de Lier Fracture Containment Study

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Contents

1 Introduction

EnergieWende operates de Lier doublet in Westland, South-Holland, consisting of wells LIR-GT-01 (producer) and LIR-GT-02 (injector). The doublet produces brine from the Delft formation, providing heat to its customers, and reinject the fluids in the same formation they are extracted from after the heat has been extracted.

An important aspect that needs to be addressed to ensure safe operation of a geothermal doublet is the containment of the fluids within the reservoir: the fluids are not to enter other formations than the formation they are extracted from. In light of this requirement, it is important that no flow paths are created to other formations through the impermeable layer above the reservoir (also known as the top seal) by means of production induced fracturing. This means that top seal integrity needs to be maintained. As a first pass, a protocol has been formulated by TNO-AGE and SodM (SodM, 2013) to outline maximum injection pressure before fracturing could occur, the assumption being that if these maximum injection pressures are not exceeded, the seal integrity is by definition maintained, as no injection induced fractures will be formed. The protocol also states that a limited amount of injection induced fracturing is allowed, so long as the seal integrity is maintained, or stated differently: reservoir confinement is not compromised. It is of course paramount that the operator shows that reservoir confinement is not compromised by the limited fracturing that occurs.

The protocol will be adjusted to a cooling (i.e. difference between reservoir temperature and injection temperature) by not more than 40°C. For a cooling exceeding 40 °C, the protocol prescribes a lowering of maximum allowable injection pressure by 1 bar per degree (exceeding 40°C).

The current work is aimed at investigating whether, in the presence of (possible, but unlikely) induced (thermal) fractures, the injected water in LIR-GT-02 is still contained as mentioned in the SodM protocol.

This study consists of two parts:

(1) Preparing an input dataset including a best estimate of the minimum in-situ stress in the de Lier geothermal area based on stress measurements (leak-off tests).

(2) Using the above, fracture simulations are carried out to compute the size (length, height) of induced fractures and corresponding injection pressures for a number of realistic scenarios for the geothermal operation in de Lier. In particular, this part addresses the risk of (non-) containment of an induced thermal fracture to the appropriate container zone.

    Fracture simulations were performed using the methodology of Gheissary (1998) and van den Hoek (1999, 2000). This is an extension of the Koning method (Koning, 1988) that is also used by TNO (Veldkamp et al., 2016), including more complicated geologies with multiple layers of reservoir and cap rock.

    The fractured water injection simulator is often used for forecasting and managing waterfloods, and water disposal operations. The simulator performs numerical calculations at each time step, considering input parameters such as in-situ stress situation, elastic parameters, rock strength and properties, leak-off, poro-elastic and thermo-elastic effects.

2 Input Data

2.1 Description of Base Case

The simplified stratigraphy, as used in the fracture simulations, is depicted in Figure 2-1. Other main features of the base case are:

- A geological 'layer-cake' model is assumed.
- Minimum horizontal in-situ stress based on general correlation for the West-Netherlands Basin (Verweij et al., see section 2.2), plus Formation Integrity Test (FIT) results from the neighboring wells.
- No in-situ stress differences between sand layers and shale layers. This can be considered as a 'conservative' approach in the sense that normally, sandstone formations have a lower horizontal in-situ stress than shale layers. As a result of the higher in-situ stress in the shale, (thermal) fractures that are induced in sandstones will often be (partially) contained by the bounding shales
- Hydraulic formation pressure gradient.
- Elastic parameters of the rock (Young's modulus, Poisson's ratio) based on general geomechanical correlations and neighboring wells (Naaldwijk) shear sonic data.
- Permeability for the Delft is the gross permeability based on the product *k.h* as derived from well tests. All other permeabilities are from the ThermoGIS database.
- All geological layers are continuous with a constant pressure boundary at the drainage radius (= ½ × distance between wells of the doublet).
- There is no water injection into the Rodenrijs claystone as the permeability is very low. Water is injected at top 2325 m TVD (1 m below top reservoir) as per perforated intervals in Delft sandstone. Most of the injection is into the Delft reservoir as the permeability of Delft is much higher than the Alblasserdam reservoir.
- Injection period of 30 years with an injection rate of 300 m3/hr and injection temperature of 32°C.
- The permit is bounded at the top by the base of the Rodenrijs formation (see Figure 2-1 below).

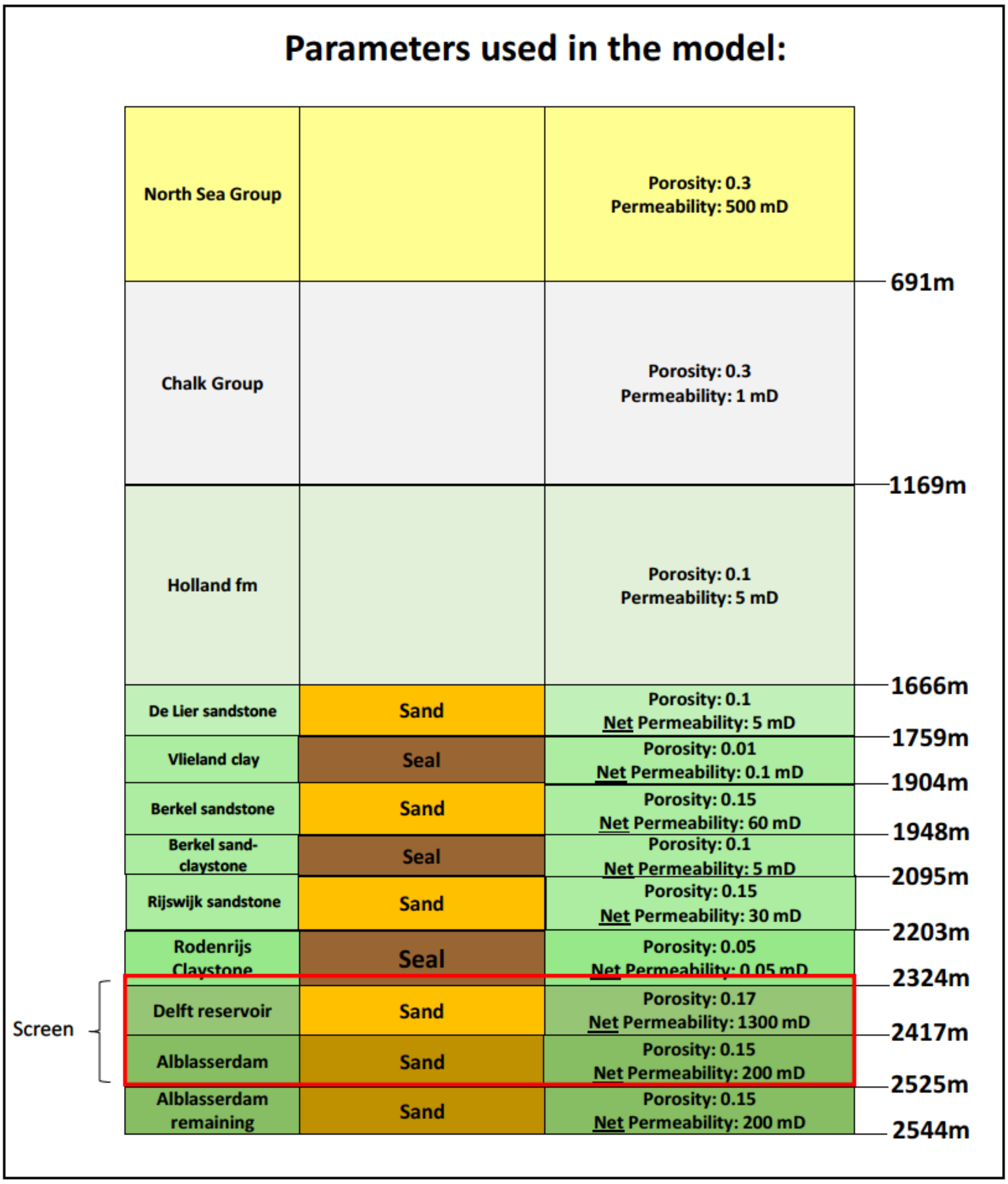

Figure 2-1 LIR-GT-02 stratigraphy

2.2 Regional trends and in-situ stress estimate from FIT data

In-situ stress trends are mostly based on measured leak-off pressures as reported by Verweij et al (2012). These authors distinguished a number of different geological areas within the Netherlands. For each of these areas, an in-situ stress trend map was generated. The geological area that is relevant for the current discussion is the so-called West Netherlands Basin (WNB), as shown in Figure 2-2.

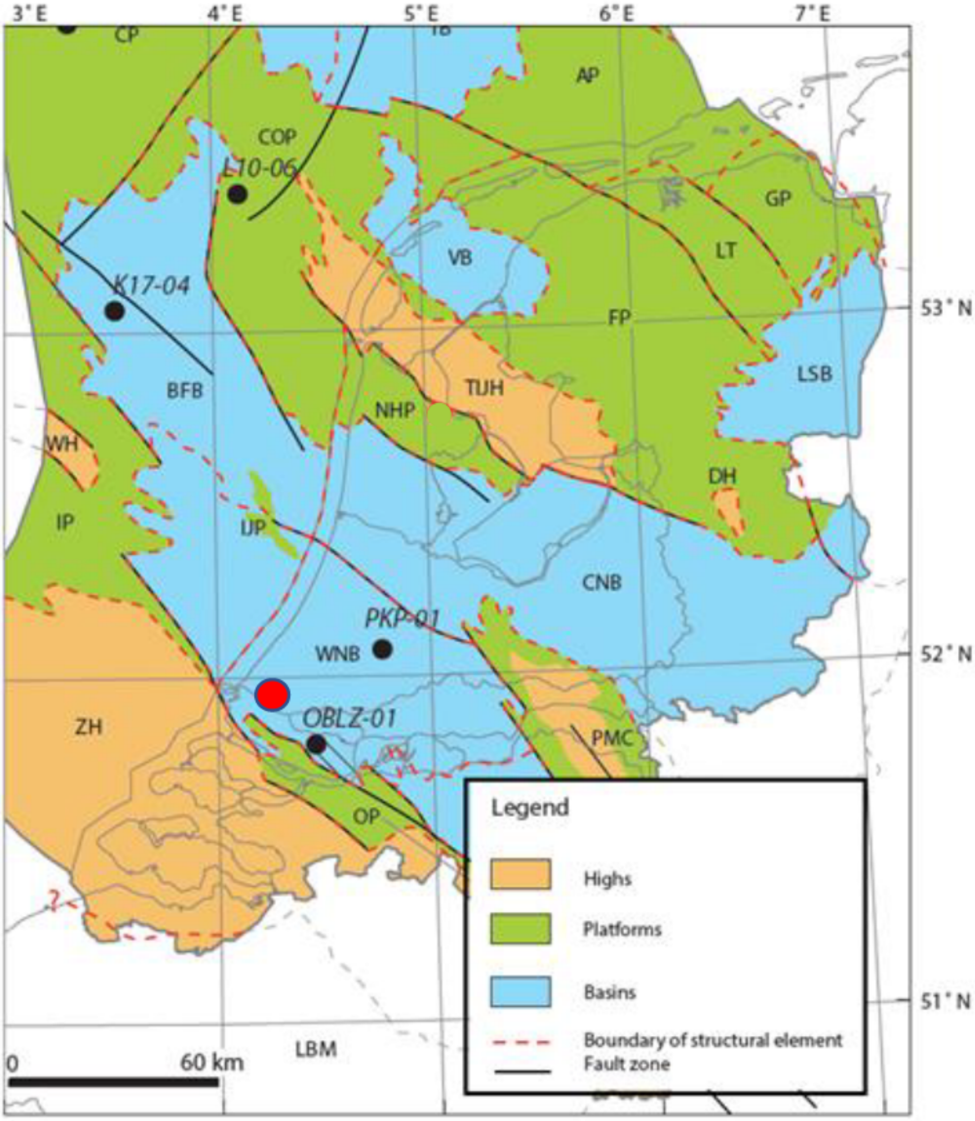

Figure 2-2 Map modified from Verweij et al (2012) showing the Mesozoic structural framework. Red dot indicates the LIR area, located within the West Netherlands Basin (WNB).

Figure 2-3 displays measured leak-off pressures as a function of depth in the West Netherlands Basin. The Verweij et al. dataset has been complemented by five Formation Integrity Test (FIT) measurements in the Naaldwijk geothermal wells, which are very close to the de Lier geothermal wells. Only one FIT reached formation breakdown pressure in the Berkel claystone which is above the Delft sandstone and its seal. Therefore, this FIT pressure is considered irrelevant for the Delft reservoir. Note that pressures derived from FIT tests are considered as lower bounds to the local minimum in-situ stress as the leak-off stress (determined with LOT-tests) has not been reached.

As can be seen from Figure 2-3, the data can be trended very well ($R^2 = 0.96$). Until a depth of around 1500 m, the trend closely follows the well-known minimum in-situ stress gradient of 0.158 bar/m (0.7 psi/ft) for an extensional stress regime, whilst at greater depths, it starts to bend somewhat towards higher stresses. It can be seen from the figure that the local FIT results in Naaldwijk are somewhat below the overall trend. As a base case minimum in-situ stress, we use the regional minimum in-situ stress gradient of 0.158 bar/m.

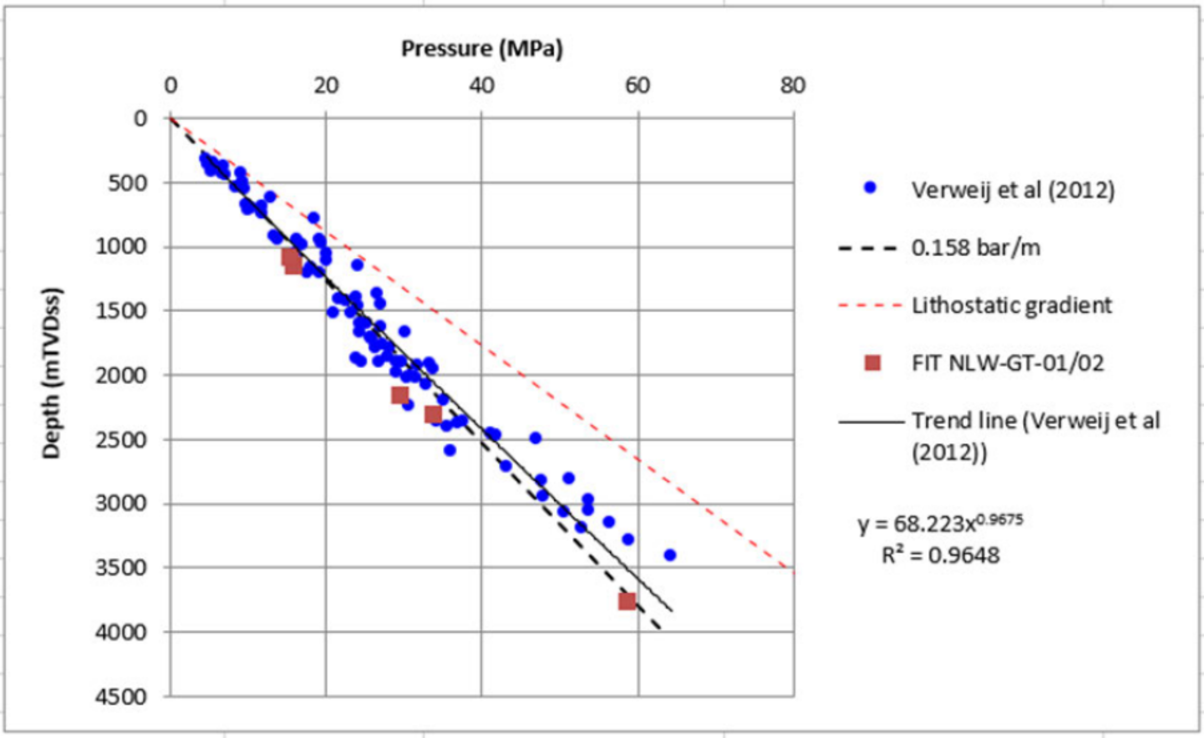

Figure 2-3 Minimum in-situ stress versus depth trend in the West Netherlands platform area based on leak-off pressures (Verweij et al, 2012) and Formation Integrity Tests (FIT) in wells NLW-GT-01 and -02 (2017/18).

2.3 Allowable injection rate and THP

To monitor well performance and monitor for any changes in injection and production behaviour, Hall plots have been made for the LIR-GT-02, which is updated with injection and production figures on a monthly basis. The Hall Plot analyses steady-state flow at an injection well. In general, the slope of the Hall plot is interpreted as an indicator of the average well injectivity. At normal conditions, the plot is a straight line. Kinks on the plot indicate changes in injection conditions. For example, if wellbore plugging or other restrictions to injection are gradually occurring, the net effect is a gradual increase in the skin factor. As skin increases, the slope of the Hall Plot increases. Conversely, if skin decreases (as would be the case if injecting pressure exceeds fracture pressure, causing fracture growth), the slope of the Hall Plot decreases.

As shown in Figure 2-4 and Figure 2-5, at the beginning (the first 3-4 months of injection) there is a small increase in the slope of the hall plot or decrease in the injectivity. This can be ascribed to the propagation of cold water front around the well (higher viscosity) and/or a possible skin build-up around the injector. As the cold waterfront propagates from the wellbore, the injectivity decreases until it reaches equilibrium injectivity, almost 80% of the original injectivity. There is no indication of injection induced fracturing at the current injection temperatures and pressures. This can be seen from the Hall Plot by the fact that the Hall slope is independent of injection rate. Therefore, injection up until the time of this study has been taking place under matrix (i.e. non-fracturing) conditions.

Using the SodM criteria as described in section 2.2, the maximum allowable injection rate and tubing head pressure (THP) without allowing thermal fracturing have been computed as a function of injection temperature. In Figure 2-6, the maximum allowable injection rates (blue lines) and THP (black lines) are presented for de Lier doubles, assuming the base case input parameters.

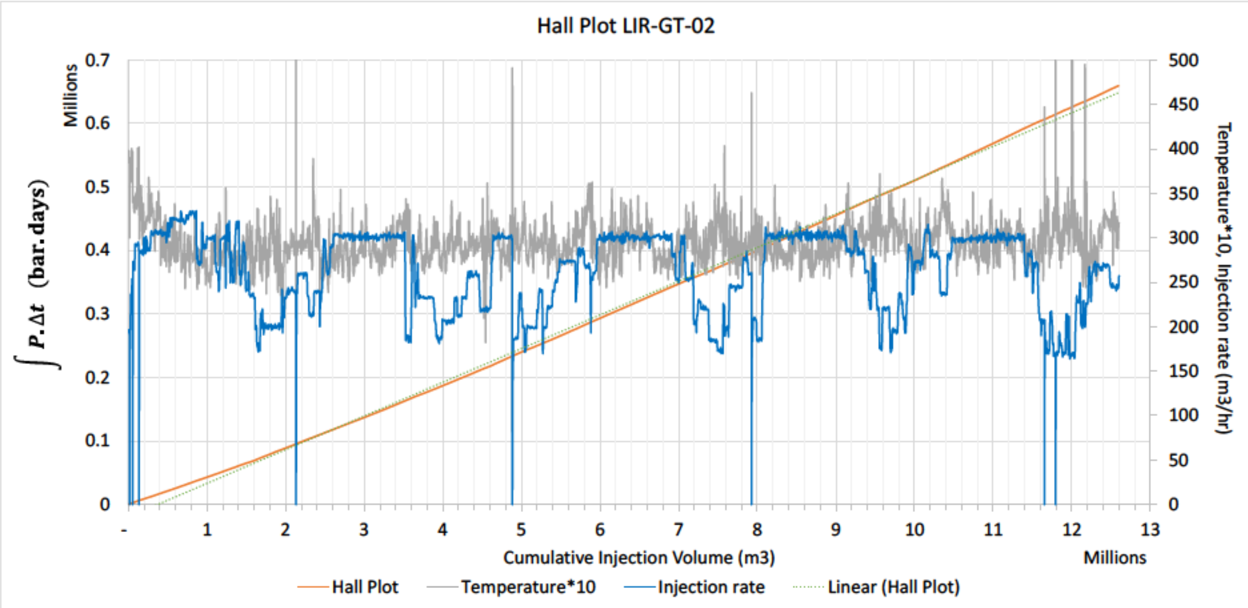

Figure 2-4 Hall plots and injection rates and temperature for de Lier geothermal doublet, THP w.r.t. the static THP are used

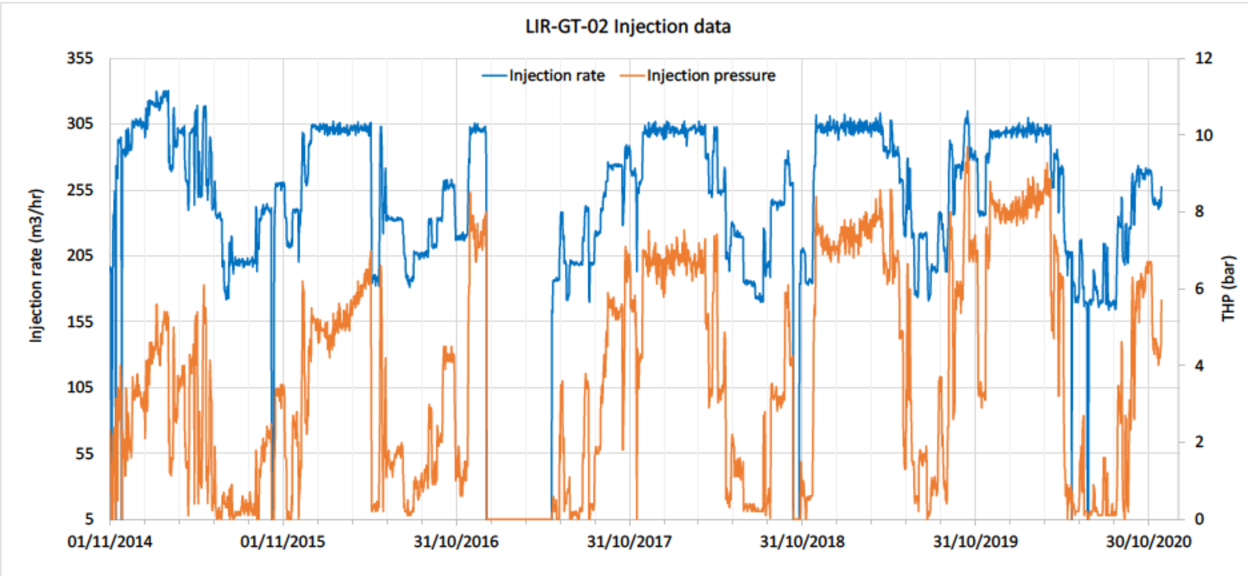

Figure 2-5 injection rates and pressure for de Lier geothermal doublet

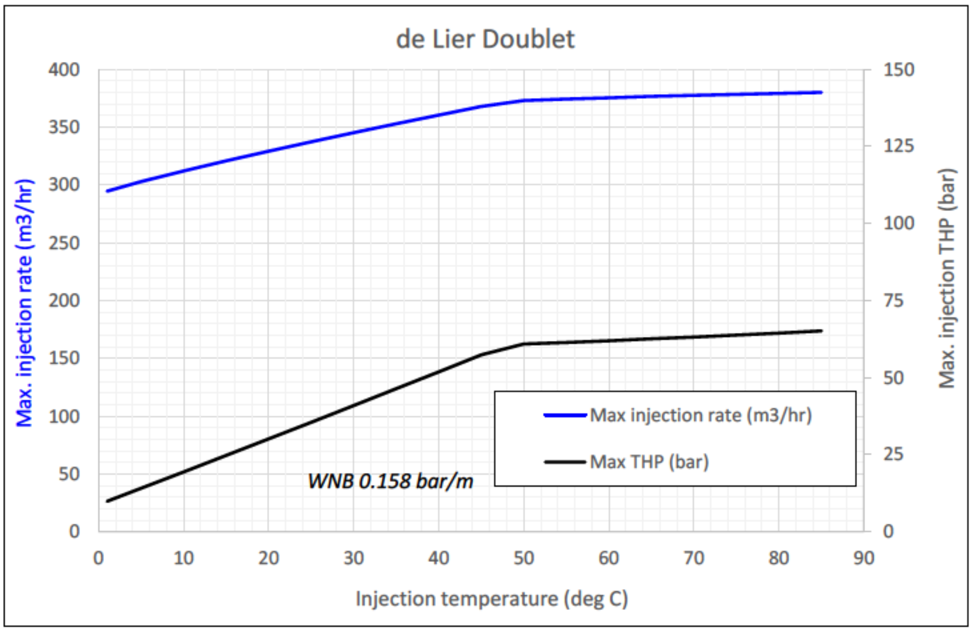

Figure 2-6: Maximum allowable injection rate and THP calculations, without allowing thermal fracturing as a function of THT.

As can be seen in the figure, with reducing THT (i.e. increase cooling), the maximum allowable injection THP and injection rate also reduces. For the current injection temperature of 32.5°C (~56°C cooling), the maximum allowable injection THP is equal to 43 bars with a corresponding flow rate of 348 m3/hr.

Reducing the THT to 15°C (~73°C cooling), these numbers are also reduced to 24 bar and 320 m3/hr, respectively. Considering the de Lier base case injection rate of 300 m3/hr, LIR-GT-02 currently does not exceed the maximum allowable injection pressure.

3 Simulation Results

3.1 Results of Base Case

Base case results, as described in section 2 above, are presented in this section. As shown in Figure 3-1, the Rodenrijs Claystone interval is located above the Delft reservoir. In the base case, a constant stress gradient of 0.158 (fitting the WNB) is taken. No in-situ stress differences between sand layers and shale layers were assumed. This can be considered as a conservative approach in the sense that normally, sandstone formations have a lower horizontal in-situ stress than shale layers. It is assumed that the fracture will be initiate just 1m below the cap rock.

As can be seen in Figure 3-2, the fracture propagation is very limited (below 1m) in the reservoir and it does not enter the overlying Rodenrijs claystone. After 30 years of injection, the upward and downward fracture growth and also the half-length of fracture (horizontal direction) is about 0.6 m. This is expected as the reservoir permeability is very high (1300 mD).

The calculated injection THP is ~170 bar, which is significantly higher than the current injection pressure of 10 bar This is a further confirmation of the fact that injection currently takes place under matrix conditions.

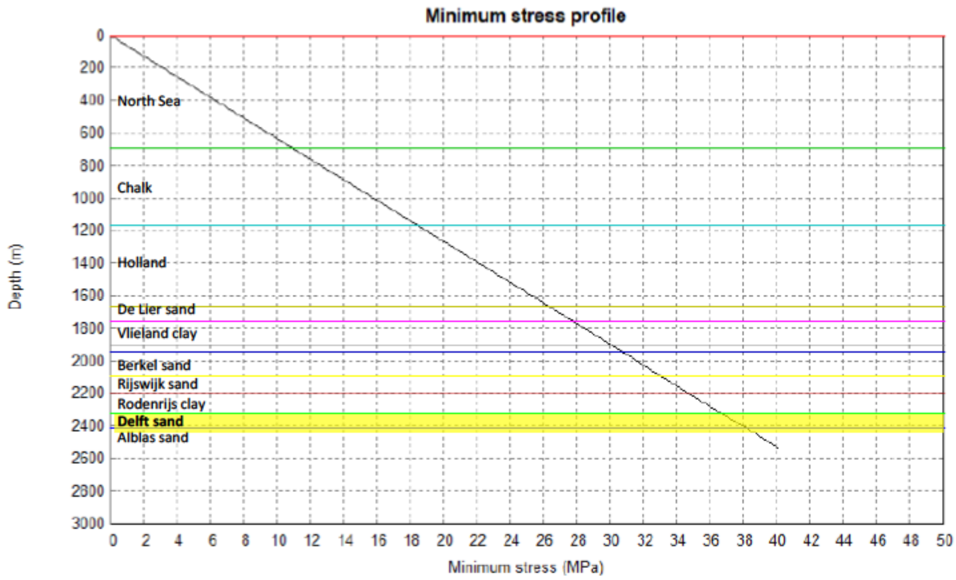

Figure 3-1 Input stratigraphy and stress profile for de Lier doublet, based on the stratigraphy from LIR-GT-02 (injector). A constant stress gradient of 0.158 bar/m is taken.

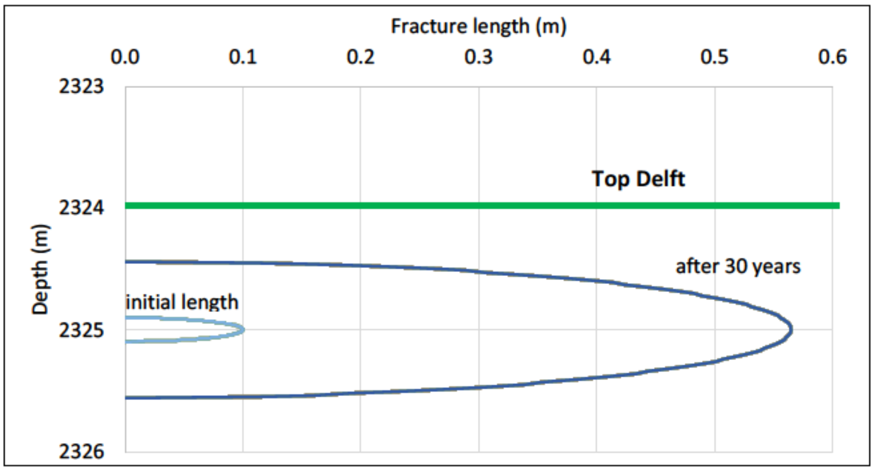

Figure 3-2 Fracture contours for the base case. It was assumed that the fracture will be initiated 1m below the caprock

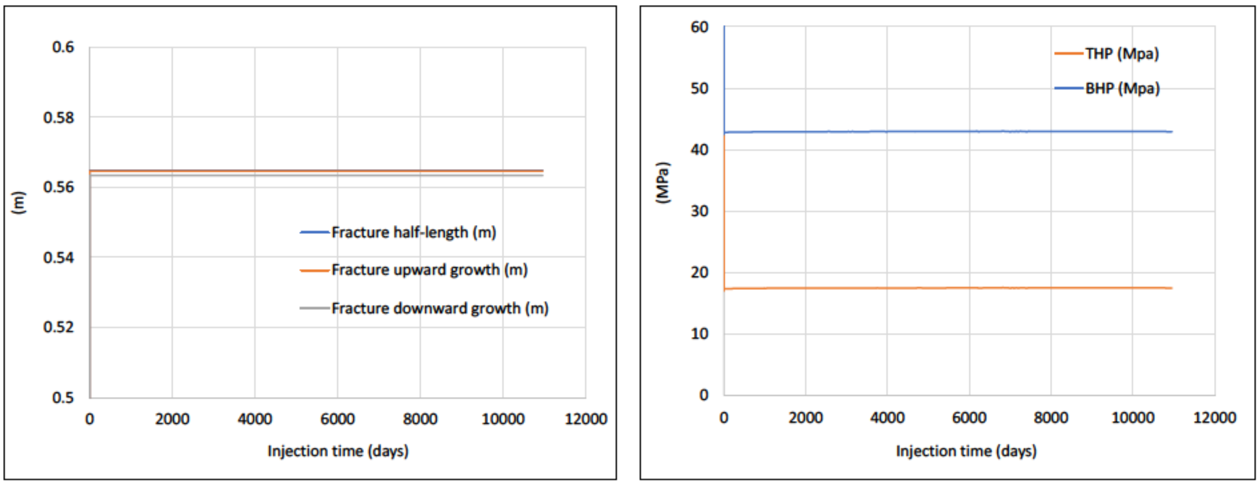

Figure 3-3 Fracture length, upward height, downward height, and injection Tubing Head Pressure (THP) and Bottom Hole Pressure (BHP) for the base case

3.2 Results of Sensitivities

An overview of the addressed 4 sensitivities plus a summary of the results for each sensitivity is given in the table below. Figure 3-3 to Figure 3-11 show more detailed fracture dimensions results.

Table 3-1 Summary of sensitivity analysis

No	Description of sensitivity	Results after 30 years of injection	Fracture half-length	Fracture height above reservoir
1	Thermal diffusion of the base of the Rodenrijs	Motivation: Over time, the largely impermeable claystone above the Delft sand cools by thermal diffusion. The cooled bottom of the caprock reduces its minimum stress and becomes more prone to fracturing. As a rule of thumb, about 30 meters cools down in 30 years. The simulator cannot model diffusion; therefore, a conservative approach has been taken assuming that the bottom 30m of the claystone has already cooled from day 1. *Result: Fracture grows slightly into the cooled portion of the claystone. Horizontally, a small fracture develops.*	~2.4 m	~0.5 m
2	Increase injection rate to 400 *m^3/hr* *(Base Case: 300 m^3/hr)* *-Thermal diffusion is considered.*	Motivation: During ongoing injection, the flow rate is kept around 300 m^3/hr. To increase doublet performance in the future, flow rates may be increased. *Results: At a high flow rate, the fracture dimensions are almost the same as the base case. However, fracture downward growth in the Delft slightly increases.*	~2.4 m	~0.5 m
3	Lower injection temperature of *T: 15°C* (base case *T: 32°C)* -Thermal diffusion is considered.	Motivation: Over time, it may be decided that water injection temperatures can be decreased. *Results: Water temperature does not affect the penetration depth into the Rodenrijs significantly. At low T, the fracture size mostly increases within the Delft reservoir itself.*	~46 m	~0.5 m
4	lower reservoir permeability 1000 *mD* *(base case 1300 mD)* -Thermal diffusion is considered.	Motivation: Even though interference test shows a very high permeability of 2220 mD, the production test of well LIR-GT-01 shows a permeability of around 1000 mD, which is slightly lower than LIR-GT-02 permeability. *At a lower permeabilities (1000mD), the fracture length slightly increases.*	~3.3 m	~0.6 m

3.2.1 Sensitivity: thermal diffusion of the caprock

Sensitivity number 1 *("bottom 30 m of the shale above the Delft sandstone cooled by thermal diffusion")* warrants a more elaborate discussion. The injection of "cold" water into the Delft sandstone will slowly cool the bottom part of the overlying shale (Rodenrijs) by thermal diffusion.

A practical guideline for the penetration depth of a thermal diffusion front as a function of time is given by 1 foot per $\sqrt{\text{day}}$ (Martins, 1995). This means that after one day, the diffusion front has penetrated 1 foot, after 4 days 2 feet, etc. As a result, we can estimate that after 30 years of operation, the bottom 30 m of the shale will have cooled as a result of diffusion.

Now, the exact evolution of thermal diffusion as a function of time cannot be simulated by the fracture simulator. Therefore, a sensitivity was added in which the bottom 30 m of the shale was set to a 56 bar lower in-situ stress. The 56 bar is the estimated thermo-elastic effect because of the injection of cold water for the current injection temperature of 32°C (~56°C cooling). Thus, the effect of slow cooling of the bottom 30 m of the caprock shale by thermal diffusion is 'mimicked' by a situation in which the bottom 30 m had already been cooled from day 1. This obviously is a conservative approach.

The results for the cooling effect are shown in Figure 3-4 and Figure 3-5. As can be observed, the induced fracture is larger than in the base case. This is not surprising because the cooled zone of the caprock has lower stress (56 bar less). It breaks upwards through the cooled bottom of the overlaying caprock with the following dimensions: upwards growth = 0.5, half-length 2.4 m, and 1.4 m downwards.

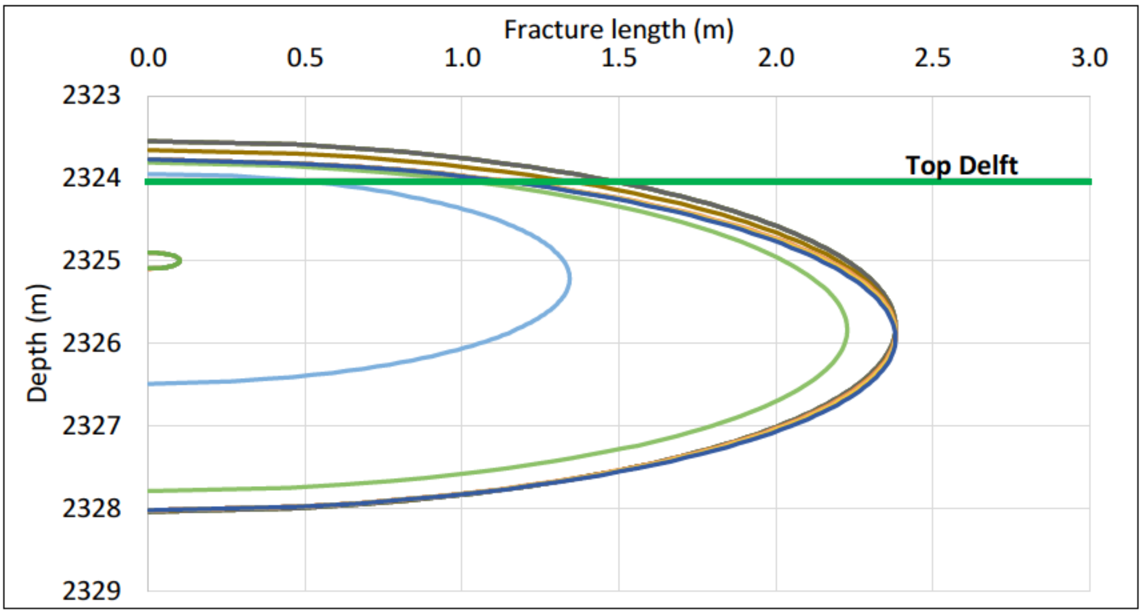

Figure 3-4 Fracture contours, including thermal diffusion of the caprock. It was assumed that the fracture will be initiated 1m below the caprock

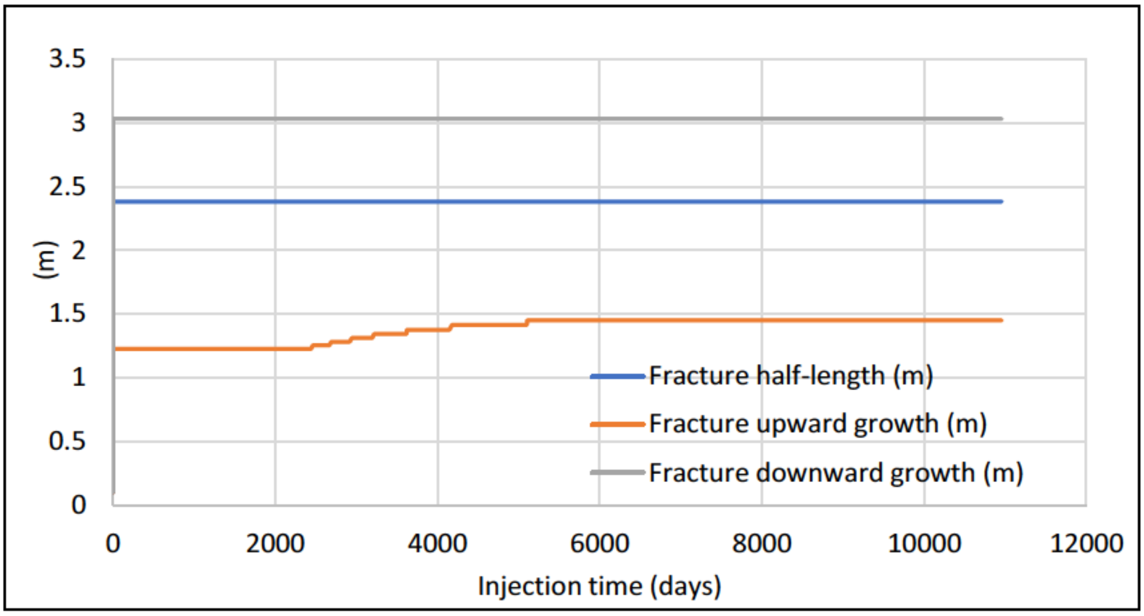

Figure 3-5 Fracture length, upward height and downward height including thermal diffusion.

3.2.2 Sensitivity: higher injection rate

During ongoing injection, the flow rate is kept around 300 m3/hr. To increase doublet performance in the future, flow rates may be increased. The thermal diffusion of the caprock as described above was also considered in the simulation. The results are shown in Figure 3-6 and Figure 3-7.

For the higher injection rate of 400 m3/hr, the fracture dimensions are almost the same as the base case with the thermal cooling. However, fracture downward growth in the Delft slightly increases. Fracture half-length is 2.5 m and downwards growth 2.3 m. See Figure 3-7.

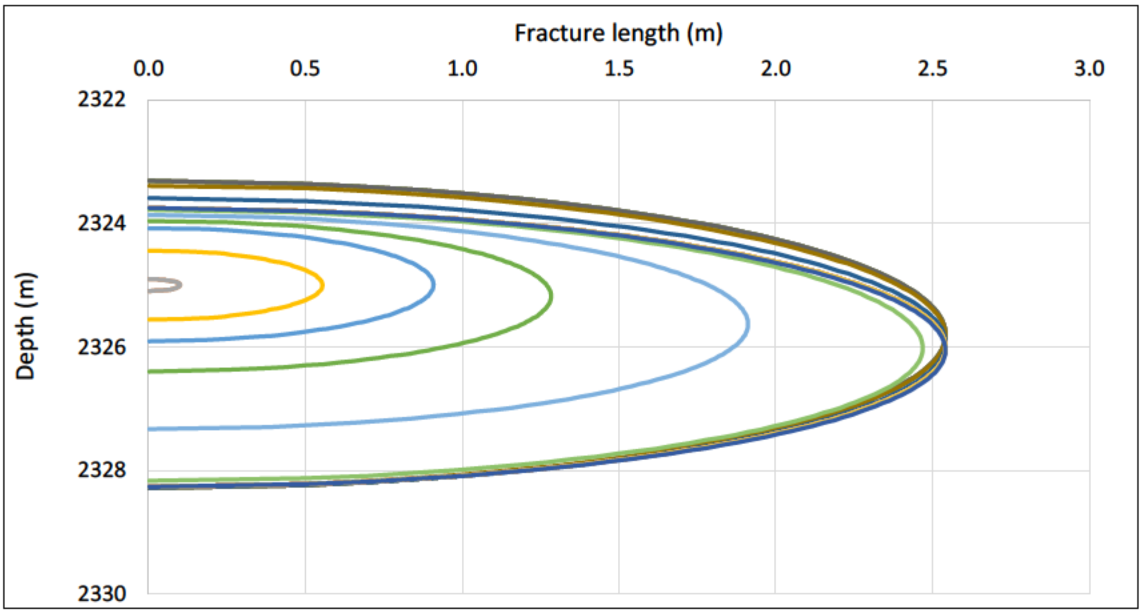

Figure 3-6 Fracture contours for the higher injection rate sensitivity. It was assumed that the fracture will be initiated 1m below the caprock

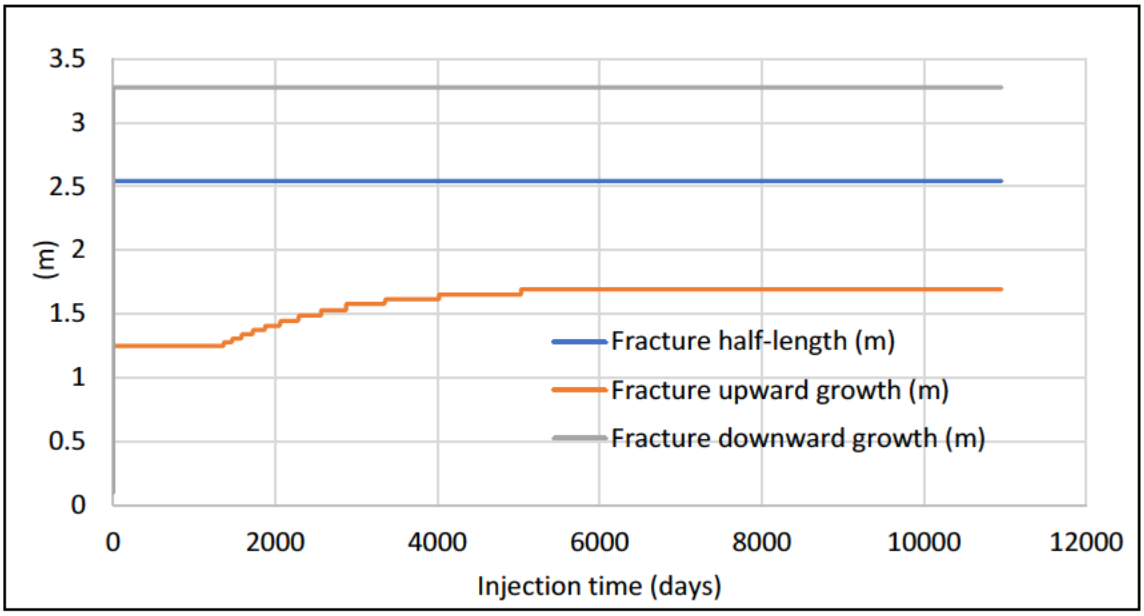

Figure 3-7 Fracture length, upward height, and downward height for the higher injection rate sensitivity.

3.2.3 Sensitivity: lower injection temperature

Over time, it may be decided that water injection temperatures can be decreased. Figure 3-8 and Figure 3-9 show the results of this sensitivity analysis. For a lower injection temperature (15°C instead of 32°C), a larger fracture is created than in the base case. Water temperature does not affect the penetration depth into the Rodenrijs significantly. At low temperatures, the fracture size mostly increases within the Delft reservoir itself. The induced thermal fracture remains contained to the Delft sandstone and it does not enter the overlying Rodenrijs claystone.

The fracture propagates upwards 0.5 m, half-length 46 m horizontally, and downwards 51 m. This is because the injected water is more viscous (cooler) than in the base case and also the cooled zone of the caprock has lower stress (73 bar less).

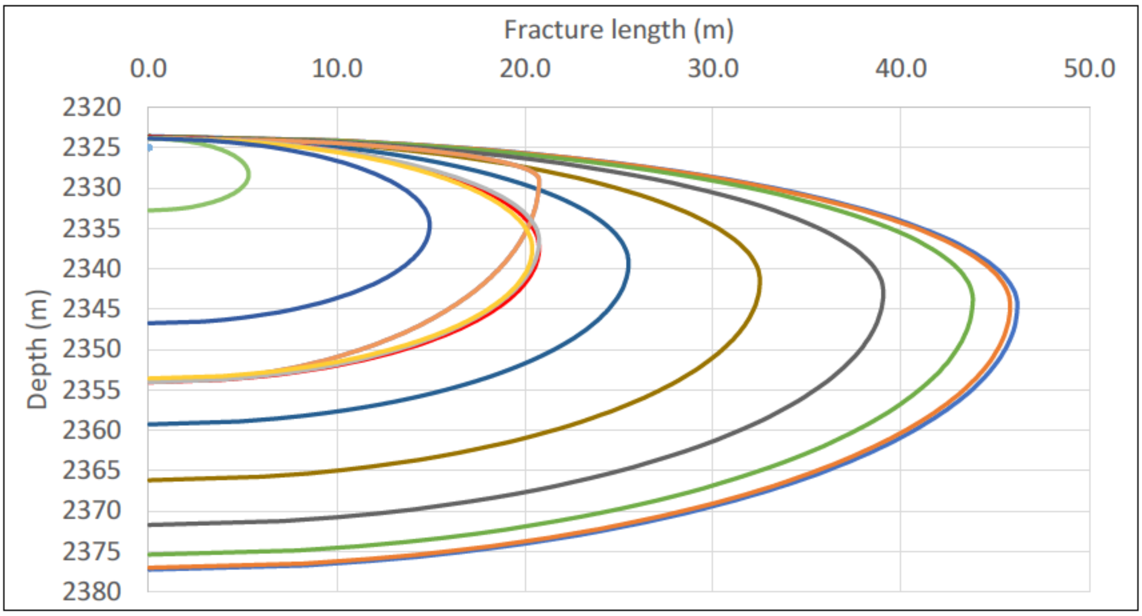

Figure 3-8 Fracture contours for the lower injection temperature sensitivity. It was assumed that the fracture will be initiated 1m below the caprock

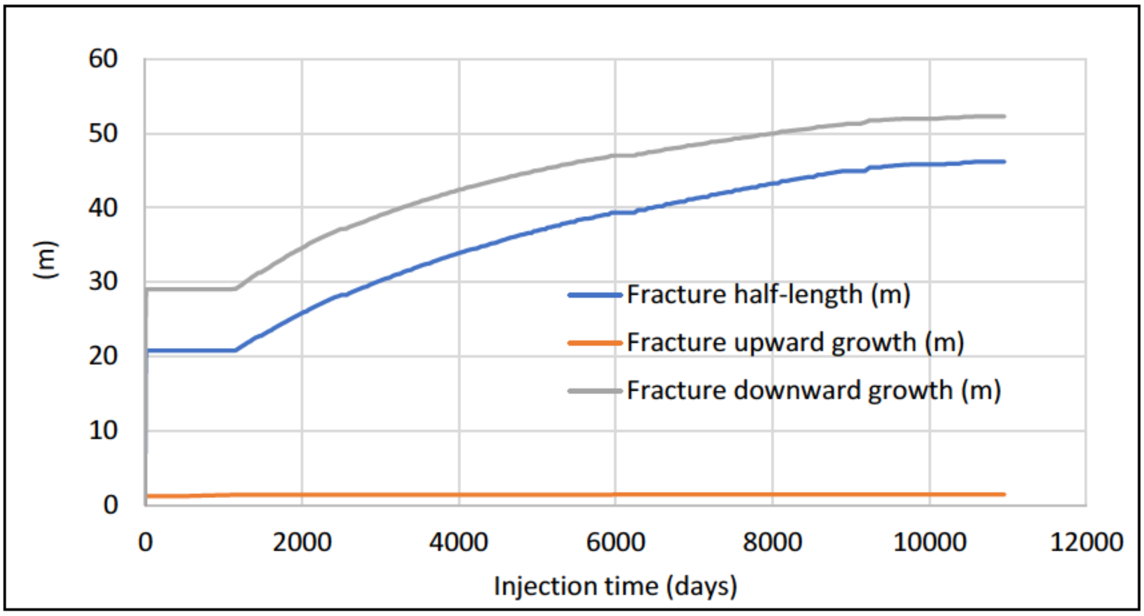

Figure 3-9 Fracture length, upward height, and downward height for the lower injection temperature sensitivity.

3.2.4 Sensitivity: lower reservoir permeability

The injector Well LIR-GT-02 was production tested in 2014 and the permeability of the 64 m net Delft formation was analyzed to be 1300 mD. The permeability derived from the producer LIR-GT-02 test was estimated to be 1000 mD. In this study, the base case permeability of 1300 mD was used. Although the interference test between the wells LIR-GT-01 and LIR-GT-02 showed much higher directional permeability of 2220 mD between the wells, in this section just as a sensitivity analysis the lower permeability of 1000 mD is used. Figure 3-10 and Figure 3-11 show the results of this sensitivity analysis.

For the permeability of 1000 mD, the induced thermal fracture is slightly larger than in the base case. Fracture dimensions are as follows: 0.5 m upwards growth, half-length 2.5 m, and downwards growth 2.3m.

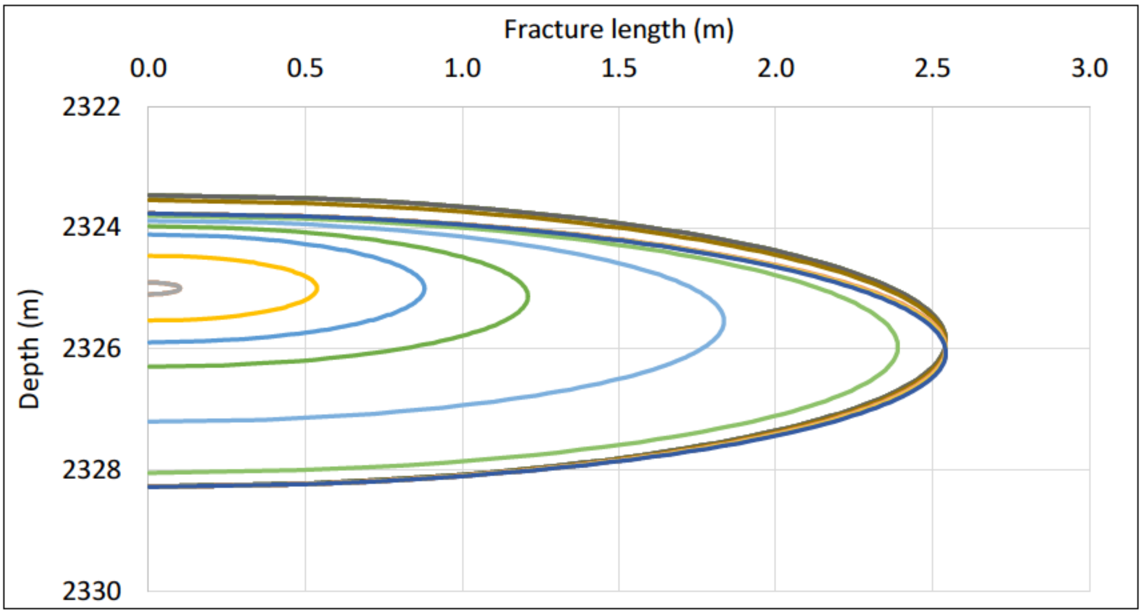

Figure 3-10 Fracture contours for the lower reservoir permeability sensitivity. It was assumed that the fracture will be initiated 1m below the caprock

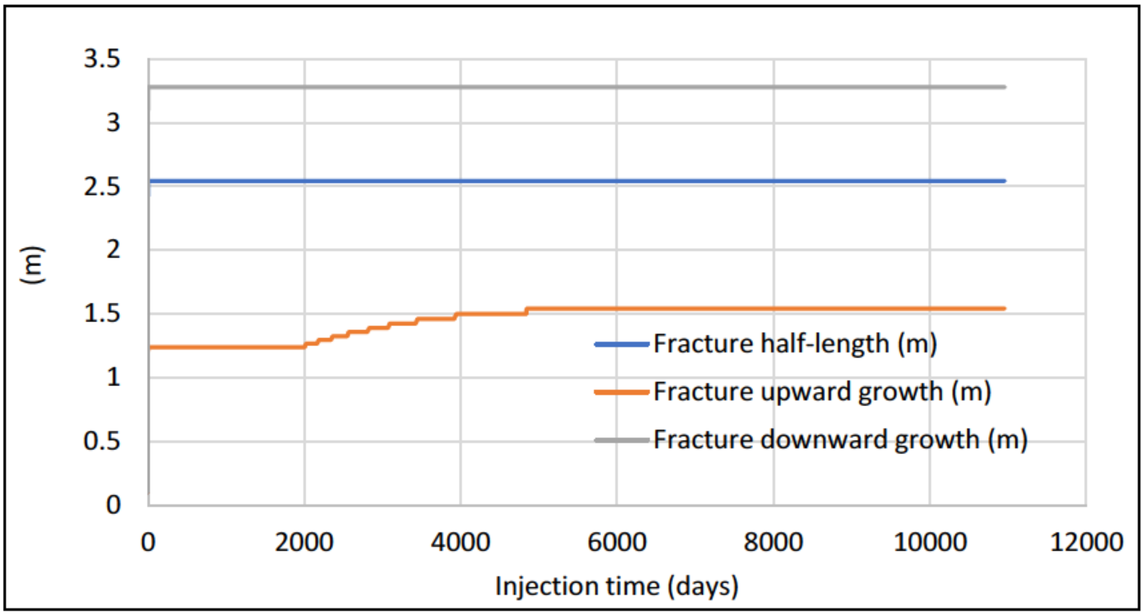

Figure 3-11 Fracture length, upward height, and downward height for the lower reservoir permeability sensitivity

4 Conclusions

Based on the obtained results, the following conclusions were made:

- To date, the doublet has been injecting under matrix conditions. If induced fracturing would take place, the modelling work demonstrates that it is fully contained within the Delft sandstone and bottom part of the Caprock (Rodenrijs claystone). The thickness of the overlaying caprock is much larger than the computed maximum possible upward fracture growth.
- As the Rodenrijs claystone is almost impermeable (K= 0.05 mD) compared to the reservoir (K= 1300 mD), there is no production/injection from/into the Rodenrijs. The Delft permeability is also much higher than Alblasserdam reservoir and most of production/injection is from/into the Delft reservoir.
- Conclusions for the base case are as follows. Fracture propagation is very limited (below 1m) in the reservoir and it does not enter the overlying Rodenrijs claystone. After 30 years of injection, the upward and downward fracture growth and also the half-length of fracture (horizontal direction) is about 0.6 m.
- Wide range of uncertainties was covered, simulating sensitivities with different input parameters. In all cases, the induced thermal fracture remains contained to the Delft sandstone and the diffusion-cooled part of the overlying caprock.
- In the case of lower injection temperature (15°C instead of 32°C), the fracture length increases compared to the base case. But the induced thermal fracture remains contained to the Delft sandstone and it does not enter the overlying Rodenrijs claystone.
- The sensitivity analysis of higher injection rate and lower reservoir permeability show no significant changes to the base case.

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Appendix A – Base Case with cooling- Input Data

Geological Model

	Layer name	Depth at top (m)	Depth at bottom (m)	Layer height (m)	Stress at top (MPa)	Stress at bottom (MPa)	Stress gradient (kPa/m)	Formpres at top (MPa)	Formpres at bottom (MPa)	Formpres gradient (kPa/m)
1	North Sea	0	691	691	0	10.9178	15.8	0	7.02747	10.17
2	Chalk	691	1169	478	10.9178	18.4702	15.8	7.02747	11.88873	10.17
3	Holland	1169	1666	497	18.4702	26.3228	15.8	11.88873	16.94322	10.17
4	De Lier sandstone	1666	1759	93	26.3228	27.7922	15.8	16.94322	17.88903	10.17
5	Vlieland claystone	1759	1904	145	27.7922	30.0832	15.8	17.88903	19.36368	10.17
6	Berkel sandstone	1904	1948	44	30.0832	30.7784	15.8	19.36368	19.81116	10.17
7	Berkel sand-clayst	1948	2095	147	30.7784	33.101	15.8	19.81116	21.30615	10.17
8	Rijswijk sandstone	2095	2203	108	33.101	34.8074	15.8	21.30615	22.40451	10.17
9	Rodenrijs clayston	2203	2294	91	34.8074	36.2452	15.8	22.40451	23.32998	10.17
10	Rodenrijs cooled	2294	2324	30	30.6452	31.1192	15.8	23.32998	23.63508	10.17
11	Delft sandstone	2324	2417	93	31.1192	32.5886	15.8	23.63508	24.58089	10.17
12	Alblas sand	2417	2544	127	32.5886	34.5952	15.8	24.58089	25.87248	10.17
13		2544								
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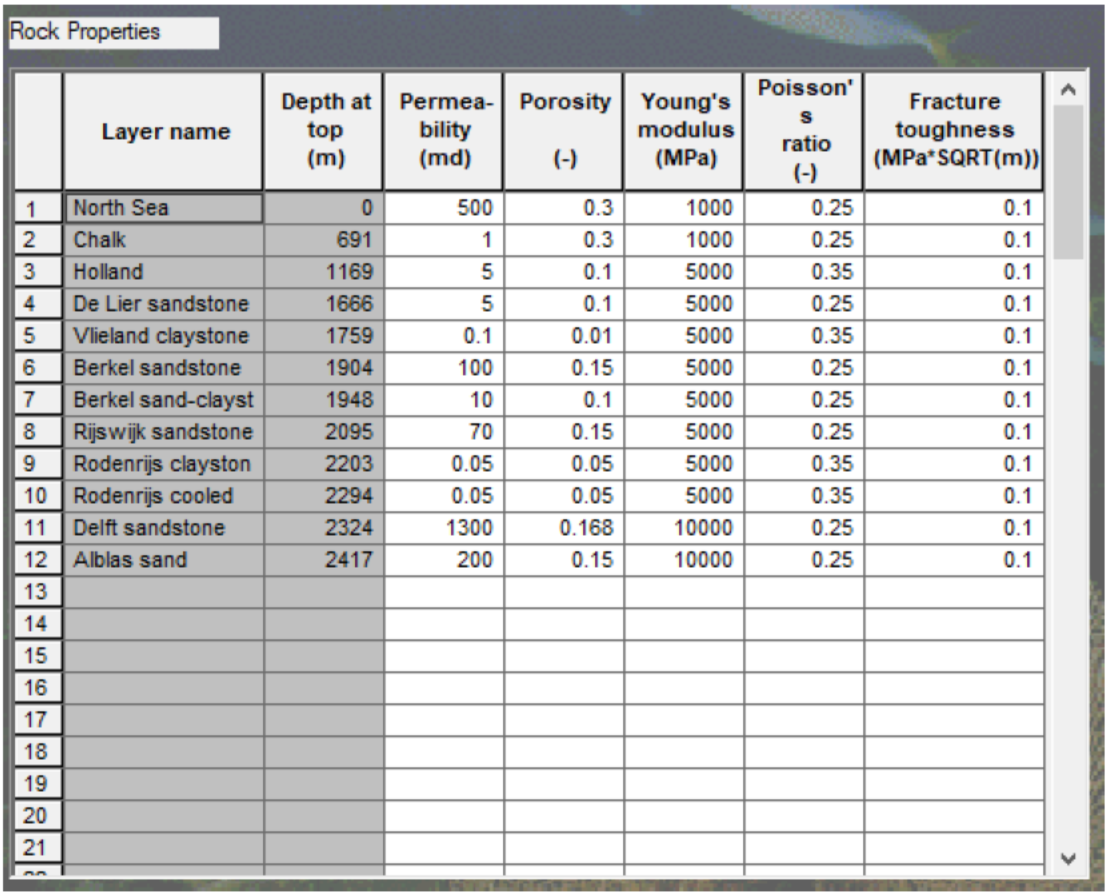
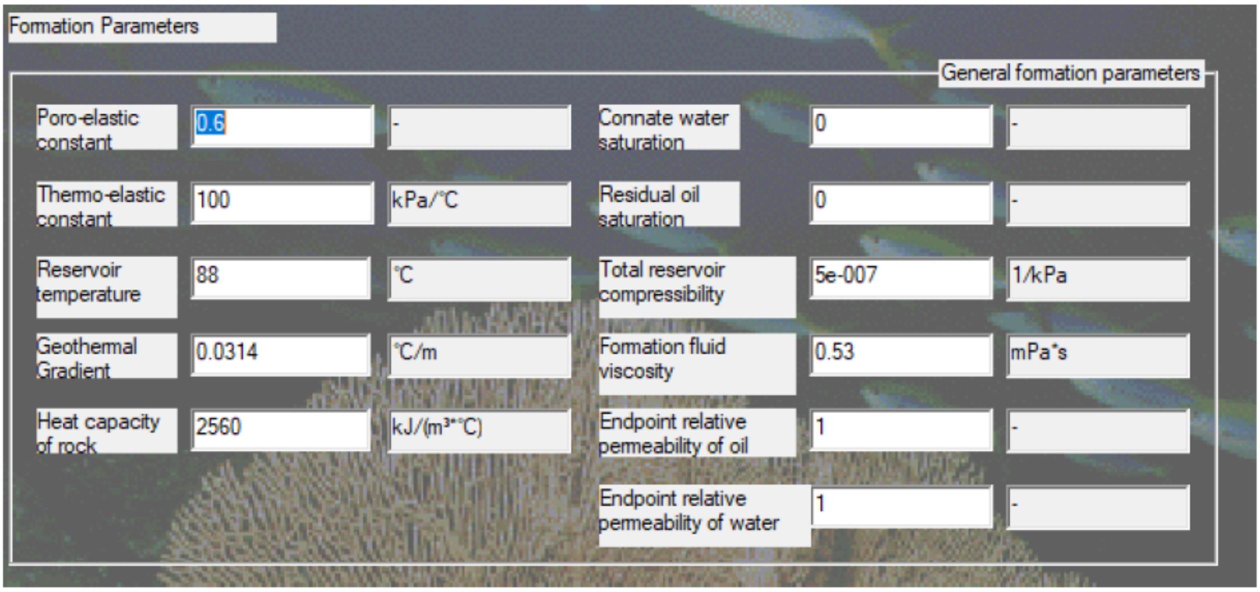


Rock Properties

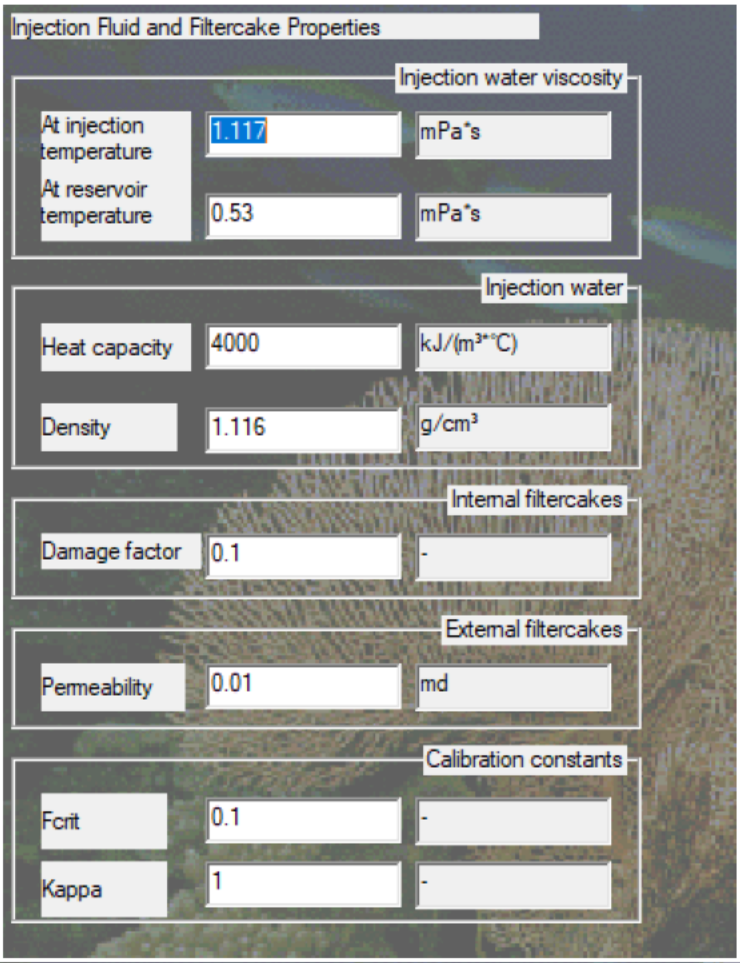
	Layer name	Depth at top (m)	Permea-bility (md)	Porosity (-)	Young's modulus (MPa)	Poisson's ratio (-)	Fracture toughness (MPa*SQRT(m))
1	North Sea	0	500	0.3	1000	0.25	0.1
2	Chalk	691	1	0.3	1000	0.25	0.1
3	Holland	1169	5	0.1	5000	0.35	0.1
4	De Lier sandstone	1666	5	0.1	5000	0.25	0.1
5	Vlieland claystone	1759	0.1	0.01	5000	0.35	0.1
6	Berkel sandstone	1904	100	0.15	5000	0.25	0.1
7	Berkel sand-clayst	1948	10	0.1	5000	0.25	0.1
8	Rijswijk sandstone	2095	70	0.15	5000	0.25	0.1
9	Rodenrijs clayston	2203	0.05	0.05	5000	0.35	0.1
10	Rodenrijs cooled	2294	0.05	0.05	5000	0.35	0.1
11	Delft sandstone	2324	1300	0.168	10000	0.25	0.1
12	Alblas sand	2417	200	0.15	10000	0.25	0.1
13							
14							
15							
16							
17							
18							
19							
20							
21							

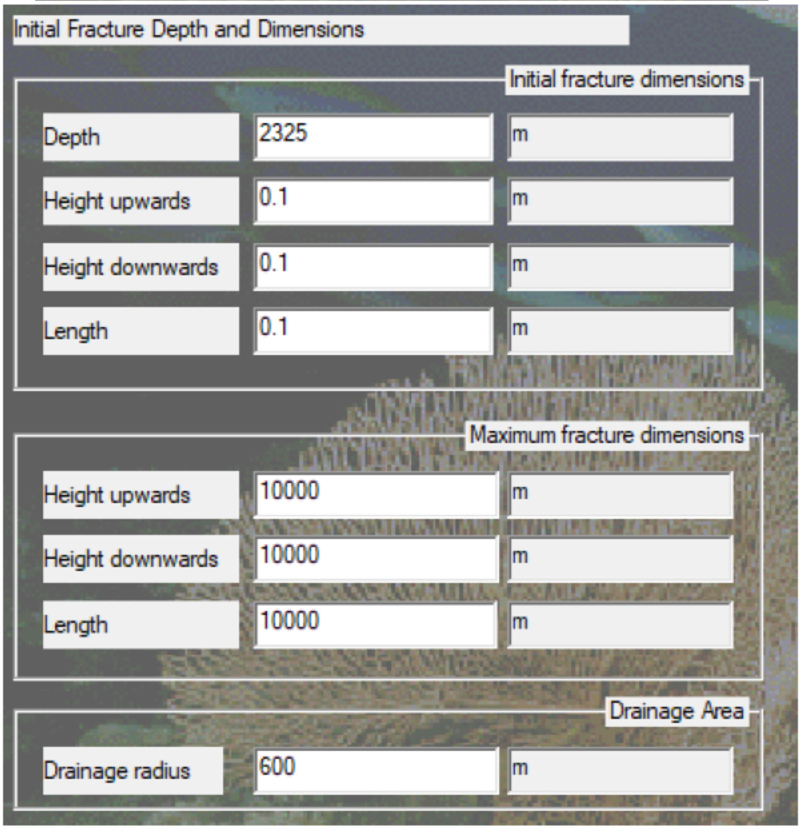


Formation Parameters

General formation parameters

Poro-elastic constant	0.6	-	Connate water saturation	0	-
Thermo-elastic constant	100	kPa/°C	Residual oil saturation	0	-
Reservoir temperature	88	°C	Total reservoir compressibility	5e-007	1/kPa
Geothermal Gradient	0.0314	°C/m	Formation fluid viscosity	0.53	mPa*s
Heat capacity of rock	2560	kJ/(m³*°C)	Endpoint relative permeability of oil	1	-
			Endpoint relative permeability of water	1	-


Injection Fluid and Filtercake Properties
Injection water viscosity
At injection temperature
1.117
mPa*s
At reservoir temperature
0.53
mPa*s
Injection water
Heat capacity
4000
kJ/(m³*°C)
Density
1.116
g/cm³
Internal filtercakes
Damage factor
0.1
-
External filtercakes
Permeability
0.01
md
Calibration constants
Fcrit
0.1
-
Kappa
1
-


Initial Fracture Depth and Dimensions
Initial fracture dimensions
Depth
2325
m
Height upwards
0.1
m
Height downwards
0.1
m
Length
0.1
m
Maximum fracture dimensions
Height upwards
10000
m
Height downwards
10000
m
Length
10000
m
Drainage Area
Drainage radius
600
m

Wellbore Hydraulics

	Description	Depth at botm (AH) (m)	Depth at botm (TV) (m)	Length of sect (AH) (m)	Length of sect (TV) (m)	Inner diameter (mm)	Outer diameter (mm)	Friction multplier (-)
0	0	0	0	0	0	0	0	1
1	8 5/8" Inj tubing	132	132	132	132	201.1934	219.075	1
2	13 3/8"casing	1123	1123	991	991	315.341	339.725	1
3	'9 5/8" liner	2528	2276	1405	1153	220.4974	244.475	1
4	6 5/8" liner	2880	2544	352	268	150.3934	177.8	1
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								

Fracture Depth	2251	2325

Insert section

Delete section

Injection Cycles

	Description	Start time (mon)	Injection duration (mon)	Injection rate (m^3/day)	Solids loading (vol ppm)	Oil loading (vol ppm)	Inj. water surf.temp (°C)	Inj. water BH temp (°C)
1		0	360	7200	0	0	32	32.313232
2								

Appendix B – Welltest results summary

Resultaten van de puttest LIR-GT-01

Gegevens voor test interpretatie	Waarde	Dimensie
Naam van de put LIR-GT-01	LIR-GT-01	
Coördinaten van de put (X, Y)	51°58'39.975"N	4°16'57.311"E
Top aquifer	2651	m (langs boorgat)
	2387	en m (TVD)
Basis aquifer	2830	m (langs boorgat)
	2528	en m (TVD)
Dikte Aquifer	70	m (TVD)
Netto/bruto aquifer	50	%
Gemiddelde porositeit aquifer	16.4	%
Zoutgehalte formatiewater (TDS = total dissolved	140,000.	ppm
solids)		
Maximum temperatuur geproduceerde water[1]	90	ºC
Diameter boorgat bij aquifer	8.5	Inch
Top productie-interval/filter	2602	m (langs boorgat)
	2353	en m (TVD)
Basis productie-interval/filter	2868	m (langs boorgat)
	2553	en m (TVD)
Filter weerstand	3.5	bar @ 332 m3/hr
Filter weerstand	2.7	bar @ 254 m3/hr
Filter weerstand	2	bar @ 194 m3/hr
Locatie pomp	711.3	m (langs boorgat)
	710.43	en m (TVD)
Locatie meetsonde voor druk	2398	m (langs boorgat)
	2196.22	en m (TVD)
Clean up gegevens		
Ponpdruk	55	bar
Debiet vs. tijd	330	m3/uur
Duur	4	uur
Meetreeksen Puttest[4]	Eind pompdruk, bar	Eind Debiet, m3/uur
Flow 1	61.9	194
Flow 2	59.1	254
Flow 3	54.8	332

[1] Deze temperatuur wordt als gemiddelde aquifer temperatuur beschouwd

Uitkomsten test interpretatie en analyse LIR-GT-01		
Permeability thickness kH	70	Dm (Darcy-meter)
Aangenomen H	70	m
Permeability k	1000	mD
Reservoir Skin S	-1.3	
Totale effectieve Skin	2.2	@ 332 m3/hr
Productivity Index (P.I.) (ESP level)	23	m^3/uur/bar
Productivity Index (P.I.) (at wellbore)	40	m^3/uur/bar

Resultaten van de puttest LIR-GT-02

Gegevens voor test interpretatie	Waarde	Dimensie
Naam van de put LIR-GT-01	LIR-GT-02	
Coördinaten van de put (X, Y)	**E (m) = 79090.55**	**N (m) = 443734.51**
Coordinaten mid reservoir at 2370 mtv	**E (m) = 79583**	**N (m) = 443305**
Top aquifer	2590	m (langs boorgat)
	2324	en m (TVD)
Basis aquifer	2715	m (langs boorgat)
	2418	en m (TVD)
Netto dikte Aquifer	64	m (TVD)
Netto/bruto aquifer	68	%
Gemiddelde porositeit aquifer	16.8	%
Zoutgehalte formatiewater (TDS = total dissolved	140,000.	ppm
solids)		
Maximum temperatuur geproduceerde water[1]	88	ºC
Diameter boorgat bij aquifer	8.5	Inch
Top productie-interval/filter	2531	m (langs boorgat)
	2279	en m (TVD)
Basis productie-interval/filter	2855	m (langs boorgat)
	2525	en m (TVD)
Filter + casing weerstand	6.0	bar @ 351 m3/hr
Filter + casing weerstand	3.3	bar @ 259 m3/hr
Filter + casing weerstand	1.7	bar @ 189 m3/hr
Locatie pomp	700	m (langs boorgat)
	700	en m (TVD)
Locatie meetsonde voor druk	700	m (langs boorgat)
	700	en m (TVD)
Clean up gegevens		
Pompdruk	53	bar
Debiet vs. tijd	350	m3/uur
Duur	3	uur
Meetreeksen Puttest[4]	Eind ESP druk, bar	Eind Debiet, m3/uur
Flow 0	66.5	0
Flow 1	60.4	189
Flow 2	57.6	260
Flow 3	52.55	350

1 Deze temperatuur wordt als gemiddelde aquifer temperatuur beschouwd

Uitkomsten test interpretatie en analyse LIR-GT-02		
Permeability thickness kH	83	Dm (Darcy-meter)
Aangenomen H	64	m
Permeability k	1300	mD
Reservoir Skin S	0.3	
Totale effectieve Skin	7.2	@ 351 m3/hr
Productivity Index (P.I.) (at ESP depth)	23.5	m^3/uur/bar
Productivity Index (P.I.) (at wellbore)	40	m^3/uur/bar