger. The steam is rapidly condensed but the so called non-condensable gases have to be continually removed by vacuum pumps. If the vacuum level drops due to inefficient gas removal or due to an elevation in the condenser temperature, as can happen on a warm day, the generator output will decline.

The condensed steam has to be pumped from the condenser and a part of it goes to the cooling tower as make up water and the other part is disposed of to reinjection wells. Because of the low pH of the

condensate going to the cooling tower, soda ash is added for control. The cooling towers can deposit sulphur compounds and various bacteria thrive which periodically have to be removed by water jetting or brushes from the water distribution nozzles. Controlling the pH in the range 4.5-5.5 and adding biocide are the countermeasures employed. Cleaning sulphur deposits and bacteria colonies is required at regular intervals by high pressure washing and using wet “vacuum cleaners” to suck up the loosened material in the concrete sump under the cooling tower.

7.7 Gas removal system – gas cleaning

The gases are cooled as they leave the condenser and are piped to the vacuum pumps. About 80% of the non-condensable gases pass through the gas removal system, the rest go with the condensate to the cooling tower. They are of several types: a set of steam ejectors, mechanical vacuum pumps (liquid ring), a system combining both turbine and compressors (hybrid). The selection is influenced by the concentration of non-condensable gases in the steam, very roughly in this way: if the gas concentration is low 0.5-1.5% the simple and reliable steam ejectors are used, or a vacuum pump; if the gas concentration is in the range 1.5-5% the combination of ejectors and vacuum pumps is favoured and turbine compressors for higher than 5% gas concentration. As most geothermal steam contains 0.5-2% gas, it is most common to use steam ejectors or the combination of ejectors and liquid ring vacuum pumps.

The gas will typically contain about 2% H₂S by weight, which is a poisonous gas and there are regulatory limits on its release in many countries. A common method to stay within limits is to assure good dispersion of the gas in the atmosphere is by piping it to the cooling tower fans to mix it with the steam plume from the cooling tower. Other plants have a high chimney and sometimes two chimneys to take advantage of prevailing winds by diverting the flow to the downwind one to reduce the H₂S levels at the plant site. In the United States, Italy and Japan, gas cleaning is used to remove the H₂S from the gas before its release to the atmosphere. These plants are very close to densely populated areas where just the slightest smell evokes strong reactions. In Iceland the smell is one people are familiar with from visits to natural geothermal areas and the geothermal hot water piped to every house even has a slight odour. There are growing demands in Iceland to have the plants control the H₂S gas emissions. In the Mediterranean countries hydrogen sulphide it is the smell of death from decaying corpses and thus not popular. Hydrogen sulphide is a very poisonous gas, and has to be disposed of with care. Any person working in cellars, in tanks and pipelines that can accumulate gas must be made aware of the dangers of this gas.

There are a number of processes employed for H₂S removal from the main gas stream before the release of the carbon dioxide such as: gas incineration and scrubbing, Stretford process, Lo-Cat process, and PSA system. The release of a few hundred tonnes of sulphur per year in sparsely populated areas may not warrant the extra cost of today’s technology. This is, however, a tricky issue that must be handled with care. Future technology may lie in converting the H₂S to acid that is then used to hinder silica precipitation in the reinjection system and leave the CO₂ clean enough to be a source of liquid CO₂ industrial gas. Experiments are under way to reinject the CO₂ into wells and trap it as calcite in the basalt lavas. Carbon dioxide typically is about 98% of the gas and is released in thousands of tonnes annually from most geothermal power plants. For example, the typical annual release of CO₂ from a 50 MW power plant would be (with 1% non condensable gas, 98% of it CO₂): $50 \text{ MW} * 2 \text{ (kg/s)/MW} * 0.01 * 0.98 * 3600 \text{ s/h} * 24 \text{ h/d} * 365 \text{ d/yr} = 30,905,280 \text{ kg}$ or 31,000 tonnes per year. Carbon dioxide has numerous uses in the soft drink industry, as dry ice that preserves vegetables and fish for market by maintaining a low temperature and excluding oxygen, plus use in carbon dioxide enrichment inside greenhouses. A pilot plant in Iceland is being constructed that will convert the geothermal CO₂ to methanol.

Small non-harmful hydrogen sulphide concentrations around the plant site are common. Thus cleaning the air with H₂S filters placed in trays inside in the air conditioning system is required. By maintaining the control rooms and control centres at slight overpressure with clean air, the copper and

silver in modern electronic equipment in control rooms is protected.

7.8 Reinjection system

Total reinjection of wastewater, brine or condensate, from geothermal plants is usually the requirement nowadays. The water fraction from the high-pressure separators is typically 75-80% of the total flow for liquid dominated reservoirs, 20-25% being the high pressure steam that drives the turbines. This water fraction is smaller for wells with a disproportionately high steam fraction, referred to as high enthalpy wells. Nowadays, this waste water is usually reinjected into wells, preferably that are in hydraulic contact with the reservoir being produced to assist in pressure maintenance, but far enough away not to cause cooling due to short-circuiting. Ideally for this the reinjection wells should be about 2 km away from the production wells not to cause a thermal breakthrough. The nature of each field, however, has to be taken into consideration for spacing of wells and the strategy for reinjection.

There are several methods employed at present to minimize the damage to reinjection wells due to scaling. The most common one is to do "hot injection" that is when the water temperature is maintained above the scaling limit for amorphous silica, commonly above 150°C. Where surface condensers are used, it is a good idea to mix the condensate with the brine to be reinjected, and ideally to dilute it below the silica saturation limit. These wells usually retain their injectivity for a long time and the wellhead pressure will be the saturation pressure for the temperature of the injected water. This means that the wells accept the water readily and it is not necessary to pump the water down the well. In several non-saline fields silica super-saturated water is being reinjected. In those cases before the reinjection well, the silica is allowed to polymerize in open ponds or retention tanks. The reinjection wells will initially accept the water quite readily but may lose the injectivity after few years due to scaling. Then the wells will require very expensive treatment to recover the injectivity such as: workover with a drilling rig to drill out the scaling, sidetracking to make a new well parallel to the old one, acidizing by pumping hydrochloric acid and mud acid (hydrofluoric acid) into the aquifer to dissolve some of the deposited silica in the veins.

Another method gaining popularity for treating water before reinjection is acidizing the brine to say pH 4.5-5.5 by injecting sulphuric acid (or hydrochloric acid) to stabilize the silica way below the amorphous silica saturation limit. The precipitation of silica is highly pH dependant, being highest in the range pH 7-8, and is also influenced by the salinity. The pH control method allows more energy to be extracted from the fluid, either by a double flash cycle or by a binary fluid cycle (working fluids: isopentane or ammonia/water).

There are several cases where a plant is not able to produce at full load not because of lack of steam but due to inadequate reinjection capacity. Wells that are not very productive or have been retired are many times used for reinjection but the disadvantage is that they may be too close to the production wells for long term injection.

8. CONCLUSIONS

This paper has presented a brief description of the geothermal fluid cycle from the reservoir up the production wells through the surface equipment and power plant and back down the reinjection wells. Explanations were given why, for geothermal generation, more studies are called for and for a longer time, compared to other power sources. Also how decisions made early, affect these problems e.g. on pressure at which to operate and power conversion equipment selection and affect the maintenance and operations problems to be encountered. In spite of this, most problems have been found to be manageable and a testament to that are the many geothermal power plants around the world. Much can be learned from the long experience gathered from these operations where the reservoirs and fluids can be quite different.

The most persistent problems have to do with the chemistry of the fluid, mainly where the desire is to generate as much electric power from the fluid as possible. By small scale pilot studies and chemical modelling it is possible to find ways around or to manage the most serious chemical problems. Pilot studies together with practical experience gained in each field and by applying proven methods will lead to the lowest cost of production.

The general experience is that it is easy to avoid silica scaling in production wells by maintaining proper wellhead pressure. The most common scaling problem is where calcite scaling occurs at the zone of boiling. Minor scales in turbine inlet nozzles are removed by “turbine washing” without shut-down. In the surface equipment and turbine periodic cleaning is called for, usually by high pressure washing. Scaling in reinjection wells and loss of injectivity is, however, a very common problem and is costly to deal with. This “un-glorious” side of the geothermal power cycle therefore deserves very careful attention as several of the decisions made early in the project can be costly to deal with later. Finally one must remember that the geothermal reservoir evolves over time delivering the fluid at different pressure, mass flow, enthalpy and chemical composition. The geothermal power companies are thus facing a constantly changing environment. By successfully managing the operation of the plants they can continue to produce over many decades.