Recommended minimum functional specifications and standards for geothermal wells in the Netherlands v.5

1. Introduction

Experience to date in the Netherlands (July 2011) has proven that production of gas together with geothermal water is commonly observed. In all cases the amount of gas can be attributed to gas that is dissolved in the geothermal water. In one case small amounts of oil are produced. These observations have lead to a requirement to tighten up the specifications and standards for geothermal wells.

It is general practice that geothermal doublets are drilled under an exploration license that allows the geothermal operator to test the wells to collect information for a responsible long term winning of the ‘delfstof’ (natural resource) hot water with possible necessarily co-produced ‘delfstoffen’ (Mining Law § 2.2, Art 11.1) and other associated substances (including gases like CO_2, H_2S and N_2).

The exploration phase is - strictly spoken- concluded as soon as all information necessary for the preparation of a responsible Winnings Plan has been collected. If the Winnings Plan meets the satisfaction of the Authorities, a Winnings Vergunning (Production Permit) will be given and formal winning of the ‘delfstof’ hot water and co-produced substances can then routinely take place within the framework of the Winning Vergunning. However before issuing a Winnings Vergunning the Authorities will demand that the wells and associated surface system meet all requirements for safe and responsible operation based on the result obtained in the exploration phase.

In view of the frequently observed co-production of hydrocarbons observed in the test period, Well Engineering Partners, after discussions with State Supervision of Mines, developed the minimum functional specifications and standards for geothermal wells compiled in this note.

2. Rationale

Experience with the initial geothermal wells in the Netherlands indicates that it is not unlikely that gas is present in the produced formation water. In the Westland quantities of gas up to the saturation level at bottom hole conditions are observed, likely caused by dissolution in the formation waters of gas being generated in underlying formations and migrating through the aquifers to overlying trapping structures or –in the case of absence of effective trapping structures- to the surface.

Dissolved gas cannot be observed on seismic; however gas migration features are sometimes visible. Apart from dissolution, migration can lead to accumulation of free gas in trapping structures (pockets) that may be too small to be detectable on seismic. If oil is generated in underlying formations and oil migrates through the aquifer it also can be trapped in pores, pore throats and structural traps; strong permeability contrasts within the aquifer with active oil migration can also lead to dynamic accumulation.

The quantity of gas that can dissolve at bottom hole conditions depends on the mineral composition of the water and the temperature, and is typically one to several m3 gas (at atmospheric conditions) per one m3 of geothermal water for geothermal wells to 3 km depth. As the geothermal water is produced up the well, the pressure will decrease. At a certain pressure and temperature condition dissolved gas will start to break out (so called bubble point). As the pressure lowers more gas will come out of solution.

In the typical situation in the Netherlands a geothermal well will not flow to surface by itself and a submersible pump is required. Break out of **dissolved** gas will lead to a limited reduction of the hydrostatic head in the well and in typical production conditions in the Netherlands from hydrostatically pressured aquifers (pressure gradient ca 1 bar/10 m), producing saline geothermal water, it can be virtually excluded that the well will flow by itself without pumping due break out of **dissolved** gas. This should however be checked in every individual case. Even if the well will not start flowing by itself, there are significant risks to cope with: the gas is generally combustible and in some cases toxic and thus represents risks for explosion and intoxication.

A limited pocket (structural trap) of **free** gas in the production zone of a geothermal well poses comparable threats to the safety of a drilling and production operation as a major gas zone in a gas well. The entry of **free** gas is likely to reduce the hydrostatic head in the well so much that the well may start flowing by itself. If such a situation is not effectively controlled, it may lead to a so called blow out. If the well is closed in at surface, the well may become predominantly filled with a gas column with a surface pressure equal to the aquifer pressure minus the insignificant head or ‘weight’ of the pressurized gas column. Free gas may not immediately be detected at the start of production since the pressure drop and the large fluid displacement in the production zone may bring free gas to the production well at a later stage.

Significantly more gas can be dissolved in oil than in water. Production of oil without free gas at reservoir conditions can lead to self flowing conditions due to break out of dissolved gas, however the production of the well has then to be predominantly oil. Inability to control the well represents a major pollution risk. Oil pockets may be associated with free gas.

Risks for explosion and pollution increase tremendously if a well is capable of flowing to surface by itself. The mining law and regulations therefore prescribe for naturally flowing wells that such wells must be completed with production tubing, a production packer and a subsurface safety valve (SSSV). Co-production of gas and oil that does not lead to a self flowing condition is expected to be the most common situation that will be encountered in the Netherlands and the minimal functional specifications in this note are based on this case.

Gas or oil pockets may be so small that they are not be detectable on seismic, resulting in the situation that it is virtually impossible in the typical setting for a geothermal well in the Netherlands to conclusively prove the absence of free gas or oil before drilling and producing a well. Pockets may be very local, such that the absence of free gas or oil in the first well of a doublet often does not conclusively prove the absence of free gas in the other well of the doublet. This leads for geothermal wells to the situation that the risk for free gas or oil is very small, but that the presence of free gas or oil cannot be entirely excluded in the assessment of the worst case.

Since we have to be able to cope safely with any possible situation that may arise it follows that each geothermal well has to be designed, drilled, tested and produced as if it could become filled with gas anytime from the deepest point of the well until the contrary has been conclusively proven. This proof may not be obtained after a short initial test period as long term production may liberate gas or oil further away from the production point.

Other mechanisms that may change the situation in a well over its lifetime can be leakage from nearby hydrocarbon wells, communication with shallower gas bearing horizons due to corrosion etc. Of particular concern are shallow fresh water sands that may become polluted by leakage from the geothermal well.

In terms of well safety there is no difference between the production and injection well of a doublet, as it is good practice that the pump can be switched to each of the wells and that the injection well may also be produced during cleaning operations like back surging using nitrogen or an ESP.

A geothermal well may develop a weak spot or leak due to corrosion. Air may be sucked in during production if the level in the injection well falls below surface on the injection side. There is also a risk to create a vacuum in the production and injection well if the well is shut down. Of particular concern is the pollution of shallow fresh water sands with geothermal water, oil and gas.

During production a well will leave a trace of information and data about its condition, underground changes, fluid composition and co produced substances. Particularly after changing the conditions in a well a lot of information may be gained. For responsible operation of geothermal wells it is therefore indispensible that information is frequently collected and that samples are retained to review behavioral trends of the system. Generous collection and analysis of data will lead to overall lower cost than operating a geothermal system blindly.

For hydrocarbon self flowing wells two independent and tested barriers must be established prior to disturbing the integrity of the wellhead (e.g. removal of the Xmastree) and installation and testing of BOP’s. Only after full integrity with BOP’s is established, the two barrier criteria may be tuned to subsequent operations. The completion of geothermal wells does not generally provide for the same integrity of hydrocarbon self flowing wells. In view of possible co-production of hydrocarbons and changes in the flow behavior and production over time, clear standards must be defined for the well conditions under which well re-entry can responsibly take place.

The minimum functional specifications and standards described in this note are not exhaustive and intended to ensure the basic safety of geothermal wells. There are many other aspects that are important for the success of a geothermal system and as such require competent engineering.

3. Minimum functional specifications

In view of the above, each geothermal well must be designed to cope with the worst case and be constructed in such a way that the well can be safely re-entered for repairs or corrective measures. This leads to the following minimum functional specifications for geothermal wells:

1. The well must cover all shallow fresh water sands with a ‘double wall’ consisting of double casing (e.g. conductor and production casing) or a configuration of production casing and a tubing/packer combination. SodM is to be informed in the drilling program of deepest depth of fresh water zones.
2. The production casing and the wellhead must be sufficiently strong to withstand the pressures caused by a closed in gas column from the deepest point of the well to surface.
3. The formation strength at the shoe of the last cemented casing (LCC) in the completed well must be higher than the worst case gas pressure that may develop in the well.
4. The casing above the intersection of the formation strength profile and the worst case gas pressure must have gas tight connections; exclusive use of gas tight connections for the entire production casing is strongly advised.
5. The liner in a geothermal well must be provided with a liner top packer and a PBR (Polished Bore Receptacle) to allow the installation of a tie back string in case the well becomes naturally flowing or if the condition of the upper production casing becomes compromised due to e.g. corrosion.
6. The wellhead must be provided with at least one side outlet equipped with a ‘barrier’ valve of at least 2” with the same rating as the wellhead. A valve removal plug profile or similar facility must be available in the wellhead side outlet that allows the installation under pressure of a valve removal plug or packer.
7. The tubing for the pump and injection strings must be landed on a tubing hanger, sealed in the wellhead and locked in place with a hold down facility (normally bolts). The hold down facility shall be able to withstand the upward force that may occur due to pressure below the hanger - without the weight of a string below - equal to the rating of the upper wellhead flange.
8. The hanger must be provided with a facility to install a sealing back pressure (BPV) or two way check valve (TWCV), such that the hanger/plug combination can be tested from below (BPV) or from both sides (TWCV) to the value of the rating of the upper wellhead flange.
9. The pump cable must be fitted through the hanger in such a way that pressure from below and above to the value of the rating of upper

wellhead flange can be accommodated. Normally this requires using a 'penetrator'.

10. The neck of the hanger and the cable penetrator must seal in the bonnet flange with a double neck seal system, allowing a hydrostatic test in between the seals to the rating of the upper connection of the bonnet flange.
11. The cavity formed by the top of the hanger, the wellhead, the cable penetrator and the bonnet after make up must be tested to the value of the upper flange of the wellhead.
12. At least one 'barrier' valve with the rating of the upper flange of the wellhead must be fitted above the bonnet, such that the valve allows full bore vertical access to the hanger plug facility (so that the tubing hanger plug can be installed under pressure via this full bore barrier valve) and full bore access to the tubing under pressure to allow installation of full bore equipment like bridge plugs.
13. Barrier valves shall be rigged up such that they can be closed without requiring access to the well cellar. Operation of the barrier valves may be mechanical, e.g. by the use of a temporary extension bar, or hydraulic.
14. Only seals and connections that have been pressure tested to the required values are allowed to be considered as a valid seal.
15. The wellhead and cable design must allow the installation and testing of BOP's with the tubing hanger and tubing plug forming one of the barriers for safeguarding of the well.
16. If a well produces more gas than can be explained from the release of gas that is dissolved at bottom hole conditions and/or oil is co-produced, the wellhead of the production well must be reconfigured as a hydrocarbon production wellhead. This means that additional valves must be installed 'outboard' of the barrier valve; the additional 'outboard' valves are then used as 'working' valve to protect the integrity of the barrier valve.

4. Minimum standards for well entry

1. For any well re-entry a written a work plan must be made and a 'veiligheids and gezondheidsdocument'. This VG-Document contains a task-risk analysis and an action plan to keep the risks As Low As Realistically Possible (ALARP principle). The work program and the V&G document must be submitted to SodM 14 days before the work starts. Use of the SodM template available from the SodM website is preferred.
2. A well can be entered (i) without disturbing the integrity of the wellhead and Xmastree combination (e.g. for logging or mechanical operations via the vertical barrier valve(s) and (ii) with disturbing the integrity (e.g. removing the vertical barrier valves and bonnet for pulling the ESP).

3. For vertical well entries without disturbing the integrity of the wellhead and Xmastree combination (i.e. case (i)) a wire line or coiled tubing BOP (with at least one set of shear rams) and lubricator must be used.
4. For vertical well entries involving disturbing the integrity of the wellhead (case (ii)) a BOP must be used in accordance with MR art 8.3.1.3 and 8.3.1.4.
5. If a well produces no more than dissolved gas and, after shutdown and degassing, is dead and stable, exemption may be requested for the use of BOP/lubricator equipment on a case by case basis from SodM. If exemption is requested the operator will be invited to SodM to present their case. Together with the exemption request, the work programme, the V&G document and task-risk analysis must be submitted to SodM Processing time with SodM is up to 2 weeks.

5. Minimum standards for well evaluation

1. While drilling, an online gas monitoring system, including a gas chromatograph shall be used to sample the mud returning from the well. Cuttings samples shall be evaluated for the presence of oil by testing for fluorescence.
2. If hydrocarbons are observed or suspected while drilling the section must be logged with at least a deep resistivity and a porosity log.
3. In view of risks for explosion, oxygen free gas must be used for lifting or surging a well. Thus air lifting for testing is not allowed, however the use of pure nitrogen for such a purpose is allowed.
4. The use of an ESP for well testing is preferred, as more precise well test data will be obtained. After flow tests a pressure build up shall be made for a period equal or longer than the cumulative flow period. Pressure and temperature measurement at the ESP depth are required; use of pressure and temperature gauges deeper in the well is preferred.
5. The primary data of the system, such as production and injection pressure, flow rate, annular pressures, pump voltage and amps must be recorded on a data logger. A monthly chart of the data logger with primary data must be submitted to TNO, including details of co-produced substances.
6. During the first two months after the start of production and after a major well treatment operation, take daily at least one sample of production water and retain these samples to observe trends for mineral composition, solids contents, oil contamination and gas. Take and retain at least one pressurized sample each week during this period. If gas is observed measure the amount of gas through a gas flow meter or measure low gas rates with an inverted bucket daily. Take a gas sample at least weekly and retain the sample.

7. After the initial period of two months the sampling frequency may be relaxed to one water sample per week and a gas sample per month. The purpose of these samples is to detect changes over time and problems such as screen washouts.

6. Minimum standards for corrosion prevention

1. The injection tubing must be 50 m deeper than the free level in the well, to provide a controlled annulus that can be protected with a nitrogen blanket.
2. Nitrogen blanketing shall be applied in the pump and injection annuli to prevent the access of air into the well system. If the system is frequently switched on and off, nitrogen must be used when turning down the system to avoid sucking in of air.
3. The geothermal water must be tested each month to detect trends (Fe content, pH, etc)
4. A base line corrosion log shall be run in the production casing as a reference log prior to the start of the production. This corrosion log shall be repeated after the first two years. Depending on the results the operator might increase the logging interval but in any case a corrosion log shall be run at least every 5 years. In case of substantial corrosion, corrective measure must be taken.
5. The pressure in the surface system must be maintained at minimum 2 barg. If necessary a flow control valve must be used at the bottom of the injection tubing that ensures the required back pressure.

7. Minimum standards for hydrocarbon co-production

1. The site and all well and production equipment within the explosive limits of this equipment must be must be in compliance with NPR 7910-1 “Classification of hazardous areas with respect to explosion hazard- Part 1: Gas explosion hazard, based on NEN-EN-IEC 60079-10-1:2009 .
2. If oil is produced with the geothermal water, the location must be configured with a double barrier, an oil/water separation facility and a spill free oil evacuation facility.
3. The amount of oil must be measured daily and reported monthly to TNO, for the attention of Mr. Harmen Mijnlieff, email address Harmen.Mijnlieff@tno.nl