The United Nations University

GEOTHERMAL TRAINING PROGRAMME   IGC2003 - Short Course
Orkustofnun, Grensásvegur 9,   September 2003
IS-108 Reykjavík, Iceland

Geothermal well operation and maintenance

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Abstract

Proper maintenance and operation of geothermal wells is vitally important in achieving success for a geothermal project. The geothermal industry grew rapidly worldwide in the last decades of the past century. These assets are aging and in some cases repairs or rebuilding are called for in order to extend their life and to maintain generation capacity. Geothermal wells have been found to be an extremely reliable source of power and in fact it is best if the wells can be allowed to run continuously. Considerable experience has been gained in how best to operate and maintain the geothermal wells. The things described here are mainly from experience gained in Iceland where 50 high-temperature wells are currently in operation and some 320 low-temperature wells, several over 40 years in age. The paper presents an overview of how to detect whether something is abnormal in the behaviour of a well and in deciding what can be done if the problem is related to the well itself. Methods as to how to start and kill wells are described. How to combat scaling with reaming or by inhibition is also described.

Keywords: *geothermal well, well maintenance, well operation, workover, wellhead, scaling, monitoring.*

1 Introduction

The geothermal industry worldwide grew rapidly in the latter half of the last century, especially after 1970. Considerable experience has been gained in operating and maintaining geothermal wells, steam systems and generating plants. The generation industry is rapidly changing from a stable, regulated past to a future of competition, changing asset ownership, and new business goals. As the business environment continues to evolve, managers and engineers are being challenged to adopt new competitive business models, to manage change, and to obtain the highest levels of performance from the work force and the assets. Maintenance of these assets has become and will continue to be a key aspect of these challenges. As competition grows, and as the drive to improve reliability and performance with fewer resources continues, new maintenance techniques and technologies will be ever more important. This paper focuses on the operation and maintenance of geothermal wells. The wells are 30-50% of the total asset value of a geothermal electric generating plant and are an essential part of the operation, as there is no way to make up for any shortfall in steam except from wells. A high-temperature well typically costs 1.5-3 million USD and thus it is important to maintain the wells and manage the field in such a way to extend their life as much as possible. A life of 20 years was considered adequate for high-temperature wells in the past, but in reality the wells may be able to safely produce twice as long. Low-temperature wells can be expected to last much longer.

2 Geothermal well designs

2.1 Casing profiles

Geothermal wells are of two main types, high-temperature and low-temperature (Figure 1). The design of high-temperature wells worldwide is remarkably similar in the casing profiles and materials. The casing sizes and materials are based on standards for oilfield tubular goods. The most common casing size for the production casing in high-temperature wells is 9-5/8" o.d. (normal diameter) or 13-3/8" (wide diameter). For many wells, the maximum flow rate is dictated by the well diameter, which is roughly proportional to the cross-sectional area of the casing. Wide diameter wells are known to produce twice as much as normal sized ones. The casing profile usually has three or four cemented casing strings of different lengths to meet the safety requirements while drilling, and a slotted line hung in the open hole. The length of each casing is somewhat different, but it is roughly 1/3 of the depth for the next section of hole to be drilled (e.g. 100 m surface casing to drill to 300 m, 300 m anchor casing to drill to 900 m, and the production casing shoe is at 900 m to drill to 2,700 m). The exact determination of casing depth considers the reservoir pressure and geological conditions but this 1/3 "rule of thumb" is just to explain that in general, the deeper you drill, the deeper all casing strings have to reach. The casing connections are typically thread of the Buttress type and the steel material API grade K55 (weldable) or L80 (not weldable). The only casing hardware going down into the hole with the casing is a float shoe and float collar for cementing the casing, to prevent return flow, and centralizers to hold the casing in the middle of the hole while being cemented.

The low-temperature wells only have two or three casing strings and in Iceland do not require a well-screen, they are open hole in the productive interval – "barefoot". The depth of casing is governed by the target temperature and geological criteria as danger of uncontrolled flow is not as great as for high-temperature wells. These wells are also drilled with special valves, so called blow-out preventers (BOPs). The output of low-temperature wells is for very productive reservoirs, limited by the diameter of the deep well pump that can fit inside the casing (e.g.15 l/s for 7" casing, 45 l/s for 9-5/8" casing, 100 l/s for 13-3/8" casing).

2.2 Wellhead designs

There are two main designs of the wellhead. Early on, the casing head and master valve were attached directly to the production casing and the annulus to the anchor casing left open or had a stuffing box (Figure 4). Now most wells have an expansion spool where the casing head is attached to the anchor casing and the wellhead built up from there (Figures 2 and 3). The expansion spool allows the production casing to expand freely without the wellhead moving. Wellhead expansion is, however, not a major problem as a properly cemented casing only expands by a couple of centimeters. Manufactured expansion spools have a pressure seal between the production casing and anchor casing (Figure 3). This seal has to be carefully installed and the seal maintained pressure tight by periodic injection of a special sealing compound. The expansion spool is sometimes fabricated locally and is then without the pressure seal (Figure 2). There are several side outlet valves attached to the casing head and expansion spool to allow pressure testing of the annulus, and for killing of wells. These outlets often cause leaks that can be difficult to seal. That is the reason why most high-temperature geothermal wells in Iceland do not have these outlets below the master-valve, and the killing takes place through a valve between the master valve and the operation valve. The operation valve for the master valve sits either directly above it or on the horizontal leg downstream of the wellhead T-ee. The wellhead T-ee has a flange on top with a 3" valve for logging. A guiding tube is attached to the flange to keep the logging wire from going with the

flow, through the side port of the T-ee. The well flow is usually throttled at the wellhead by a fixed orifice or a control valve. The preferred method now is to use a control valve in order to match the flow requirements of the plant. Usually there is a small by-pass around these valves to allow the well to flow when shut. For the same purpose there is a pipe from the well to a small separator or rock muffler to keep the wellhead hot, when not in use. The wellhead also has a small valve for fluid sampling and for pressure gauges etc.

The wellheads on low-temperature wells are quite different, and do not need a valve, unless artesian. Artesian wellhead pressures as high as 15-25 bar-g have been measured in Iceland but most low-temperature wells require pumping. The deep well pumps, either of the shaft driven type or with a submersible motor, are simply attached to the casinghead. The annulus between the pump riser pipe and production casing should be closed so that atmospheric oxygen does not get into the hole and cause corrosion. The shaft driven pumps can pump water at high temperatures but the submersible ones are limited by the temperature rating of the motor and cable.

3 Geothermal well monitoring

3.1 Main parameters measured

As an integral part of any reservoir exploitation, a monitoring system is set up. The main purpose is to provide information on the fluid produced and reinjected, and to allow long-term monitoring of the physical and chemical changes that occur. Interpretation of this data and reservoir modeling is necessary for understanding the reservoir behavior. In most countries such data must also be sent to a designated government authority at regular intervals. This data is also very valuable to the daily running of the power plant to meet production goals and to detect any abnormality in the well or its operation that may require human intervention. The main parameters measured are:

1. The wellhead pressure (WHP bar-g) is recorded continuously for each well and in many cases also the wellhead temperature (WHT °C).

2. The total flow rate is measured continuously for each well (Q kg/s), and because of the difficulty of measuring 2-phase flow also the total steam and water flow may be measured. In some cases, the turbine output (MWe) is used to estimate the steam flow as a turbine is quite a good "steam meter". Also on control valves it's position (valve opening) is sometimes recorded for indication of flow.

3. Down hole temperature and pressure surveys are made 1- 2 times per year, either with the well shut in or while flowing.

4. Observation wells and reinjection wells have the pressure recorded on surface or down-hole.

5. Caliper surveys are made of the well casing intermittently, for determination of any change in diameter either from scaling, casing damage or corrosion. For this, baskets of different diameters are run on a wireline into the hole. Special multi-finger casing calipers are sometimes run to detect corrosion damage along with a CCL tool. A multi-arm electrical caliper tool can be run into the well when quenched. Some high-temperature calipers are available.

6. Chemical samples are taken at the wellhead 1-2 times per year through a small sample separator of the steam and water phases.

7. Steam samples are taken regularly at the turbine inlet to measure non-condensible gases and selected minerals for determination of steam purity.

8. An output test is made about once a year by diverting the well flow temporarily to a silencer/separator and measuring equipment. Usually the lip-pressure method for total flow and V-notch weir for water flow is used. This allows the well "output curve" to be

determined (by measuring mass flow vs. WHP for several points) and for the average fluid enthalpy to be calculated (kJ/kg). Temporary injection of tracers into 2-phase pipelines is also used to determine the flow rate of steam and water phases separately by injection of a volatile (e.g. sulphur hexaflouride SF_6 for steam flow) and non-volatile tracers (e.g. sodium benzoate $C_7H_5O_2Na$ for water flow). This method does not require diversion of the flow or silencer/separator measuring equipment in the field. It does, however, require portable dosing equipment and balances to measure the dosing rate and laboratory equipment for determination of the tracers in the respective phases.

9. On low-temperature wells having down-hole pumps, the motor Amp, Hz (on variable speed pumps), down hole pressure (draw-down) and discharge pressure at the surface is also measured.

10. Corrosion coupons are sometimes installed at the wellhead of production and reinjection wells to monitor the corrosion/scaling situation. It is preferable to use coupon holders that can be inserted and withdrawn without stopping the flow (Figure 5).

3.2   Monitoring systems

The continuously recorded well parameters, items 1 and 2 listed above, are measured by electronic sensors and logged in a computer SCADA system. In Iceland, solar powered recording stations are used for distant wells to transmit data through a commercial mobile phone network (GSM modem, Figure 4). Such data is frequently published on the Internet, at regular intervals, to allow greater access to the data for persons not on site, such as company managers, engineers and scientists. Greater awareness of what is happening in the field by such an expanded group has proven valuable, as quite a lot can be gleaned from the well data. Any abnormality thus gets identified and acted on a lot sooner than without such direct access.

The instruments and methods applied must give reliable data. For this purpose, a manual recording is made to confirm the logged readings e.g. with calibrated pressure gauges to confirm the logged readings or by cross checking by mass and energy balance calculations. Because of the harsh environment of the sensors, the most frequent cause of changes in instrument readings is the instrument itself failing! The electronic recording devices have become very reliable, but the measuring devices and sensors are still giving problems in geothermal operations. Partly this is due to inherent problems in measuring 2-phase flow, scaling in the capillary tubes and ports, gases in the steam, pressure pulsation in the wells and vibration.

The data is a valuable resource but a lot of it gets collected without it being used to the fullest. The benefits of data interpretation as far as operation and maintenance is concerned are many. The short-term benefits are in the daily operation of the field and to insure adequate steam supplies and injection capability. Venting of any excess steam to the atmosphere was the practice in the past but now most plants try to modulate the well output to match the requirements. The long-term benefits are to allow planning of preventive maintenance and adequate time to plan for drilling of make-up wells or workover operations. A good number of geothermal power plant around the world are not producing at full capacity due to shortfalls in steam supplies, loss of steam pressure or not enough reinjection capacity. The commonly reported statistics of installed power in MW can thus be somewhat misleading. Reporting also the MWh generated gives a fuller picture.

3.3   Indications of abnormality

Normally any changes in well behavior are very gradual and can sometimes only be detected after several years of observation. Changes that occur over a short period are indications of

abnormality that may require operator interaction or maintenance work. Thus having access to such trend data is important in identifying what may be the cause (trouble-shooting). This chapter focuses on such sort-term changes that are indications of abnormality.

1. Sudden changes in pressure readings or in other parameters are quite frequently simply the result of instrument failure!
2. Lower or higher WHP than expected can be caused by more or less fluid withdrawal from the well. Thus check the control valve opening and any other signs of flow restriction e.g. a plug of scale just behind the control valve or orifice by the wellhead.
3. Gradual lowering of WHP over several days or weeks, at a fixed well opening may indicate scaling in the well that restricts the flow.
    a. Calcite ($CaCO_3$), a common scaling mineral in wells of 180-250°C, occurs at and above the zone of flashing and develops a ventury like throat (Figure 10). The deposition is gradually reduced higher up in the hole and at the surface there may be no signs of scaling. Once the opening becomes small (<100 mm) choking sets in and the WHP pressure decline becomes more rapid. Calcite scaling can thus be limited to a few hundred meters inside the casing where it can easily be removed. After cleaning out the scale, the well is again like new. Scaling down in the slotted liner are, however, not so easy to remove.
    b. Silica or sulfide scale are more evenly distributed in the well and thus the pressure decline is not as rapid as for calcite in the terminal phase.
    c. Inrush of colder water into the reservoir.
    d. General lowering of the reservoir pressure due to exploitation.
4. Gradual increase in WHP.
    a. The well is being transformed from a water dominated reservoir to a 2-phase reservoir and finally to a steam cap. Such increase in WHP from 14 bar-g to 25 bar-g has been noted on a well in Iceland. Generally, such a transformation also results in much higher concentrations of non-condensible gases, mainly CO_2, in the steam.
    b. While the well is heating up after cooling e.g. due to killing.
5. Flow pulsations or slow pulse rate, may be due to too low a flow rate resulting in "Geysering" or slugging. Opening the well further may solve this problem. Higher pulse rates of several Hz are normal for 2-phase flow wells, the greater the flow rate the higher the pulse rate. Should the vibrations of the wellhead become too great, lowering the flow rate should help.
6. Pressure and flow cycling of wells due to two different feed zones, dependent upon which one is dominating. Chemical analysis may reveal this e.g. salinity or geothermometers.
7. Sudden lowering of WHP.
    a. Collapse of the casing or sudden casing damage.
    b. Low yielding wells may self-quench if produced at too high a flow rate. They will normally return back to flow themselves, but need to be held back more on flow to maintain even flow.
    c. Earthquake.
    d. A coiltube for chemical inhibition may have broken and fallen down causing a restriction.
    e. Control valve or choke problem.
8. Sudden increase in WHP.
    a. Earthquake.
    b. Scale may have broken loose, especially where the choking is occurring.
    c. Control valve or choke problem.

4 Killing and starting wells

4.1 Well temperature and pressure profiles

The temperature and pressure profile of each well (p & t vs. depth) can take many forms and no two reservoirs are the same. Wells within the same reservoir in fact are remarkably different. It is important to know the characteristics of each well in terms of down-hole pressures, flowing and static, and the output curves. This, together with the casing design and knowledge about the reservoir, is important for the operations people and persons carrying out the well maintenance. Old data may not show the presence of such things as a steam cap or of a boiling reservoir - especially dangerous for drilling and killing any well. Because of the effects of draw-down and other things, the methods and designs that worked initially may not be applicable today. The procedures used for killing a well and starting the flow are very much affected by the reservoir and well conditions, as the next two sections will explain.

4.2   Killing procedures

In order to carry out maintenance work on a well, it may be necessary to stop the flow and reduce the WHP to zero. This is called to "kill" or "quench" the well. There are several methods that can be applied and which have been applied in Iceland:

1. Killing by closing the well and then pumping freshwater into the well, is probably the most common method. Usually, the reservoir pressure is underpressured and thus it is simply enough to pump the water into the hole to condense the steam and then the cold water travels down the hole to the loss zones thereby causing the weight of the cold column of freshwater to be higher than the reservoir pressure. Thus no inflow into the well and the well has been killed. The amount of water it takes to kill a well is usually somewhat less that the theoretical volume of the hole. As the cooling induces high tensional stresses in the casing steel, the pumping should be done at a slow rate. It may be necessary to continue the pumping of freshwater into the well after the WHP drops to zero to insure that the well does not start to flow again. By measuring the depth of the water level in the killed hole, and running a temperature log, the margin of safety in the well not returning to flow can be determined.

2. To kill wells in overpressured reservoirs, it is necessary to pump fluid of higher density than water, e.g. saturated brine having a density of about 1.2 g/cm^3 or mud with barite weighted to give a density up to 1.4 g/cm^3 (Figure 7). In Iceland, an overpressure of 4 bar-g has been observed at the wellhead in a high-temperature field but 15-25 bar-g in a low-temperature area. Once you know the pressure to be overcome you can calculate the required density and volume of fluid to pump. In this case, only the required volume is pumped into the well. The pressure exerted by a column of fluid is:

    $$p \text{ (bar)} = 9.81 * density \text{ (g/cm3)} * length \text{ of column (m)}/100$$

    For a well filled to the brim with this heavy fluid, the pressure calculated as above has to be equal to or greater than the highest feed zone pressure at the respective depth.

3. By shutting the well and waiting a few days, the well may be killed by itself. This is especially true for low-enthalpy wells.

4. Some wells are impossible to kill permanently. These are steam cap wells with insufficiently long casing strings, e.g. 250 m deep casing into a 29 bar-g steam cap, and a loss zone close to the casing shoe. The WHP can temporarily be brought to zero with a continuous high pumping rate of water. Just as soon as the flow is stopped, the well erupts as the well is acting like a long condenser. This gives only a minute or so to close the well before steam comes to the surface again. In this case, the weight of the column

of water is not heavy enough to balance the steam pressure. Heavy fluid may not work either as there has to be a continuous flow into the hole.

5. Wells that form a calcite plug will self-seal if allowed to flow long enough. The throat, where the scaling is most rapid, simply closes completely. This kind of self-sealing was probably instrumental in stopping uncontrollable blow-outs on to high-temperature wells in Iceland.

4.3   Methods of starting wells to flow

The majority of geothermal wells are underpressured, and have a free water level at some depth at the end of drilling. The exception is wells in steam-dominated reservoirs, wells where there is internal flow, or wells in overpressured reservoirs. Human intervention is required to induce these wells to flow. These are the methods that have been applied in Iceland:

1. By pumping compressed air into a closed well, the water table is depressed, about 10 m for every bar of compressor pressure. By pushing the water column down, it will be heated up to the surrounding rock temperature. The well is opened rapidly, once the temperature of the water becomes high enough to cause the water to boil spontaneously and cause enough steam "air-lift" for the well to flow. It is usually enough to open a 2" or 3" valve fully to release the air to induce the well to flow (Figure 6). First the air escapes, causing the valve to freeze on the outside. When the pressure has dropped considerably, the mixture of steam and water appears and the WHP starts rising again – the well is free flowing. Quite typically the water level is depressed to the maximum, which is the casing shoe depth. More air will then leak into the formation and there will be no increase in WHP. Thus, for a well with a water level at 260 m and a casing shoe at 500 m, a compressor with 24 bar pressure rating is required.

2. Some wells release gases and will in time build up pressure naturally due to gas accumulation in the casing. In such cases, a compressor is not required.

3. Wells where the temperature is high at shallow depths, and the water level less than 100 m in the cooled well at the end of drilling, will sometimes be heated up enough naturally for them to start flowing. In this case the water level will rise over a period of about three weeks as the density of the water is affected by the heating up. This is also so for wells that have internal upward inter-zonal flow, as gas may be released that elevates the water level.

4. By lowering a drill pipe or coil-tube into the well and pumping compressed air through them, the well can be pumped by so called "air-lift pumping". The density of the water column is reduced by about half with air bubbles. The air-froth is light enough to reach the surface and cause the well to flow. Once the well starts to flow, warmer water from depth reaches the surface and it will start flashing, causing the well to spontaneously flow. For this to work, the air pipe has to be lowered into the well twice as deep as the water level. For example, for a well with a water level of 150 m the air-lift pipe should ideally reach 300 m and the air compressor have a capacity of 15 bar. One difficulty with this method is to remove the pipe after the well starts to flow spontaneously. The pipe or coil-tube can be withdrawn through a stuffing box or stripper. Some just leave the pipe hanging in the well, but then the master valve can't be closed.

5. By injecting steam from an adjacent well it will heat up and can be started. In some countries, oil-fired steam boilers are brought on site to do the same.

6. By lowering a piston with a seal against the casing (a bailer-like arrangement) into the hole on a heavy wire rope, the well can be pumped or "swabbed". The piston is lowered 10-20 m below the water table. A truck then pulls on the wire, running over a sheave, to

bring the bailer out with the water. This may have to be repeated 3-5 times for the water to become hot enough to spontaneously flash, causing the well to flow spontaneously.

7. One method used in the past was to make up a 0.5 m long plastic bag with "carbide" inside and drop it in free fall into the well. The "carbide" is calcium carbide CaC_2 that reacts rapidly with water to produce acetylene gas C_2H_2 and lime $Ca(OH)_2$. Once the bag reaches a high enough temperature for it to melt, a large volume of acetylene gas is formed due to the reaction with the well water. The release of the gas is sufficient to lower the density of the column of water above it and cause the well to spontaneously flow.

8. To start wells with a water level less than 8 m, such as over-pressured wells that have been killed with a brine, a vacuum pump on a tank has been used. The equipment used was a farm version of a "honey wagon" – equipment used to suck up cow manure.

5 Workover, well cleaning

The most common workover operation on geothermal wells is to clean mineral deposits from inside well casings. The most common minerals are calcite, silica and silica-rich sulfide deposits. There is good theoretical understanding on the occurrence of calcite and silica, and predictive chemical models exist that are used to evaluate the scaling tendency. The modeling of silica-rich sulfides is, however, more difficult. The scaling problem is very specific to the chemistry of the individual well, which can vary quite a lot even between wells within the same field. The most common procedure is to remove the scaling deposit with a drill bit of the same type as the well is originally drilled with, but other methods have been applied. These are the methods that have found use in Iceland:

1. The most common method is to ream the well with the well flowing (Figure 9). The benefits are that the casing is not stressed due to killing with a cold fluid, the cuttings are swept out of the hole, and the well is back in service in two or three days. A small truck or trailer mounted drilling rig with top drive is used and a special seal for the drill pipes that can withstand the full wellhead temperature and pressure (Figure 8). The wellhead T-e is temporarily removed, the rig installed, and drilling is carried out as normally. The first drill rods need to be pulled-in due to the well pressure. The cuttings are diverted to a silencer separator.

2. A conventional drilling rig can also be used to ream the well but then the well has to be killed first, before reaming with the conventional drilling assembly can start. In this case, the casing steel is stressed due to the killing operation and the cuttings go to the formation. The well may be out of service for up to a month because of the time it takes to reheat.

3. Acid cleaning has been applied to cleaning wells with calcite scale as it is readily dissolved in acid and then releases CO_2 gas. First the well has to be killed. The acid is corrosive to the steel casing and therefore a inhibited acid solution (HCl) is used and the acid injected through tubing down to a spot where the calcite plug starts. The tubing used in Iceland is polypropylene plastic pipe on a reel, but steel coiltubes and drill rods are used in other countries. Acid is pumped down to dissolve the scale, and as long as any CO_2 gas is still being released, this is a sign that the acid is still doing its job. The acid is then displaced into the formation by pumping cold water into the well.

4. High-pressure jetting has been tried in several wells abroad that had been previously killed. In this case, a jetting nozzle was installed on a coiltube rig and water pumped at 200-300 bar and 5-10 l/s. Water jetting has been applied very successfully in Iceland for cleaning scale in valves, surface pipes and separators at pressures of 700-1000 bar.

5. In low-temperature wells, hydraulic stimulation with cold water has been applied. This is mainly done at the end of drilling but on occasion also during work-over. Just pumping

water at high pressure onto the casing has not worked well, but by installing an open hole packer in a sound geological formation the pressure can be focused on the interval below the packer. The packer is set and then a pressure of up to 100 bar and a flow of 50 l/s is applied. This has been very successful in increasing the permeability of wells, especially at the end of drilling, where the geological conditions are right. This method has not been used routinely in high temperature wells, as the rubber sealing elements are not able to take the temperature.

6. Injection of a scale inhibitor down hole is a method that aims to eliminate the scale buildup by "coating" the calcite crystals, as they are being formed, with a long molecule polar substance and thus preventing them from adhering to each other and to the walls of the well. The inhibitors in use are polyacrylate, polymaleic acid or phosphonates. This typically requires a threshold dosage of about 2-10 mg/kg and is quite effective. A chemical metering pump on the surface is used for the dosing, and the conduit to a depth below the flashing level in the hole (e.g. 800 m) is a ¼" corrosion resistant tube.

7. Calcite scaling of a gas rich 150°C well in Iceland has been prevented by installing a down-hole heat exchanger in the well to a depth of 250 m to prevent boiling and to take advantage of the reverse solubility of calcite (more soluble in cold water). This well meets Iceland's needs for commercial CO_2 (Figure 11).

6 Wellhead maintenance

The only part of the geothermal well where there is direct access is the wellhead and this is where the only moving parts are, namely the valves. There is usually not much to do to keep the well properly maintained. It is extremely important that the initial construction of the well is good and that the materials and installation be of the highest standard. Any money saved on poor material or workmanship can be quickly lost e.g. if there is a leak or a problem with a valve. Once the well is in service, it is important that a weekly visual inspection be made to detect any signs of leaks or damage. Annual inspections are called for in many countries to comply with the local Pressure Vessel Codes, but for the high–temperature geothermal wells, there is no access to the inside of the well below the master valve. Leaks are especially troublesome as they just tend to get bigger and bigger due to the high pressures, and more difficult to seal as mineral deposition takes place where the water evaporates, leaving the minerals behind. Long-term leaks lead to what is called "wire drawing" as the steel becomes worn due to the action of the high-pressure fluid. Such leaks can't usually be repaired without replacing the part. Thus, all flanges with packing or ring tool joints need proper bolting (API B7 bolts, 2H nuts) and be torqued properly. All valves connected to the wellhead with direct access to the well should have a second back-up one for redundancy. The valves are especially troublesome, especially leaks on stems and on seals. Special High Temperature Teflon packing material is injected with a special tool to energize the master valve stem and expansion spool. These seals have to be repacked with a special injection tool to maintain a pressure tight seal. Usually the problem is not with the big valves, but rather with the smaller outlet valves on the casing head and expansion spool, and also on pressure and sampling ports. The valves sometimes have a conventional gland with thread packing. The valve stems have to be polished so as not to tear up the seal when closing the valve. Lubrication of the wheel is another maintenance item. The parts in contact with the steam should not contain any copper or silver due to H_2S corrosion and the valve stems should be from stainless steel or duplex.

Leaks on the wellhead are also a serious safety problem as the non-condensible gas that are in the steam can accumulate in the cellar. Special safety precautions should be taken when working in cellars that are on most high-temperature wells due to possible accumulation of gases. A buddy system, gas ampoules to measure the gases H_2S and CO_2 or H_2S personal

alarms are useful. Design of the cellar to allow the gases to escape through the drains, natural draft or even electric fans have all proven useful in this respect.

By closing the master valve and operation valve, maintenance work can safely be carried out on the wellhead above the valve. The problem arises then what to do if the master valve itself needs to be worked on or has to be replaced. One way is to kill the well, but preferably a valve removal tool should be used. The valve removal tool is a packer, with the same diameter as the i.d. of the production casing, that is passed through the valve and the casing packer set below the valve (Figure 16). When the packer has been set, the rod holding the packer and the high-pressure chamber used for the insertion can be removed along with the valve. Then only the packer is holding the pressure, and there is free access to the casing head without the master valve. Once the new valve is in place, the insertion chamber is reattached and the packer released and pulled out. Such a valve replacement operation only takes a few hours but may only have to be carried out every ten years for each well. Work on the expansion spool or casing head requires this tool to also be used, or alternatively the well has to be killed. On wells 20-40 years old, it may be necessary to replace the wellhead completely and even for the top 2-3 m of casing to be renewed (Figure 18). The old casing is cut and a new one welded in place or the old casing is reinforced from the outside by two half-moon sections of a slightly larger casing (e.g. 10-3/4" over 9-5/8" casing) sandwich sections that are then welded together and to the casing. The most common reason for renewing the top of the casing in this way is corrosion, usually outside corrosion (Figure 17). For these casing repairs the weldability of the original casing becomes an issue.

The most popular master valve for geothermal wells is the expanding-gate valve. In this design, the valve sealing surfaces (seats) are always protected, and thus no scales will be deposited, neither in the open or closed positions. Also, while the gate travels, it is pulled together and thus moves more freely. The operation valve is sometimes of the same design or with a non-expanding gate, but conventional gate valves are also used. These valves have to be full bore to pass drill bits or packers The pipeline valves are conventional gate valves, preferably with a flexible wedge gate and hardfacing. Valves 3" and smaller are typically ball valves. Control valves are of several designs: butterfly, modified ball, and "flow-choke" design. Sticking of control valves is a problem, especially when handling separated water. They are removed for cleaning, sometimes several times a year as preventive maintenance. An oversized actuator, condensate injection ports on the stem, and exercising (open/close) the valves are also methods used to overcome the sticking problems.

Small wellhead valves may also be easy to fix but a master valve requires a knowledgeable person and extra equipment. In addition, die penetrant testing, x-ray raidography and pressure testing may all be required. Due to the high cost of such valves, some firms may decide to do the work themselves, but need to consider that it is not a simple task.

Leaks on flanges are another wellhead problem. Proper bolt torque and make-up is important to prevent these leaks. Should a leak appear it is important to take actions immediately to retighten the flange bolts, as that will quite often solve the problem. In a few cases the leak will heal by itself due to scaling. If the leak is on the downstream side of valves the flow can be stopped by closing the valve and the problem addressed directly once the pressure has been bled down. For leaks on the high-pressure side where closing the master valve will not relieve the pressure, the problem becomes more difficult. There are service companies that specialize in sealing leaks temporarily by installing clamps around or over the leak and then injecting a special sealing compound. A mechanical seal, a patch or a gland, can sometimes be installed to stop the leak temporarily (Figure 19). These leaks on the high-pressure side eventually have to be repaired permanently. For that it is necessary to install a casing packer or to kill the well, as when the master valve is being replaced.

7 Casing damage or leaks

The most serious and costly problems arise when there is a leak on the casing, or it is damaged in some way. Usually, the problem can be traced to corrosion damage, breaks caused by thermal expansion and contraction, wear from drill pipes, erosion or bad welding, or cementing of the casing.

The most common manifestation of a leak is that steam starts escaping from the exposed annulus between the casing strings or in the cellar. Steaming ground around or near the well is another indication. Damage can also go undetected and only shows up when a logging tool does not pass to the bottom of a hole, or a drill bit is held up while reaming scale deposits. The leak can initially be small, but will grow as the erosive effect of steam and water increase the size of the hole and passageways to the surface. For this reason, it is necessary to act quickly while the problem can still be managed, usually by killing the well. In the extreme, such leaks have developed into a crater with escaping steam or a steam eruption throwing out mud and rocks. They can be quite violent and dangerous.

Once the well has been killed, there are several methods that can detect the location of the hole or damage. These have been applied in Iceland:

1. A temperature log will often reveal where there is a leak. There may be a spike in the log by the hole or a change in temperature due to leaking in or out of the hole.

2. A caliper survey together with a CCL (Constant Collar Locator) will show collapses in the casing, whether there is a break in the casing, whether the threads have jumped (Figure 13), badly corroded sections or even holes. A more exact inspection can be carried out with a mechanical multi-finger casing inspection tool that is run on a wireline.

3. Pumping compressed air into the well will reveal the depth of the hole as the pressure will increase slowly until the water level has been depressed to the hole allowing the air to escape. A water level sensor can then be lowered to measure the exact depth, and thus the location of the leak (Figure 12).

4. A packer can be placed in the casing at several depths and then a pressure test carried out (Figure 12). Hot or cold water can, for example, be used as a "tracer" by pumping it slowly into the hole. With a packer set at the casing shoe, and noting how far down the well is heated, that is the location of the hole.

5. A video camera can be lowered into the hole for visual inspection. Cameras that are used for inspection of sewage pipes have been used. Some debris may restrict the view and one way to overcome that problem is to lower the camera quickly enough, above the terminal settling velocity of the particles. Cameras in a pressure tight housing have also been used (Figure 14). Lowering of a lamp on a wire or shining the sun into a well allows near surface visual inspection, aided by low light binoculars or a star scope. A sonic borehole televiewer, used for mapping fractures in the formation, can also be used for casing inspections.

6. Wire baskets or "go-devils", circular objects of different diameters, can be lowered on a wireline until they hit an object. Several such runs with different diameter will reveal where the restriction is and very roughly its shape.

7. Impression pictures have been made by lowering a lead impression block onto the damage or a soft rubber sleeve on a packer has been pressed against the walls. This kind of an impression mold will produce a "negative" of the damage.

Corrosion is generally not a big problem in geothermal wells, unlike what conventional wisdom holds. The most common corrosion problems are from outside and mainly near the surface in the hot moist soil or cement where oxygen can also get to the steel (Figure 17). Exposed annuli can also be a trap for water on standby wells or reinjection wells. The best

corrosion protection in this case is to keep the well hot by steam bleeding. A shelter over the cellar is also a good idea.

It is critical that the casing be supported full length by good cement. Cementing is one of the most essential operations to get right during the drilling of the well. As the cement slurry commonly does reach surface it is necessary to fill up either from surface through a so called "spaghetti" string, or by perforating the casing just above the top of the cement. The top of cement is detected by a CBL tool (Cement Bond Log). Any casing section that is uncemented or has bad cement is bad, especially in the annulus between two casings where trapped water is known to cause the inner casing to collapse when it heats up rapidly (Figure 14). The high-temperature cement contains about 40% silica flour to counteract aging of the cement. Not much can be done to repair poor cement. Sometimes new cement is "squeezed" down the annulus if there is a path for it. Cement plugs are placed in wells for safe repair conditions, squeeze cementing of a hole, running of new casing or sidetracking or permanent abandoning of the well.

The casing damages can be repaired in a number of ways. Most of the following methods have successfully been applied in Iceland:

1. Near-surface damage can be repaired by excavating a pit around the well and replacing the bad casing with a new one (Figure 15). Excavations as deep as 12 m have been dug in Iceland to replace a full length of casing down to the first threaded connection.
2. Collapsed sections can be milled out with a drilling rig, usually with a tapered milling bit dressed with carbide. Afterwards the well may have to be relined with a new casing. A tapered chisel was dropped repeatedly on a collapsed section of casing to straighten it out. A down-hole photograph of the collapse allowed the chisel to be shaped for the job.
3. A new liner may be run inside the production casing of smaller diameter. In order for it not to make the well too narrow, the new casing is frequently welded together. Afterwards, the casing is cemented with the aid of a plug that prevents the cement from going down into the production zone.
4. Broken liners have been retrieved with a fishing tool and replaced.
5. Casing patches or expandible casing has not been used to date in Iceland.
6. Squeeze cementing has been applied to a hole and then the cement plug was drilled out. No further repair was done as the leak was not serious and the conduit for fluid flow unrestricted.

8 Life expectancy of wells

If the geothermal reservoirs can be managed in a sustainable way, then the life expectancy of the wells becomes important. Wells have been taken out of service due to a decline in output, or physical damage. The main reasons for a decline in output are the following:

1. Decline in reservoir pressure "draw-down".
2. Change in enthalpy of the fluid.
3. Restrictions in the well due to casing damage, scaling or other obstructions.
4. Decline in inflow due to scaling or other causes.

The main physical damages to geothermal wells are:

1. Casing damage.
2. Poor condition of the wellhead due to leaks and corrosion.
3. Casing not deep enough.

The oldest high-temperature well in Iceland reached 47 years in age, and many wells are now 20 years or older. The wells drilled over the past 25 years will benefit from a more robust design than the earlier wells, and can thus be expected to last considerably longer. The two oldest high-temperature wells still in use in Iceland are in Ölfusdalur, wells 2 and 4 drilled in

1958, in spite of requiring reaming of calcite once a year. The secret for the longevity of high-temperature wells is not to kill the wells, but to always keep them hot to the wellhead and minimize thermal cycling, seal any leaks as soon as they appear, and keep the cellar dry (Figure 20). Best for the high-temperature wells is to operate at a steady load and never be shut in!

The oldest low-temperature well still in use in Iceland is at Brautarholt originally drilled in 1950 and recased in 1967. In Reykjavik, there are wells from 1959, e.g. RV-5 that is still pumping 53 l/s of 128°C water. The longevity of the low-temperature wells can be explained by the fact that the deliverability of the wells has proven unaffected by time, temperature changes in the reservoirs are the exception, and casing corrosion is minimized by not allowing atmospheric oxygen into the casing. Replacing the top 2-3 m of casing is not uncommon after 20-30 years due to corrosion (Figure 18). A hole is simply excavated around the well and a new section welded in place. The low-temperature wells can last practically forever!

9 Conclusions

The best way to extend the life of geothermal wells and minimize maintenance and costly repairs is to allow the wells to flow continuously to avoid thermal cycling, and to keep them hot. Killing of wells and repeated shutting-in is likely to stress the casing steel beyond the yield point of the steel. Several such cycles can break or cause damage. In operating and maintaining the wells, procedures that can eliminate the thermal cycling should be selected. Today, it is possible to clean mineral deposits from well casings with the well hot and under pressure, and also to replace the master valve and work on the wellhead. Developing methods to evaluate the condition of wells and repair techniques, in order to improve performance and save cost, is a constant challenge.

It is important to have a clear understanding of the reservoir behavior and well performance in order to operate the wells optimally and ensure reliability of steam supplies and increased performance. Information from a monitoring system is a valuable resource in this respect and also to plan maintenance and in long-term planning e.g. in timing the drilling of new make-up wells. When wells are taken permanently out of service, it is usually either because of casing damage or due to long-term changes that occur in the reservoir. Fortunately, geothermal wells have generally proven to be extremely reliable. The repair and work-over procedures mentioned in this paper are available and ready to be used, but fortunately have seldom to be applied in Iceland.

HIGH - TEMPERATURE WELLS   LOW - TEMPERATURE WELLS
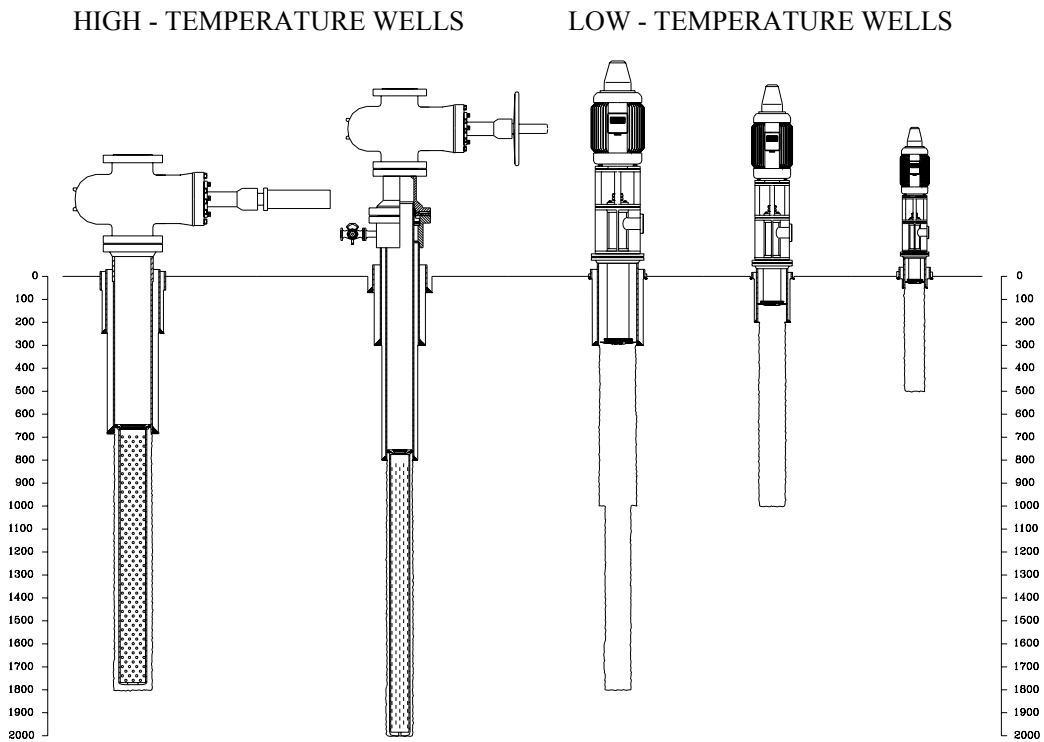
Figure 1: Casing profiles of wells drilled in Iceland.

Figure 2: Wellhead with a locally fabricated expansion spool, without annulus pressure seal or side outlets below the master valve. Side outlet above master valve is for killing.

Figure 3: Wellhead with an expansion spool and pressure seal for annulus. Four side outlets.
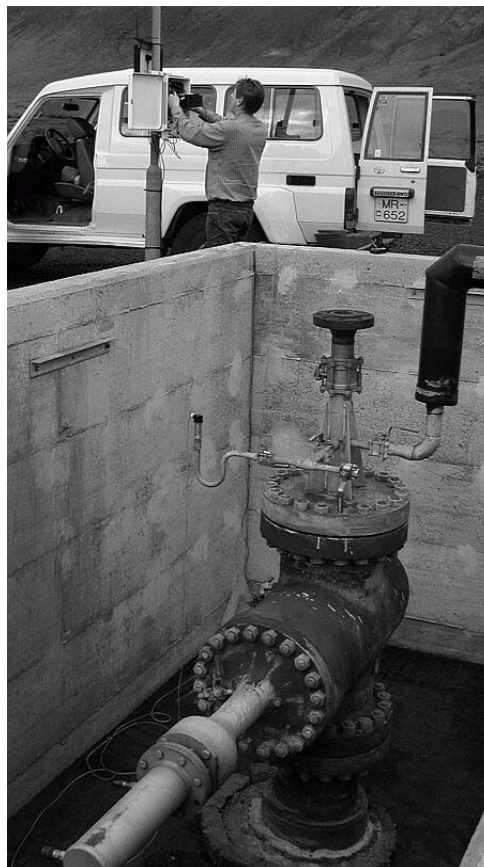
Figure 4: Wellhead without expansion spool. Monitoring of WHP and transmission via GSM phone network. The data logging equipment is solar powered in remote locations.

Figure 5: In-line monitoring of scaling and corrosion by use of retractable coupons.

Figure 6: Starting a well to flow by opening a 3" valve on the wellhead to release the compressed air. Once steam comes to surface the flow is diverted to the separator/silencer.

Figure 7: A well being killed with 1.2 g/cm^3 brine mixed in a ready mix truck and then pumped with a fire engine. Two mixes were enough to kill the well with artesian pressure of 3.6 bar-g.
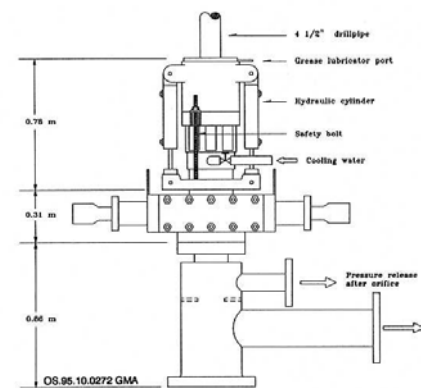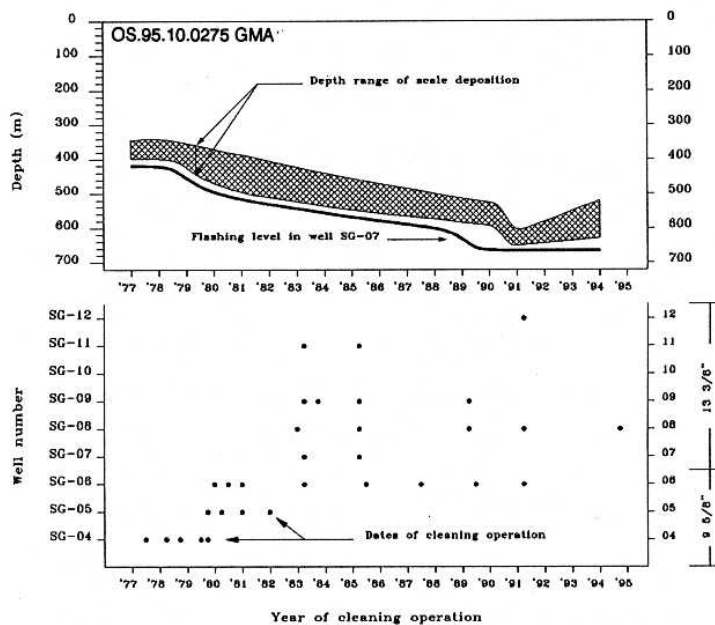
Figure 8: Reaming of calcite deposits with the well flowing – case of Svartsengi, Iceland. The shaded area on the graph shows the depth interval of calcite plug. This goes down in tune with the draw-down. The dots indicate what year the wells were reamed. The frequency of well cleaning decreases with time due to degassing of the reservoir through the steam cap.

Figure 9: Well being reamed of calcite scale with the well flowing.

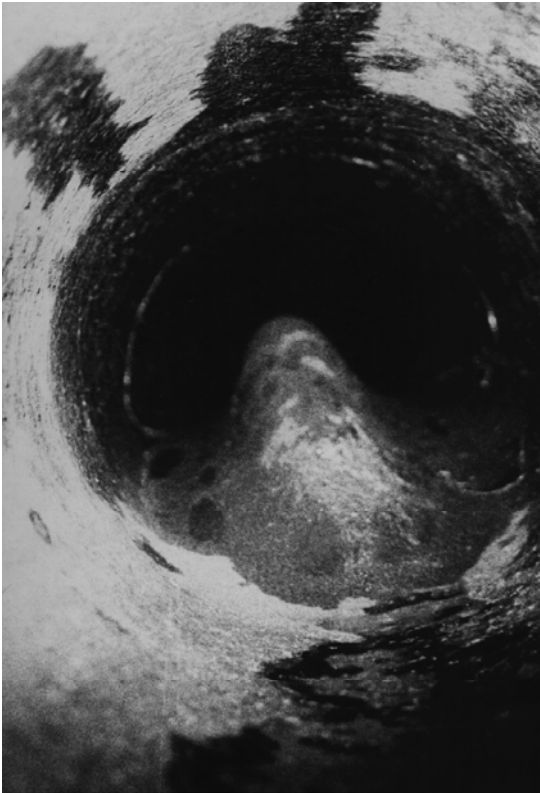**Figure 10: Calcite scaling inside a liner. Note that some slots are plugged.**
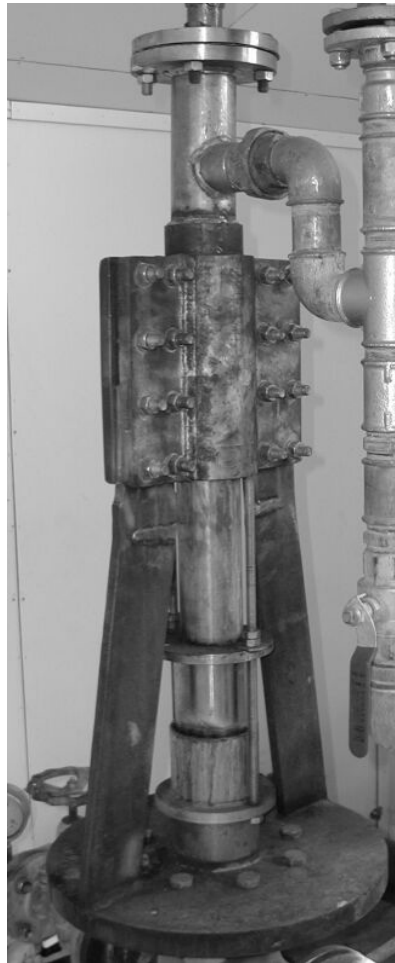
Figure 11: Down-hole heat-exchanger to 250 m to prevent calcite scaling in gas-rich well.
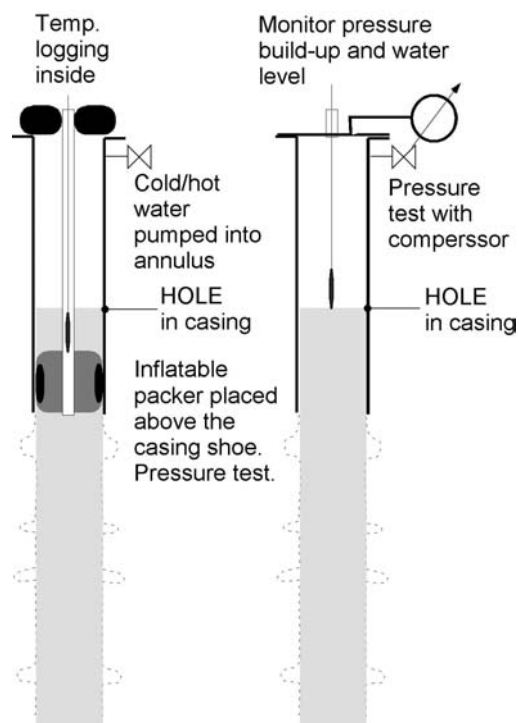
Figure 12: Two of several methods to check for casing leaks.
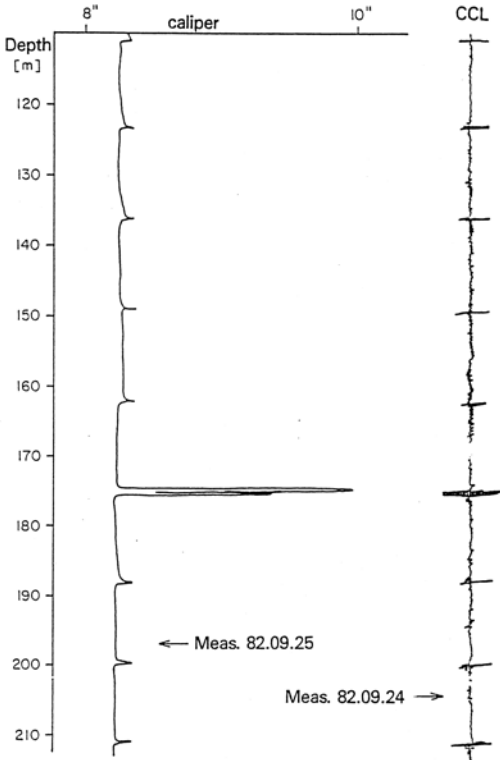
Figure 13: Calliper log showing thread separation at a depth of 175 m as also indicated by CCL.

Figure 14: Collapse of production casing due to trapped water in annulus. Repaired by a tapered chisel dropped repeatedly to straighten out the hump.

Figure 15: A hole excavated 12 m to the first casing joint where there was a leak. The top-most casing was then replaced.
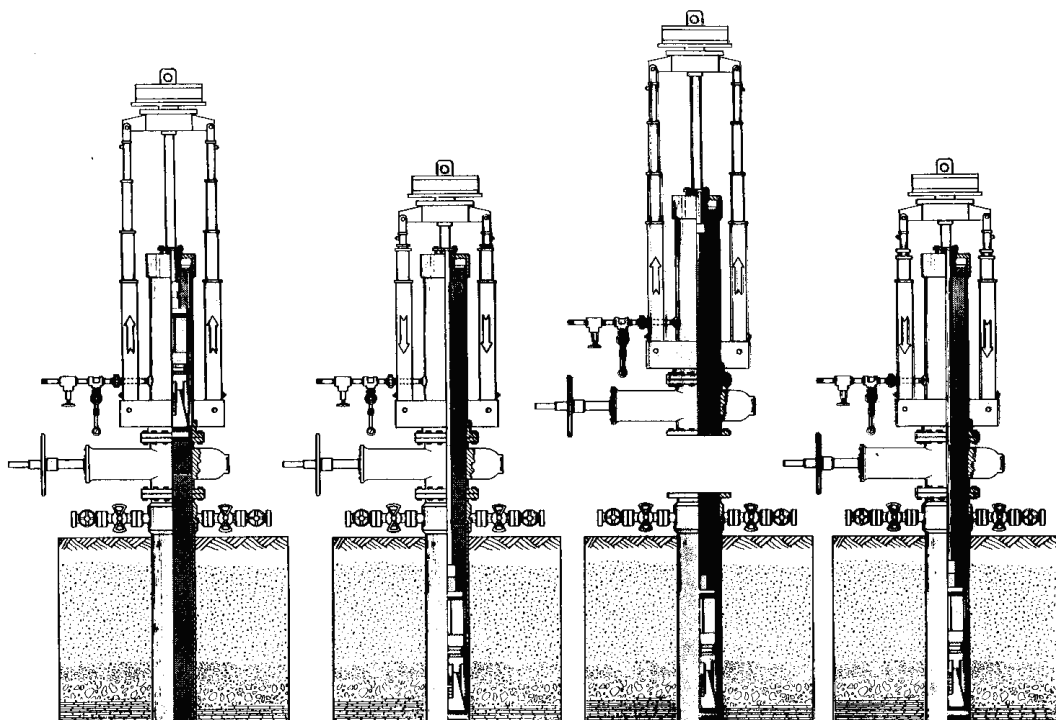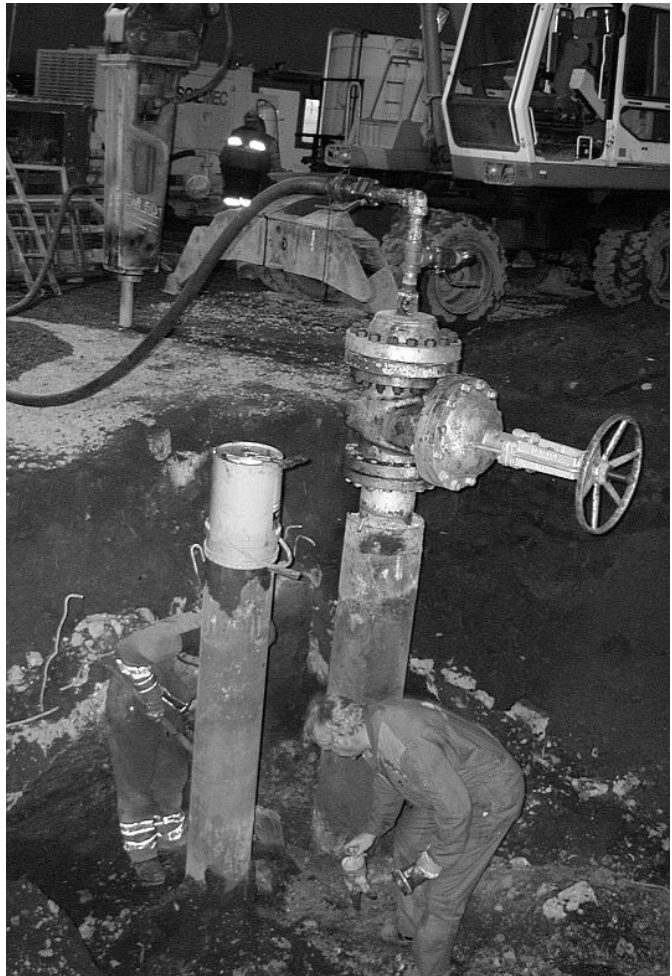

Figure 16: Valve removal tool on a hot well. A packer is temporarily set below the casing head.
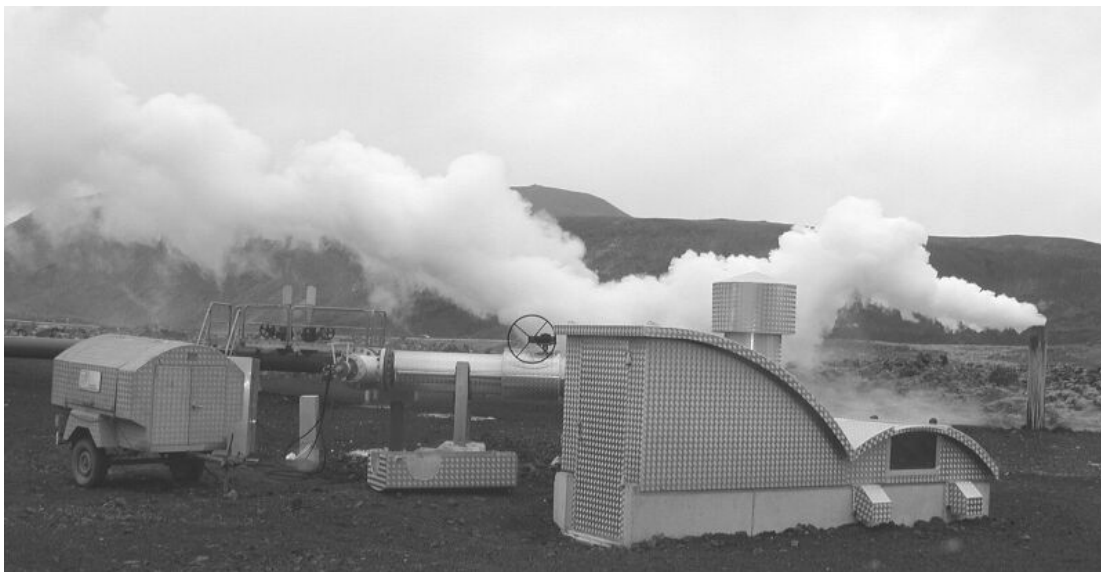
Figure 17: Corrosion on the outside of 9-5/8" casing (7 mm) at the top of cement after 20 years. Repaired with an outside patch of 10-3/4" casing and welding.

Figure 18: Excavation to repair corrosion damage near surface. Second pipe is rathole.

Figure 19: A gland installed on an old well to seal a leak in the annulus by the anchor casing.

Figure 20: Keeping the well hot at all times and the cellar dry is best for long life of the well. This well is closed but a small flow is diverted to a small silencer.