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Consequences of thermal fracture developments due to injection of cold CO_2 into depleted gas fields

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Abstract

CO_2 storage is planned in a depleted gas field called P18, which is located offshore in the vicinity of the Dutch coast. This project is also known as the ROAD project, which is the Rotterdam capture and storage demonstration project. In the P18-4 compartment, cold CO_2 will be injected into a formation with a temperature of 120°C. Cooling of the reservoir with the cold CO_2 will induce thermal stresses, similar to those resulting from injection of cold water. The thermal stresses around the well can promote the propagation of fractures into the reservoir and possibly the caprock. This is usually called thermally induced fracturing. In contrast to cold water injection, for CO_2 injection thermally induced fracturing is usually not taken into account. In this paper, we are exploring the potential development of thermal fractures and their impact on the reservoir rock, caprock and well injectivity of the P18-4 reservoir.

The P18-4 reservoir was modelled by a modified TOUGH2/ECO2M module. The module is designed for geological storage of CO_2 in a wide range of temperature, pressure conditions and therefore different CO_2 phase conditions, but was not able to model phase transitions in low pressure – high temperature reservoir. We modified the ECO2M module to be able to model the transition of gaseous to liquid CO_2, needed for the pressure temperature conditions investigated in P18-4.

To estimate the maximal extent of a fracture into the reservoir we started with 2D simulations of cold CO_2 injection without any fracture development in TOUGH2/ECO2M module. The resulting pressure and temperature fields were used in a geomechanical analysis to determine the thermo-elastic and poro-elastic stresses, and to assess the fracture development into the reservoir (using the finite-element software tool DIANA). After completing a number of timesteps, these fractures were introduced back into the TOUGH2 model and the potential injectivity enhancement was analysed. The TOUGH2-DIANA coupling was made semi-automatic, therefore an efficient exchange of data between the two software packages was possible.

The DIANA model was initialised with the corresponding stresses at a depth of 2500m, rather than the actual depth of 3200m at which the minimum in-situ stress was too high for any (thermal) fracture to occur. On one side of the cylinder the fracture development was modelled. We employed a layered model representing a quarter cylinder of the reservoir for the TOUGH2 simulations. The model was initialised at 20 bar and 100°C. Injection of 1.1 Mton/yr was assumed, which resulted in a temperature front up to 250 meters into the reservoir after 5 years of injection. The quarter cylinder was mapped upon a 2D plane strain geometry for the geomechanical simulations.

The large temperature changes resulted in a fracture development in “the shallow P18-4 reservoir” (2500m depth) of up to 140 m after 5 years of injection. The fracture development was translated into a permeability change in the fractured part of the reservoir

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and in this way we are able to predict the new injectivity of the reservoir. The injectivity increased from 0.7 Kg/s bar to 2.0 Kg/s bar.
In the 2D simulations, we have seen the extent of a fracture in a single-layer reservoir, however this does not completely reflect the vertical heterogeneity in "the shallow P18-4 reservoir". Also, it was not possible to examine the effect on the caprock with this model. Therefore a 3D model was constructed in both TOUGH2 and DIANA, which resulted in even more shallow P18 reservoir in order to show the ability to simulate the development of a crack inside the caprock. Not only horizontal propagation of the fracture was considered, but also to allow vertical fracture propagation of the fracture into the caprock. The stresses due to the cold injection have to overcome not only the horizontal minimum stress, but also the vertical stress in order to propagate into vertical direction.
From the 2D simulations and 3D simulations, it was clear that for the true depth (3200m) of the P18-4 reservoir, no fracturing as a result of the cold CO_2 is expected, which is in line with the earlier results. However in "the shallow P18-4 reservoir" (2500m) there is fracture development into the reservoir. The 3D simulation results are very sensitive for the values of the following properties: permeability in the fracture, brine salinity and the reduction of permeability due to salt precipitation.
The main impact of thermal fractures are:

- Well injectivity increases.
- The shape of the CO_2 front changes, which means that the cold CO_2 can extent much further away from the well than without fracturing.
- The probability of the development of fractures in both the reservoir and the caprock increases.
- CO_2 flow patterns become complicated due to salt precipitation and blocking in the reservoir and/or caprock
- The result is very sensitive for the values of the following properties permeability in the fracture, brine salinity and the reduction of permeability due to salt precipitation

Keywords:CO_2 injection; Thermal fractures;TOUGH2; DIANA;

1. Introduction

CO_2 storage is planned in a depleted gas field called P18, which is located offshore in the vicinity of the Dutch coast (Figure 1). This project is also known as the ROAD project, which is the Rotterdam capture and storage demonstration project [1]. In the P18-4 compartment, cold CO_2 will be injected into a formation with a temperature of more than 120°C. Cooling of the reservoir with the cold CO_2 will induce thermal stresses, similar to those resulting from injection of cold water [2]. The thermal stresses around the well may promote the propagation of fractures into the reservoir and possibly the caprock. This is usually called thermally induced fracturing. In contrast to cold water injection, for CO_2 injection thermally induced fracturing is usually not taken into account. In this paper, we are exploring the potential development of thermal fractures and their impact on the reservoir rock, caprock and well injectivity of the P18-4 reservoir.

Within the CATO2 program, an extensive feasibility study for the storage of CO_2 in P18 has been done [3]. In that study, the integrity of the top seal was assessed based on a maximum possible temperature difference of 10°C. However, the assumption of the maximum possible change in temperature in the caprock was not checked. Thermal simulation of the effects of injecting cold CO_2 were analyzed for the reservoir, but not for the caprock. Also, thermally induced fracturing had not been taken into account.

The reservoir of the P18 field is in the Lower Germanic Trias Group and consists of three formations: Hardegsen, Detfurth and Volpriehausen. Of these three, the Hardegsen has the best properties in terms of permeability and porosity, but has limited thickness. On top of the Hardegsen, the clay stones and evaporites of the Solling Claystone Formation can be found, which act as the primary seal and caprock.

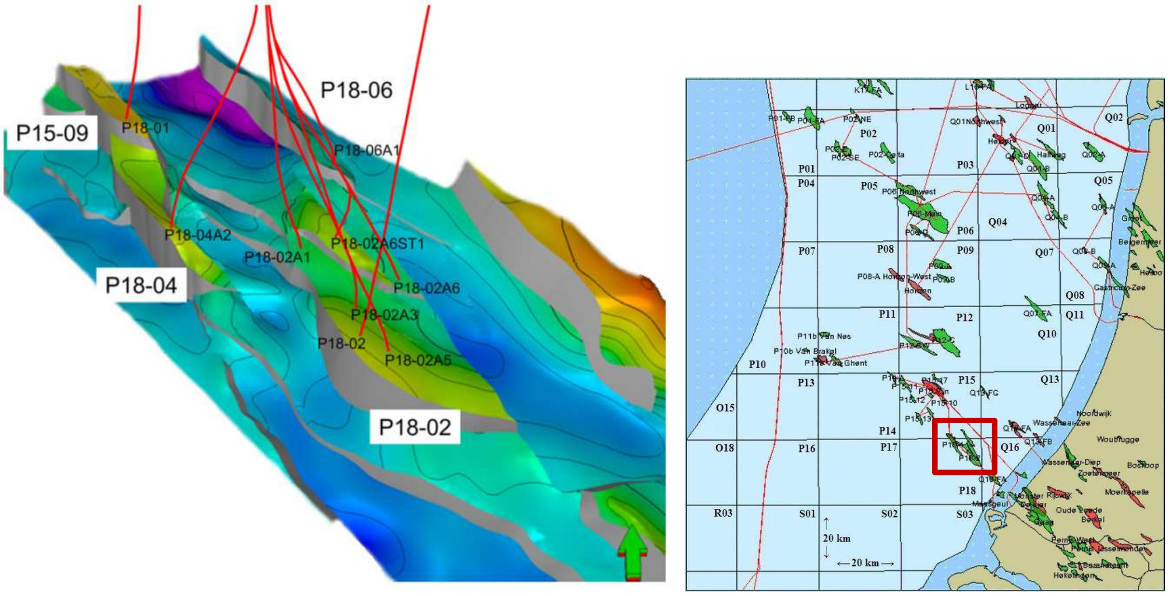

Figure 1. 3D view of the top of the P18 fields. Faults are shown in grey, well traces are shown in red. Reproduced with permission from (Arts et al, 2012)

Coupled flow-geomechanical numerical simulation is used to analyse the thermally induced fracturing. The workflow is illustrated in Figure 2. For the flow simulations, the P18-4 reservoir was modelled by a modified TOUGH2/ECO2M module [4,5]. The original module ECO2M is designed for the simulation of geological storage of CO_2 in a wide range of temperature, pressure conditions and therefore different CO_2 phase conditions, but was not able to model phase transitions in low pressure – high temperature reservoir. We modified the ECO2M module to be able to model the transition of gaseous to liquid CO_2, needed for the pressure temperature conditions investigated in P18-4. The geomechanical analysis was performed using the generic finite element code DIANA® [6]. The first step was to model only the main reservoir layer (Hardegsen) in a detailed 2D radial model. The main goal of this step is to analyse the thermal fracturing simulation workflow and process and effect on well injectivity. In the next step, a 3D model including the caprock was created to analyse possible fracturing of the caprock.

In the following, first the adjustments needed for TOUGH2 are discussed. Next, the results of the 2D and 3D model are discussed.

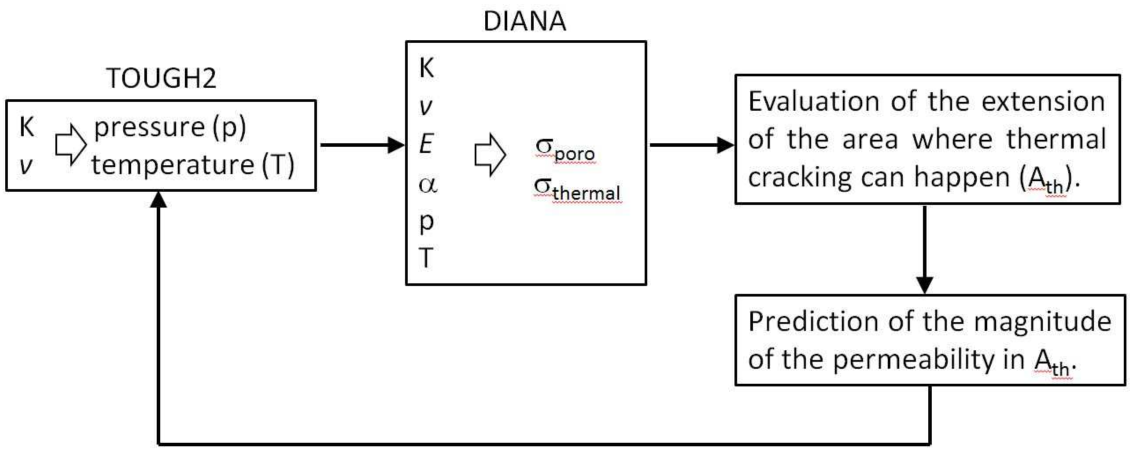

Figure 2. Coupling TOUGH2 – DIANA.

2. Simulation of CO_2 in TOUGH2

TOUGH2-ECO2M is one of the few available simulators that can simulate the full range of CO_2 behavior as a function of temperature and pressure and in particular the phase transition of CO_2 from subcritical to supercritical. Also the presence of liquid and supercritical or gaseous phase in the reservoir can be simulated simultaneously.

However, after initial tests failed, it was found that the code was untested for the application considered in this paper (low temperature injection in first low pressure reservoir and later high pressure reservoir). Therefore, the first step was to fully test and debug the program in cooperation with the main author of the code Karsten Pruess, formerly with Lawrence Berkeley National Lab. Furthermore, two main changes were implemented:

1. CO_2 properties: In the ECO2M module the thermophysical properties of pure CO_2 are based on the Altunin correlations [5]. In this study, a new set of properties (density, viscosity and specific enthalpy) is generated based on NIST data between 3°C and 103°C.
2. Relative permeability: A new formulation for the relative permeability was introduced to ensure consistency for phase changes across and above the critical point (eq. 1). The main characteristic of the new relative permeability curve is that the relative permeability of a phase (as defined in TOUGH2: aqueous, gaseous CO_2, liquid CO_2) depends on its own saturation only. Eq. 1 corresponds to the “Corey” formulation for relative permeability, e.g. [7].

$$k_{ph,r} = \left(\frac{S_{ph}-S_{ph,r}}{1-S_{ph,r}}\right)^{c} \qquad (1)$$

Where:

S_{ph} : phase saturation
$S_{ph,r}$: residual phase saturation
$k_{ph,r}$: relative permeability of the phase
c : Corey exponent

3. Thermal fracture development with 2D simulations

3.1. Input TOUGH2

To simulate the injection of cold CO2 in a depleted gas reservoir (P18-4), detailed processes around the well such as Joule-Thomson cooling need to be simulated. Therefore a radial model with small gridblocks near the well was used. Usually for a 2D radial model, radial symmetry is assumed. However, this would not allow the implementation of a fracture, because that breaks the radial symmetry. Therefore a radial, layer model was created containing only the Hardegsen formation. Figure 3 shows an overview of the TOUGH2 grid. The following settings were used:

- Grid size: 87x22.
- Rock properties are listed in Appendix A.
- 5 years injection of 1.1 Megaton CO_2 per year in P18-4 of 12°C. The temperature of 12°C has been chosen, because lower injection temperatures might result in hydrate formation and for even lower temperatures of freezing conditions around the well due to the Joule-Thomson effect. In the feasibility study temperature as low as 259 K were considered [3].
- Distribution of the injection is based on the permeability-depth product of the well: 66% in Hardegsen and 34% in Detfurth. The Detfurth is not simulated.

- initial reservoir conditions: 20 bar and 100°C (constant over depth). The real temperature of the reservoir is 120°C, but this is outside the range of applicability of the new properties dataset included in TOUGH2 module.
- well: 20 bar and 12°C.
- initial gas present is CO_2 because the behaviour of CH_4-CO_2 mixtures cannot be simulated yet [8].
- Relative permeability that depends on the saturation of the analyzed phase only as discussed in the previous section.
- No capillary pressure.

The TOUGH2 output of pressure and temperature is mapped to the DIANA grid. To minimize errors, the grids have the same grid block size.

The fracture was simulated explicitly in TOUGH2. This was achieved by applying increased permeability in the first row of grid blocks (with y=0). Since the width of the grid blocks is not set to the actual fracture width, the grid block permeability is calculated as:

$$k = T_{frac}/w_{frac} \tag{2}$$

Where:

k : grid block permeability (m^2)
T_{frac} : fracture transmissivity (m^3)
W_{frac} : fracture width (m)

In DIANA only the expected length of the fracture is calculated. Permeability of a fracture is in the first place related to fracture width. Predicting fracture width is not a trivial problem, especially for non-isothermal cases (e.g. [9]). Moreover, sensitivity analysis showed that if the fracture permeability reaches above 1E-6 m^2, the solution is quite insensitive to the actual values but can get unstable numerically. Using the well-known cubic law [10,11,12], it can be derived that these values are already reached for a fracture width in the order of 5 mm, a width which is already reached for quite short fractures. Therefore it was decided to assume a constant maximum fracture width at the well of 5 mm. The fracture width decreases elliptically with the length of the fracture. Permeability was then calculated using the cubic law ($T=w^3/12$). Figure 4 shows the permeability as calculated using the cubic law, adjusted for the grid block width and as implemented in the TOUGH2 model.

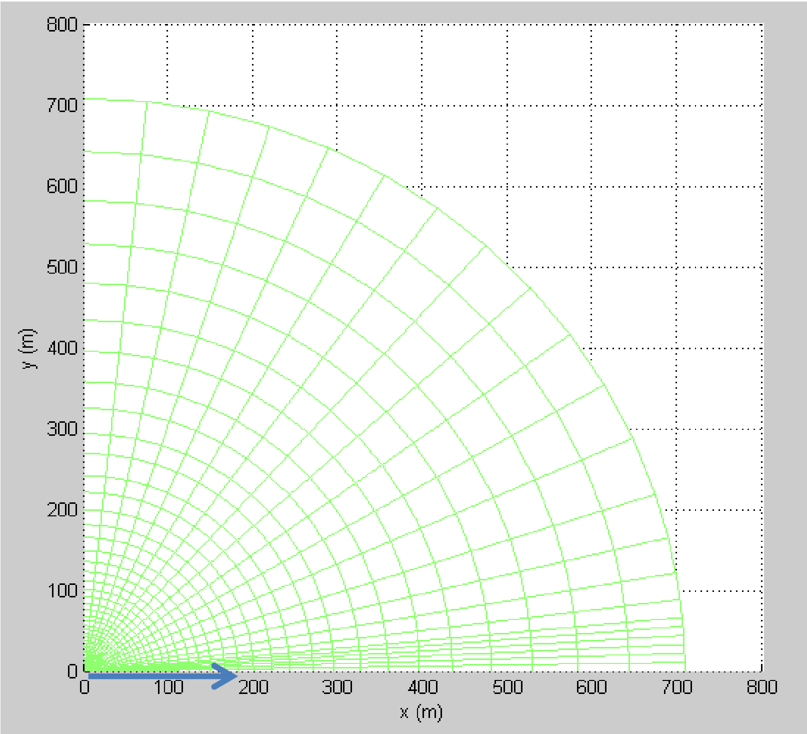

Figure 3. Top view of the grid (green lines). The arrow indicates the location of the fracture.

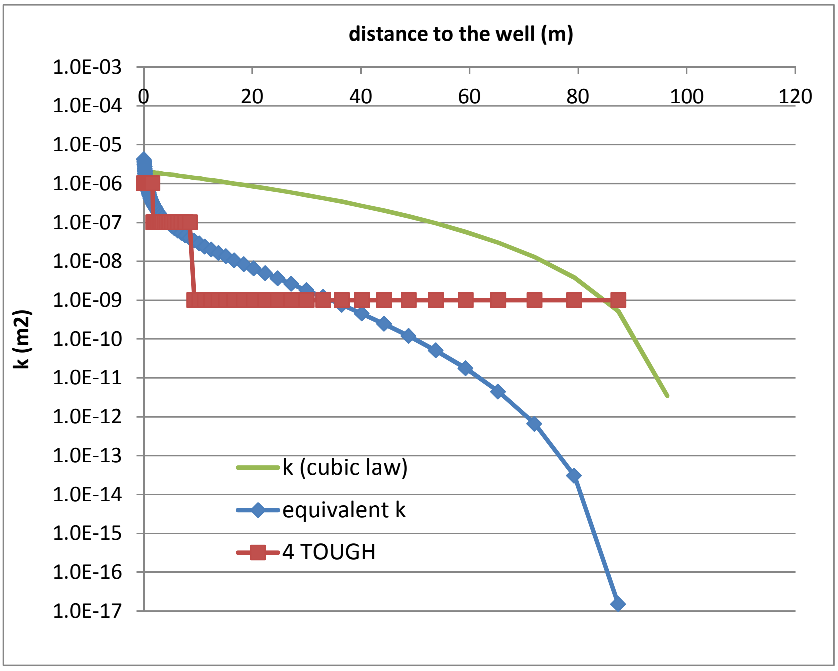

Figure 4. Example of permeability (k) as calculated for a 100 m long fracture with a maximum width of 5 mm showing k based on the fracture width (green line), the equivalent k corrected for grid block width (blue line) and k as entered in TOUGH2 (red line with squares).

3.2. Input DIANA

A fracture can develop if the combined thermo and poro-elastic stresses as a result of injection exceed the minimum horizontal in-situ stress ($\sigma_{h,min}$). This was calculated in two steps:

- First the minimum total horizontal stress based on the average reservoir pressure was calculated according to Figure 5. In this case, the expected case curve with depletion coefficient (DC) is 0.7 was used. No arching effect has been considered in the evaluation of the in situ stresses. In order to show the ability to simulate the development of a fracture and to compensate for the underestimation of the thermal stresses due to the reservoir temperature of 100°C instead of 120°C, a test case was created. In the test case a depth of 2500m instead of the real depth of 3200m was used, which results in lower horizontal stresses.
- In the second step, the stresses as a result of injecting cold CO_2 are calculated and compared to the minimum total horizontal stress. If the stresses as a result of injection exceed the minimum total horizontal stress, a fracture can develop (illustrated in Figure 6). Since thermal fractures are typically driven by the tensile stresses (for the 2D radial model, the tangential stresses) that are perpendicular to the sides of the crack, the radial stress is not taken into account.

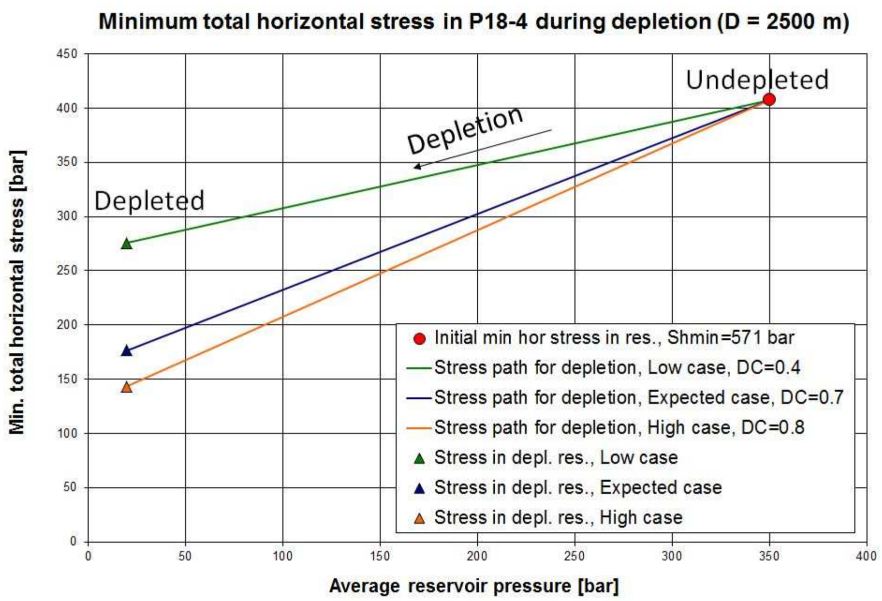

Figure 5 Value of the horizontal stresses for the undepleted and depleted reservoir at a depth of 2500 m [3].

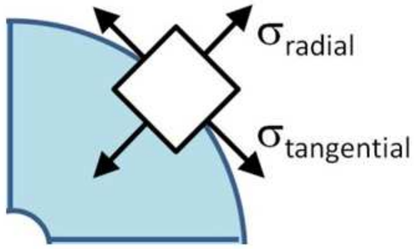

Figure 6. Representation of the radial and tangential component of the thermal stresses.

3.3. 2D Simulation results

Figure 7 shows the total tensile stresses and $\sigma_{h,min}$ (which is 23 MPa for field average pressure of 9.7MPa) after 1 year. The fracture can develop up to the point where the tensile stresses become lower than $\sigma_{h,min}$. Figure 8 shows the extent of the fracture together with the pressure and temperature profile for four different time steps. As has been observed for cold water injection [2], the thermally induced fracture extends to the cooling front.

After 5 years, the pressure has (just) exceeded the initial pressure of the reservoir. This is not realistic, but due to the fact that the injection into the Hardegsen was based on kh (permeability-depth product) of the well rather than the available volume.

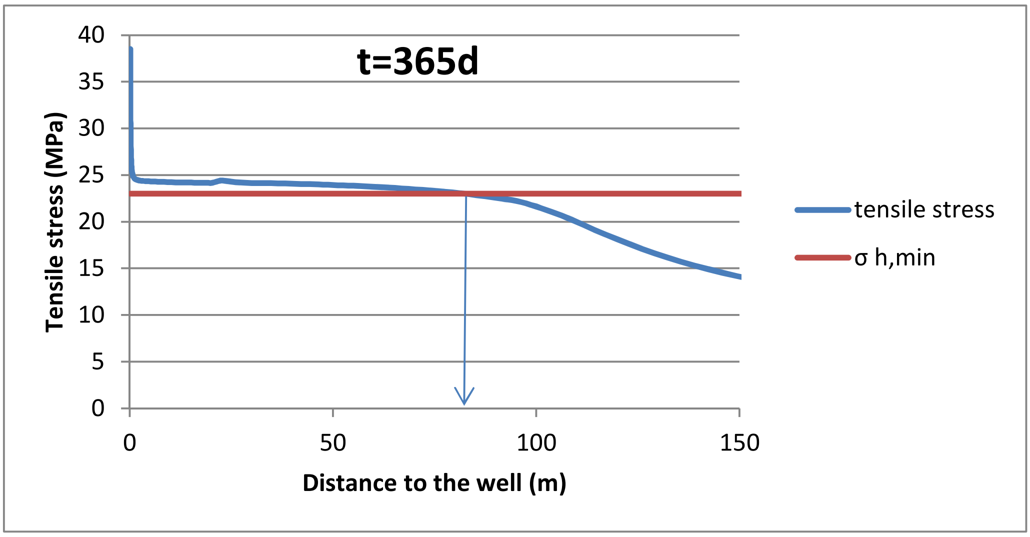

Figure 7. Tensile stresses with distance from the well after 365 days after the start of injection with $\sigma_{h,min}$=23MPa (red line).

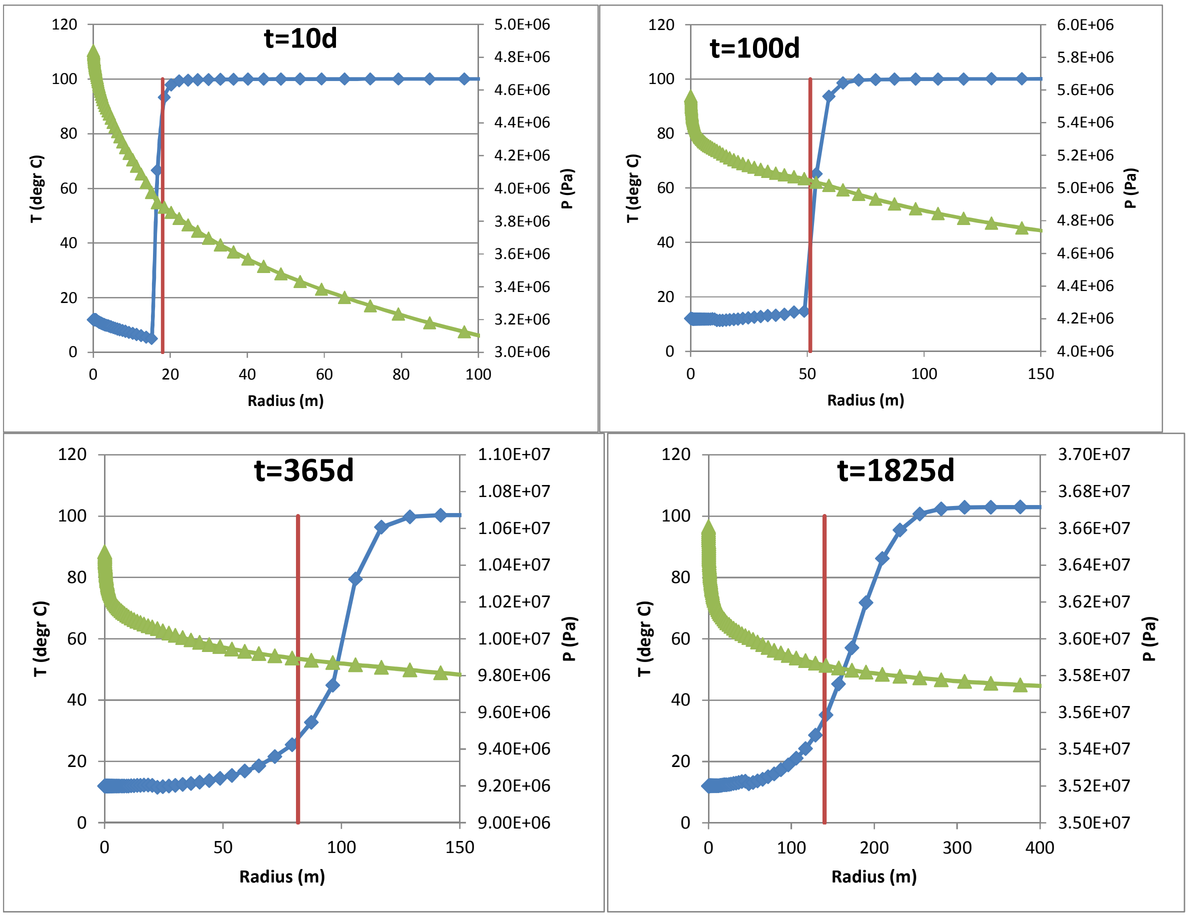

Figure 8. Temperature and pressure profile with distance from the well for four time steps: 10d, 100d, 1 year and 5 years. The red line indicates the extend of the fracture

In the next step, a fracture of 100 m long is introduced in the reservoir and the effect on the CO_2 flow calculated. The fracture is introduced after 1 year. It was found however that the presence of the fracture deteriorates the numerical performance considerably. In fact, for the chosen configuration, a complete run up to 5 years was not achieved. Therefore, a variety of adjustments was tested to achieve convergence. The most efficient way of improving convergence was to reduce the permeability of the fracture by a factor of 10. The resulting change in temperature was less than 0.5% in all grid blocks.

The fracture more than doubles the well injectivity from 0.68 kg/s/bar to 1.64 kg/s/bar. Figure 9 shows the full development of the injectivity over the full 5-year period, both with and without the 100m long fracture.

These results show that the thermal front can extent considerably further from the well due to the development of thermal fractures. If the P18-4 reservoir had been more shallower, this might have posed a risk for well P18_04A2 , which is very close to two major faults. The change in thermal stresses might increase the risk of fault re-activation and thus possibly of leakage. In previous studies, only the effect of changes in pressure were included in the analysis of possible fault re-activation.

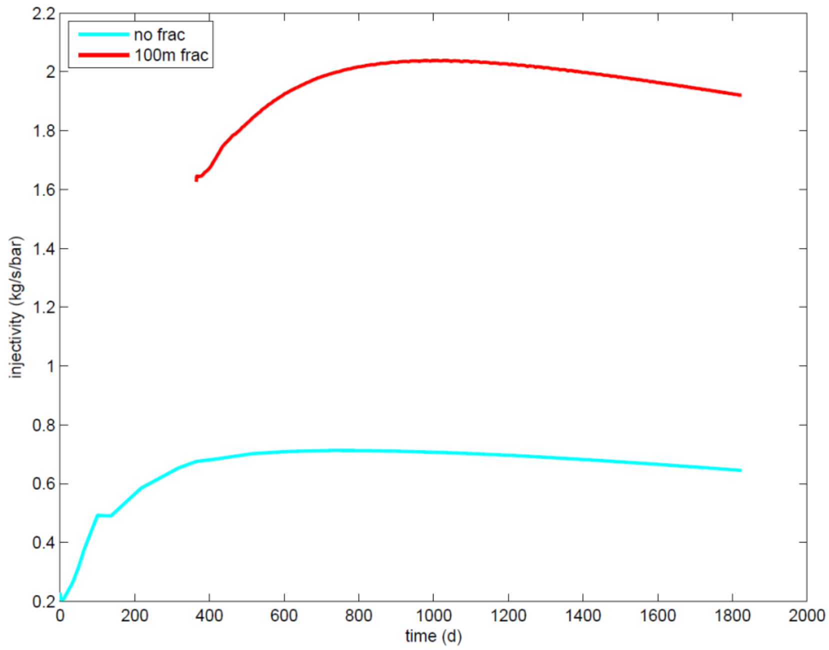

Figure 9. Injectivity with and without a fracture.

4. 3D simulations

In the 2D simulations, we have seen the extent of a fracture in a single-layer reservoir, however it did not reflect the situation in P18-4. The vertical layering of the P18 reservoir is not taken into account in the 2D simulations. Also, it was not possible to examine the effect on the caprock with this model. Therefore a 3D model was constructed in both TOUGH2 and DIANA. Thermal cracks are typically caused by normal loading or unloading. A crack always propagates perpendicular to the minimum in-situ stress. In our case the minimum in-situ stress is horizontal, so a crack will propagate horizontally and the crack front will belong to a vertical plane. To evaluate an eventual propagation of the crack within the caprock we need to model a vertical plane as well, but a 2D vertical plane model only is not enough because the stresses that drive the propagation of the crack are perpendicular to the vertical plane. For these reasons we needed to build a 3D geomechanical model.

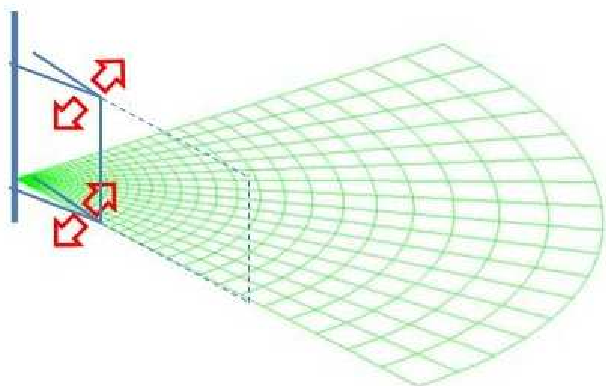

Figure 10. From 2D to 3D grid

4.1. Input TOUGH2

In line with the geomechanical model, the flow model in TOUGH2 also needs to be 3D. The size of the model is 47x11x8, where the caprock is represented by 3 layers of thickness 6.7, 13.3 and 20 m. Except for the grid, the input is identical to the 2D model (see Appendix A). The caprock was assumed to be at virgin pressure (340 bar) after the depletion phase. This was also assumed for the geomechanical simulations. Because the main goal for this model is to analyze the influence on the caprock, the bottom part of the reservoir (Volpriehausen), which has a relatively low permeability (~0.2 mDarcy) has not been included in the reservoir model to keep run-times acceptable. Instead it was assumed for the geomechanical model that the temperature remains virgin at T=100°C and that the pressure is the same as in the Lower Detfurth.

Within the reservoir, thin shale layers may separate different parts of the reservoir. Especially, a shale layer is present between the Hardegsen and the Detfurth formation which might separate the reservoir in two distinct parts with their own pressure regime. However, this has not been taken into account.

4.2. Input DIANA

For the 3D model, a full geomechanical model was constructed including over-, under- and side-burden. In our 3D axisymmetric model, the total thickness of the model is 6000 m and the radius of the model is 2500 m. The reservoir is at a depth of 3190 m and has a radius of 878 m. The model is based on the stratigraphic units and their thickness and properties are taken from [3]. For details see Appendix B. Figure 11 shows the complete model with the stratigraphic units in different colors and the mesh.

Figure 11 From left to right: 3D view of the stratigraphic units, side and top view of the mesh. The mesh is finer in the area of interest (reservoir and caprock) and coarser closer to the borders.

4.3. 3D Results

Similar to the 2D simulations, first a forward run for 5 years was done with the TOUGH2 model. Figure 12 shows the development of the temperature front. Clearly the layers with different properties can be recognized. In the Hardegsen (formation with the highest permeability), the front has advanced the most. Also in this formation the effect of gravity segregation is visible. Since this model is still radially symmetric, a cross section over depth provides a complete overview of the results. After 5 years the thermal front has advanced furthest in the Hardegsen (between 100 and 120 m). For the 2D results, the thermal front had advanced much further (~200m, see Figure 8). The difference is that in this case the injection is distributed better over the Hardegsen and the Detfurth. Also the pressure is much lower (~160 bar after 5 years compared to ~360 bar after 5 years for the 2D results (Figure 8, lower right corner).

The simulated pressure and temperature were used to calculate the changes in stresses as a result of the CO_2 injection. For the real depth of the reservoir (3190 m) no fractures developed. In Figure 14, after 1 year of injection all the stresses are negative, which means that both the reservoir and the caprock stay in a compressive state of stress.

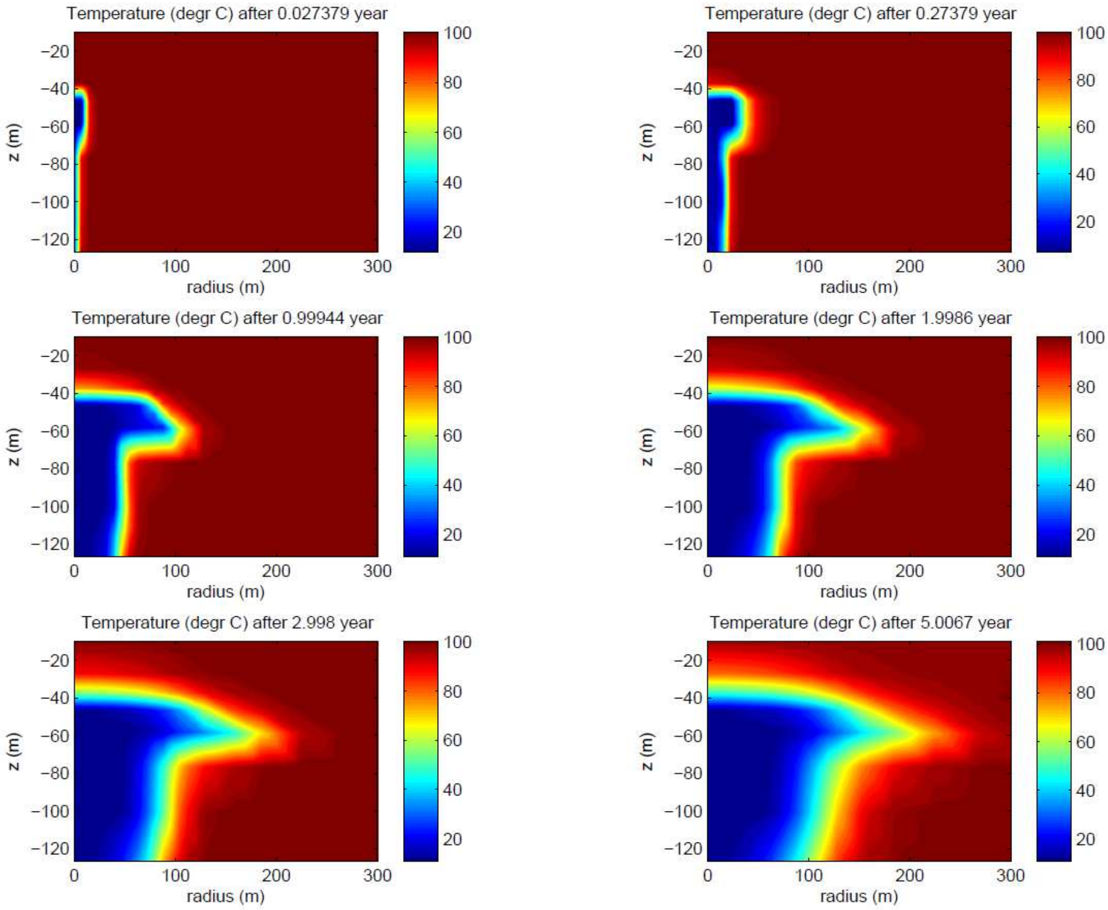

Figure 12. Development of the temperature front over 5 years.

To be able to show the ability to simulate the development of a crack inside the caprock and to compensate for the underestimation of the thermal stresses due to the reservoir temperature of 100°C instead of 120°C, a test case was created. In this new geomechanical model, the reservoir is placed 1314 m deep, and it has the same length (878 m) and the same material properties of the deeper located P18-4 case. The rest of the volume, under-, side- and over-burden have the material properties of the caprock of the P18-4 case.

The reservoir was placed even on a more shallow depth compared to the 2D simulations. The reason is that not only horizontal propagation of the fracture was considered, but also to allow vertical fracture propagation of the fracture into the caprock. The stresses due to the cold injection have to overcome not only the horizontal minimum stress, but also the vertical stress in order to propagate into vertical direction.

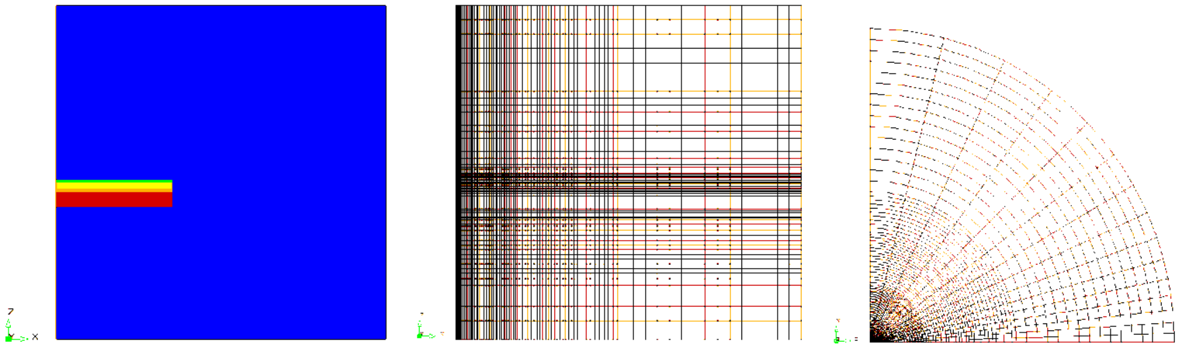

Figure 13. From left to right: view of the stratigraphic units, side and top view of the mesh of the test case.

In the test case, a fracture develops in the cooled part of the reservoir (Figure 14) in line with the results for the 2D model. Also in the caprock a fracture penetrates although the temperature did not drop below 75°C, probably because the caprock is more brittle. The extent in vertical direction was around 5 m into the caprock after one year of injection.

Figure 14. The shallow P18-4 reservoir, from left to right: state of stress (MPa) at the beginning of the injection (depleted reservoir) and after 1 year of injection with a zoom of reservoir and caprock around the well.

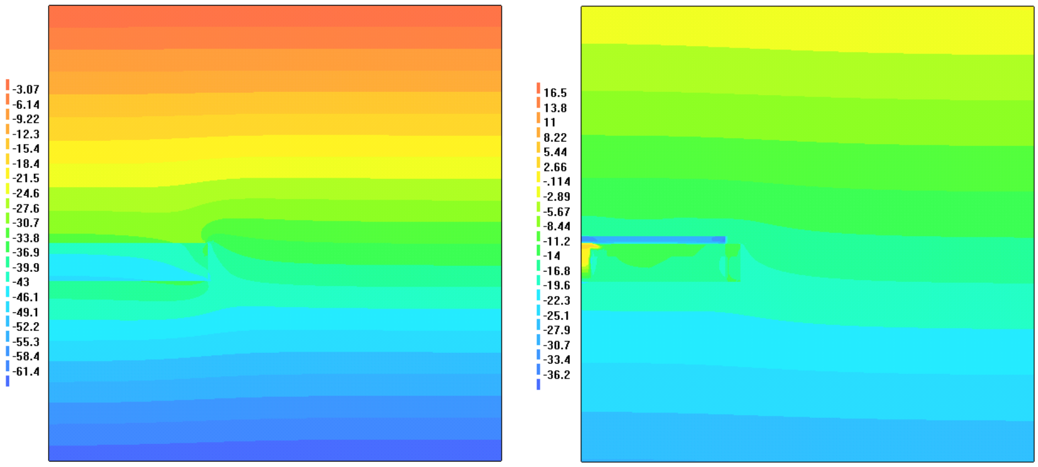

Figure 15. Test case, from left to right: state of stress (MPa) at the beginning of the injection (depleted reservoir) and after 1 year of injection.

Figure 16. Test case: the yellow and orange surface show the area of the thermal crack in the reservoir and caprock (positive stresses in Figure 15 (right)).

As for the 2D model, the effect of the fracture on the flow was examined by restarting with a fracture in place after 1 year. The fracture extent was implemented in the TOUGH2 model with the dimensions as shown in Figure 17. In the caprock, the fracture was only implemented in the bottom layer, which has a thickness of 6.67 m. Fracture permeability and extent were assumed to be 10^{-10} m^2 and 30 m respectively. The properties of the fracture in Hardegsen and Detfurth were calculated in the same way as for the 2D model and were again multiplied by 10 to increase simulation stability.

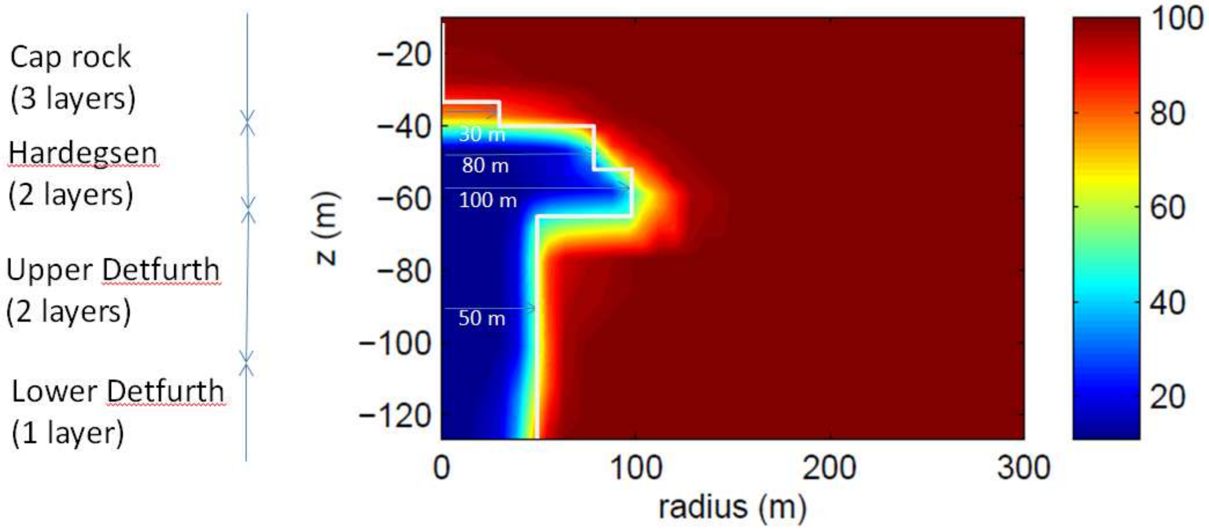

Figure 17. Temperature (°C) after 1 year and the extent of the fracture that is implemented in the reservoir model.

After implementation of the fracture, pressure dropped very fast in the caprock close to the fracture, which was initially at hydrostatic (virgin) pressure. As a result, salt precipitation occurs in the top part of the fracture in the Hardegsen close to the well. In fact, after 5 days, the first 40 cm of the fracture are almost blocked by salt. After about 100 days, this zone has extended to ~1.5 m. The temperature change is much slower than the pressure change (Figure 18). Initially, in most areas the flow is from the caprock to the Hardegsen (which is mostly still overpressured compared to the depleted gas field), resulting in rather low temperature change in the caprock. In the area with the fastest change in temperature (near the well), the flow is from the Hardegsen into the caprock. Later in time the flow becomes increasingly complex and difficult to understand. Figure 19 shows that the temperature development in the fracture over the entire 5-year period. After about 520 days, a sharp drop in temperature is observed in the fracture. The sharp decrease occurs at the moment that the critical pressure (73.9 bar) is exceeded. However, since the CO_2 is at supercritical conditions with a temperature of ~70°C, this hardly affects the properties of CO_2. The most likely explanation is that the cooling is the result of evaporation of water, since the saturation of the aqueous phase decreases with a decrease in temperature. The solubility of water in CO_2 reaches a minimum around this point [8].

Sensitivity to fracture permeability

From a sensitivity analysis, it was found that the results are quite sensitive to the chosen parameter settings like permeability, brine salinity and the reduction of permeability due to salt precipitation. A very uncertain parameter is the fracture permeability. Decreasing the fracture permeability from 10^{-7}, 10^{-8} and 10^{-10} m^2 to 10^{-9}, 10^{-10} and 10^{-11} m^2 respectively, completely changed the temperature solution. The amount of salt deposition in the fracture in Hardegsen decreased and circulation into the caprock fracture increased. Temperatures dropped much faster in the caprock in this case (Figure 20).

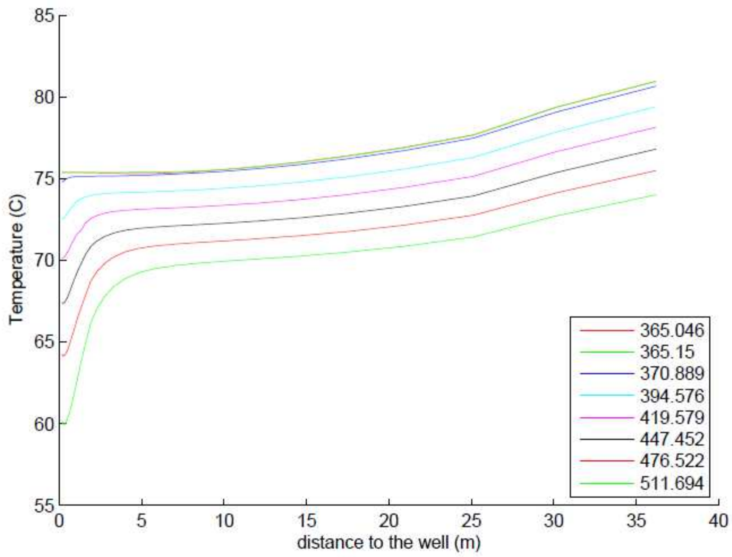

Figure 18. Initial temperature development in the fracture in the caprock. One line per time step (legend shows the time in days).

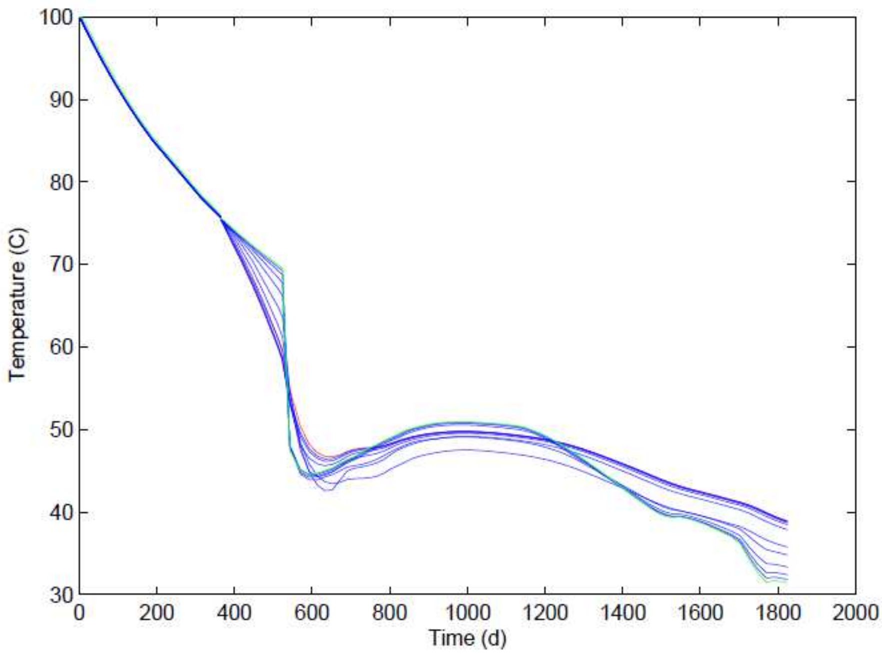

Figure 19. Temperature development over time in the fracture. Every line represents one grid block. The red line is the grid block closest to the well and the green line is the grid block at the end of the fracture.

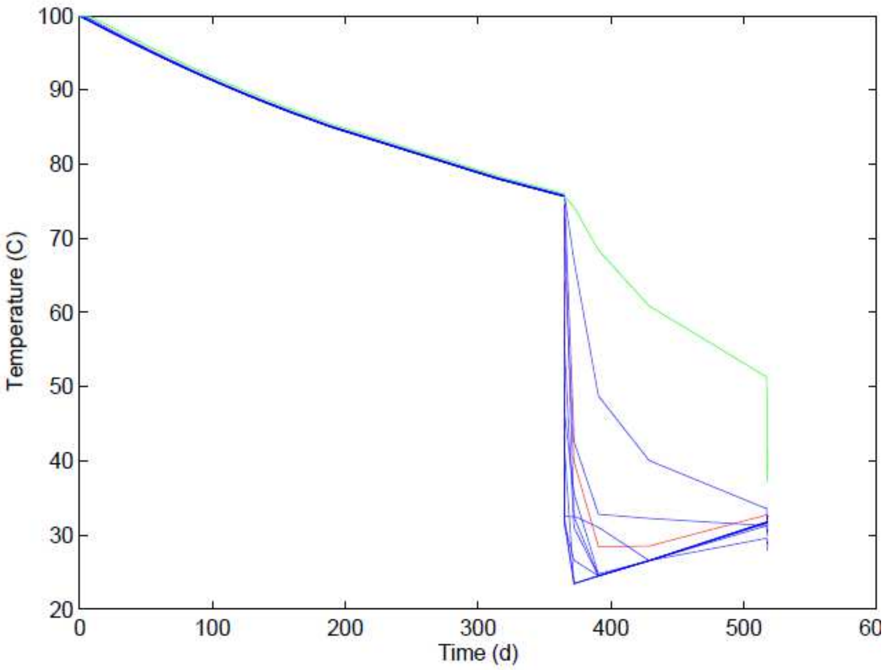

Figure 20. Temperature development over time in the fracture. Every line represents one grid block. The red line is the grid block closest to the well and the green line is the grid block at the end of the fracture for the case with decreased fracture permeability.

5. Conclusions

From both the 2D and 3D simulations, it was clear that for the actual P18-4 reservoir, no fracturing as a result of the cold CO_2 is expected, which is in line with the earlier results [3].

In the shallower test cases which were modelled in order to allow fracturing to occur, the injection of cold CO_2 indeed induced the development of thermal fractures in the reservoir and/or caprock. The main changes due to the thermal fractures are:

- Well injectivity increases.
- The shape of the CO_2 front changes, which means that the cold CO_2 can extent much further away from the well than without fracturing.
- The probability of the development of fractures in both the reservoir and the caprock increases.
- CO_2 flow becomes patterns complicated due to salt precipitation and blocking in the reservoir and or caprock
- The result is very sensitive for the values of the following properties: permeability in the fracture, brine salinity and the reduction of permeability due to salt precipitation

6. References

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