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TNO report

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Radial drilling for Dutch geothermal applications

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Summary

Radial jet drilling is a well stimulation technique that has drawn the attention of operators of geothermal doublets, mainly as a potential technique to improve the performance of the injector well. With radial jet drilling, several open hole laterals are jetted from the main well bore, which enhance the connectivity of the well to the rock and thereby the well productivity or injectivity. As with any stimulation technique, the suitability of radial jet drilling depends on the specific situation of the geothermal system.

In this report, the findings, simulation results, conclusions and recommendations of a technology cluster (TC) are documented. A TC is aimed at providing its (SME – small and medium-sized enterprises) participants with the information to potentially make a next step with a certain technology. The geothermal operators participating in the TC Radial Drilling can use the set of questions and answers below to assess the potential of radial jet drilling for their specific situations.

What makes radial jet drilling attractive compared to other stimulation techniques?
Radial jet drilling does not require large volumes of water to be applied and its application is more controlled than for example hydraulic fracturing, resulting in lower costs and less risk.

For what wells and formations is radial jet drilling applicable?
The formation rock needs to have a minimum porosity of about 3-4% to be jettable. The most important criteria for the well are the minimum diameter (about 4 inch) and maximum along hole depth (about 5 km). See section 2.3.

What are risks?
Currently no major risks to the well have been identified. The main risk appears to be sand production from the open-hole completion. Also risks to the environment appear to be limited, due to the limited amount of water needed for jetting and the fact that no pressure is put on the formation. However since the amount of experience and well-documented cases is limited, not all risks may have been identified at this moment in time.

How much does radial jet drilling enhance the performance of a well?
Simulation on representative cases show a potential performance increase[1] by a factor of up to 3 when 8 laterals of 100 meter are successfully jetted and geological conditions are favourable. For fewer or shorter laterals, or in less favourable conditions, performance increase is considerably less (Figure 11). It should be noted that there appears to be a mismatch between modelled performance enhancement and observed enhancement as documented in publications. Major uncertainties in the production estimates are the long-term (>1 year) stability of the jetted laterals, the actual achieved length of the lateral (which is not observed during or after jetting) and the effect of sub-surface heterogeneity.

[1] Productivity increase factor (PIF), see section 3.3.2 for the details.

How does well performance increase relate to the (increased) efficiency of a geothermal system?
In this study, we present a way to compute an equivalent skin factor for a stimulated well, which can be used in calculations of doublet performance (using, for example DoubletCalc). In this way, the operator can compute the decrease in required pump power or increase in flow rate and thereby geothermal power depending on his own operating conditions (section 3.1). A simple way is presented to get a first estimate of the skin value depending on the most important influencing factors (section 3.3.2, 3.4.2).

Is radial jet drilling economic?
A first estimate of the benefits of well stimulation by radial jet drilling can be obtained as described in this report in terms of increased performance (depending on the operating conditions and specific situation). With these estimates, the operator can make his own calculations for savings of energy required for the pumps, extra revenues due to more output of thermal heat, et cetera.

In the project, indications of the costs of stimulation in different scenarios were discussed between the participants and the involved service provider.

In a final business decision, considerations other than expected revenue and costs, such as risks, subsidies, et cetera, are relevant but these are beyond the scope of this technology cluster.

All-in-all, is radial jet drilling proven technology?
Radial jet drilling has been applied to increase production in the oil-and-gas industry for over 10 years. Development of the technology aims at improving its applicability and effectiveness and remains ongoing. Nevertheless, creating open-hole laterals by jetting can be regarded as proven technology.

The ultimate goal of well stimulation by radial jet drilling is to enhance performance. In some reported cases there is a mismatch between expected and realised performance improvement. From literature, the reason for this mismatch remains largely unclear. From this perspective, we conclude that the technology should be qualified as not yet fully mature.

No documented cases of application of radial jet drilling to geothermal doublets have been found.

What are possible next steps?
- Site specific assessment of the applicability of radial jet drilling requires more detailed investigation of the site specific conditions and more sophisticated modelling to get a more accurate estimate of the expected revenues.

- Further development of the technique is and will be pursued in several research programs, among others within the European Horizon2020 framework.

Contents

1 Introduction and scope

1.1 Background: poor injectivity in geothermal installations

In the Netherlands, there are currently about a dozen operational geothermal systems (doublets). They target aquifers of about 2 to 3 km deep, the temperature of the produced water is 60-100°C and, after usage of the thermal energy, the water is injected back at a temperature of 25-35°C. Typical flow rates through the system are 150-250 m^3/hour, while the installations produce in the order of 8-10 MW of power. Apart from the operational settings, the efficiency (or coefficient of performance) of installations is highly dependent on the geological setting (for example, permeability of the rock), the properties of the water and performance of the wells.

A number of geothermal operators have experienced disappointing injectivity in the injection well of their doublets, which can be caused by various reasons (see, for example, Degens et al., 2012). Well stimulation is aimed at improving the injectivity (or productivity). The suitability of any stimulation approach will depend on the specific situation of a geothermal system.

1.2 Technology cluster radial jetting

Radial jetting[2] is a well stimulation technique that is commercially available. The technique potentially competes with, for example, hydraulic fracturing in terms of costs, expected (well) performance improvement and public acceptance. This potential has motivated Dutch geothermal operators to participate in a so-called technology cluster (TC) run by TNO.

In a technology cluster, TNO provides the sponsoring participants with knowledge to a number of research questions, upon which the participants can improve their operations or business. Also, general and specific recommendations are made. In this TC, the following questions have been investigated:

- What increase in well performance may be expected from stimulation by radial jetting and how can the improvement of the performance of the entire geothermal installation be calculated from the well performance increase?

- How does radial jetting work, what are the limitations (in terms of applicability to specific geothermal systems) of the technique, and what are the risks? What are experiences with the technique (also in the oil-and-gas industry).

The following approach has been followed:

- The potential well performance increase has been investigated by model simulations of cases representative for Dutch geothermal installations.

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[2] Radial jetting is also referred to as radial jet drilling, radial drilling or short radius drilling

- The technology, including its limitations and risks have been explained based on findings in literature and other publicly available material. A commercial provider of the technology (Coil Services) has participated in the discussions and contributed to this report.

1.3 Setup of this report

In Chapter 2, radial jet drilling will be explained and the practical procedure explained. Also current possibilities and limitations will be described. In Chapter 3 the potential increase in injectivity (or productivity) will be presented for different radial well configurations. Finally, in Chapter 4 experience with radial drilling as derived from literature will be described.

2 Radial jetting

2.1 Introduction

Radial jetting is a technique in which hydraulic jetting is used to create small-diameter laterals up to 100 m long from a main backbone. The goal is to increase the productivity or injectivity of a well. The description as presented in this chapter is mostly taken from the information provided by Coil Services for this project. In Figure 1 the typical setup of laterals (or radials) resulting from radial jetting in a vertical well is presented. The radials make an angle of 90° with the main well bore (also called backbone) and are typically set in groups of four at the same depth with 90° angles in between. The working procedure is described in the next section.

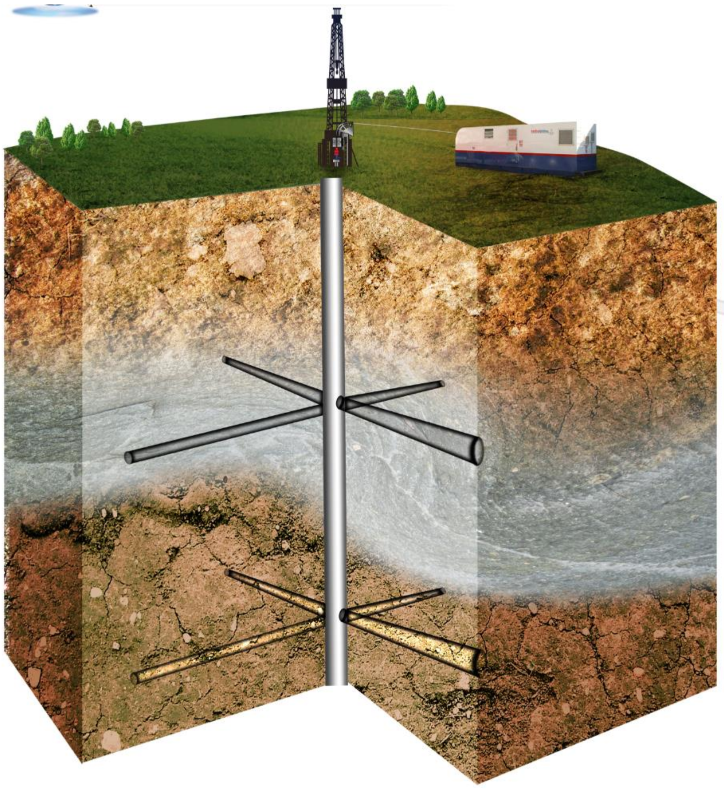

Figure 1. Overview of laterals as created by radial jet drilling (http://www.radialdrilling.com/)

Instead of using conventional drilling, the holes are created by hydraulic jetting. The setup of the nozzle head used for jetting is shown in Figure 2. The forward nozzle causes the penetration in the rock. The main mechanisms of penetration are surface erosion, poro-elastic tensile failure and cavitation. The backward nozzles jet water backward which creates the forward thrust needed to move the nozzle head forward.

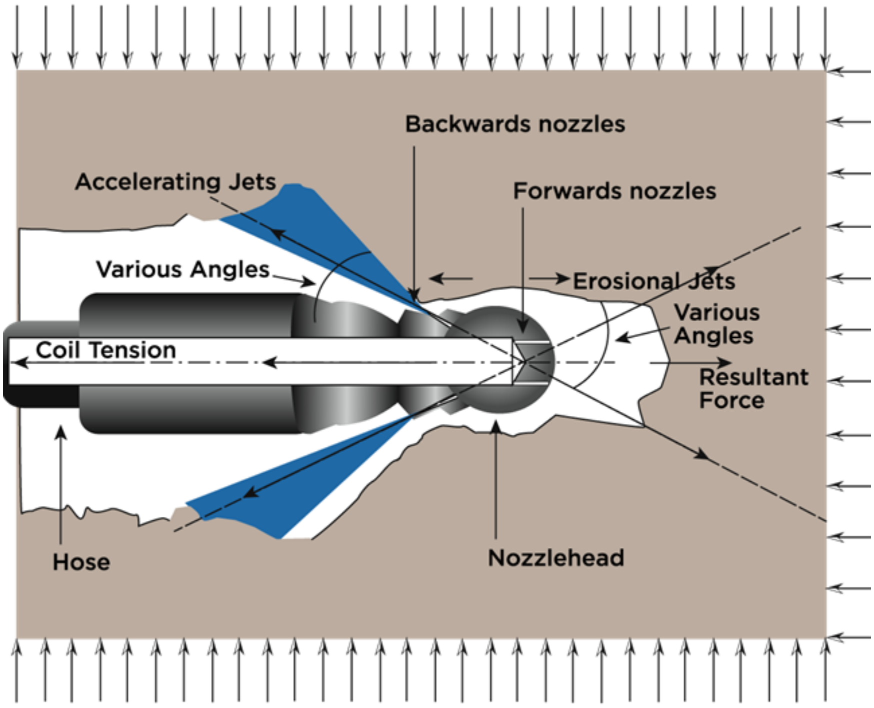

Figure 2. Setup of the nozzle head used in radial jetting.

2.2 Procedure

The working procedure consists of four steps which are described below:

- A workover rig brings the deflector shoe to the required depth
- An optional step is to orient the deflector shoe using a gyro orientation. This will determine in which direction the lateral will be drilled
- Run in hole (RIH) with ½ inch mini coil and a milling assembly to mill a hole into the casing (if present)
- RIH with ½ inch mini coil and jetting assembly to jet up to 100 m into the formation

More details on the work programme and procedure can be found in Appendix H.

In most formations, jetting the laterals is fast and the fluid requirements are modest: for a single about 2 m^3 of fluid is required (1 m^3 for milling the hole and 1 m^3 for jetting) and the actual jetting of the lateral generally takes only 5-30 min.

The procedure can be changed to allow for special options, such as jetting with acid, jetting with rotating nozzles (for difficult to jet rocks), jetting of radials with a dip of 45° (in case the normal radials would be aligned to the bedding of the formation).

Mitigation or remediation options are limited: the hole cannot be plugged once it has been jetted. This is probably more an issue for petroleum applications than geothermal applications. For geothermal wells a reason for plugging could be sand production (in case of producers). If the radials are jetted *before* sand screens are put in place, this is not likely to be a problem.

Technology cluster radial drilling

The potential for environmental issues is limited for this procedure:

- Induced seismicity: unlikely because the pressure on the formation is limited to a very small area in contrast to hydraulic fracturing.
- Pollution of ground and surface water: since the amount of fluid needed for jetting is very limited, this is not likely to be a large issue. Probably the most important risk is surface spills during the operation.
- The impact on the local community during the procedure in terms of noise, truck movement and such is expected to be relatively low (much lower than for hydraulic fracturing) and comparable to a conventional workover.

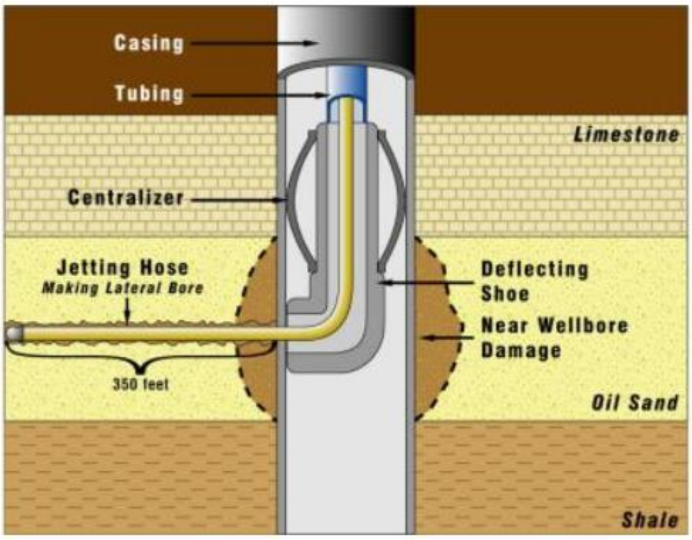

Figure 3. illustration of the radial jetting procedure in a vertical well (http://wes-ok.com/technology/)

2.3 Applicability

Whether radial jetting can be used depends on both the well configuration and the formation in to which the radials should be jetted.

Range of applicability:
- Radial jet drilling can be applied both in existing and new (un-cased) wells
- The minimum inner diameter of the well is 4 inch (4½ inch liner)
- Screens can be milled through as well as steel pipes
- Deviated wellbores are not an issue (even horizontal wells are possible)
- Temperature up to 210°C if necessary
- Maximum along hole depth is 5 km (this limit is determined by the length of the mini coil which is used).

For the formations or rock to be jettable, they should generally have a porosity exceeding 3-4%. Some rock types such as evaporates (rock salt, gypsum, anhydrite) are difficult to jet (Elliott, 2011). Jetting of formations with high permeability and porosity is easiest, but in these formations the expected benefits are usually less. If it is suspected that the formation of interest is difficult to jet, it is possible to test rock samples prior to radial jetting to optimize the nozzle configuration.

3 Potential injectivity enhancement

3.1 DoubletCalc

The potential productivity or injectivity enhancement is calculated for a large range of well configurations and geological scenarios. However, injectivity improvement alone is not an intuitively clear indicator of geothermal doublet performance enhancement. Therefore a skin value can be calculated from the productivity or injectivity index. The skin value can then be used in DoubletCalc to calculate benefits in terms of geothermal power, required pump power or COP (Coefficient of Performance). Below, the concept of 'skin' and the way DoubletCalc uses skin is further explained. Next, the details of the simulations and results are presented.

Skin

The simplest possible well is vertical and unstimulated. It will subsequently be referred to as a 'standard well'. Non-standard wells, therefore, are either non-vertical and / or stimulated. In this context, non-vertical may either mean inclined, or (sub-)horizontal. Stimulation can be hydraulic fracturing, acidizing, jetting of radials and/or the drilling of one or more laterals. The opposite of stimulation is well damage, where the relevant properties (esp. permeability) of the reservoir around the wellbore decline by mud invasion, scaling etc.

The DoubletCalc software tool was originally designed to calculate an indicative geothermal power of a doublet consisting of vertical (or slightly inclined), unstimulated wells, based on estimated aquifer properties and simple installation parameters. This implies that in principle non-vertical and / or stimulated wells cannot be used in DoubletCalc as such. In the oil and gas industry it is common practice to compare the productivity / injectivity of non-standard wells to that of a standard well by means of a so called skin factor (Figure 4). Any non-standard well has a productivity / injectivity equal to that of a standard well plus a skin factor. A skin factor is a dimensionless number that can either be positive or negative. A positive skin factor indicates that the well underperforms with respect to the standard well. A well that has negative skin performs better than a standard well.

Wellbore damage results in (positive) mechanical skin. Other types of skin are geometric skin (resulting from partial penetration or completion and/or well inclination) and rate dependent skin (resulting from non-laminar flow, observed when flow rates are high). The effect of a hydraulic fracture or radials may also be expressed as a (negative) skin factor.

1. n. [Well Completions]

A dimensionless factor calculated to determine the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A positive skin value indicates some damage or influences that are impairing well productivity. A negative skin value indicates enhanced productivity, typically resulting from stimulation.

2. n. [Well Testing]

The zone of reduced or enhanced permeability around a wellbore, often explained by formation damage and mud-filtrate invasion during drilling or perforating, or by well stimulation.

Figure 4 Schlumberger Oil Field Glossary description of skin.

The current version of DoubletCalc (1.43) already accounts for slanted wells with a deviation from the vertical up to about 80°. The corresponding skin factor is automatically calculated from the specified inclination of the well in the reservoir section of the well using analytical formulae (Mijnlieff et al. 2014: DoubletCalc v1.43 user manual; Figure 5).

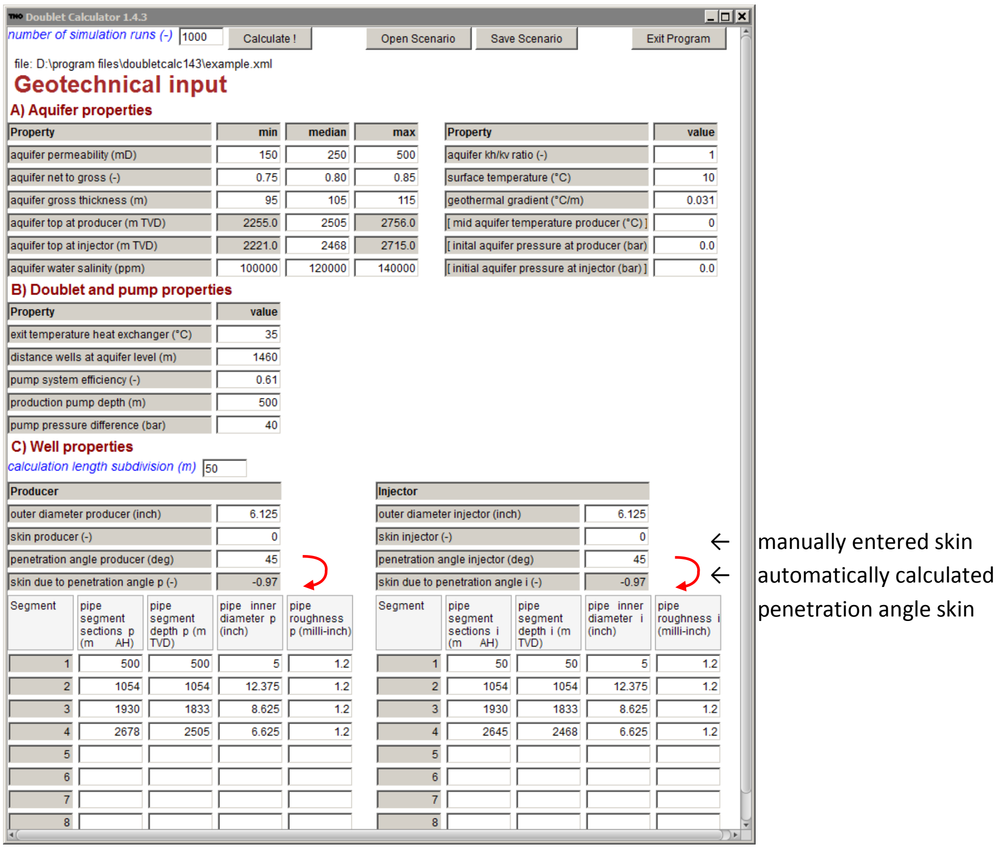

Figure 5. DoubletCalc input screen showing well inclination and automatically calculated penetration angle skin. Additionally, a 'skin producer' and / or 'skin injector' can be specified.

In order to model various other doublet configurations in DoubletCalc, either non-standard wells or damaged wells, it is possible to enter a skin value manually, for instance if the mechanical skin was calculated from a well test (Figure 5). Determining the skin value for complex well configurations is not trivial. Sometimes a single analytical solution does not exist. TNO has compiled the mathematical formulae required to calculate or approximate the skin factor for a number of well configurations:

- Horizontal drain
- Two laterals
- Radials
- Thermal fractures

The analytical solutions were all tested against a reservoir model to check the validity. All configuration mentioned above were implemented in a spreadsheet. Currently, only a spreadsheet calculating the skin of a horizontal drain can be found on the NLOG website[3]. Other spreadsheets will be made available at a later stage. The relevant parameters like reservoir thickness, horizontal drain length, anisotropy, distance between the laterals, casing diameter, et cetera need to be entered in the spreadsheet. After all parameters have been entered, the skin factor is calculated.

In order to calculate the flow rate, power etc. of a doublet containing one or more of such special well configurations, the well(s) need(s) to be specified in the DoubletCalc software as a vertical, fully penetrating well. The calculated skin value(s) are then entered manually as 'skin producer [-]' and / or 'skin injector [-]'. This is because the productivity / injectivity improvement, expressed as skin factor, is defined with respect to a vertical unstimulated well.

Note that skins cannot always be added. This is especially true for geometrical skin. For instance, if a well containing a horizontal drain has a skin value of -3, adding a second horizontal drain to the same well nearby will not result in the well having a skin value of -6. Two close drains influence each other in a negative way. Therefore the combined skin is less than the sum of the individual skin. On the other hand, if an inclined well has some well damage, the negative inclination skin and the positive well damage skin can be added.

Example of using skin in DoubletCalc calculations

The range of skin values that was calculated for radial stimulation is from -6 to 0. For specific reservoir settings, these values can be translated to changes in geothermal power (Figure 6), required pump power (Figure 7) or COP (Coefficient Of Performance) (Figure 8). The reservoir settings used to create these figures are (see Appendix A for the full input):

- Depth = 2500 m
- Reservoir thickness = 100 m
- Reservoir horizontal permeability = 200 mD
- Reservoir vertical permeability = 20 mD
- Net over gross ratio (NTG) = 0.75

For these reservoir settings, a vertical well with a rate of 150 m^3/h produces 8 MW at a pump pressure of 59 bar and has a COP of 17. For example, a skin of -3 resulting from stimulation of the well with radials, would change the required pump pressure to achieve 8 MW to 45 bar (Figure 7) and increase COP from 17 to approximately 22 (Figure 8). Conversely, at the same pump power, the capacity could be increased to 10 MW (Figure 6).

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[3] http://nlog.nl/resources/Geothermie/Equivalent%20skin%20horizontal%20well.xlsx

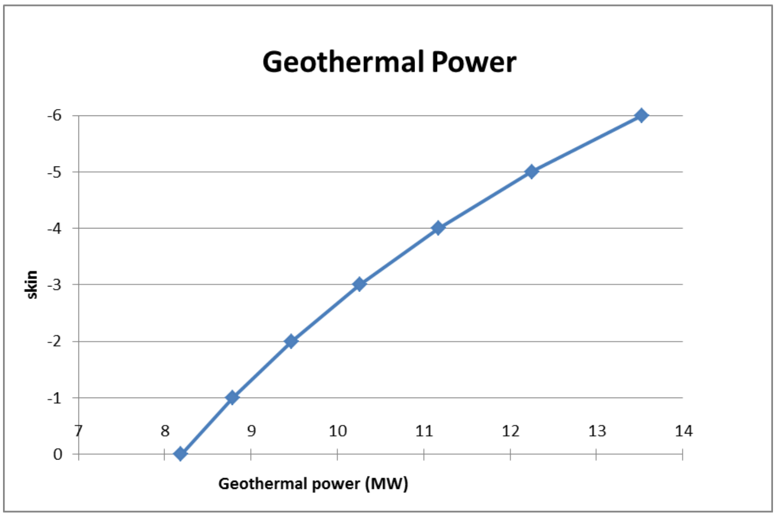


Figure 6. Change in geothermal power for skin changing from 0 to -6, with equal pump pressure (59 bar).

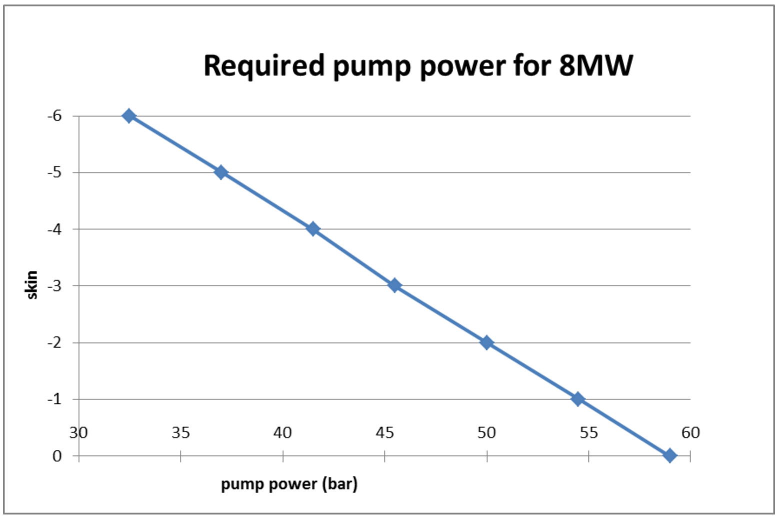


Figure 7. Change in required pump power to achieve 8 MW for skin changing from 0 to -6.

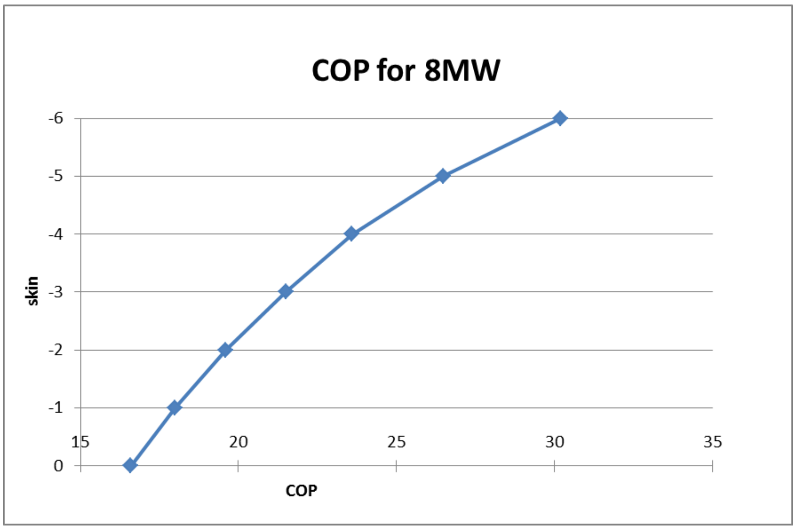


Figure 8. Change in COP (Coefficient of Performance) at 8MW for a range of skins from 0 to -6.

3.2 Methods

Two different methods were used to calculate the increase in productivity resulting from adding radials to a well:

- A semi-analytical method which can only simulate homogeneous cases and vertical wells. This approach is referred to as Analytical Element method (AEM). The AEM method is developed in-house at TNO and is documented in (Egberts et al., 2013) and (Egberts and Peters, 2015). The AEM tool currently cannot simulate a deviated well in combination with radials.
- A full numerical model (industry standard tool Eclipse) which is used to:
  - Validate the results from the simplified approach by AEM
  - Estimate the effect of a non-vertical backbone such as is common in geothermal applications.
  - Estimate the impact of radials in heterogeneous cases.

Appendix B describes how to calculate the skin based on the results of numerical models. The skin value is always calculated with respect to the case of a vertical, unstimulated, fully perforated well in the same reservoir.

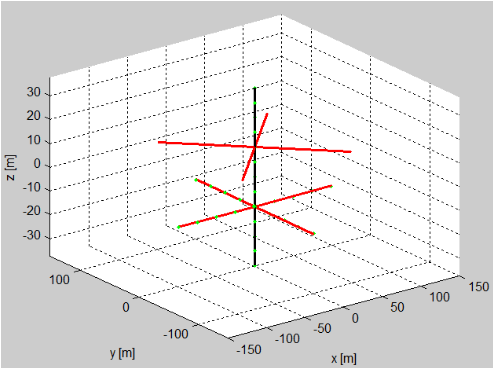
In Table 1, the results of both methods are compared for three radial well configurations and a deviated well without radials (Figure 9):

- one configuration with 8 radials of 100 m length divided over 2 kick-offs (Figure 9a). The radials at the second kick-off are rotated 45° compared to the radials at the first kick-off. The angle between the radials at a kick-off is 90°.
- two configurations with 4 radials (at 1 kick-off) (Figure 9b and c). The angle between the radials is 90°. The length of the radials is 100 m and 25 m respectively.
- one configuration without radials but a deviated main well bore (35° from vertical)(Figure 9d).

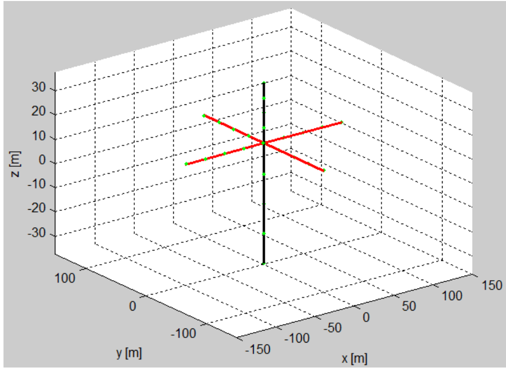
The comparison of the results of AEM and Eclipse shows only small differences.

Table 1. Comparison of the calculated skin for the AEM method and Eclipse.

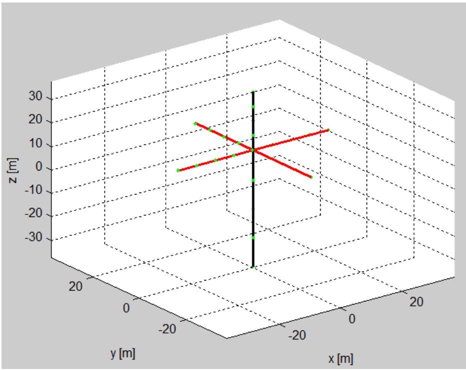
	AEM	**Eclipse**
Vertical well with 8 radials of 100 m long	-5.08	-5.26
Vertical well with 4 radials of 100 m long	-3.88	-3.83
Vertical well with 4 radials of 25 m long	-1.23	-1.47
Deviated well of 35° without radials	-0.27	-0.20



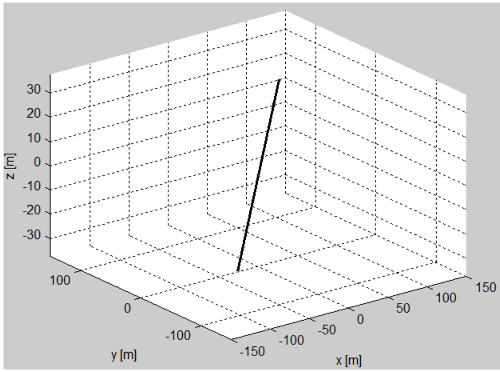
a. 8 radials of 100 m



b. 4 radials of 100 m



c. 4 radials of 25 m



d. 35° deviated well without radials

Figure 9. Overview of the simulated radial well configurations.

3.3 Homogeneous cases

3.3.1 Input

Two formations were identified as most relevant for the participants of this project: the Slochteren sandstone and the Schieland-Delft sandstone. From the input of the participants, a set of properties for the geothermal injection wells and the formations was selected for both formations. These are presented in Appendix C.

As a first step, a sensitivity analysis was done to check which parameters affect the results most. From the parameters which were checked (permeability, porosity, anisotropy and reservoir pressure and height), only reservoir height and anisotropy are important. The others had no impact on the resulting skin. The figures in Appendix D show the results of these initial simulations.

Since the height and anisotropy of the Slochteren sandstone and Delft/Schieland sandstone cases in Appendix C are very similar, a general setup is chosen. For reservoir height *a range of 50 to 200 m* is used and anisotropy[4] in the *range of 1 to 100* is used. Because of the importance of anisotropy for the results, an explanation

[4] Please note that for many applications anisotropy is defined as k_v/k_h (vertical over horizontal permeability). Here we follow the convention used in DoubletCalc were anisotropy is defined as horizontal over vertical permeability.

on anisotropy and its effects on flow is provided in Appendix E. The AEM tool does not take the Net over Gross ratio (NTG) into account. For relatively large NTG (>0.7), the used reservoir height can be interpreted as net height. For small NTG the tool is not valid.

The other input settings are given below:

- Depth is 2500 m and hydrostatic gradient = 1 bar/100 m resulting in an initial pressure of 250 bar.
- Injection pressure (at reservoir level) is 14 bar over the reservoir pressure
- Porosity = 0.2
- Permeability (x-dir) = 100 mD
- Permeability (y-dir) = permeability (x-dir)
- Well bore radius = 0.0762 m (diameter = 6 inch)
- Radial radius = 0.5 * 0.0635 m (diameter = 2 inch)
- Vertical, fully perforated well
- water viscosity = 0.54 mPa·s

From the ranges of height and anisotropy, 500 samples were taken and the increase in injectivity or productivity and skin were calculated using the input settings above. The increase in productivity (PIF= Productivity Increase Factor) is defined as productivity of stimulated well divided by the productivity of the unstimulated well.

The simulations were done for 6 radial well configurations. The 6 configurations are: 8 radials of 100 or 50 m and 4 radials of 100, 50, 25 or 10 m. For illustration of the radial configurations see Figure 9. The diameter of the main well bore (backbone) and radial have not been varied. A limited sensitivity analysis was done to test the effect of the diameters. Changing the radial diameter from 2 inch to 1 inch hardly affected the results. It should be noted that is assumed that even in laterals of 1 inch, flow rates are not large enough to results in significant pressure drops within the lateral. Also, it is assumed that the laterals themselves have zero skin. It is difficult to verify these assumptions without actual flow measurements in jetted radials, which are to our knowledge not reported anywhere.

Increasing the diameter of the well bore from 6 inch to 8 inch changed the skin from -3.9 to -3.7. In other words, for a larger well bore diameter, the effect of the radial stimulation reduces slightly. This can be understood when we realise that adding radials can also be interpreted as increasing the diameter of the well. For a larger diameter of the main well bore, adding the same length of radials is a relatively smaller increase in diameter.

3.3.2 Results

Figure 11 shows the Productivity Increase Factor (PIF) for all six radial well configuration for all samples. For all configurations the general conclusions are similar (also see illustration in Figure 10):

- For increasing height of the aquifer, the PIF due to radial stimulation decreases. This means that 4 radials in a 50 m thick aquifer increase the productivity more than 4 radials in a 200 m thick aquifer, assuming that the original well was perforated over the entire thickness of the aquifer.

- For lower vertical permeability (high anisotropy), the PIF due to radial stimulation decreases. This is due to the fact that the radials are horizontal and the main flow towards the radials is vertical, whereas the flow to the main well bore is horizontal. Thus the inflow to the main well bore is determined by the horizontal permeability and the inflow to the radials by the vertical permeability.

It is also clear that fewer and shorter radials have a smaller increase in productivity. This is illustrated in Figure 12, in which mean PIF (mean from the 500 samples) is plotted as a function of the total jetted length. Total jetted length is calculated as the product of number of radials and the length of the radials. For 2 cases (4 x100m-radials and 8 x 50m-radials), the total jetted length is identical. In that case, the longer radials show more benefit than the larger number of shorter radials.

The results can also be presented in terms of skin (Figure 13). This shows that although the increase in productivity is almost linear, the increase in skin isn't. This follows from the relation between PIF and skin which can be expressed as (see Appendix B for explanations):

$$skin = \left(\frac{1}{PIF} - 1\right)\left(\ln\left(\frac{L}{r_w}\right)\right) \qquad \text{Eq. 1}$$

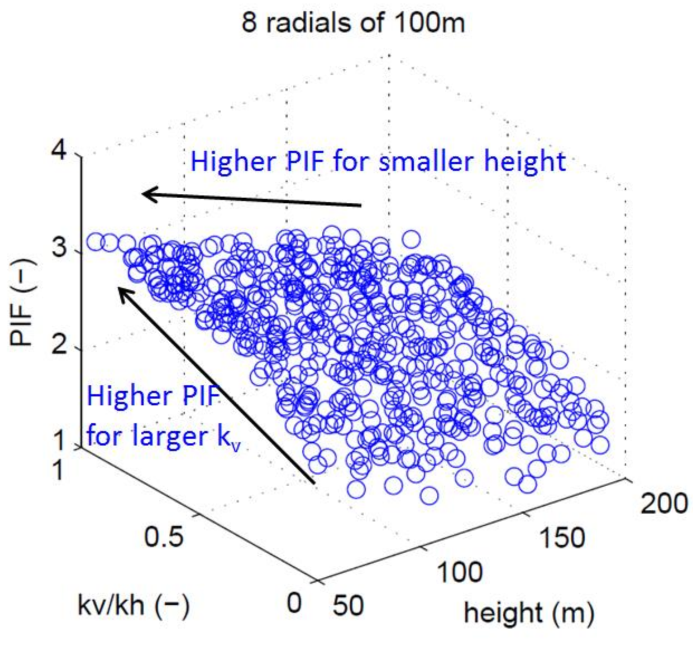


Figure 10. Illustration of the main conclusions showing the increase in PIF (productivity of stimulated well / productivity of the unstimulated well) as a function of anisotropy and reservoir height.

Technology cluster radial drilling

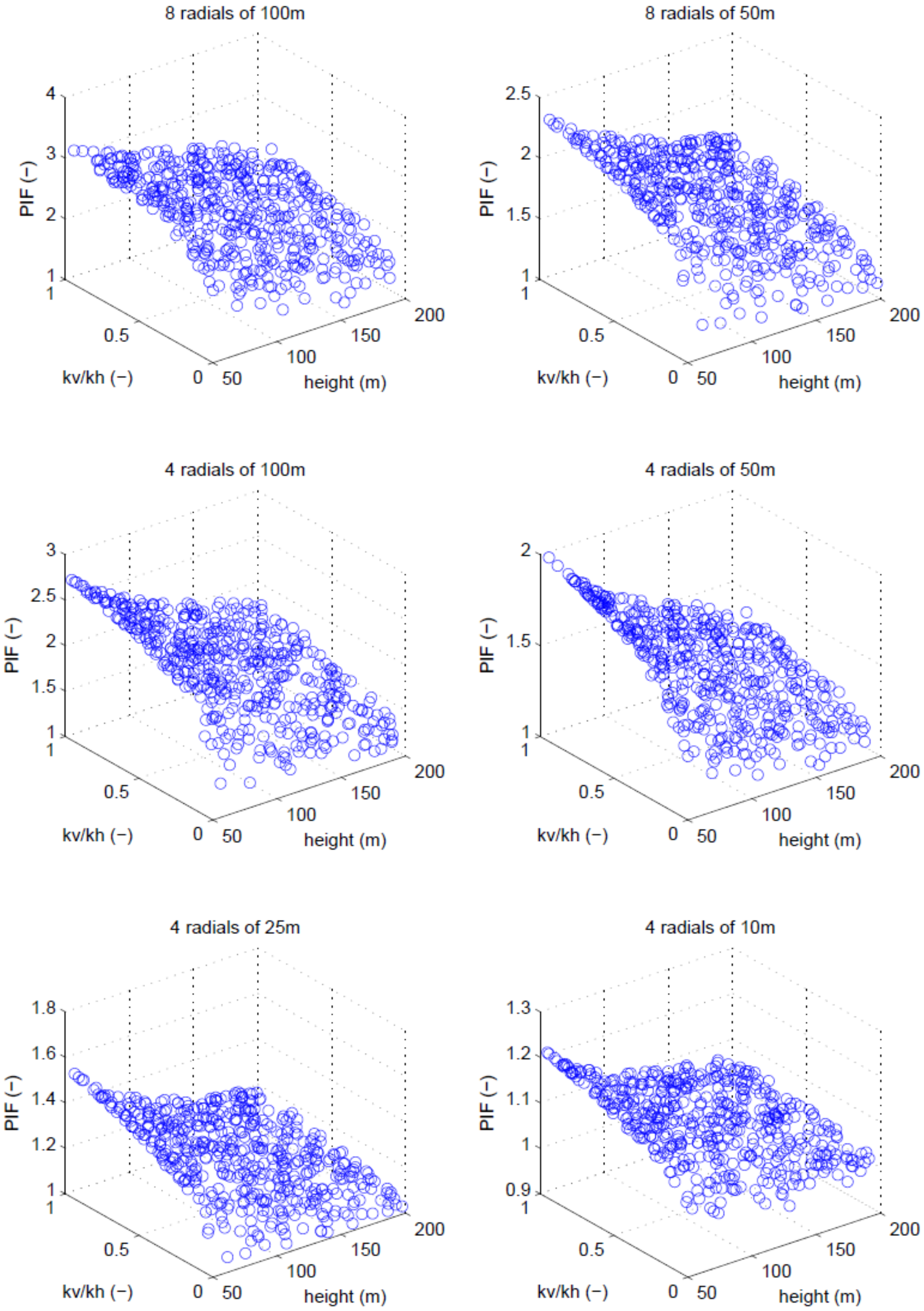


Figure 11. Simulated increase in productivity (PIF=productivity of stimulated well / productivity of the unstimulated well) (Please note: different axis on each plot; for plotting purposes k_v/k_h is used instead of k_h/k_v)

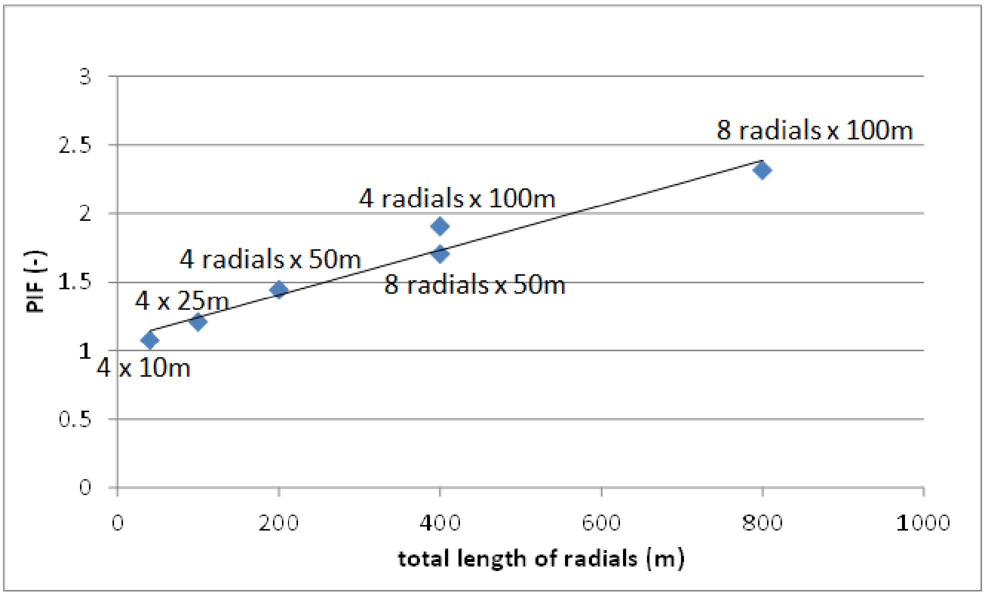


Figure 12. Mean PIF (productivity of the (stimulated) radial well / productivity of the unstimulated well) from 500 samples as a function of the total length of radials jetted.

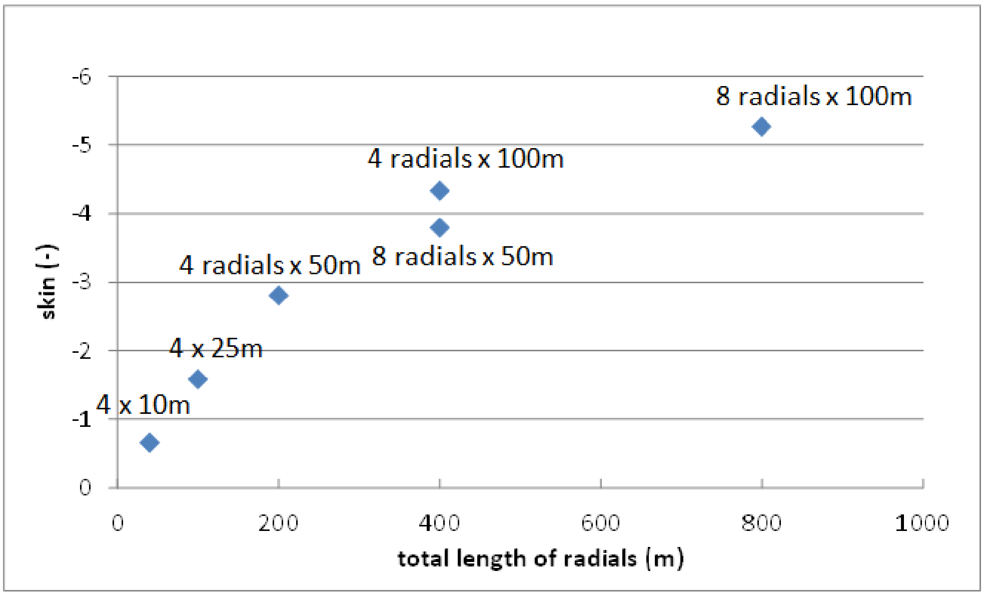


Figure 13. Mean skin from 500 samples as a function of the total length of radials jetted.

To enable a first estimate of the skin for a specific reservoir height and anisotropy, a simple function is fitted to the results presented above for each of the radial well configurations (500 samples for each well configuration). The function is shown below:

$$skin = a + b\sqrt{\frac{k_h}{k_v}} + cH \qquad \text{Eq. 2}$$

where

a,b,c parameters to be estimated for each radial well configuration
k_h horizontal permeability (mD)
k_v vertical permeability (mD)
H height of the reservoir (m)

The three parameters a, b and c are specified for the six radial well configurations in Table 2. Figure 14 shows the fit of this simple function to the simulation results. Discrepancies mainly occur for very low or very high skins. Overall, this simple approach gives a very first indication of the potential additional production of radials. Of course for real applications a dedicated simulation is necessary to give a more accurate estimate.

Table 2. Overview of the parameters for equation 2 for 6 radial well configurations

	a	**b**	**c**	**Msqe* (-)**
8 radials of 100 m	-7.6072	0.5668	0.0106	0.0259
8 radials of 50 m	-6.3387	0.5094	0.0125	0.0668
4 radials of 100 m	-7.1746	0.6097	0.0141	0.0620
4 radials of 50 m	-5.4982	0.5620	0.0135	0.0703
4 radials of 25 m	-3.4352	0.3003	0.0101	0.0636
4 radials of 10 m	-1.6124	0.1520	0.0054	0.0197

* mean squared error

For example, for a reservoir with a thickness of 120 m and anisotropy of 8 (horizontal permeability 8 times larger than vertical permeability), stimulating a (vertical) well with 4 radials of 50 m long in a homogeneous reservoir would result in:

$$skin = -5.4982 + 0.5620 * \sqrt{8} + 0.0135 * 120 = -2.3$$

From Figure 14 it can be seen that for these values the fitted skin using this equation is on average close to modelled skin value. Thus, if the assumptions are valid and the radials are jetted as expected (reaching 50 m distance to the well), the theoretically expected skin is in the order of -2 to -2.5.

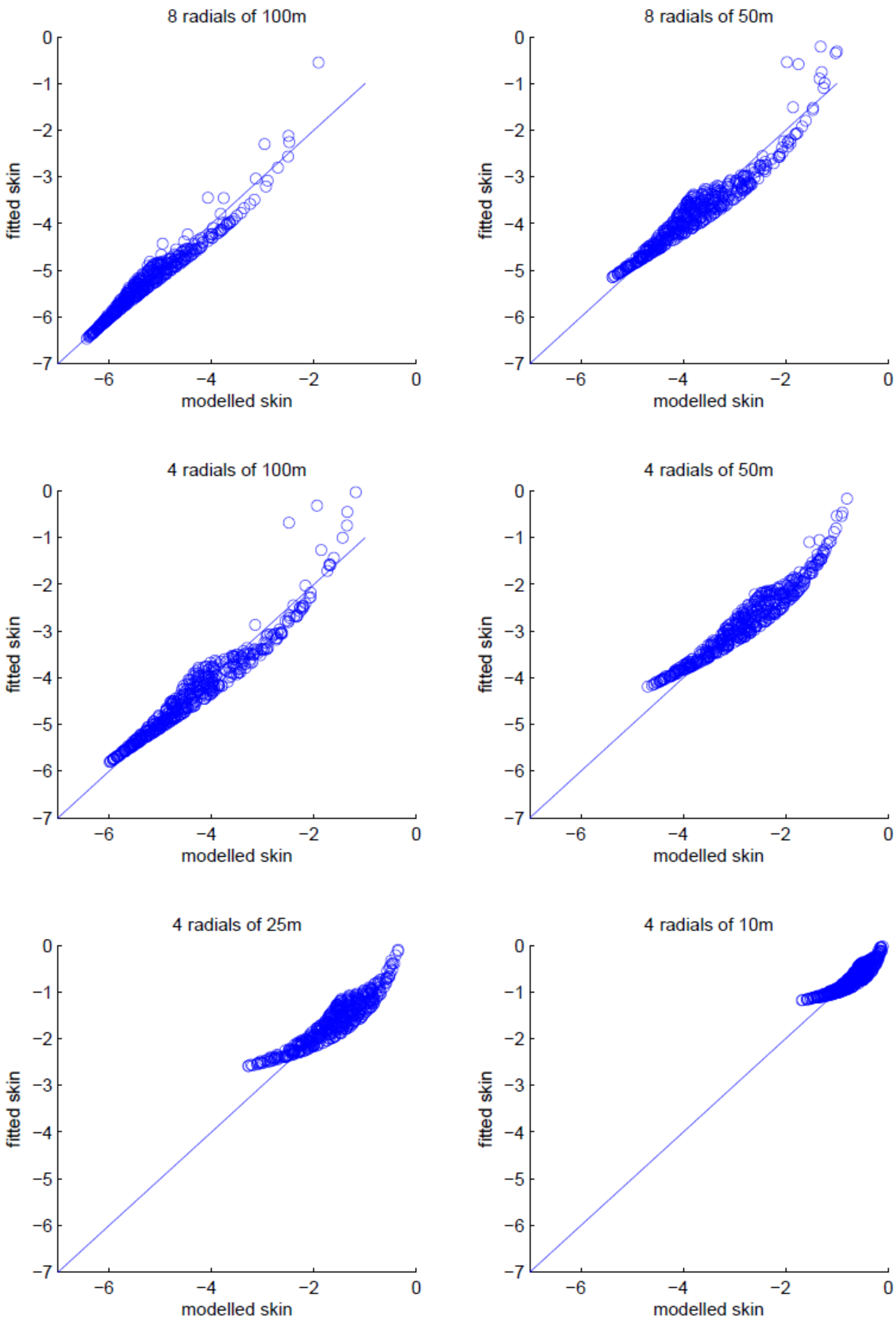


Figure 14. Fit of the skin using the simple function in Eq. 6 to the skins simulated/modelled by AEM.

3.3.3 Effect of non-vertical well

In a geothermal doublet, the main well or backbone is normally not vertical (as was assumed in the simulations) but deviated. In the simulations, the radials are perfectly horizontal, since the radials have a 90° angle with the well bore. For reservoirs with a low vertical permeability, this is unfavourable. A difference in productivity is therefore expected when the backbone is deviated. A brief analysis was done to test the effect of a deviated well versus a vertical well using the numerical reservoir simulator. The results in Table 3 show indeed that the skin is consistently more negative for the deviated backbone compared to the vertical backbone (or productivity is higher). The difference is in the order of 0.2 to 0.5.

Table 3. Comparison of the skin for a vertical backbone and a deviated backbone in case the vertical permeability is a factor 10 lower than the horizontal permeability.

	Vertical backbone	**35° deviated backbone**
8 x 100m-radials	-5.26	-5.46
4 x 100m-radials	-3.83	-4.12
4 x 25m-radials	-1.47	-1.96

3.4 Heterogeneous cases

3.4.1 Input

One of the assumptions in the previous chapter is that the reservoir is homogeneous, which means that the important characteristics are the same everywhere in the reservoir. However many reservoirs are heterogeneous, which means that the properties vary throughout the reservoir. For example, there may be layers in the reservoir with very low permeability, or permeability is degraded in some areas because the pores have been filled, for example with illite (a clay mineral that can strongly reduce permeability) or anhydrite (Henares et al., 2014). Also not addressed previously in the homogeneous cases is the possibility having fractured reservoirs, which can for example occur in the south of the Netherlands (Jaarsma et al., 2013).

A full investigation into the effect of heterogeneity on radial performance is outside the scope of this project, but via a limited number of cases we aim to get some insight into the possible effects of heterogeneity. Three cases were defined:

– A layered reservoir: main heterogeneity in vertical direction
– A ‘patchy’ reservoir: main heterogeneity in horizontal direction
– A fractured reservoir: main production from fractures

Although it is not the goal to simulate specific wells, we have based the input for the models on data from existing wells to ensure realistic settings. For the reservoir with horizontal heterogeneity, the input settings are loosely based on the geothermal wells KKP-GT-1 and KKP-GT-2 as described in Henares et al. (2014) in which reservoir quality is locally impaired by anhydrite cementation. The wells produce in the Slochteren Formation (aeolian sandstones). The settings of the fractured reservoir are loosely based on data from the well CAL-GT-01 which produces in fractured Dinantian Limestone (EBN et al, 2012).

Layered reservoir
For the layered reservoir, the input is the most straightforward. It is assumed that the layers are perfectly horizontal. The good reservoir layers have permeability of 200mD, the poor-quality layers 5 mD. Porosity is 0.2 and 0.005 respectively. 25% of the reservoir height is poor quality, which is consistent with NTG = 0.75. In fact, this simulation could be interpreted as a case in which NTG is taken into account explicitly. Figure 15 shows the definition of the layers. The length of radials is

sufficient to cross the low-permeability layers. The deviated backbone of the well is clearly beneficent for this case, because it ensures that the radials are not located in a good layer that is trapped between low-permeability layers.

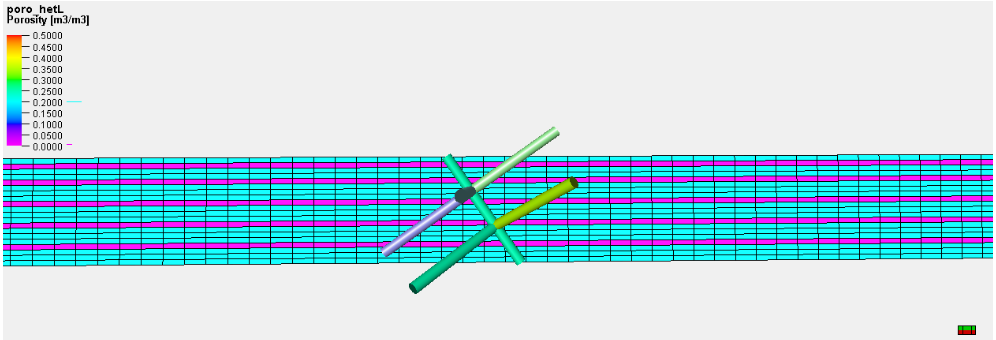


Figure 15. Overview of the layered reservoir showing porosity (blue is high porosity, pink is low porosity) and a radial well with 8 radials of 100 m long with 2 kick-offs (4 radials per kick-off). Reservoir height is 100m.

Reservoir with horizontal heterogeneity

For the horizontal heterogeneity, the possibilities are endless. To limit this scope, two main considerations were taken into account:

1. The range in permeability should be large (more than 3 orders of magnitude) to get a clear effect.

2. The scale of the heterogeneities should be in order of the length of the radials. For example, if the size of the low perm areas is small compared to the well/radials, they will average out in the result and little impact is expected.

The pattern and size of the heterogeneity is based on the description in (Henares et al., 2014) of the Slochteren formation in the Koekoekspolder area, with elongated NNE-SSW trending shapes. Using sequential Gaussian simulation porosity and permeability are generated. The used input values can be found in Appendix F. The resulting permeability is shown in Figure 16. It should be stressed that the generated permeability depends on a random process of assigning values to the grid blocks which means that the exact distribution of the permeability depends on chance.

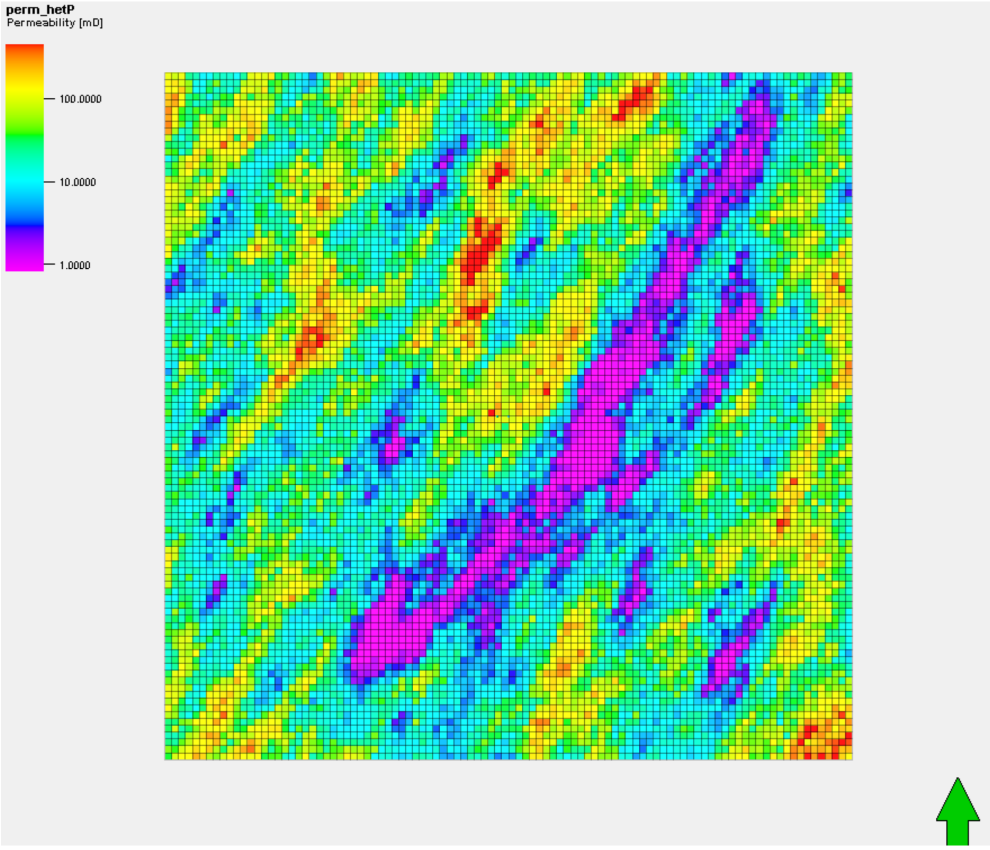


Figure 16. Top view of the heterogeneity in the permeability.

Fractured reservoir

For the fractured reservoir, properties are loosely based on the properties in well CAL-GT-01 in Dinantian limestone which are described in Appendix G (restricted).

For the input to the numerical reservoir model, it was assumed that the fracture density of conductive fractures in x-direction is 1 per m. For fractures in y-direction, only 1 fracture per 100 m is assumed. This produces a fracture network in which the main fracture orientation is in y-direction. In horizontal direction we assume a density of 1 per 10 m. Furthermore we assume a fracture width (w_f) of 0.1 mm. This fracture width is not based on observations, but chosen to ensure that the injection pressure is similar to the other cases for the deviated well without radials. From these settings, matrix-fracture interaction (σ_v) the fracture porosity (ϕ_f) and permeability (k_f) can be derived from the following equations:

$$\sigma_v = 4\left(\frac{\mathbf{1}}{l_x^2} + \frac{\mathbf{1}}{l_y^2} + \frac{\mathbf{1}}{l_z^2}\right) \quad \text{Eq. 3}$$

$$\phi_f = \frac{w_f * l_x * l_z + w_f * l_y * l_z}{l_x * l_y * l_z} * \phi_{in\ fracture} \quad \text{Eq. 4}$$

$$T_f = k_f w_f = w_f^3 \quad \text{Eq. 5}$$

In which:

l_x,l_y,l_z: matrix block size in x, y and z direction (m)

Eq. 4 is the cubic law (see for example Golf-Racht, 1982), which gives a good first approximation of fracture permeability. Furthermore, matrix permeability and porosity were chosen as 5 mD and 0.1 respectively.

In real reservoirs, fracture density is unlikely to be homogeneous across the reservoir. Also the presence of larger faults with a much higher permeability influences the production behaviour considerably. However, these types of features are very case specific and cannot be included in this more generic setup. Therefore, this analysis is limited to a homogeneous case.

3.4.2 Results

Table 4 shows the simulated skin for the heterogeneous cases. For the layered case, the results are very close to those of a homogeneous case with comparable net reservoir height as a result of NTG. However the heterogeneous case has quite different results. These differences can be explained for a large part by the difference in contact with the reservoir, which can be characterised by the kh of a well: the kh is the product of the permeability and the perforated length of a well taking into account the orientation of the well with respect to the permeability. For example, for a *vertical* well kh is the *horizontal* permeability x (multiplied by) perforated length of the well in *vertical* direction. For a *horizontal* well or radial, kh is the *vertical* permeability x perforated length in *horizontal* direction. For deviated wells the calculation becomes more complex.

For the calculation of kh, also NTG is taken into account for the calculation. Well diameter on the other hand is not taken into account in the calculation of kh. In Table 5 the kh of each of the wells is listed.

Table 4. Overview of the skin* for the heterogeneous cases (35°-deviated well)

	No radials	**4 x 100m-radials**	**8 x 100m-radials**
Homogeneous and anisotropic	-0.2	-4.1	-5.5
Vertical heterogeneity (Layered)	0.1	-3.8	-5.3
Horizontal heterogeneity	1.3	-2.1	-2.8
Fractured (anisotropic fracture distr.)	-0.7	-6.5	-6.7

* Skin compared to a vertical, fully perforated well in the same reservoir at the same location.

The kh values for the layered reservoir deviate little from the kh values for the homogeneous case. However, the case with horizontal heterogeneity differs markedly: the deviated well actually shows a lower kh than the vertical resulting in a positive skin. The lower kh is result of local variability (see Figure 17). For the wells, with radials, the kh values are comparable between the homogeneous case, layered case and the case with horizontal heterogeneity. But the skin values are considerably lower for the case with horizontal heterogeneity, even correcting for the positive skin of the deviated well. This is a well-known effect of heterogeneity. Heterogeneity strongly reduces the connectivity to the well to the reservoir, which initial, short well tests may not reveal.

For the fractured case, both the skin values and kh values are very large. The radials increased the connection with the fracture network considerably. The increase from 4 to 8 radials has only a minor effect on the skin even though the kh doubles. This relatively small increase in productivity is probably due to much interference between the radials.

Table 5. Overview of the kh (product of permeability and length of the well) (mDm) for the heterogeneous cases

	Vertical well, no radials	Deviated well, no radials	4 x 100m-radials	8 x 100m-radials
Homogeneous and anisotropic	15,000	14,858	40,006	67,382
Vertical heterogeneity (Layered)	14,008	14,353	37,583	63,311
Horizontal heterogeneity	15,381	9,175	46,378	63,242
Fractured (anisotropic fracture distr.)	10,600	12,199	204,068	427,175

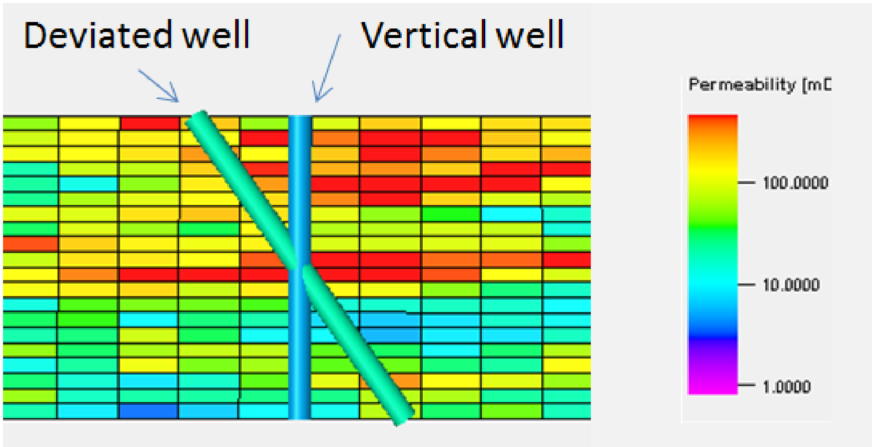


Figure 17. Position of the vertical and deviated well in the heterogeneous grid (property shown is permeability).

3.5 Conclusions

The theoretical injectivity improvements as a result of well stimulation by radials in homogeneous reservoirs are very promising. Even for shorter radials a considerable increase in injectivity or productivity can be achieved (for example a 50% increase in injectivity for 4 50m-radials in a vertical well). Maximum achieved injectivity increase is around 230% for 8 radials of 100 m long for a vertical well. Jetting radials from a deviated well, does not harm the effect of the radials. In the cases examined in this report, the injectivity increase of the radials even improved for a deviated well, because the vertical coverage is better for a deviated well.

From the analysis of the effect of heterogeneity it was found that horizontal heterogeneity decreases the effectiveness of the radials. On the other hand, the radials appear to be very suitable for fractured systems.

4 Experience from literature

4.1 Overview

In this chapter we will describe the experience as documented in literature or elsewhere concerning the application of radials. First an overall summary is presented, next individual cases are discussed in detail.

There are many radial jet drilling providers, mostly in the US and Canada and all work in the petroleum industry. Some examples are:

- Radial Drilling Services (www.radialdrilling.com): one of the largest and oldest jet drilling companies.
- Coil Services (www.coilservices.com) is a Dutch supplier involved in this project. According to the website, they have stimulated over 1500 wells with radial jetting with a total of over 8000 laterals jetted.
- PetroJet (www.petrojet.ca): A Canadian company that uses larger nozzle heads, higher flow rates and more powerful pumps.
- http://www.jet-drill.com/
- http://www.radjet.com/ also operates in Australia (apart from US).
- http://www.witsunjetdrill.com/en/: located in China
- http://zrldrilling.com/: claim to have developed a method to 'push on the hose' in order to avoid the hydraulic losses from having to pull the hose forward through the formation.
- http://wes-ok.com/technology/

On their websites these companies also provide potential production increases from jet drilling of radials, however these are not included in the literature review, since they are not independent. For the literature review, we have used as much as possible independent literature resources. However, many of the papers used are not peer-reviewed and should be treated with caution.

Although in the petroleum industry, radial jet drilling has been employed for over 10 years, it is still very much under development. Initially it was not possible to jet in deviated or horizontal wells and through hard rocks, but the range of applicability continues to be expanded. Currently, some of the main limiting factor for the petroleum industry are the lack of steering of the nozzle head and lack of proof of penetration depth. For only one case documentation on the jetted path was found (Balch, 2013). Other disadvantages of radial stimulation are the limited remediation and surveillance possibilities (Kamel, 2014). Also there are few well-documented cases in which radial jetting is accompanied by detailed observations.

All documented cases are in the petroleum industry. The experience is mostly in production wells: only one documented example of radial jet drilling in a water injector has been found. This stimulation was not successful, but it was not explained why (Bruni et al, 2007).

The realized increase in production is highly variable (more details in the next section). Best results have been achieved in cases in which near-well bore damage was a limiting factor for production. Several cases were documented in which radial jet drilling appeared to have made no impact. However, no cases were found in which the well was damaged as a result of radial jet drilling.

An important point of attention is the sustainability of the increase in production. Mostly the increase in production is largest shortly after jetting, but decreases clearly within a year (Ragab, 2013; http://www.jet-drill.com/jet-drill-facts.php). Fast decrease in production may be related to unconsolidated formations (in which the jetted holes may not be stable), but does not appear to be limited to such formations. In oil and gas fields, a decrease in production may also be caused by other factors such as a decrease in reservoir pressure. Thus it is not straightforward to understand the reasons for the decrease without supporting data. However, since the jetted laterals are small, open holes, it is likely that they have a limited life time. Ragab (2013) concludes that “an improvement is needed in order to maintain the rate increase in production rate, such as gravel packing or using slim tubes specially in unconsolidated formation.”

Occasionally, problems were reported in the process of jetting the radials, for example when a borehole is enlarged due to acid stimulation. Problems during production as a result of for example sand production were not recorded, but since the completions are open hole, this is likely to occur to some extent. A mitigating circumstance is that since the contact area is large, the flow speed is expected to be relatively low.

Alternatives for radial jet drilling include Short Radius drilling (SR) or Ultra-short Radius drilling (USR), which employs drilling techniques to create very short laterals. They don’t exit the well with a 90° angle with respect to the main well bore (like radial jet drilling), but need to make the angle in the reservoir. See for example http://www.usrdrilling.com/.

4.2 Cases

Golfo San Jorge Basin and Neuquen Basin in Argentina (Bruni et al, 2007)

An extensive evaluation campaign of radial jet drilling was executed in Argentina in which a total of 22 wells was stimulated including one injection well in a variety of depths and formations. The stimulated wells also showed a large variety of problems including skin, low reservoir pressure, heavy oil (i.e. with very high viscosity) and low permeability of the reservoir. The best results were achieved in wells in which skin as a result of well damage was present. For two wells, well tests were performed after jetting the radials: these showed a change in skin as a result of radials of -1 to -1.5. Many wells showed an initial increase, but in only 2 wells this lasted longer than 300 days. Since this application is already 10 years ago, improvements to the technique due to increased experience are expected.

Belayim field, Egypt (Ragab, 2013)

The Belayim field in Egypt is a layered reservoir with sand/shale layers mixed with anhydrite at a depth of around 2700 m. 3 Wells were stimulated with 7, 6 and 4 50m-long radials respectively. The initial increase in oil production was 73, 37 and 14% respectively. However, after 1-2 years in only one of the wells an increase in production compared to the pre-stimulation production was still visible. For all three wells, well tests were performed before and after the jetting of the radials. In none of the wells an increase in Productivity Index was observed. Unfortunately, it is not explained how these inconsistent results can be explained.

Urtabulak field, Uzbekistan (Elliott, 2011)

In the Urtabulak field, 5 wells were stimulated with radials in combination with a 10% hydrochloric acid wash. The field is a carbonate reef structure of Jurassic age and is located at a depth of around 2000-2500 m. Before stimulation, several of the wells shows extensive well damage. Production also suffered from pressure depletion. In 4 of the 5 wells, 4 laterals of 100 m long were jet drilled. In the fifth well, 2 sets of 4 laterals were planned. Only two of the planned laterals failed, which was attributed to difficulties with the casing. Unfortunately, it was not specified what the increase in productivity of the wells is. Only flow rates are reported. Two of the five wells are reported to have increased flow rates a year after jetting the radials. The well in which 8 radials were jetted showed only a very marginal increase in flow rate.

Tarim field, China (Teng et al, 2014)

In this field, a single well was stimulated with an unknown number of radials, but probably 8 radials divided over two depths. The field is a tight siltstone and the well appeared to have severe near well bore damage (clogging). Post-stimulation production was up by 300% immediately after stimulation.

Donelson West field, Kansas, US (Cinelli and Kamel, 2013; Kamel, 2014)

The Donelson West field is a fractured, fine crystalline limestone with low permeability (1-10 mD) and very low thickness (net thickness of 2-3 m). In this field, 10 wells were stimulated with radials. Unfortunately, at the same time several other changes were implemented (such as stronger pumps) and there is no way to separate the effects of the different modifications. One well did not come back on stream after the stimulation, but that was not attributed to the radial stimulation.

4.3 Conclusions

Compared to the large number of wells that is reported to have been stimulated with radial jetting, documented cases are rare: only 5 were found. The reported increases from implementation of radials in the field are highly variable: for many wells a good initial increase in production is reported. Several wells showed no or hardly any response to the radial stimulation without explanation. In many wells the initial increase in production declined rapidly and disappeared within a year. This might be caused by pressure decline in the reservoir due to production, but also because the radials may not be stable. In the few well tests that were done before and after radial stimulation, no increase in productivity could be detected. Overall, best performance of the radial stimulation was observed for cases with near-well damage.

Overall, realised performance appears to fall short of theoretical performance. The reasons for this are not clear at this moment in time. However, it should be realised that the same is true for other well stimulation techniques such as hydraulic fracturing or acid stimulation.

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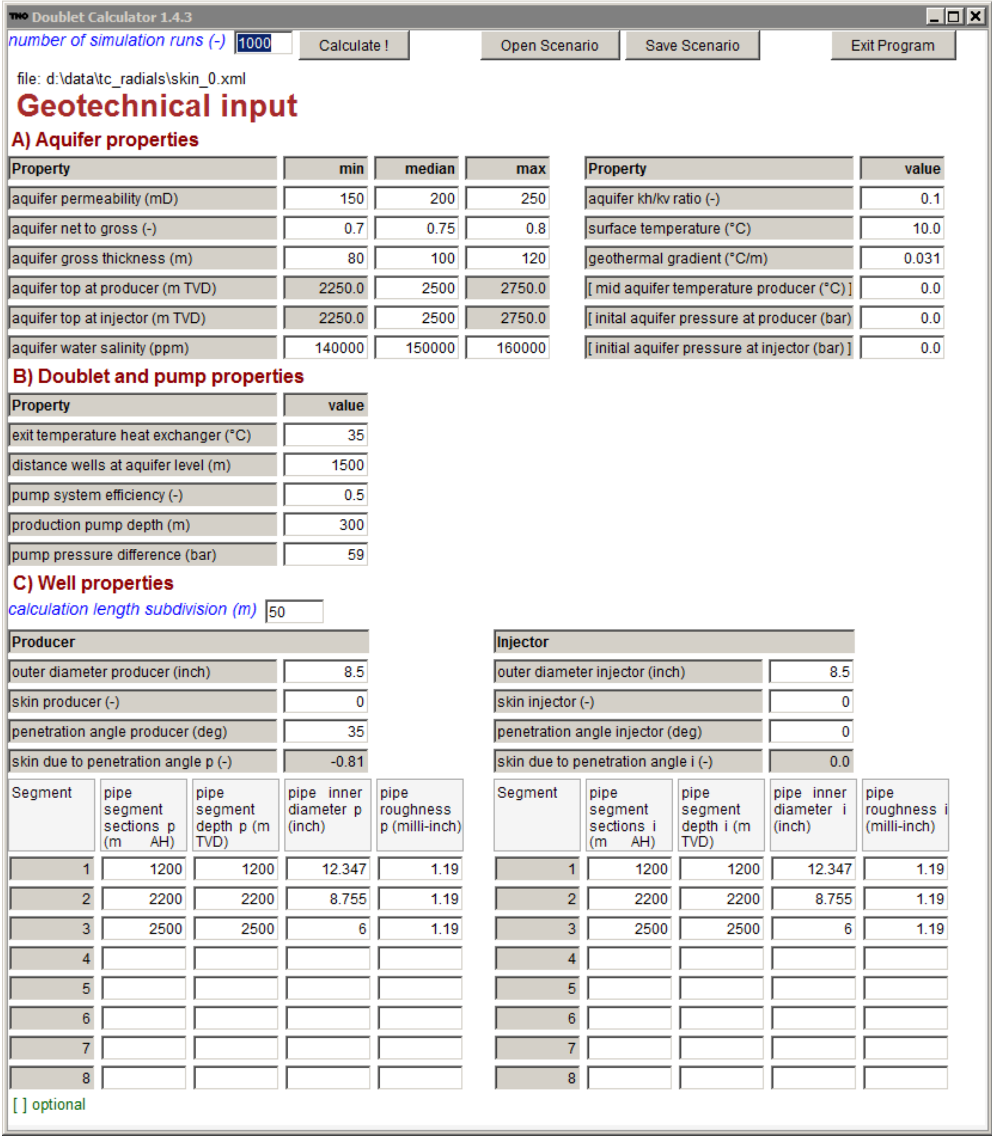
6 Signature

Utrecht,

F. Wilschut
Project manager

Appendix A. DoubletCalc input for example §3.1.



Doublet Calculator 1.4.3

number of simulation runs (-) 1000 | Calculate ! | Open Scenario | Save Scenario | Exit Program

file: d:\data\tc_radials\skin_0.xml

Geotechnical input

A) Aquifer properties

Property	min	median	max
aquifer permeability (mD)	150	200	250
aquifer net to gross (-)	0.7	0.75	0.8
aquifer gross thickness (m)	80	100	120
aquifer top at producer (m TVD)	2250.0	2500	2750.0
aquifer top at injector (m TVD)	2250.0	2500	2750.0
aquifer water salinity (ppm)	140000	150000	160000

Property	value
aquifer kh/kv ratio (-)	0.1
surface temperature (°C)	10.0
geothermal gradient (°C/m)	0.031
[mid aquifer temperature producer (°C)]	0.0
[inital aquifer pressure at producer (bar)	0.0
[initial aquifer pressure at injector (bar)]	0.0

B) Doublet and pump properties

Property	value
exit temperature heat exchanger (°C)	35
distance wells at aquifer level (m)	1500
pump system efficiency (-)	0.5
production pump depth (m)	300
pump pressure difference (bar)	59

C) Well properties

calculation length subdivision (m) 50

Producer	
outer diameter producer (inch)	8.5
skin producer (-)	0
penetration angle producer (deg)	35
skin due to penetration angle p (-)	-0.81

Segment	pipe segment sections p (m AH)	pipe segment depth p (m TVD)	pipe inner diameter p (inch)	pipe roughness p (milli-inch)
1	1200	1200	12.347	1.19
2	2200	2200	8.755	1.19
3	2500	2500	6	1.19
4				
5				
6				
7				
8				

Injector	
outer diameter injector (inch)	8.5
skin injector (-)	0
penetration angle injector (deg)	0
skin due to penetration angle i (-)	0.0

Segment	pipe segment sections i (m AH)	pipe segment depth i (m TVD)	pipe inner diameter i (inch)	pipe roughness i (milli-inch)
1	1200	1200	12.347	1.19
2	2200	2200	8.755	1.19
3	2500	2500	6	1.19
4				
5				
6				
7				
8				

[ ] optional

Figure 18: DoubletCalc input for the example of the usage of skin (section 3.1) in the actual user interface.

Appendix B. Calculation of the skin from numerical results

To calculate the geometrical skin from numerical results in which a single well is simulated, two runs are always necessary: one run with the well configuration that is required and one run with a vertical, fully perforated well for comparison. To arrive at an equation for the calculation of the skin from numerical results, the following equation which the describes the steady state flow to a single well (Dake, 1978) is used:

$$Q = \Delta P \frac{2\pi kh}{\mu\left(ln\left(\frac{L}{r_w}\right)+S\right)} \qquad \text{Eq. 6}$$

Assume two vertical wells (1 and 2) for which the only difference is the skin S and thus the pressure drop ΔP. All other values are identical for both configurations: rate (Q), L (distance to the reservoir boundary at which the pressure is constant), r_w (well radius), k (permeability), h (aquifer height) and μ (viscosity). Then:

$$\frac{\left(ln\left(\frac{L}{r_w}\right)+S\right)}{\Delta P} = \frac{2\pi kh}{\mu Q} = \text{constant} \qquad \text{Eq. 7}$$

Taking ΔP_1 for well 1 (which has no skin) and ΔP_2 and S_2 for well 2, we get:

$$\frac{\left(ln\left(\frac{L}{r_w}\right)\right)}{\Delta P_1} = \frac{\left(ln\left(\frac{L}{r_w}\right)+S_2\right)}{\Delta P_2} \qquad \text{Eq. 8}$$

Which can be rewritten to:

$$\frac{\Delta P_2}{\Delta P_1} = \frac{P_r - BHP_2}{P_r - BHP_1} = 1 + {S_2}\Big/{ln({L}/{r_w})} \qquad \text{Eq. 9}$$

Resulting in the following equation for the skin:

$$\mathrm{S_2} = \ln({\mathrm{L}}/{\mathrm{r_w}})\left(\frac{\mathrm{P_r - BHP_2}}{\mathrm{P_r - BHP_1}} - 1\right) \qquad \text{Eq. 10}$$

This can also be expressed in terms of PIF (Productivity Increase Factor = productivity of the stimulated well / productivity of the unstimulated, vertical well):

$$\mathrm{S_2} = \ln({\mathrm{L}}/{\mathrm{r_w}})\left(\frac{1}{\mathrm{PIF}} - 1\right) \qquad \text{Eq. 11}$$

Appendix C. Characterisation of geothermal sites

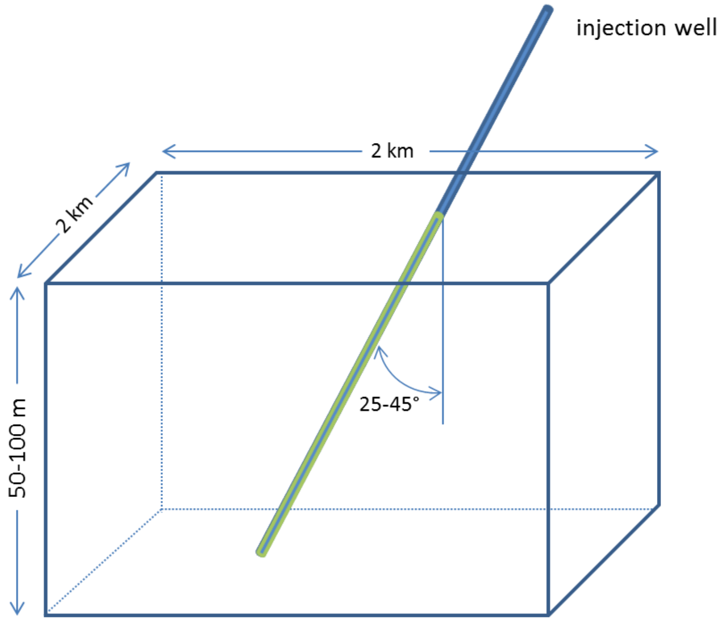


Figure 19. Overview of typical spatial settings for the Slochteren sandstone. and Schieland-Delft sandstone.

Table 6. Characterisation of the properties as found in geothermal injection wells from the participants of this project for the Slochteren and Schieland-Delft sandstone for which radial drilling might be interesting (relatively low permeability).

	Slochteren	Schieland Delft
Reservoir properties		
Depth (m)	2000-2500	2000-2500
Porosity (-)	0.15-0.25	0.15-0.25
Permeability (k_h) (mD)	100-200	100-200
Anisotropy (k_h/k_v) (-)	2-20	2-20
NTG (-)	0.7-1.0	0.5-0.75
Temperature (°C)	60-90	60-75
Well properties		
Perforation height (%)	70-100	70-100
Outer diameter (inch)	5-7	5-7
Completion type	Open hole, slotted liner, sand screen	Open hole, slotted liner, sand screen
Inclination (° with respect to vertical)	25-45	25-45
Injection temperature (°C)	25-35	25-35

Appendix D. Sensitivity results of skin as a function of permeability, porosity and reservoir depth.

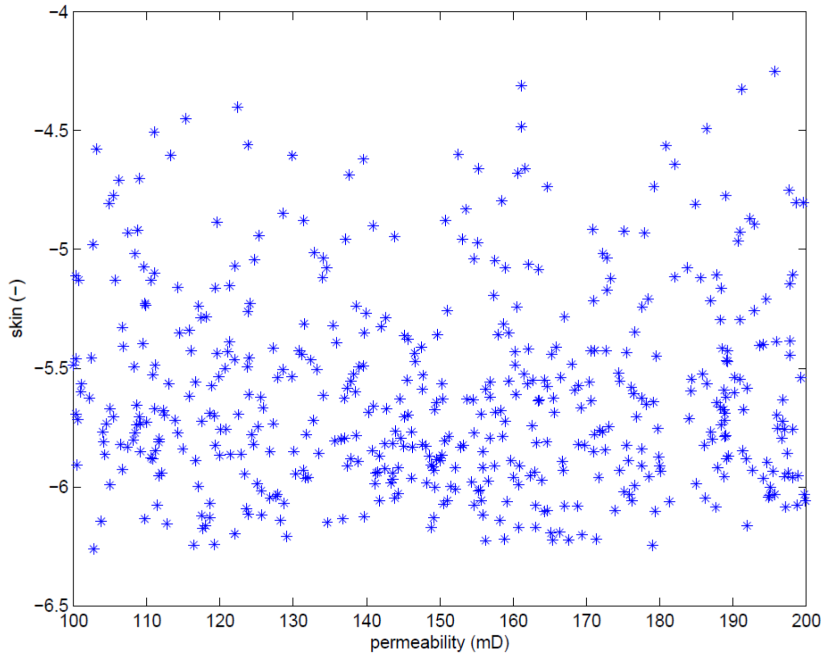


Figure 20. Results of a sensitivity run showing that the calculated skin is independent of permeability.

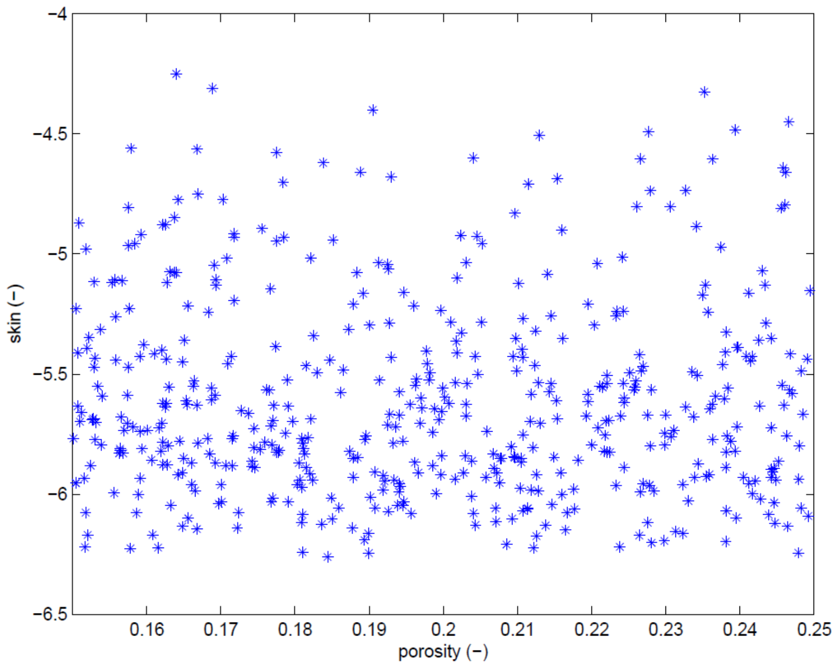


Figure 21. Results of a sensitivity run showing that the calculated skin is independent of porosity.

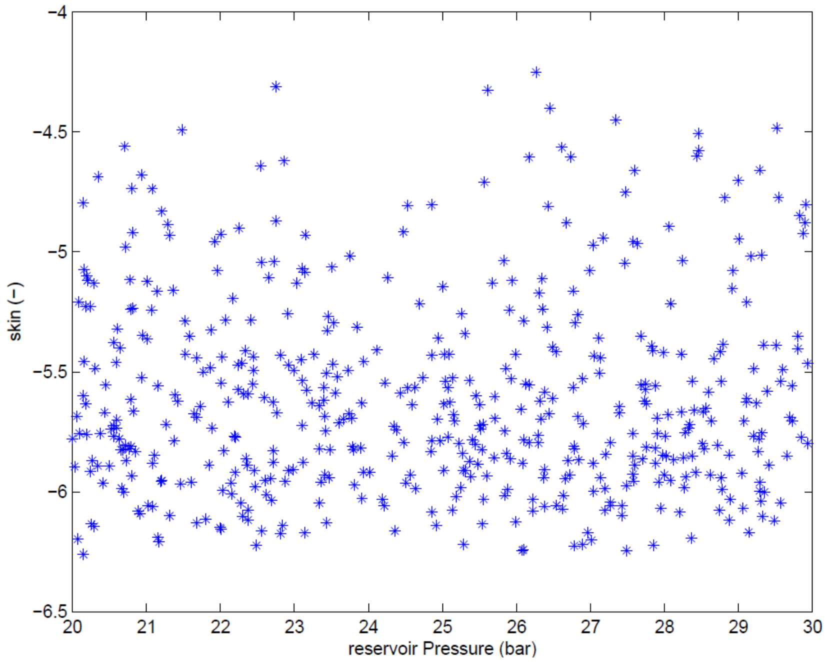


Figure 22. Results of a sensitivity run showing that the calculated skin is independent of reservoir pressure.

Appendix E. Anisotropy and the effect on well flow

Anisotropy is a term that is used to indicate that the properties of a material vary in different directions. Sedimentary rocks are rarely isotropic. Horizontal fluid flow in a rock is usually easier than vertical or oblique fluid flow, because of the occurrence of generally (sub-)horizontal clay(ey) layers. Cementation processes can also cause zones of diminished permeability. Anisotropy is defined in DoubletCalc as the ratio between horizontal and vertical permeability: k_h / k_v (note that in this report the inverse k_v / k_h is used). The value of k_h / k_v is larger than 1 (k_v / k_h lies between 0 and 1). Alternations of permeable and less permeable layers occur at various scales:

- on a millimeter to centimeter scale, measured in core plugs,
- on a meter scale observed by well logs and in cores,
- on reservoir scale as observed in large outcrops.

Anisotropy is scale dependent. Consider a volume of rock that has alternating sand and clay layers on a decimeter scale. A small sample measuring only 1 cm^3 may contain either only sand, or only clay and therefore be relatively isotropic. 1 m^3 of rock will surely contain both sand and clay layers and be relatively anisotropic. Smaller samples are usually more isotropic. If we want to study flow towards a well in a reservoir, the anisotropy on reservoir scale is important. Therefore, measurements on a small scale cannot be used as such and need to be upscaled. Upscaling is a process too complex to describe here. Geological knowledge about the reservoir is imperative.

Anisotropy ratios measured from cm-scale core plugs in sandstone-dominated rocks of Rotliegend and Triassic age in the Netherlands lie roughly between k_h / k_v 1 and 3, but the spread is very large (source: core plug measurement data www.NLOG.nl). Anisotropy ratios k_h / k_v derived from permeability log data are usually higher and lie between 10^0 and several 10s. Those values are very much dependent on the definition of the reservoir – very low permeability layers have an immense influence. Methods for deriving a reservoir scale anisotropy from smaller scale measurements and estimates of flow barrier frequencies and dimensions have been proposed by Begg et al. (1985). For similar reservoirs as mentioned above, this method yields values between k_h / k_v 10^1 and 10^2.

In case a well was drilled vertically, the flow towards the well is horizontal (parallel to the sedimentary layers; Figure 23). Hence, the vertical permeability, and therefore anisotropy, is irrelevant. If a well was drilled in an angle unequal to 90° to the sedimentary layers, the less permeable layers will hamper the flow towards the well (Figure 24). Note that in Figure 24 it is assumed that the impermeable layers have a lateral extent that is large compared to the well. Non-horizontal flow is therefore effectively hampered. If a well was drilled horizontally, the vertical permeability strongly determines the flow towards the well.

Technology cluster radial drilling

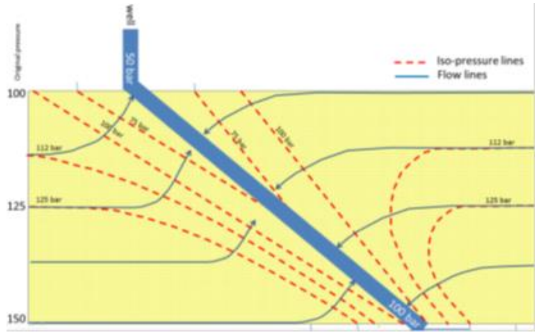


Figure 23 Schematic drawing of pressure and flow lines within the vicinity of a slanted wellbore in an isotropic aquifer (k_h / k_v = 1).

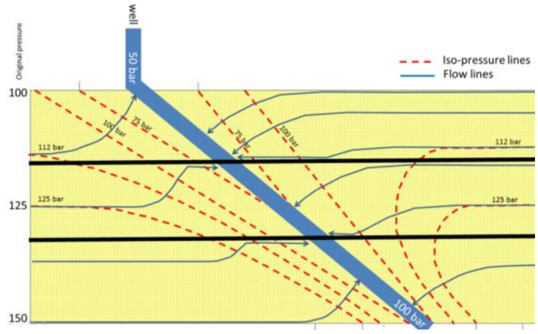


Figure 24 Schematic drawing of pressure and flow lines within the vicinity of a slanted wellbore in an anisotropic aquifer (k_h / k_v >> 1)

Appendix F. Input for the horizontal heterogeneous reservoir.

The porosity for the case with heterogeneity in horizontal direction was generated using sequential Gaussian simulation with mean of 0.2, standard deviation of 0.065 and variogram settings of 500 m (major direction), 200 m (minor direction) and 20 m (vertical). The azimuth of the major direction is 30°.

The permeability is not generated separately, but based on the porosity via the following relationship resulting in a log-normal distribution for permeability:

$perm=10^{(-0.65 +10*poro)}$

The resulting permeability is shown in the histogram below (Figure 25). The permeability in z-direction is 10% of the permeability in x-direction.

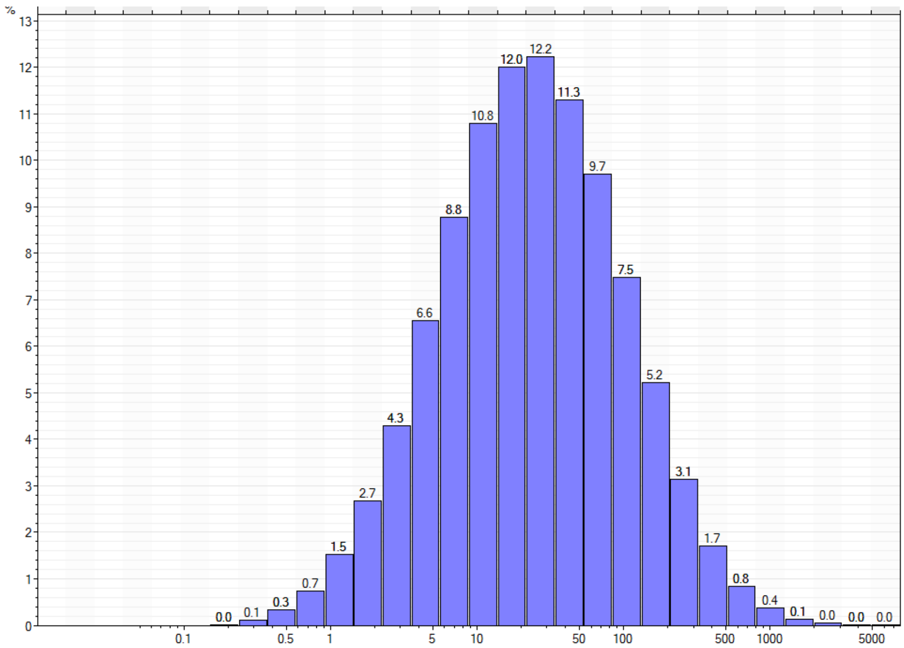


Figure 25. Histogram of the permeability in x- and y-direction.

Appendix G. Input for the fractured reservoir (restricted)

Appendix H. Example work program radial jetting as provided by Coil Services (restricted)