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TNO report

TNO 2012 R10719

BIA Geothermal – TNO Umbrella Report into the Causes and Solutions to Poor Well Performance in Dutch Geothermal Projects

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Number of pages	32 (incl. appendices)
Number of appendices	1
Project name	BIA Geothermie
Project number	052.03667

Contents

1 Executive Summary

TNO has been requested by the Branche Geothermie to examine the causes of, and solutions for, injectivity (and productivity) problems in the recent geothermal projects. A total of 6 existing projects have been examined, as well as inputs from two future project operators and other consultants.
Whilst the scope of this study focusses very much on skin damage in the well, resulting in poor injectivity (and productivity), it rapidly became clear that a lot of potential causes related to design and operational practices. TNO has therefore included conclusions and recommendations relating to these as well, where relevant
Under the assumption that the poor performance relates to 'damage' in or near the wellbore, in this report we use the generic term '**skin damage**' to cover the spectrum of possible damage mechanisms at locations in or near the wellbore
Against the recommendation of TNO, the Branche Operators have decided to retain confidentiality over the details of their individual projects. Therefore this "umbrella report" will cover generic conclusions only, without reference to specific projects
We **have** been able to achieve:

- A good initial understanding of the histories and key facts of each of the historical projects
- Additional confirmation of the understandings and conclusions from the preceding ADH second opinion study
- A ranked list of the potential causes of damage, particularly in the injector wells
- A list of recommendations for data gathering
- A pragmatic list/decision-tree for actions to eliminate/bypass damage
- A good list of recommendations for new projects
- Some important recommendations for further study
- Inputs from a number of external consultants and oil industry experts

Given the limited budget of this study, we have not been able to achieve the following. We propose that these are handled via follow-up studies:

- Significant new learnings on the causes and magnitude of skin damage, in the sense that the new projects did not trigger new insights beyond those from the ADH project, and also because of often limited and poorly structured data
- In many cases a clear quantitative reservoir engineering analysis of well testing, primarily due to poor test design or execution, and insufficient data having been recorded or kept
- A clear single culprit for causing the damage (de "seriemoordenaar")
- A clear (individual or regional) view of the geochemical interactions of the formation water and/or the formation minerals, also as a function of temperature.
- Regional geological studies or comparisons
- International inputs
- DoubletCalc modeling of the individual projects
- A quantitative understanding of how much the free gas in the wellbore impacts/distorts the well test analysis of permeability and skin

Based on our studies of well performance, we conclude that:

1. The Dutch geothermal industry has been, and still is, going through an enormous learning curve. This is a young industry, so, yes; lots of lessons have to be learnt. But on the other hand, it is surrounded by a major gas and oil industry who have drilled 5000 wells, and a lot of lessons have already been learnt there
2. The lack of actual industry experience has been often compounded by :
    - incomplete advice from contractors/consultants
    - (universal) lack of understanding of non-geological technical/organisational risks
    - absence of minimum or best-practice standards
    - emphasis on low cost, without an understanding of the negative implications
    - lack of knowledge transfer from other subsurface knowledge areas (the extensive Dutch oil and gas industry)
    - absence of clear leadership from the Branche or other stakeholders, in terms of maximizing knowledge flow and setting minimum standards
3. As a result of, inter alia, the above, the majority of the projects now suffer from limited data gathering, sub-optimal well completion designs and practices, and poor flow rates
4. Of the 6 projects examined, we conclude that two projects have no apparent injectivity/productivity problems, two have a poorer reservoir than expected, and 3-4 have clear signs of near-wellbore damage, particularly in the injectors
    - It is worth noting that in most cases, we do not have sufficient information to quantitatively determine skin damage, as a result of poor test design, or limited/absent data
5. Where wells have been switched between production and injection, wells' injectivity is "immediately" substantially poorer than the prior productivity. And, given the in some cases limited operational history, there are no signs yet of ongoing deterioration of injectivity. One project indeed shows a continuing cleaning-up over time
6. There is <u>no clear single cause</u> of low injectivity / productivity problems.
    - It is clear however that the projects do not so far have clear criteria and processes for obtaining a good cleanout of the wells prior to startup of the geothermal system.
    - Also, insufficient respect has been paid to sensitive (clay) minerals in the reservoir and/or the mineralogy of the reservoir water
7. The good news is that it is almost certain that the damage zone is limited to a few metres of the wellbore, so activities which can bypass this damage zone should provide long term solutions.
8. TNO have identified a range of solutions to the damage problem, and have fitted these in a stepwise approach.
    - It is worth noting that one of the projects with the best flow rates believes that an initial period of alternating flow between the wells was effective in flushing out the damaging agents. Another pumped damage away from the wells by applying high pressures
9. There is a significant list of key learnings for new projects, particularly relating to (a) good risk assessment, particularly when making cost-

reduction choices, (b) good standards and procedures during well cleanups, (c) good (result-oriented) data gathering and sample archiving. It is also apparent that all (?) projects have been through a major learning curve during their project design, execution and operation. In retrospect, a good oil industry second-opinion would have highlighted in advance the weaknesses in some of the decisions made

10. Understanding of the projects has often been hindered by insufficient data gathering (either due to poor design, absence of procedures, incomplete advice, or simply not doing it, or insufficient record keeping). TNO has therefore made a number of recommendations for data gathering, and we have recommended a follow-up study to quantify best practices.

2 Key Project Management Conclusions

- Most/all projects have been through a steep learning curve in terms of gaining familiarity with a complex concept, starting from an initial position of unfamiliarity. In the majority of projects, this learning curve has led to sub-optimal key decisions being made early in the project lifetimes
- Projects have suffered from not having a good second opinion, particularly with relation to drilling and completion activities – design and execution
- Projects have not undertaken a good risk analysis of subjects other than pure geological risks
- Data gathering has been haphazard, often without clear planning beforehand, nor good data management and analysis afterward
- The retained advisors and designers have failed to challenge their proposed designs/plans from a cost-risk perspective
- In hindsight, it would have been good if projects had more effectively shared learnings early enough with each other…and perhaps the Branche has could have done more to bring the community together to effectively share experiences and learnings
- The oil industry has so far failed to bring their expertise in to help…or has the Branche effectively asked for help?

3 Key Well Performance Conclusions

- In what ways (geology and activities) do successful wells differ from problem wells?
  - The universal conclusion is that a well as injector is substantially poorer than using the same well as a producer
  - Generally, initial well productivities are as expected or are considered satisfactory.
    - For the wells in the L Cretaceous (Delft, Berkel, Rijswijk, Pijnacker formations, etc.) productivity does not tie 1-to-1 with the observed log quality or quantity of the sand
- To what degree does actual reservoir geology/quality differ from pre-drill expectations?
  - On average, the actual reservoir quality (on logs) does match expectations, given the current (in some cases sparse) data submitted
  - Worth noting that in some cases the pre-drill expectations of Lower Cretaceous reservoir(s) character differ substantially from the post-drill actuals
- What are the symptoms of productivity/wellbore damage?
  - <u>Production</u> wells tend to have productivity indices at or close to that expected from the observed/predicted reservoir properties.
    - One project shows a poor productivity index, which is most likely linked to inadequate suspension and cleanup practices
  - <u>Injectivity</u> rates/indices are often substantially lower than those expected prior to drilling, or those expected based on observed reservoir properties, or those observed in initial production (airlift) testing
  - In cases where producer wells have been put on injection, and vice versa, the injectivity index rapidly/immediately declines to well-below the prior productivity index
    - And is reversed when the roles of the 2 wells are reversed
  - So far, even in projects with operation histories lasting months or years, there has been no sign of ongoing further deterioration over time. Indeed, at least one project shows a continuing cleanup
  - In most cases, the (surprisingly limited) data collected from the wells during initial testing, cleanup, and longer term operation, is not sufficient in quantity or quality for quantitative interpretations/conclusions
- What are the most likely causes of productivity/injectivity damage in wells?
  - The locations and rankings of the various causes of damage are shown in the associated PowerPoint file
  - The basic physics of fluid flow are reversible: a given well (with clean fluid and clean rock formation) on production should give the same performance as on injection. There are two ways in which a geothermal injector well differs from a producer, both resulting from the colder injection temperature: the density of the cold injected water is more than the hot water, and the viscosity is higher. Density increases the well flow rate, whereas the viscosity decreases the well flow rate. TNO has studied the impacts of these two factors, and give results

elsewhere in the report. Viscosity is seen to be (often, but not always) the dominant effect. Viscosity of cold injected water is approximately 1,5 to twice as high as that of produced water. This difference relates directly to the expected well flow rate, and can explain very well the doublets where the observed injectivity is 2/3 or half of the equivalent production well

- There now follows a list of other mechanical causes of poor performance, resulting from skin damage. These are presented in approximate order of probability of causing a significant effect. The ranking would obviously vary from project to project, depending on operational practices, geochemistry, etc.

- 1. Insufficient cleanout, leading to mix of drilling fluid solids, drilling grease and formation solids forming a “filter cake”, potentially in both wells
    - TNO is very concerned that in the geothermal projects, the cleanout of wells has <u>not</u> been formally discussed in the project design phase, with clear criteria for success being defined in writing. Nor do post-operation reports (if they exist) quantitatively review the cleanup operations and demonstrate that targets have been met
    - Indeed in some cases, cleanup has been limited to a quick initial flow, and straight onto the filters. With little data gathering
    - TNO understands that most (??) wells do not have an access port to allow flow behind the wire-wrapped screens. If this is the case, then we wonder how effective were the behind-screen washes reported by several projects, if the only way out for debris was via the screens. Could larger debris have remained there, to be redeposited on the injector sandface as soon as injection restarted?
- 2. Too early hookup of the wells to the system, and initial use of coarse filters, leading to carry over of reservoir solids from the producer to the injector, again forming a filter cake. Primarily of relevance for the injector well only
    - In TNO’s view, the filters, and injection into the injector, should be done only when produced fluids have reached a pre-defined quality spec. It should not be the intention that the geothermal system filters should hoover out all the crud from a well still cleaning up
- 3. The injection (if carried out) of foul fresh water (with potential bacterial and iron oxide) into the injector, potentially forming not only a filter cake, but also entering the invasion zone near the wellbore
    - Fresh water should only enter wells if it is pre-filtered and treated with biocide and oxygen scavenger. And it should only injected into the formation if geochemists confirm that no damage (particularly clay fines mobilization) will result
- 4. Chemical reaction between injected (non-reservoir) fluids (e.g. drilling fluid filtrate, the cleanout chemicals/acid, and/or fresh water

suspension fluid) and the formation, leading to, for example, mobilization of kaolinite or illite fines, or other chemical precipitation.

- Mud filtrate interactions with the formation has long been a concern in the oil industry. Clay mineralogy is a prime concern, and the geothermal wells do sometimes report the presence of the sensitive mineral kaolinite and sometimes illite. The geothermal wells have (all?) chosen a KCl mud type with the specific intention of minimizing clay interactions. Note also that in general, the better-permeability reservoir sections (which should be taking most of the injected fluids) will have the lowest clay contents. Watch out for wells which had clay swelling problems whilst drilling above/through the reservoir section
- Acid flushing results in a decrease of the pH in the reservoir which can lead to precipitation reactions as well as dissolution. However, dissolution of carbonates (if present) will probably be dominant on the short term, and these are relatively minor in most of the projects. Clay swelling due to cation exchange and temperature effects could potentially happen, but depends on the type of clay mineral (e.g. smecite).
- Ideally, treatment fluids and reaction products should be back-produced out of the wells, rather than pumped into the formation
- Question: is there any chance that the initial drilling/completion fluids could have a delayed impact, or later chemical interactions, during the suspension period?

- 5. Reaction of reservoir clays, drilling grease, natural crude oil, and iron scale to form “schmoo”, forming a filter cake. Primarily in the injector
  - Several Lower Cretaceous projects have observed a brown precipitate, which redissolves on being heated to 60 degC. One project analysed the precipitate, and determined it to be schmoo
  - TNO’s geochemists note that a hydrated iron oxide (ferrihydrite) can also redissolve on heating
- 5. Casing iron oxide scale, either pre-existing, or created due to chemical interactions
  - In the oil industry, in critical wells, it is not unusual to use wire brushes over the casing surfaces as part of the cleanup process
- 5. Calcium carbonate or perhaps iron oxide/hydrate precipitation, inter alia as the result of CO2 being removed along with hydrocarbon gas, resulting in a pH change and soluble bicarbonate in the formation water changing to insoluble carbonate
  - For aquifer fluids containing calcium bicarbonate and CO2, the removal of CO2 will move the equilibrium towards carbonate precipitation. Several projects have observed either carbonate crystals in their separators or in their filters – detectable by application of acid. The existence or strength of carbonate precipitation will depend on the concentration in the aquifer water – geochemical studies would be required to confirm the

degree of risk. The good news is that near-wellbore carbonate buildup are removable by acid, providing the acid has no second-order consequences on the formation minerals

- 5. Reservoir fines movement
    - Key concern areas are mobilization of clay minerals, due to chemical changes, or the movement of very fine sand/siltstone particles in less-consolidated layers. The risk is that the fines can either build up a “filter cake” in the injector wells, or lead to near-wellbore blockages (bridging in the pores) in injector or producer. One key lesson from the oil industry is that chemicals should only be put into the wells if they are believed to be compatible with the formation mineralogy
    - One project’s water analysis showed a substantial volume of <1um fines being produced, at rates of 1.5-10kg/hour – these are substantially finer than the 300um screens in the wells, but also finer than the 5um filters used at surface. It is not clear at the time of sampling how well the producer wells were cleaned up, Over time, this rate of solids movement could cause a skin and near wellbore damage zone to build up
- 6. Other reservoir fluid precipitation (iron oxide, or other minerals such as barium scale) as a result of e.g. lower temperature or turbulence of reinjected fluids
    - Reservoir damage could occur by in situ precipitation or by transport of precipitates to the reservoir. This latter is discussed in literature for colloidal particles of iron hydroxide (when the formation water is oxidised at the surface) and silica. This process will have a similar effect as fines migration, another possible cause of formation damage. In situ precipitation is less likely unless the brine is significantly changed by precipitation of minerals at the surface. Another option is bio-mineralisation: the formation of ‘precipitates’ by bacteria which can cause significant scaling if oxygen/ nutrients are injected with brine during injection or the drilling process.

- Is there any evidence of solids precipitation in the wells or surface facilities?
    - Several of the L Cretaceous projects do show calcium carbonate (crystals) precipitation in the separators and filters. Otherwise, there has been to date no sign of serious precipitation or scaling in any of the projects
    - Several projects report deposits precipitating from their water samples. TNO suspects that most of these are probably iron (Fe^{3+}) oxide precipitating out as a result of exposure to air. Two report that their deposits redissolve on gentle heating, of which one has a lab study indicating ‘schmoo’

4 Key Recommendations

The key recommendations have been organized in the following order. Firstly we provide an ordered list of activities which should be deployed to understand and repair the skin damage. Facilitating these steps are recommendations towards data gathering. Thirdly we make recommendations towards future projects. These outline best working practices. Finally, we outline steps to be taken to incorporate these best practices in the working routine of Dutch operators and outline steps for further study to assess geological factors responsible for the skin damage.

5 TNO Updated Ranked List of Recommendations to improve Productivity/Injectivity

In this section, we give an ordered list of activities to understand and repair skin damage in the wells. Not all activities will apply to all projects. Projects should select those activities most appropriate to their situation, and fit them into a decision tree. In general, the later activities are more expensive. A project could consider jumping to some of these, bypassing some intermediate options.

Group A: Data and Simple Chemistry
- 1. Obtain a good representative reservoir fluid sample. Unless agreed otherwise, this should be a downhole sample to retain original gas components. Likewise obtain a good (pressurized) sample of reinjected water (in the absence of oxygen)
- 2. Identify existing fluid, rock and contaminants samples and analyses to date. Carry out lab inspection (microscopic/physical/chemical analysis) of key samples to confirm most likely damage causes. Carry out lab analysis of formation water samples, looking at mineral and gas components. Carry out nodal geochemical simulation of the reservoir fluid sample to determine its potential for precipitation at the different pressure/temperature situations of the geothermal project, and/or potential mineralogical interactions with the reservoir formation on reinjection. This work should lead to a clear understanding of the mineralogical/chemical changes resulting from geothermal reinjection. Consider teaming up with local geothermal projects (a) to give economies of scale in this study work, and (b) to see where common elements emerge
- 3. Run a DoubletCalc simulation of the geothermal project to determine the influence of water density & viscosity on the injection well performance. This will determine the degree to which the injector well performance is affected by the physical (non-chemical) changes to the reinjected fluid, and give an indication of skin damage

Group B: Chemical Treatments
- 4. Depending on the above understandings, consider a batch acidisation of the injector well. The type and strength of acid should be chosen to limit negative consequences from e.g. clay fines mobilization
- 5. Should the batch acidisation show benefits, consider installing continuous low-strength acid injection into the facilities/injector. The purpose and strength of this acid is to return the fluid pH to original (pre-production/separation) values. Citric acid is a potential candidate. Due to the low concentrations required, the costs of this continuous injection will not be excessive. Observe the injector well performance over some time, to determine if an ongoing improvement ensues
- 6. In the event that schmoo or other oil deposits are expected to be a cause of damage, consider a batch solvent treatment to dissolve the oil/schmoo. Should schmoo buildup continue over time, repeat batch solvent treatments can be considered

Group C: In the event the chemical approach fails to work, then we move onto a second set of mechanical solutions:
- 7. Install a temporary pump in the injector well, and alternate production/injection flow. In this way, over a period of weeks, try to flush out any solids or mobile fines at the sand face or in the near wellbore zone. Avoid exposing the filters and the injection well to pulses of solids being flushed out of the wells.

- 8. If that fails to provide sufficient benefit, carry out a behind-screen cleanout. If the lab tests indicate that schmoo might be a problem, consider including a solvent wash (based on lab testing first). Install a temporary pump in the injector well, and flow the well hard to attempt to shift all remaining filtercake/solids at the sand face. Note that a clear decision needs to be made on the minimum flow rate to ensure good turbulence behind the two layers of steel. If coiled tubing is to be used, then consider using a straddle assembly to ensure maximum local flow rates.
- 9. Attempt to inject into the well(s) at sufficient pressure to force fines away from the wellbore. One project had significant success doing this at surface injection pressures between 50 and 80 Bar

Group D: Determine new productivity. If insufficient, proceed to stimulation activities:
- 10. Carry out a hydraulic frac to confirm the formation parting pressure (expectation 110 Bar WHP for the L Cretaceous projects, significantly higher for the Slochteren), and iterate several times to see if (a) injectivities increase as a result, and (b) the parting pressure reduces.
- 11. Analyse results, and determine pumping requirements and costs of meeting target injectivities. Obtain cost estimate for screen cleanout and propped frac. Depending on economic decision, then carry behind-screen cleanout and propped frac ("frac & pack")
    - The above recommendation applies primarily to the injector, but depending on a cost-benefit analysis, a similar logic could be applied to the producer, taking advantage of economies of scale
    - TNO understand that a number of wells (indeed most??) do not have a port to access behind the screens. This means that propped fraccing or gravel packing cannot be carried out without either removing the screens (which itself has significant risks and costs), or by perforating through the pipe above the screens. The options and risks would need to be confirmed with industry contractors

- TNO have also considered the merits of using perforation as a means of cutting through the near-wellbore damage zone in the injector. This is a standard industry technique, and is a much lower cost than the fraccing above. However, we have concerns about perforating through the wire-wrapped screens (leading to their disintegration and subsequent collapse of the hole in softer formations. Industry advice should be taken on the possibilities and risks of such perforation

Note: During the various operations above, a clear a-priori decision needs to be made about when (i.e. at what quality) produced fluids are allowed to be injected. This should be based on a benefit versus risk analysis. Likewise, the use of any chemicals should be based on understandings of their compatibility with the reservoir fluid and minerals

6 TNO General Recommendations for Data Gathering

- The project should collect and retain samples of fluids and contaminants and filter contents wherever relevant (during significant events), and should record details of dates and approximate amounts present. Where possible, historical samples should be clearly identified by labels. And all should be stored properly
- Consider making thin sections of cutting samples for microscopic analysis of mineralogy
- When taking water analysis samples, consider taking pairs of water samples upstream of the separator and at the injector wellhead. If there is a concern that gas removal at the separator may influence the water chemistry, consider taking a pressurized downhole sample (with gas). A pressurized sample from the producer wellhead may also be considered, but there is a significant risk that the gas-water ration will be incorrect (as observed in the unrealistic bubble points derived from projects' samples to date). In any case, unpressurised samples should minimize exposure to air/oxygen – bottles should be completely filled
- Data gathering should be designed to meet study/interpretation needs, rather than studies having to adapt to whatever is delivered.
- Wherever possible, analysis/interpretations of gathered data, and lab analysis of samples, should quantify the potential uncertainty in the results
    - Key examples of poor practice: determination of permeability from well tests, and determination of permeability from log porosities
- The proposed use of any chemicals in the well should be confirmed by formation compatibility tests on cuttings or (regional) mineralogy understandings. Note that the cuttings are to some extent corrupted (witness the observation that the dried stored cuttings reacted strongly to acid, presumably due to the presence of calcium carbonate drilling mud)
- Q: what logging programme is considered the minimum acceptable in the wells?
    - A basic GR Logging-Whilst-Drilling run will define (a) the position of the reservoir sands, (b) qualitatively the overall sand/clay quality versus the pre-drill expectation. It does not give a quantitative reservoir quality statement
    - Adding a density-neutron log will give porosity information, which allows a quantitative comparison of reservoir quality versus pre-drill expectations. It does not give reservoir flow capacity (permeability) directly, but could give some confidence via regional porosity-permeability cross plots
    - Adding a resistivity log could give information about how far drilling/completion fluid filtrate has moved into the formation. In principle, this would only be useful if there is a concern that the filtrate has triggered chemical reactions with the formation clays etc. And in principle, if well stimulation (and perforation often) should extend beyond a normal invasion zone
    - In areas/zones with only limited regional data, then additional logging or other data gathering could be considered – individual studies should be required. In some cases, sidewall cores, or coring, could be considered
- TNO is concerned at the often fairly primitive "well testing" of the new wells to date. Well testing is intended to answer quantitative questions about well productivity, formation permeability and skin. The tests should be designed to supply this information.
    - We recommend the use of downhole pumps, rather than (non-quantitative) airlifting.

    - Tests should contain three flow rates and a good final shut-in.
    - Use of downhole gauges also removes some of the complications resulting from gas coming out of solution.
    - And definitely carry out injection tests as well as production tests
- Consider designing well testing to gather well interference data – in other words the observation of pressure waves in the second well acting as an observation well. The time lag and signal response can be used to derive inter-well average permeability and pore volume. Indeed interference testing could provide an independent calibration of permeability’s and potentially skin damage. Doing interference testing in both directions could add value in terms of skin damage understanding
- Question: what are the procedures to date for doing a shut-in during a well test (either on a stand-alone well, or as part of a doublet)? After stopping the ESP, is a wellhead valve closed, or is water actually (back)flowing through the stopped ESP pump – in other words, is the transient being distorted by system flows, on top of wellbore storage? (One well test report appeared to show a non-zero pump frequency during the “shut-in”)
- For projects which complete wells in more than one reservoir sand (where the sands are well-separated), TNO recommend taking water samples from each reservoir, to ensure geochemical compatibility testing. Such samples can be taken downhole during testing, or by wireline sampling. In some cases, it is possible that regional information is already available
- For projects completed in multiple zones, consider running (mulit-rate) PLT logs, to determine zonal contributions (and potentially pressure (differences), Kh and skin). It is possible to combine these logging runs with sampling
- See also some of the recommendations in the section below on advice for future projects

7 TNO Recommendations applicable to Future Projects

- Risk Management
    - All consultant reports (either pre-drill prediction, post-drill analysis, and lab measurements) should include an estimation of uncertainty in the quoted figures
    - A detailed TECOP (Technical, Economic, Commercial, Organisational, Political) risk register should be produced early in the project initiation phase, and kept live as the project evolves. The register should include (a) impact magnitude, (b) probability, (c) actions to avoid and (d) actions to minimize
        - This register should certainly look beyond the pure geological risks, which seem so far to be the only ones handled in the geothermal projects pre-drill reports. Definitely include completion and operational risks
    - Project economics should examine the impact of (positive) skin factors on injection well capacities, to determine the risks (and solutions) of formation damage.
        - Where skin factors have been considered in pre-drill reports, these have been limited only to the impact of well deviation extending the reservoir length in the wellbore. For example, one project examined assumed a single skin factor of -0.3 across their spectrum of P90-P50-P10 cases – this is obviously unacceptable. What would have been the impact on project choices of assuming an injection well skin factor of +10?
    - Operators should consider employing an experienced oil (or equivalent) industry petroleum engineer with relevant field experience, to act as second opinion on proposals/reports submitted by contractors and consultants. This should bypass key parts of the significant learning curve for first-time geothermal operators
    - TNO are concerned that the geothermal projects appear often to focus on cost-reduction, without having quantified the (technical/operational) risks of the apparent financial savings. We therefore recommend that all well completion and cleanup activity proposals should include a detailed cost-risk-benefit analysis, including comparisons of alternative scales of operation – for example the completion design itself, the duration of cleanup flows, use of higher cleanout flow rates, use of chemicals, options for screen washing
        - Where possible, a choice should be made (if economically justifiable) for injection or booster pumps with additional capacity or horsepower, to cover downside risk. Also consider whether pairs of pumps, capable of series and parallel operation, could give additional flexibility over one single pump
- Well Drilling & Clean-up
    - Consider having a drilling contract on day rate, rather than lump sum
    - TNO supports the use of a calcium carbonate drilling mud over the reservoir section, with the logic that if necessary, the filter cake from this mud can be dissolved using acid – providing of course, that prior confirmation be provided that the formation mineralogy will not be damaged by the use of such acid
    - Cleanup activities should have clearly defined water/cleanout quality targets, and be designed to achieve these targets, including management of the produced fluids and their disposal

    - Storage ponds for produced fluids should be designed large enough for good cleanup flows (rate x time). In other words, set a success target for required storage volume, and aim to maximize this.
        - Aim to creatively challenge and minimize tanker disposal, from the first phases of project design. Within this, investigate with the local Waterschap the possibilities/limits on disposal volumes/qualities in local canals/rivers/sea. Use the storage ponds as buffers to allow approved disposal rates. Perhaps engage with the Waterschappen at a Branche level to ensure a consistent/optimum approach
    - Reinjection via filters should be used as a final resort, only when pre-defined target solids-content levels have been achieved. Perhaps storage ponds' contents can be reinjected, but only after (a) a formation compatibility check of any chemistry changes, and (b) injection of biocides and oxygen scavenger
    - If fresh water is used to suspend wells, (a) it should never reach the reservoir, and (b) it should be treated with biocide and oxygen scavenger
    - Oil industry practice on well cleanup in critical wells includes the use of wire brush scrapers to remove iron scale from casings and completion. Cleanout/completion fluids are recirculated through dedicated filters, and fluid quality targets met, before handover
- Well Testing
    - As a minimum, a good 3-rate test design, including intervening build-ups, as is specified inter alia in the Garantiefonds rules
    - Test both wells in production and injection
    - Use of ESP's in well production testing, as being more defined and measurable than airlift
    - Do the testing whilst the rig is still in location, to allow use of rig pumps in injection testing, and to break down any resistance/damage observed during injection
    - Unless agreed otherwise, use downhole gauges in well testing
- Well Stimulation
    - Consider pre-defining a well stimulation programme decision-tree prior to drilling the wells, and carrying out the stimulation actions at the time of original well completion, whilst the drilling rig and facilities are on site, leading to synergy savings. The performance of both wells should be reviewed, with particular emphasis on the injector…
- Other technical issues
    - Based on regional understandings, assume the presence of hydrocarbon gas dissolved in the formation water, and explore economic design options to use (burn) this gas as part of the project's energy output
        - TNO has quickly examined the solubility of natural gas in water, and at a typical project depth of 2000m (200 Bar), the correlations give around 2 Nm3/m3 of gas in formation water. This ties with actual observed gas production ranging between 0.5 and 2.8 Nm3/m3
        - A natural gas production of 1Nm3/m3 adds about 30% to the potential energy output of a typical current geothermal project
    - Assume a realistic downside case in the design of surface facilities – more specifically, include gas separation and wellheads, and size the injection pump(s) on the expectation of needing high injection or breakdown pressures
    - Explore with pump vendors the cost/benefit/risk relation of turning off the geothermal pumps in periods of low thermal demand,

    - We advise against the practice, seen in one project, of operating the geothermal system without filters. Whilst in that case, stable operation shows no solids movement; it is very likely that startups and other transients may well generate a short pulse of solids from the producer well. And there will be an ongoing slight ‘rain’ of scale and rust solids, which over time will lead to a damage ‘skin’ building up in the injector
- Projects (or the Branche) could consider the temporary use of an ESP in one project, e.g. for cleanup and testing in an injector, before moving to its permanent home in another project
- There is some evidence in the industry that designing for flow reversal (i.e. having a pump in both wells, and designing surface facilities to allow a switchover) does sometimes improve flow efficiency. This would need to be the subject of a separate study
- For projects considering the addition of heat pumps to extract more energy from the geothermal water, and reinjecting at lower temperatures, we recommend that a quick specialist study be done of thermal stress impacts on the casing in the injector well. There is a risk that exposing the wells to low temperature water could lead to casing joint leaks. This study could well be done as a joint (Branche) project

8 Recommendations for Further Study

- Organisational
  - We strongly recommend that the industry/Branche create and take ownership of a work programme to understand and minimize the risks mentioned in this report. This has the aim of not only helping existing Operators to understand their projects (and know how best to manage them), but also helping to lower the risks for new projects with the aim of creating a healthy Dutch geothermal industry. The study areas suggested below could be brought into the this programme
    - Under this heading, we are reminded of the comments from several Operators of "Why were we not informed of these risks before we started?", and expressing dissatisfaction with the (incomplete) advice they had received from consultants and contractors, to date
  - We recommend including in this programme the definition of a range of minimum standards (and communication of best practices), possibly in cooperation with government supervisory agencies and the oil & gas sector
- Sub-surface:
  - Very Important: as a primary recommendation, TNO recommends a Branche West Netherlands Lower Cretaceous geochemical study, covering (at least) the 4 Operators to date. This project should start with good sample collection of the reservoir, produced and injected water, with particular attention on the gathering of a good downhole reservoir sample from each project. The combined dataset of water, gas and formation mineralogy analyses should be used to carry out geochemical simulations to determine (a) obvious candidates for precipitation and/or formation damage (fines/clay mobilization), and (b) longer term precipitation buildup issues, resulting from inter alia temperature change and natural gas/CO2 removal from produced fluids prior to reinjection. These simulations should be carried out for/at the various points in the geothermal project flow loop – producer, separator, filters, injector well, injector formation…
    - If appropriate consider a calibration by a core flood experiment (either from existing public domain cores, or on a core taken in a future well)
    - The regional geochemical will be expensive (several hundred thousand Euros), but the benefits would include:
      - A clear understanding of any dangers of mineral precipitation out of the hot or cold formation water
      - A clear understanding of any sensitive minerals in the reservoir formations
      - The impact of gas removal on the downstream behavior of water and rock minerals
      - The impacts, if any, of mixing waters from different reservoirs
      - Learnings from projects outside your own, in the same or similar reservoirs

        - Risks, if any, from lower temperature injection resulting from installation of heat pumps
        - Optimal design of chemical treatment solutions, and clear "don't do" lists
        - Recommendations for design and operation of future projects
    - H: A short quantitative reservoir engineering study to determine the impact of free gas (coming out of solution in the wellbore) on the interpretation of well tests to derive permeability and skin –with recommendations for optimal design of well tests
        - Gas coming out of solution has two effects: (a) increase of wellbore compressibility (potentially masking the near wellbore skin) and (b) the rising bubbles in the wellbore distorting the pressure buildup used to determine permeability. Initial expert reactions are that these should be minor effects, due to the comparatively low gas content
    - H: A study to design a good sampling and analysis programme for the next L Cretaceous project not only during the cleanup phase, but also during initial operation
    - M: We propose a short study, linked to the geochemical study, to bring together reservoir particle size information and formation strengths, to define a filtration strategy
    - M: We recommend a short reservoir engineering study to define the benefits of inter-well interference testing, and to set out a workflow. Within this, determine whether a two-direction interference test can also supply skin factors. Consider creating a transient-DoubletCalc to allow investigation of e.g. interference testing, and fluid movement over time
    - M: A short reservoir engineering study to examine the exact cost-benefit advantage of a high well deviation to improve well flow capacity versus than other completion/stimulation techniques
    - M: A study of the overburden (depth of burial) impacts on permeability and porosity
    - L: Consider a (Branche) PhD study to simulate/predict cold water front movement tracking from well test interpretation
- Data Gathering:
    - Very Important: as a primary recommendation, TNO recommends geothermal projects to prepare a template for data gathering – what, how, when, why, and quality
    - Important: as a primary recommendation, TNO recommends geothermal projects to design a good well testing programme and minimum standards
-
- Project Management:
    - Very Important: as a primary recommendation, TNO recommends future projects to prepare a template TECOP risk register
    - H: Prepare a risk-benefit-(cost) comparison of design/operational alternatives
- Other:
    - H: A (Branche) study to gather relevant international learnings, relevant for the design and operation of Dutch geothermal projects

  - M: As mentioned earlier, a short (Branche) study of thermal stress impacts on the injector wells of cold(er) water injection resulting from installation of heat pumps
  - M: A study to clarify, and if possible define, recommended best practices and minimum standards for well cleanup, prior to handover to doublet operation

9 Additional Questions posed by Operators

- Q: Is it necessary to install a screen in injector wells?
    - It is TNO's position that in well-consolidated reservoirs such as the Slochteren Sandstone, a screen is not necessary to hold formation solids in the injector well
    - In the case where poor reservoir quality or formation damage necessitates a propped frac and/or a gravel pack, then screens will be required
    - Screens should include an access port to allow future operations such as gravel packing and/or propped fraccing
- Q: Were the breaker fluids effective/necessary/optimum in removing wellbore skin?
    - The selection of optimal fluids to use in the drilling and completion of wells is outside the scope of this study
    - TNO recommend that consultant recommendations are double-checked with oil industry service providers, with particular emphasis on damage removal and minimizing formation damage
- Q: Why do we find different injection pressures when injecting cold fluids than with warm fluids?
    - A number of projects have observed a difference between warm and cold injection rates. Interestingly, some projects have observed an increase in cold injection rate, and some have observed a decrease. TNO has not analysed this specifically in our project, nor have we asked operators to supply detailed datasets. We have however examined the physics of the difference
    - The viscosity of cold reinjected water can be as much as twice that of the produced water. This means that the friction resistance in the injector wellbore and in the reservoir can be twice as much as in the producer. Putting it another way, from a friction perspective, an injector's performance may be only half of the equivalent producer. A second factor is that the density of the cold water is higher than in a warm producer. This means that a cold injector has a higher bottom hole pressure, and hence a higher flow rate, than if warm water is used. Thus, density works in the opposite direction as viscosity
    - The cooling of (saline) formation water from e.g. 80 to 40 degC typically increases the density by about 2% (across a range of salinities). Over a vertical height of 2000m, with an average wellbore pressure of 100Bar, this adds about 4 Bar to the bottom-hole pressure. For a typical well productivity/injectivity of 2 m3/hr/Bar, this would add about 8 m3/hour to the well's flow rate, at a fixed tubing head pressure
    - The cooling of saline water by the same amount increases the viscosity by about 70%. This increases both the wellbore friction and the resistance within the reservoir. For a fixed reservoir pressure, the extra friction losses reduce the flow rate.
    - A quick calculation using DoubletCalc (which includes both viscosity and density effects), demonstrates that at a constant injector wellhead pressure, the injectivity decreases as shown below (for a 350ppm salinity formation water). Injection at 15degC is ¾ of that at 38degC

T-Injection	Flow Relative to 38 degC
^{o}C	%
38	100%
30	91%
25	84%
20	78%
15	72%
10	65%
5	59%

  - It is worth noting that the pressure drop over a mechanical skin can alter the relative impacts of viscosity and density, which could swing the dominant effect between viscosity and density. An example of this is shown in Appendix 1 of this report
- Q: Why do we get natural gas being produced with our formation water?
  - The Netherlands is an active hydrocarbon province, meaning that hydrocarbon gases and oils have, and continue to, migrate through the subsurface geological formations, seeking the highest points
  - The Lower Cretaceous and Slochteren sands being targeted so far by the geothermal projects (and the Bunter sands being targeted by future projects) are all hydrocarbon reservoirs somewhere in the Netherlands
  - Natural gas (methane) and CO2 do dissolve in water under pressure. CO2 is well known (see Coca Cola), but methane also has a solubility. At a pressure of 200 Bar (typical of a depth of 2000m) and a temperature of 75 degC, the solubility of methane is between 2.3 and 2.7 Nm3/m3 of water, depending on the water salinity. The observed separator gas-water ratios of 0.5-2.8 Nm3/m3 lie in the same ballpark
  - TNO recommends that future projects assume from day-1 the presence of natural gas/CO2 in their water, until proven otherwise – and as a first step, include a separator and flare in the basic design. And if gas is then proven, then consider CHP or use of the produced gas in the boiler
- Q: What impact does removal of natural gas (and included CO2) have on the reservoir fluid (precipitation)?
  - CO2 removal does move the equilibrium point between soluble bicarbonates and less-soluble carbonates.
  - Precipitation does depend on the concentrations of less-soluble minerals
  - Combinations of minerals do lead to second-order effects
  - In the Netherlands oil & gas industry, production and injection wells do occasionally suffer from formation damage e.g. by carbonate precipitation (which is usually removed with an acid treatment) and some limited scale formation in the wellbore (barium sulphate is most often referred to). Salt precipitation is rare, primarily triggered by cooling and evaporation in gas wells. As a first approximation

therefore, geothermal wells should not be any more sensitive than hydrocarbon wells
  - In summary, expect that some carbonate precipitation will take place, until proved (or simulated) otherwise. Do lab studies as soon as possible, based on good reliable (pressurized, downhole) samples, to confirm the actual situation
  - TNO have added this to the list of potential future studies
- Q: what international learnings can we bring into the discussion on injection well formation damage?
  - A: Within the limited scope of this project, TNO has not been able to pull together a list of international learnings. We have included this in our list of future studies
- Q: Can we achieve higher well productivities/injectivities by drilling our wells at a higher angle through the reservoir, thereby exposing a longer reservoir section in the wellbore?
  - A: In the case of a relatively homogeneous (unlayered) reservoir formation, then as a first approximation, the well capacity is proportional to the completion length of the well, which grows with x1/*(Cos(deviation angle)) – up to, say, a 60% deviation. In a (very) layered formation, the benefit is reduced because the fluid flow is forced along the layers, rather than perpendicular to the wellbore. The exact cost-benefit advantage of a high well deviation rather than other completion/stimulation techniques would need to be examined in another study
  - DoubletCalc calculates the improvement factor (negative skin) resulting from well deviation
  - TNO have added this to the list of potential future studies
- Q: what is the impact on wellbore cleanout processes of a high well deviation?
  - In the current conventional geothermal completion with WWS and perforated pipe, a key question is how efficient is the turbulent flow during the cleanout operation in removing debris from the formation sand face? TNO does not have access at present to (case history) documentation on the relative efficiencies of such cleanout activities, but note that this is a standard oil industry procedure. In a case with insufficient turbulence, then high wellbore deviations (>60 degrees) could well lead to solids not being efficiently removed from the well.
  - Further analysis is outside the scope of this study
- Q: where can we find, in the public domain, details of oil and gas (and injection) well production rates, well logs, fluid analyses, and core porosities/permeabilities:
  - This data, for wells more than 5 years old, can be found on the Dutch NLOG public domain website: http://www.nlog.nl/nlog/listAllWellLocations?menu=act
  - Use this link for production / injection data: http://www.nlog.nl/nlog/requestData/nlogp/prodfig/queryForm.jsp?menu=pro

10 Individual Operator Reports

Our brief evaluations of individual Operators' projects are captured in Appendices. The Branche Operators have decided to retain confidentiality over the details of their individual projects. Therefore the Appendices will be circulated only to the relevant Operator.
Due to budget limitations, and often limited data, the level of detail in our individual Operator evaluations has been restricted, and the Appendices are in the form of an informational note, rather than a formal TNO Report.
For the following Operators: Koekoekspolder (Appendix B), Duijvestijn (Appendix C), Ammerlaan (Appendix D), and Greenwell (Appendix E), an individual informational note has been prepared.

No report has been prepared for van den Bosch and ADH – the latter has been evaluated under a separate project.

A short review was made of Floricultura pre-drill documents, leading to a TNO note (Appendix F) with TNO conclusions and recommendations.

A meeting was held with Brabant Water and their consultant, Panterra, to receive their inputs. Brabant did not request any review of their project documentation.

11 Signature

Utrecht, October 2012

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A Impact of Temperature on Viscosity and Density Pressure-drops in an Injection Well

A1.1 Individual Well Modelling

Two processes are influenced by temperature in the wellbore itself and the near wellbore of the reservoir. First, the liquid density increases for decreasing temperature, increasing sandface pressure (i.e. pressure in the wellbore at reservoir depth). Secondly the viscosity increases for decreasing density, increasing the pressure drop experienced by radial flow in the first few meters of the reservoir, being dominant in reservoir pressure drop.

The hydrostatic pressure at reservoir depth is calculated using the following relation

$$p_{hyd} = \rho g h$$

Radial Darcy flow is described by

$$p_i = p_e - \left(\frac{141.2 q B_0 \mu}{kh} \right) Ln \left(\frac{r_e}{r_i} \right)$$

Where p_i is the wellbore radius and p_e is the radius of interest within the reservoir (here 6 feet). Especially the pressure drop at Darcy flow is dependent on reservoir (and fluid) properties, as can also be seen in Figure 1 and 2. Changing permeability only (400 to 150 mD) shows that the *gain* in sandface pressure by increased density is now overtaken by dominance in frictional pressure drop. In the case of a 400 mD-reservoir permeability, decreasing injection temperature (70 degrees Celsius is taken as base case here, hence pressure is zero) would increase injectivity. Having a 150 mD-reservoir permeability yields lower injectivity as a result of decrease in pressure. Note that the assumption of constant liquid temperature throughout the wellbore *and* near wellbore is much more conservative than one would find in the field.

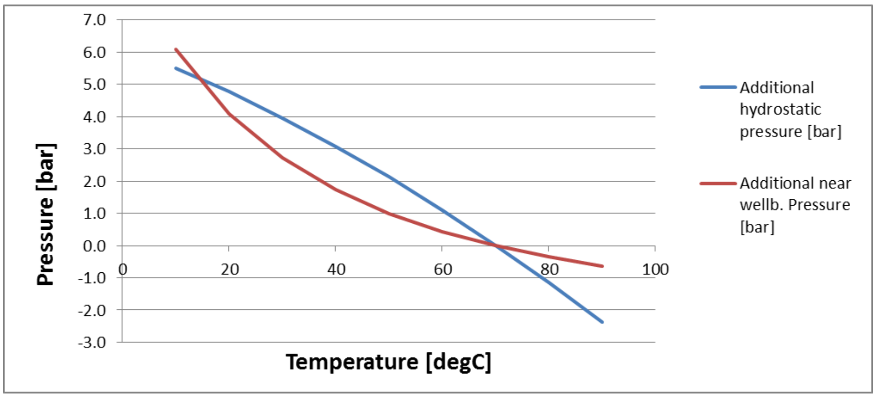

Figure 1. Additional pressure by hydrostatic head and radial Darcy-friction in the near wellbore (6 ft.) as function of fluid temperature. Constant temperature of the fluid is assumed throughout the well and near wellbore. Permeability k=400 mD.

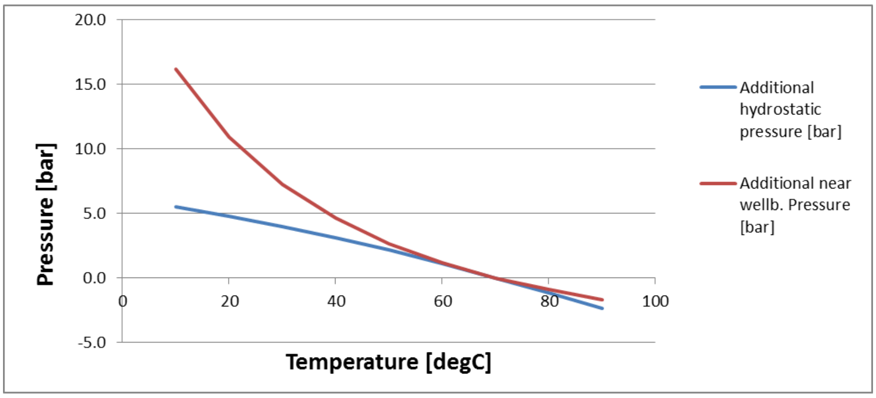

Figure 2. Additional pressure by hydrostatic head and radial Darcy-friction in the near wellbore (6 ft.) as function of fluid temperature. Constant temperature of the fluid is assumed throughout the well and near wellbore. Permeability k=150 mD.

In summary, the first figure shows that with a reservoir permeability of 400mD, at an injection temperature of 20 degC, the pressure changes due to increased density (increasing flow) and increased viscosity (decreasing flow) approximately cancel out. In the case of a 150mD reservoir, the impact of increased viscosity dominates, and the flow will be lower at 20 degC

Used parameters:

Q_{water}	110	*m3/hr*
TVD	2000	*m*
h	77	*m*
skin	0	-
B_0	1.0	
μ	μ(t)	*cP*
r_i	0.5	*ft*
r_e	6	*ft*

And density and viscosity, being temperature dependent (salinity 130 ppt):

	10 °C	20 °C	30 °C	40 °C	50 °C	60 °C	70 °C	80 °C	90 °C
ρ [kg/m3]	1101.9	1098.2	1094.1	1089.6	1084.8	1079.5	1073.9	1068.0	1061.8
μ [cP]	1.78	1.38	1.11	0.91	0.77	0.65	0.57	0.50	0.44

A1.2 DoubletCalc Modelling

TNO has also undertaken a DoubletCalc investigation of a geothermal well doublet for the temperature range of 40 to 5 ^{o}C, and for fresh and very 35% saline water conditions.

The assumed DoubletCalc inputs are as follows based as realistically as possible on the West Netherlands Lower Cretaceous (Delft Sandstone) projects:

Property	Value	Unit
Well interdistance at formation level	300	m
Depth production well formation	2040	m
Depth injection well formation	1951	m
Height formation	100	m
Permeability	400	mD
Flow	110.3	m3/hr
Geothermal gradient	0.031	^{o}C/m
Injection temperature	40 – 5	^{o}C
Salinity	350 000	mg/l
Well inner diameter	7	Inch
Hole diameter	8	Inch
Well tube roughness	1.38	milli – inch
Skin producer	1	
Skin injector	5	
Depth pump in producer	428	m
Pump efficiency	75	%
Pump pressure	30 - 100	bar

TNO has looked at two scenarios: fixed booster pressure, and fixed flow rate.

Boundary condition: fixed ESP booster pressure

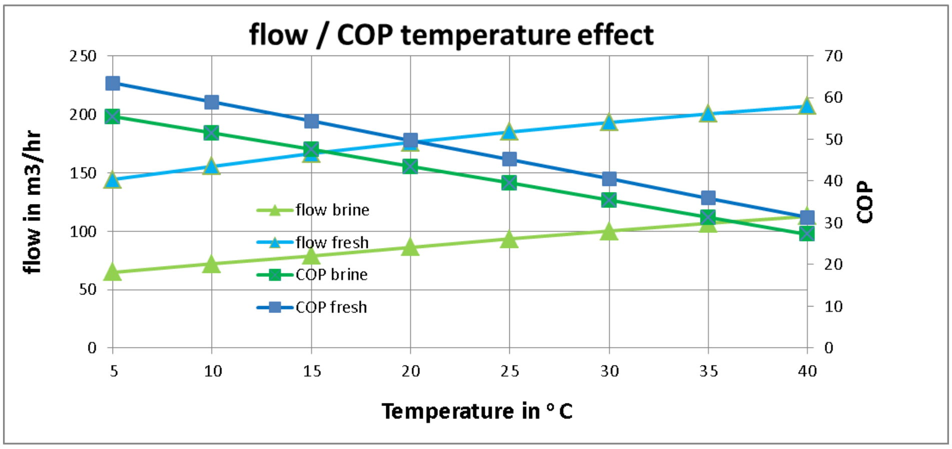

Figure A1.1 Temperature effect of doublet flow and of doublet Coefficient of Performance (COP) in case of fixed boost pressure

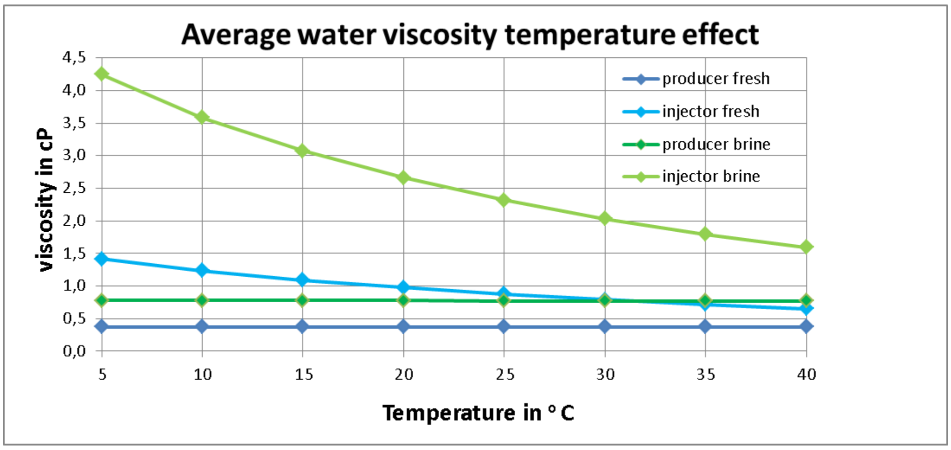

Figure A1.2 Temperature effect of average viscosity in case of fixed boost pressure

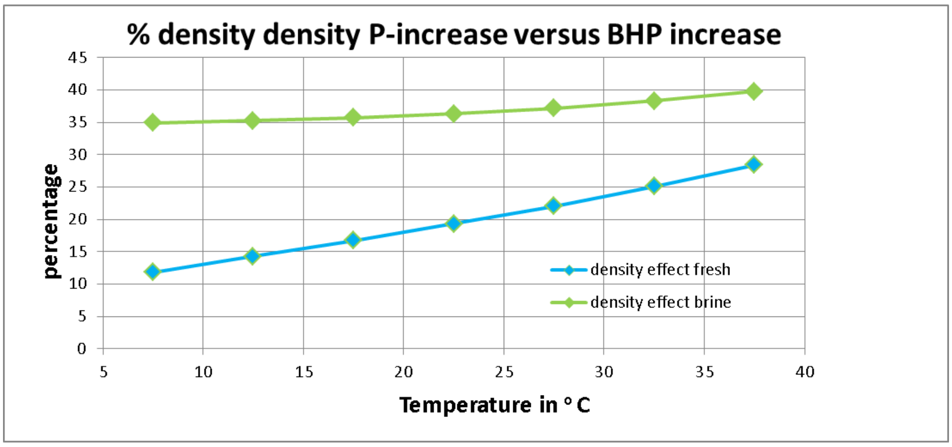

Figure A1.3 Temperature effect of relative water density weight in case of fixed boost pressure

Boundary condition: fixed doublet flow

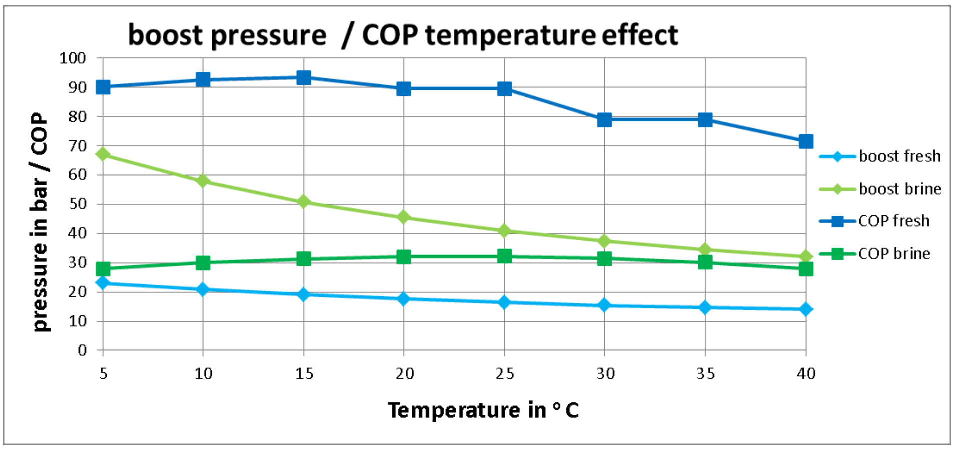

Figure A1.4 Temperature effect of ESP boost pressure and of doublet COP in case of fixed flow

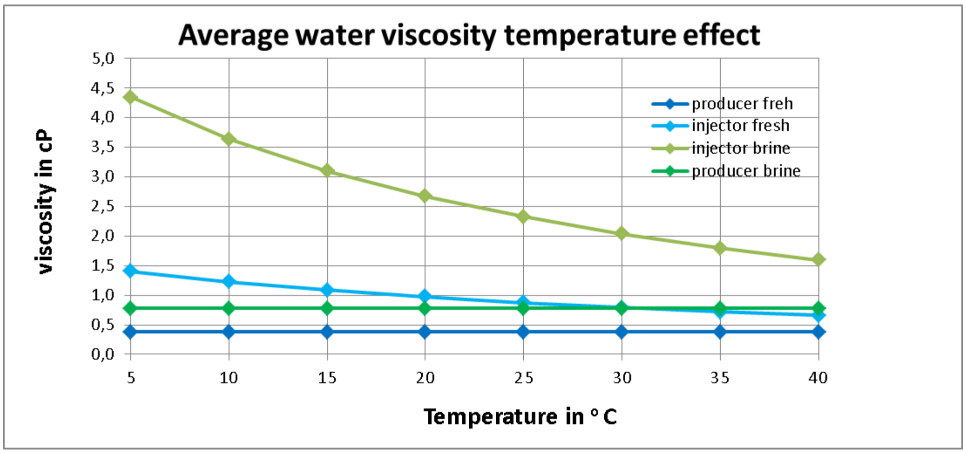

Figure A1.5 Temperature effect of average viscosity in case of fixed flow

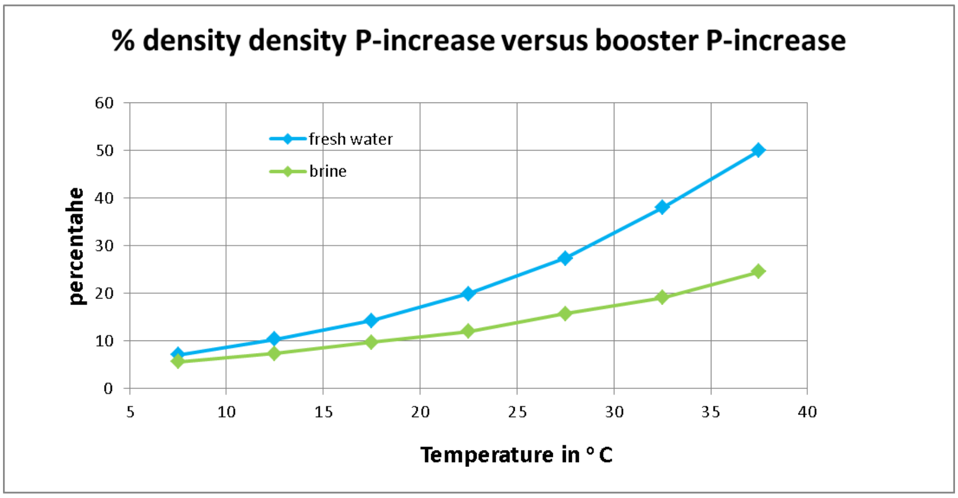

Figure A1.6 Temperature effect of relative water density weight in case of fixed flow

Conclusions

Coefficient of Performance (COP) temperature effect: The COP will increase with decreasing temperature for fixed booster pressure.

Viscosity temperature effect: The viscosity will increase with temperature. This increase is accelerated by salinity.

Flow temperature effect: With a fixed ESP booster pressure the temperature decrease will result in a lower flow. For example, reducing injection temperature from 40degC to 5degC in Figure A1.1 reduces the flow rate from 200 to 150 m3/hr – a reduction of 25%. Typical reductions are 1 ½ - 2 m3/hr per degree C reduction.

ESP booster pressure temperature effect: In a case with a fixed system flow rate, the ESP booster pressure will in general increase with decreasing temperature. For example, reducing injection temperature from 40degC to 5degC in Figure A1.doubles the required booster pressure. The booster pressure increase ranges for fresh water from 0.1 – 0.5 Bar extra pressure per degree cooling, and for brine a much steeper 0.5 – 1.8 bar/degC.

Water density effect on pressure: Temperature decrease results in a decrease of effect of water density on pressure. This decrease is stronger for fresh water compared to brine (See Figures A1.3 and A1.6).

Observed effect of higher WBHP needed of warmer injection water: The main effect of warmer water is a reduced resistance to flow through the reservoir formation (and hence a higher flow rate). The decreasing viscosity has a larger effect than decreasing water density (which would decrease the pressure acting on the reservoir, decreasing the flow rate). The viscosity effect is considerable: some 2% per degreeC.