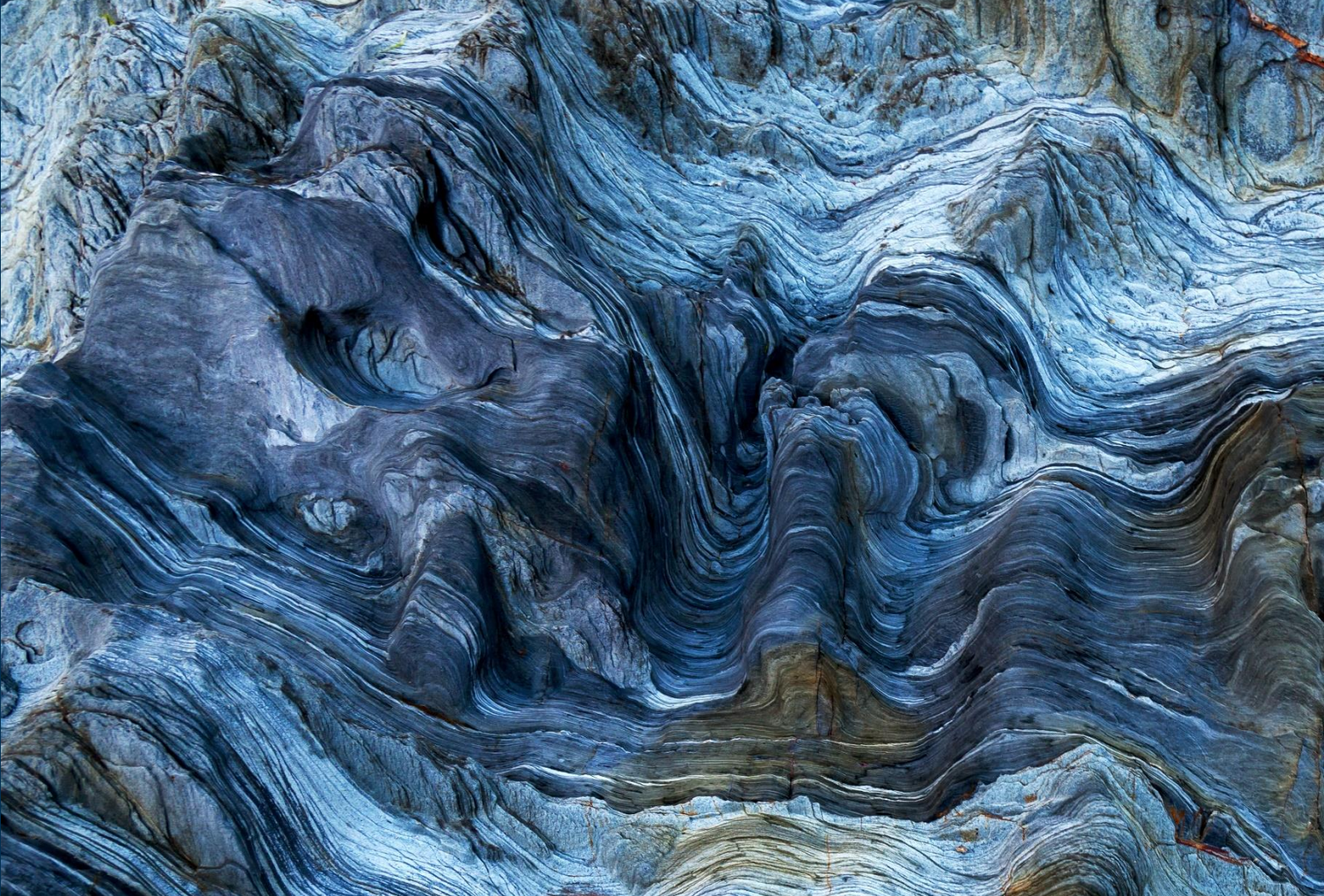




Potential hazards related to the use of multiple reservoirs in geothermal operations

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SUMMARY

Background and scope

State Supervision of Mines (SSM, “Staatstoezicht op de Mijnen”), a department under the Ministry of Climate Policy and Green Growth in the Netherlands, is exploring the potential safety and technical challenges associated with commingled production during geothermal operations: *i.e.* the geothermal exploitation scheme of simultaneous use of multiple, hydraulically isolated reservoirs.

Commingled production is a subsurface resource extraction process where different reservoirs that are isolated hydraulically are exploited simultaneously through a single tubing string. This exploitation scheme is common practice in hydrocarbon reservoirs to accelerate production and access marginal reservoirs which may be sub-commercial if targeted individually. This approach provides several advantages to operators, such as optimizing resource production and lowering costs by using the well infrastructure more efficiently and reducing the number of wells. Commingled production is also employed in the geothermal industry, where hot brines can be produced from and, subsequently, reinjected into multiple reservoirs using a single doublet (*i.e.*, a well-pair consisting of one producer and one injector). These reservoirs are vertically separated by low-permeability layers resulting in no or negligible hydraulic reservoir communication. This is different to a “stacked reservoir”, where production is taking place from different reservoir flow zones as a result of intra-reservoir heterogeneity.

Commingled production in geothermal systems remains relatively underexplored, and insights drawn from analogue hydrocarbon systems are limited due to key distinctions such as much higher flow rates commonly applied in geothermal systems (up to 300 m³/h or more), and the production of hot brine combined with reinjection at significantly lower temperature (typically 30–40°C). Consequently, the impacts of geothermal operations employing a commingled scheme are largely unexplored.

The research questions to be answered in this project are:

1. In the context of geothermal systems typical for the Netherlands, what is the effect of reservoir, well, and fluid properties on fluid circulation and pressures in geothermal systems with production from multiple reservoirs? Particular attention should be paid to the conditions under which unbalanced flow may originate.
2. What are the possible effects of unbalanced fluid circulation per reservoir and what are the associated hazards?
3. What are potential mitigation measures of the effects of unbalanced flow, such as potential pressure gradients?

Methodology

In this study, a reservoir model is constructed following a base case scenario involving two reservoirs of 50 m thickness each, separated by an impermeable 200 m thick layer. The subsurface and reservoir properties chosen are not taken from a particular location or site, they are, however, in line with a typical Dutch geothermal setting corresponding to siliciclastic sedimentary aquifers at a depth of 1500 to 2500 m. Dynamic simulations of the base case scenario are carried out to arrive at a reference temperature and pressure impact around the wells due to geothermal production and injection.

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In addition to the pressure and temperature field, the mass and volumetric flow rate are tracked for each well and reservoir. One of the outcomes is that any case of commingled production from two separate reservoirs will show an initial period of flow imbalance because of differences in permeability in the two reservoirs.

Impact of extreme parameter values

To assess the impact of reservoir, well, and fluid properties on flow, temperature, and pressure in the different reservoirs, alternative scenarios are defined where specific properties are changed. This allows analyzing the impact of extreme parameter values. The following aspects are studied:

- Permeability variations in one of the reservoirs.
- Thickness variations in one of the reservoirs (including cases where one reservoir is absent in one of the wells).
- Compositional differences of the water present in the reservoirs, leading to differences in density and viscosity.
- Different temperature gradients and hence temperature differences between the reservoirs.
- Difference in well completion, such as a reduction in wellbore diameter in the lower reservoir and/or the presence of a horizontal well section.
- Positive or negative skin in one or both reservoir(s) in one or both well(s).
- Geochemical interaction between the brines from both reservoirs because of differences in chemical composition.

The main conclusions from the above evaluations are the following:

- Reductions in permeability or thickness of the bottom reservoir result in longer periods of flow imbalance (the time required for equalization of injection and production flow rate toward/from each individual reservoir), increasing in length as reductions in permeability or thickness become stronger.
- In case of lateral reductions in thickness of a reservoir, production and injection will result in larger pressure changes in the reservoir compared to the Base Case as reservoir thickness is reduced around one of the wells, with a risk of over- or underpressurization increasing as a reservoir pinches out completely.
- In case a reservoir pinches out laterally (and is therefore absent in one of the wells) it may no longer contribute to flow when pressure in this laterally discontinuous reservoir approaches downhole well pressure and there is no longer sufficient dP in the well to force flow into/out of the reservoir.
- Reducing the wellbore diameter increases the required pressure change in the well for injection or production but has limited impact on the reservoir pressure in that layer. Flow in that reservoir is reduced slightly.
- Horizontal well completions reduce the peak pressure change near the well, but increase the pressure change further away as flow in that reservoir rises.
- Non-zero skin in a well results in differences in pressure and pressure changes (versus the initial state) different from the Base Case in that well. Reservoir pressure effects are limited in case of uniform skin, but are greater in case of non-uniform skin as flow

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is redistributed through the different reservoirs. The cases combining negative skin and with high positive skin in the same well also result in a long duration of flow imbalance.

- Differences in the composition or temperature of the brine result in viscosity and density differences leading to changes in pressure, but their impact is small compared to differences caused by permeability or thickness variation.
- The impact of mixing brines of different composition (and therefore viscosity and density) is generally small.
- The overall scaling tendency does not change when mixing brine from the Delft and/or Berkel Sandstone members with brine from the Main Buntsandstein Subgroup, or when mixing brines from the Main Buntsandstein Subgroup and Rotliegend Group.

Comparing the effect of variations of different parameters, the strongest impact is caused by the presence of a laterally discontinuous reservoir (which is absent in one of the wells). In such a case, dP in the well (pressure increase or decrease due to injection or production) can be up to 55-60 bar different from in the Base Case. Further away in the reservoir, the difference compared to the Base Case may still amount to 20 to 60 bar. For cases with uniform skin in the well (skin 30), the dP may be even 70-100 bar higher than the Base Case, but the effect in the reservoir is negligible (< 1 bar). Temperature variations and a reduced diameter in the lower reservoir well section result in minimal pressure impact in the well as compared to the Base Case (dP up to 5 bar different). That impact decreases to 1-2 bar in the reservoir.

In terms of flow imbalance, no equilibrium is reached in case the brine has different composition (and therefore density and viscosity) in top and bottom reservoir. In case of a laterally discontinuous reservoir, the duration of imbalance may last up to 15 years (with an initial difference of 3000-4000 ton/day). The same duration occurs in case of non-uniform skin in the well (combining negative and strong positive skin). For comparison, flow imbalance in the Base Case remains for less than 5 years (starting at 100-200 ton/day).

Specific case model

In addition to these generic models, a specific model is set up representing a real project site in the Netherlands, with its subsurface and reservoir characteristics and the real conditions found in a geothermal system that is currently producing from two reservoirs using a single doublet. The geothermal sites in the Netherlands that currently produce in commingled are situated in the West Netherlands Basin. They extract heat from the Lower Cretaceous Berkel Sandstone Member and/or Rijswijk Sandstone Member (top reservoir), and the Delft Sandstone Member and/or Alblasserdam Member (bottom reservoir). The chosen geothermal site for the specific geological case is located in Zuid-Holland where commingled production has been ongoing since 2018. Its doublet system targets the Berkel Sandstone and Delft Sandstone Members, which are hydraulically separated by the Rodenrijs Claystone Member.

The objectives of the specific model are to simulate a more realistic scenario and determine under which conditions commingled production effects and their associated hazards may arise, and to determine whether real heterogeneous and generic cases are comparable or if the former adds additional considerations to keep in mind.

The main learning from the specific case model is that realistic permeability distributions can serve to form a connection between two reservoirs. If that connection is strong enough, the two reservoirs essentially behave as one reservoir (as seen in PERM1 and PERM2). The main findings of the specific case simulations can be summarized as follows:

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- The results reveal the effect of nearby faults, where faults can act as barriers or conduits, depending on the fault permeability assumptions.
- In case reservoirs are connected hydraulically (i.e., conductive faults are defined in the model), flow injected into (or produced from) each reservoir is determined by local reservoir permeability values (near the well) and injection and production flow rates for specific reservoirs may not equalize before simulation end time (30 years).
- In the case where reservoirs are disconnected (separated by a hydraulic barrier and/or non-permeable faults are defined), there is an initial imbalance between production and injection flow rates that tends to equilibrate in time, but that equilibration in flow can lead to over/underpressure in disconnected reservoirs compared to the Base Case.

Assessment of possible effects

The operational window represents the range of pressure, temperature, and flow conditions of a geothermal system that is generally considered to be safe to operate within. During operations, reservoir pressure can generally be considered the primary parameter that defines the operational window, while flow rate, temperature, and injection pressure are the key factors that drive these pressure changes. Hence, in practice, pressure serves as the main constraint for the operating window. In reality, common geothermal systems that target matrix-permeable sandstone reservoirs in the Netherlands typically operate within the *effective operational window*, which is constrained by the maximum permitted injection pressure (upper operational limit) and the maximum drawdown of the ESP (lower operational limit).

Conditions in the near-wellbore region determine the potential occurrence of events leading to geohazards near the well. In turn, these conditions are strongly governed by the effective operational window. Hence, operating within the effective operational window limits the occurrence of these events and prevents these geohazards from happening. This is, for example, the case for seal integrity breach or thermal fracturing. Therefore, these hazards are not further assessed in this study.

However, as variations of geological properties lead to different pressure, temperature, and flow conditions in the two reservoirs, and may result in unbalanced flow, even when operating within the *effective operational window*, there are events that could occur due to unbalanced flow in commingled geothermal systems that could increase the likelihood of triggering geohazards: (i) *faster-than-expected cold front propagation* (relative to the propagation assumed in the permit), or (ii) *accelerated reservoir depletion* in one of the reservoirs. These events could increase the likelihood of *fault reactivation* or *subsidence*, respectively.

Two approaches are applied to assess the likelihood of fault reactivation. The first is an analytical approach to determine direct pore pressure and thermal stress effects, based on results of simulations with the generic models introduced in Chapter 4, at the end of the 30-year simulation times. These results indicate that shear failure is possible for critically oriented faults near the injection well even in the Base Case scenario. However, the stress drops quickly away from the wellbore and failures are not expected at more than about 200 m away from the well, in this scenario. This enforces the idea of injecting away from known critically oriented faults. The exact conditions that can lead to an increased likelihood of potential shear fault reactivation are situation dependent, but a few conclusions can be drawn from this analysis for commingled production scenarios:

- Laterally discontinuous reservoirs with no hydraulic connection to larger reservoirs or the production well, present the relative highest likelihood of potential shear fault reactivation (even at large distance from the injection well).
- Conditions that lead to over-injecting into a reservoir can result in overpressurization of that reservoir and an increased likelihood of potential shear fault reactivation (*i.e.*, large negative skin with a relatively low permeability or long horizontal drilling in very low permeability reservoirs).
- Cooling effects can be significant. As such, in elevated risk situations, it is important to have a good hand on material parameters that can affect the thermal stress (*i.e.*, Young's Modulus, Poisson's ratio, coefficient of thermal expansion).

A second approach involves a thermo-hydro-mechanical reservoir simulation using the open-source simulator DARTS in a semi-analytical nucleus of strain approach. The approach allows for an inclusion of elastic stress transfer through Poisson effects and poro/thermo-elasticity to go beyond the direct effects of the first analysis. This approach is applied to the Base Case and to the case with a laterally discontinuous bottom reservoir where this reservoir is absent in the production well (Bot Pro).

Neither of the THM models tested here predict shear failure. This does not necessarily mean that the situation is always safe from induced shear failure. However, this model can help to understand some of the fundamental physics in play and to understand the areas to improve in future models. The results of the THM analysis help to highlight the stabilizing effects of hydrostatic stress changes (pressure or temperature related) in a homogeneous half-space. The vertical component of the stress tensor sees larger magnitude changes whereas changes in the horizontal direction are smaller (due to the presence of a free surface at $z=0$ and the Poisson effect that redistributes stress anisotropically). This is true even in thermal stress analysis. The nucleus of strain approach is well documented and accurate; however, the simplifications of such a mesh-free method do average out many details and may underestimate differential stresses that could be critical to induced shear failure.

The combination of the two analyses indicates that the uniaxial direct pore pressure assumption is more conservative and predicts more shear failures at a given production-related temperature and pressure change scenario. That is largely due to the assumption that the vertical component of the thermal stress is unchanged (free deformation vertically). The THM nucleus of strain approach allows for stress transfer effects and shows that some vertical stress change is possible, even thermal stress.

A semi-analytical procedure is used for the subsidence/uplift analysis. The results of simulations with the generic models from Chapter 4 are taken as input into the surface displacement calculations by the nucleus of strain concept to estimate potential elastic deformations at the surface. A few conclusions from this analysis are:

- The cases of extreme flow redistribution lead to the relative highest values of subsidence and uplift, due to larger magnitude of pressure change in the reservoirs.
- The estimated magnitudes of the surface displacements are in the order of cm in the worst case scenarios.
- Material properties of both the reservoir and immediately overlying rocks should be investigated in cases where the potential for subsidence and its impact are high.

The effects of commingled production on well integrity are not very different from single-reservoir systems. The main issues on well integrity for operational geothermal systems are related to corrosion, burst and collapse, and erosion. No new corrosion drivers due to commingling of different aquifer fluids are identified. For burst and collapse well integrity envelopes, the load cases for commingled reservoirs are not different from the load cases of a single reservoir. However, it might be possible that there are flow capacity limits for a multiple reservoir production system versus a single reservoir production system and this needs to be considered by the production and well engineering as part of the detailed well design.

Based on operational experience, no direct impact of commingled production is expected on well integrity. Provided that well design, material selection, and load-case assessments are properly engineered for the operating conditions, commingled operations are not expected to introduce additional hazards compared to single-reservoir systems.

The results obtained within this study and the insights derived from them are combined with the regulatory limits and in-house operational knowledge to assess the operational window of commingled geothermal systems. If the reservoir pressure at a given depth falls outside the effective range defined by the lower and upper bounds, the likelihood of some geohazards may be increased.

The lower operational limit defines the threshold below which further pressure depletion may cause the reservoir to underperform (*i.e.*, requiring larger drawdowns to sustain production) and may increase the likelihood of triggering geomechanical hazards such as surface subsidence and fault reactivation.

Although simplified, the results strongly suggest that, at the conditions applied in the models in this study, after 30 years subsidence is limited to maximum 3 cm in scenarios within the effective operational window and < 8 cm for more extreme cases where one of the reservoirs is laterally discontinuous. While it is difficult to define an exact lower pressure boundary for safe operations based solely on this study, the findings indicate that typical pressure drops expected during geothermal operation (limited by the maximum drawdown for the ESP and usually not above 60 bar) are unlikely to pose significant geomechanical changes that can lead to significant geohazard potential increase. It should be noted that the study does not assess the occurrence of depletion-related fault reactivation.

The upper boundary of the operational window defines the pressure threshold beyond which further pressure increase may increase the likelihood of inducing fault reactivation or compromising the seal integrity of the reservoir system. In terms of pressure, the upper operational limit is strongly governed by the maximum allowable injection pressure in the geothermal permit (the *effective* upper operational limit).

The simulations reveal that discontinuous reservoirs with limited hydraulic connectivity on the production side represent the highest likelihood to increase shear reactivation potential. Unbalanced flow between reservoirs can further increase this potential by causing over-injection into one aquifer, leading to faster-than-expected cold front propagation and localized overpressurization. This condition may occur when there are strong contrasts in permeability or skin between the two reservoirs.

Thermal effects also play a role in the upper operational limit. Cooling of the formation induces thermoelastic contraction, which can modify the local stress field around the injector, increasing the likelihood of shear failure. The magnitude of this effect depends on the thermal and elastic properties of the rock and the difference between the formation and injection

temperature. The temperature difference in the simulations amounted up to 50°C which, for the material parameters used, was enough to induce cooling-related shear failure in critically oriented fractures near the well. Cooling effects may be more pronounced when horizontal completions are used, as they typically deliver a higher volume of colder fluid to the formation over a larger contact area.

Mitigation

In cases where strong reservoir heterogeneities are present within one or both reservoirs, and significant pressure contrasts are anticipated within each reservoir (e.g., due to limited hydraulic connectivity), additional completion controls could be employed to manage flow distribution and maintain well integrity. The choice of completion strategy should be guided by location-specific reservoir characterization and field data. Potential mitigation strategies (in the well design phase) include:

- Installation of swellable packers to restrict undesired crossflow through the annulus.
- Cemented casing sections at selected intervals (e.g., across impermeable layers) to achieve localized zonal isolation.

Following up on injectivity and productivity behavior after the well has been drilled and completed, operators should monitor injection temperature, flow rate, and brine composition. Continuous monitoring enables early detection of compatibility issues or performance decline, allowing for adaptive adjustments to the operational strategy.

The primary hazards, subsidence and fault reactivation (leading to induced seismicity) are related to accelerated reservoir depletion and faster-than-expected cold-front migration in one of the reservoirs. These events could occur even within the effective operational window. These hazards are further evaluated using bow-tie analyses to systematically assess their causes, consequences, and mitigation measures. The central event identified for fault reactivation and induced seismicity is relatively fast propagation of the cold front within one of the reservoirs, (i.e., faster-than-expected from reservoir simulations in the permit application). The central event considered for subsidence is accelerated reservoir depletion, which can occur when pressure decline progresses unevenly within the reservoir due to production and injection imbalance.

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LIST OF ACRONYMS AND SYMBOLS

Acronym	Explanation
AoI	Area of interest
BHP	Bottomhole pressure
DARTS	Delft University Advanced Research Terra Simulator
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
GR	Gamma Ray well log (reading)
MIC	Microbiological Induced Corrosion
mVRR	Mass voidage replacement ratio
NSSG	North Sea Super Group
SHRA	Seismic hazard and risk analysis
SI	Saturation index
SSM	State Supervision of Mines (SodM: Staatstoezicht op de Mijnen)
TAS	Tensile failure assessment of seal
THM	Thermo-Hydro-Mechanical
TLS	Traffic light system
TVD	True vertical depth
vVRR	Volume voidage replacement ratio
WellIndex / WI	Well productivity or injectivity index

Symbol	Explanation
C	Cohesion
C_f	Rock compressibility
C_{ijkl}	4 th order elasticity tensor
C_l	Liquid compressibility
C_m	Compaction coefficient
C_{rock}	Rock thermal conductivity
C_v	Coefficient equal to $3 - 4\nu$
CP_{matrix}	Heat capacity of the rock matrix
CP_{vol}	Volumetric heat capacity
d_x	Cellsize in x direction
d_y	Cellsize in y direction
e	Element or cell
E	Young's modulus
D	Depth of nucleus
dP	Delta pressure in the reservoirs
dT	Delta temperature in the reservoirs
g	Gravity
G_I	Geometric gradient contribution
GR_{sst}	Gamma ray log value for pure sandstone
GR_{shale}	Gamma ray log value for pure shale
h	Thickness
H_{cap}	Heat capacity
I	Cartesian coordinate direction
k_i	Permeability in direction 'i' for $i = x, y, z$
K_h	Horizontal permeability
M_w	Molecular weight

N	Number of grid cells
Perm _x	Permeability in x direction
Perm _y	Permeability in y direction
Perm _z	Permeability in z direction
P	Pressure
P_{ref}	Reference pressure
Pore	Effective Porosity
q	Volumetric flow rate
Q	Heat flow
r	Radial distance from the underground nucleus
r'	Distance to the nucleus of strain image above ground (-z)
r_e	Peaceman equivalent radius for vertical well
s	Skin
T	Temperature
u_I	Displacement vector in direction I
u_{zP}	Surface displacement (vertical) related to pressure
u_{zT}	Surface displacement (vertical) related to temperature
$v_{r,brine}$	Relative volume of brine
V	Volume of nucleus
V_e	Volume of the cell or element
V_{shale}	Volume or fraction of shale
$V_{shale\ corrected}$	Corrected volume or fraction of shale
z	Depth
z_e	Depth of element e
∇_I	Displacement gradient along I direction
∇_z	Displacement gradient along z direction

Greek symbol	Explanation
α	Linear coefficient of thermal expansion
β	Biot coefficient
δ_{ij}	Identity tensor
$\Delta\sigma_{ij}$	Change in Cauchy stress tensor
$\Delta\varepsilon_{kl}$	Change in strain tensor
$\Delta\varepsilon_{kl}^T$	Thermal component of change in strain tensor
$\Delta\sigma_x, \Delta\sigma_y$	Change in horizontal stress components
$\Delta\chi$	Change in primary variable (pressure or temperature)
ΔP	Change in pressure
ΔT	Change in temperature
ε_{kl}	Strain tensor
μ	Coefficient of friction
μ_{brine}	Brine viscosity
μ_{max}	Slope of the line from the intercept of the failure envelope to the maximum point on the shifted Mohr circle
μ_w	Pure water viscosity
ν	Poisson ratio
ρ_{brine}	Brine density
ρ_{RHOB}	Bulk density
ρ_{sst}	Sandstone density
σ_{ij}	Cauchy stress tensor
σ_H	Maximum horizontal stress

σ_h	Minimum horizontal stress
σ_N	Normal stress
σ_V	Vertical stress
τ	Shear stress
τ_f	Failure shear stress
Φ	Scalar displacement potential due to changes in pressure and temperature
Φ_{NPHI}	Neutron porosity
$\Phi_{NPHI,\rho}$	Average of neutron porosity and density porosity
Φ_ρ	Density porosity
χ_i	Molar fraction of component i

1 INTRODUCTION

1.1 Research issue

The State Supervision of Mines (SSM; Staatstoezicht op de Mijnen), a department under the Ministry of Climate Policy and Green Growth in the Netherlands, is exploring the potential safety and technical challenges associated with the simultaneous use of multiple reservoirs in geothermal operations under the commingled exploitation scheme. This practice involves producing hot brine from and re-injecting cold brine into multiple reservoirs using a single doublet (producer-injector pair), without any means for regulating the outflow or inflow of each reservoir. These reservoirs are vertically separated by low-permeability layers, resulting in limited or negligible hydraulic communication between them. This is different to a “stacked reservoir”, where production is taking place from different reservoir flow zones as a result of intra-reservoir heterogeneity.

In commingled reservoir systems, the individual injection and production rates in each reservoir are mainly governed by their respective petrophysical properties in the near well region, the dynamic pressure gradients between the well and the reservoir, and the well and fluid characteristics, and the boundary conditions, all of which are inherently non-homogeneous. In the context of geothermal systems typical for the Netherlands (low-enthalpy, matrix-permeable, clastic, sedimentary systems at depth of approximately 1500–3000 m), SSM seeks to better understand how these non-homogeneous conditions affect fluid flow and pressures within multiple reservoirs systems. Key areas of interest include whether the production and injection from/in the reservoirs are balanced or unbalanced, the potential hazards associated with such unbalanced conditions and the action itself of mixing different water compositions, and mitigation measures to ensure safe and efficient operation.

1.2 Research objectives

The main objective of this research project as proposed by SSM is: *“Determining the effects of reservoir, well and fluid properties on fluid flow and pressures in systems that use multiple reservoirs and the associated hazards and potential mitigation measures.”*

The research questions to be answered in this project are:

1. In the context of geothermal systems typical for the Netherlands, what is the effect of reservoir, well, and fluid properties on fluid circulation and pressures in geothermal systems with production from multiple reservoirs? Particular attention should be paid to the conditions under which unbalanced flow may originate.
2. What are the possible effects of unbalanced fluid circulation per reservoir and what are the associated hazards?
3. What are potential mitigation measures of the effects of unbalanced flow, such as potential pressure gradients?

1.3 Methods

In a geothermal system that produces from two or more reservoirs using a single doublet (commingled production), non-homogeneous reservoir properties and well characteristics may affect fluid flow, pressure, temperature, and stress distributions. In fact, it is expected that

certain reservoir heterogeneities (e.g., permeability and thickness variations) could lead to unbalanced flow that could translate into significant pressure changes in the reservoirs. Similarly, differences in brine characteristics (e.g., composition and temperature) between the reservoirs or well completion characteristics can affect the skin factor per reservoir, which also could lead to unbalanced flow that results in overpressurization (see Section 6.2.1) or depletion of the reservoirs. Here, pressure changes in the exploited reservoirs, caused by this unbalanced flow, can become a concern relative to potential hazards. Therefore, it is key to better understand the operational limits in terms of stress changes with depth for the case of two reservoirs under commingled production. However, it is important to realize that stress changes can be induced by both pressure changes as well as temperature changes in the subsurface.

Our approach aims to map the pressure-depth operating window (or more general stress/depth-dependent operational window) relative to potential geohazards, and to understand the sensitivities of non-homogeneous reservoir and well properties that may lead to unbalanced fluid circulation. Defining and understanding this operation window will provide clarity on risk prevention, mitigation strategies, and requirements for responsible geothermal exploitation from multiple reservoirs using a single, commingled doublet.

The project has been divided into several tasks:

- Literature overview and background research.
- Construction of reservoir and simulation models.
- Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production.
- Assessment of the possible effects of unbalanced fluid circulation
- Definition of mitigation and prevention measures for minimizing hazards

1.4 Content of the report

Initially, background information on exploiting multiple reservoirs has been gathered and a general description of the main geothermal reservoirs in the Netherlands is provided (Chapter 2). It is followed by the preparation of simple static reservoir models (generic models) and the definition of the dynamic conditions for the reservoir simulation models (Chapter 3). The objective of the generic reservoir models is to establish general relationships between reservoir-well properties and evolution of pressure, fluid rates, temperature in each independent reservoir. For instance, this allows to determine under which conditions unbalanced flow could be taking place. These models consider variations of: (i) permeability and reservoir thickness between the injector and producer within one reservoir; (ii) formation water salinity and temperature between the reservoirs; and (iii) well completion and varying skin factors. The dynamic models simulate a single doublet. Then, simulations are carried out using these models and the results are analyzed in terms of temporal variation of pressure and temperature in the reservoirs, fluid rate profiles of every reservoir along the wells trajectory, and computation of the voidage drainage ratio (injected to produced mass ratio) for each exploited reservoir. The objective is to determine under which reservoir-well conditions unbalanced flow and excessive changes of pressure or temperature could take place. In addition, the mixing of different geothermal brines is studied from a geochemical point of view. The results of these simulations are presented in Chapter 4.

Additionally, a specific, heterogeneous, geologic model is constructed ("specific model") based on the real conditions found in a geothermal system that is currently producing from two reservoirs using a single doublet in the Netherlands. To date, the geothermal systems (low-enthalpy matrix-permeable sedimentary reservoirs) in the Netherlands that produce from

two reservoirs involve the *Berkel Sandstone* and/or *Rijswijk Sandstone* members (upper reservoir), and *Delft Sandstone* and/or *Alblasserdam* members (lower reservoir) in the Upper Jurassic to Lower Cretaceous play in the West-Netherlands Basin. The model is set up as realistically as possible based upon publicly available data. The purpose is to determine how applicable the general models of Chapter 4 are to a more realistic scenario and to see if any additional considerations should be kept in mind when producing reservoirs in a commingled strategy. The setup of the model and the simulation results for the specific case are presented in Chapter 5.

Chapter 6 presents the analysis of the possible effects of unbalanced fluid circulation triggered by commingled production from two geothermal reservoirs. This is done based on the results obtained in Chapter 4 in terms of pressure, temperature, and fluid rate distribution between the reservoirs. The chapter begins with an introduction and definition of the operational window, presenting the main events that increase the likelihood of geohazards while staying within the operational window. This forms the basis for defining which hazards will be assessed (and why certain hazards are not addressed in this study). Hazards that are addressed include subsidence/uplift, nearby fault reactivation – induced seismicity, and impairment of well productivity and injectivity. Chapter 6 concludes with looking back at the operational window, summarizing the assessments made.

Finally, mitigation and prevention measures to avoid or minimize undesirable effects are drafted and bow-tie analyses are done for the two main events (Chapter 7). It is important to mention that the steps to be followed in this research are intended to serve as a methodology for the operators when assessing their development plans for the use of multiple reservoirs.

2 BACKGROUND ON COMMINGLED PRODUCTION

Commingled production is a subsurface resource extraction process where two or more reservoirs are exploited simultaneously through a single tubing string (Figure 2-1). This approach allows operators to tap into different, vertically overlying geological layers, optimizing resource production by extracting simultaneously from various geological formations and helping maintain reservoir pressure as the depletion rates from each individual reservoir are usually lower than in segregated production. In this context, operators can accelerate cumulative production rates and extend the economic life of wells by reducing the overall pressure drawdown required at the wellbore (e.g., Al-Shehri et al., 2005). This can also enhance recovery factors by delaying the abandonment of individual reservoirs and allowing them to produce at lower pressures (Ferrer, 1998). Furthermore, a more efficient use of the well infrastructure and a reduction in the number of wells to be drilled lead to lower upfront costs and easier well maintenance (Jongkittinarukorn et al., 2021 and references therein).

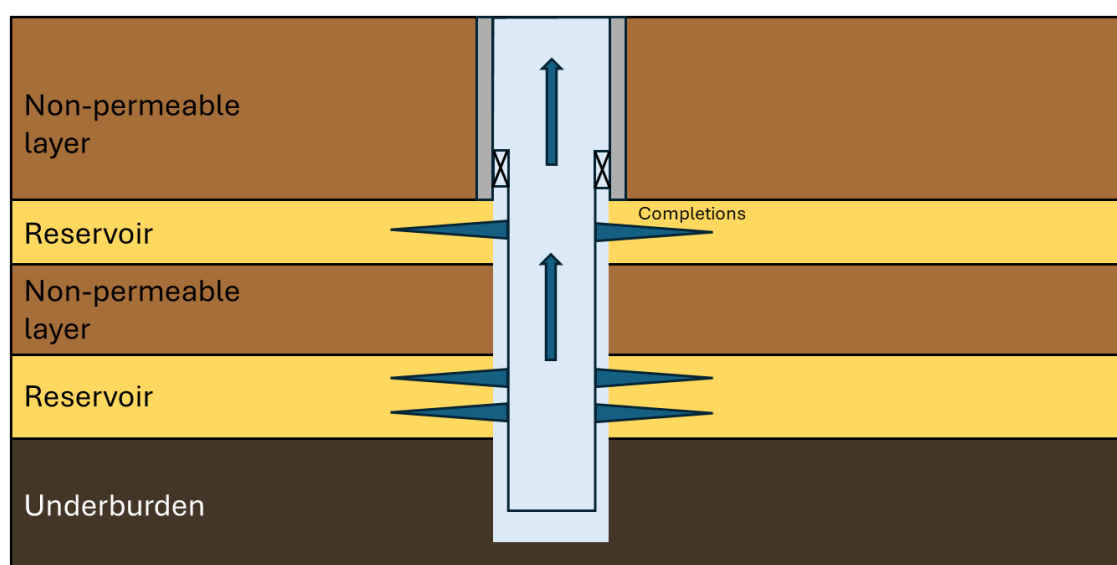


Figure 2-1: Example of a commingled production, with simultaneous production occurring from two vertically overlying reservoirs separated by a non-permeable layer.

However, commingled production also presents several challenges. The exploited reservoirs can have different physical properties, which in turn affect the production output at the wellhead, depletion rates, and the production allocation of the system. Crossflow can occur if the reservoirs are in hydraulic communication, while this is not the case in settings where the reservoirs are hydraulically separated by flow barriers such as impermeable shale layers (Civan & Triana, 2013). In hydrocarbon reservoirs, differential depletion can lead to premature water breakthroughs in high-permeability zones, while in geothermal systems, unbalanced flows during injection and production may result in inefficient heat extraction and potential stress buildups.

Accurate reservoir management becomes more complex due to the difficulty in isolating individual contributions from each reservoir, making well-test analysis and performance evaluation more challenging. Monitoring downhole pressures is often employed to ensure the safety and efficiency of operations. However, downhole monitoring usually involves deploying costly pressure gauges with real-time pressure and flow rate measurements (Jongkittinarukorn et al., 2021). To mitigate these, numerical models are often employed upfront to rapidly and economically assess the contributions of each zone to production and the sensitivity of different reservoir properties (Civan & Triana, 2013).

While commingled production has been widely applied and extensively studied in hydrocarbon reservoirs, its use in geothermal systems remains relatively less documented. The lack of available research creates a gap in understanding how commingled strategies can be effectively implemented in geothermal operations. In this context, hydrocarbon literature provides a valuable foundation because of the strong parallels between the two domains. Both hydrocarbon and geothermal sedimentary reservoirs are governed by similar geological settings, including stratigraphic heterogeneity, reservoir connectivity, and complex permeability distributions. Furthermore, the engineering aspects of well design, completion, and flow management also share many similarities. Consequently, modeling approaches, reservoir management strategies, and production optimization methods developed in hydrocarbon studies can serve as a critical starting point for addressing challenges in geothermal commingled production. Therefore, in this study, we build on insights from hydrocarbon systems to introduce the concept of commingled geothermal production and highlight the associated engineering and reservoir challenges.

2.1 Commingled production from hydrocarbon reservoirs

Commingled production is a common practice in hydrocarbon reservoirs to accelerate production and access marginal reservoirs which may be sub-commercial if targeted individually. Commingled production is deployed in regions where reservoirs are overlying vertically and can be easily targeted with a singular string. In the Western Canadian Sedimentary Basin, up to eight potential reservoirs have been targeted for completion (Dixon & Flint, 2010). While single-pool production was the standard practice in Western Canada prior to 2003, commingled production has become increasingly common since then. In response, a series of regulatory measures were introduced by the government to promote safe operations, resource conservation, and the orderly development of hydrocarbon resources (AER, 2005). These regulations require operators to submit an application for commingled production in high-risk scenarios, such as when hydrocarbon pools exhibit significantly different pressures or fluid compositions, and to provide supporting data such as pressure and deliverability tests. This led to a substantial increase in commingled production, with the number of installed multiplay systems rising sharply from about 50 to approximately 350 over a six-year period.

A series of studies have been published to assess the impact of different reservoir properties on commingled production (Yildiz, 2002; Civan & Triana, 2013; Jongkittinarukorn et al., 2021). Yildiz (2002) assesses the long term-effects of multilaterals in commingled productions and indicates that during early production, reservoir size does not have an impact on the flow, while productivity and initial pressure control flow from the different reservoirs. The reservoirs with lower permeability tend to produce less, thus being depleted more slowly. If such a permeability contrast exists, this induces differential depletion rates between the different reservoirs and complex pressure behaviors. During late production, reservoir size is instead important as smaller, more permeable reservoirs typically deplete faster than larger, tighter reservoirs, which results in varying pressure levels over time. The flow contributions from individual reservoirs are not immediate but are transient and time-dependent. Park (1989) shows how higher-permeability zones tend to dominate early-time flow in stratified reservoirs where multiple reservoirs have contrasting permeability and pressure characteristics, while lower-permeability or gas-bearing reservoirs may only begin to contribute as the system evolves and pressure gradients stabilize.

As production continues, less permeable reservoirs may still dominate due to their larger hydrocarbon pore volume and slower depletion. During shut-in periods, fluid will flow from higher-pressure reservoirs to lower-pressure reservoirs via the wellbore, but this process can be slow, especially when there is a significant permeability contrast between reservoirs (Kuppe et al., 2000). As a result, the wellbore pressure during shut-in usually follows the pressure of

the most productive reservoir. These dynamics are essential for understanding and optimizing commingled well performance and for formulating effective production strategies.

When two reservoirs are commingled without appropriate control, a series of production issues can arise that can affect operations. For example, one zone may crossflow into another. Ultimately, gas or water breakthrough in one zone may affect the production from the other zone (Al-Sheri et al., 2005).

2.2 Commingled production/injection in geothermal reservoirs

Commingled production is a process that is also employed in the geothermal industry. Specifically, when extracting heat from hot sedimentary aquifers. This practice involves producing hot brines from and, subsequently, reinjecting the now cooled brine into multiple reservoirs using a single doublet (*i.e.*, a well-pair consisting of one producer and one injector). These reservoirs are vertically separated by low-permeability layers resulting in no or negligible hydraulic reservoir communication (Figure 2-2).

Although many studies have investigated production from single hot sedimentary aquifers both in the Netherlands and internationally, commingled production in such geothermal systems remains relatively unexplored. Insights can be drawn from analogue hydrocarbon systems, as the two share many similarities in terms of reservoir geology, flow dynamics, and well engineering. However, several important differences distinguish geothermal from hydrocarbon production, which may lead to operational scenarios not typically encountered in the hydrocarbon sector. One key distinction lies in the much higher flow rates commonly applied in geothermal systems, which is typically around 280–300 m³/h for Dutch geothermal projects, but can be higher in cases of higher than average permeability. These elevated rates may intensify crossflow between reservoirs or accelerate pressure redistribution across formations with contrasting properties. In addition, geothermal operations inherently involve the production of hot brines (often exceeding 60°C) that are subsequently re-injected at significantly lower temperatures (typically 30–40°C). This thermal contrast can induce temperature-related pressure and stress redistribution. Understanding these and other dynamics is crucial in assessing potential hazards and developing reservoir management strategies tailored to geothermal conditions.

In the Netherlands, geothermal commingled production is occurring in three geothermal systems operating in Zuid-Holland that target the Lower Cretaceous/Upper Jurassic geothermal play (see Section 2.3). These three doublet systems simultaneously exploit the Berkel Sandstone and/or Rijswijk Sandstone Members aquifer (upper reservoir), and Delft Sandstone Member and/or Alblasterdam Member aquifer (lower reservoir) at depths between 1500 and 2500 m TVD. Each of the two aquifers have a gross thickness of approximately 40 m and are hydraulically separated by a 200 m thick, low-permeability claystone interval (Rodenrijs Claystone Member) that effectively prevents crossflow. The aquifers have average porosity 15% and average permeability of approximately 250 mD. These doublet systems produce/inject at cumulative flow rates of 100–350 m³/h, with producing temperatures ranging between 60–80°C and injection temperatures between 20–60°C. The brines have salinity in the order of 120 g/L. More details about these reservoirs are outlined in Chapter 5 on a specific geological case.

As of present, commingled production within other or across different geothermal plays, does not occur in the Netherlands. Notably, commingled production across different geothermal plays is unlikely in the Netherlands due to the regional differences in geothermal potential of these geothermal plays.

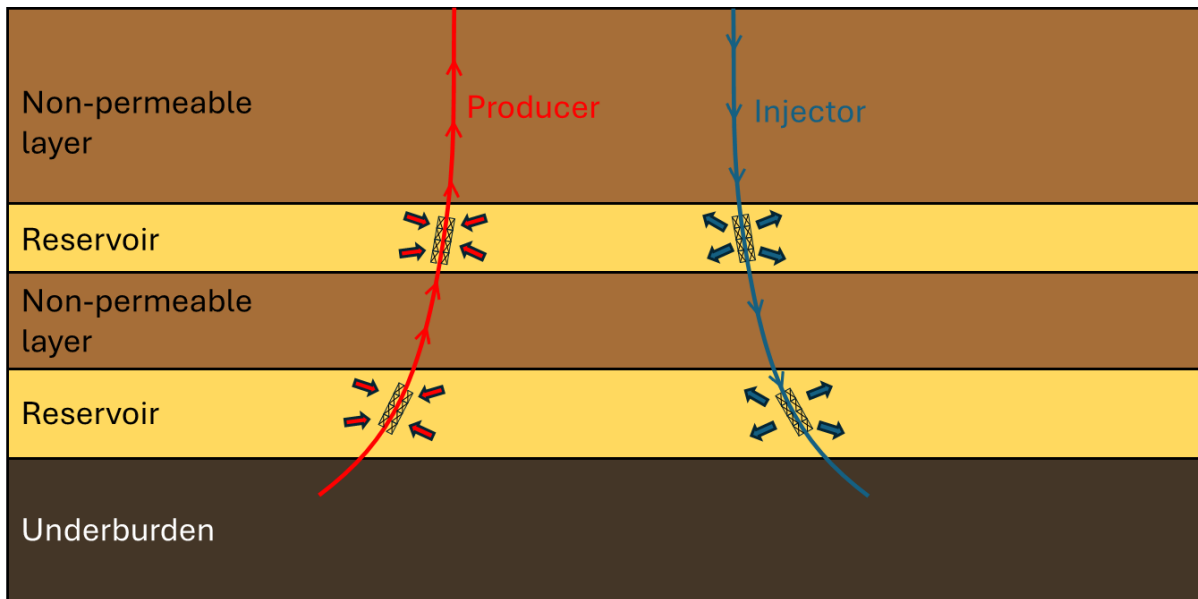


Figure 2-2: Schematic of a commingled geothermal production from hot sedimentary aquifers.

Although commingled production/injection offers several benefits, such as access to larger cumulative water volumes and reduced cooling in individual reservoirs, various challenges can limit production and injection efficiency. Although geothermal production from single reservoirs has been widely studied (e.g., Voskov, 2017; Mottaghy et al., 2011), studies on geothermal commingled production appear to be far less documented in the public domain.

Reservoirs are often heterogeneous, with complex permeability structures that control productivity and injectivity (Willems et al., 2017). This can lead to unbalanced flow conditions, affecting stress distribution and temperature variations within the exploited reservoirs. Additionally, differences in production or injection rates can create localized overpressurized or underpressurized zones within each individual reservoir and may result in unpredictable cold front migration around the injector.

Variations in fluid composition between reservoirs can theoretically introduce engineering challenges, such as scaling issues and alterations in the skin factor, which can further impact flow dynamics and result in flow imbalances. Crossflow within the wellbore can also occur. For example, during shut-in, fluids will crossflow from a higher-pressurized reservoir via the wellbore into a lower-pressurized reservoir (Jongkittinarukorn et al., 2021). Addressing these complexities requires careful reservoir management and well design to optimize performance and mitigate uncertainties associated with commingled production/injection. It is key to understand the operational window and its limits in terms of pressure or effective stresses and depth as highlighted in Figure 2-3.

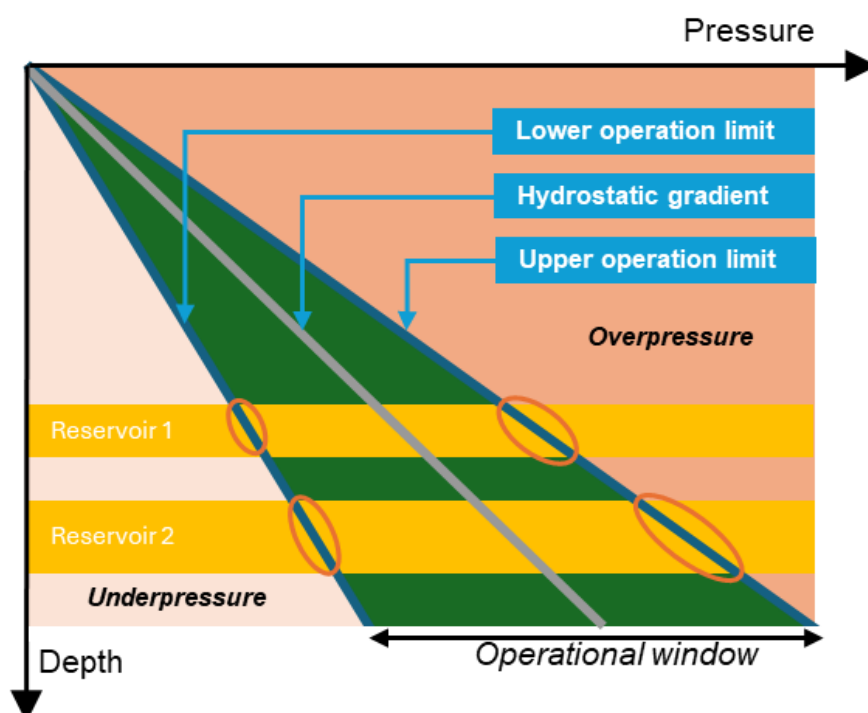


Figure 2-3: Simplified depth-pressure plot, showing two reservoirs, the hydrostatic gradient (light blue), and the lower and upper operation limit (blue zone), the operational window, and zones of underpressure (pink) and overpressure (salmon) relative to potential

2.3 Review of the Netherlands deep geothermal context

The Netherlands has experienced rapid growth in geothermal activities since the first successful geothermal doublet system installation in 2007. As of the 1st of January 2025, 38 doublets have been installed (NLOG, 2025). These doublet systems are largely concentrated in the southern west and northern part of the Netherlands (Figure 2-4) and target the following geological reservoirs at different depths below the surface:

- the Cenozoic Lower and Middle North Sea Group play at depths between 700–800 m;
- the Upper Jurassic (Delfland Subgroup)/Lower Cretaceous (Rijnland Group) play at depths between 1600–2800 m;
- the Lower Triassic Main Buntsandstein play between 2200–2400 m;
- the Permian Rotliegend play between 1800–2700 m; and
- the Carboniferous Dinantian play at depths between 2200–2300 m.

Each geothermal play will be described individually.

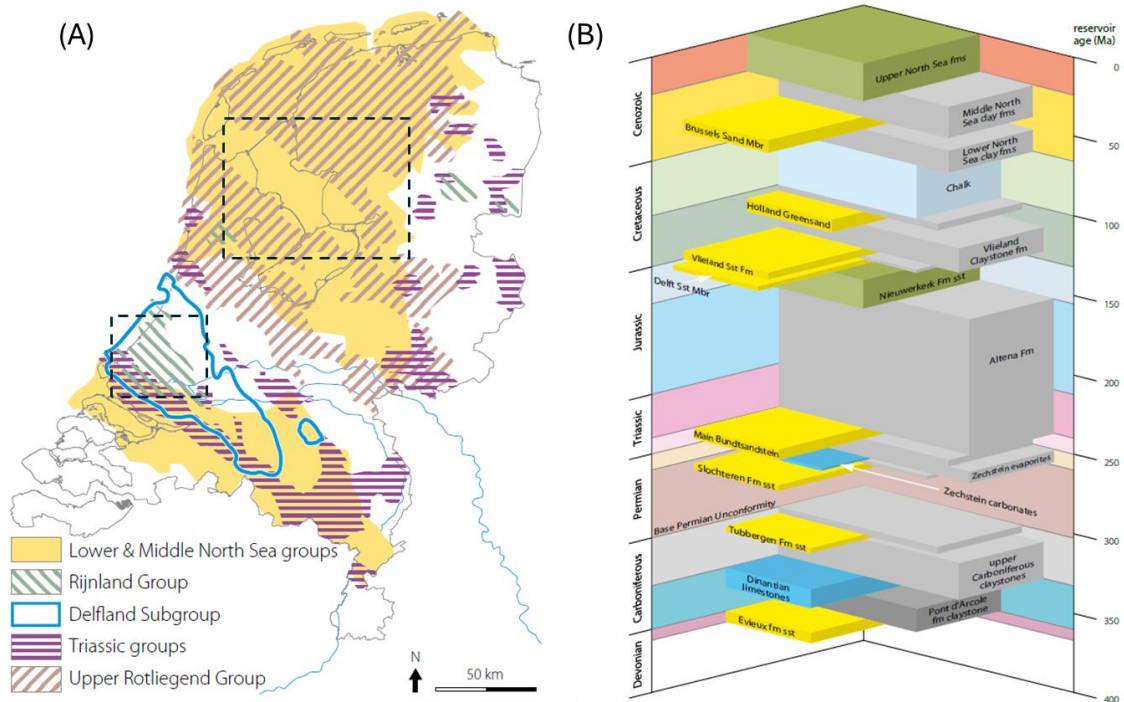


Figure 2-4: (A) Distribution of the main geothermal reservoirs in the Netherlands. The Carboniferous Dinantian play is not included in the figure, but is considered a potential geothermal play, especially in the southern Netherlands. The black dashed squares represent the areas where most of the installed doublet systems are concentrated. (B) Stratigraphic column highlighting the main potential reservoir zones, which will be described more in detail in the text later. Both figures are from (Veen et al., 2025).

2.3.1 Cenozoic play

Cenozoic sediments are present everywhere in the Netherlands, except for the areas of Limburg and Twente where these sediments are absent (Mijnlieff, 2020). These sediments are stratigraphically grouped into the North Sea Super Group (NSSG) and consist of an alternation of sandstones and claystones deposited in a marine environment (Van Adrichem-Boogaert & Kouwe, 1993-1997). Although the NSSG sediments are penetrated by many wells onshore in the Netherlands, well test or log data of these sediments are sparse and only available for a few of these wells. This results in a large degree of uncertainty about the properties of the reservoir NSSG sediments.

The geothermal reservoirs are expected to be found only in the Middle North Sea Group and Lower North Sea Group, with the best reservoirs likely to be found in the Brussels Sand Member (Dongen Formation) given their thickness up to ~250 m and permeability in the order of hundreds of millidarcy (ThermoGIS, 2025). This interval has already successfully been tested for heat recovery in the southern part of the Netherlands (LTA Zevenbergen (ZVB-GT-01 and ZVB-GT-02 in Figure 2-5)). When stacking all the potential reservoirs in the Middle and Lower North Sea Groups, the northern and southern parts of the Netherlands appear to be the areas where higher values of transmissivity are expected to be found (Figure 2-5). These higher transmissivity areas are interpreted to be a consequence of the proximity to paleo shoreline and sand sources (Mijnlieff, 2020). Temperatures for these sedimentary layers reach about 70°C in the southern part of the Netherlands where these sediments are buried down to 1600–1800 m.

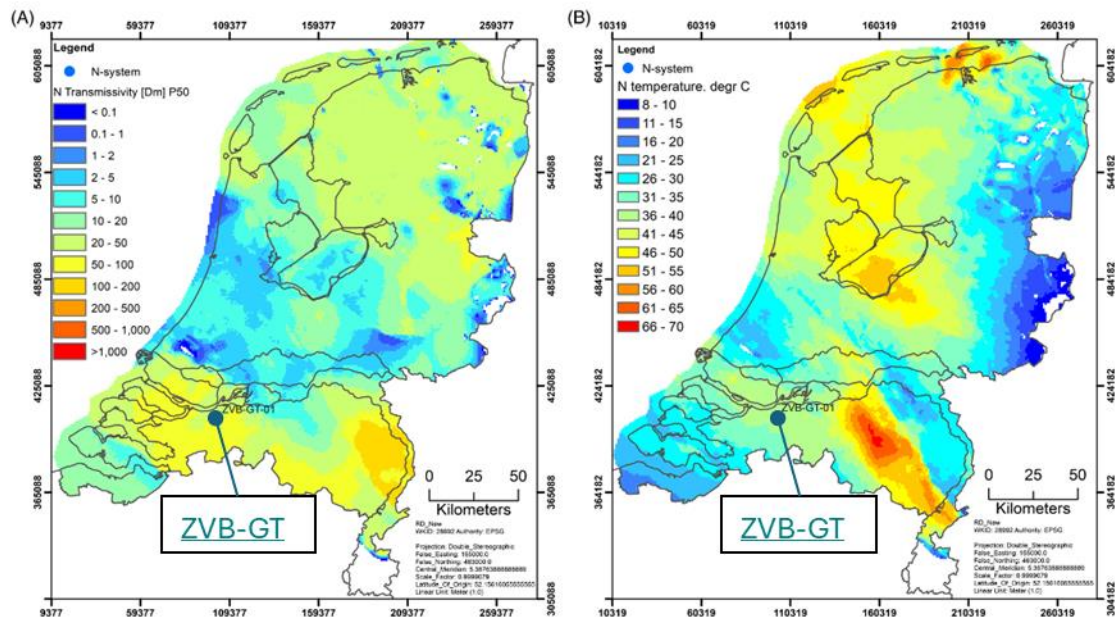


Figure 2-5: Cenozoic Middle and Lower North Sea Groups (A) transmissivity and (B) temperature after Mijnlief (2020).

2.3.2 Upper Jurassic/Cretaceous play

The Upper Jurassic and Lower Cretaceous sediments represent the most prolific geothermal play with 20 geothermal systems producing heat from these sediments as of the 1st of January 2025 (NLOG, 2025). The Lower Cretaceous Vlieland Sandstone Formation from the Rijnland Group and the sandstones from the Upper Jurassic Schieland Group are the main geothermal reservoirs within this play (Mijnlief, 2020). Within the Schieland Group, the Delft Sandstone Member is the primary target for geothermal operations in the area of the West Netherlands Basin, where geothermal heat demand is currently the highest in the Netherlands. The sandstones from the Delft Sandstone Member are usually of better reservoir quality and deeper, thus hotter than the overlying Vlieland Sandstone Formation. Below, the Lower Cretaceous Vlieland Sandstone Formation and the Upper Jurassic Delft Sandstone Member are detailed independently.

2.3.2.1 Lower Cretaceous play

The geothermal reservoirs within the Lower Cretaceous play are part of the Rijnland Group, specifically the Vlieland Sandstone Formation. The Vlieland Sandstone Formation is deposited in a shoreface/marine environment with fining-upward sequences forced by marine transgressions as a result of tectonic and sea level rise (Bourroullec et al., 2018). These sequences are generally formed by a basal sandstone overlaid by a clay-rich sequence, with stacking pattern, sedimentary facies, and preservation being strongly controlled by the basin structural configuration and depositional environment. In this context, the reservoir quality changes accordingly. The Vlieland Sandstone Formation sediments have high reservoir quality when deposited in shallow marine environments. These are the sediments of the Berkel and Rijswijk Sandstone members in the West Netherlands Basin. Conversely, the Vlieland Sandstone Formation sediments have lower reservoir quality in the northern part of the Netherlands, where the glauconitic shoreface/offshore sandstones exhibit lower permeability (Mijnlief, 2020). This results in a strong zonation of the quality of the geothermal play. The high-quality, lower reservoirs can only be found in the southern part of the Netherlands (Figure 2-6), where the clay content is low as a result of the proximity to paleobasin fringes (e.g., West

Netherlands Basin). The Vlieland Sandstone reservoirs are usually found at depths between 1500 and 3000 m, thus temperatures at the reservoir range between 40 and 100 °C.

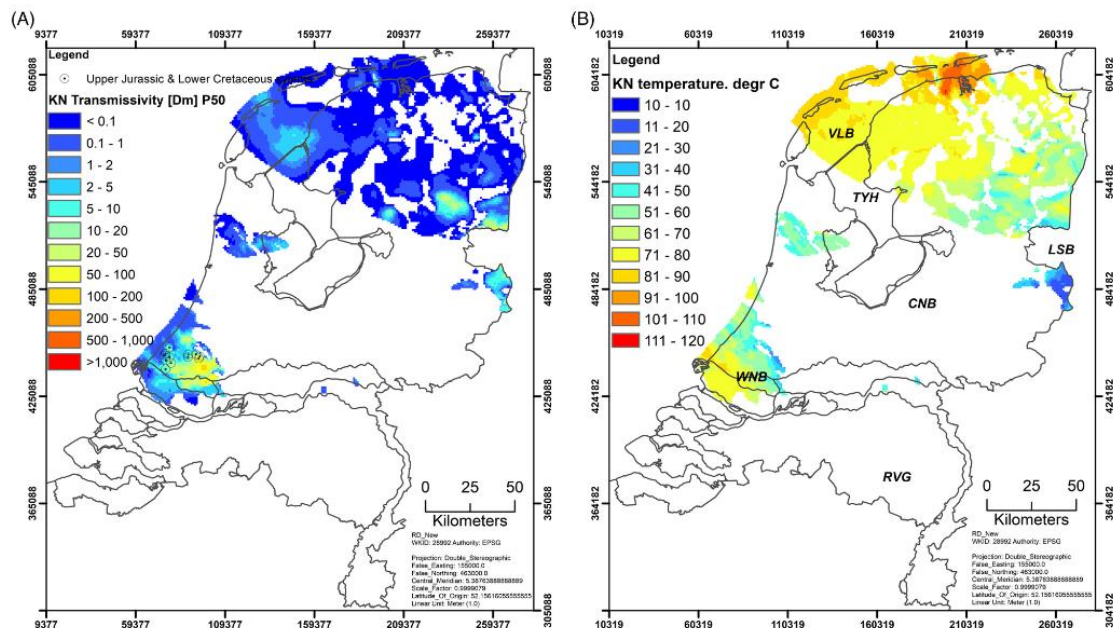


Figure 2-6: Lower Cretaceous Vlieland Sandstone Formation (A) transmissivity and (B) temperature after Mijndieff (2020).

2.3.2.2 Upper Jurassic play

The Upper Jurassic play is formed by the sediments of the Schieland Group, which is formed by several sequences of mostly syn-rift deposits. The Schieland Group sediments are only present in areas active as depocenters during the Late Jurassic and that were not strongly affected by later erosional stages. In the West Netherlands Basin, sediments from the Schieland Group are largely preserved. These are grouped into the Nieuwerkerk Formation, which is then subdivided into three members: the syn-rift Alblasterdam and Delft Sandstone Members and the post-rift Rodenrijs Claystone Member. The primary target for most of the geothermal projects in the Netherlands are the fluvial sandstones from the Delft Sandstone Member, which are widely deposited in the West Netherlands Basin. Locally, the sandstones from the underlying Alblasterdam Member can represent an additional target or contribute to increasing the recoverable volume (Willems et al., 2020). The Delft Sandstone Member is overlain by the Rodenrijs Claystone Member, a claystone sequence deposited in a terrestrial to lagoonal environment. The thickness of the Schieland Group largely changes because of the syn-tectonic sedimentation. For this reason, the thickness of the Nieuwerkerk Formation ranges from 0 to 200 m in the highs while the thickness in some of the grabens reaches up to 1500 m (Willems et al., 2020). Overall, the sandstones from the Delft Sandstone Member have high permeability that can reach several darcies and temperatures that can reach 100°C (Figure 2-7). The average high permeability, appropriate thicknesses, and relatively high temperatures make the Upper Jurassic reservoirs a favorable geothermal play in the southern part of the Netherlands.

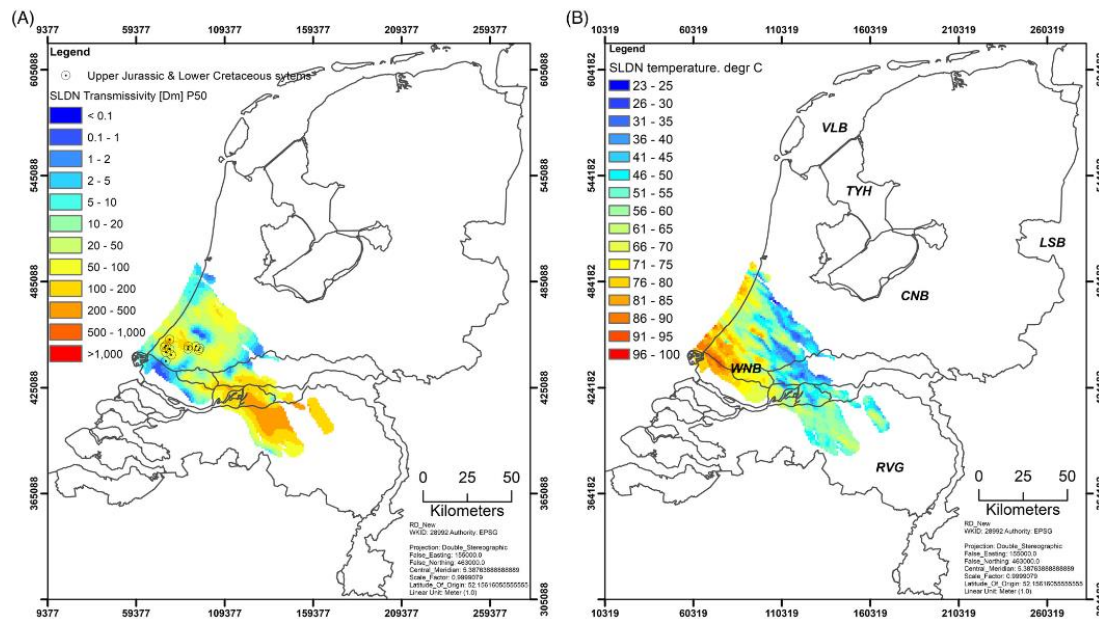


Figure 2-7: Upper Jurassic Nieuwerkerk Formation (A) transmissivity and (B) temperature after Mijnlief (2020).

2.3.3 Triassic play

In the Netherlands, the Lower Germanic Trias Group is currently the only subsurface interval with reservoir temperatures that are potentially suitable for geothermal electricity production. Despite the rapid growth of geothermal initiatives, Triassic aquifers remain underdeveloped, with only two doublet systems currently extracting heat from Triassic clastic reservoirs (MEA, 2024). However, these aquifers hold significant geothermal potential, reaching up to 1 GJ/m² in the southeastern region of the country (ThermoGIS, 2025).

Within the Triassic sequence, the Main Buntsandstein Subgroup is the primary target for geothermal exploration. These fluvial and aeolian sandstones are widespread onshore and have a well-documented history of hydrocarbon production, as seen in fields such as Waalwijk in Noord Brabant. In the southern Netherlands, the Main Buntsandstein Subgroup is found at depths of 1 to 4–5 km, where temperatures reach up to 120–140°C, and thicknesses can reach 200–250 m (Figure 2-8). Additional contributions to the overall aquifer thickness may come from the Röt Fringe Sandstone Member and the Nederweert Formation, where present (Mijnlief, 2020).

However, the quality of Triassic aquifers varies considerably due to complex depositional and diagenetic processes, posing challenges for geothermal development (Purvis & Okkerman, 1996; Mijnlief, 2020; Boersma et al., 2021). This variability was highlighted in 2017 when the NLW-GT-01 exploration well, drilled to approximately 4 km depth in the lower Triassic Main Buntsandstein sandstones, encountered very poor reservoir properties. Due to diagenetic effects, the well recorded porosity values of just 3–4% and permeability below 0.01 mD (Felder & Fernandez, 2018). This highlighted the geological uncertainties associated with the Triassic play and emphasized the necessity for a more detailed understanding of these deep-seated formations before further geothermal development.

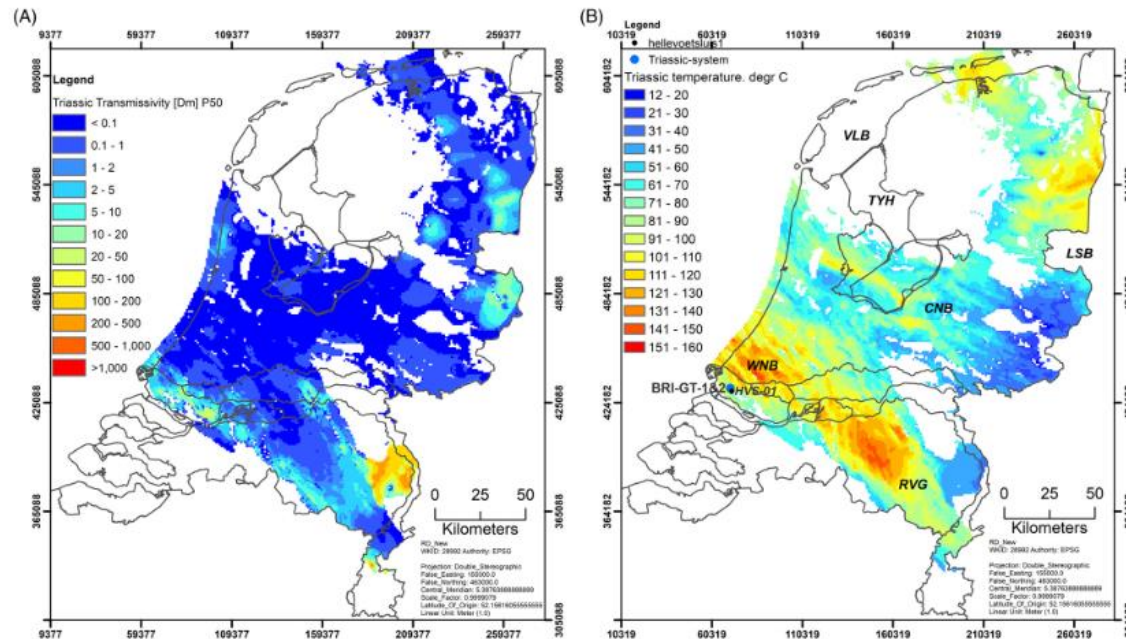


Figure 2-8: Triassic (A) transmissivity and (B) temperature after Mijnlief (2020).

2.3.4 Permian Rotliegend play

The Slochteren Formation from the Rotliegend Group represents the main geothermal reservoir within the Permian play in the subsurface of the Netherlands. The Slochteren Formation is also a very prolific hydrocarbon play. However, in the central and southern part of the Netherlands the Zechstein seal is largely absent, thus, while the sandstone reservoirs are still present, the hydrocarbon system is missing. The Slochteren sediments were deposited in an arid environment mostly through alluvial and aeolian processes. In the northern part of the Netherlands, the Rotliegend is formed by two claystone intervals (Ten Boer and Ameland members) and two sandstone intervals (Upper and Lower Slochteren members). To the south, the claystone members are absent and the Rotliegend is formed by a singular sandstone interval of up to 200 m thick. However, in the southern domain, areas where the Slochteren sandstones are absent exist, either due to pinching out close to basin margins or due to erosional truncation post-deposition. This results in an overall low Rotliegend transmissivity in the southern part of the Netherlands (Figure 2-9).

Geothermal systems in the Rotliegend are developed only in the northern part of the Netherlands adjacent to the Texel-IJsselmeer High (Figure 2-9). In this area, the sandstones are of aeolian origin with permeability ranging between 50 and 350 mD and thickness values between 100 and 250 m (ThermoGIS, 2025). Temperatures range between 60 and 90°C (Figure 2-9). While the Slochteren Formation is more favorable for geothermal heat in the northern part of the Netherlands, in the southern part of the country the overall reduced thickness and deeper burial make this reservoir less favorable for geothermal exploitation.

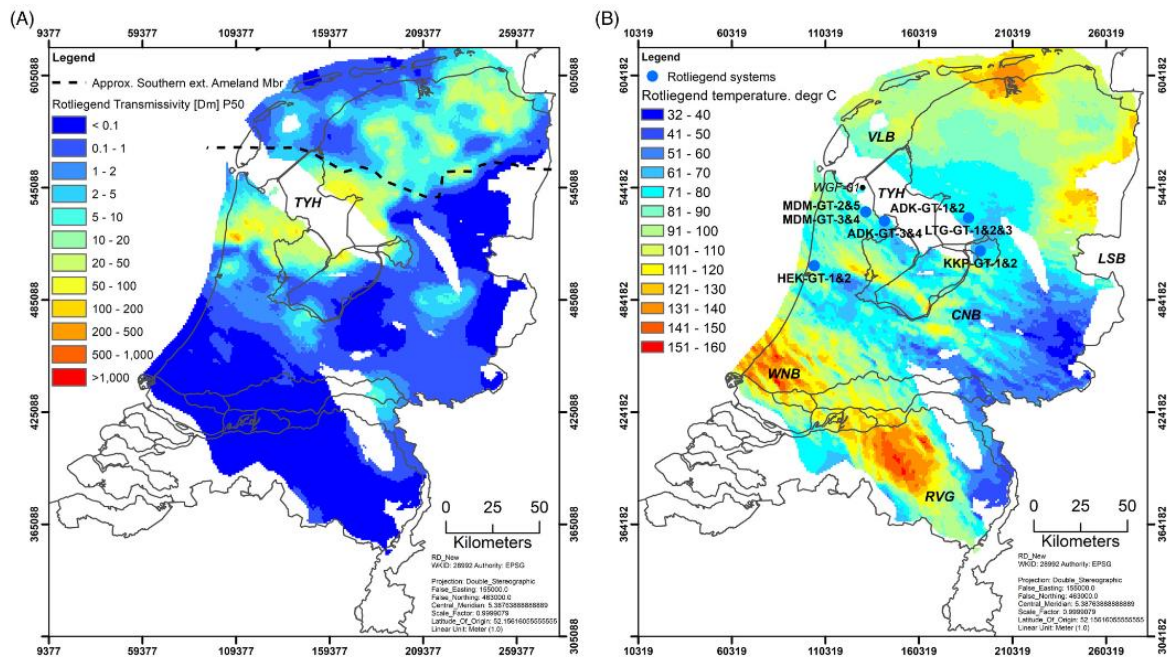


Figure 2-9: Permian Rotliegend (A) transmissivity and (B) temperature after Mijnlief (2020).

2.3.5 Carboniferous play

The Lower Carboniferous Dinantian limestones represent the main proven geothermal reservoir unit of the Carboniferous play. These limestones are for the most part extremely tight, therefore they are mostly exploited through the natural fracture systems/karst features. Two geothermal systems have been installed in these limestones in the southeastern part of the Netherlands. In this area, the Dinantian limestones are found in large anticlinal structures on the flanks of the Roer Valley Graben locally subcropping the base Permian Unconformity or the base of the Cretaceous (Reith, 2018). In these conditions, the presence of fractures and faults in the limestones may have provided pathways for hydrothermal fluid flow that enhanced fault-related karstification (Mijnlief, 2020). Furthermore, the exposure during erosional times may have allowed infiltration of meteoric water and enhanced further karstification. However, the presence in this area of active fault zones makes operations more challenging, due to geohazard risks such as induced seismicity (Vörös & Baisch, 2022). In other areas of the Netherlands, the Lower Carboniferous limestones are found largely below 4 km with temperatures higher than 120°C. Although temperatures are favorable for geothermal energy, the challenge in these areas lies in finding an area with permeable faults that are not critically stressed and can be exploited under geothermal operation conditions (Mijnlief, 2020).

2.3.6 Overview of relevant reservoir parameters

Table 2-1 summarizes the main reservoir parameters for the geothermal plays described above. The collected data will then be to establish property ranges for subsequent tasks in the project.

Table 2-1: Main reservoir parameters for the main geothermal plays in the Netherlands. All data are collected from ThermoGIS (2025) except for the Brussels and Rijswijk members, which are retrieved from Sproule ERCE in-house data.

Reservoir unit	Porosity (%)	Permeability (mD)	Thickness (m)	N/G	Depth (m)	Temperature (°C)
Brussels Sand Mbr (Dongen Fm)	35	749	55	1	654	29.7
Berkel Sandstone Mbr (Vlieland Sandstone Fm)	7.9-35.4 (17.3)	0.01-1040 (190)	0.05-113 (37)	0.6-0.9 (0.8)	510-2444 (1755)	26-84 (63)
Rijswijk Mbr (Vlieland Sandstone Fm)	15	360	37.3	0.6	2080	72
Delft/Alblasserdam mbrs (Nieuwerkerk Fm)	5-26 (17.4)	1.7-1789.7 (264)	0-1153 (290)	0.5-0.8 (0.5)	314-2772.5 (1456)	28-96 (61)
Main Buntsandstein SubGrp	3-28 (12.8)	0.1-2334 (90)	0-730 (74)	0.5-0.9 (0.7)	74.7-4682 (2013)	11-148 (76)
Slochteren Fm (Upper Rotliegend Grp)	2.5-25 (14.5)	0.0-1698 (62.1)	0-317 (84)	0.5-1 (0.9)	634-5054 (2564)	31-156 (89)

3 CONSTRUCTION OF RESERVOIR AND SIMULATION MODELS

In this study, we leverage the open-source reservoir simulator DARTS (Delft University Advanced Research Terra Simulator) developed at TUDelft (Wang et al., 2020). DARTS is a multiphysics finite volume-based simulator that takes advantage of the operator-based linearization ‘OBL’ concept to speed up simulation problems with non-linear physics (Voskov, 2017).

The response of a geothermal doublet under a commingled production/injection scheme is explored via numerical reservoir simulation. This requires the representation of the geothermal reservoir and non-reservoir rocks via a discretized model or grid where petrophysical properties are assigned in accordance with the desired cases to be evaluated. In addition, well characteristics and flow/boundaries conditions are also supplied to the reservoir simulation.

3.1 Generic models

To study the behavior of commingled production/injection in a general way, a simple two-layer reservoir model was constructed. The model assumes a well doublet that is completed with vertical wells in two reservoirs when both are present. A Cartesian mesh was used. This mesh was populated with different petrophysical characteristics according to the scenarios to be tested. The magnitudes of the petrophysical properties of Berkel Sandstone and Delft Sandstone members, defined in Table 2-1, are used as reference in the simulation model. Nevertheless, the analysis of the simulation results is expected to be extendable to other combinations of reservoirs.

3.1.1 Model description and gridding

The model was defined as a rectangular hexahedral volume of 5000 m long ‘x’ by 5400 m wide ‘y’-direction and 850 m in height. The top of the model is defined at 1550 m TVD while the bottom at 2400 m TVD. Within the model, five geological layers are defined: overburden, underburden and two reservoirs (Top and Bottom) separated by a sealing clay/shale layer as shown in Figure 3-1 (right). The top of these five layers is indicated in Table 3-1.

Table 3-1: Layers description

Layers	Overburden	Top reservoir	Seal layer	Bottom reservoir	Underburden
Top [m TVD]	1550	1800	1850	2050	2100
Thickness [m]	250	50	200	50	300

A ‘base’ structured grid with a total of 117,078 elements, where the reservoirs are represented by only one cell in the vertical direction, was defined for all the simulations except for those investigating thickness variation effects and well trajectory analysis (Chapter 4). Those models have increased mesh refinement in the ‘z’-direction (vertical) through the reservoir section. The number of elements is described in Table 3-2 and the mesh is visualized in Figure 3-1.

The size of the cells in ‘x’ and ‘y’-direction (dx, dy) varies from 25 m to 100 m, with increased refinement around the wells as shown in Figure 3-1 (left). The size of the cells in the vertical direction (dz) is 50 m in the reservoirs and seal layer in between while the cell size varies logarithmically in the overburden and underburden, getting finer toward the reservoirs (Figure 3-1, right). For the effects of thickness variation, a finer grid in z direction (16.67 m) in the reservoir and seal layers is used.

*Table 3-2: Description of the grid elements. ** Log: the top and bottom 10 layers have log-variable size from coarse to fine towards the reservoirs.*

Number of grid blocks in x direction 'Nx'	Number of grid blocks in y direction 'Ny'	Number of grid blocks in z direction 'Nz'	Total number of grid blocks
57	79	26	117078
Elements along the x direction	Elements along the y direction	Elements along the z direction Top-Bottom	
15, 27, 15	15, 5, 10, 19, 10, 5, 15	10, 1, 4, 1, 10	
Corresponding delta 'x' [m]	Corresponding delta 'y' [m]	Corresponding delta 'z' [m]	
100, 75, 100	100, 50, 25, 75, 25, 50, 100	Log, 50, 50, 50, Log**	

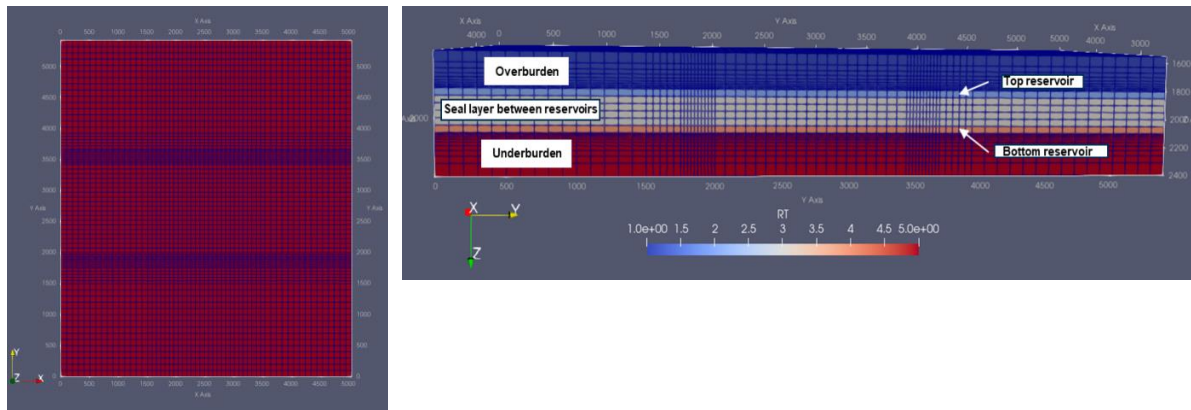


Figure 3-1: Representation of mesh. Discretization in 'x' and 'y' direction (left) and discretization in 'z' direction (right) where the layers that form the model are described.

3.1.2 Reservoirs and properties 'Base Case'

Reservoir properties for the Base Case are inspired by the information gathered in Chapter 2, obtained from ThermoGIS and Properbase databases (Kolah Kaj, 2024). The mean petrophysical properties of the Berkel and Delft Sandstone members were taken as reference to represent the top and bottom reservoirs, respectively. Nevertheless, the simulations are intended to be general and provide referential behaviors of different combinations of reservoirs. Additional cases are also considered in the simulation section. Thermal properties from the sandstones were taken from Properbase. Properties of the non-permeable layers (including the seal layer) were defined to represent rocks with low permeability (1e-4 mD) and low thermal conductivities consistent with shale properties. This low permeability of the seal layer restricts communication between the reservoirs.

The description of the Base Case that considers the reservoir as homogeneous and continuous is described in Table 3-3. These properties work as a reference when exploring the impact of permeability and thickness in the next chapter.

Table 3-3: Description of model properties for the case the reservoirs are considered continuous and homogeneous ‘Base Case’. ** for a Young’s modulus of 18.2 GPa.

Layers	Overburden	Top reservoir	Seal layer	Bottom reservoir	Underburden
Pore [frac.]	0.01	0.17	0.01	0.12	0.01
Permx [mD]	0.0001	190	0.0001	265	0.0001
Permy [mD]	0.0001	190	0.0001	265	0.0001
Permz [mD]	0.0001	19	0.0001	26.5	0.0001
c_{rock} [W/m/K]	1.6	3.3	1.6	3.3	1.6
Hcap [kJ/m ³ /K]	2000	1640	2000	1640	2000
h [m]	250	50	200*	50	300
C_f [bar ⁻¹]**	5.5E-6	5.5E-6	5.5E-6	5.5E-6	5.5E-6

3.1.3 Water properties

IAPWS-IF97 model

IAPWS-IF97 water properties (Kretzchmar & Wagner, 2019) are used to provide values of density, viscosity and thermal properties as a function of pressure and enthalpy and for the calculation of temperature. Figure 3-2 provides a sample of water density and viscosity values for fixed pressure. This model is used in most simulations except for the brine mixing effects study.

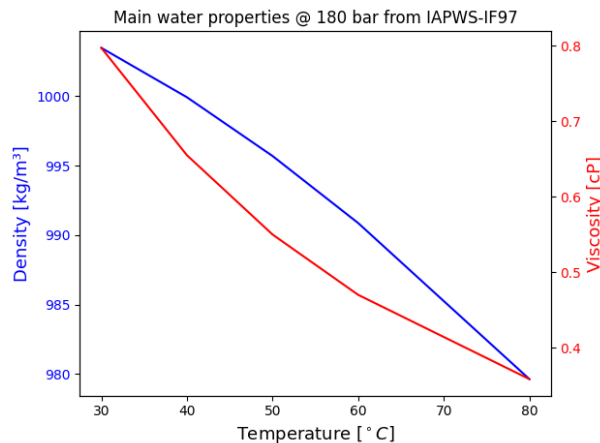


Figure 3-2: Water density and viscosity from IAPWS-IF97 model within the range of temperature of the simulation for a constant pressure (180 bar).

Simplified compositional model

For the studied cases, where the reservoirs are saturated with different brines (different water compositions), a compositional model with two components, water and salt, was used. In this model, density and viscosity of the brine can be modeled as a function of the molar composition of these two components, which allows it to capture the effects of mixing brines on the dynamic properties.

The water density and viscosity models are described below. The input parameters as well as the water properties were assumed to be independent of the composition and are described in

Table 3-4 and Table 3-5. The density of the mixtures (ρ_{brine}) was computed based on the mass-weighted calculation of the relative volumes ($\frac{1}{\rho}$) of each component (water and salt) as described in the equations below.

$$w_i = \frac{x_i M_{w_i}}{\sum x_i M_{w_i}} \quad (1)$$

$$v_{r\ brine} = \sum w_i * \frac{1}{\rho_i} \quad (2)$$

$$\rho_{brine} = \frac{1}{v_{r\ brine}} \left(1 + c_l (P - P_{ref}) \right) \quad (3)$$

Where:

i : i^{th} component (H_2O , salt)

x : molar fraction [frac.]

M_w : molecular weight [g/gmol]

ρ : density [kg/m³]

P_{ref} : reference Pressure [bar]

$v_{r\ brine}$: Relative volume each brine [m³/kg]

c_l : Liquid Compressibility [bar⁻¹]

ρ_{brine} : Brine's density [kg/m³]

P : Pressure in reservoir [bar]

For the viscosity of the brine (μ_{brine}), a Kestin style correlation (Kestin et al., 1981) was used to account for the increase of water viscosity as concentration of the salt is increased. It does not represent an actual brine but accounts for the general effects of brine mixing. Viscosity is considered independent of pressure for further simplification. Pure water viscosity is computed based on Korson's correlation (Korson et al., 1969).

$$\mu_{brine} = \mu_w (1 + A * m + B * m^2) \quad (4)$$

$$m = \frac{1000 x_{salt}}{M_{w_{H_2O}} x_{H_2O}} \quad (5)$$

$$\mu_w = C * 10^{\frac{D}{(T-E)}} \quad (6)$$

Where:

μ_w : Pure water viscosity [Pa.s]

T : Temperature [K]

m : molality [mol/kg]

Constants

A : 0.1682 [kg/mol]

C : 2.414e-5 [Pa.s]

B : 0.0219 [kg²/mol²]

D : 247.8 [K]

$M_{w_{H_2O}}$: water molecular weight [g/mol]

x_i : molar fraction [frac.] for $i = H_2O$, salt

E : 140.0 [K]

Table 3-4: Components properties at approximate injection conditions (210 bar, 50°C)

Components	H ₂ O	Salt
Molecular weight [g/mol]	18.015	58.44
Density [kg/m ³]	997	2160

Table 3-5: Water properties assumed to be independent of composition.

c_l [bar ⁻¹]	P_{ref} [bar]	Water thermal conductivity [W/m/K]	Water heat capacity [kJ/m ³ /K]
4.3 10 ⁻⁵	180	0.6	4.180

3.1.4 Boundary and initial conditions

Initial conditions

The thermal initial conditions consider a fixed temperature at the bottom and top of the model. The temperature at the top was estimated based on a ground surface temperature of 10°C and a temperature gradient of 30 °C/km. Thus, the top temperature (T_{top}) is 56.5°C at a depth of 1550 m. The bottom temperature was computed based on the top temperature, the rock thermal conductivity and the heat flow (0.058 W/m²) and using equation (7). The initial pressure condition at the top of the model was set to be 152.9 bar. The final pressure state was obtained after running a natural (steady) state simulation.

$$T_{bottom} = T_{top} + \sum_1^i \left(\frac{dT}{dZ} \right)_i h_i \quad (7)$$

Where:

$\left(\frac{dT}{dZ} \right)_i$: Temperature gradient of the i^{th} rock layer [°C/km]

h_i : thickness of the i^{th} rock layer [°C/km]

Initial pressure is defined following (8), water density of 1000 kg/m³, a surface referential pressure of 1 bar and the depth (z) of the model's cells, which considers that the reservoir pressure is hydrostatic.

$$P = P_{ref} + z * \rho_w * g \quad (8)$$

Where:

P : Initial guess of pressure in the model [Pa]

P_{ref} : referential pressure [Pa]

ρ_w : Referential water density [kg/m³]

g : gravity [$9.8 \frac{m}{s^2}$]

z : depth [m]

However, the final initial conditions of the system are obtained after running the model during a long time (10⁸ days) without wells (the natural state), so that equilibrium conditions are

reached. This ensures that any changes in the primary variables (pressure and temperature) are the result of operational production conditions, not disequilibrium. The initial temperature and pressure profiles after an equilibrium simulation are shown in Figure 3-3.

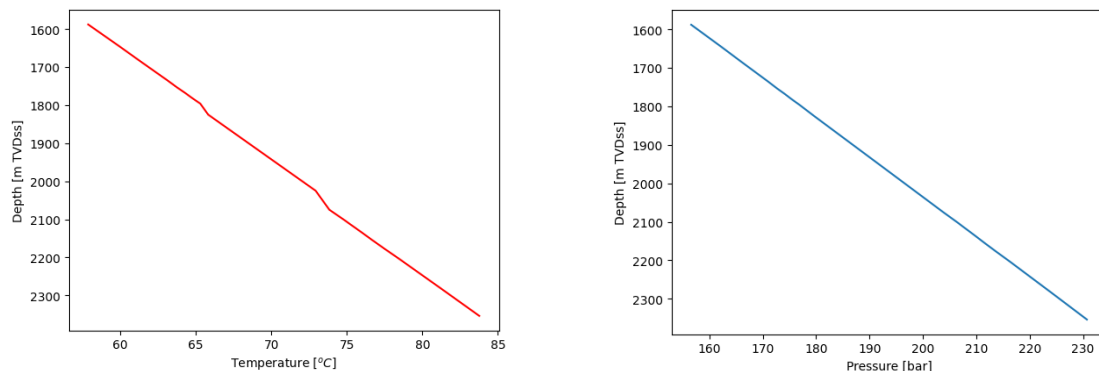


Figure 3-3: Initial conditions after running natural state. Temperature profile (left) and pressure profile (right). The change of temperature gradient is due to the difference between reservoir and non-reservoir thermal conductivities.

Lateral Boundary Conditions

On the sides of the model (lateral boundary conditions), two options are explored:

Closed system:

- From a thermal point of view, no heat flux boundaries.
- From a hydraulic point of view, no mass flux.

Semi-open system:

- Cells at the boundaries are assigned a larger volume of 10^8 m^3 , which represents a 20 km additional extension of the reservoir in x and y direction.
- From a thermal point of view, the volume increment leads to constant temperature in the lateral boundaries.
- From a hydraulic point of view, the volume increment allows certain in/out flow.

3.2 Well characteristics and injection/production constraints

A geothermal doublet with a well spacing at depth of 1500 m is positioned in the center of the model. This distance is considered representative for a typical doublet. The geothermal doublet system that is modeled considers vertical wells for most of the analyses performed in subsequent chapters. Well trajectories other than vertical are only used when assessing the impact of well completion. The well characteristics are described in Table 3-6. The vertical well trajectories with respect to the model are shown in Figure 3-4. The wells are completed in both reservoirs.

The well injection conditions are described in Table 3-7. The values were chosen as representative for a typical Dutch geothermal project. The reservoirs are produced and injected following a commingled scheme. The total produced mass from and injected into the wells are equal. These mass rates are split and distributed over the reservoirs depending on the hydraulic resistance offered by the reservoir at the given time step. This split is done by the simulator while solving the problem. The general procedure for calculating the flow rate from each reservoir after simulations are run is described next.

Table 3-6: Injector and producer well properties description. The well radius is equivalent to a 8 ½" diameter.

Well	Well radius [m]	Skin	Trajectory
Injector	0.10795	0	Vertical
Producer	0.10795	0	Vertical
<u>Well spacing [m]</u>	<u>1500</u>		

Table 3-7: Well injection and production conditions

Injection temperature [°C]	40
Total average volumetric production flow rate [m³/hr]	280
Total simulation time [years]	30
Injected mass is equal to produced mass	

The volumetric flow into or out of each reservoir grid block completed by the well, as a function of time t , is estimated using the well's productivity/injectivity index (WellIndex) and the pressure difference between both the well bottomhole pressure (BHP) and the reservoir pressure at the completed grid block ($P_{well\ block\ i}$), following Equations 9 to 13. The Well productivity or injectivity Index (WI) depends on parameters such as permeability, reservoir thickness, fluid viscosity, wellbore radius, grid block dimensions, and the orientation of the well. Consequently, any changes to these parameters will affect the calculated injection or production rates.

$$q_i(t) = WI_i * (BHP_i(t) - P_{well\ block\ i}(t)) \quad (9)$$

$$WI_i = \frac{Peaceman_{index\ i}}{\mu_w i(t)} \quad (10)$$

$$Peaceman_{index\ i} = \frac{2 * \pi * k_i * h}{\ln\left(\frac{r_e}{r_w}\right) + s} \quad (11)$$

$$r_e = 0.28 * \frac{\sqrt{dx^2 + dy^2}}{\frac{kx^{\frac{1}{4}}}{ky} + \frac{ky^{\frac{1}{4}}}{kx}} \quad (12)$$

$$q_{total} = \sum_{i=1}^n q_i \quad (13)$$

Where:

i : i^{th} completed cell in the well

q_i : volumetric flow from the i^{th} completed cell in the well [m³/s]

n : total number of completed cell in a well

μ_w : water viscosity [Pa.s]

r_e : peacemean equivalent radius for vertical wells [m]

k_i : geometric average permeability $\sqrt{k_y k_x}$ for a well oriented in the vertical direction [m²]

k_y, k_x : permeabilities in y and x directions in cell i^{th} [m²]

d_y, d_x : cell sizes where the well is completed in y and x directions [m]

h : cell thickness [m]

s : skin [-]

r_w : well radius [m]

WI : productivity or injectivity well index [m³/Pa.s]

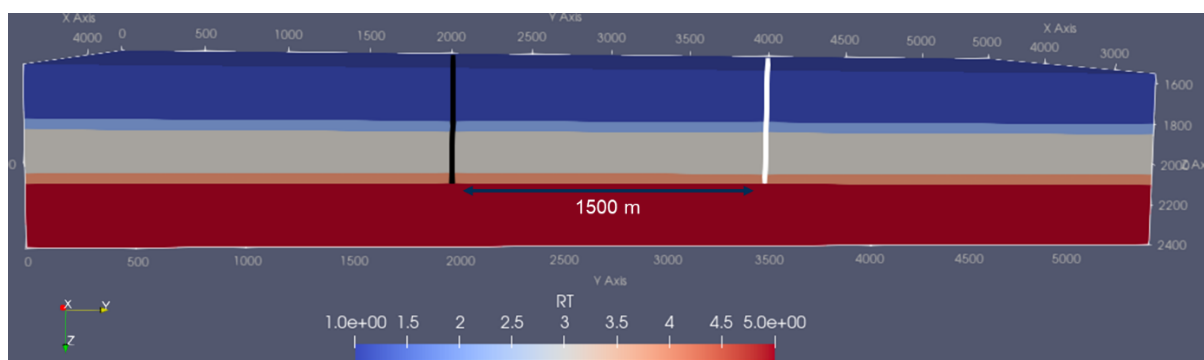


Figure 3-4: Injector (black) and producer (white) well locations. Reservoirs are indicated by the rock type 'RT' equal to 2 and 4. Wells are spaced 1500 m in the horizontal direction.

3.3 Reservoir simulator

In this study, the DARTS's geothermal module and the IAPWS-IF97 water properties (Kretzchmar & Wagner, 2019) were used to predict flow distribution along producer and injector wells during geothermal operations through a simplified coupling of a wellbore flow model to the reservoir flow model. The "multisegmented" well approach implemented in DARTS was chosen for modelling flow from the wellbore to the reservoir. The approach assumes a well block is in communication with the corresponding reservoir block (within which the well block is located) and the pressure in the corresponding well blocks are correlated through elevation. The total well flow for the well is divided among "feedzones" (reservoir blocks that the well intersects) by the Peaceman relations (equations 10-14) assuming that the internal friction in the well is 0. This means that the dP in the wellbore blocks is only a function of elevation.

3.4 Commingled production response considering properties of the Base Case

The initial simulation was run for 30 years following the reservoir properties indicated in Table 3-3 and the well conditions described in Table 3-7. This case considers that permeability in each reservoir remains the same between the injector and producer, as indicated in Figure 3-5. Two boundary conditions were tested: closed system and semi-open as indicated in the section on boundary conditions.

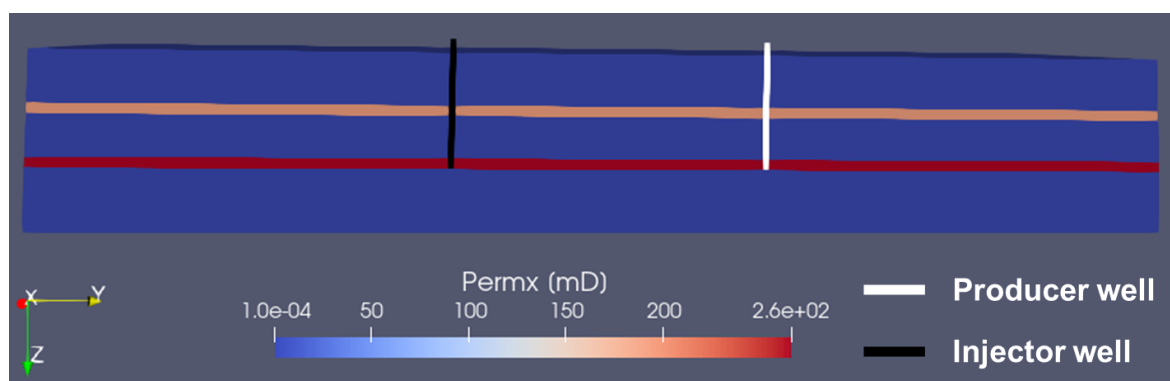


Figure 3-5. Permeability distribution of base case. Injector well (black) and producer well (white)

The $Peaceman_{index}$ or geometric productivity/injectivity index for the two reservoirs is shown in Table 3-8. This index together with the water viscosity and pressure drop determine the proportion of the injected or produced flow rate in/from each reservoir at each well.

Table 3-8: $Peaceman_{index}$ or geometric productivity/injectivity index for the base case.

	Injector well $Peaceman_{index}$ [m ³ *cP /(day*bar)]	Producer well $Peaceman_{index}$ [m ³ *cP /(day*bar)]
Top reservoir	110	110
Bottom reservoir	153	153

3.4.1 Balance indicators

The mass voidage replacement ratio (mVRR) is defined as the ratio of the injected mass to the produced mass, as shown in equation 14. The mVRR will be computed for each reservoir 'i' to monitor whether there is a mass unbalance. Alternatively, the volume voidage replacement ratio (vVRR) can be used to monitor the volumetric balance of the system (equation 15), that can be directly related with changes of pressure because, if injected volume is different from the produced volume, pressure will change. Given that the density of the water will slightly change with temperature (Figure 3-2) both indicators will be similar.

$$mVRR_i = \frac{mass_{injected_i}}{mass_{produced_i}} \quad (14)$$

$$vVRR_i = \frac{volume_{injected_i}}{volume_{produced_i}} \quad (15)$$

Where i indicates the ith reservoir.

3.4.2 Base Case – Closed system

The results are presented in terms of: temperature and pressure change in each reservoir (Figure 3-6 and Figure 3-7), volumetric and mass flows rates per reservoir (Figure 3-8), mass voidage replacement ratio 'mVRR' (Figure 3-9) and average, maximum, minimum reservoir pressures in Figure 3-9. The observations are summarized below:

- Given that both reservoirs have the same thickness but different permeability, most of the water is injected in and produced from the more permeable bottom reservoir (Figure 3-8) which leads to a larger cooled area in the bottom reservoir (Figure 3-6). Thus, commingled production leads to uneven sweeping of the reservoirs due to permeability differences between reservoirs.
- The mass flow rates and mVRR are equal to 'one', indicating the reservoirs are in mass-balance (Figure 3-8 and Figure 3-9), except at very early time where mVRR slightly deviates from 'one' due to transient flow conditions caused by differences in petrophysical and dynamic water properties (density, viscosity) between the reservoirs. If the reservoirs are considered to have the same petrophysical and dynamic properties, the mVRR yields a value of 'one' at both early and late times, see Annex A.2. A similar transient behavior of flow rates has been shown using analytical solutions for commingled production wells in infinite reservoirs (Park, 1989).

- The well boundary condition enforces mass flow rate equivalence between production and injection well. So, the total mass flow rate is enforced. The volumetric flow rate differences arise from changes in the fluid density of produced vs injected fluid.
- Although the reservoirs remain mass-balanced (Figure 3-8 and Figure 3-9), the minimum, maximum and average pressure in the reservoirs declines slightly (Figure 3-10 and Figure 3-11). This pressure reduction is primarily due to the lower density of the injected water compared to the produced water, a result of heat extraction (cooling). Consequently, the volume of injected water is lower than the volume of produced water, resulting in a pressure decline. This decline is magnified by the hydraulic-closed boundary condition (no lateral pressure support). When the water is injected at the average temperature of the reservoirs, pressure remains constant during the simulation time because there is no major cooling (see Annex A.1).

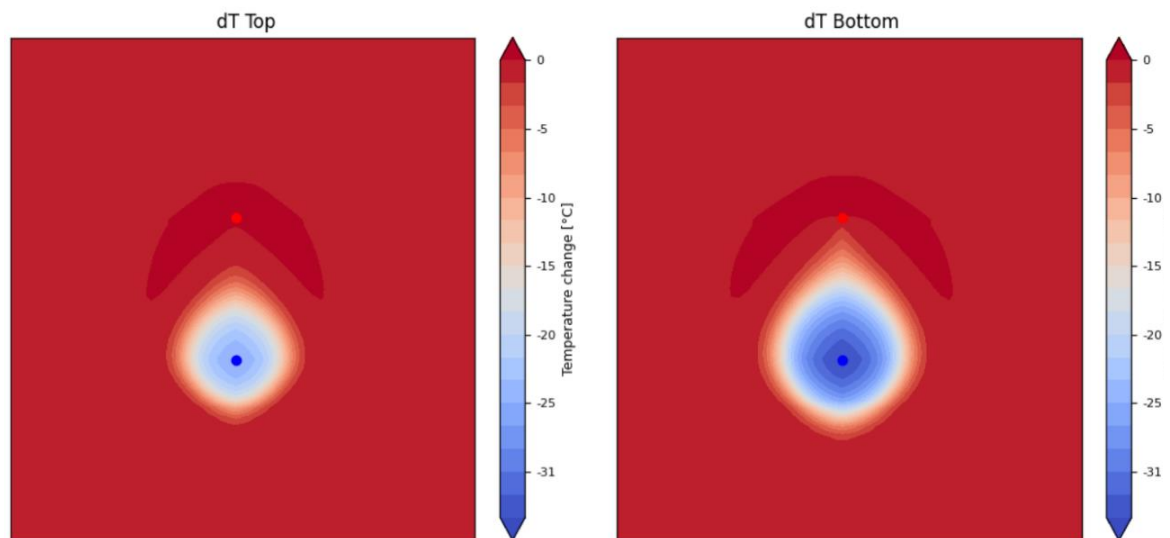


Figure 3-6: Change of temperature (initial minus final temperature) after 30 years of injection at constant rate of 280 m³/h, for the Base Case with closed side boundaries. Blue colors indicate temperature has declined over time. Top reservoir (left) and bottom reservoir (right). Injection well shown in blue and production well in red.

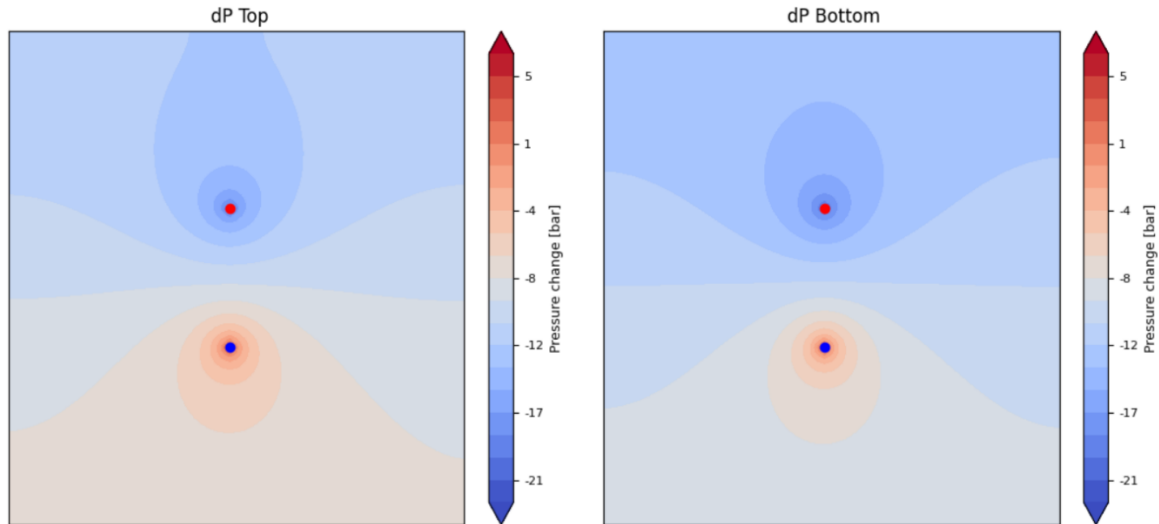


Figure 3-7: Change of pressure (dP) after 30 years of injection at constant rate of $280 \text{ m}^3/\text{h}$, for the base case with closed side boundaries. Negative values (blue) indicate depletion while positive values (red) point to pressurization. Top reservoir (left) and bottom reservoir (right). Injection well shown in blue and production well in red.

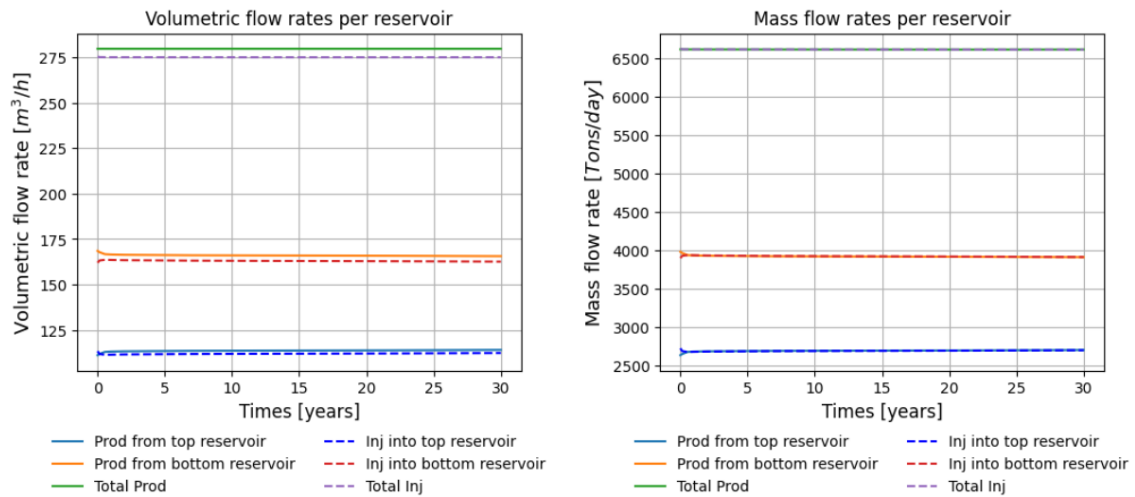


Figure 3-8: Evolution of injection and production volumetric (left) and mass (right) flow rates per reservoir and total for the Base Case, for a closed system. Please note that some curves for the mass flow rates overlap.

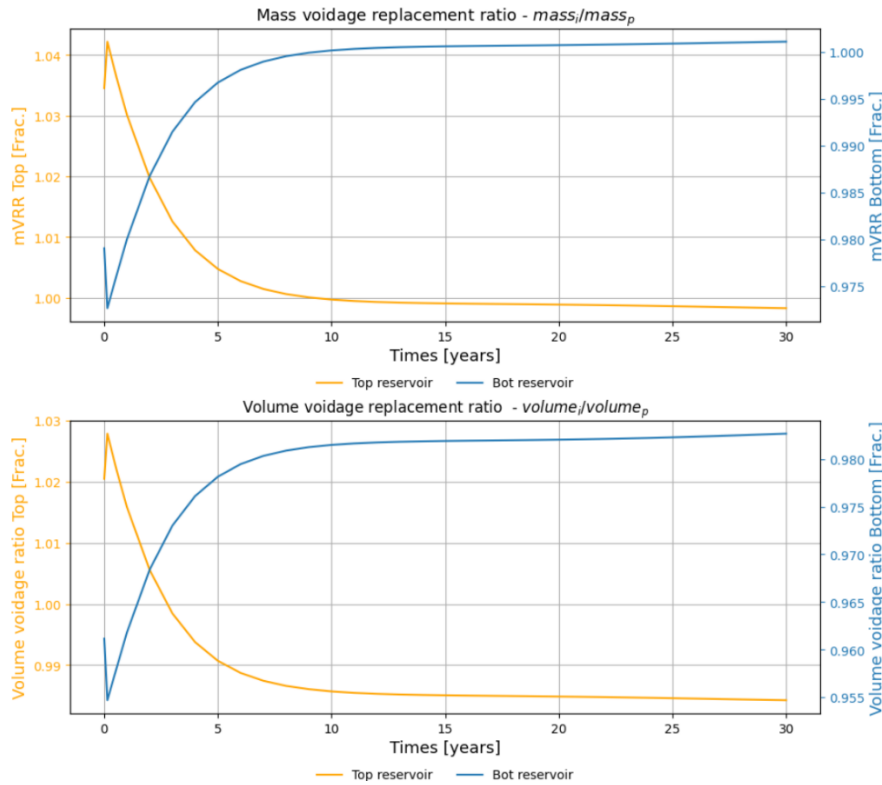


Figure 3-9: Evolution of the mass (top) and volume (bottom) voidage replacement ratio in every reservoir, for a closed system with Base Case properties. p : produced and i : injected

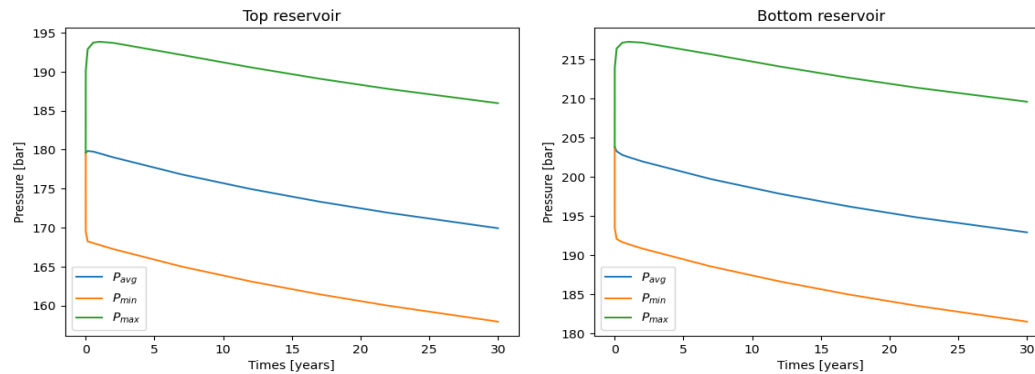


Figure 3-10: Top reservoir (left) and bottom reservoir (right) pressures: average, minimum and maximum pressures (P) for the Base Case (closed system). Pressure declines because the system is considered closed laterally and vertically and hot water is replaced by denser cold water that leads to pressure reduction.

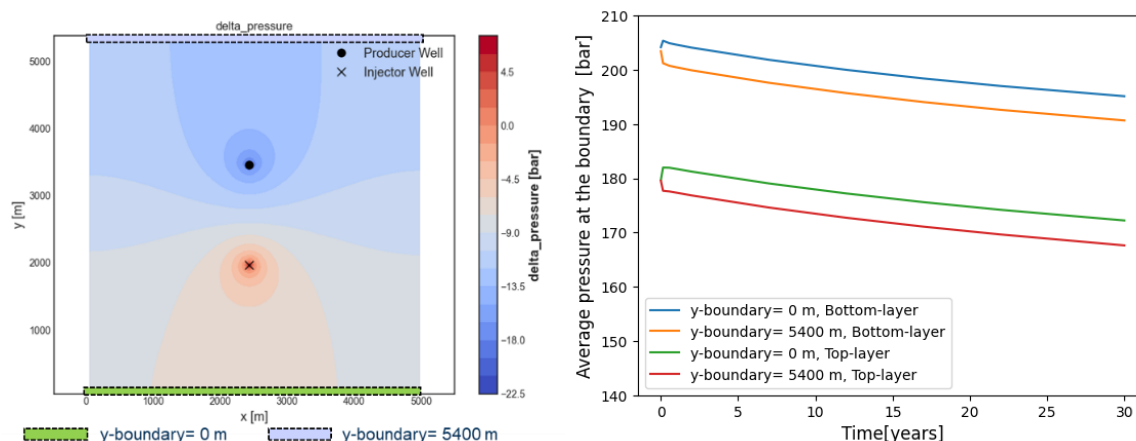


Figure 3-11: Evolution of pressure in the boundaries (highlighted in green (bottom) and blue (top)) for the Base Case for a closed system. It shows pressurization and depletion at early time depending on the boundaries ($y = 0$ m, $y = 5400$ m) as shown on the left, which are responsible for the early unbalance.

3.4.3 Base Case – Semi-open system

The same simulation conditions as in the previous case were used, but with the reservoir modeled as semi-open by setting the volume of boundary cells to $1e8$ m³ (which is equivalent to extending the reservoir approximately 20 km in the lateral directions). These simulations allow us to assess the impact of boundary conditions (pressure support by reservoir volume).

Observations:

- When comparing results with respect to the closed system case, it was found that cold affected areas remain the same (Figure 3-12) and pressure changes are smaller (Figure 3-13) as there is more volume available laterally providing pressure support.
- For this boundary condition, the reservoirs show a subtle unbalance at early times (< 5 years) as shown in Figure 3-14 and Figure 3-15, which is practically not seen for the closed system (Figure 3-8 and Figure 3-9). This is the result of time dependent pressurization/depletion of the boundaries as shown in Figure 3-16 and Figure 3-17 at early times. Thus, differences in rock properties and initial conditions between the bottom and top reservoirs could lead to subtle mass unbalance in the individual reservoirs. Once pressure reaches steady state, the $mVRR$ reaches unity for each reservoir. This time dependent effect in individual flow rates has been shown using analytical solutions for commingled producer wells in infinite reservoirs (Park, 1989). This imbalance causes a subtle pressure decrease in the bottom reservoir, where $mVRR$ is slightly lower than 1 (Figure 3-16).
- The time dependent response is not seen when reservoirs are considered with the same petrophysical properties and initial temperature and pressure conditions (same viscosity) as shown in Annex A.3. In the closed system, this response is very short (Figure 3-10) because there is not much volume to be pressurized.

- The pressure depletion due to the replacement of hot water by cold water as observed in the closed system is minimized due to the larger volume in the boundaries of the model (Figure 3-17).

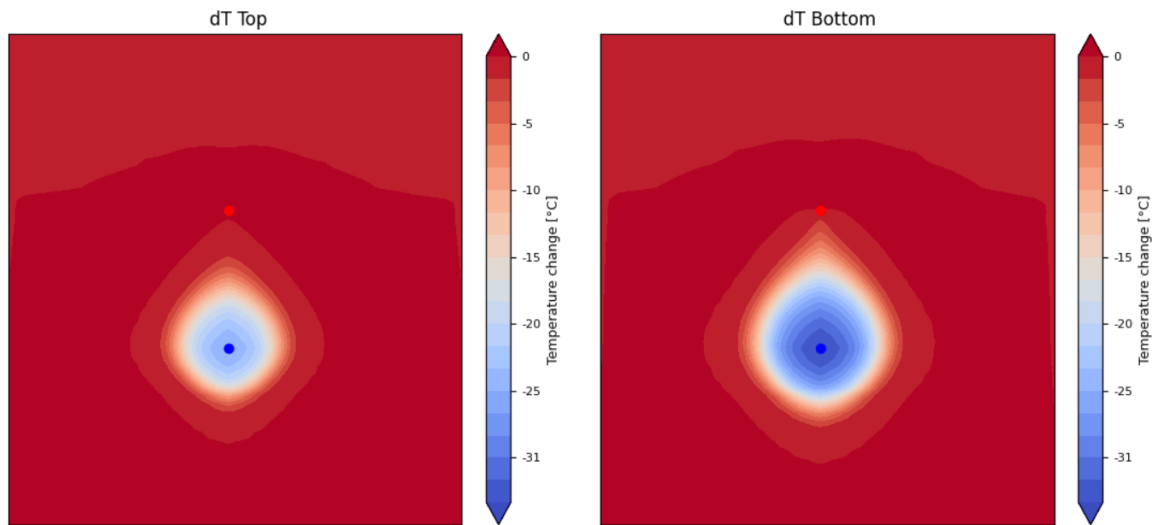


Figure 3-12: Change of temperature after 30 years of injection at constant rate of 280 m³/h, for the Base Case scenario for semi-open side boundaries. Top reservoir (left) and bottom reservoir (right). Injection well shown in blue and production well in red.

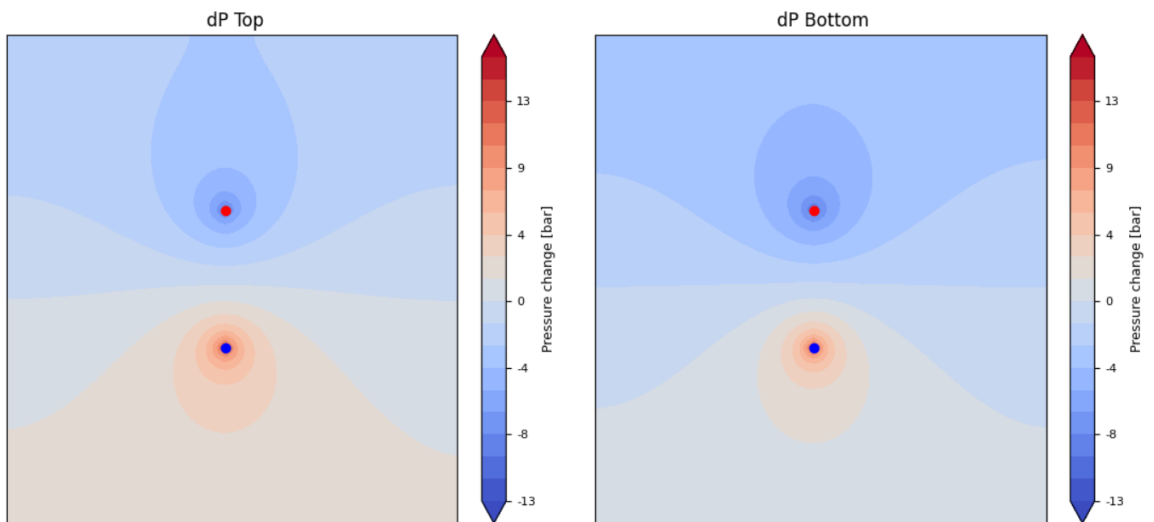


Figure 3-13: Change of pressure after 30 years of injection at constant rate of 280 m³/h, for the Base Case with semi-open side boundaries. Negative values indicate depletion while positive values indicate pressurization. Top reservoir (left) and bottom reservoir (right). Injection well shown in blue and production well in red.

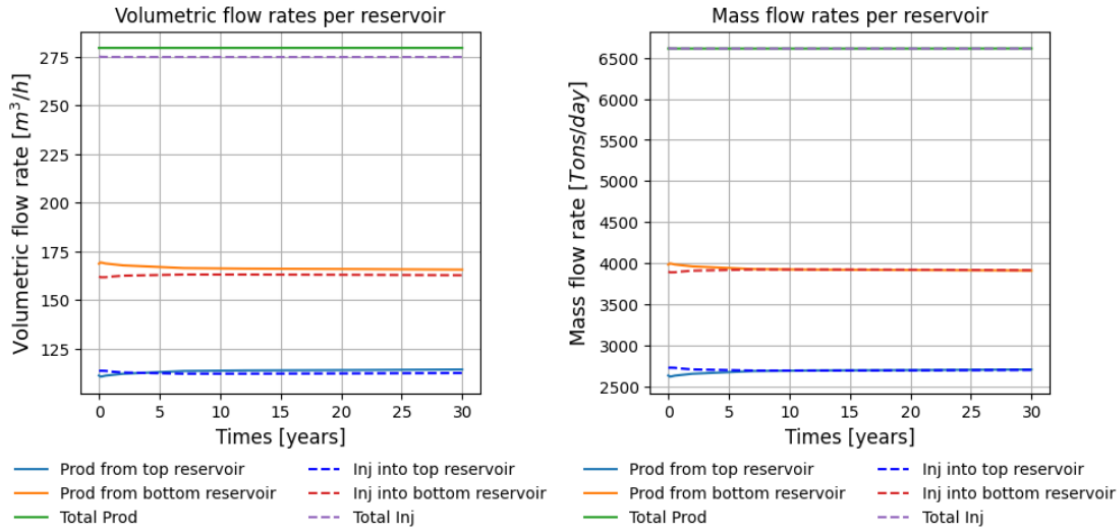


Figure 3-14: Evolution of injection and production volumetric (left) and mass flow rates (right) per reservoir for the Base Case, for a semi-open system.

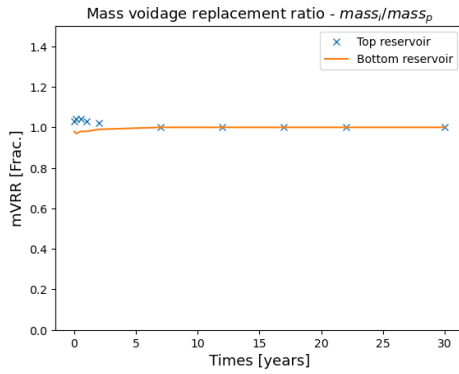


Figure 3-15: Evolution of the mass voidage replacement ratio (mVRR) in every reservoir, for the Base Case system with semi-open boundaries. p : produced and i : injected.

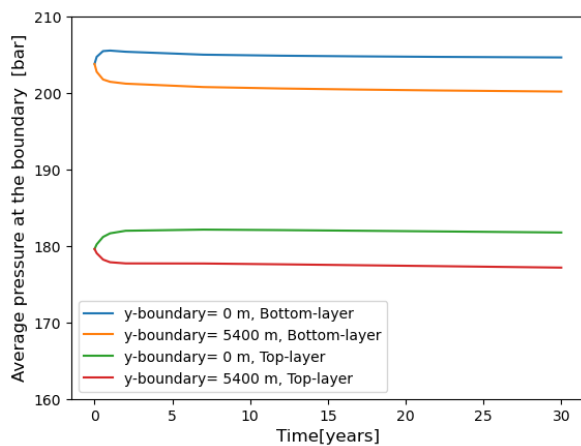


Figure 3-16: Evolution of pressure in the boundaries (Base Case, semi-open system). It shows pressurization and depletion at early time depending on the boundaries ($y=0$ m, $y= 5400$ m), which are responsible for the early imbalance.

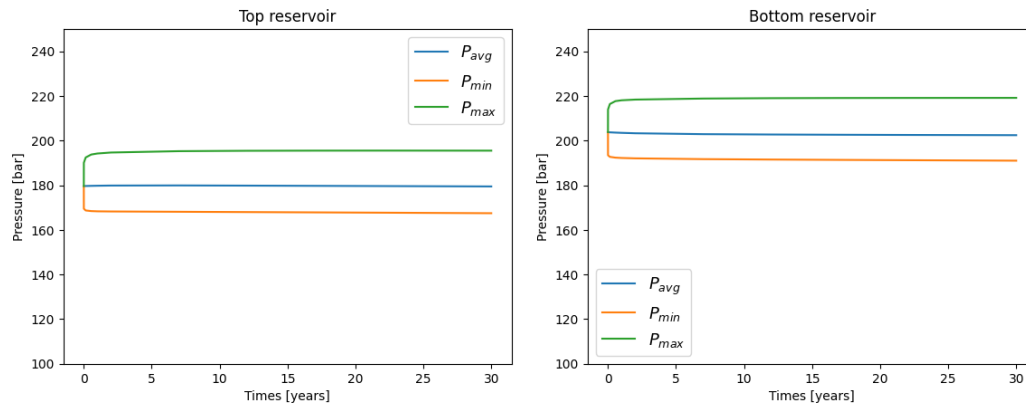


Figure 3-17: Top reservoir (left) and bottom reservoir pressure (right): average, minimum and maximum pressures for the Base Case, in a semi-open system.

4 EFFECT OF RESERVOIR, FLUID, AND WELL CHARACTERISTICS ON THE USE OF MULTIPLE RESERVOIRS UNDER COMMINGLED PRODUCTION

To assess the impact of various potential conditions that may cause production/injection unbalances across individual reservoirs in a commingled geothermal doublet system, a series of simplified numerical experiments have been designed. Potential conditions addressed in this chapter are differences in permeability, thickness, density and viscosity (brine composition), temperature, well completion, and skin.

These experiments are based on the Base Case considering semi-open boundary conditions. These boundary conditions have been chosen because aquifer systems may extend for kilometers and because of the longer duration of the unbalanced effects compared to cases with closed boundaries, where steady state is reached almost instantaneously (see Figure 3-9 and Figure 3-14).

Additionally, the geochemical interaction of two brines with different compositions is analyzed. In all figures of the numerical reservoir model, blue is used to indicate an injection well and red for a production well. The distance between the wells is 1500 m.

Each section includes a table listing the simulated cases related to that parameter. An overview of all simulated scenarios is included in the appendix of this report (Annex C).

4.1 Impact of permeability variation between producer and injector

The effect of heterogeneous permeability on a geothermal doublet is assessed via two general case studies compared to the Base Case. The first case study is the extreme case where one reservoir pinches out between the wells and, thus, is present in one well but not the other well. We refer to these cases as “laterally discontinuous reservoirs”. The second case study is a less extreme case where reservoir permeability is variable, with a higher permeability around one well location and a lower permeability around the other well location.

4.1.1 Simulation setup

4.1.1.1 Laterally discontinuous reservoirs

In addition to the Base Case, four cases with different configurations including a laterally discontinuous reservoir were tested in this analysis (Figure 4-1): 1) bottom reservoir absent in the production well only (Bot Pro); 2) bottom reservoir absent in the injection well only (Bot Inj); 3) top reservoir absent in the production well only (Top Pro); and 4) the top reservoir absent in the injection well only (Top Inj).

In these scenarios, each well was completed through each reservoir section, but the permeability was set to 0.0001 mD in the discontinuous or absent portion of the reservoir. The permeability of the continuous reservoir was left unchanged (as compared to the Base Case).

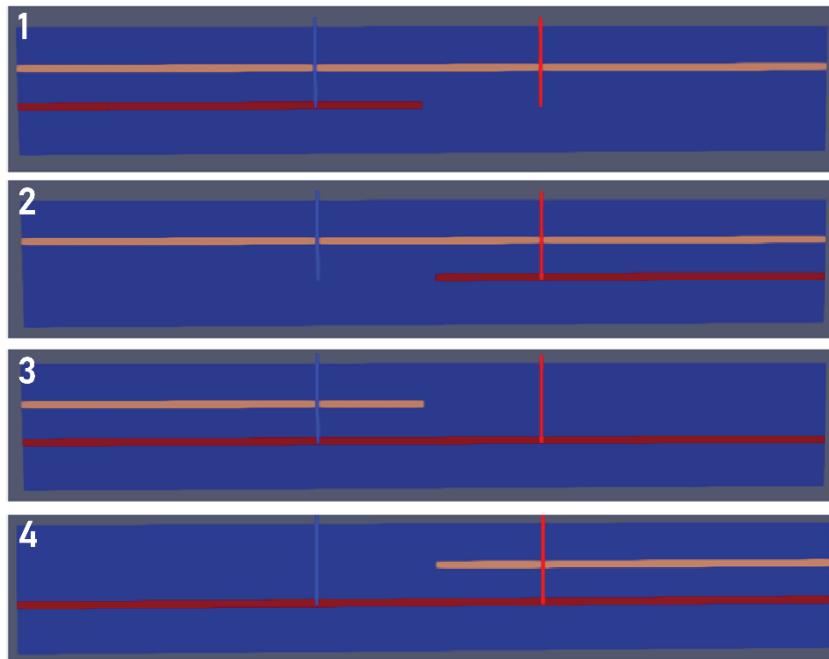


Figure 4-1: Laterally discontinuous reservoir cases tested in this study: 1) Bot Pro, 2) Bot Inj, 3) Top Pro, 4) Top Inj.

4.1.1.2 Smooth permeability variation

In this scenario, the top reservoir was assumed to have homogeneous permeability, while the bottom reservoir exhibits a smooth linear variation between the injector and producer wells that extends towards the boundary of the models (Figure 4-2) with a value of permeability in between the wells equivalent to the permeability in the Base Case. High permeability values were assigned near the producer, while low permeability values were set toward the injector as shown in Table 4-1.

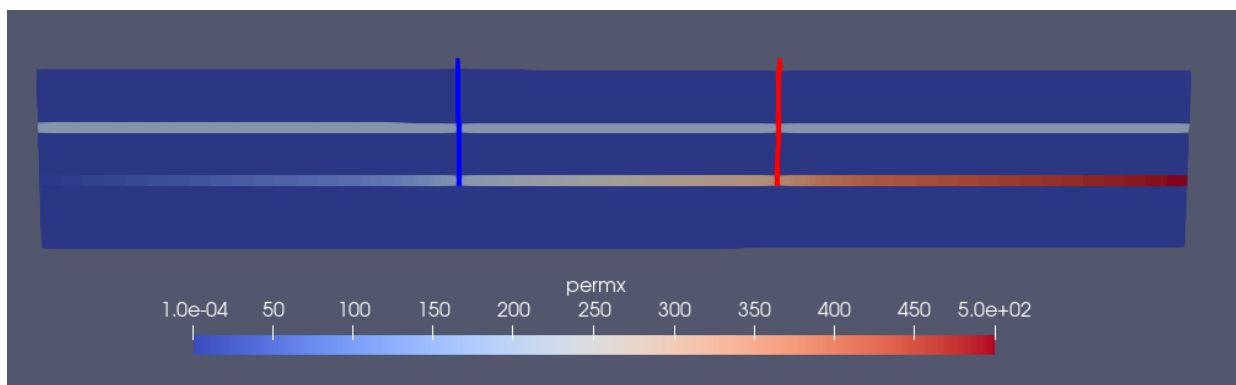


Figure 4-2. Permeability field description for the smooth permeability variation case.

Table 4-1: Permeability at the wells for the case of smooth permeability variation.

Reservoir	Injector well Perm_x [mD]	Producer well Perm_y [mD]
Top	190	190
Bottom	183.5	322.7

Table 4-2: Overview of scenarios simulated in Section 4.1.

Scenario	Description
Base Case	Base Case scenario (semi-open boundaries) with continuous reservoirs in both wells
Bot Pro	Laterally discontinuous bottom reservoir, absent in production well
Bot Inj	Laterally discontinuous bottom reservoir, absent in injection well
Top Pro	Laterally discontinuous top reservoir, absent in production well
Top Inj	Laterally discontinuous top reservoir, absent in injection well
Smooth	Scenario with homogeneous permeability in the top reservoir, and a smooth linear permeability variation between injector and producer in the bottom reservoir

4.1.2 Simulation results

4.1.2.1 Laterally discontinuous reservoirs

The results for all the laterally discontinuous cases have one thing in common: flow in the discontinuous reservoir eventually tends toward zero. This occurs through over/under pressurization of the entire reservoir volume until a pressure difference required to drive fluid flow is no longer possible. Ultimately, the permeability in the continuous reservoir determines the pressure difference required in the well and the level then reached in the discontinuous reservoir. Figure 4-3 shows the mass flow rates per well per reservoir for the cases with laterally discontinuous permeability in one reservoir. The flow rate results are qualitatively the same for each discontinuous case – the reservoir with higher permeability initially has a higher flow rate and the flow in the discontinuous reservoir eventually tends to zero after some time.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

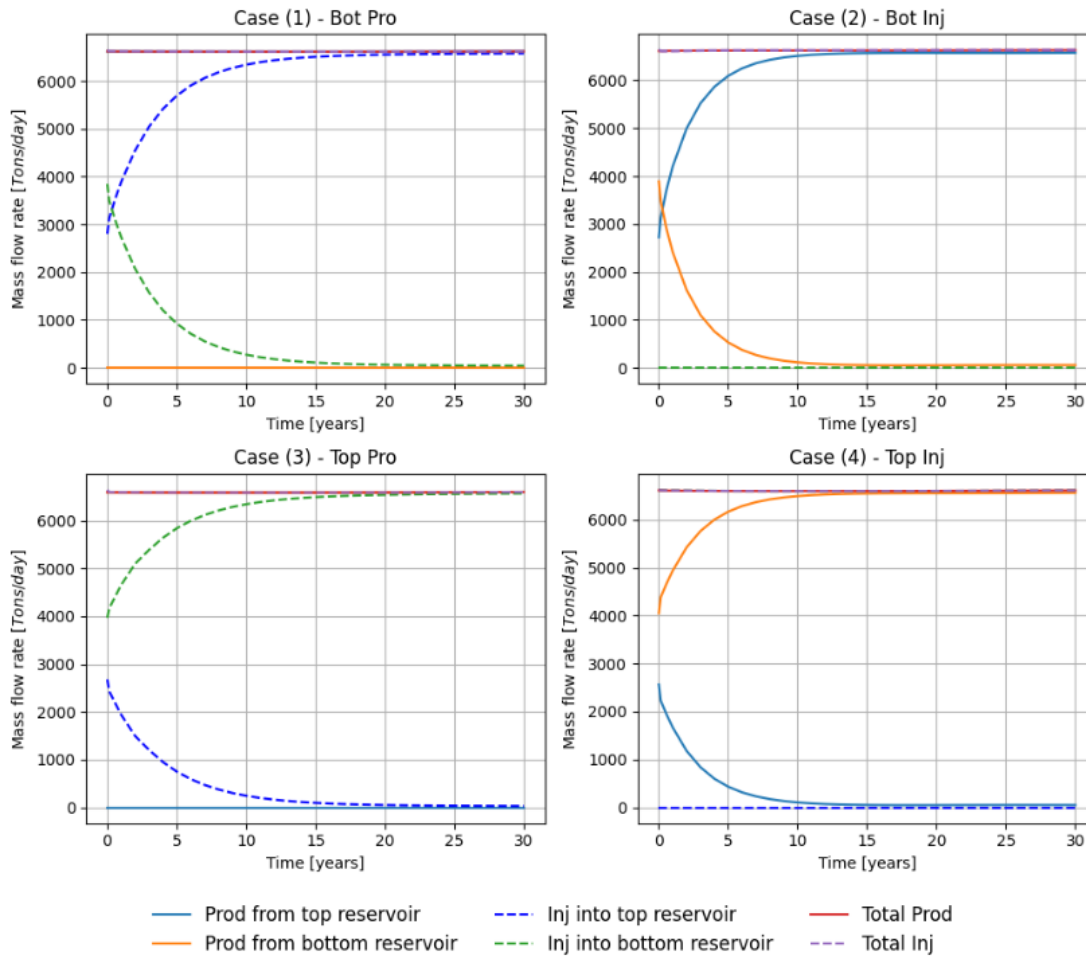


Figure 4-3: Mass flow rate for each well and for each reservoir for discontinuous reservoir cases. Production from top reservoir is the same as total production, so curves overlap.

Figure 4-4 shows pressure and temperature changes compared to the natural state before production for each reservoir for the scenario with a laterally discontinuous bottom reservoir (absent in the production well, case Bot Pro, 1 in Figure 4-1). The results show that pressure change in the discontinuous reservoir is extensive. Since flow eventually goes to zero in that reservoir, the thermal impact is significantly reduced compared to the top reservoir. The green line marks a center line across the model. Plots of the pressure change along the green line are shown in Figure 4-5. In continuous reservoirs, the magnitude of the pressure changes is maximized near the well and falls off away from the well. However, in the laterally discontinuous reservoirs, the pressure change is seen across the entire reservoir as the flow reaches zero.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

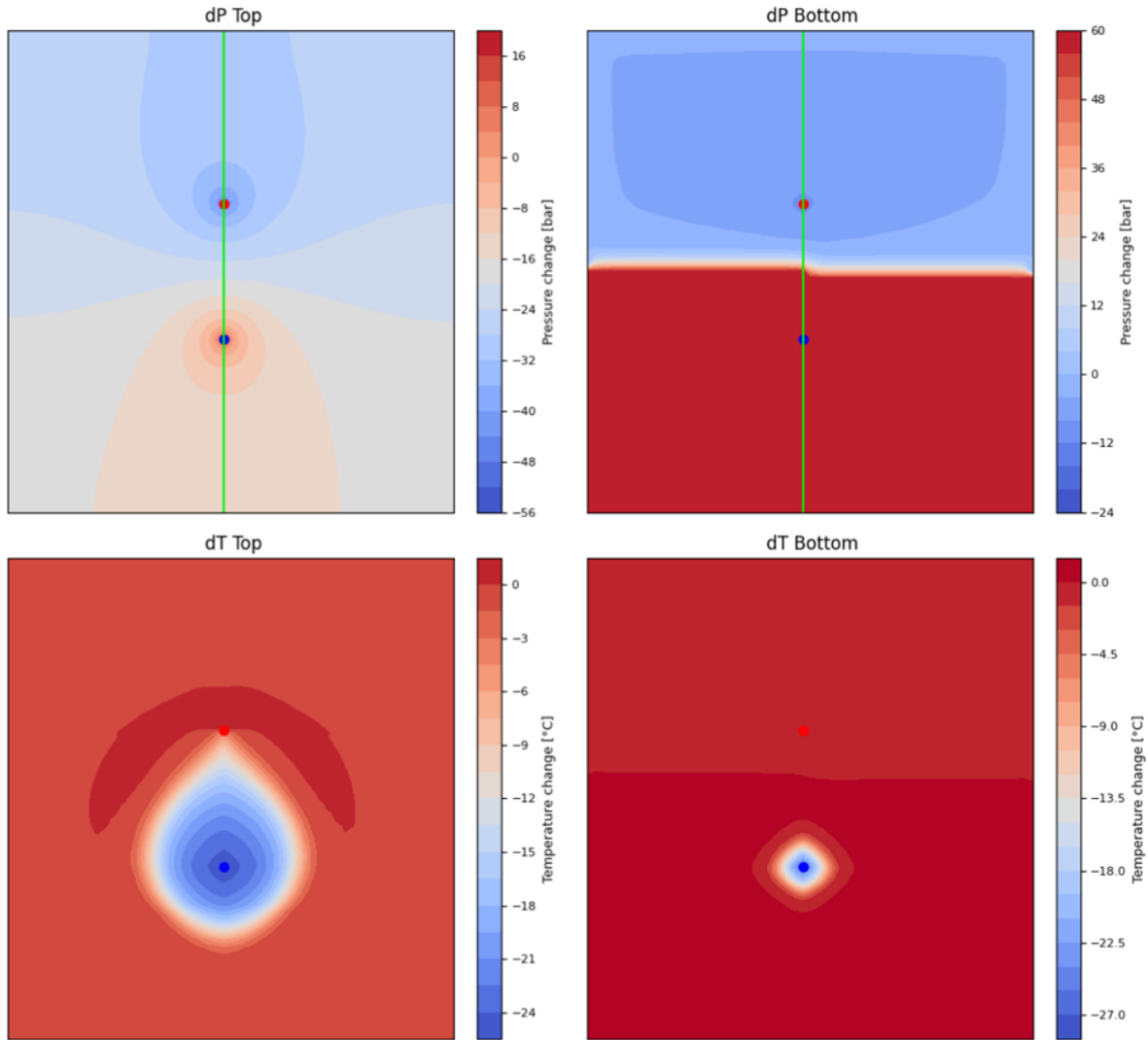


Figure 4-4: Pressure changes (top) and temperature changes (bottom) in top view of the model due to production for the top (left) and bottom (right) reservoirs in the laterally discontinuous bottom reservoir case at the end time of 30 years (case Bot Pro with bottom reservoir absent near production well). Green lines in top figures show the position of the pressure profile along the wells. Injection well shown in blue and production well in red.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

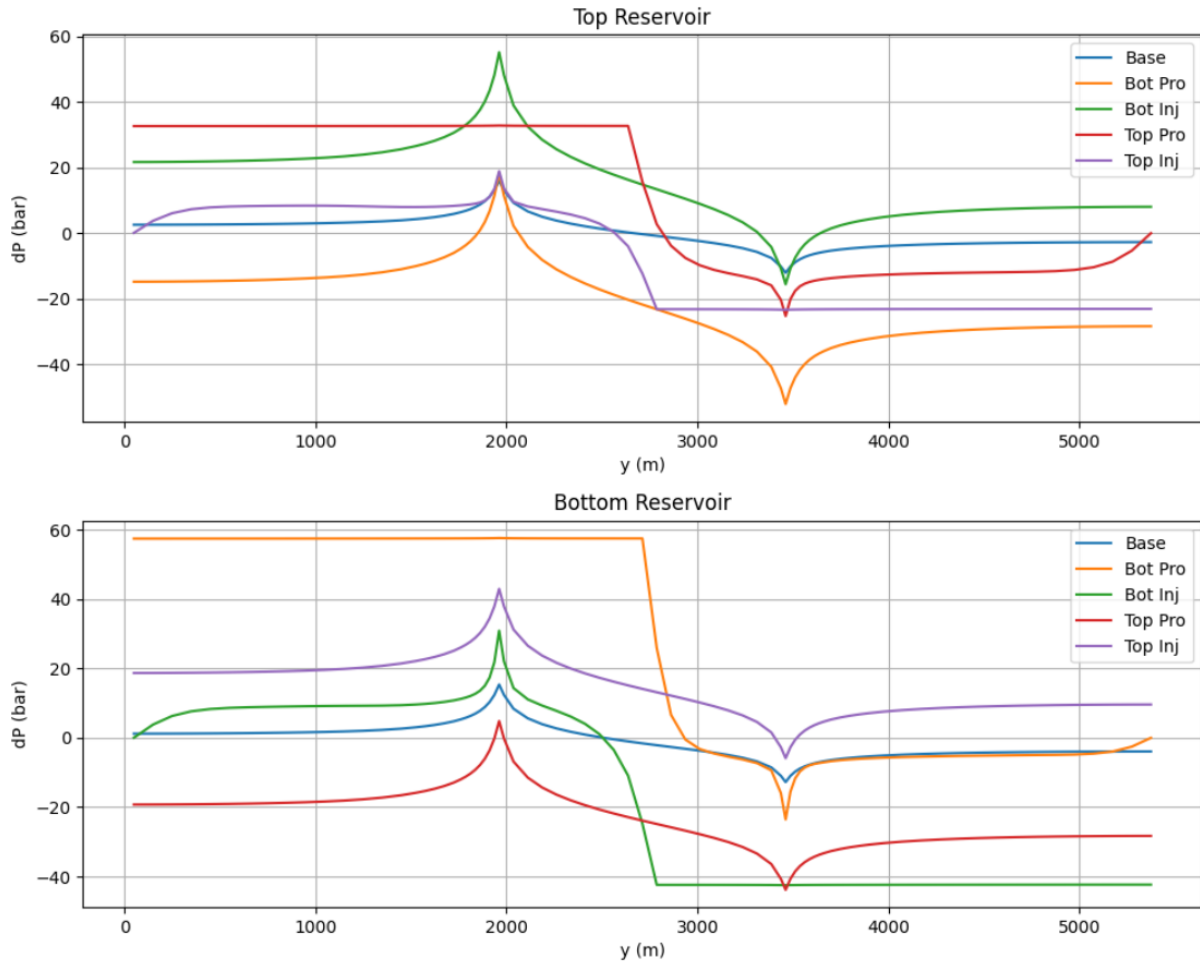


Figure 4-5: Delta pressure profiles along green line shown in Figure 4-4 (from bottom to top of the green line) for Base Case and for discontinuous permeability cases for top and bottom reservoirs at the end time of 30 years (upper and lower graph respectively). The changes in pressure are relative to the initial condition in each model, so pressure changes are due to production.

Figure 4-6 displays the pressure results at the depth of the bottom reservoir both in the wells (well) and in the numerical simulation blocks containing the wells (res) for the case with a laterally discontinuous bottom reservoir in the production well. The reservoir is overpressurized near the injection well and after about 10-15 years of production and injection, there is no longer sufficient dP (pressure difference) between the reservoir and the well to drive fluid flow into the reservoir. This would present itself as a loss of the reservoir.

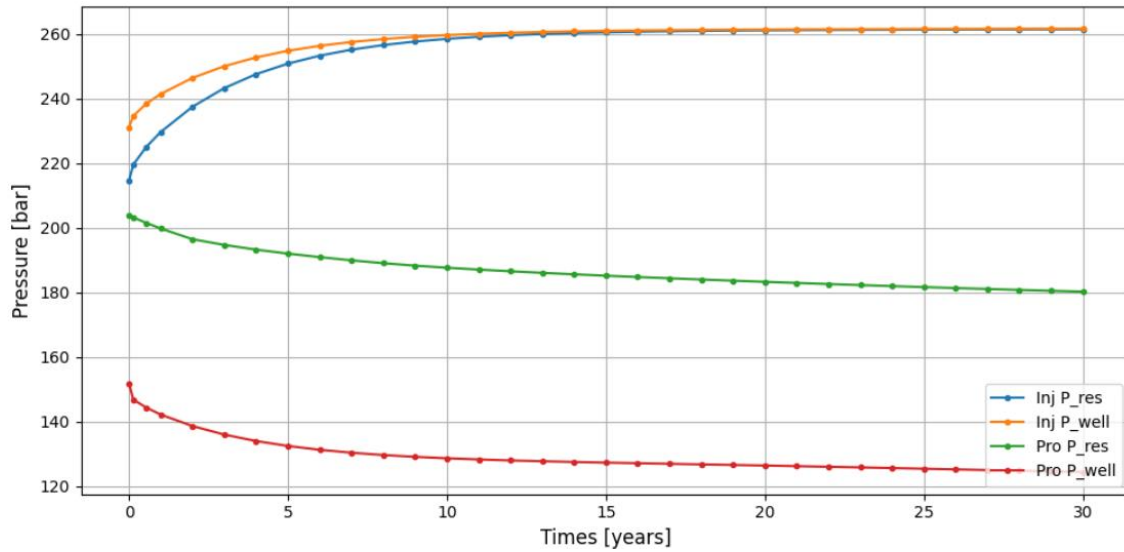


Figure 4-6: Bottom hole pressure in wells (well) and in the numerical simulation blocks containing the wells (res) for the case with a laterally discontinuous bottom reservoir in the production well (Bot Pro).

Figure 4-7 displays the mass and volume voidage ratios for each reservoir for the case with the laterally discontinuous bottom reservoir in the production well (Bot Pro). The high initial ratios for the bottom reservoir are due to zero production in that reservoir. The initial ratios for the top reservoir are low as all production comes from this reservoir, whereas injection goes into both reservoirs. Through time, injection in the bottom reservoir declines, hence the ratios for the top reservoir increase (and decrease for the bottom reservoir).

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

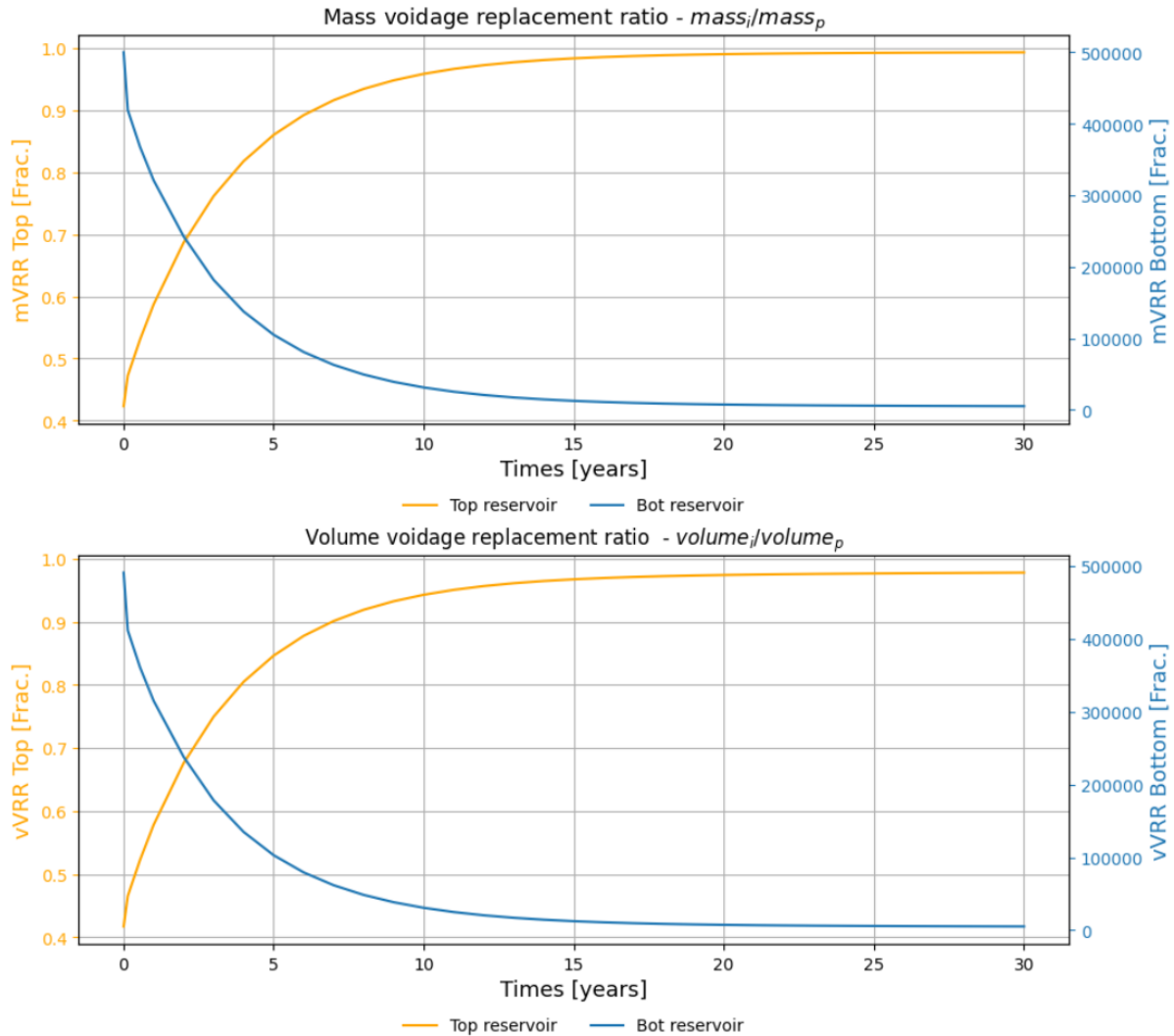


Figure 4-7: Mass voidage replacement ratio (mVRR - top) and volume voidage replacement ratio (vVRR – bottom) for the case with a discontinuous bottom reservoir in the production well (Bot Pro).

It is worth mentioning that the pressure changes (final minus initial state) are a function of the permeability of the continuous reservoir and the flow rate as shown in Figure 4-8 for the Bot Pro case. In the figure, different flow rate/permeability combinations were tested. Some of these may lead to extremely high injection pressure but serve to help understand the physical processes at play. These extreme cases may not occur in reality as the pressure changes may be beyond the maximum permitted pressure. The figure shows a dashed line indicating an example maximum pressure gradient of 0.135 bar/m, following the (now disused) protocol for the calculation of injection pressures by SSM (2020). The conclusion is that the significance and magnitude of the observed pressure changes will vary depending on the reservoir's characteristics. Moreover, these changes can be regulated by adjusting the operational flow rates when, for example, maximum allowable pressures are met.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

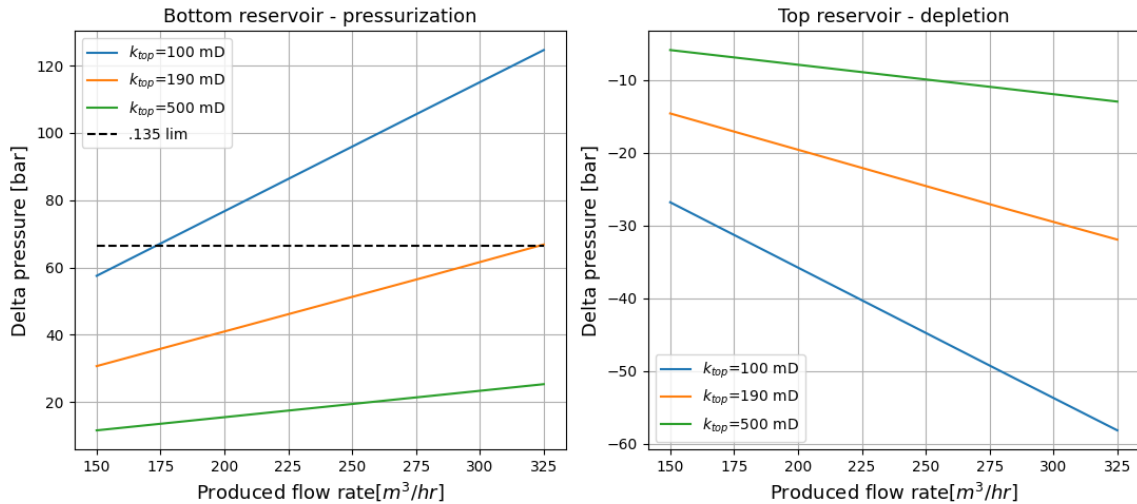


Figure 4-8. Effect of the permeability of the continuous reservoir (k_{top}) on the pressure changes at the end of the simulation (30 years) in the y-boundaries of both reservoirs (for the Bot Pro laterally discontinuous permeability case). Pressurization at the y boundary ($y=0$ m) of the bottom reservoir near the injection well (left) and depletion at the y boundary ($y=5400$ m) of the top reservoir near the production well (right). The dashed line shows an example maximum limit to the pressure gradient and follows from the protocol for the calculation of maximum injection pressures by SSM (2020).

4.1.2.2 Smooth permeability variation

Figure 4-9 shows the comparison of mass flow for the Base Case (left) and smooth permeability variation model (right). The permeability is higher in the bottom reservoir near the production well than near the injection well, so there is initially an unbalanced flow situation. Eventually, the flows balance with injection and production from each reservoir equilibrating.

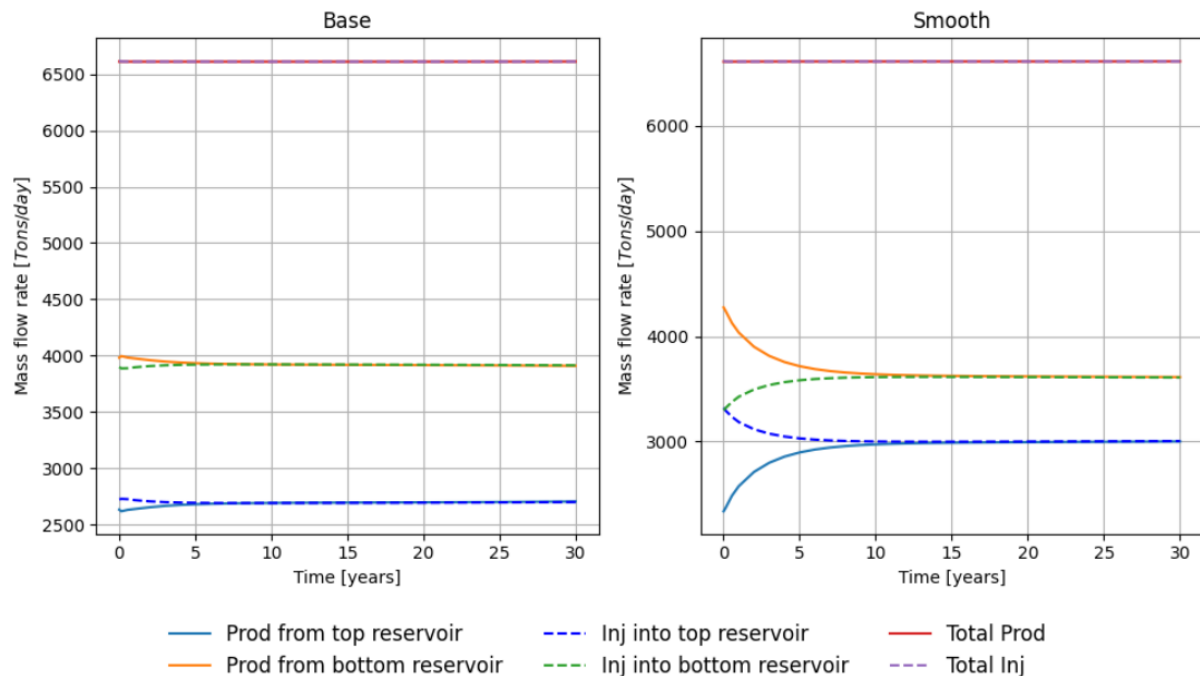


Figure 4-9: Mass flow comparison for each reservoir for Base Case model (left) and smooth permeability model (right).

The effects of mass/volume balancing are more readily observed in the voidage replacement ratio plots shown in Figure 4-10. Both reservoirs tend toward a replacement ratio of 1 after about 15 years.

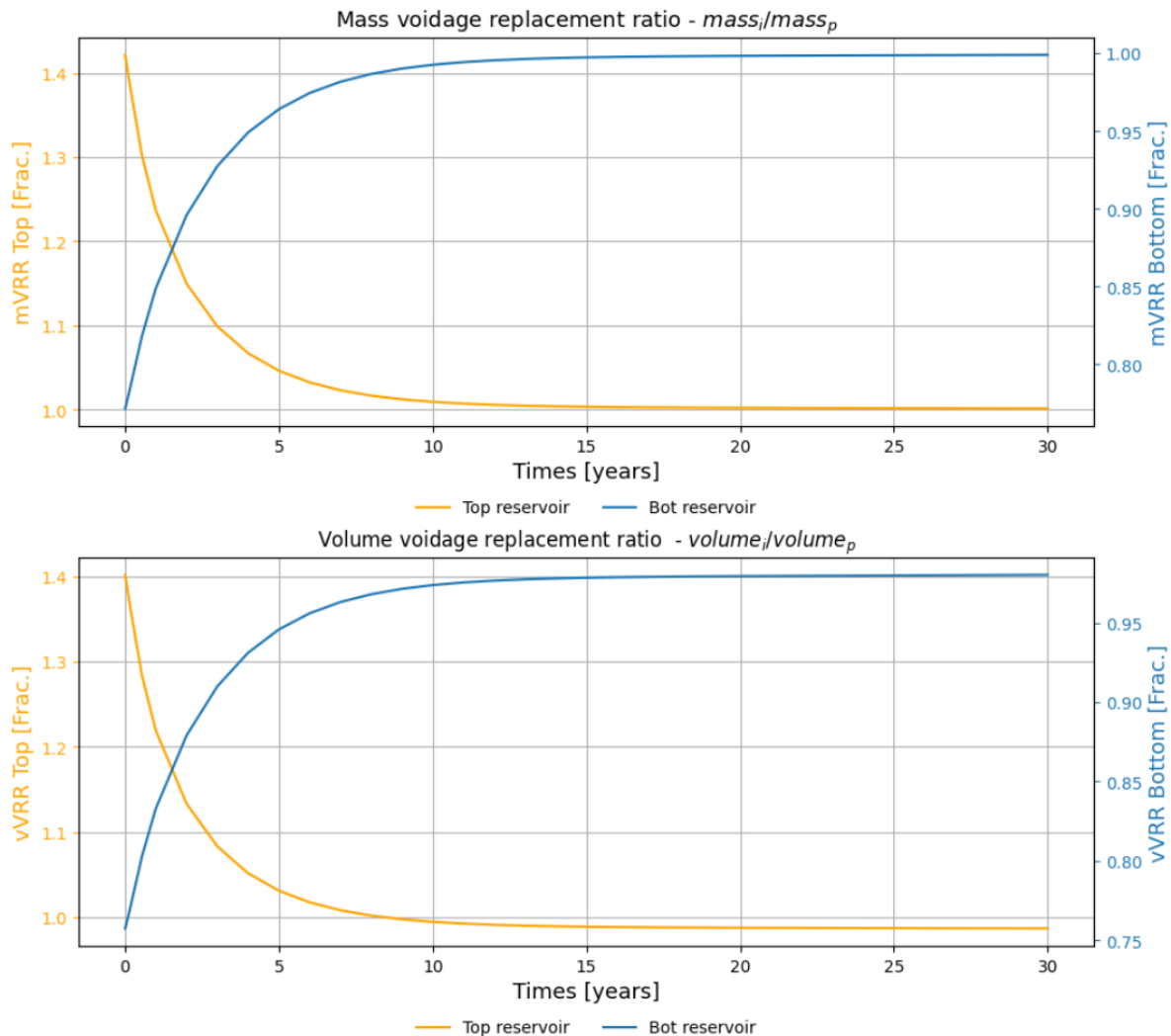


Figure 4-10: Mass (mVRR - top) and volume (vVRR – bottom) voidage ratio plots for the smooth permeability variation case.

The pressure profiles (along the wells) of the Base Case compared to the smooth permeability variation case are shown in Figure 4-11. In general, lower permeability results in less flow and larger pressure change compared to the Base Case. The long-term balance of the flows depends on the relative permeabilities of the two reservoirs while the short-term behavior (imbalance) is determined by the local permeability near the well.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

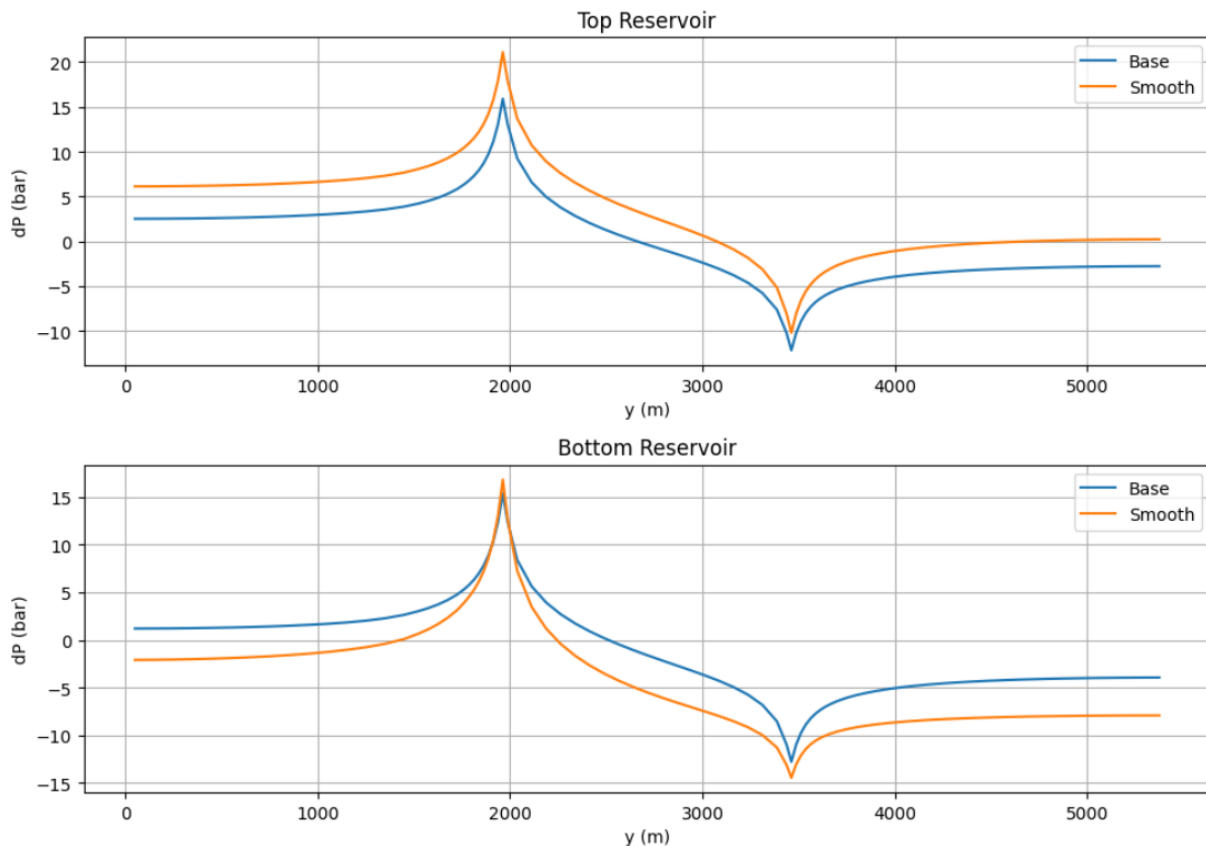


Figure 4-11: Top and bottom reservoir pressure profiles after 30 years of production and injection for the Base Case and the smooth permeability variation case. Pressure is plotted along a section through the wells where the x-axis represents the numerical model y-coordinate.

4.1.3 Permeability case main findings

Some observations that can be made include:

- Permeability variations between injector and producer wells lead to longer imbalanced commingled production (time period it takes for injection and production rate to equalize within the reservoir) at early times while at later times the system reaches balanced conditions (injection and production rates are equal within a reservoir) as shown in Figure 4-3 and Figure 4-9. This early imbalance condition was already triggered by differences in permeability between the reservoirs, even though permeability within the reservoir was continuous (e.g. Base Case).
- The observed mass imbalance, induced by permeability heterogeneities, is transient and persists only until the system reaches practical steady state, when injection and production mass flow rates, as well as pressures at the boundaries of each reservoir become practically constant. The duration of the imbalanced period increases with the degree of heterogeneity in the system. For example, in the Base Case assuming homogeneous but different petrophysical properties in each reservoir, the transient flow period lasts about 3 years, for the smooth variation of permeability it lasts 10 years (Figure 4-9), and for the laterally discontinuous cases (Figure 4-3) it can last up to 20 years. This time dependent response is also a function of the volume of the reservoir

as indicated by the difference in mass flow rate response between the closed and semi-open boundaries in the Base Case (section 3.4).

- The lateral discontinuity of a reservoir (or a limited volume, e.g., reservoir compartment) will result in the eventual loss of that reservoir in a well as the pressure builds up or depletes in that area unless there is connection to another aquifer.
- A practical observation in cases of laterally discontinuous permeability between wells is that the pressure within the discontinuous reservoir (where injection or production is taking place) tends to equilibrate with the bottomhole pressure (BHP) of the injector or producer, as illustrated in Figure 4-6. This indicates that BHP serves not only as a key parameter for monitoring wellbore conditions but also as a proxy for estimating reservoir pressure in such discontinuous systems. Consequently, BHP measurements can be valuable for assessing geomechanical hazards associated with reservoir pressurization.

4.2 Impact of thickness variation between producer and injector well

For this analysis, additional cases were modelled to represent a pinch-out or thinning scenario where reservoir thickness may vary between wells. This could be viewed as a transition study from the continuous permeability base case to the laterally discontinuous reservoir cases in the previous section. Consider Figure 4-12 as an example where the bottom reservoir is thicker near the injection well but gradually thins toward the production well.

Practically, to represent the changes in thickness, the initial grid described in section 3.1.1 and Figure 3-1 was refined in the z-direction. This was done from the top of the top reservoir to the base of the bottom reservoir. The Δz (cell size in the z-direction) in this domain was reduced from 50 m to 16.7 m, so three numerical grid layers were used to represent one reservoir. Then, certain grid layers were assigned either a reservoir or a sealing (10^{-4} mD) permeability to represent the thinning of that reservoir.



Figure 4-12: Example of bottom reservoir thinning between injection and production well.

Table 4-3: Thickness of the bottom reservoir in the studied cases.

Case	Thickness in the producer well ' h_{prod} ' [m]	Thickness in the injector well [m]
h0	50	50
h1	33.3	50
h2	16.7	50
h3	0	50

4.2.1 Simulation setup

The thickness of the bottom reservoir was reduced stepwise from the injector to the producer well (Figure 4-13 and Figure 4-14).. Two cases with thickness for the bottom reservoir of 50 m in the injector well and 33.3 m (Case h1) and 16.7 m (Case h2) in the producer well were studied and compared with the results of continuous thickness (Case h0) and no thickness (Case h3) in the mentioned reservoir and well. Table 4-3 summarizes the cases tested. Case h0 is equivalent to the Base Case but with higher vertical grid resolution in the reservoir zones (3 layers per reservoir) and Case h3 is equivalent to the discontinuous permeability case Bot Pro.



Figure 4-13: Cross-section of numerical model for the stepwise thickness variation case. Bottom reservoir thickness at the producer well equal to 16.7 m (case h2).



Figure 4-14: Cross-section of the numerical model for the stepwise thickness variation case. Bottom reservoir thickness at the producer well equal to 33.3 m (case h1).

Table 4-4: Overview of scenarios simulated in Section 4.2.

Scenario	Description
h0	Base Case scenario (semi-open boundaries) with uniform reservoir thickness (50 m) in both wells, but with 3 cell layers per reservoir
h1	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 33.3 m thick at production well)
h2	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 16.7 m thick at production well)
h3	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 0 m thick at production well), which is the same as scenario Bot Pro
h4	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 33.3 m thick at injection well)
h5	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 16.7 m thick at injection well)
h6	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir m thick at injection well), which is the same as scenario Bot Inj

4.2.2 Simulation results

Figure 4-15 displays the flows for each reservoir for the cases with variable thickness. The higher permeability bottom reservoir (top reservoir horizontal permeability 190 mD, bottom

reservoir horizontal permeability 265 mD) has a decreasing thickness at the production well in the simulations. So, initially injection is good in that reservoir, but decreases over time as the production capacity is limited by thickness. Like the permeability investigation case, initially the reservoirs are used in an unbalanced condition that eventually equilibrates after some time. The time to equilibration increases as the production thickness decreases.

For the simulated cases, the bottom reservoir is pressurized (positive delta pressure) and the top reservoir is depleted (negative delta pressure). This is shown on the resulting pressure change profiles (delta pressure from initial state to 30 years) in Figure 4-16.

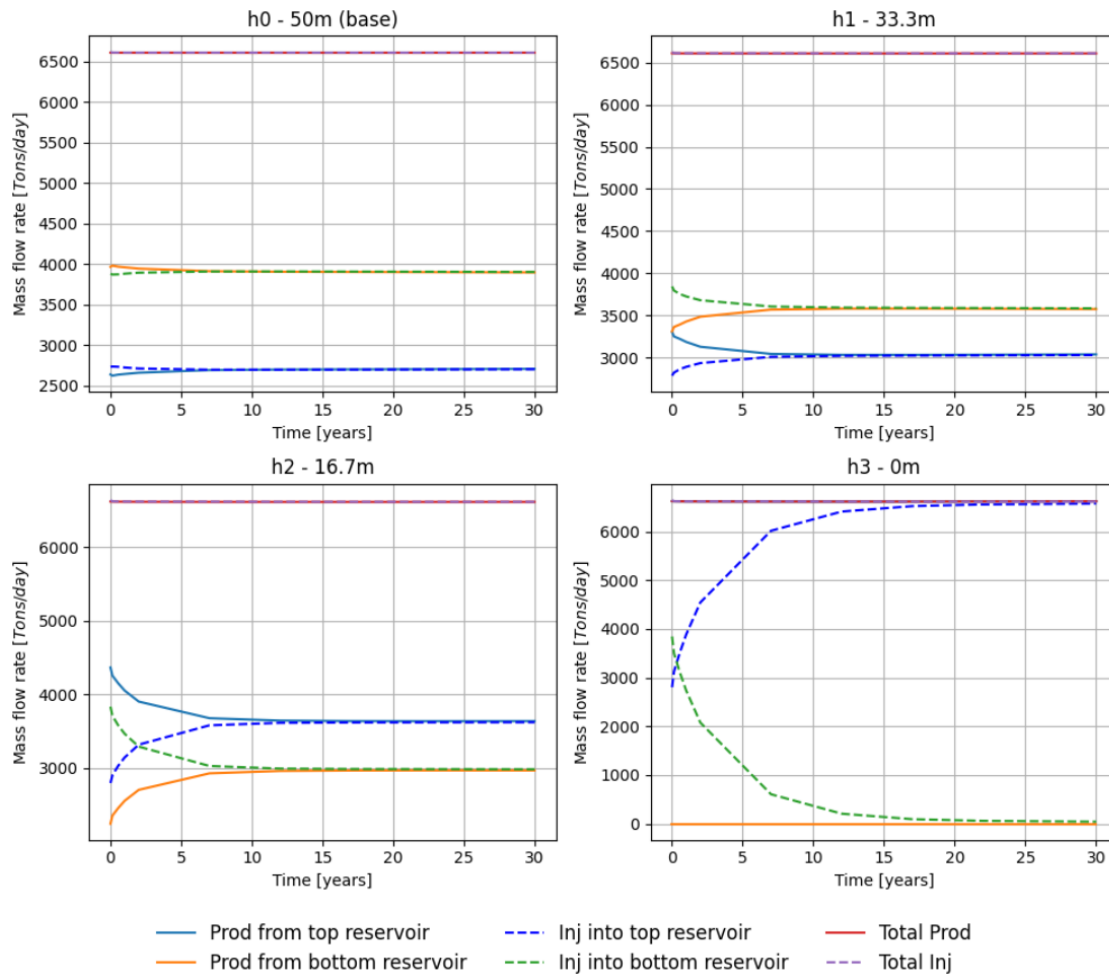


Figure 4-15: Mass flow results for each reservoir for variable thickness simulations (h0: Base Case, h1: 33.3 m thick production, h2: 16.7 m thick production, h3: discontinuous case or Bot Inj).

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

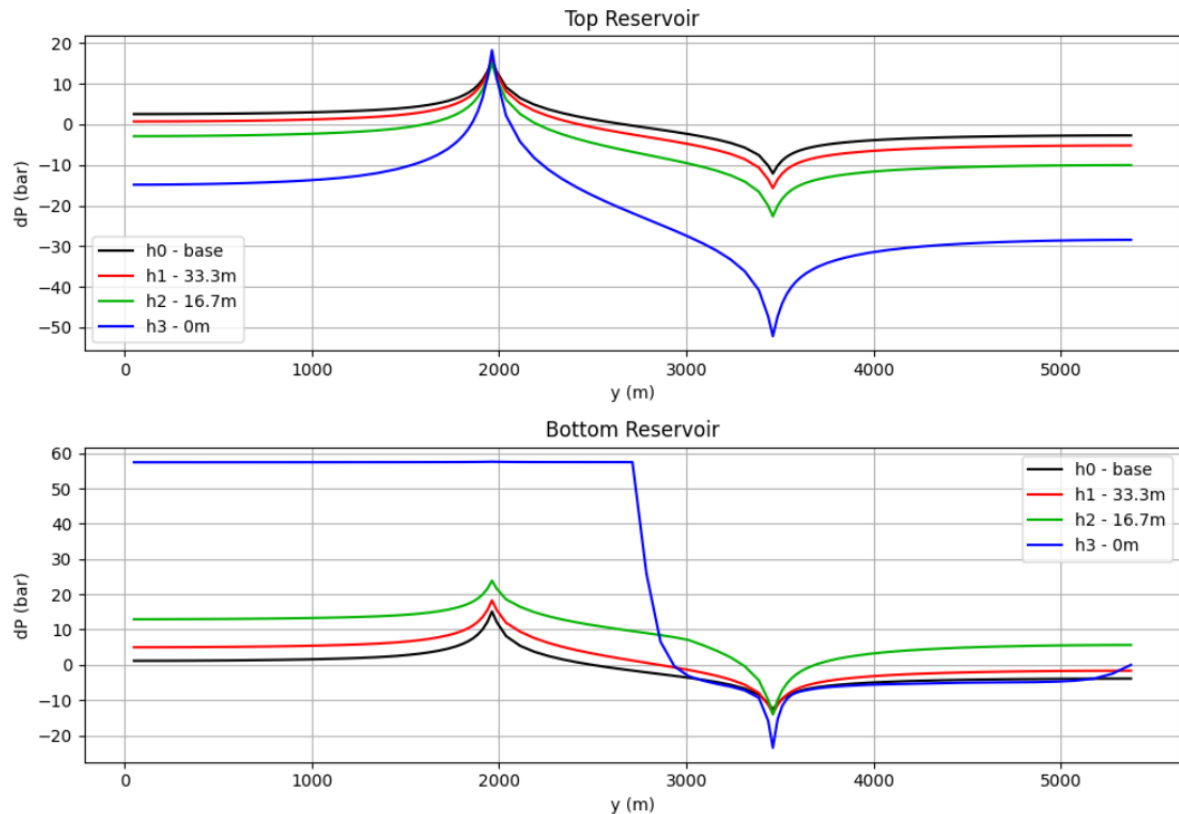


Figure 4-16: Pressure profiles after 30 years for the thickness case scenario investigations.

It is important to note that reversing the direction of reservoir thinning by changing bottom reservoir thickness towards the injector while keeping it constant at 50 m at the producer will lead to the opposite effect: depletion will occur in the bottom reservoir, while pressurization will affect the top reservoir. This effect can most easily be seen in Figure 4-17, as pressure change is mostly positive in the top reservoir and negative in the bottom reservoir. The extreme case of a discontinuous bottom reservoir in the injection well is modelled in the previous section and represented by case Bot Inj in Figure 4-3 and Figure 4-5.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

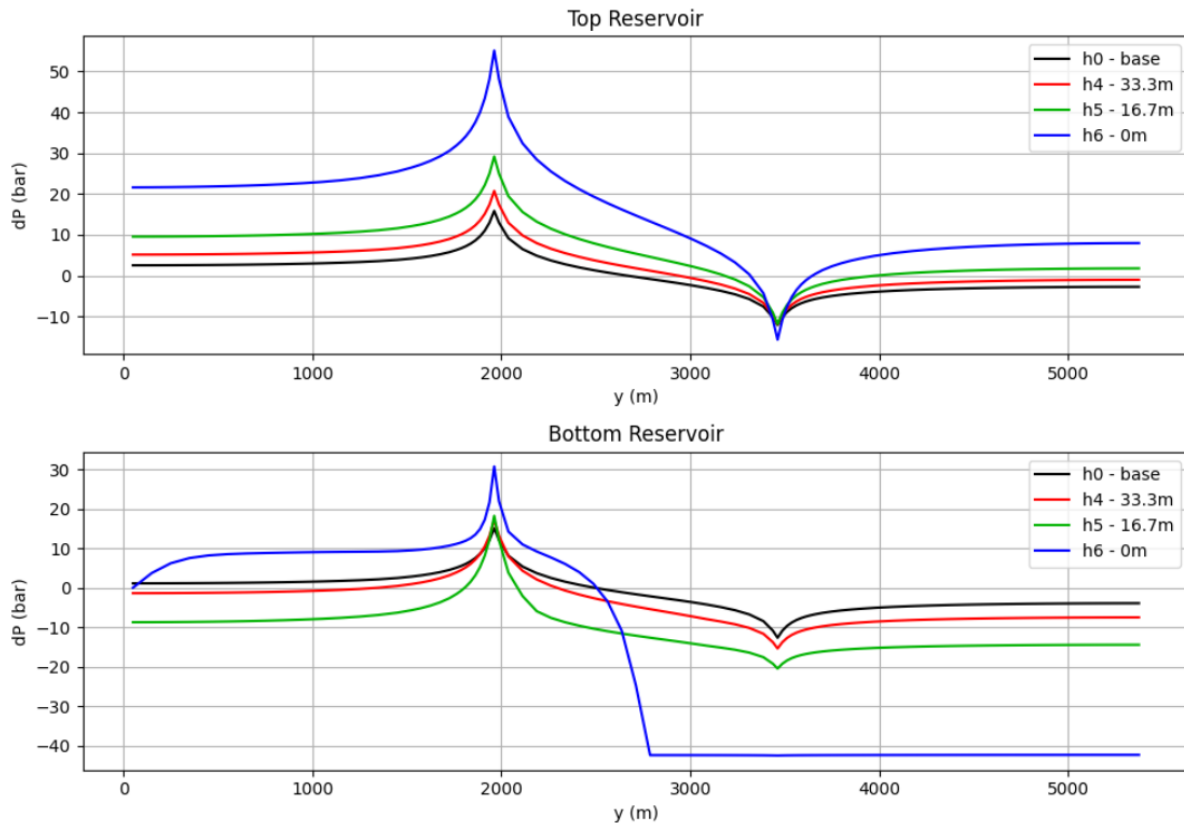


Figure 4-17: Pressure change profiles after 30 years for the opposite case where the bottom reservoir is thinning in the injection well while reservoir thickness is fixed at 50 m in the production well.

4.2.3 Reservoir thickness main findings

In general, the results of the simulations assessing the effects of reservoir thickness variations are in line with the observations from the permeability variations. This is because total productivity or injectivity is a function of transmissivity, which is defined by the product of reservoir thickness and permeability. The main conclusions from this analysis are:

- The magnitude of pressure changes (dP) from initial state to 30 years increases near a well when reservoir thickness is reduced near that well. So decreases in thickness near an injection well result in more pressure increase whereas decreases in thickness near a production well result in more pressure reduction near the well.
- The imbalance flow duration lasts longer in time in more extreme thickness variations.
- The likelihood of over- or underpressurization is greatest when a reservoir completely pinches out and there is no hydraulic connection between producer and injector in that reservoir.

•

4.3 Impact of density and viscosity variations due to brine mixing

For this analysis the simulation approach was changed from one component to a compositional model in DARTS. The brines that saturate the reservoirs are defined here as a mixture of two components: water 'H₂O' and dissolved salt 'Salt' (NaCl). The dynamic properties (density and viscosity) of these brines are a function of the molar composition of the mentioned two components as was introduced in section 3.1.3 'Water properties'.

The brine-mixing process occurs during commingled production, where fluids from multiple reservoirs are combined within the wellbore of the production well. This results in an injection stream with a composition that differs from any individual reservoir's brine. The objective of this analysis is to understand how this mixing affects the injection rates for each reservoir, as flow-related properties—such as viscosity—vary with the resulting fluid composition. It is important to mention that mixing will also take place inside the reservoirs due to the injection of the mixed brine.

4.3.1 Simulation setup

For this analysis, the goal was to isolate the salinity mixing effects on viscosity and density. Therefore, the model was set to a uniform temperature of 70°C and the water density and viscosity are taken to be a function of salinity only. The injection temperature was also set to be constant at 70°C. This compositional model does not consider any chemical reaction that could lead to reduction of permeability in the reservoir or potential scaling in the wellbore. Those effects are captured in other scenarios (permeability and skin).

Six different compositional models were considered and are described in Table 4-5. COMP1 and COMP2 represent extreme cases with no salt present in the top reservoir. The bottom reservoir in COMP1 has a high but realistic brine concentration of 0.02 molar fraction salt (~120 g/L). COMP2 presents a case with an even higher molar fraction salt (0.05 or ~270 g/L) in the bottom reservoir. This value was chosen to test a very extreme case to help elucidate the impact of fluid mixing. It is worth noting that 270 g/L salt concentration has not been measured in any well in the Netherlands. COMP3 is meant to represent a more realistic mixing scenario with a top reservoir salinity of 50 g/L and a bottom reservoir salinity of 150 g/L. COMP4 is a comparison case with a salinity of 100 g/L in each reservoir. In addition, two zero salt cases were tested as a baseline for comparison, one with the thermal property variation of water ignored as in the other COMP simulations (COMP5) and one with the thermal property variation of pure water (COMP6 - Base Case from previous cases).

As mentioned earlier, the viscosity and density of the brine are calculated by DARTS to depend on salinity (Korson et al., 1969). An example calculation for viscosity, over the salinity range of this study, for brine at approximate reservoir conditions (180 bar, 70°C) is shown in Figure 4-18.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

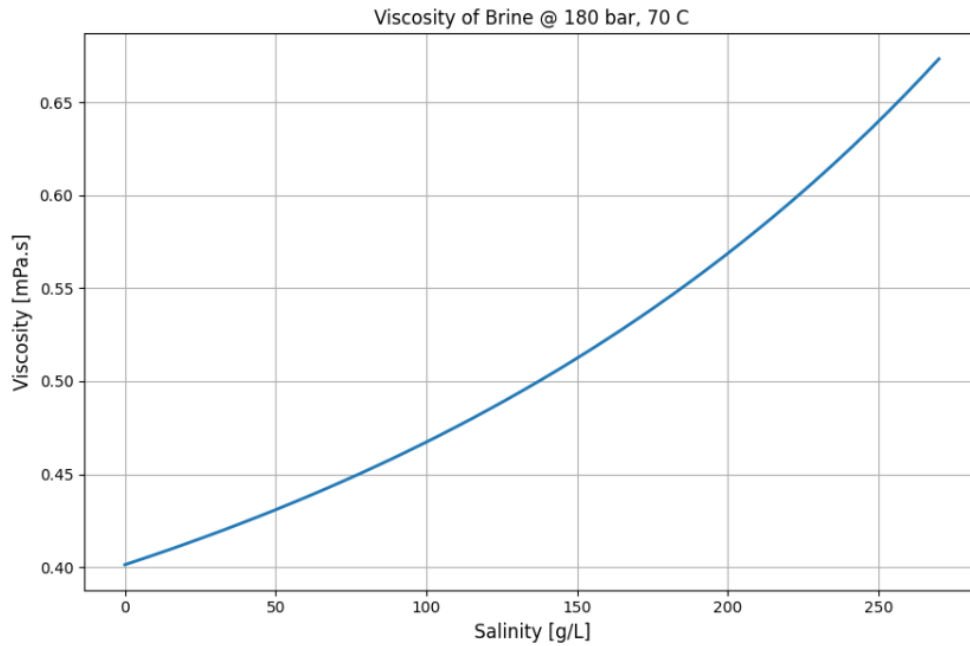


Figure 4-18: Example viscosity calculation as a function of brine salinity, using Equations 4 to 6 (Korson et al., 1969).

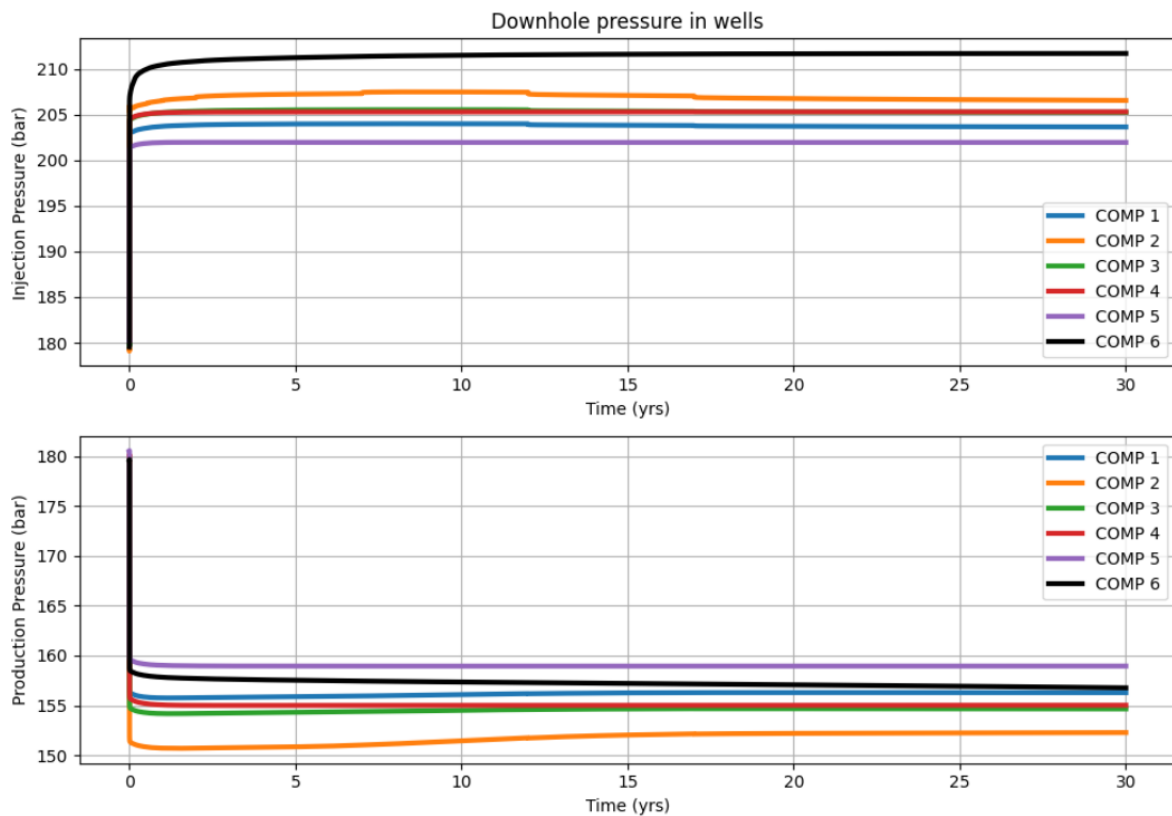


Figure 4-19: Downhole pressure in injection well (top) and production well (bottom) for the compositional model scenarios.

Table 4-5: Overview of scenarios simulated in Section 4.3.

Scenario	Description
COMP 1	Scenario with fresh water in the top reservoir and salt water in the bottom reservoir (molar fraction of 0.02, roughly equivalent to 120 g/L)
COMP 2	Scenario with fresh water in the top reservoir and salt water in the bottom reservoir (molar fraction of 0.05, roughly equivalent to 270 g/L)
COMP 3	Scenario with salt water in the top reservoir (molar fraction of 0.008, roughly equivalent to 50 g/L) and salt water in the bottom reservoir (molar fraction of 0.025, roughly equivalent to 150 g/L)
COMP 4	Scenario with salt water in both reservoirs (molar fraction of 0.016, roughly equivalent to 100 g/L)
COMP 5	Scenario with fresh water in both reservoirs, with the thermal property variation of water ignored
COMP 6	Scenario with fresh water in both reservoirs, accounting for the thermal property variation of water (= Base Case)

4.3.2 Simulation results

Figure 4-19 shows the downhole pressure results in the wells. The salinity composition of the fluid affects density and viscosity. Well injectivity/productivity is a linear relationship of fluid viscosity (Equations 10 and 11). Higher viscosity scenarios result in higher changes in well pressure required to supply the selected flow rate of 280 m³/h.

The pressure profile response in the reservoir for the compositional scenarios is shown in Figure 4-20. The pressure differences in the top reservoir are generally less than in the bottom reservoir. This is because many scenarios had lower salinity in the top reservoir. The very high salinity in the bottom reservoir for COMP2 results in higher dP values. Compared to the “no salt” case (COMP5), the total pressure changes are <5 bar in the most extreme case (COMP2).

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

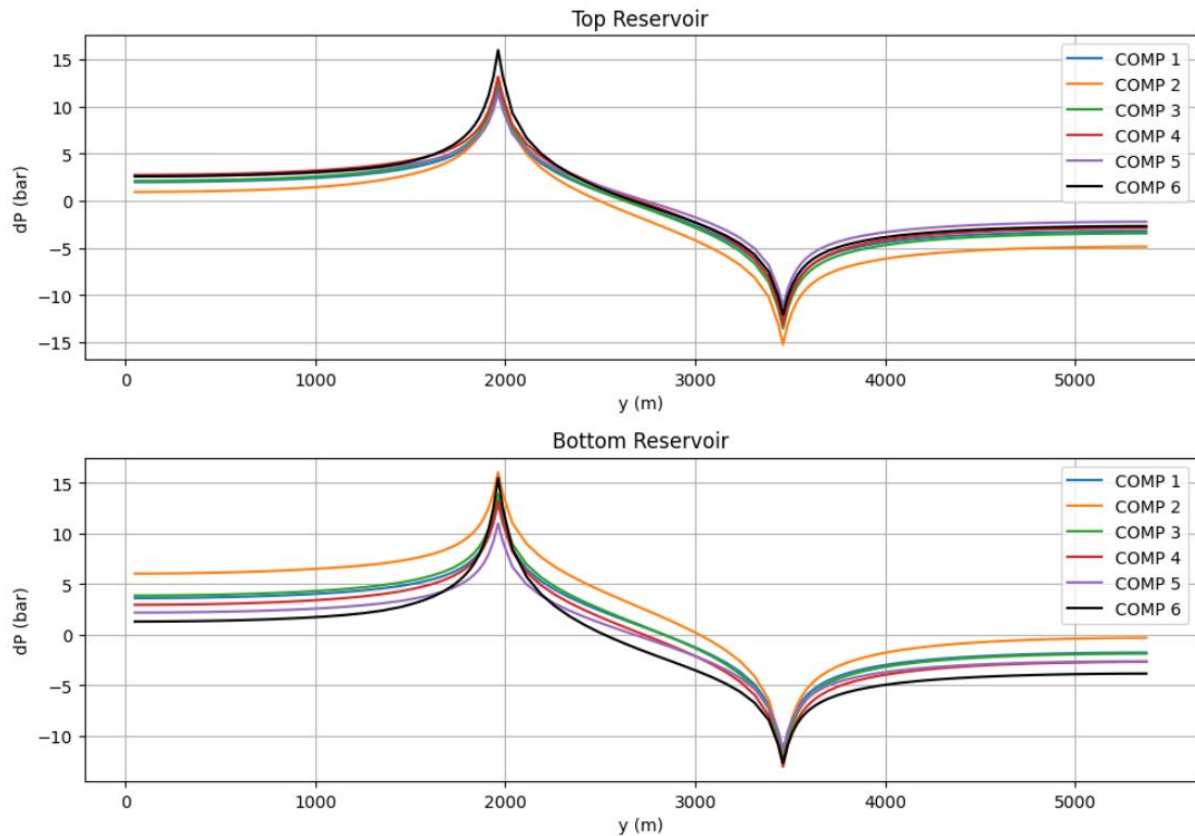


Figure 4-20: Pressure change profile after 30 years along center line in top and bottom reservoirs for the compositional model results.

The mass flow rate results for each reservoir and the total mass flows in all the compositional models are shown in Figure 4-21. The composition of each reservoir affects the viscosity and the injectivity/productivity of that reservoir. Generally elevated salinities result in lower flow into and out of the reservoir (see lower total rate values compared between COMP 1 and COMP 2). This is most clearly manifested in COMP1-3 where the bottom reservoir has a higher salinity. The injection well initially injects more than is produced since injection is a mixture of high and lower concentration brine. Eventually, mixed fluids are produced and the systems begin to equilibrate. However, in the extreme case of COMP2, that process has not yet fully occurred within 30 years. When the salinity values are within moderate ranges (COMP 3 and 4), there are initial imbalances, but the duration is not longer than those caused by temperature differences. As an example, a top view of the model with the water molar concentration for each reservoir after 30 years for COMP1 is shown in Figure 4-22.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

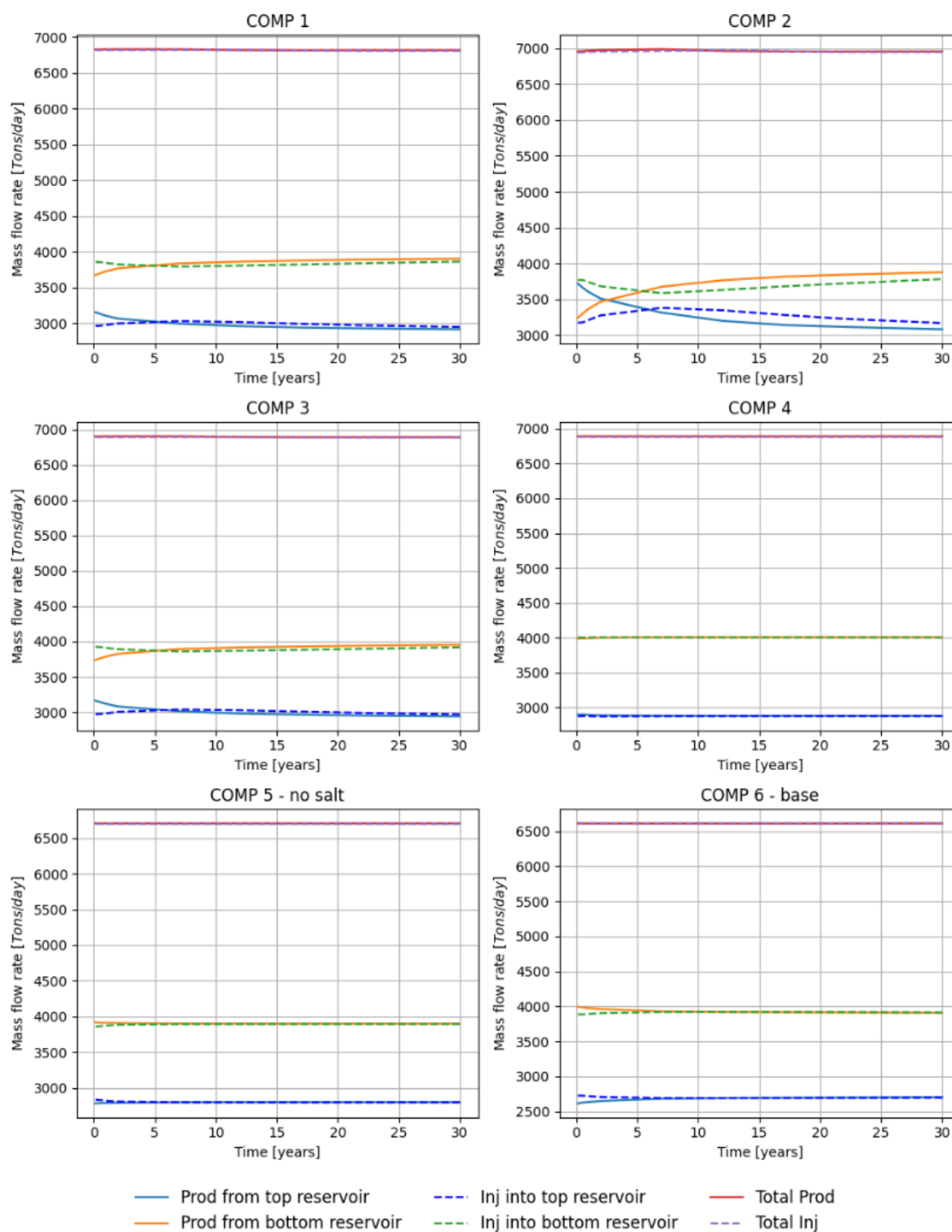


Figure 4-21: Mass flow in each reservoir and total mass flow for the compositional models compared to 0 salt (COMP 5) and original Base Case (COMP 6).

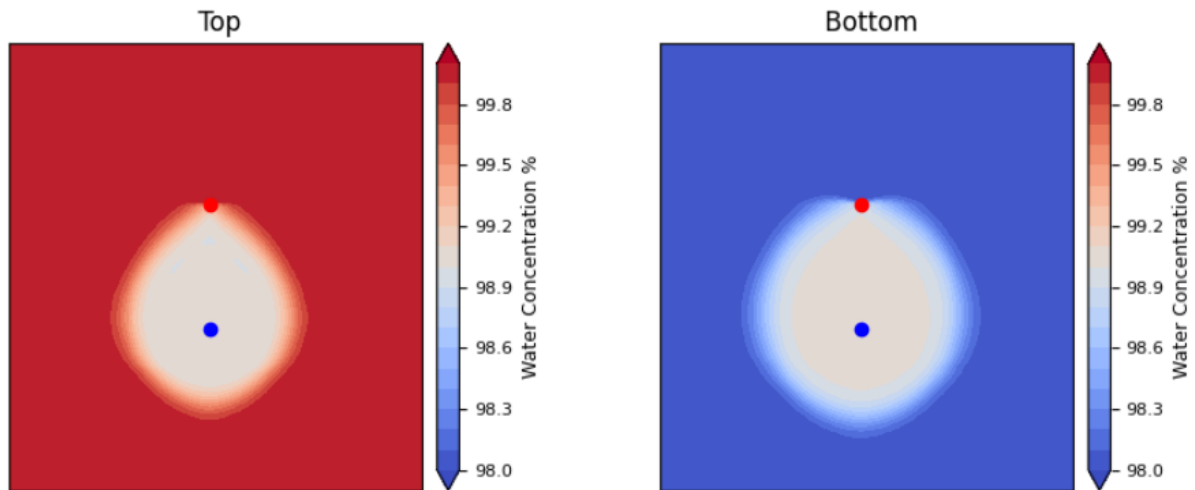


Figure 4-22: Water molar concentration [%] in top reservoir (left) and bottom reservoir (right) for COMP 1 (salt: 0% - top and 2% - bottom) model after 30 years. Injection well indicated by blue dot and production well indicated by red dot.

Further, the salt concentration for the produced fluid for each compositional simulation is shown in Figure 4-23. The cases with mixed reservoir compositions (COMP 1, 2, 3) show a long period of differing composition of the produced brine compared to the no salt case (COMP 5). This is caused by the imbalances (different flows from each reservoir also varying in time) and the eventual production of the re-injected fluid. Certainly, the viscosity changes in the reservoirs (reducing in the bottom, increasing in the top) also play a role in the temporal evolution of salt concentration and mass produced from the reservoir. In the COMP2 simulation (5% bottom reservoir salt, 0% top reservoir), the initial increase in composition is due to the increase in production from the bottom reservoir. The salt concentration (and produced mass from the bottom reservoir) continues to increase for 7 years, which marks the onset of injection breakthrough and the beginning of the normalization of the produced brine concentration.

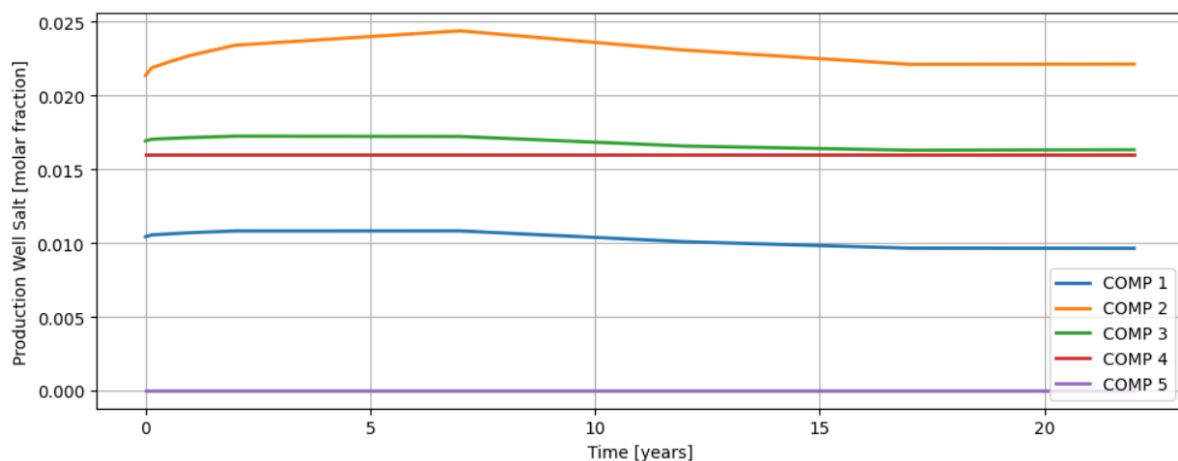


Figure 4-23: Salt concentration [molar fraction] of the produced fluid over time for the compositional models.

4.3.3 Compositional model main findings

The main conclusions derived from the compositional model simulations:

- The viscosity of the reservoir fluid is affected by salt concentrations. Higher salt concentrations result in higher brine viscosities.
- The viscosity has an impact on the productivity/injectivity of each reservoir. A higher viscosity fluid will require a higher dP for the same flow rate in a reservoir.
- The impact on viscosity due to salt content is smaller than the impact due to temperature differences. Even relatively high salt concentrations do not result in the same magnitude of viscosity changes as the temperature changes that water may experience in these geothermal operations.
- The impacts of brine mixing (even in extreme scenarios) on reservoir pressure changes are generally small.
- Longer duration (~5 years) flow imbalances due to brine mixing are only present in extreme mixing scenarios (fresh water with brine).

4.4 Impact of temperature differences

For this analysis, the effect of producing from and injecting in reservoirs of varying temperature differences was investigated. The key differences induced by the temperature changes were fluid density and viscosity changes through the water equations of state. Time-varying permeability values as a result of thermal stimulation were not accounted for. The varying temperatures were achieved by applying distinct geothermal gradients. Three different thermal gradients were tested in this analysis: 20°C/km, 30°C/km, and 40°C/km.

4.4.1 Simulation setup

For all simulations, a surface temperature of 10°C was assumed. The three thermal gradients (20°C, 30°C, and 40°C /km) were then enforced via large volumes at both the top and bottom of the model. The Base Case scenario of 30°C/km was tested with continuous top and bottom reservoirs and baseline permeabilities of 190 and 265 mD respectively. The temperature profiles in Figure 4-25 show the comparison between the calculated values according to equation (7) in Chapter 3.1.4 and the modelled values from a natural state simulation. The effect of the higher thermal conductivity in the reservoirs can be seen as a slight deviation in the thermal gradient at 1800 m and 2050 m. The average gradients were preserved, however. A fixed injection temperature of 40°C was used in all simulations.

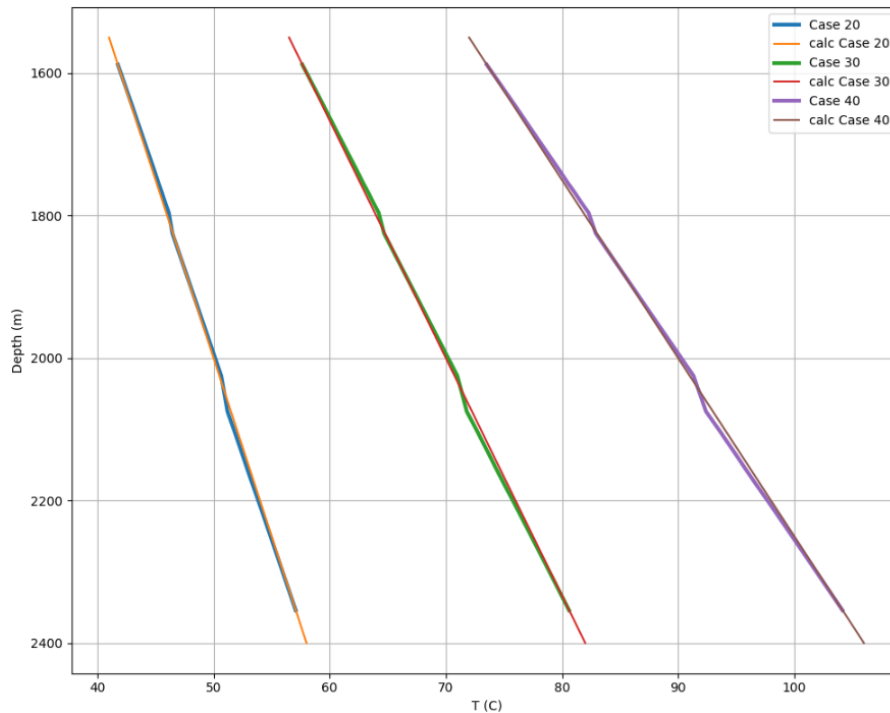


Figure 4-24: Initial temperature profiles for each gradient tested and natural state equilibrium result for the analogous numerical models.

Table 4-6: Overview of scenarios simulated in Section 4.4.

Scenario	Description
Case 20	Scenario with a thermal gradient of 20°C/km and a surface temperature of 10°C
Case 30	Scenario with a thermal gradient of 30°C/km and a surface temperature of 10°C, equivalent to the Base Case (semi-open boundaries)
Case 40	Scenario with a thermal gradient of 40°C/km and a surface temperature of 10°C

4.4.2 Simulation results

The simulation results reveal that as the thermal gradient decreases (lower temperature and lower temperature difference between the reservoirs) more elevated pressure gradients (dP) are required for injection/production at the same flow rate (Figure 4-25). There are two factors influencing these results. The first one is the viscosity of the water: fluid viscosity is higher at lower temperature, therefore production and injection require larger pressure differences. Another factor is the greater general reduction in pressure across the model when temperature is higher, as this results in a greater temperature difference between the injected and produced fluid and the enforced mass balance. This means that the injected volume is lower in models where production temperature is higher (Figure 4-26). In other words, the higher temperature results in lower mass production rate since the volumetric flow rate was a constant 280 m³/h in the different cases. The mixed production temperatures of the models are summarized in Table 4-7.

Table 4-7: Production temperatures for different initial reservoir temperature gradients.

Gradient Case [°C/km]	Injection Temperature [°C]	Production Temperature [°C]
20	40	50
30	40	70
40	40	89

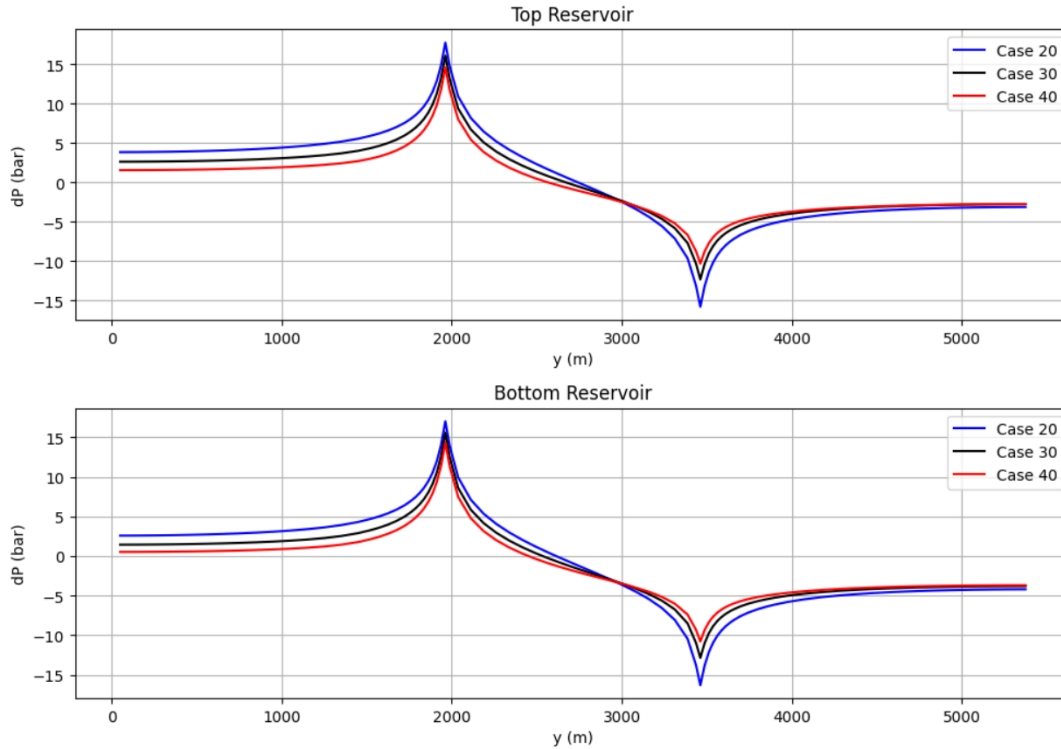


Figure 4-25: Pressure profiles along model centerline after 30 years for each thermal gradient case.

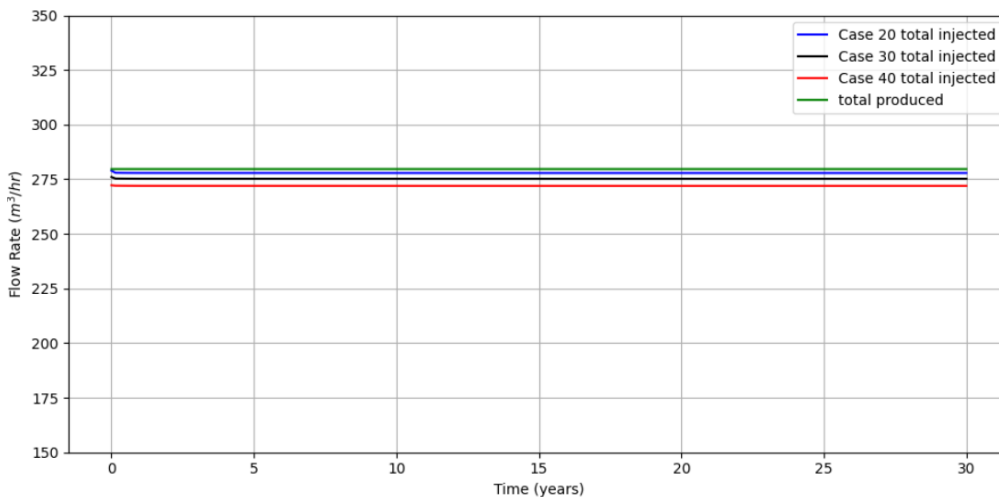


Figure 4-26: Volumetric flow rates over time for production well (green) and injection wells (colored by scenario) for each thermal gradient case.

Figure 4-27 displays the mass flow rates for each reservoir in the thermal gradient scenarios. The mass flow rates for both top and bottom reservoirs decrease as thermal gradient is increased in the simulation cases, which is due to volume differences associated with density changes. The graphs also reveal a longer duration of the imbalanced flow period in a cooler reservoir with lower geothermal gradient (and shorter in the warmer reservoir simulation with higher gradient value).

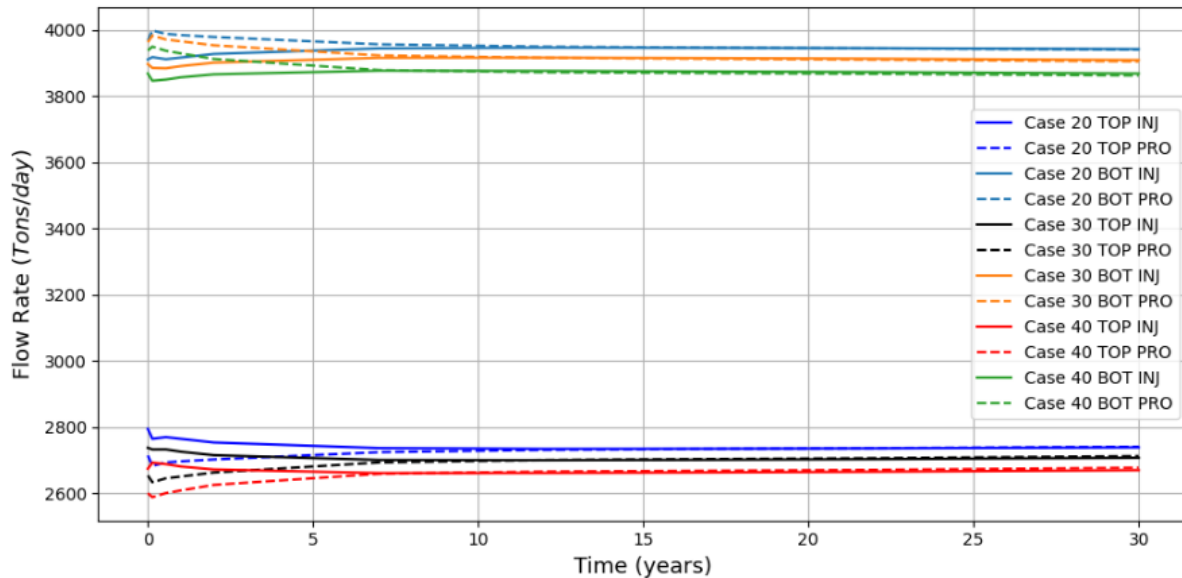


Figure 4-27: Injection (INJ, solid lines) and production (PRO, dashed lines) mass flow rate per reservoir (Top or BOT) for temperature impact scenarios.

4.4.3 Temperature main findings

The impact of differing thermal gradients is not large compared to the permeability or thickness cases previously presented. The differences in reservoir pressure after 30 years of operation between the cases is generally limited to about 5 bar. In contrast, the cases with gradually decreasing reservoir thickness reveal pressure differences (after 30 years) in the order of 5-10 bar, while pressure varies up to 20-40 bar in the cases with a laterally discontinuous reservoir. The small differences are due to viscosity and density differences of pure water at different temperatures. Potential thermo-mechanical interactions and effects like thermal stimulation were not accounted for. However, differing thermal gradients (and consequently reservoir temperatures) can impact the duration of the imbalanced flow period as well as the maximum pressure changes seen in wells. The specific takeaways from this modelling exercise are:

- Higher temperature reservoirs generally require less injection pressure due to viscosity differences in the fluid.
- The imbalanced reservoir flow duration lasts longer in cooler temperature reservoirs.

4.5 Impact of well completion differences

In this section, well completion differences are considered to mean well geometry differences, such as wellbore diameter and wellbore trajectory. These factors affect the geometry of the inflow/outflow zones in wells and, thus, the physical behavior of those zones. Other actual well completion elements (such as wire screen, slotted liner, sand/gravel fill, completion damage,

etc.) are better addressed in the following section (4.6 Impact of skin factor) through increased skin factor. In the most extreme case, sand/gravel fill could result in an entire loss of a lower reservoir. In that case, it is best represented by the discontinuous permeability case of section 4.1 Impact of permeability variation between producer and .

4.5.1 Simulation setup

4.5.1.1 Wellbore diameter investigation

For the wellbore diameter investigation, in the Base Case model, the wellbore diameter is assumed 8.5" through both reservoir sections. To test the imposed effects, the diameter of the wellbore in the top reservoir was set to 8.5" and the wellbore diameter was reduced to 5.5" in the bottom reservoir with higher permeability. This represents a possible wellbore construction if a smaller diameter was drilled in the bottomhole section of the well intersecting the bottom reservoir. Three cases were tested: r1) 5.5" in injection well only; r2) 5.5" in production well only; and r3) 5.5" in both wells. An idealization of this completion scenario is shown in Figure 4-28. It should be noted here that wellbore diameter impacts the pressure in the well and flow rate values, but the wellbore simulator in DARTS does not account for wellbore pressure losses through friction. So, the effects of wellbore dP shown in this section could be larger. However, the basic outcomes presented here still hold.

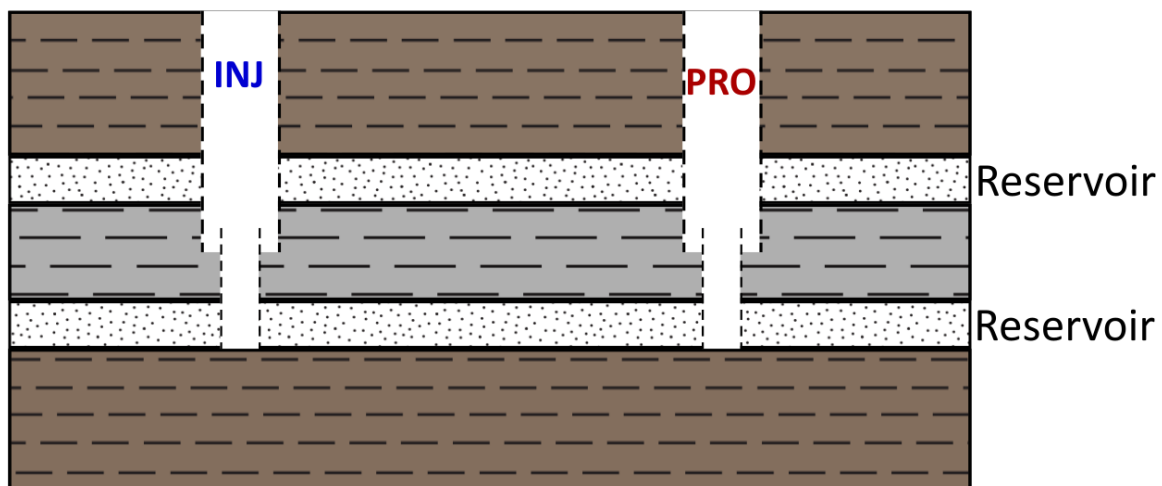


Figure 4-28: Example of idealized completion with well diameter differences. The wells are 8.5" diameter in the top reservoir and 5.5" diameter in the bottom reservoir.

4.5.1.2 Horizontal section investigation

For the well trajectory investigation, horizontal completions in the bottom reservoir were tested. The well trajectories for 3 tested scenarios were: horiz1) 500 m horizontal section in the injection well in the bottom reservoir; horiz2) 500 m horizontal section in both wells in the bottom reservoir; and horiz3) 500 m horizontal section in both wells in the bottom reservoir section with a reduced reservoir permeability. The first case would be used practically to increase injection capacity for a project. The second case would be used to make use of a highly permeable reservoir to maximize project heat production. In the third case, the permeability of the bottom reservoir was set to 50 mD (instead of 265 mD in the Base Case). Long horizontal sections could be used in that scenario to make up for the lower permeability yet still meet production requirements. An additional low permeability model was also run where the bottom reservoir permeability was 50 mD and no horizontal sections were drilled

(i.e., two vertical wells) to make fair comparisons. The case where both wells are horizontal in the bottom reservoir is idealized in Figure 4-29.

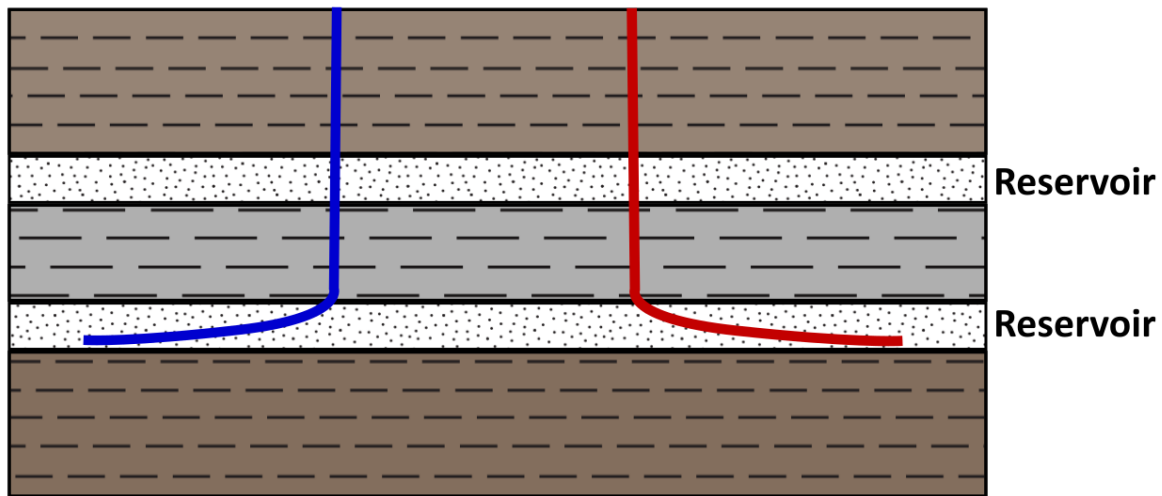


Figure 4-29: Example of completion scenario with horizontal wells in the bottom reservoir.

Table 4-8: Overview of scenarios simulated in Section 4.5.

Scenario	Description
Base Case	Base Case scenario with a wellbore diameter of 8 ½" in both wells in both reservoir sections (vertical) (semi-open boundaries)
r1 (Inj)	Scenario with a wellbore diameter reduced to 5 ½" in the lower reservoir section in the injection well and a diameter of 8 ½" in the production well (both reservoir sections)
r2 (Pro)	Scenario with a wellbore diameter reduced to 5 ½" in the lower reservoir section in the production well and a diameter of 8 ½" in the injection well (both reservoir sections)
r3 (Both)	Scenario with a wellbore diameter reduced to 5 ½" in the lower reservoir section in both wells
horiz1 (Inj)	Scenario with a 500 m long horizontal section in the bottom reservoir of the injection well
horiz2 (Both)	Scenario with a 500 m long horizontal section in the bottom reservoir of both wells
horiz3 (Both Low Perm)	Scenario with a 500 m long horizontal section in the bottom reservoir of both wells with a reduced reservoir permeability of 50 mD
low perm vertical wells (Low Perm)	Scenario with vertical sections in both reservoirs in both wells, but with reduced permeability in the bottom reservoir of 50 mD

4.5.2 Simulation results

4.5.2.1 Wellbore diameter investigation

For the cases with varying wellbore diameter In the wellbore, a smaller diameter results in elevated pressure changes (after 30 years of operation) in the wellbore compared to the Base Case, as shown in Figure 4-30. In wells where the wellbore diameter is reduced in the bottom reservoir, pressure change increases by approximately 1 bar compared to the Base Case (additional drawdown in the production well, additional pressure buildup in the injection well). A reduction in wellbore diameter in one well only has a limited effect on pressure changes (either additional drawdown or additional buildup) in the opposite well.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

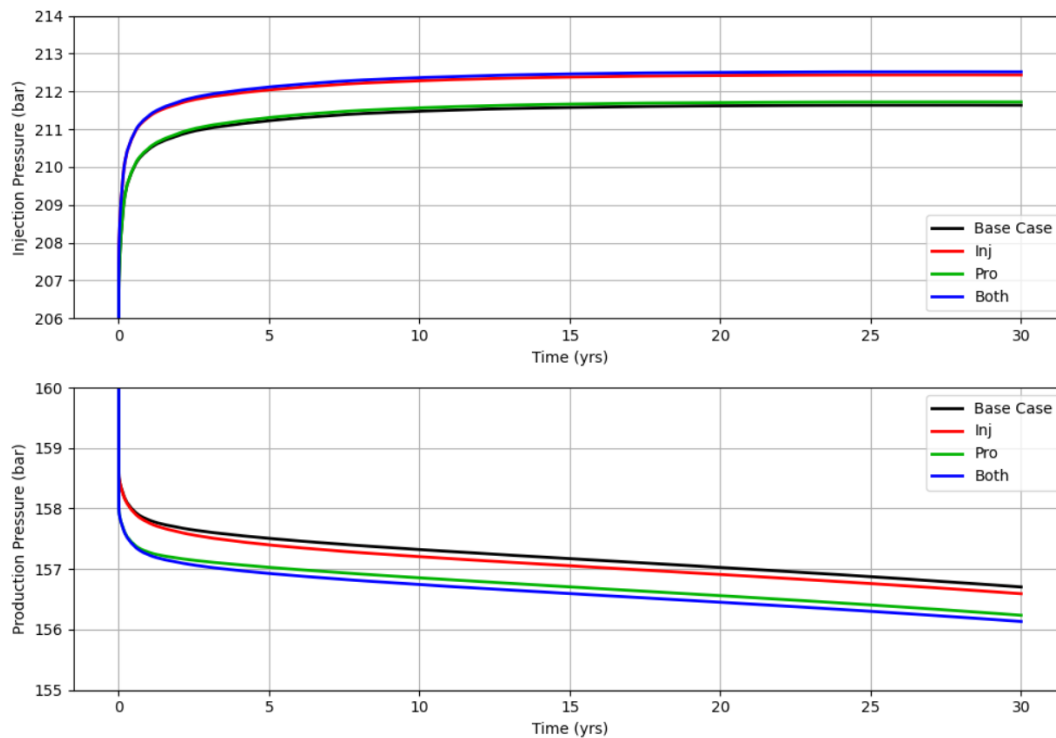


Figure 4-30: Bottomhole pressure (absolute values) in the wellbore for the injection well (top) and production well (bottom) for the different wellbore completion diameter scenarios. “Inj”, “Pro” and “Both” indicate whether the diameter of the wellbore in the bottom reservoir is smaller in the injection well (case r1), production well (case r2) or both wells (case r3), respectively.

The larger pressure changes in the wellbore manifest themselves as slightly larger pressure changes in the reservoir (Figure 4-31). The impact is small, but present. The bottom reservoir especially has larger pressure changes as that is the location of the smaller diameter wellbore. The pressure changes observed in the bottom reservoir show less than a 1 bar difference between all the cases.

The mVRR plot (Figure 4-32) shows that the imbalance in each reservoir’s flow is also affected by the wellbore diameter. If both the injection well and production well are completed in the same way (8.5” throughout – Base Case, or 5.5” in bottom – ‘Both Case’), then the mVRR responses per reservoir are similar to each other, while deviation compared to the Base Case can be seen in the mVRR responses for those cases where each well is completed differently (i.e. only one of the wells has a 5.5” section in the bottom reservoir, cases r1 and r2). In those cases, the well with the smaller diameter in the bottom reservoir has a slightly reduced flow rate in that reservoir (compared to Base Case) in early times due to the diameter difference.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

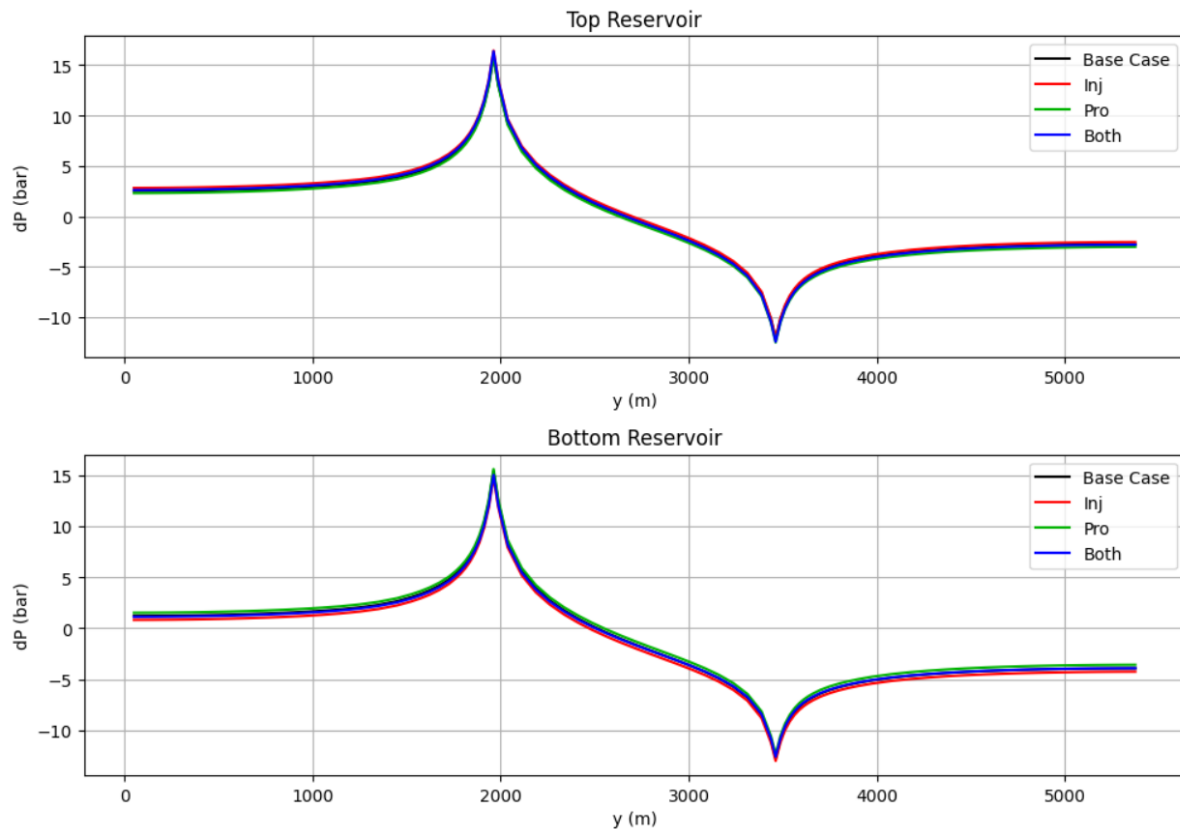


Figure 4-31: Pressure change profiles after 30 years along center line for wellbore diameter investigation cases for each reservoir. “Inj”, “Pro” and “Both” indicate whether the diameter of the wellbore in the bottom reservoir is smaller in the injection well (case r1), production well (case r2) or both wells (case r3), respectively.

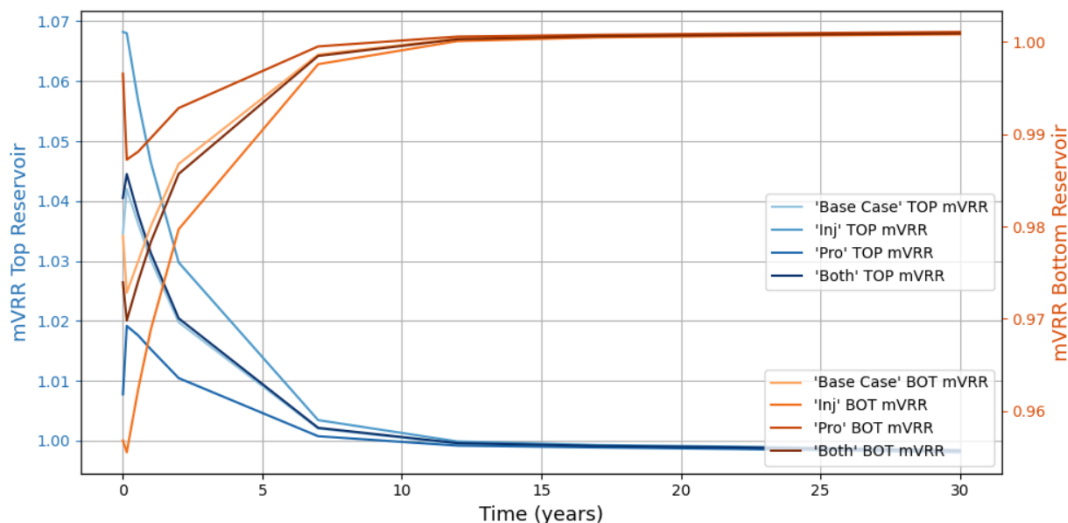


Figure 4-32: mVRR for wellbore diameter investigation cases – top reservoir in blue colors, bottom reservoir in orange colors. “Inj”, “Pro” and “Both” indicate whether the diameter of the wellbore in the bottom reservoir is smaller in the injection well (case r1), production well (case r2) or both wells (case r3), respectively.

4.5.2.2 Horizontal section investigation

Horizontal extension of the wells reduces the bottomhole pressure difference seen in the wellbores (compared to the Base Case). This is clearly shown in Figure 4-33. The vertical well simulation with lower permeability (50 mD instead of 265 mD, case Low Perm) shows the largest pressure differentials (largest drawdown in the production well, largest pressure buildup in the injection well). This effect is reduced in the Both Low Perm case (horiz3), where the bottom reservoir also has lower permeability but both wells are completed with a horizontal section. However, pressure differences remain higher than in the Base Case. In cases where bottom reservoir permeability is equal to the Base Case (265 mD), the pressure differences after 30 years of operation are lower when either the injection well (case Inj or horiz1) or both wells (case Both or horiz2) have a horizontal section. Pressure effects in the reservoir are discussed after presenting the results for mass flow rate.

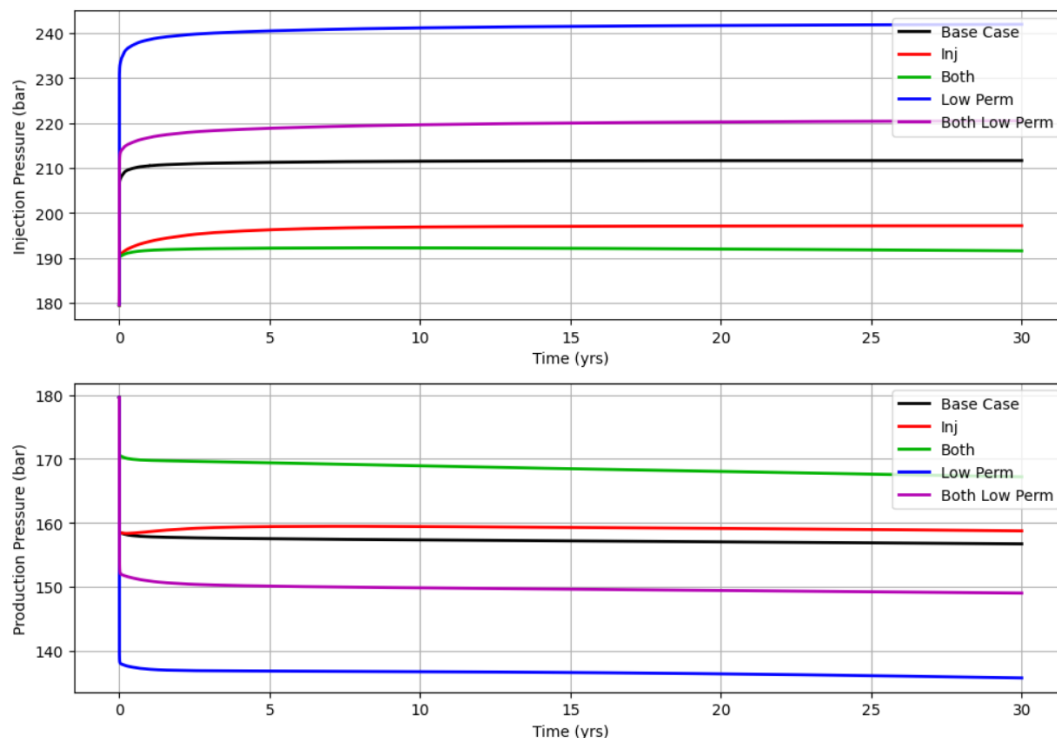


Figure 4-33: Bottomhole well pressures for horizontal completion scenarios for both injection (top) and production (bottom) wells. Inj (horiz1) and Both (horiz2) indicate cases where either the injection well or both wells are completed with a horizontal section. Cases Low Perm and Both Low Perm (horiz3) indicate scenarios where bottom reservoir permeability has been reduced. Both wells are vertical in the Low Perm case, whereas they have a horizontal section in the Both Low Perm case.

The effects of the horizontal completions in the bottom reservoir on the imbalance of mass flow are presented in Figure 4-34 and Figure 4-35. The total wellbore surface area in the bottom reservoir increases and, subsequently, so does the mass flow in the bottom reservoir. If only the injection well is completed horizontally (case Inj or horiz1), initially there is an imbalance in flow distribution that can last for several years. If both wells are completed horizontally (case Both or horiz2), the imbalanced flow period is shorter in duration.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

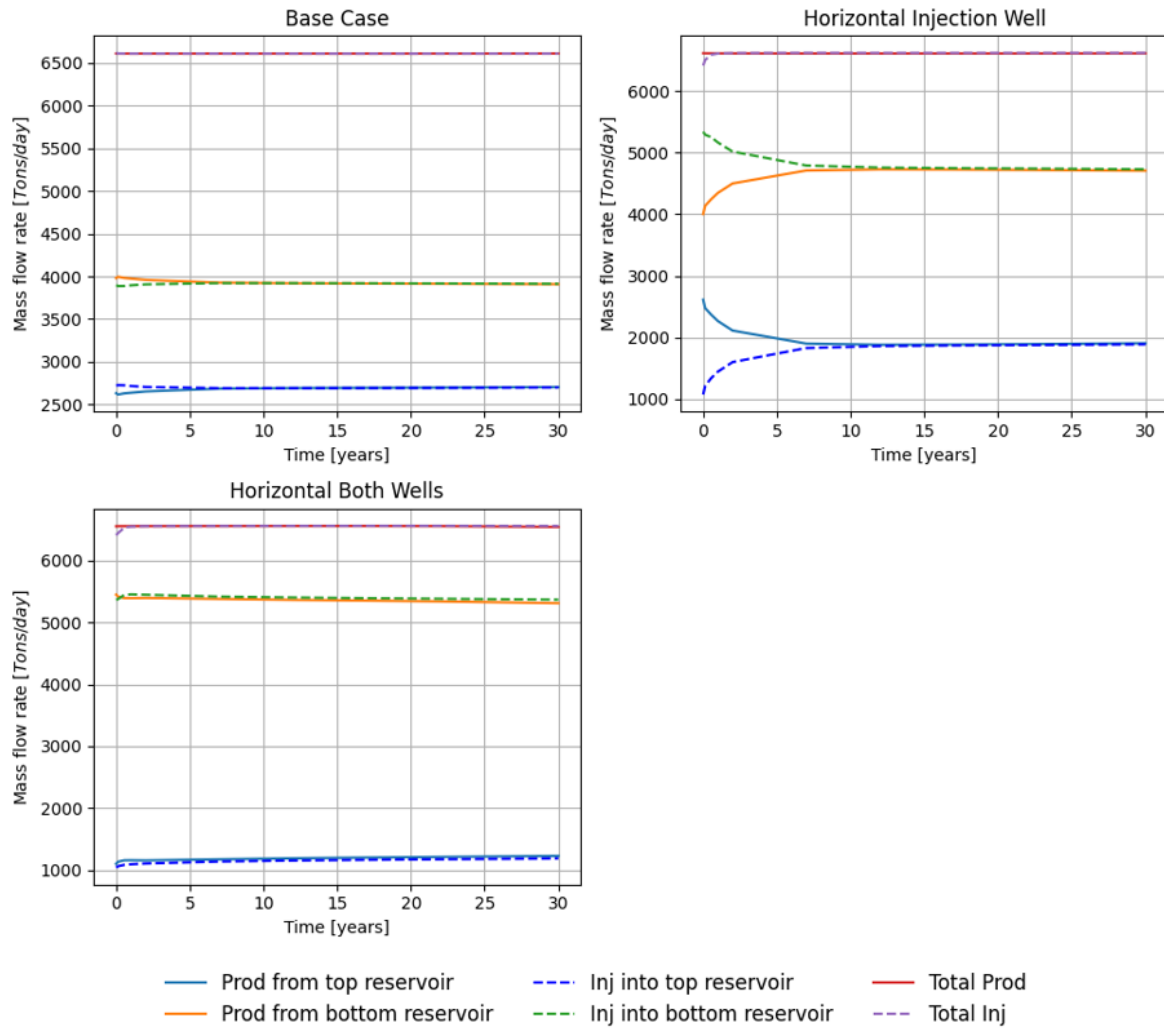


Figure 4-34: Total mass flow and mass flow from each reservoir for the Base Case (top-left) and the horizontal well completion cases – injection well only (top-right, case horiz1) and both wells (bottom, case horiz2). The initial difference between total produced and total injected flow is a post-processing artefact.

In the lower permeability bottom reservoir case (Low Perm case), the bottom reservoir produces much less than the top reservoir (Figure 4-35). Introduction of the horizontal sections (Both Low Perm or horiz3 case) helps to improve the productivity/injectivity of the well in that reservoir and redistributes the flow more toward that section. The imbalance between injection and production is not too large as the wells were completed in a similar fashion (both horizontal) in the bottom reservoir.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

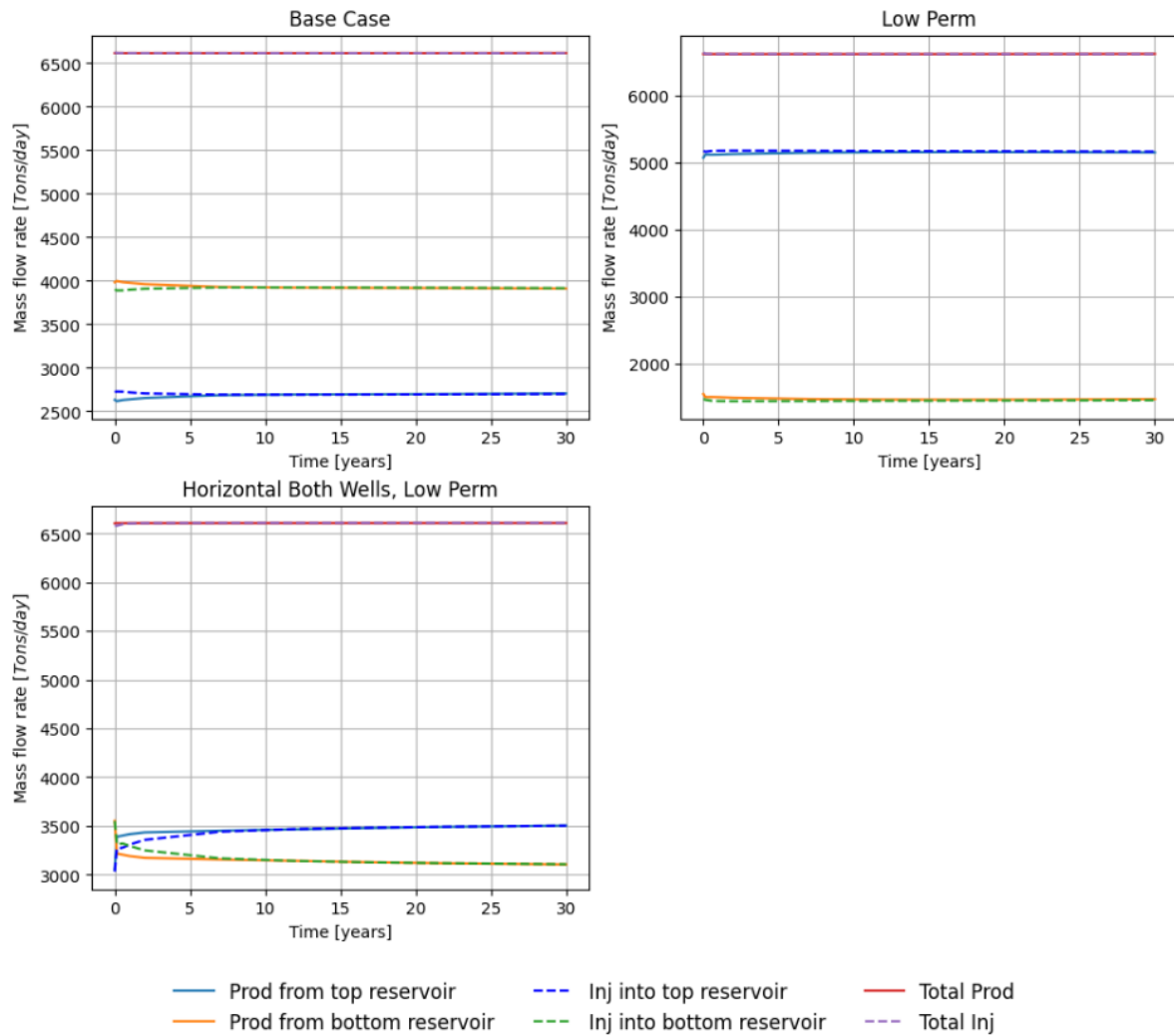


Figure 4-35: Total mass flow and mass flow from each reservoir for the Base Case (top-left), the low permeability bottom reservoir case (top-right, Low Perm case), and the horizontal wells included in the low permeability case (bottom, Both Low Perm case).

Figure 4-36 shows the pressure profiles through the centerline for all the horizontal completion scenarios after 30 years compared to the initial state. In the injection well only case (Inj or horiz1), increasing the mass flow into the bottom reservoir raises its average reservoir pressure, but the peak in pressure is distributed (thus, not as large) compared to the Base Case. Introduction of horizontal sections in both wells (Both or horiz2) allows for better balancing and a further reduction in pressure differential. The low permeability cases have the largest pressure change (dP) values and introduction of the horizontal completions (Both Low Perm or horiz3) also helps to reduce the peak dP seen in the respective reservoir but does increase the average dP (and farther field dP) in the bottom reservoir.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

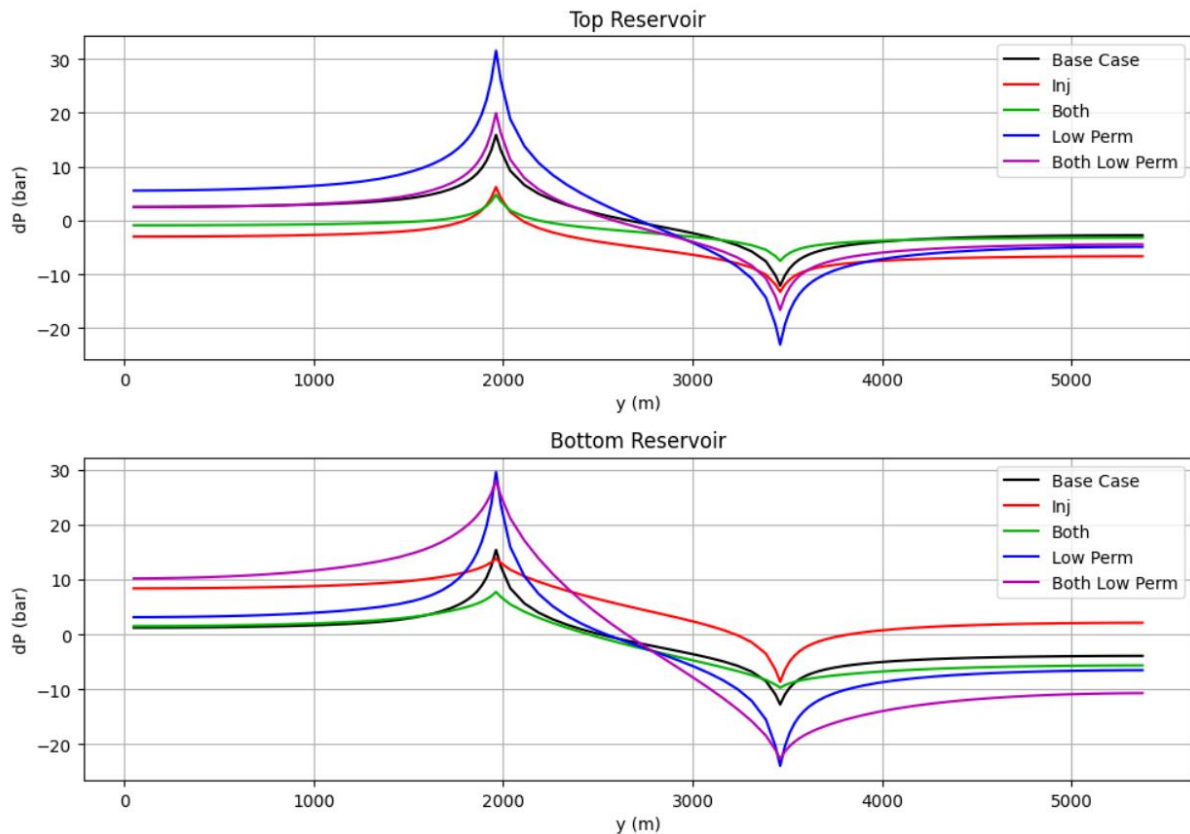


Figure 4-36: Pressure change profiles along center line after 30 years for horizontal completion test case scenarios for each reservoir.

4.5.3 Well completion main findings

The main findings regarding well completion aspects:

- Wellbore completion diameter does slightly affect the pressure seen in the wellbore itself. However, the impact on the reservoir itself is relatively minor (<1 bar in the cases tested here). If one well has a smaller diameter completion, the flow rate into or from the bottom reservoir will decrease slightly in that well.
- Horizontal completions generally reduce the peak dP seen near the well (through a distribution of the flow) compared to the Base Case, but increase the farther field dP by increasing the total flow rate in the horizontally-completed reservoir.
- Horizontal completion of both wells reduces the flow imbalance period duration (and magnitude of dP) vs horizontal completion of only one well.

4.6 Impact of skin factor differences

Wellbore skin factor has a broad range of applicability in this study. Skin affects the pressure change near the well in an area called the skin damage zone (see Figure 4-37). As mentioned in the previous section, various completion elements such as wire screens, slotted liner, sand/gravel fill, and drilling induced damage (mudcake or fracturing) can cause changes in the apparent skin factor near the well. Those could usually be represented as positive skin, though fracturing near the wellbore could result in negative skin. Well stimulation (thermal,

pressure, or acid) are all possible (and sometimes common) effects seen in geothermal operations that can result in negative skin near the well. Additionally, solid migration or geochemical effects such as mineral precipitation could result in positive skin near the well. In this study, the cause of the skin is not considered beyond this paragraph. The simulations and results in this section seek to quantify the impact of various skin combinations on the perceived downhole wellbore pressure, reservoir pressure, and flow imbalance due to the skin's presence.

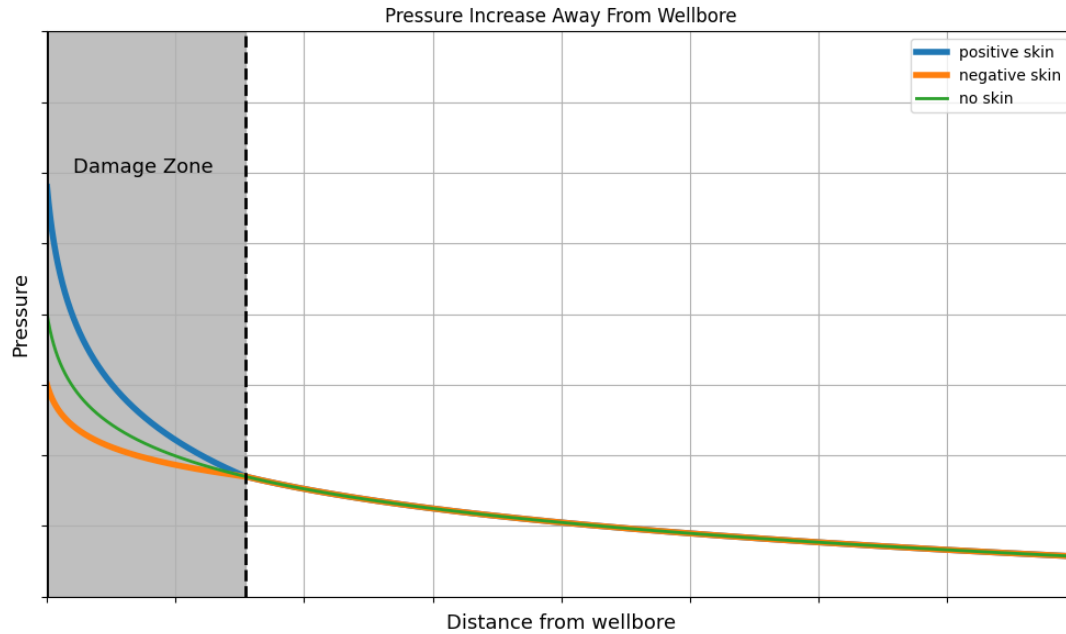


Figure 4-37: Qualitative effect of skin near the area of a hypothetical injection well. Positive skin (blue) results in an increase in pressure gradient in the skin damage zone and negative skin (orange) reduces the pressure gradient in the skin damage zone. Figure modified from Zarrouk & McLean (2019).

4.6.1 Simulation setup

In the skin study, the general Base Case scenario with constant permeability was considered. Various skin options were tested both on the injection well and on the production well on both reservoirs. The Peaceman index (Equation 11, repeated here) determines how flow in a well is distributed among the various reservoirs:

$$Peaceman_{index\ i} = \frac{2\pi * k_i * h}{\ln\left(\frac{r_e}{r_w}\right) + s} \quad (11)$$

The skin factor (s) was tested to be -2, 0, or 30 and could vary within the same well between the reservoirs. The relationship is intended for radial flow cases and is numerically invalid for large negative skin values as the Peaceman index will drop below zero. In those cases, a different near wellbore technique (such as fracture flow) may be more appropriately used. However, -2 is sufficient to test the effects of stimulation on flow imbalances.

The study was conducted in two basic scenarios: injection skin effects and production skin effects. In the injection case, all 9 combinations of skin value [-2,0,30] were tested for the top

and bottom reservoir sections (e.g., top reservoir $s = -2$, bottom reservoir $s = 30$) while the production well skin was kept constant at 0 in both reservoir sections. In the production testing case, 4 combinations of skin value (0 or 30) were tested for the top and bottom reservoir sections, while the injection well skin was kept constant at 0. This resulted in 13 total scenarios as seen in Table 4-9. It should be noted that there are two combinations where all skin values are 0 and hence represent the Base Case.

Table 4-9: Matrix of skin scenarios tested.

			TOP RESERVOIR				
			INJECTION WELL			PRODUCTION WELL	
			-2	0	30	0	30
BOTTOM RESERVOIR	INJECTION WELL	Skin	-2	0	30	0	30
		-2	X	X	X	-	-
		0	X	X	X	-	-
		30	X	X	X	-	-
	PRODUCTION WELL	0	-	-	-	X	X
		30	-	-	-	X	X

The nomenclature was automatically generated when setting up the simulation files. In the names, 'p' stands for *production*, 'i' for *injection*, 't' for *top*, and 'b' for *bottom*. The number preceding the letters is the skin value '2' for -2 and '30' for +30. An example would be Case_Opt_30pb_2it_0ib that represents a (fictional) scenario with (Opt) 0 skin for the production well in the top reservoir section, (30pb) 30 skin for the production well in the bottom reservoir section, (2it) -2 skin for the injection well in the top reservoir section, and (0ib) 0 skin for the injection well in the bottom reservoir section. That nomenclature appears on plots in the following results.

Table 4-10: Overview of scenarios simulated in Section 4.6.

Scenario	Description
Case_Opt_0pb_0it_0ib	Base Case scenario with 0 skin for both wells in all reservoir sections (semi-open boundaries)
Case_Opt_0pb_0it_2ib	Scenario with 0 skin for the production well, 0 skin in the top reservoir section in the injection well, and a skin of -2 in the bottom reservoir section in the injection well
Case_Opt_0pb_0it_30ib	Scenario with 0 skin for the production well, 0 skin in the top reservoir section in the injection well, and a skin of -2 in the bottom reservoir section in the injection well
Case_Opt_0pb_2it_0ib	Scenario with 0 skin for the production well, a skin of -2 in the top reservoir section in the injection well, and a 0 skin in the bottom reservoir section in the injection well
Case_Opt_0pb_2it_2ib	Scenario with 0 skin for the production well and with a skin of -2 for the injection well
Case_Opt_0pb_2it_30ib	Scenario with 0 skin for the production well, a skin of -2 in the top reservoir section in the injection well, and a skin of 30 in the bottom reservoir section in the injection well
Case_Opt_0pb_30it_0ib	Scenario with 0 skin for the production well, a skin of 30 in the top reservoir section in the injection well, and 0 skin in the bottom reservoir section in the injection well
Case_Opt_0pb_30it_2ib	Scenario with 0 skin for the production well, a skin of 30 in the top reservoir section in the injection well, and a skin of -2 in the bottom reservoir section in the injection well
Case_Opt_0pb_30it_30ib	Scenario with 0 skin for the production well and with a skin of 30 for the injection well
Case_Opt_30pb_0it_0ib	Scenario with 0 skin in the top reservoir section in the production well, a skin of 30 in the bottom reservoir section in the production well, and with 0 skin for the injection well
Case_30pt_0pb_0it_0ib	Scenario with a skin of 30 in the top reservoir section in the production well, 0 skin in the bottom reservoir section in the production well, and with 0 skin for the injection well
Case_30pt_30pb_0it_0ib	Scenario with a skin of 30 for the production well and with skin 0 for the injection well

4.6.2 Simulation results

4.6.2.1 Uniform skin scenarios

Uniform skin scenarios are scenarios where the skin value is constant in the well (so the same for both reservoir sections). The results are shown in Figure 4-38. The positive skin cases result in larger pressure changes in the well with the positive skin compared to the Base Case with 0 skin, as expected. Negative skin values result in reduced pressure changes. If the skin values are equal (between top and bottom reservoir) in one well, then there is no pressure change in the opposite well with 0 skin. The pressure profile plots in Figure 4-39 show that even though a well with strong positive skin has a higher downhole pressure change in the well (see Figure 4-39, large pressure difference between wellbore pressure curves of Case_30pt_30pb_0it_0ib and Case_Opt_0pb_30it_30ib compared to the Base Base), that additional pressure buildup in the well (or additional drawdown in case of the production well) is not seen further away in the reservoir as shown by the delta pressure plots in Figure 4-40. The small variation in far-field pressure can be attributed to the slight changes in the reservoir mass flow imbalances seen in Figure 4-40. This is consistent with the definition and theory of skin as shown earlier in Figure 4-37 (Zarrouk & McLean, 2019).

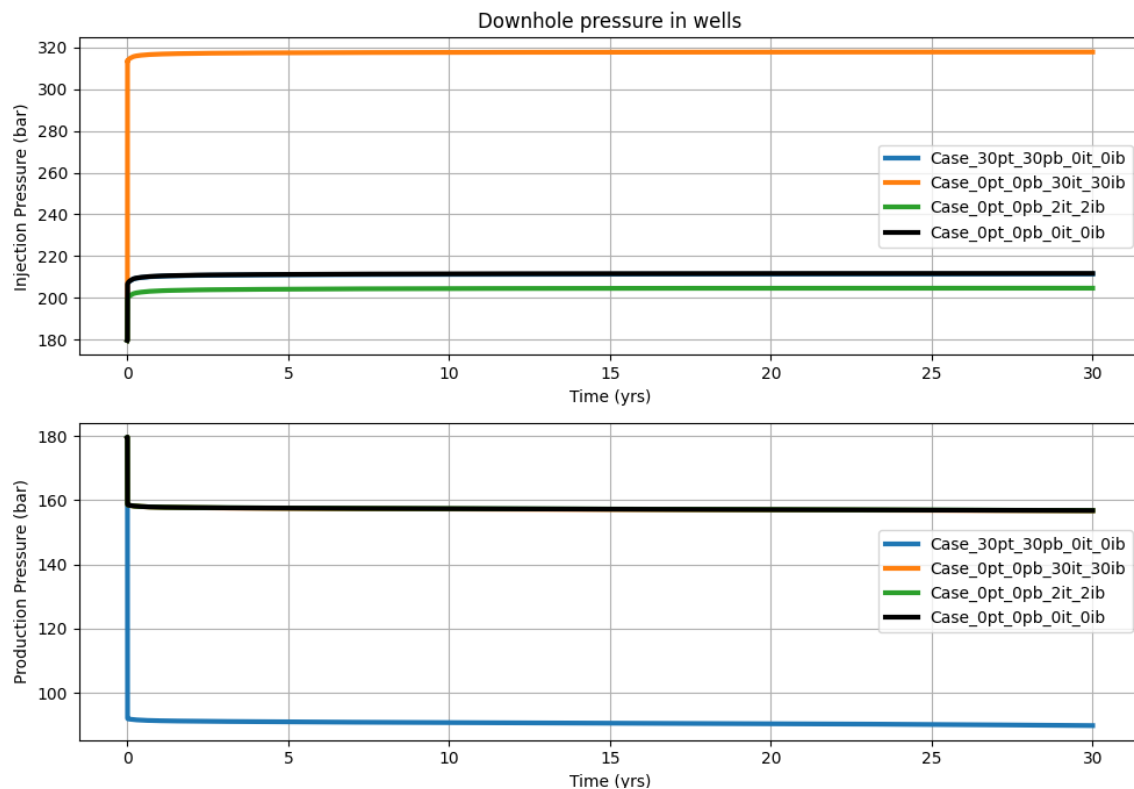


Figure 4-38: Downhole pressure in injection well (top) and production well (bottom) for the uniform skin scenarios. Base case in black. The results for Case_30pt_30pb_0it_0ib (blue) at the top, and for Case_Opt_0pb_30it_30it (orange) and Case_Opt_0pb_2it_2ib (green) in the bottom graph are not visible as the curves coincide with the Base Case. This is because uniform skin in one well does not lead to pressure effects in the opposite well.

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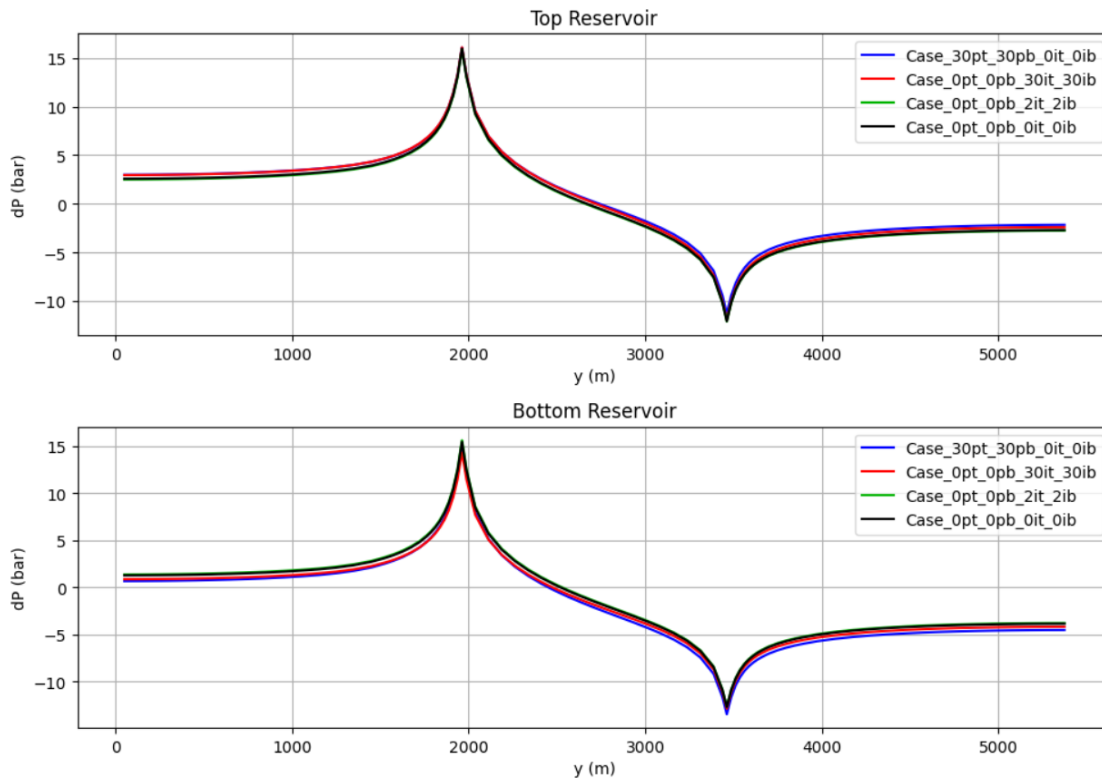


Figure 4-39: Pressure change profiles compared to the initial state after 30 years of production and injection, for top reservoir (top) and bottom reservoir (bottom) for the uniform skin scenarios.

The difference between well pressure change and reservoir pressure change after 30 years is further clarified in Figure 4-40 which shows the reservoir flow rates for each of the uniform skin scenarios: if the skin in the well is the same in the bottom and top reservoir sections, there is only minor impact on the equilibrated flow rates for each reservoir (and thus the imbalance time-evolution and duration). Since permeability in the reservoir itself is not different from the Base Case, the pressure in the reservoir is also not drastically affected.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

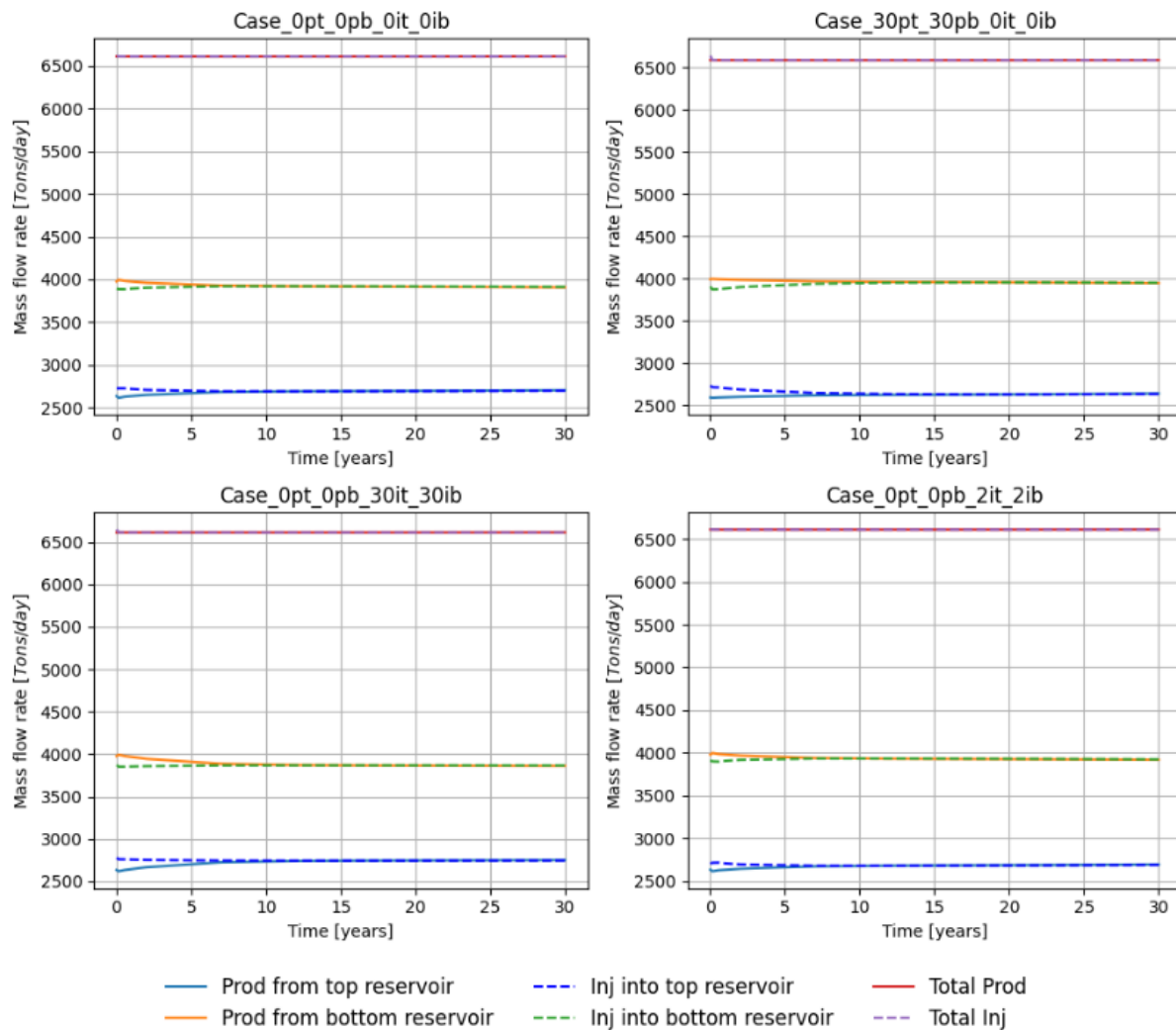


Figure 4-40: Mass flow rates by reservoir (and total) for the cases with constant skin in each well. Note that Case_Opt_0pb_0it_0ib represents the Base Case.

4.6.2.2 Non-uniform scenarios with positive skin

The scenarios described below have wells with non-uniform skin values. For example, a well may be stimulated in only one reservoir section, or perhaps a single reservoir is lost due to mineral scaling or the infill of fine particles.

First, those cases are considered where the well has a positive skin value (30) in only one reservoir section. The results of these scenarios are plotted in Figure 4-41 with the Base Case of 0 skin and the uniform positive skin cases included for comparison. The main conclusion is that having one good reservoir without positive skin in the well helps to reduce the pressure change seen inside the well (drawdown in production well, pressure buildup in injection well); the largest pressure differentials are seen in cases where the well has positive skin in both reservoir sections. A flow imbalance is created in case there is one well with positive skin in one reservoir section. Total flow in that reservoir will be reduced and hence also the pressure change in that reservoir, which can be seen in the opposite well.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

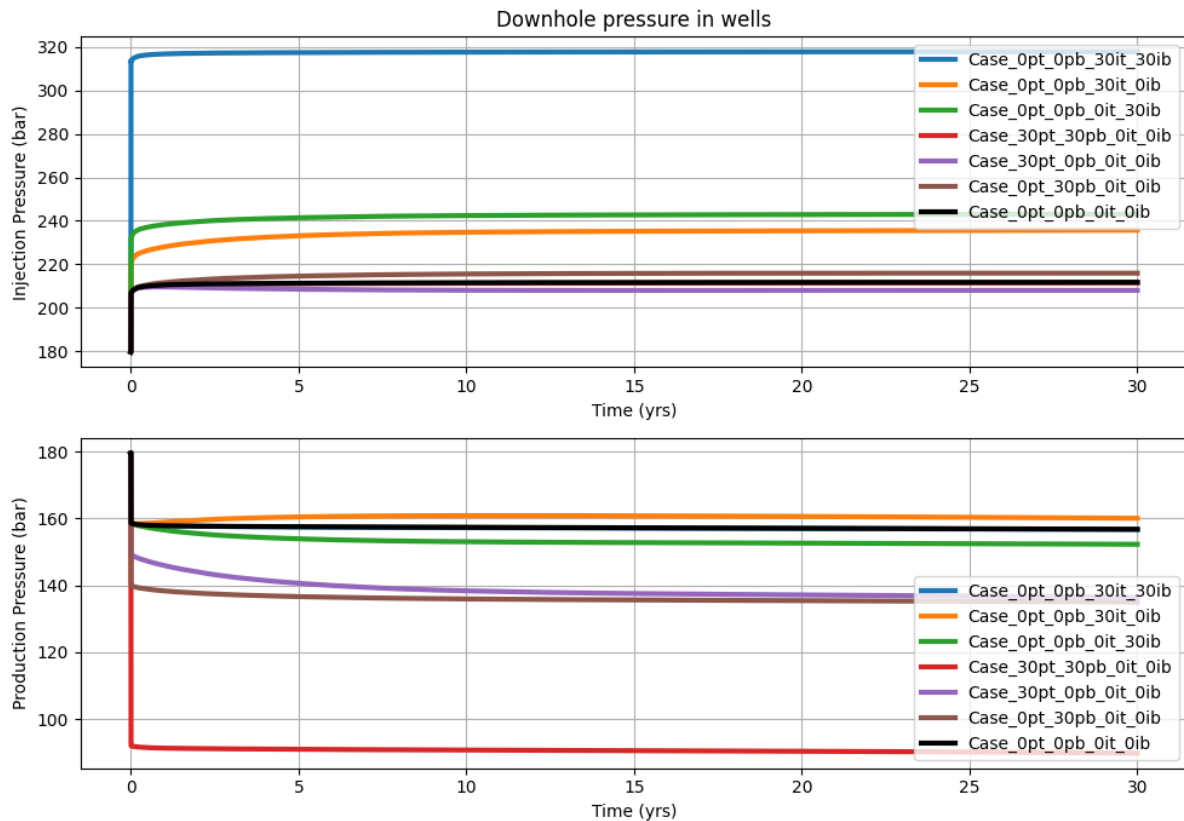


Figure 4-41: Downhole well pressures for injection (top) and production (bottom) wells for non-uniform scenarios with positive skin. Non-uniform scenarios with positive skin and the Base Case (in black) are shown for comparison.

While the downhole pressure changes (either drawdown or buildup) may be muted by unequal positive skin values, the reservoir pressures are not. Figure 4-42 shows the reservoir pressure profiles for each reservoir. In general, the largest pressure differentials occur in the top reservoir when the well has non-zero skin in the bottom reservoir section or in the bottom reservoir when the well has non-zero skin in the top reservoir section. This is due to diversion of flow to the other reservoir when skin is present.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

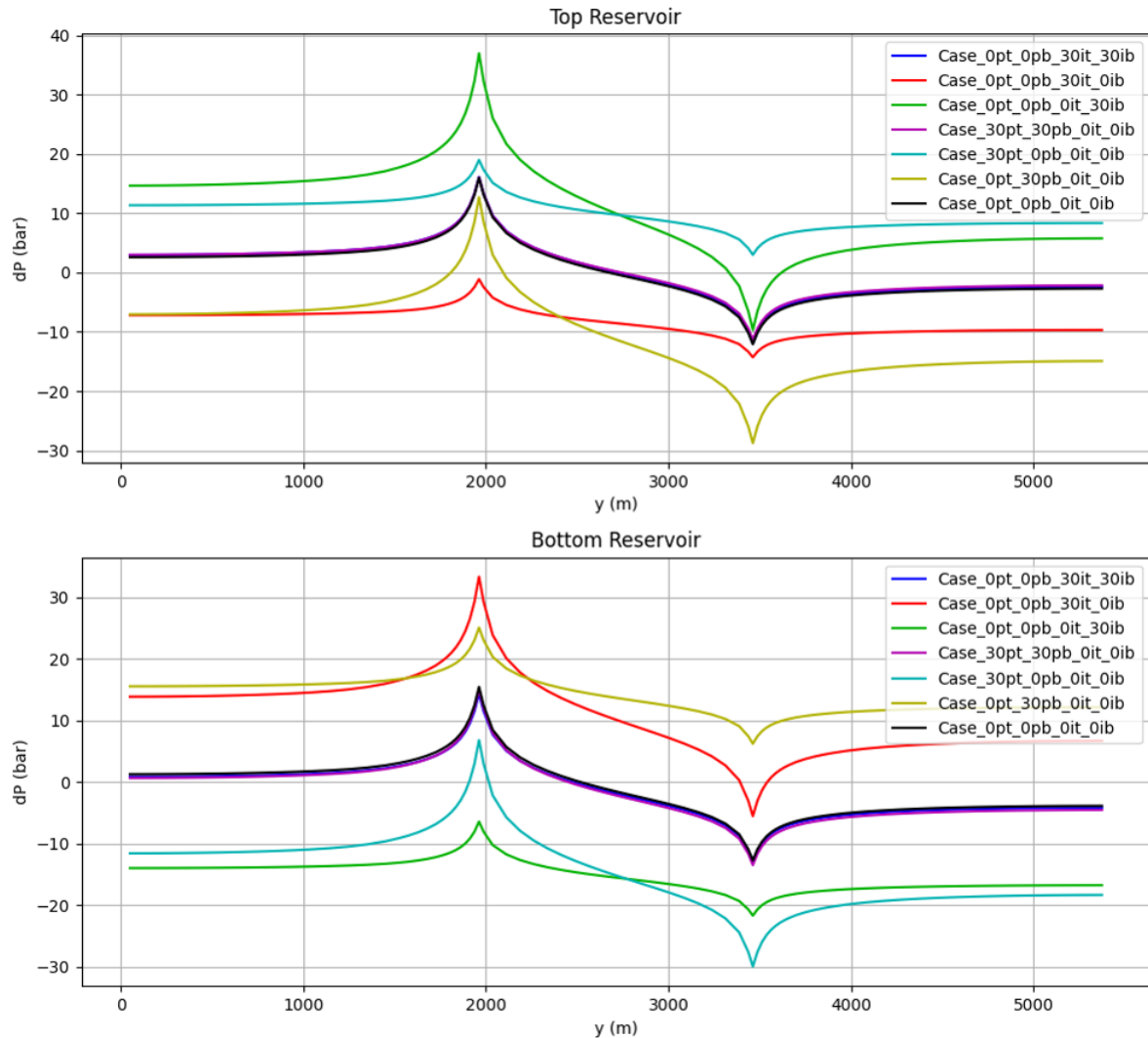


Figure 4-42: Reservoir pressure profiles after 30 years for top (top) and bottom (bottom) reservoir for positive skin cases. The cases with uniform positive skin plot very closely to the Base Case.

These effects are also seen in the mass flow rate per reservoir plots in Figure 4-43. Positive skin in the top reservoir section results in a higher percentage of flow being diverted to the bottom reservoir (top plots), while skin in the bottom reservoir section results in more flow being diverted to the top reservoir (middle plots). The initial flow imbalance is also much longer as the permeability in the bottom reservoir is generally high, so initial flow in or out of that reservoir is high on the side without well skin. The imbalanced period lasts for some years (~15).

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

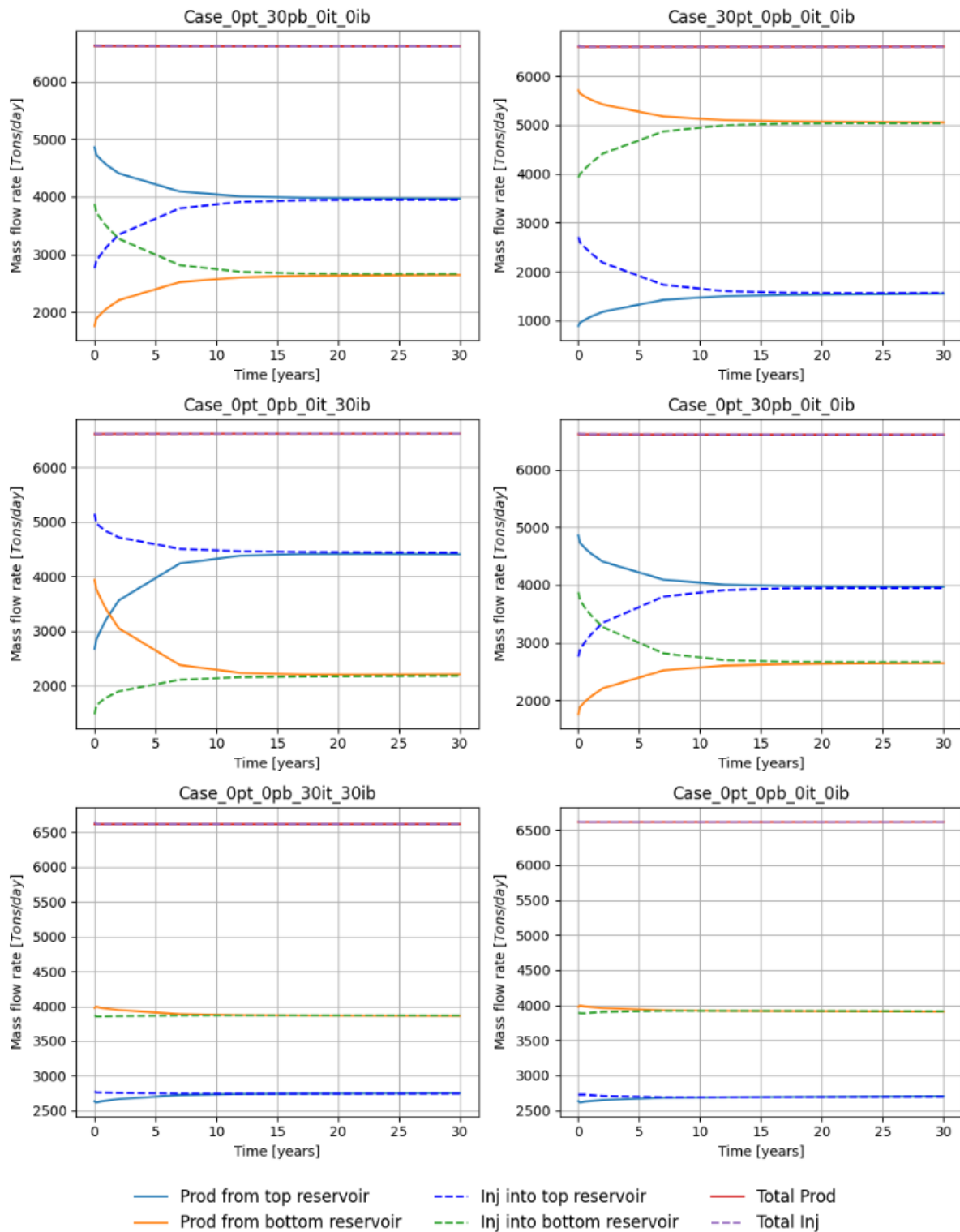


Figure 4-43: Reservoir and total mass flow results for the positive skin cases, with the Base Case for comparison (bottom right).

4.6.2.3 Non-uniform scenarios with negative skin

Lastly, the results for negative skin scenarios are presented. These could be cases where acid stimulation is limited to one reservoir section or non-uniform thermal/pressure stimulation has occurred. The impact of having negative skin in the top reservoir section and positive skin in the bottom reservoir section is also considered. The results are shown in Figure 4-44. Negative skin from stimulation reduces the pressure change seen in the well compared to the Base Case with zero skin.

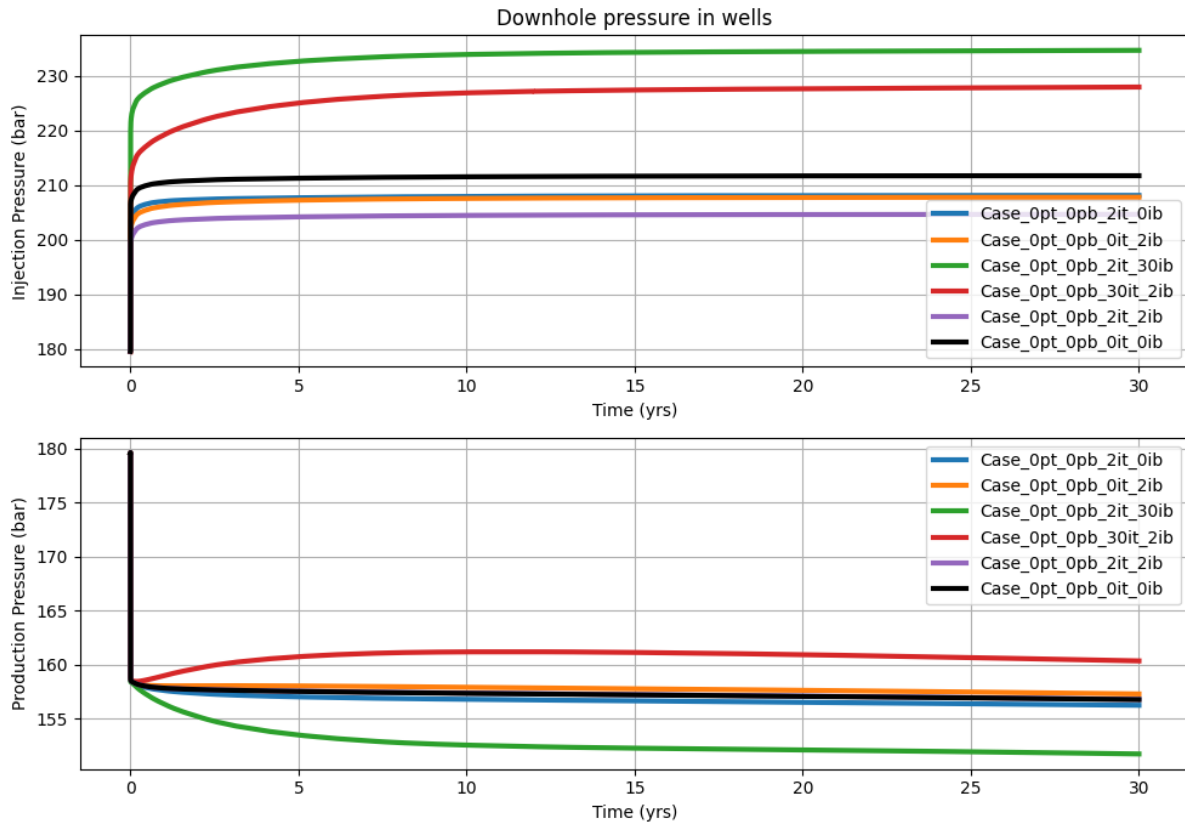


Figure 4-44: Downhole pressure effects for injection well (top) and production well (bottom) for cases with negative skin. Base Case in black.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

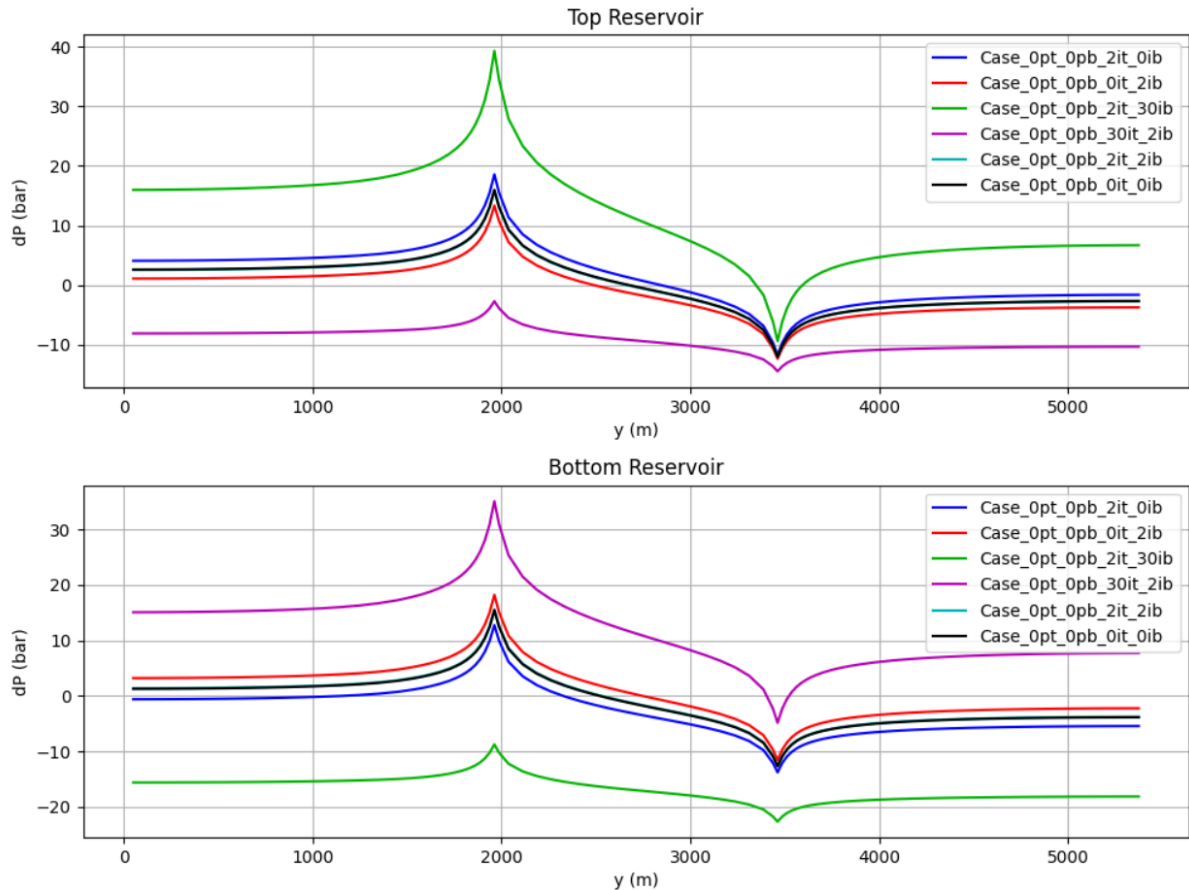


Figure 4-45: Reservoir pressure profiles after 30 years for top (top) and bottom (bottom) reservoir for negative skin cases. The cases with uniform skin again plot very closely to the Base Case.

The reservoir pressure profiles (Figure 4-45) reveal that in cases with only a one well section with a skin of -2, dP in the reservoir diverts < 5 bar from the Base Case. However, if the well has contrasting skin values between sections (high positive skin of 30 in one section and negative skin of -2 in the other section), flow is diverted heavily to a single reservoir, resulting in the larger dP values (10-20 bar).

The reservoir and total mass flow rates can be seen in Figure 4-46. Generally, in all scenarios, skin imbalances lead to flow imbalances, which can lead to extra pressure changes in the reservoirs. These impacts become more significant as the skin contrast increases, that is when the well exhibits positive skin in one reservoir section and negative skin in the other.

Effect of reservoir, fluid, and well characteristics on the use of multiple reservoirs under commingled production

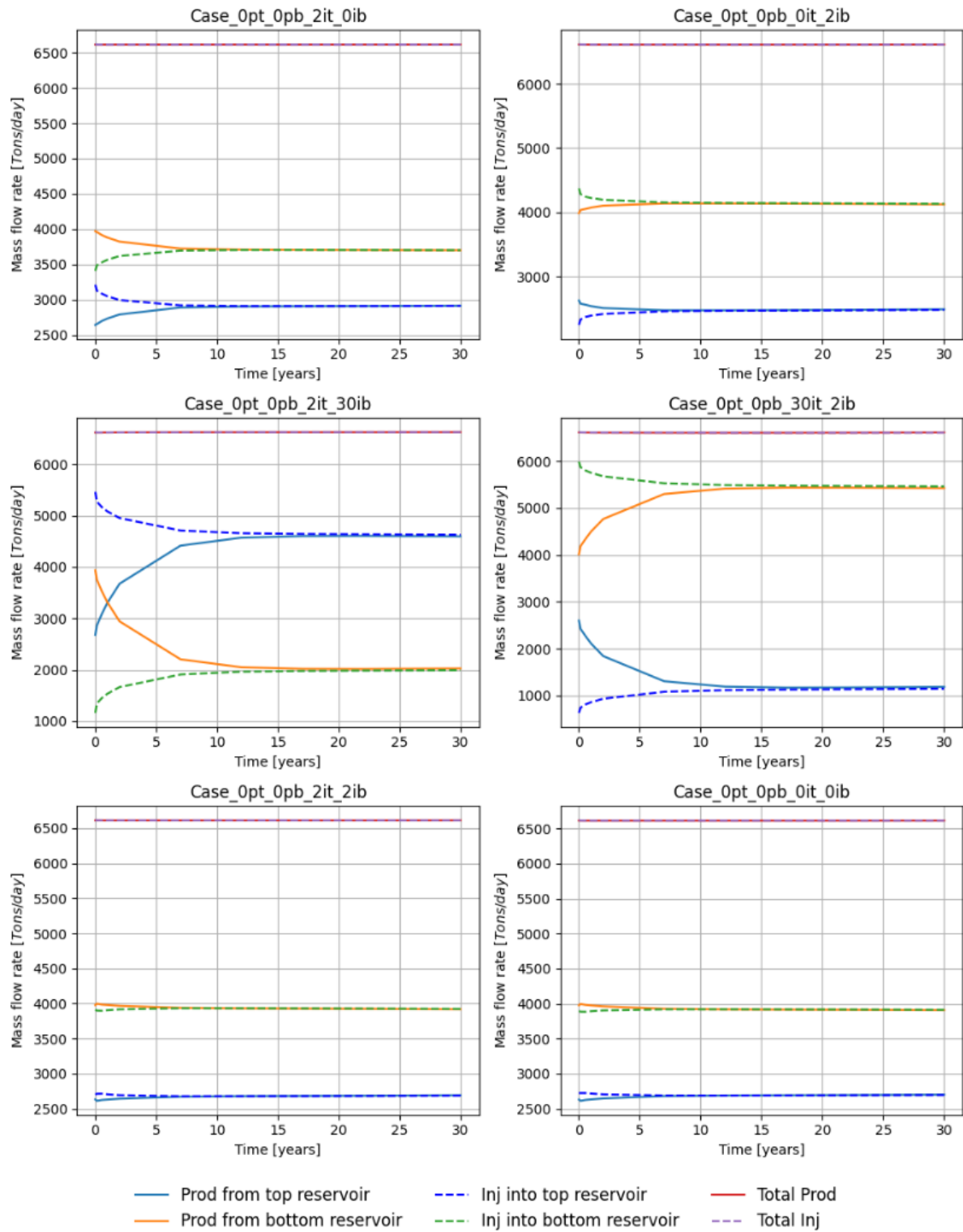


Figure 4-46: Reservoir and total flow results for the non-uniform negative skin cases. The case with a uniform negative skin in the injection well (bottom left) and the Base Case (bottom right) are shown for comparison.

4.6.3 Skin factor main findings

The main conclusions derived from the simulation of the various skin scenarios:

- Skin affects the wellbore pressure and pressure change within the skin 'damage' zone – generally near wellbore.
- Reservoir pressure effects are greatest when wells show non-uniform skin (a well exhibiting different skin value in different reservoir sections). This creates a flow re-distribution which can then affect the reservoir pressure through flow imbalances.
- If the skin in a well is uniform for both reservoir sections, then there is minimal impact on reservoir pressure as there is no flow re-distribution. Well pressure however, may be strongly affected.
- Stimulating a reservoir will increase the flow into that reservoir over time. This could impact the pressure change in that reservoir over time.

4.7 Geochemical interaction between brines

4.7.1 Geochemical data

Geochemical data from 6 wells were selected for the analysis (Table 4-11). The formation waters all belong to the NaCl-type (Figure 4-47). Total dissolved solids (TDS) range from 96 g/l to 175 g/l. Comparison with the data collected by Kottsova & Brehme (2022) reveal that the samples are representative of the selected formations. The quality of the samples from the wells is fair, with an electron balance within +/-5%. Moreover, data about the gas content and gas composition is available for each sample. This allows recalculation of the pH and carbonate content.

Table 4-11: Formation water samples selected to evaluate the effect of mixing on scaling/precipitation.

Sample	Reservoir	TDS (g/l)	Mol%	Electron balance (%)
LSL-GT-01.mixed	Berkel + Delft	96.01	5.51	-3.50
MLD-GT-01-S1.bh	Delft + Alblasserdam	116.10	6.52	5.02
MLD-GT-01-S1.su	Delft + Alblasserdam	115.95	6.51	4.81
NLW-GT-01.bh1+2	Delft + Alblasserdam	134.98	7.34	-8.58
BRI-GT-01.bh1+2	Buntsandstein	129.21	7.18	1.37
BRI-GT-01.su3	Buntsandstein	125.09	6.98	2.16
AMS-01.bh+su_mixed	Slochteren	175.22	9.56	-4.19
MDM-GT-04.bh	Slochteren	140.14	7.63	0.62

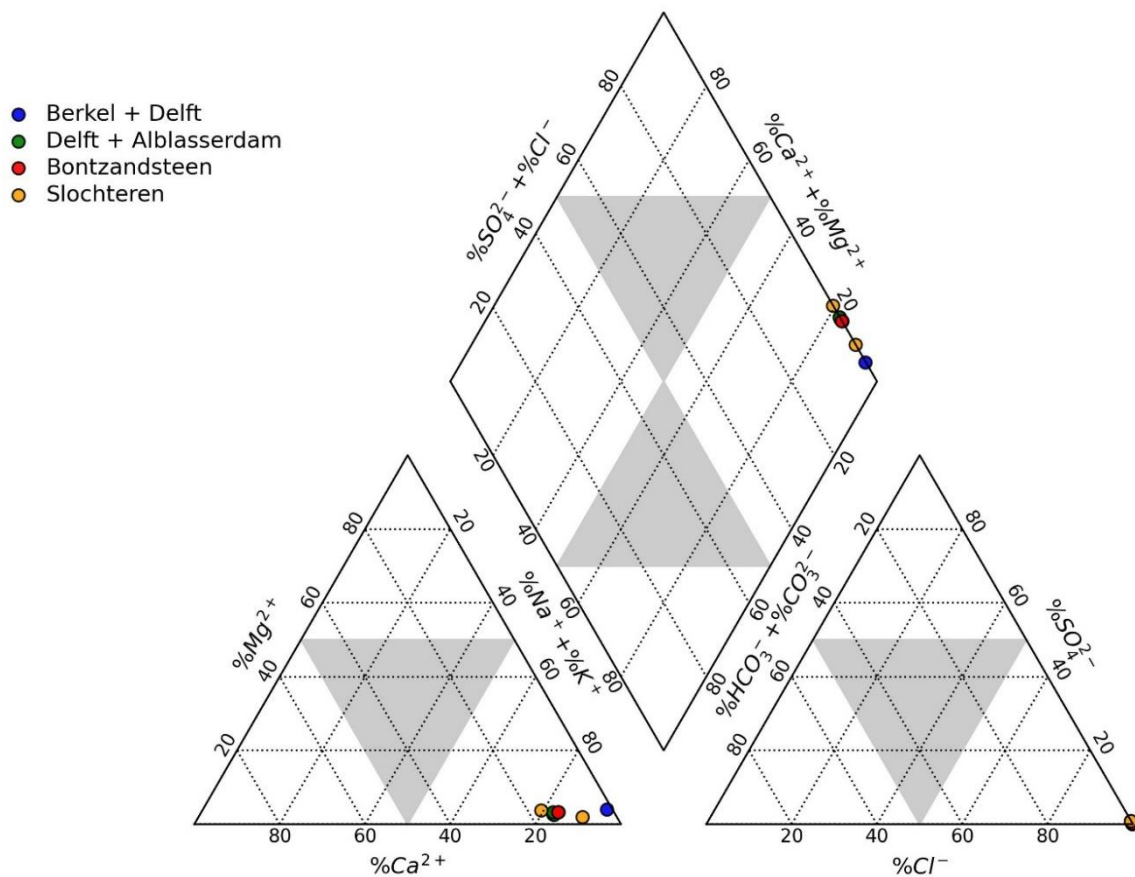


Figure 4-47: Piper diagram of the selected formation water samples.

4.7.2 Methodology and model setup

To assess the possible impact of commingled production, two mixing scenarios were defined: mixing brines from the Berkel+Delft reservoir with the Buntsandstein reservoir, and mixing brines from the Buntsandstein and Rotliegend (Slochteren) reservoirs. Samples LSL-GT-01.mixed, BRI-GT-01.bh1+2 and AMS-01.bh+su_mixed were used as endmembers (Table 4-11). The chemical data for these samples is of good quality and downhole gas data is available to approximate brine composition before degassing.

The chemical composition and gas content used to model the impact of mixing is given in Annex B. The temperature and pressure conditions at each point are given in Table 4-12. They are based on the Base Case of the conceptual reservoir model (Section 3.4).

The mixing ratio was varied from 25 to 75% in steps of 25%. Saturation indices were calculated for different locations in the geothermal system considering local pressure and temperature conditions (Figure 4-48).

1. In the production well at the level of the top reservoir,
2. At the wellhead of the production well,
3. In the injection well above the top reservoir,
4. In the top reservoir near the filter
5. In the bottom reservoir near the filter.

The effect of mixing of two fluids was evaluated using PHREEQC Version 3 in combination with the ThermoChimie.v12a thermodynamic database (Giffaut et al., 2014). Batch reactions were defined for the different mixing ratios under the pressure and temperature conditions at different points in the geothermal loop (Figure 4-48) to calculate saturation of selected minerals. Calculations assume chemical equilibrium to be achieved. In a dynamic environment like a geothermal system, a positive saturation index (SI) at a certain point does not necessarily imply that precipitation will occur. Slow reaction kinetics or inhibition of nucleation may prevent or slow down precipitation. Moreover, the ThermoChimie database contains many mineral phases that go into competition for the available anions but do not necessarily form in geothermal systems. This will affect the calculated SI. To avoid over-interpretation, the results are summarized by mineral groups that are commonly causing scaling in geothermal systems (i.e., carbonates, sulphates, sulphides, iron-oxyhydroxides, aluminum-oxyhydroxide and Cl-salts). Silicates were not included because silica data is lacking for two of the selected samples, however in case of oversaturation of Al-phases, formation of clay minerals cannot be excluded.

In the first step, the gases were redissolved into the fluid to get a representation of the original reservoir fluid. This was done by running a batch reaction of the fluid with the reported gases under reservoir pressure and temperature. Hydrocarbon gases other than methane were not included as they are not included in the ThermoChimie.v12a database. For this step, the measured gas composition (weight percent) was recalculated to mol per liter of brine. For the three (endmember) brines, supersaturation needed to be allowed to redissolve all methane back into the fluids. This suggests that free methane may occur in the 3 reservoirs (free gas bubbles).

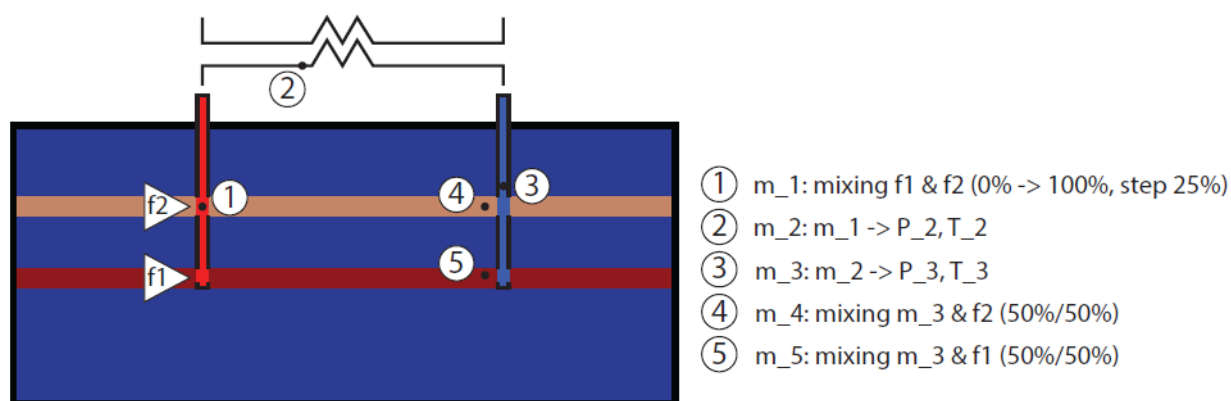


Figure 4-48: Conceptual mixing and transport model used to evaluate possible scaling/precipitation.

Table 4-12: Pressure and temperature at the different points of the model.

Point	P (bar)	T (°C)	Remark
f1	200	72.5	initial bottom reservoir conditions
f2	180	65.0	initial top reservoir conditions
①	175	70.0	
②	4	70.0	
③	190	40.0	
④	180	50.0	
⑤	200	55.0	

4.7.3 Results

4.7.3.1 Commingled production from Berkel+Delft and Buntsandstein reservoirs

The fluid from Berkel+Delft is saturated with respect to carbonate (mainly dolomite) and Fe-oxyhydroxides. The Buntsandstein fluid is saturated in Fe-oxyhydroxides and Al-oxyhydroxides. Redissolving the gases turns both brines to become strongly reducing (due to the high amount of CH_4) and lowers the pH. Under reservoir conditions, both brines are saturated in carbonates (mainly dolomite) and sulphides (mainly pyrite). The Berkel+Delft fluid also shows saturation of Fe-oxyhydroxides

Circulation of the brines results in degassing, causing slight changes in pH and pe. Scaling of carbonates and sulphides is likely at all points in the geothermal loop. The Berkel+Delft brine also has the potential of scaling by Al-oxyhydroxides or clay minerals when reinjected in the reservoir. Saturation of sulphates and NaCl is never reached.

The overall scaling tendency does not change when mixing both brines (Figure 4-49). Precipitation of carbonates and sulphides is likely at all points in the geothermal loop. Moreover, there is a potential to deposit Al-oxyhydroxides or clay minerals, especially at the point where the fluid re-enters the top reservoir.

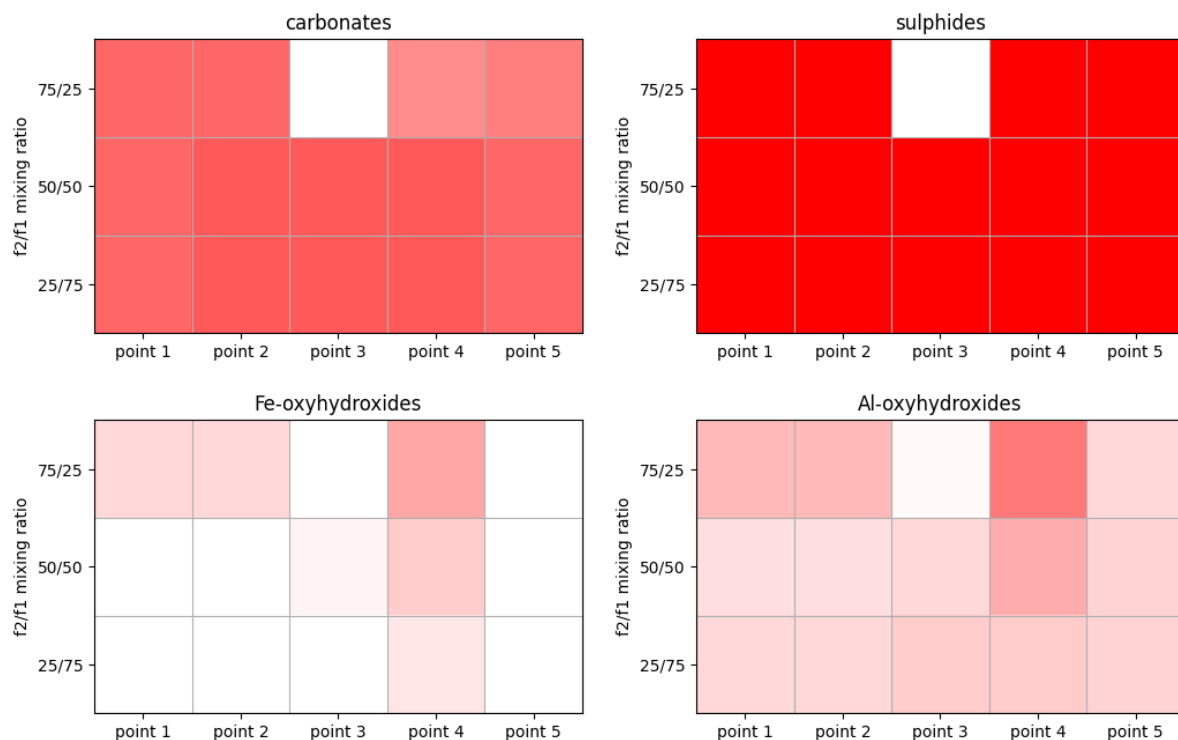


Figure 4-49: Estimated scaling potential for mixing Berkel+Delft with Buntsandstein (white is low, red is high scaling potential).

4.7.3.2 Commingled production from Buntsandstein and Rotliegend reservoirs

The fluid from the top reservoir is discussed above. The fluid from the Rotliegend reservoir shows saturation of sulphates. The other mineral groups are undersaturated. Redissolving the

gases turns both brines to become strongly reducing and lowers the pH. Under reservoir conditions, the Rotliegend brine is saturated in carbonates (mainly dolomite) and sulphides (mainly pyrite). An SI of 1.5 is calculated for barite.

Circulation of the brines results in degassing, causing slight changes in pH and pe. Scaling of carbonates and sulphides is likely at all points in the geothermal loop. Saturation of Al-hydroxides is reached at almost all points, but as the Al-content is low, significant deposition of Al-phases or clay minerals is not expected. Saturation of Fe-oxyhydroxides, sulphates and NaCl is never reached. This pattern does not change on mixing both brines. The results are presented in Figure 4-50.

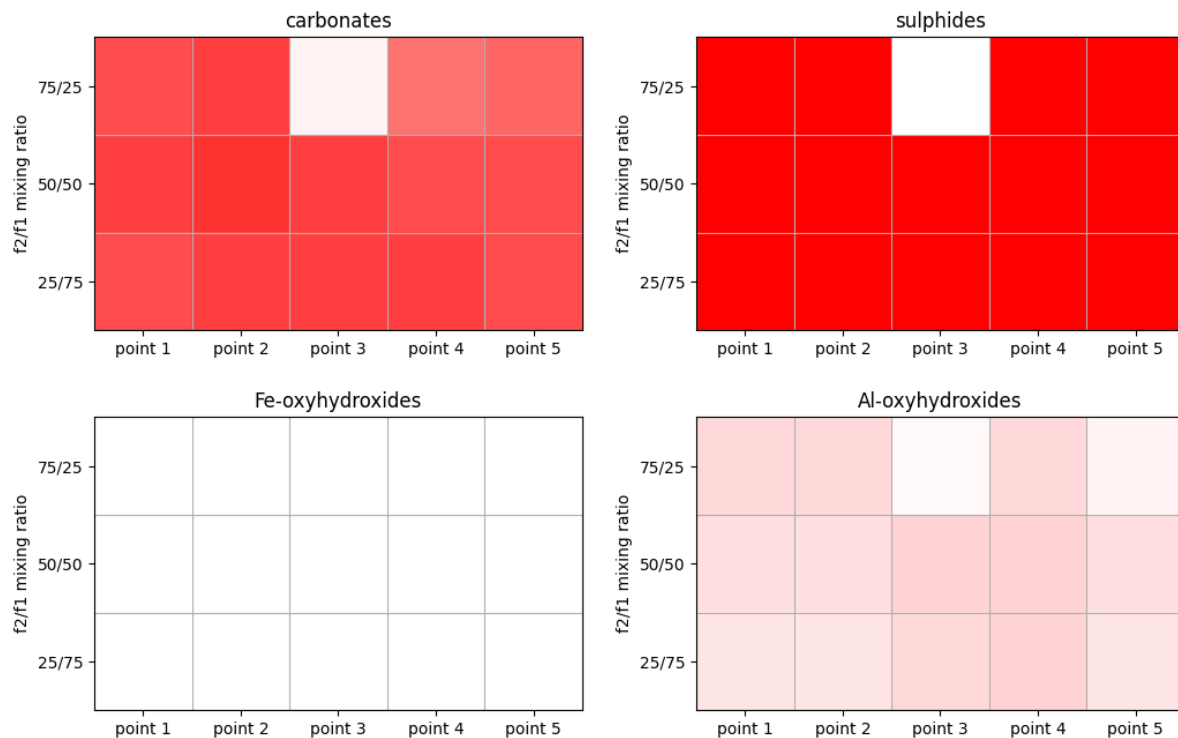


Figure 4-50: Estimated scaling potential for mixing Buntsandstein with Rotliegend (white is low, red is high scaling potential).

4.7.4 Geochemical interaction main findings

The main findings from the chemical interaction evaluation are:

- The three formation fluids are oversaturated with respect to methane suggesting the presence of free gas under the simulated reservoir conditions.
- Redissolving the gases turns the three fluids to become strongly reducing.
- Circulation of the three fluids in a geothermal system results in degassing and slight changes in pH and pe that are likely to cause precipitation of carbonates and sulphides. In the case of Berkel+Delft brine, some deposition of Al-phases or clay minerals cannot be excluded, especially at the point where the cooled brine re-enters the reservoir.
- The overall scaling tendency does not change when mixing Berkel+Delft with Buntsandstein or Buntsandstein with Rotliegend.

4.8 Discussion and conclusions

A Base Case model was simulated in Chapter 3 using reference reservoir parameter values. These simulations were repeated in Chapter 4 for models with varying parameter values to assess the effect of permeability and thickness variations in a reservoir, different temperature regimes, varying viscosity and density of the water, differences in well completion (diameter and well inclination), and skin. The results indicate that varying parameters results in differences in the magnitude and duration of unbalanced flow, in differences in well pressure and pressure changes (after 30 years of production and injection and compared to the initial state), and in differences in the migration of the cold water front.

Reductions in permeability or thickness of the bottom reservoir result in:

- Longer periods of flow imbalance (the time required for equalization of injection and production flow rate toward/from each individual reservoir), increasing in length as reductions in permeability or thickness become stronger.
- Larger pressure changes compared to the initial state as reservoir thickness is reduced around one of the wells, with the potential for over- or underpressurization increasing as a reservoir pinches out completely.
- The eventual lost contribution of a reservoir in case it pinches out (and is therefore absent in one of the well locations) as pressure in the laterally discontinuous reservoir approaches downhole well pressure and there is no longer sufficient dP in the well to force flow into/out of the reservoir.

Changes in well completion or skin result in:

- Pressure changes in and close to the well (compared to the initial state) that are smaller than in the Base Case in case of horizontal well completions, although the pressure changes may be larger further away from the well (as there is more flow from/into that reservoir).
- Pressure changes in the well (compared to the initial state) that are different from the Base Case but not-significantly different from the Base Case within the reservoir in case of uniform skin in the wells.
- Pressure changes in the well (compared to the initial state) that are different from the Base Case and also deviate from the Base Case within the reservoir in case of non-uniform skin in a well.

Changes in water composition or properties result in:

- Viscosity and density differences leading to pressure changes (compared to the initial state) that are slightly different from the Base Case.
- Limited impact when brines of different composition are mixed.

The strongest impact is caused by the presence of a laterally discontinuous reservoir (which is absent in one of the wells). In such a case, dP in the well (pressure increase or decrease due to injection or production) can be up to 55-60 bar different from in the Base Case. Further away in the reservoir, the difference compared to the Base Case may still amount to 20 to 60 bar. For cases with uniform skin in the well (skin 30), the dP may be even 70-100 bar higher than the Base Case. However, in contrast to the laterally discontinuous reservoir cases, the additional dP observed in the well does not persist in the same way in the reservoir, where it is only up to 1 bar higher than the Base Case. Other parameters that can change the dP observed in the well by about 10-30 bar are gradual thickness variations, density and viscosity variations, horizontal completions and non-uniform skin in the well. In all these cases, the dP

observed farther out in the reservoir changes by 5-15 bar compared to the Base Case. Temperature variations and a reduced diameter in the lower reservoir well section result in minimal pressure impact in the well as compared to the Base Case (dP up to 5 bar different). That impact decreases in the reservoir to 1-2 bar.

In terms of flow imbalance, no equilibrium is reached in case the brine has different composition (and therefore density and viscosity) in top and bottom reservoir, even though the initial imbalance between injection and production into the same reservoir may only be in the order of 100-200 ton/day. In case of a laterally discontinuous reservoir, the duration of imbalance may last up to 15 years (with an initial difference of 3000-4000 ton/day). The same duration occurs in case of non-uniform skin in the well (combining negative and strong positive skin). The mass flow imbalance lasts up to 10 years when there are smooth permeability or thickness variations, colder temperature conditions (lower geothermal gradient), or the lower well section is completed with a reduced diameter. For comparison, flow imbalance in the Base Case remains for less than 5 years (starting at 100-200 ton/day). The only case where flow stabilizes faster (2-5 years) is when the water has the same composition (and hence density and viscosity) in both reservoirs.

5 COMMINGLED PRODUCTION IN A SPECIFIC GEOLOGICAL CASE IN THE NETHERLANDS

Three geothermal sites in the Netherlands currently produce heat from the subsurface applying commingled production. These systems are all located in the West Netherlands Basin and have been exploiting the Upper Jurassic/Cretaceous play (Section 2.3.2) since 2013, 2018, and 2024:

- Upper reservoir: Lower Cretaceous Berkel Sandstone and/or Rijswijk Sandstone Members.
- Lower reservoir: Upper Jurassic Delft Sandstone Member and/or Alblasserdam Member.

Note that sandstones from the upper section of the Alblasserdam Member, just below the Delft Sandstone Member, can locally contribute to reservoir volume when their quality is suitable. As of present, commingled production within or across different geothermal plays, does not occur in the Netherlands.

To evaluate reservoir behavior under commingled production, a geological model was built for one of the sites. This site was chosen due to the relatively best availability of subsurface data and the relatively simple local structure of the target reservoirs. The objectives are to simulate a more realistic scenario and determine under which conditions commingled production effects and their associated hazards may arise.

A full history matching of pressure, production rate, and temperature would require detailed production data. As no detailed flow, pressure or temperature data are available, history matching is not possible. Another option for model calibration is the comparison of calculated or simulated subsidence values with the results of monitoring. It remains difficult to calibrate the numerical model based on subsidence values as the number of free parameters is larger (both solid and flow properties are free parameters) compared to the number required for well pressure calibration. However, it can be used as a “sanity check” for the parameter space.

The chosen geothermal site for the specific geological case is in South-Holland (Figure 5-1). Commingled production of geothermal heat has been ongoing at this site since 2018. Its doublet system targets the Berkel Sandstone and Delft Sandstone Members, which are hydraulically separated by the Rodenrijs Claystone Member. The Vlieland Claystone Formation overlying the Berkel Sandstone Member acts as the system seal (Figure 2-4).

To construct the model, interpretation of a 3D seismic dataset was performed mapping faults, geometries, and sediment distribution. These interpretations formed the basis of the structural model, which was then populated with reservoir properties derived from petrophysical analysis of the producer, injector, and relevant offset well data. The entire workflow was conducted in SLB's Petrel 2023 software package.

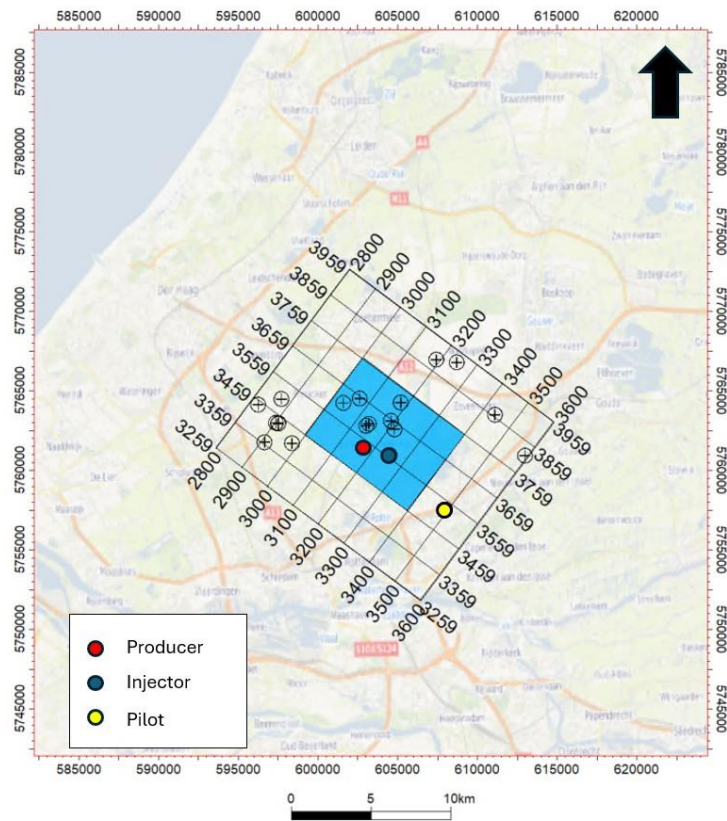


Figure 5-1: Extent of the 3D seismic survey (L3NAM2012AR) and offset wells used in the study. The Area of Interest (AoI) is outlined in blue. The producer and injector at reservoir level are shown as a red and a blue dot, respectively, while the vertical pilot well used to guide the seismic interpretation is shown in yellow. Black arrow indicates North.

5.1 Seismic interpretation

A seismic interpretation was performed to map key horizons (e.g., horizon corresponding to the top of the Berkel Sandstone Member) and faults to be used as input for the static model. The interpretation was conducted in depth domain using the 3D seismic reflection survey L3NAM2012AR (downloaded from www.nlog.nl). A total of 26 wells within the survey area were used to guide seismic interpretation. A full seismic-to-well tie workflow was not required since the seismic data are already in the depth domain. However, a vertical exploration well was particularly useful for identifying the target horizons, given the advantage to correlate events from well logs to seismic data without introducing complex geometry corrections due to the well deviation.

A broader area, where more wells were available, was initially used to guide horizon mapping during the early stages of seismic interpretation. The focus was then narrowed to an Area of Interest (AoI) of approximately 8×6 km around the doublet (Figure 5-1), where detailed interpretation was carried out at a 10 inline/crossline interval, with additional refinement as required.

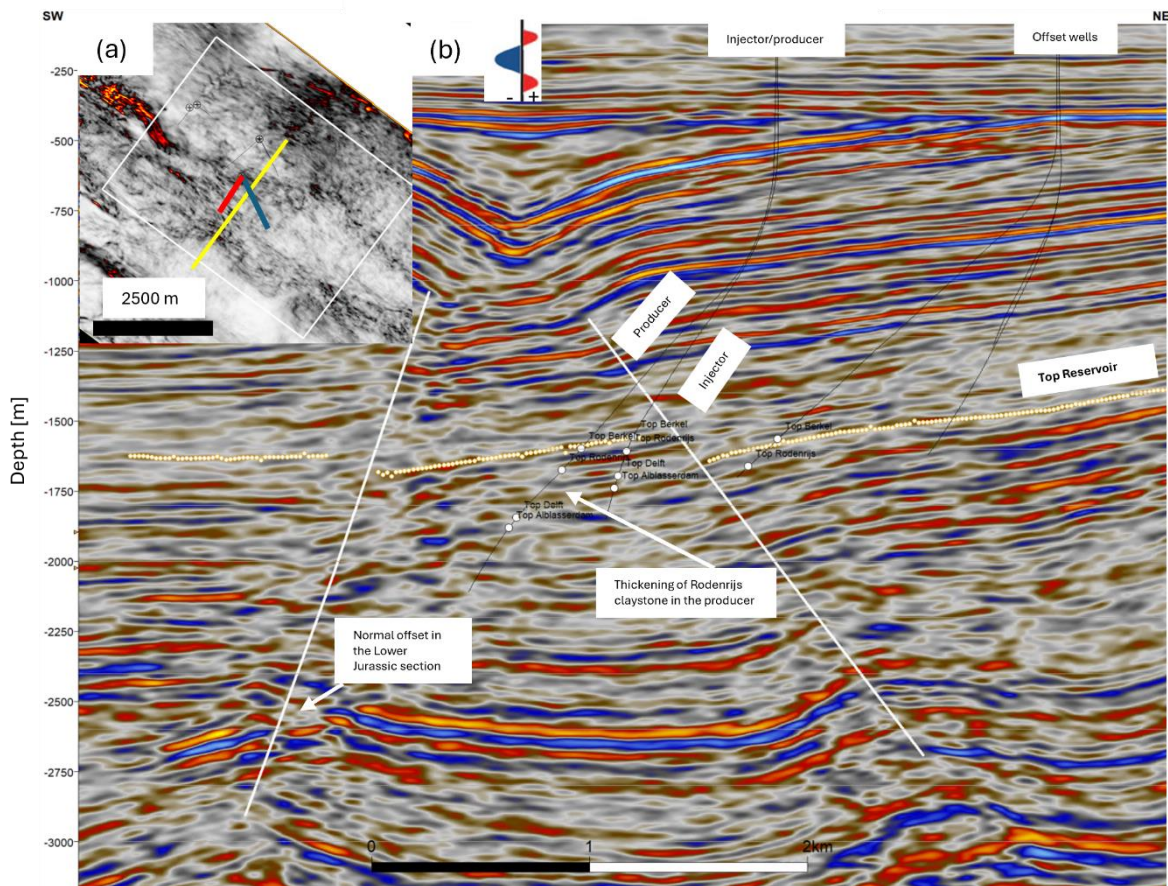


Figure 5-2: (a) Variance attribute highlighting faults (black to red lineaments) generated from the 3D seismic survey (L3NAM2012AR) outlined in white. The doublet (red and blue thick continuous lines) is located within a fault block, as shown in the seismic extracted from 3D seismic survey (b) where the wells are projected. The seismic section location is outlined by a yellow line in (a). Faults are marked in white, while the Top Berkel Sandstone is indicated by an orange dotted line. Reservoir bases and tops are indicated by white dots along the well trajectories. See the thickening of the Rodenrijs Claystone Member in the producer.

An initial attempt was made to map the top and base of the Berkel Sandstone and Delft Sandstone Members. However, due to limited thickness and noisy seismic data at depth, only the Top Berkel Sandstone Member horizon could be mapped reliably across the study area (Figure 5-2). This horizon is a strong reflector, characterized by a high-amplitude contrast with the overlying Vieland Claystone Formation and underlying Rodenrijs Claystone Member. This horizon interpretation was subsequently used as proxy to define the structural geometry of the static model. This is considered a valid approach because the other horizons are relatively subparallel to the Top Berkel Sandstone Member within the Aol and are assumed to follow similar structural trends.

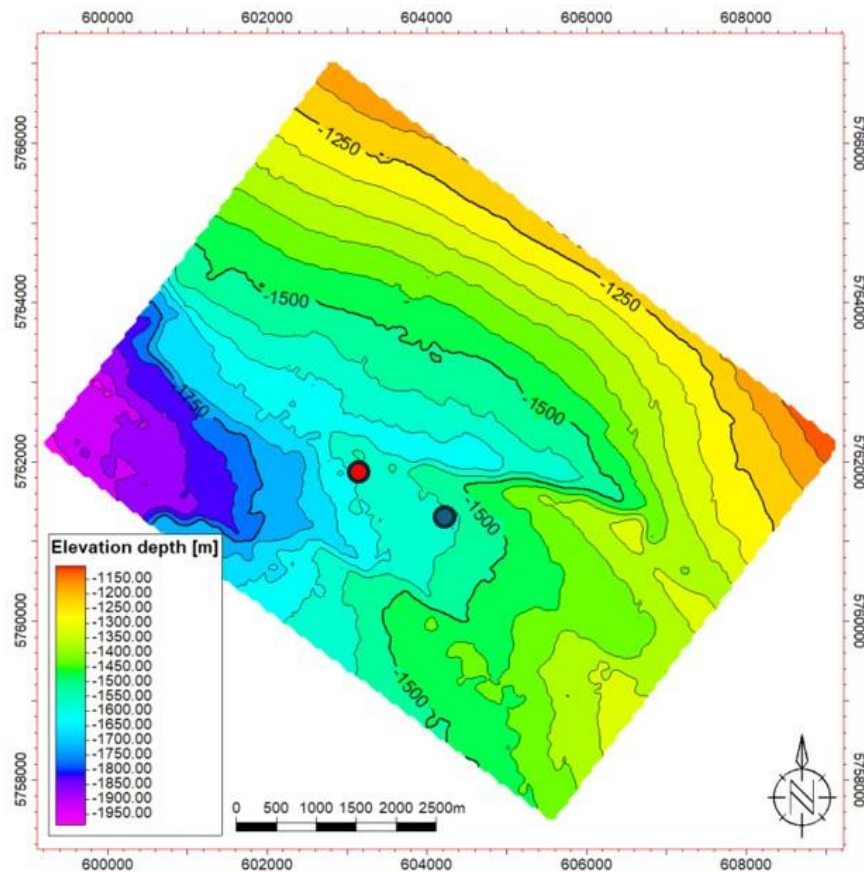


Figure 5-3: Depth map of the top Berkel Sandstone Member. The horizon deepens towards the west of the Aol, where the top Berkel Sandstone reaches a depth of 1950 m TVD. Producer and injector are marked with red and blue dots, respectively.

The doublet system is drilled within a block bounded by two faults (Figure 5-2). These faults are oriented SE–NW. The southern boundary fault exhibits a reverse throw at reservoir level, while a normal throw is observed in the underburden. This indicates that the area was exposed to an inversion event. The northern boundary fault shows a normal throw.

In the producer, the Top Berkel Sandstone Member of the upper reservoir is encountered at 1620 m TVD, while it is encountered at a slightly shallower depth of ~1563 m TVD in the injector (Figure 5-3). A similar trend is observed for the Top Delft Sandstone Member. This marker is at ~1800 m TVD in the producer, approximately 100 m deeper than in the injector. The Rodenrijs Claystone Member between the upper and lower reservoir is thicker in the producer than in the injector (Figure 5-2). No clear faulting is observed between the injector and producer; however, proximity (~1 km) to the southern boundary fault reduces seismic reflection quality due to a fault shadow.

5.2 Structural modelling

In total, only three faults and one seismic horizon were used for the subsequent structural modelling phase. Although minor faults were identified in the seismic reflection data, most exhibit limited lateral continuity and lack clear offset. Consequently, for model simplification, these features were excluded from the structural modelling phase. Prior to pillar gridding, the selected faults and horizon were quality controlled to remove features such as curvatures and kinks that could produce artifacts or complicate further modelling. Pillar gridding was defined

in Petrel to structure the static model. With three faults identified, only one extends across the entire model, effectively dividing the reservoir into two main compartments. Based on this configuration, *top*, *mid*, and *base* pillar grids were established to honor the structural framework. A grid cell size of 100×100 m was used to balance resolution and computational efficiency.

The horizons in the static model were subsequently constructed using the seismic interpretation of the Top Berkel Sandstone Member as the primary input, along with stratigraphic tops from offset wells. Subsequently, the horizons were smoothed to remove artifacts resulting from interpolation while preserving the overall reservoir architecture. The reservoirs are conformable and subparallel. However, the top of the model was assumed flat (Figure 5-4) and the layers below were adjusted accordingly to simplify the subsequent modelling phase in DARTS. The underburden and overburden were set to 200 m and 300 m, respectively.

Layering was created within each defined zone. Constant layer thickness was applied for the reservoir zones and the Rodenrijs Claystone Member, with six layers assigned to each zone. This resulted in a vertical cell resolution of 6 m in the Delft Sandstone Member and 10 m in the Berkel Sandstone Member. In contrast, the underburden and overburden were modelled with gradually increasing layer thickness (coarsening) away from the reservoir zones (Figure 5-4).

The reservoir layering was designed to capture and model heterogeneities. Both the Berkel Sandstone and Delft Sandstone Members exhibit net-to-gross ratios above 75%, though shale lenses are present. The shales encountered in the producer and injector reach a maximum thickness of 3 m. Similar lenses may exist elsewhere in the reservoir and capturing them ensures that these heterogeneities are accurately represented and properly upscaled in the model.

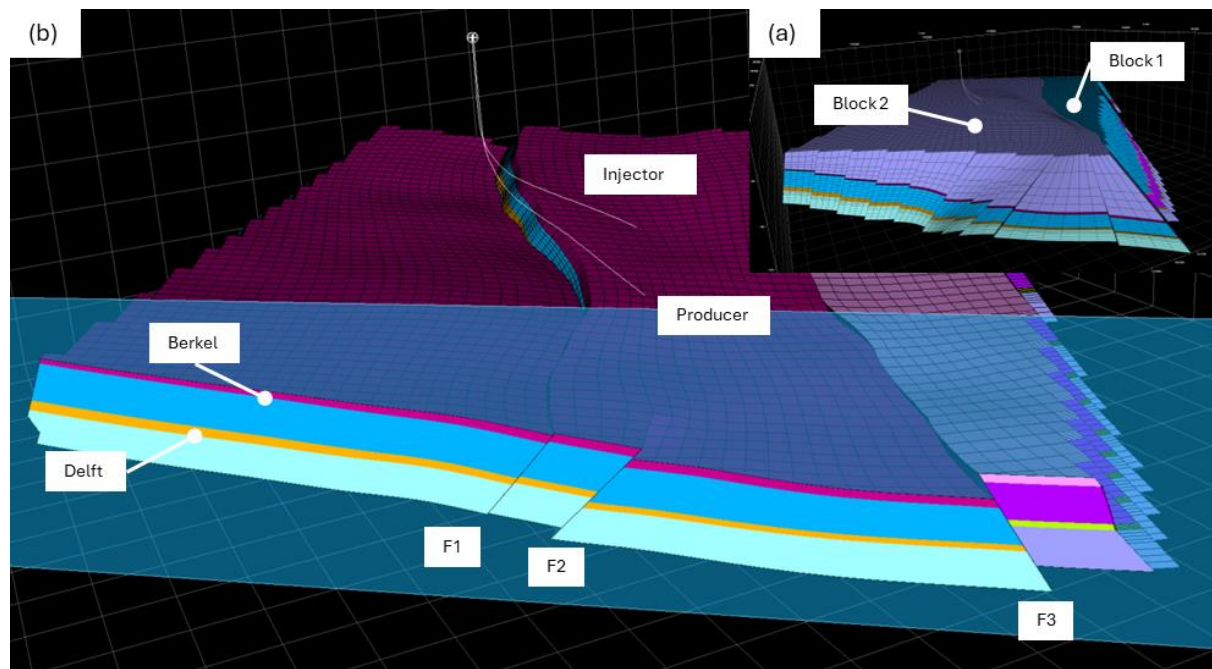


Figure 5-4: (a) Full static model with zones and layers displaying the two main model blocks. (b) Slice through the model perpendicular to faults.

5.3 Property estimation

The final static model comprises 142,848 cells across 31 geological layers. At this stage, the model grid was finalized and ready to be populated with properties. For dynamic simulation in DARTS, the following properties were assigned:

- porosity
- permeability
- heat capacity
- temperature
- thermal conductivity
- pressure

All properties, except temperature and pressure, were initially calculated at well scale using well log data and subsequently upscaled to populate the full model. The equations used in the following chapters (5.3.1, 5.3.3 and 5.3.4) for petrophysical computations can be found in Asquith & Krygowski (2004). Temperature and pressure were derived from static gradients and directly calculated for the entire model domain as depth-dependent values.

5.3.1 Porosity

Total porosity was first calculated from density through the following equation (16):

$$\Phi_{\rho} = \frac{\rho_{SSt} - \rho_{RHOB}}{\rho_{SSt} - \rho_{brine}} \quad (16)$$

Where ρ_{SSt} is the average density of sandstone (2.65 kg/m³), ρ_{RHOB} is the density reading from the corresponding well log and ρ_{brine} is the density of the brine (1.1 kg/m³). To get a more accurate total porosity, the density porosity was then averaged with neutron porosity through the following equation (17):

$$\Phi_{NPHI,\rho} = \frac{\Phi_{\rho} + \Phi_{NPHI}}{2} \quad (17)$$

Following, effective porosity, which corresponds to the volume of pores interconnected, was computed by accounting for the sediment shale volume to account for the non-productive shale intervals. The shale volume was calculated using equation (18):

$$V_{Shale} = \frac{GR - GR_{SSt}}{GR_{Shale} - GR_{SSt}} \quad (18)$$

Where GR corresponds to the gamma ray well log reading, GR_{SSt} to the average sandstone gamma ray value (15 API) and GR_{Shale} to the average shale gamma ray (150 API). Lastly, the effective porosity accounting for the volume of shale was calculated using equation (19):

$$\Phi_{Vshale\ corrected} = \frac{\Phi_{NPHI,\rho} - V_{Shale} * 0.01}{1 - V_{Shale}} \quad (19)$$

5.3.2 Permeability

Permeability was calculated using the $\Phi_{hi}-K$ transform derived from the geological report of TW OK II (PanTerra, 2018), produced by PanTerra for Trias Westland B.V., which summarizes

the geology of the Westland area and its geothermal concessions. The report provides a porosity(Φ)–permeability(K) relationship for the Delft Sandstone and Alblasserdam members in the West Netherlands Basin. The Φ – K transform, based on 760 samples, was adopted to estimate permeability (Equation 20) in mD for both the Berkel Sandstone and Delft Sandstone Members within the Aol. Furthermore, an internal Φ – K transform for the Berkel Sandstone Member in the West Netherlands Basin was modeled (Equation 21). These equations defined PERM1 (average scenario) and PERM2 (high scenario) cases, respectively (Section 5.5). Last, the permeability field calculated by using equation 20 was divided by 2 and used as a low scenario (PERM3). The Φ – K transforms that were employed are the following:

$$\ln(K_h) = -116 \Phi_{Vshale\ corrected}^2 + 85.2254 \Phi_{Vshale\ corrected} - 9.5401 \quad (20)$$

$$\ln(K_h) = 0.1361e^{0.3324\Phi_{Vshale\ corrected}} \quad (21)$$

5.3.3 Thermal conductivity

Thermal conductivity (c) of rocks is strongly dependent on mineralogical composition, thus lithology. Sandstone typically exhibits higher c values than shale-rich intervals because quartz has higher thermal conductivity, so a higher quartz content raises the rock's overall c value. Gamma ray (GR) logs, which measure natural radioactivity associated with clay minerals, serve as an effective proxy for shale content. To estimate thermal conductivity from GR, a linear interpolation between two end-member conductivities is commonly assumed: c_{max} for sandstone (3.3 W/m·K) and c_{min} for shale (1.5 W/m·K). In this study, the relationship is expressed as (equation 22):

$$c = c_{max} - \frac{GR_{max}}{GR} (c_{max} - c_{min}) \quad (22)$$

Where GR_{max} is the largest GR measurement in the reservoir interval. This formulation assumes that increasing GR values indicate higher shale content, thereby reducing thermal conductivity toward c_{min} . The end-member values are obtained from literature (Diment, 1988).

5.3.4 Heat capacity

The heat capacity of a formation is influenced by its mineral composition and fluid content, both of which can be inferred from well logs. To estimate the volumetric heat capacity, a two-step approach is applied: first, the heat capacity of the rock matrix is calculated as a weighted average of clean rock and shale components (equation 23):

$$CP_{matrix} = (1 - V_{shale}) * Heat\ capacity_{sand} + V_{shale} * Heat\ capacity_{shale} \quad (23)$$

Where $Heat\ capacity_{sand}$ and $Heat\ capacity_{shale}$ are 850 and 1000 J/kg·K, respectively (Beardmore, 2011).

Subsequently, the volumetric heat capacity is computed using bulk density (ρ_{RHOB}) and porosity ($\Phi_{Vshale\ corrected}$) (equation 24):

$$CP_{vol} = \rho_{RHOB} * [(1 - \Phi_{Vshale\ corrected}) * CP_{matrix} + \Phi_{Vshale\ corrected} * Heat\ capacity_{water}] \quad (24)$$

where $Heat\ capacity_{water}$ is 4180 J/kg·K.

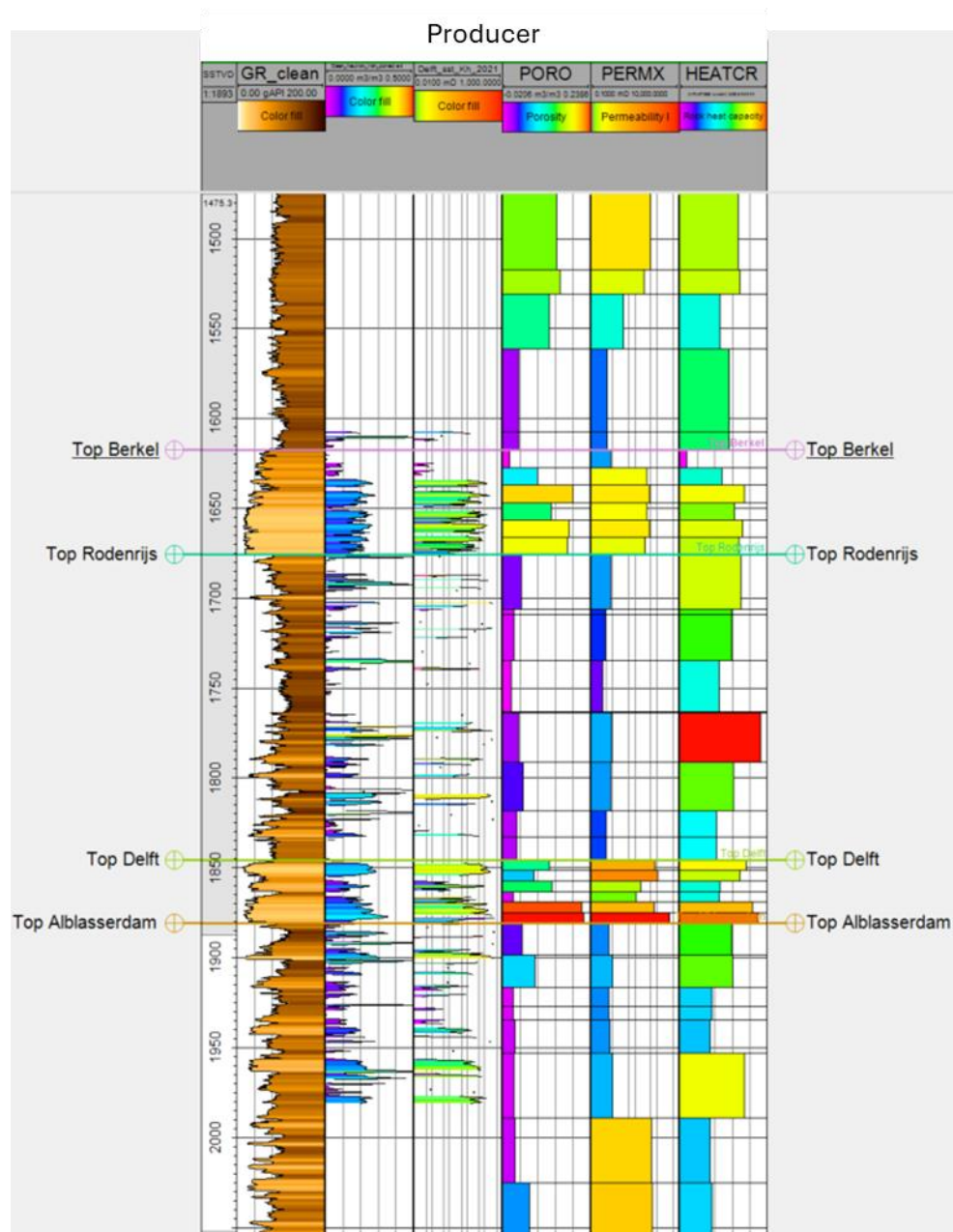


Figure 5-5: Upscaling of porosity and permeability at the producer well. From the left, the well log tracks represent: gamma ray, porosity (Φ) and permeability (K) logs, and the upscaled logs of porosity, permeability and heat capacity. Note that the upscaled porosity and permeability in the Rodenrijs Claystone Member remain low, despite the presence of high-porosity and high-permeability intervals in the well logs. This reflects the effectiveness of the harmonic averaging method in preserving the overall low-permeability character of the claystone.

5.4 Property upscaling and modelling

Once calculated from well logs, the properties were upscaled using a zone-specific approach. An arithmetic average was applied for the Berkel Sandstone Member and Delft Sandstone Member zones, while harmonic averaging was used for the Rodenrijs Claystone Member zone, as well as the underburden and overburden. This approach produced the best fit to the

original logs, particularly for permeability, where highly permeable sandstone lenses within claystones could otherwise artificially increase average permeability in zones that should behave as nearly impermeable (Figure 5-5).

Porosity, permeability, and heat capacity could only be calculated for data from the producer, as the injector lacked density and porosity logs. Offset wells in the Aol were similarly unequipped, therefore only the producer well was used to upscale porosity and permeability, and ultimately to populate the model. Thermal conductivity, however, was dependent on gamma ray logs, allowing upscaling across all wells with such measurements.

Property modelling was performed using a fully stochastic algorithm, *Sequential Gaussian Simulation*. The output data range was constrained by the absolute minimum and maximum values from the input variables. The *sill*, representing the maximum variance, was set to 1, while the *nugget* was set to 0.0001, maintaining a relatively low degree of variance within the model. These parameters may be adjusted during analysis.

Reservoir temperature was calculated directly within the model domain as a function of depth using the following equation (25) by assuming a static geothermal gradient of 31 °C/km (Békési, 2020) and an average surface temperature of 10°C:

$$Temperature = 10 + 0.031 * Depth \quad (25)$$

Pressure was also initiated similarly by assuming a regional gradient of 0.103 bar/m.

5.5 Numerical model setup

The numerical model grid was also built in Petrel and consists of approximately 120,000 active cells. Three different material permeability spaces were tested, as outlined in section 5.3.2 and are summarized in Table 5-1. The permeability values were intended to represent an average (PERM1), high (PERM2), and low (PERM3) permeability scenario – however the spatial distribution of the permeabilities also varies within and between scenarios. In addition, the PERM0 scenario was run where two distinct reservoirs were inserted with 150 m vertical distance between the two reservoirs and no vertical permeability connection between them. The same reservoir transmissivities (permeability x thickness) used in the Base Case scenario as in the scenarios of Chapter 4 (9 D.m and 13 D.m for top and bottom reservoir, respectively). In general, the PERM0 and PERM3 models had a poorer vertical connection between the reservoirs, while the PERM1 and PERM2 models had slightly higher permeability and better vertical reservoir connection. The layers had different thicknesses in the models, so the permeability needed to be appropriately scaled. The basic corner point grid (CPG) structure with well tracks can be seen in Figure 5-6. Further, the faults were assumed impermeable barriers to fluid flow.

Table 5-1: Summary of material parameters for numerical reservoir model scenarios.

Parameter	Units	Mean	Min	Max
PERM0	mD	-	450	910
PERM1 (average)	mD	55.6	0.05	323
PERM2 (high)	mD	301.6	0.18	1912
PERM3 (low)	mD	11.2	0.01	50
PORE	-	0.07	0.001	0.217
HCAP	J/kg-C	1655	1170	2177
COND	W/m-C	2.28	1.5	3

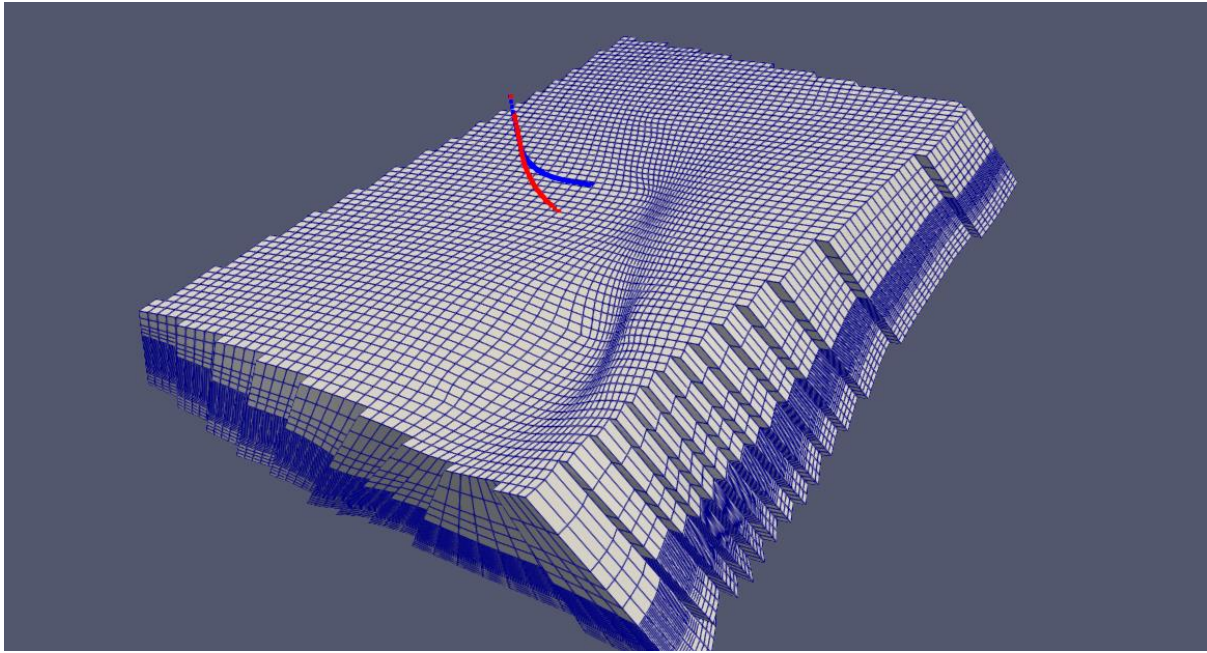


Figure 5-6: Numerical reservoir model mesh with injection welltrack (blue) and production welltrack (red).

The wells are approximately 1200 m apart at the top of the reservoir (~1600 m TVD) where the finer z refinement can be observed in the grid (Figure 5-6). The models were run to an initial steady state. The resulting temperature varies with depth/location, but the top of the reservoir temperature at the top of the wells was about 60°C and the base model temperature is around 72°C. Over 500 m, the average thermal gradient through the reservoir is 25°C/km and the average gradient through the whole model is about 30°C.

Cumulative volume data per month (in m³) over the 7 years of production history are available from www.nlog.nl. No other data are publicly available for the specific case regarding injection temperature or pressure. All forecast models were run for 30 years with a constant flow rate of 250 m³/h with an injection temperature of 40°C. The flow rate of 250 m³/h can be seen to be a reasonable average value of the actual flows in the wells as shown in Figure 5-7.

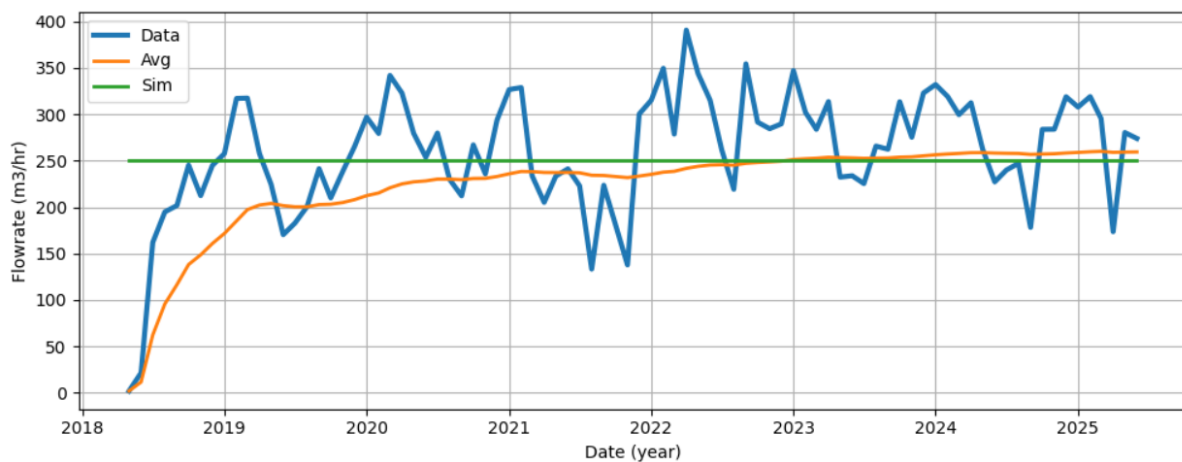


Figure 5-7: Real injection history of the specific case installation with cumulative average and simulation flow rates plotted.

5.6 Simulation results

The general behaviors of the specific case models can be grouped into two categories: the average (PERM1) and high (PERM2) permeability scenarios show similar end behavior due to the apparent connectivity in permeability between the two reservoirs, while PERM0 and the low permeability scenario (PERM3) show a disconnect between the reservoirs. Figure 5-8 displays the contour plot results from the top reservoir for the average and high permeability scenarios (PERM1 and PERM2) for dP and dT after 30 years of production. The dashed line on the plot is used for profile plotting of dP and dT similarly to the scenario analyses in Chapter 4. By contrast, Figure 5-9 displays the same results for the PERM0 and low permeability (PERM3) scenarios. In those simulations, the compartmentalization created by reservoir discontinuities across faults is observed in the pressure response and later in the flow imbalance. The stochastic material properties of the average and high permeability cases (PERM1 and PERM2) result in more connectivity and the ability of the model to transmit pressure across or around the faults. The dP values in the disconnected/compartimentalized reservoir cases of PERM0 and PERM3 can reach further distances away from the wells due to lower permeability values in general.

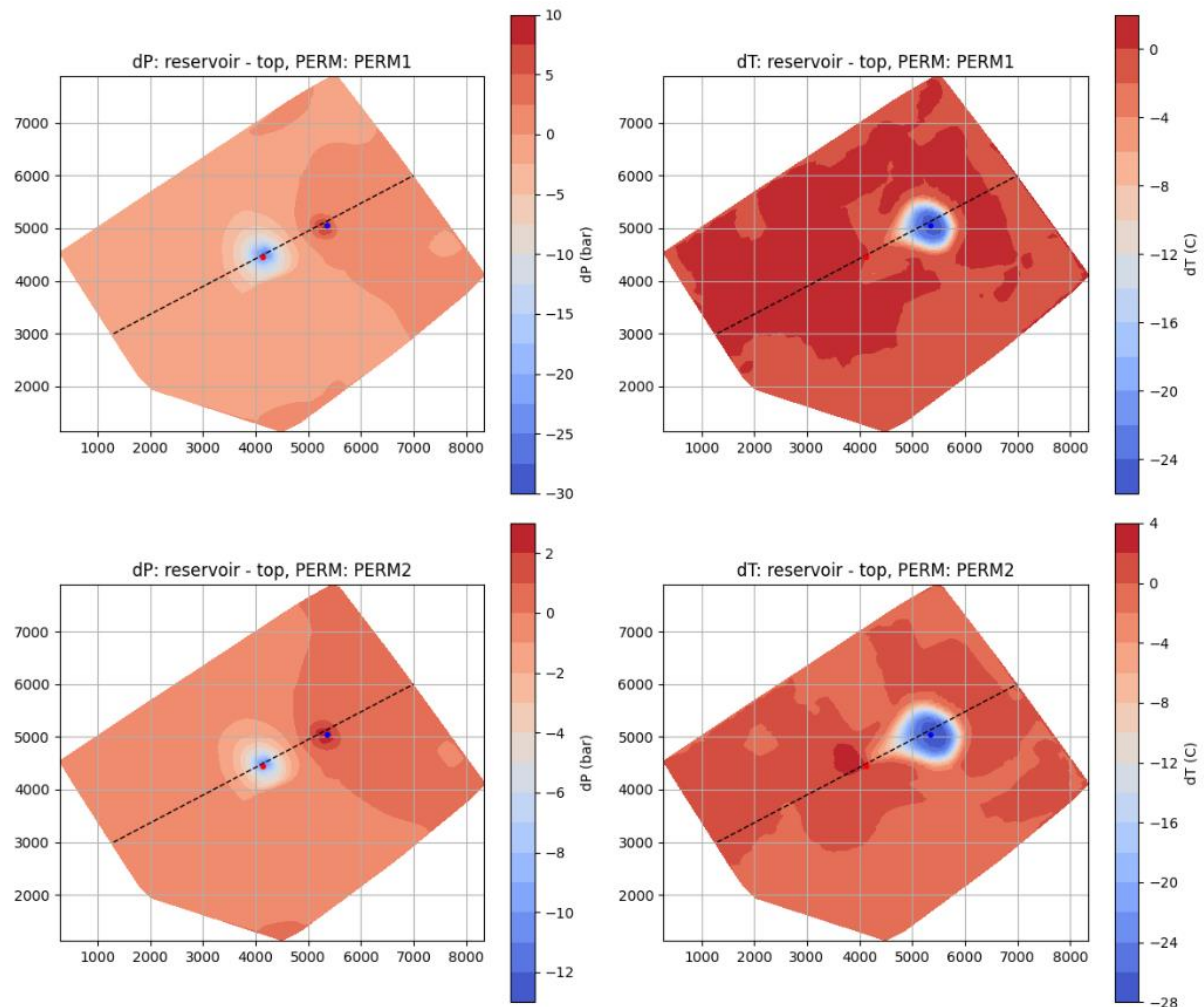


Figure 5-8: Contour plot of change in pressure (left) and change in temperature (right) for the top reservoir in the average permeability PERM1 (top) and high permeability PERM2 (bottom) scenarios of the specific case model after 30 years. Location of injection well in reservoir (blue) and production well (red).

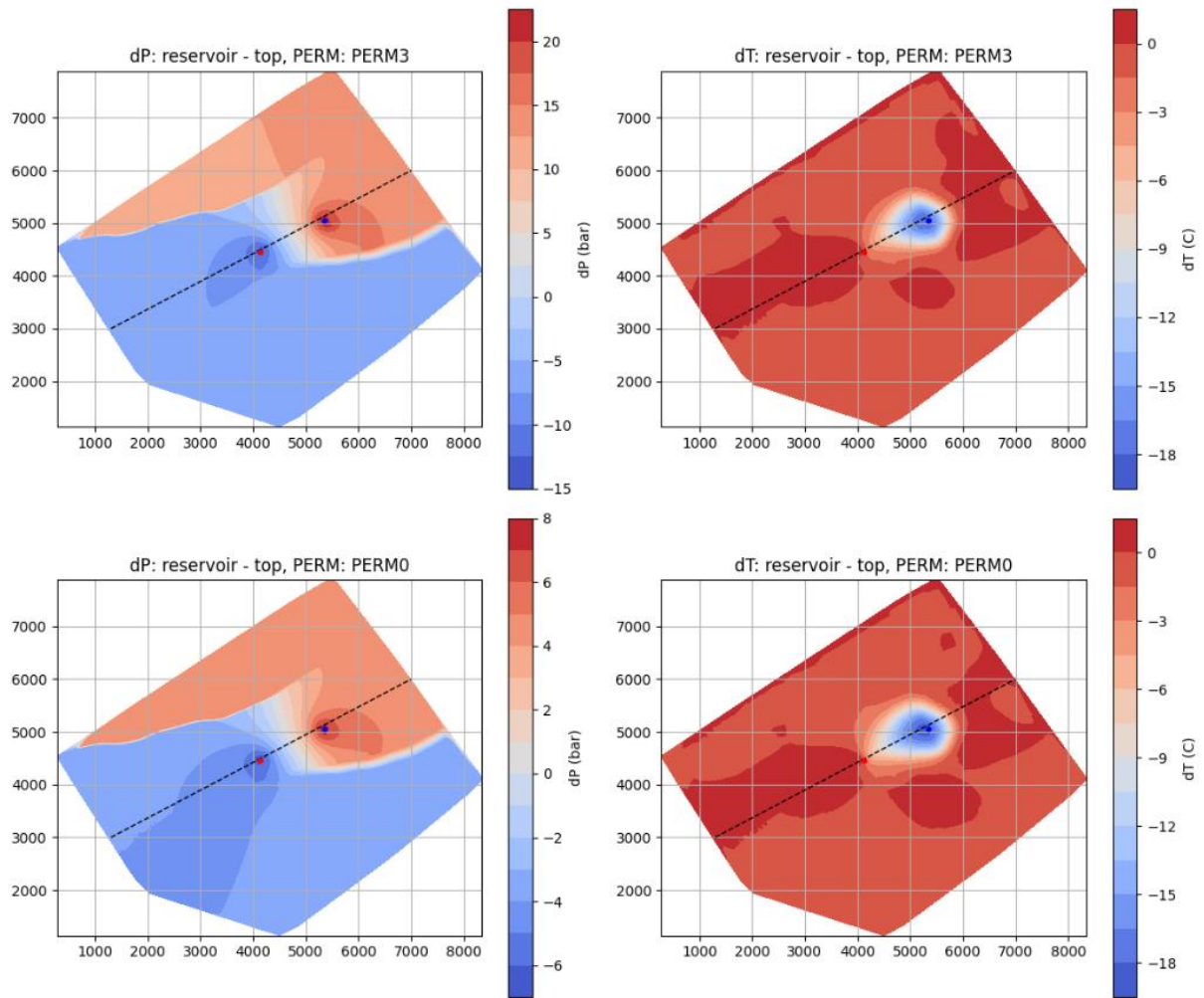


Figure 5-9: Contour plot of change in pressure (left) and change in temperature (right) for the top reservoir in the low permeability case PERM3 (top) and PERM0 (bottom) of the specific case model after 30 years. Location of injection well in reservoir (blue) and production well (red).

Similar plots are shown in Figure 5-10 and Figure 5-11 for the bottom reservoir. The extent of the cooling at the horizon of the bottom reservoir is larger in the PERM0 and PERM3 models compared to models PERM1 and PERM2. Recall that PERM0 consists of two entirely disconnected reservoirs. The other permeability models are stochastic in nature, so some permeability between the reservoirs is present. In PERM0 and PERM3, the bottom reservoir has higher permeability than the top reservoir and thus takes a larger proportion of the flow.

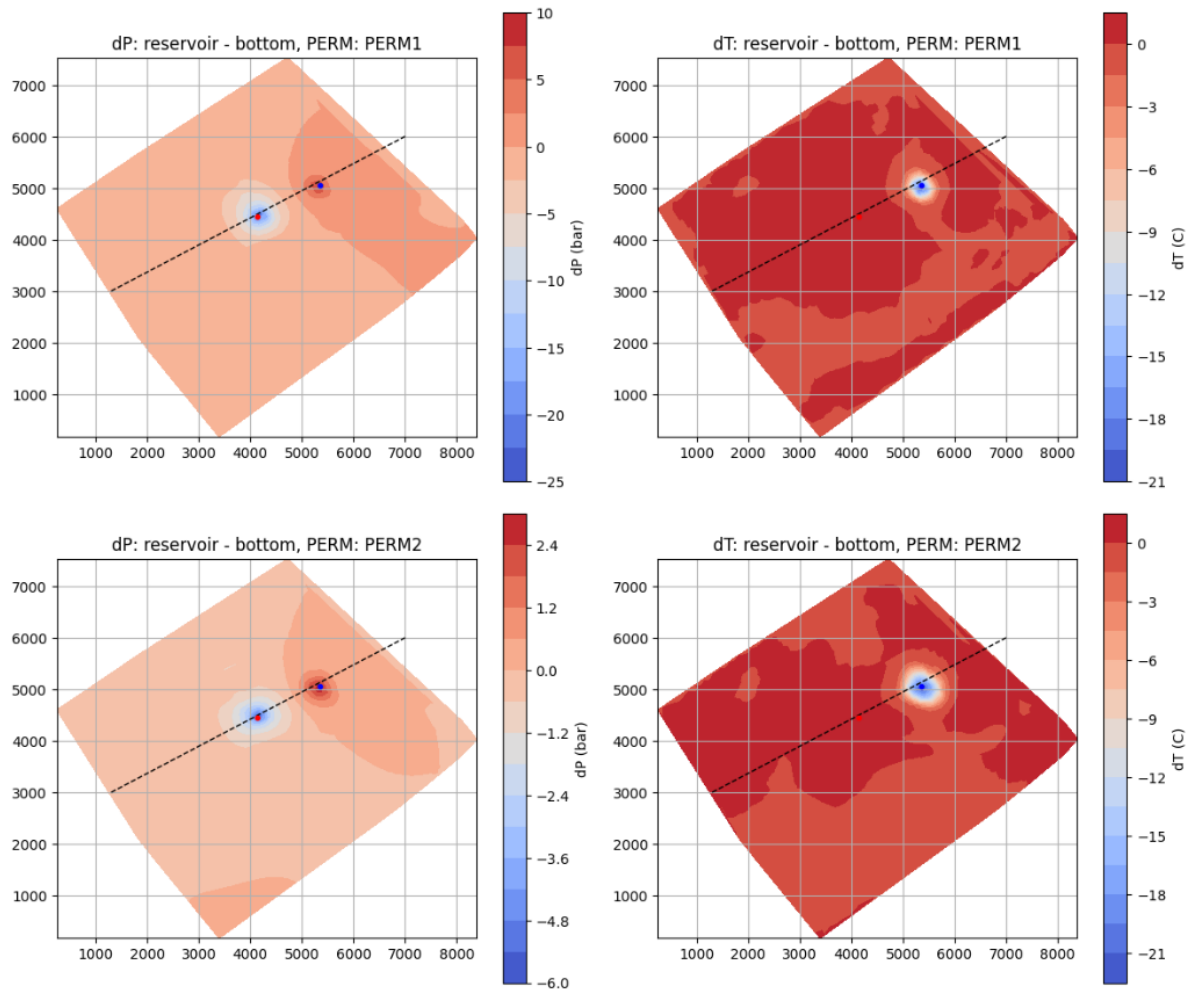


Figure 5-10: Contour plot of change in pressure (left) and change in temperature (right) for the bottom reservoir in the average permeability PERM1 (top) and high permeability PERM2 (bottom) scenarios of the specific case model after 30 years. Location of injection well in reservoir (blue) and production well (red).

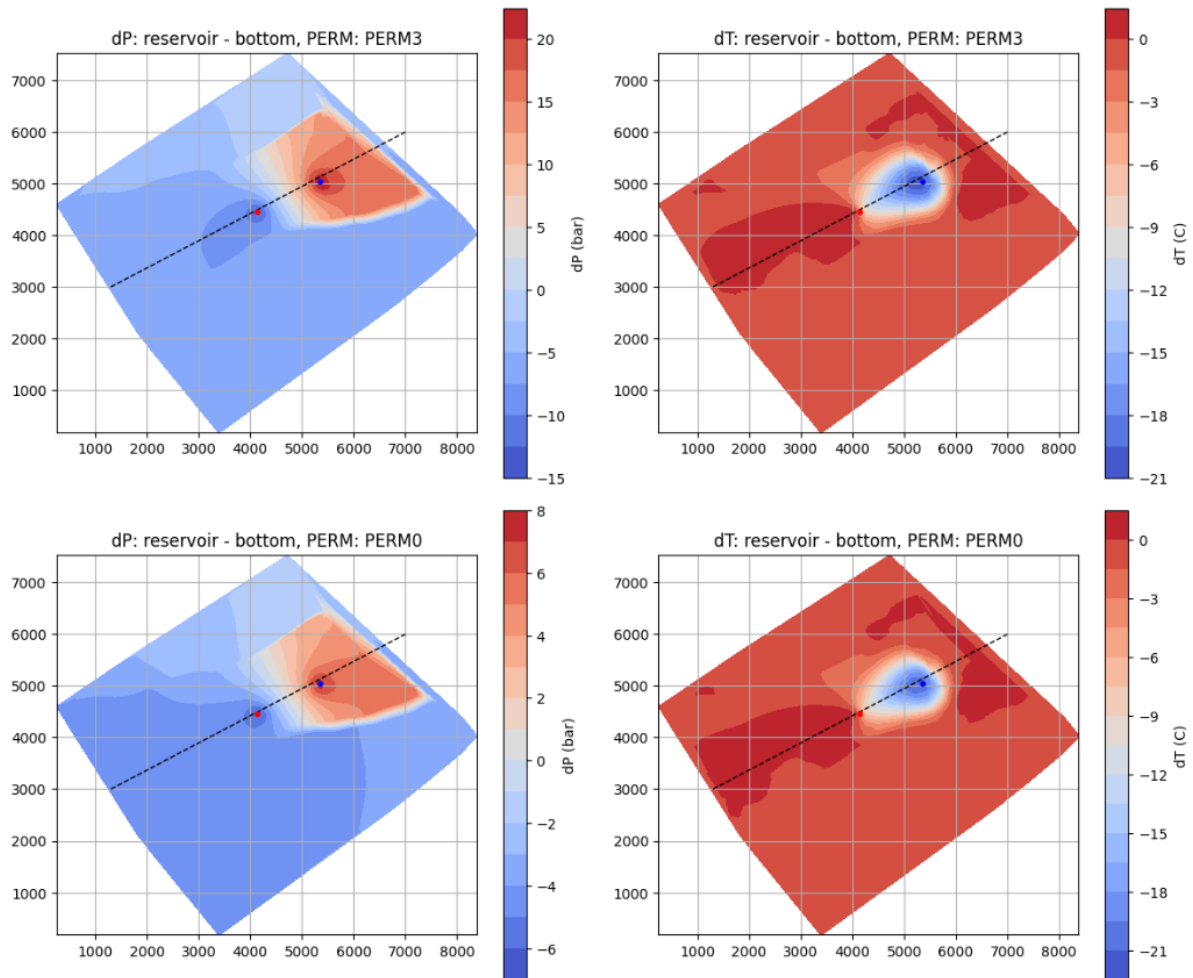


Figure 5-11: Contour plot of change in pressure (left) and change in temperature (right) for the bottom reservoir in the low permeability case PERM3 (top) and PERM0 (bottom) of the specific case model after 30 years. Location of injection well in reservoir (blue) and production well (red).

Figure 5-12 and Figure 5-13 show the pressure and temperature changes in the reservoir as a result of geothermal production (and injection), for each reservoir in the specific case scenarios. Near the production well, the average permeability case (PERM1) has a large area of reduced permeability near the base of the top reservoir that results in higher required production dP magnitudes. In the temperature plots, the connectivity of the bottom reservoir becomes apparent by the injection well, where the scenarios with less vertical permeability connections show more cooling in the direction of the production well. In PERM1 and PERM2, the cold front extends approximately 500 m from the injection well, while in PERM0 and PERM3, it extends further (>1 km). This happens due to the disconnected permeability of PERM0 and PERM3 ensuring that a greater percentage of the injection is continued to be directed toward the bottom reservoir.

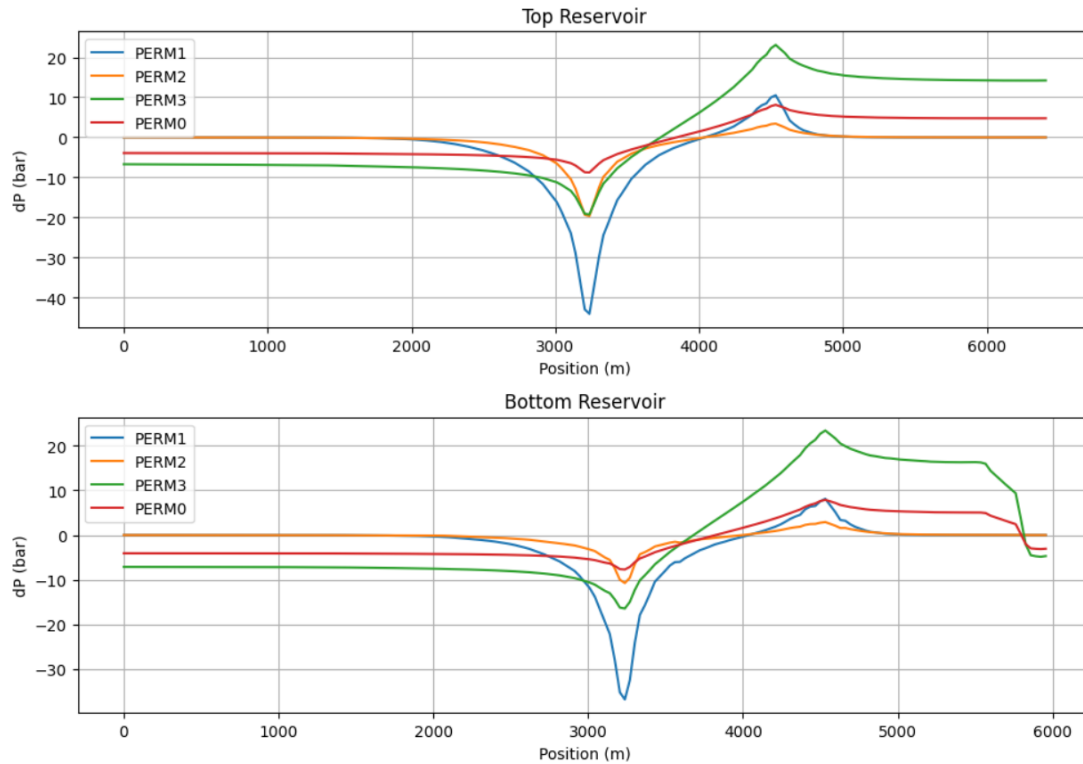


Figure 5-12: Change in pressure along dashed line for specific case scenarios after 30 years for top reservoir (top) and bottom reservoir (bottom).

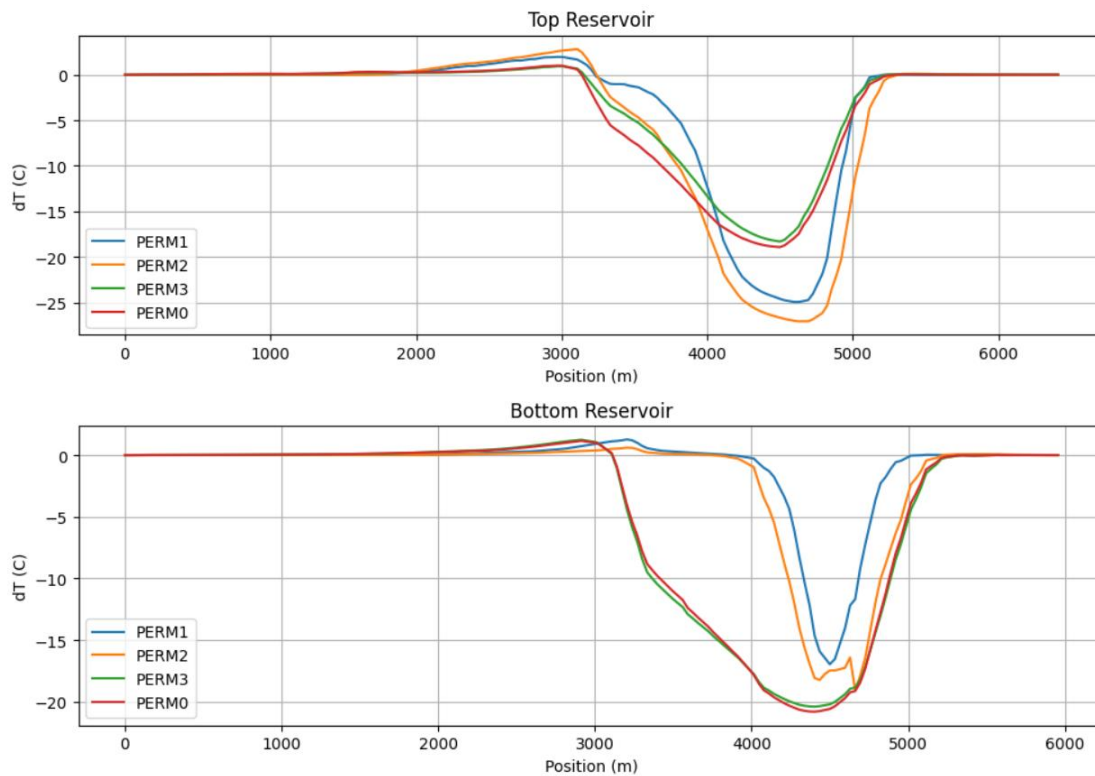


Figure 5-13: Change in temperature along dashed line for specific case scenarios after 30 years for top reservoir (top) and bottom reservoir (bottom).

The predicted downhole pressure evolution over 30 years of operations for each well is shown in Figure 5-14, for all four specific case scenarios. The figure highlights the fact that the lower permeability stochastic models are perhaps underestimating both permeability and connectivity as the dP values over ~65 bar (downhole pressure in the injection well in the range of 220 to 240 bar) would likely approach or exceed maximum permitted injection pressure values (as plotted in Figure 4-8). These models would therefore likely present situations that are not allowed. An important conclusion of these plots is the value that good pressure transient data can provide when history matching for well performance. That is, that the permeability/flow regime controls the well pressure response due to injection/production. Understanding the permeability magnitudes and flow type (fracture, radial, etc.) are very important aspects to history matching and accurately predicting the pressure drawdown in a well in operation. The best way to draw conclusions and provide a solid basis for history matching is good pressure transient data. Combining those data with downhole spinner/flow measurements can help to quantify the permeability contributions of each reservoir that a well intersects.

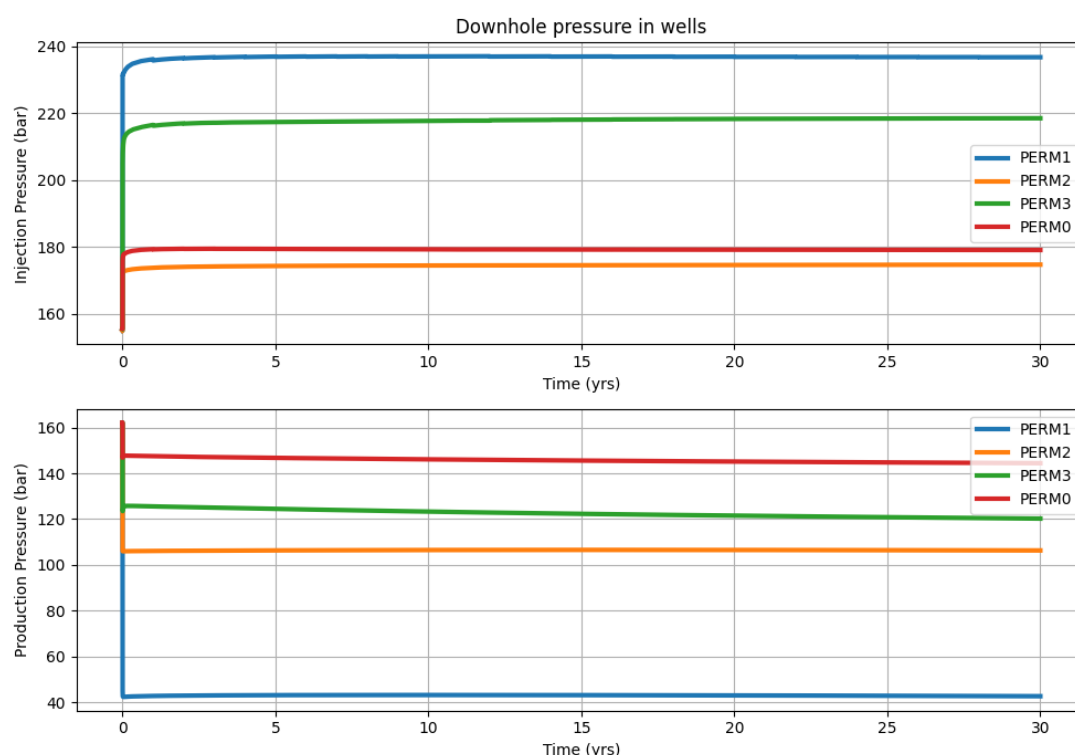


Figure 5-14: Downhole pressure for the injection well (top) and production well (bottom) for the specific case scenarios tested.

The flow balance results for reservoir mass flow and total mass flow rates are shown in Figure 5-15. The stochastic nature of the models makes comparison more difficult. The high permeability case (PERM2) has relatively lower permeability in the reservoir where it is intersected by the production well (bottom reservoir), which is reflected by near zero production from that reservoir. However, the general reservoir permeability and connectivity of the PERM2 model are not that severe, as indicated by the overall lower dP values. So, even though the flow into the bottom reservoir is lower, the fluid does eventually find its way to the bottom reservoir. The high and average permeability cases (PERM2 and PERM1) never reach a reservoir 'equilibrium' where the amount of fluid produced and injected in each reservoir is the same. This is likely due to relatively good connectivity between the reservoirs. The flow to each reservoir is directly determined by the near well (reservoir block) permeability and the

pressure is able to balance further out in the reservoir. The more discontinuous models with less connection between the two reservoirs (the PERM0 case and the low permeability scenario PERM3) show the flow imbalance more similar to the previously tested generic reservoir models in Section 3.4 and Chapter 4 where the flows initially are imbalanced but reach equilibrium after some time.

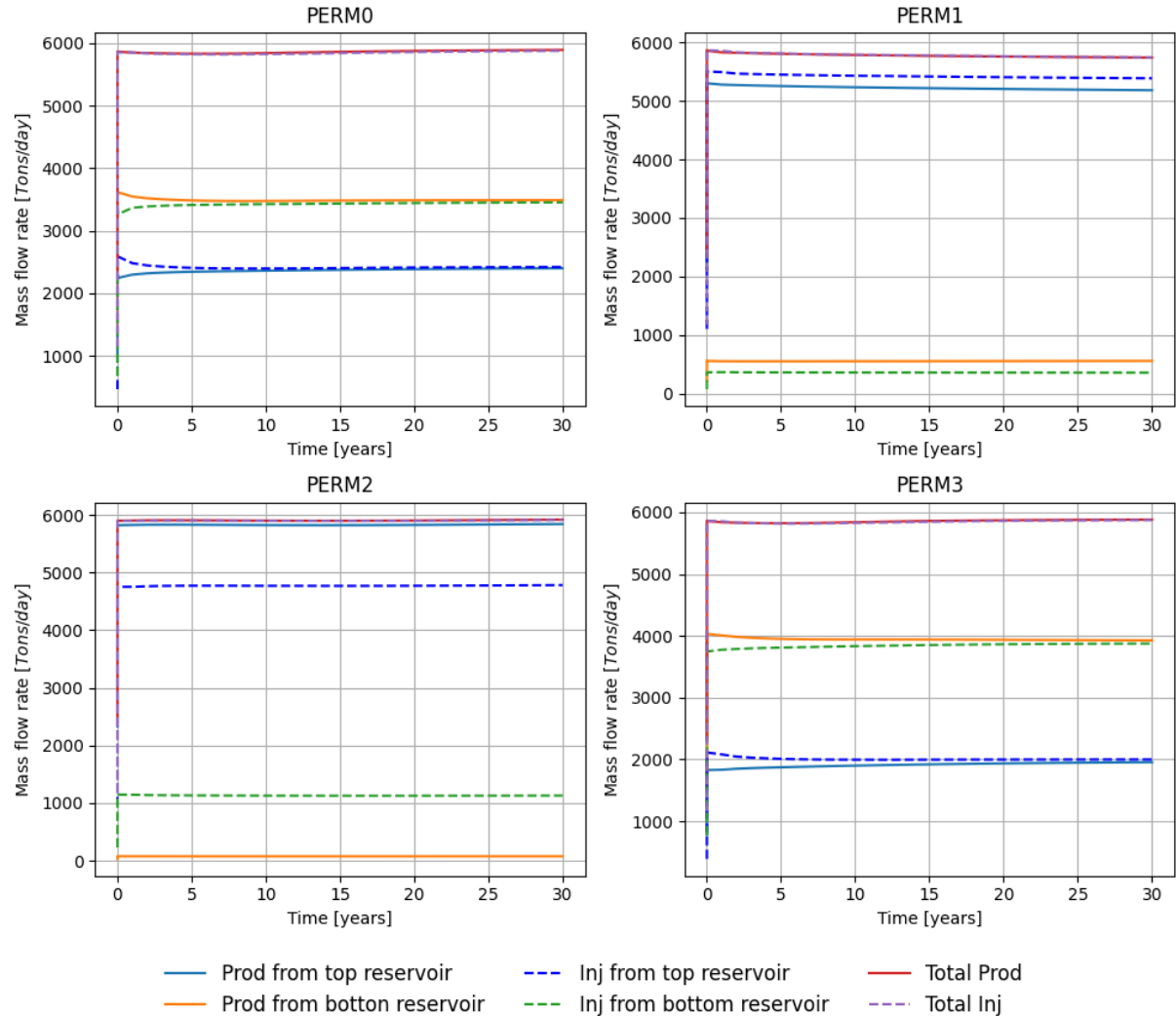


Figure 5-15: Injection and production mass flow rate per reservoir and combined (total) for the four specific case scenarios.

5.7 Model validation

As mentioned above, the amount of data available on the specific case model site freely available online is limited. Flow rate data is available as monthly cumulative volume data (m^3), but no well pressure history is available so it is impossible to calibrate the permeability models. As mentioned in relation to Figure 5-14, the lower permeability models (PERM1 and PERM3) have predicted well pressure changes that are likely a higher magnitude than the actual wells in production.

An alternative to a comparison based on pressure values is a comparison between simulated and measured subsidence values. It is difficult to calibrate the numerical model based on

subsidence values as the number of free parameters is larger (solid and flow properties are free parameters) compared to the number required for well pressure calibration. However, it can be used as a “sanity check” for the parameter space. From www.nlog.nl (dashboard bodembewegingsmetingen), the surface elevation of two points in the vicinity of the doublet has been tracked yearly since 2010 with online data running until 2021. The geothermal project began operation in 2018 (as shown in Figure 5-7). This provides 3 years of subsidence data for benchmarking. Simulated subsidence values have been calculated according to the methodology presented in Section 6.4 of this report. The subsidence data (measurements) could also include interference with other projects that is not accounted for in the numerical model. The benchmark data points have been in subsidence since 2014, so interference likely does play an additional role.

Figure 5-16 displays the predicted subsidence values from the specific case scenario models compared to the two datapoints since 2018 – subsidence before 2018 is ignored in this analysis as that was prior to the project. The relative displacement data from the two benchmark points are within 1 mm of each other for all times, so they plot nearly on top of each other in the figure. Since the duration is not very long, it is difficult to discern which model may best represent the subsidence. Further, all the subsidence calculations are made with the same solid material parameters (Young’s modulus and Poisson’s ratio), so the effects of changes in those parameters are not accounted for. However, the order of magnitude (~mm) of the subsidence is being captured in PERM0, PERM1, and PERM2. The lower permeability model (PERM3) shows deviations from the apparent trend already, so the conclusion is that the pressure changes in that model are likely too severe. This was the same conclusion reached in the well dP analysis presented in Figure 5-14.

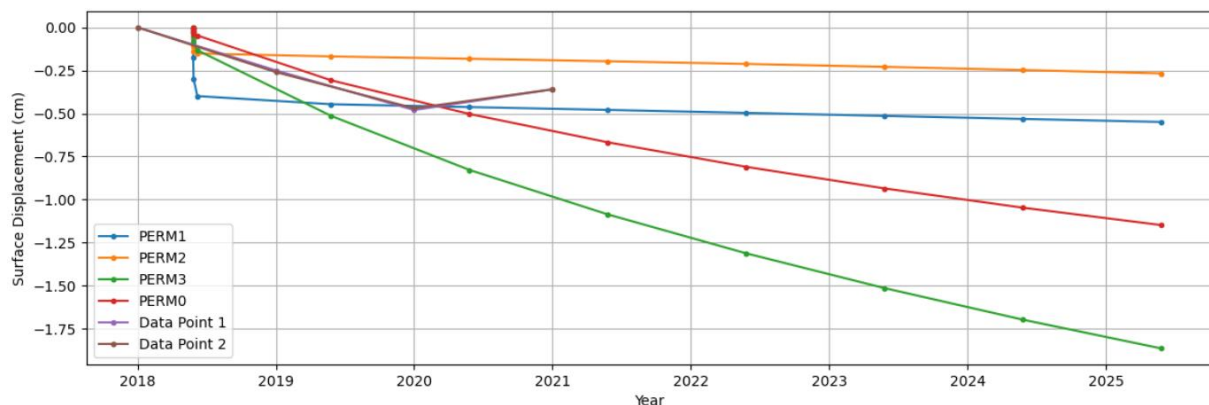


Figure 5-16: Maximum ground subsidence predicted by the different specific case scenarios compared to the two closest benchmark datapoints from www.nlog.nl (dashboard bodembewegingsmetingen). Note that the data for the benchmark points plot nearly on top of each other and do not cover the entire period until 2025.

5.8 Specific case model conclusions

The main objective of the specific case models was to determine, with realistic inputs, under which conditions commingled production effects may increase the likelihood of the undesirable outcomes of induced seismicity or subsidence. The PERM0 case showed similar results to the idealized Base Case model in terms of flow imbalance. The main learning from the specific case model is that realistic permeability distributions can serve to form a connection between two reservoirs. If that connection is strong enough, the two reservoirs essentially behave as one reservoir (as seen in PERM1 and PERM2).

The main findings of the specific case simulations can be summarized:

- The effect of nearby faults can be seen in both pressure and temperature response in reservoirs. The faults can act as barriers or conduits, depending on the permeability assumptions/characteristics. Faults acting as barriers decrease communication between reservoir compartments, leading to flow imbalance and greater over/underpressurization. The opposite is true for faults acting as conduits.
- If the reservoirs are connected hydraulically, flow to each one is determined by local permeability values (near the well) and flows (injection and production flows) for specific reservoirs may not equilibrate in time as the reservoir 'layers' behave as a single reservoir through pressure connection.
- Disconnected reservoirs (with hydraulic barriers between) show initial imbalance in flows that tends to equilibrate in time, but can show larger pressure differences in disconnected reservoirs.
- Larger magnitude of pressure changes in disconnected reservoirs can reach further away from wells.
- The comparison of simulated or calculated subsidence values with monitoring data indicates that results are of the same order of magnitude as actual measurements. However, the short time interval does not allow to distinguish between some of the permeability models.

6 ASSESSMENT OF THE POSSIBLE EFFECTS OF UNBALANCED FLUID CIRCULATION

6.1 Introduction

This chapter presents the analysis of the possible effects of unbalanced fluid circulation triggered by commingled production from two geothermal reservoirs. This is done based on the results obtained in Chapter 4 in terms of pressure, temperature, and fluid rate distribution between the reservoirs.

The chapter begins with an introduction and definition of the operational window. This part includes a presentation of the main events that increase the likelihood of geohazards while staying within the effective operational window and forms the basis for defining which hazards will be assessed (that assessment will include scenarios operating within as well as outside the effective operational window). It will also describe why certain hazards are not addressed in this study.

After presenting the relevant hazards, the chapter continues with the assessment of the impact of unbalanced fluid circulation on these events. Section 6.3 will focus on the likelihood of fault reactivation. The impact on subsidence and/or uplift is presented in Section 6.4. The impact on operations, including well integrity and well productivity or injectivity, is discussed in Section 6.5.

The chapter concludes with looking back at the operational window, summarizing the assessments made. This section qualifies the definition of both the lower and upper operational limit, and how these could be controlled.

6.2 Definition of the operational window

6.2.1 Operational limits and effective operational limits

The operational window represents the range of pressure, temperature, and flow conditions of a geothermal system that is generally considered to be safe to operate within. In general, changes in flow rate and temperature in geothermal systems, including commingled systems, ultimately induce changes in pressure. As a result, reservoir pressure during operations can generally be considered the primary parameter that defines the operational window, while flow rate, temperature, and injection pressure are the key factors that drive these pressure changes. In practice, this means that pressure serves as the main constraint for the operating window, with other operational variables acting as the controlling elements that influence it.

Figure 6-1 illustrates the operational window for a simple commingled geothermal system. The initial reservoir is assumed to be at hydrostatic pressure (dashed line), while the *upper* and *lower* operational limits define the range of reservoir pressure that is generally considered to be safe. These limits represent the threshold that once crossed leads to operating in an *underpressure* or *overpressure* regime, respectively. Operating in the underpressure regime could increase the likelihood of reservoir depletion and ultimately subsidence and/or fault reactivation, while operating in the overpressure regime could increase the likelihood of fault reactivation and/or seal integrity breach. Therefore, operating within this window reduces the likelihood of triggering unwanted geomechanical responses.

In practice, the actual operating window of a geothermal system is highly location (and system) specific, as it depends on the local subsurface conditions and system configuration. For example, when the reservoirs are discontinuous or have low permeability, the upper operational limit might tighten relative to the Base Case, while if the reservoir is highly permeable the upper operational limit will widen (Figure 6-2). As especially the *in situ* subsurface parameters are difficult to characterize accurately, defining the exact location-specific operational window is extremely challenging.

Therefore, in reality, the *upper operational limit* is effectively constrained by the maximum injection pressure that is defined in the geothermal permit (e.g., based on the maximum pressure gradient of 0.135 bar/m following from the (now disused) protocol for the calculation of injection pressures by SSM (2020), or on the results a location-specific *Tensile failure Assessment of Seal* (TAS) modelling exercise). Similarly, the *lower operational limit* defines the threshold below which further pressure depletion may cause the reservoir to underperform (i.e., requiring higher drawdowns to sustain production) and may increase the likelihood of triggering geomechanical hazards, in practice, the *lower operational limit* is effectively largely controlled by the maximum drawdown of the ESP. Here, the maximum drawdown of the ESP in geothermal systems is typically significantly lower than the reservoir depletion levels (e.g., in gas reservoirs) that could move into a potentially unsafe underpressure regime: 10s of bars versus >150 bar (Xin, et al. 2025). Therefore, in practice, common geothermal systems that target matrix-permeable sandstone reservoir in the Netherlands typically operate within the *effective operational window*, which is constrained by the maximum permitted injection pressure and the maximum drawdown of the ESP for the upper and lower operational limit, respectively.

6.2.2 Potential events occurring within or outside the effective operational window

The occurrence of potential events increasing the likelihood of geohazards near the well is determined by the conditions in the near-wellbore region. In turn, these conditions are strongly governed by the effective operational window. Hence, operating within the effective operational window limits the occurrence of these events and prevents these geohazards from happening. This is for example the case for seal integrity breach or thermal fracturing. As seal integrity breach as a result of unbalanced flow is strongly constrained by the maximum injection pressure in the permit (i.e., the effective upper operational limit), it is unlikely to occur within the effective operational window and is therefore not further assessed in this study. Similarly, unbalanced flow in a commingled production system does not increase the likelihood of geohazards to occur due to thermal fracturing in the near-wellbore, which is also constrained by the effective operational limits (defined in the permit). Therefore, this phenomenon is not further assessed in this study.

However, even when operating within the *effective operational window*, there are events that could occur due to unbalanced flow in commingled geothermal systems that could increase the likelihood of triggering geohazards further from the well: (i) *faster-than-expected cold front propagation*, or (ii) *accelerated reservoir depletion* in one of the reservoirs. For the former, it is relative to the assumed propagation in the permit application that was modelled to determine the geothermal area of influence (*boundary of the cold front after 30 years*) and associated Seismic Hazard and Risk Assessment and can occur when the injection volume in to one of the reservoirs is significantly higher as a result of unbalanced flow. The latter can occur when pressure decline progresses unevenly within the reservoirs due to unbalanced flow.

In actual, permitted commingled geothermal systems that target matrix-permeable sandstones in the Netherlands that operate within the effective operational window, *faster-than-expected*

cold front propagation or *accelerated reservoir depletion* in one of the reservoirs could increase the likelihood to *fault reactivation* or *subsidence*, respectively. The likelihood of these hazards to occur as a result of unbalanced flow while operating within the effective operating window, as well as the theoretical scenarios that operate outside of the effective operational window are assessed in Sections 6.3 and 6.4. The impact of unbalanced flow on operations (well integrity and productivity/injectivity) while operating within the effective operational window is assessed separately in Section 6.5.

Base Case

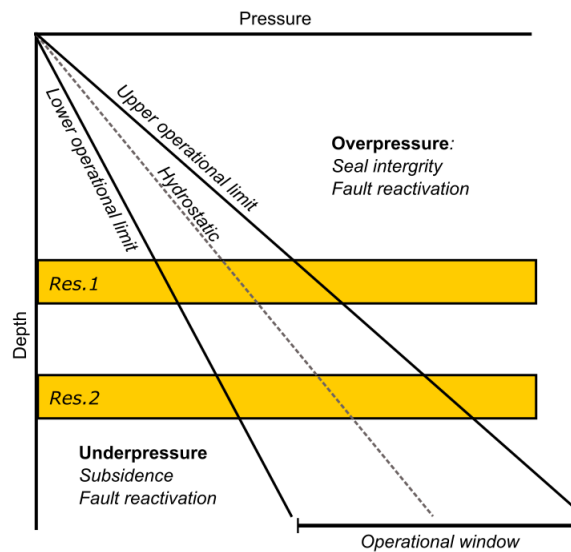


Figure 6-1: Illustration of operational window for the Base Case scenario.

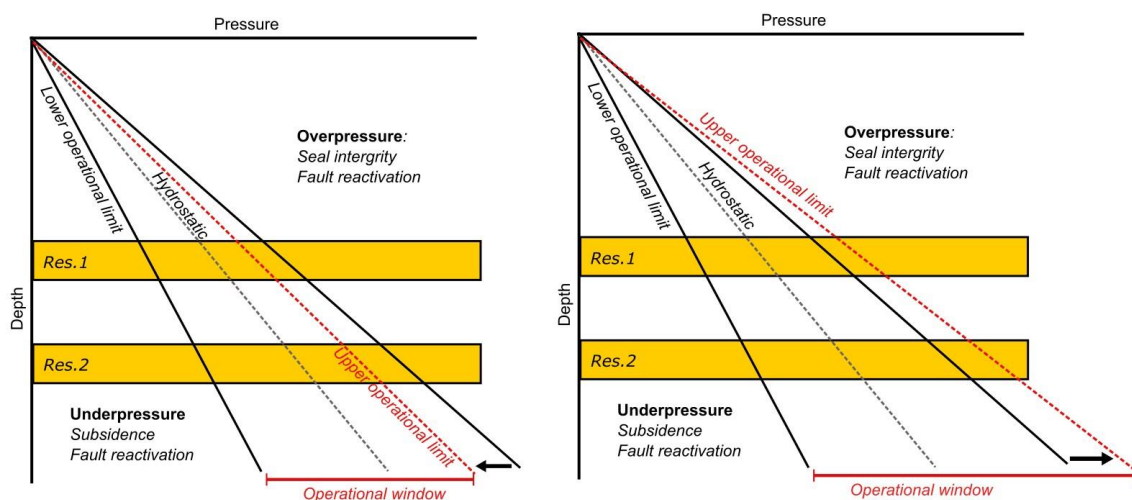


Figure 6-2: Illustration of operational window for a low (left) and a high (right) permeability scenario. The black arrows show how the upper operational limit boundary moves compared to the Base Case.

6.3 Assessment of the impact of unbalanced flow on fault reactivation

Fault reactivation and induced seismicity can occur near production sites due to a variety of mechanisms. Injection-related over pressurization and thermal cooling can affect the stress state near the reservoir and have the potential to lead to induced seismicity in geothermal projects. This sub-task seeks to establish the limits of the operational window that can result in induced shear failure and possible nearby fault reactivation. Ultimately, the in situ stress state and rock properties interact with production-related stress changes to potentially induce shear failure.

Two different approaches follow to assess the impact on fault reactivation. First, the analysis using an analytical solution approach for uniaxial reservoir deformation and Mohr-Coulomb stress failure (Fjaer et al., 2008; Grande et al., 2024) to determine if direct pore pressure or thermal stresses induce a level of stress change that may result in fault reactivation. The evaluation includes the analysis of stress changes on hypothetical fault planes at various positions away from the wells. The procedure and results for this approach are presented in Section 6.3.1.

A second approach involves a thermo-hydro-mechanical reservoir simulation using the open-source simulator DARTS in a semi-analytical nucleus of strain approach. The approach allows for an inclusion of elastic stress transfer through Poisson effects and poro/thermo-elasticity to go beyond the direct effects of the first analysis. Similarly to the previous analysis, the approach is used to determine if shear fault reactivation may be possible. This approach is applied to the Base Case and to the case with a laterally discontinuous bottom reservoir where this reservoir is absent in the production well (Bot Pro).

6.3.1 Analytical approach

6.3.1.1 Analysis procedure

This assessment investigates the likelihood of fault reactivation caused by pressure and temperature changes resulting from commingled production. A change in Cauchy stress for changes in strain, temperature, and pressure is given by the thermo-poroelastic formulation of Hooke's law (equation 26):

$$\Delta\sigma_{ij} = C_{ijkl}(\Delta\varepsilon_{kl} - \Delta\varepsilon_{kl}^T) - \beta\delta_{ij}\Delta P \quad (26)$$

Where σ_{ij} is the Cauchy stress tensor, ε is the strain tensor, C_{ijkl} is the 4th order elasticity tensor (function of elastic parameters), β is Biot's coefficient, δ_{ij} is the identity tensor, and P pore fluid pressure. The subscript T is used to indicate thermal strain which is given by equation 27:

$$\Delta\varepsilon_{ij}^T = \alpha\delta_{ij}\Delta T \quad (27)$$

Where α is the linear coefficient of thermal expansion and ΔT represents an incremental change in temperature. For a linear elastic material, the fourth-order elasticity tensor is a function of elastic constants. It is perhaps most convenient to only consider the volumetric terms of the stress-strain relationship (equation 28):

$$\sigma_{11} = \tilde{E}(1 - \nu)\varepsilon_{11} + \tilde{E}\nu\varepsilon_{22} + \tilde{E}\nu\varepsilon_{33} \quad (28)$$

Where:

$$\tilde{E} = \frac{E}{(1 + \nu)(1 - 2\nu)} \quad (29)$$

Where E is Young's modulus and ν is Poisson's ratio. For subsurface boundary conditions, the vertical component of the Cauchy stress tensor is assumed to be unchanged as the weight of the rock overburden does not change and far-field lateral displacements are assumed zero. The change in the stress of the two horizontal components follows equation 30 (Fjaer et al., 2008):

$$\Delta\sigma_x = \Delta\sigma_y = \frac{\alpha E \Delta T}{(1 - \nu)} \quad (30)$$

Thermo-poroelastic stress analysis was applied in the principal stress space of the subsurface, which is shown to be generally normal-faulting (van Wees et al., 2014). The vertical stress component is the maximum principal stress and assumed to be lithostatic. The average gradient used was ~230 bar/km (~23 MPa/km, 2300 kg/m³ rock density). The ratio between the vertical and minimum horizontal stress $k = \sigma_v / \sigma_h$ is reported to be between 0.38 and 0.48 in the area around the Western Netherlands Basin (van Wees et al., 2014). A value of 0.38 σ_v is taken here, which is the more extreme case for shear failure. The maximum horizontal principal stress is often more difficult to quantify but lies somewhere between the extremes of σ_v and σ_h . We use a ratio of 0.8 σ_v . The Mohr-Coulomb failure criterion was used to evaluate the possibility of shear fault reactivation. Shear failure is assumed when the predicted shear stress for a given normal stress falls above the failure line (equation 31):

$$\tau \geq \tau_f = \mu * \sigma_n + C \quad (31)$$

We used a cohesion (C) value of 10 bar (1 MPa, 1-3 MPa on faults reported in Buijze et al., 2017) and a slope of $\mu = 0.6$. The material parameters utilized for stress analysis are summarized in Table 6-1.

Table 6-1: Material parameters used for stress analysis.

Parameter	Units	Value	Remark
E	bar	5.00E+4	5.00E+09 Pa
ν	-	0.25	
α	1/°C	1.33E-05	
β	-	1	
μ	-	0.6	
C	bar	10	1.00E+06 Pa

We evaluate for potential fault reactivation using a semi-analytical approach for direct pore-pressure and thermal stress effects and assess for shear failure using a Mohr-Coulomb criterion. The simulations of Chapter 4 (above) were analytically evaluated for changes in the principal stresses at distances of 0, 250, 500, 750, and 1000 m away from each well and in each reservoir (Figure 6-3).

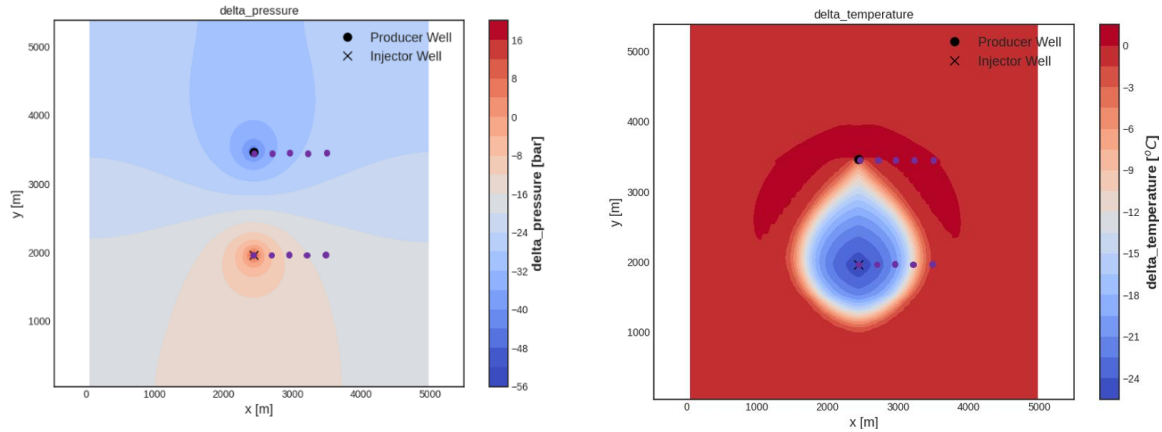


Figure 6-3: Example pressure (left) and temperature (right) change and evaluation points (purple) for the fault reactivation study at distances of 0, 250, 500, 750, 1000 m away from each well.

Pressure increases and temperature decreases result in a shift of the Mohr circle toward the origin and the failure envelope. Thermal stresses can also act to increase the overall radius of the Mohr circle since σ_V is the maximum principal stress and is assumed unchanged by thermal effects. Figure 6-4 shows an example of the shift in Mohr circle for the entire stress state at 0 m away from the injection well. Since not all fault orientations are critical, we plot all possible strike (with respect to σ_h) and dip (with respect to horizontal) combinations. The results indicate that fractures oriented roughly in the direction of σ_H with dips around 60° from horizontal are prone to shear failure. Lastly, as a means of comparing multiple simulations, we define μ_{max} to be the maximum slope of the line from the cohesion intercept of the failure envelope to the Mohr circle – typically called the mobilized friction angle. A larger value results in more critical angles of shear failure and a smaller value results in less critical angles for shear failure for a given stress state. In the example, that slope is 0.72. This parameter serves as a convenient way to compare simulations to the failure criterion or to another simulation (e.g., the Base Case simulation from Chapter 4).

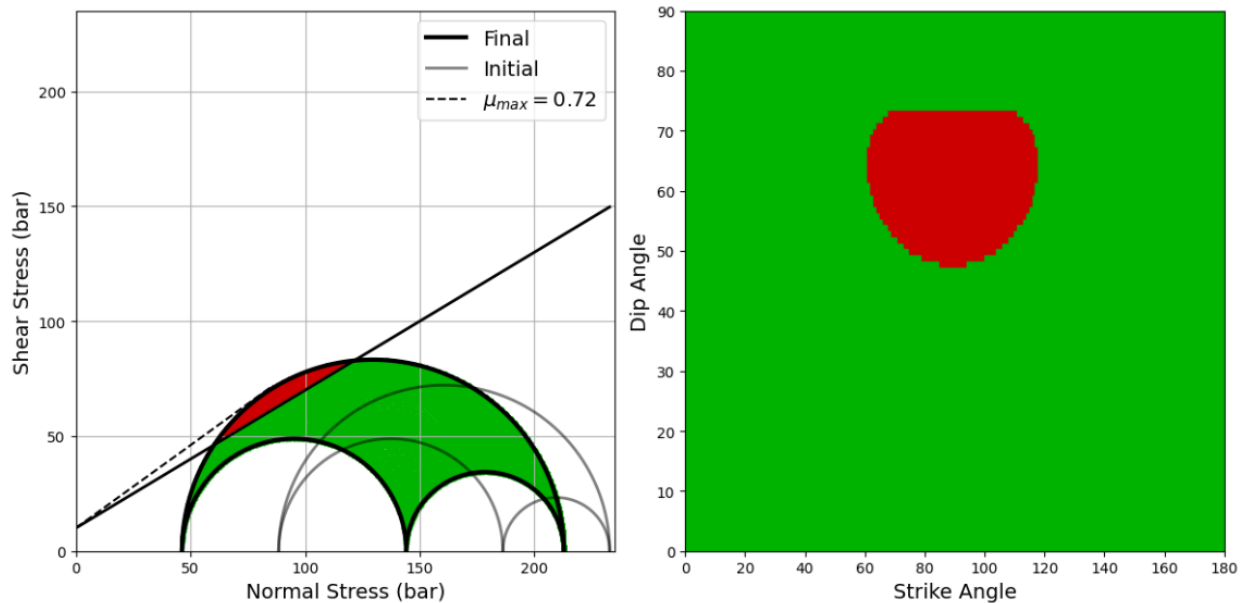


Figure 6-4: Example Mohr circle (left) for initial stress state and an example stress state with a combined 25°C temperature decrease and 20 bar pressure increase at 0 m away from the injection well of the example study. Right is an example of critical fault orientations for different strike angles (with respect to σ_h) and dips with respect to horizontal. Red coloring indicates orientations that exceed the failure criterion and green indicates orientations below the failure criterion.

The simulations of Chapter 4 were all run for 30 total years of production time. The results of this section present the results of stress analysis resulting from changes in reservoir pressure and temperature conditions at the end of the 30-year period. However, transient stress behavior was not accounted for.

6.3.1.2 Permeability variations

For reference, the pressure and temperature change profile plots for all the simulations of the permeability variation scenarios (section 4.1) are shown here in Figure 6-5 and Figure 6-6. The maximum pressure changes were around 60 bar in both reservoirs for the extreme cases where a reservoir was absent in one well. The temperature profile plots indicate the extent of cooling in the reservoirs which can affect the thermal stress development.

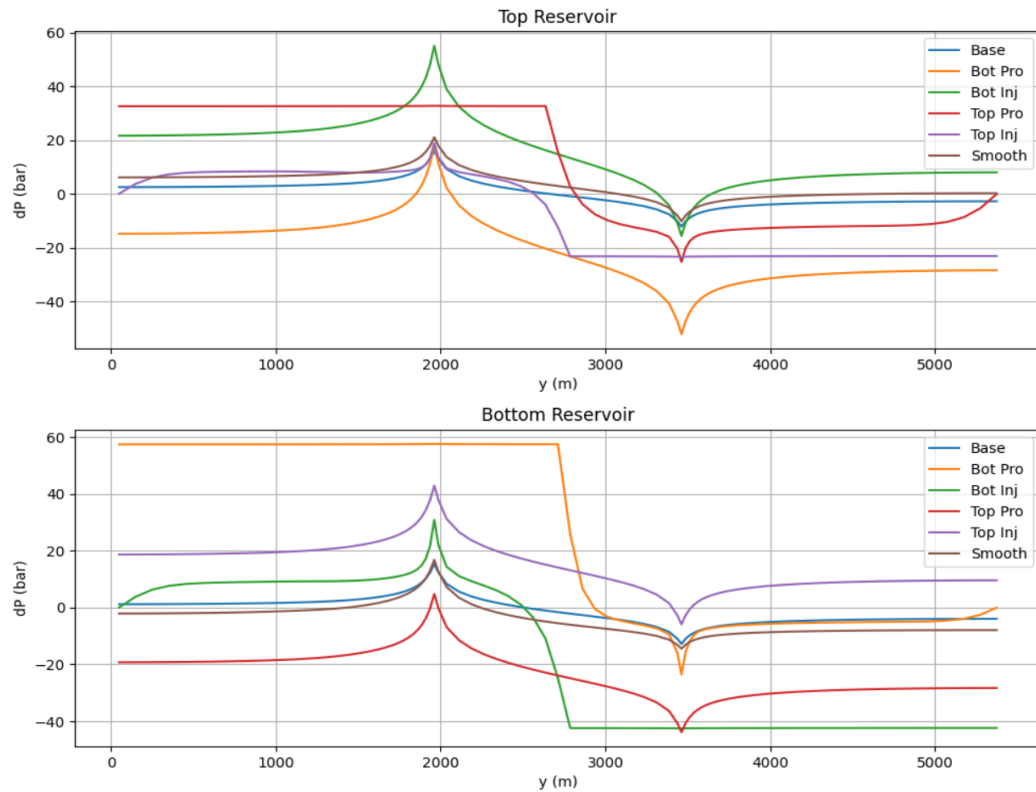


Figure 6-5: Pressure change plots for variable permeability cases tested in the top reservoir (top) and the bottom reservoir (bottom).

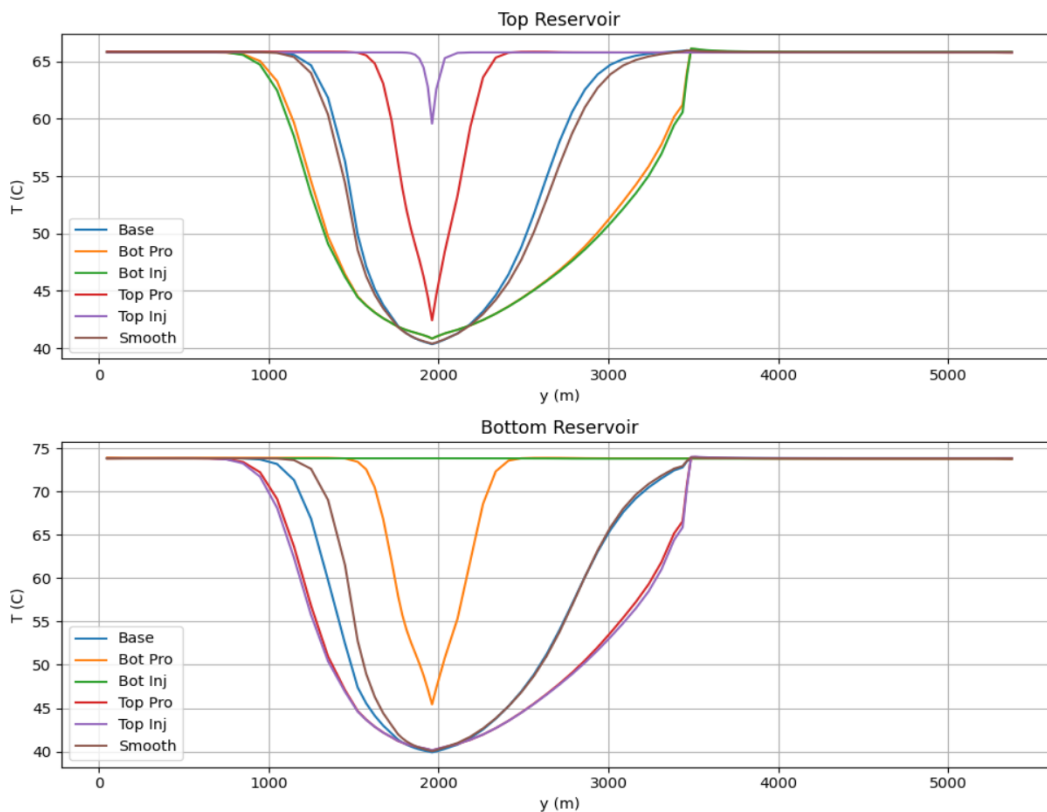


Figure 6-6: Temperature profile plots for variable permeability cases tested for the top reservoir (top) and bottom reservoir (bottom).

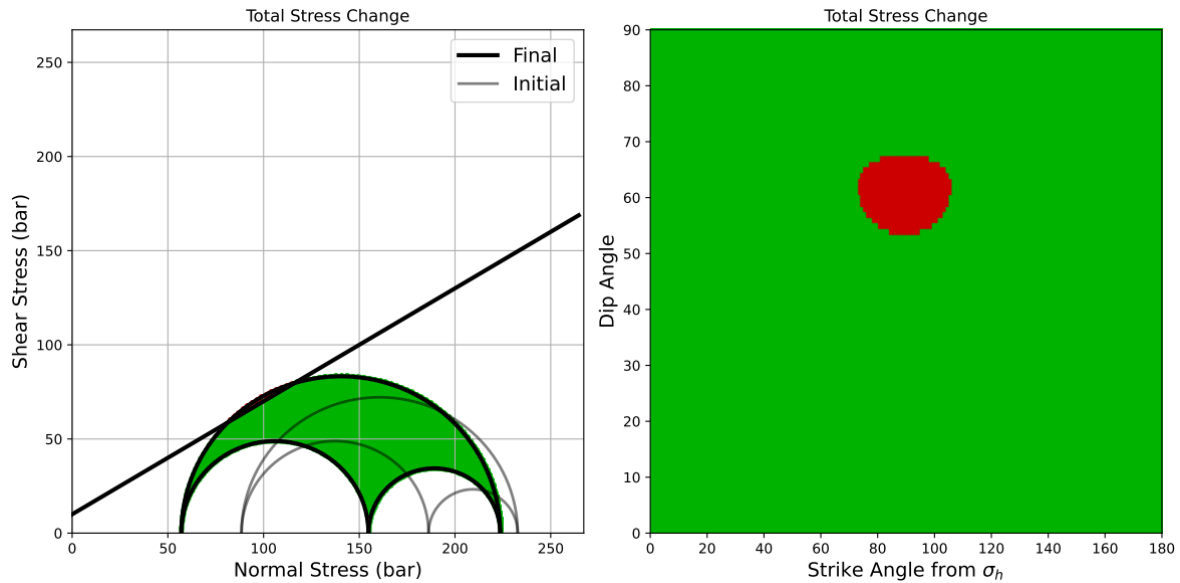


Figure 6-7: Base case stress state change (left) for both thermal and pressure-induced stress changes at 0 m from the injection well in the top reservoir and the critical fault orientations that could result in shear failure (right).

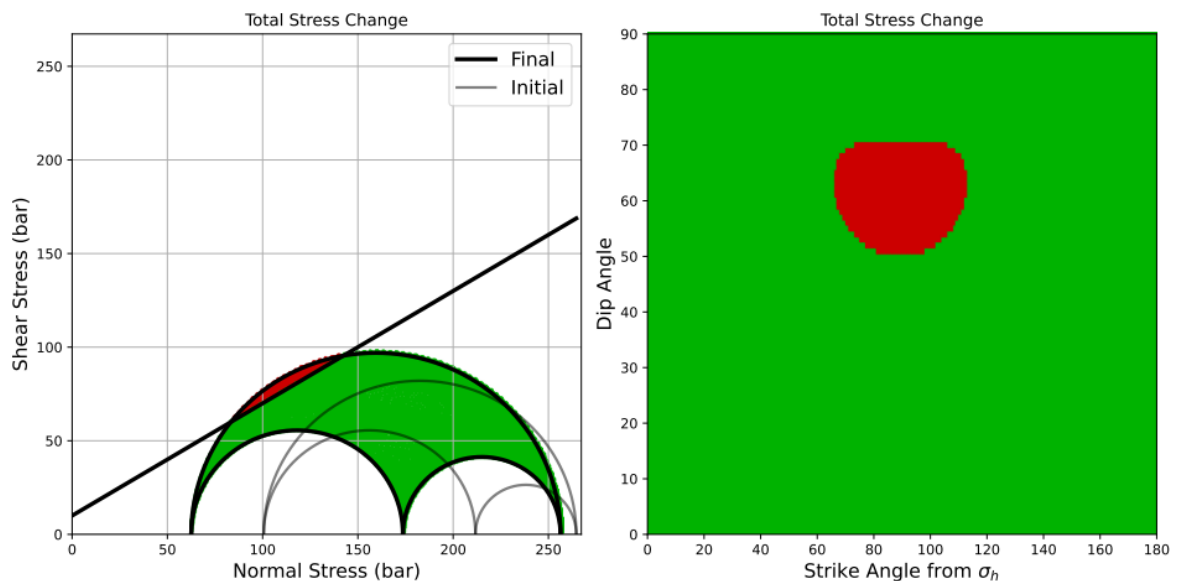


Figure 6-8: Base case stress state change (left) for both thermal and pressure-induced stress changes at 0 m from the injection well in the bottom reservoir and the critical fault orientations that could result in shear failure (right).

This section begins with an analysis of the base case model presented initially in Subsection 3.4.3, but used for comparison in all the models of Chapter 4. Figure 6-7 and Figure 6-8 show the Mohr circle plots and critical fault orientation plots at the injection well for both reservoirs. In both reservoirs, the model indicated an overpressure of about 16 bar at the injection well. The injection temperature was fixed at 40°C, so the dT was -26°C and -34°C for the top and bottom reservoirs, respectively. The direct thermal and pore pressure stresses result in the shifts seen in the Mohr circle and expected shear failure in some fault orientations.

Figure 6-9 displays the stress change related to pressure differences only (top) and thermal stress change (bottom) plots for the top reservoir. This is interesting because neither effect in isolation results in predicted shear failure for the scenario, but the combination of the two effects does.

Focusing on the bottom reservoir, in Figure 6-10, we see that the pressure change by itself is not sufficient to cause shear failure. However, the temperature change is sufficient to cause shear failure in the bottom reservoir due to the higher reservoir temperature and larger magnitude of temperature change.

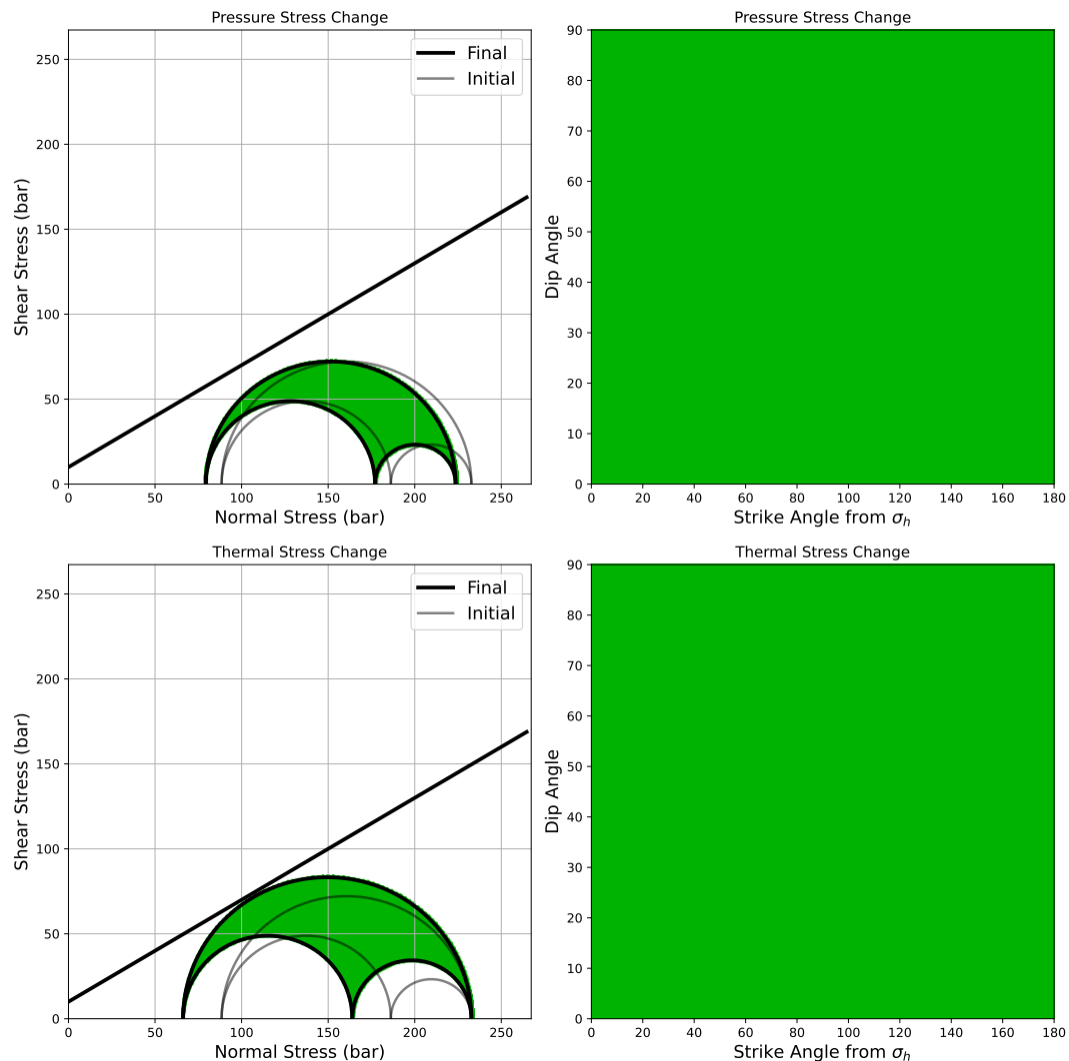


Figure 6-9: Mohr circle (left) and critical fault orientation (right) plots for the top reservoir due to only pressure changes (top) and only temperature changes (bottom) in isolation, for a point 0 m from the injection well.

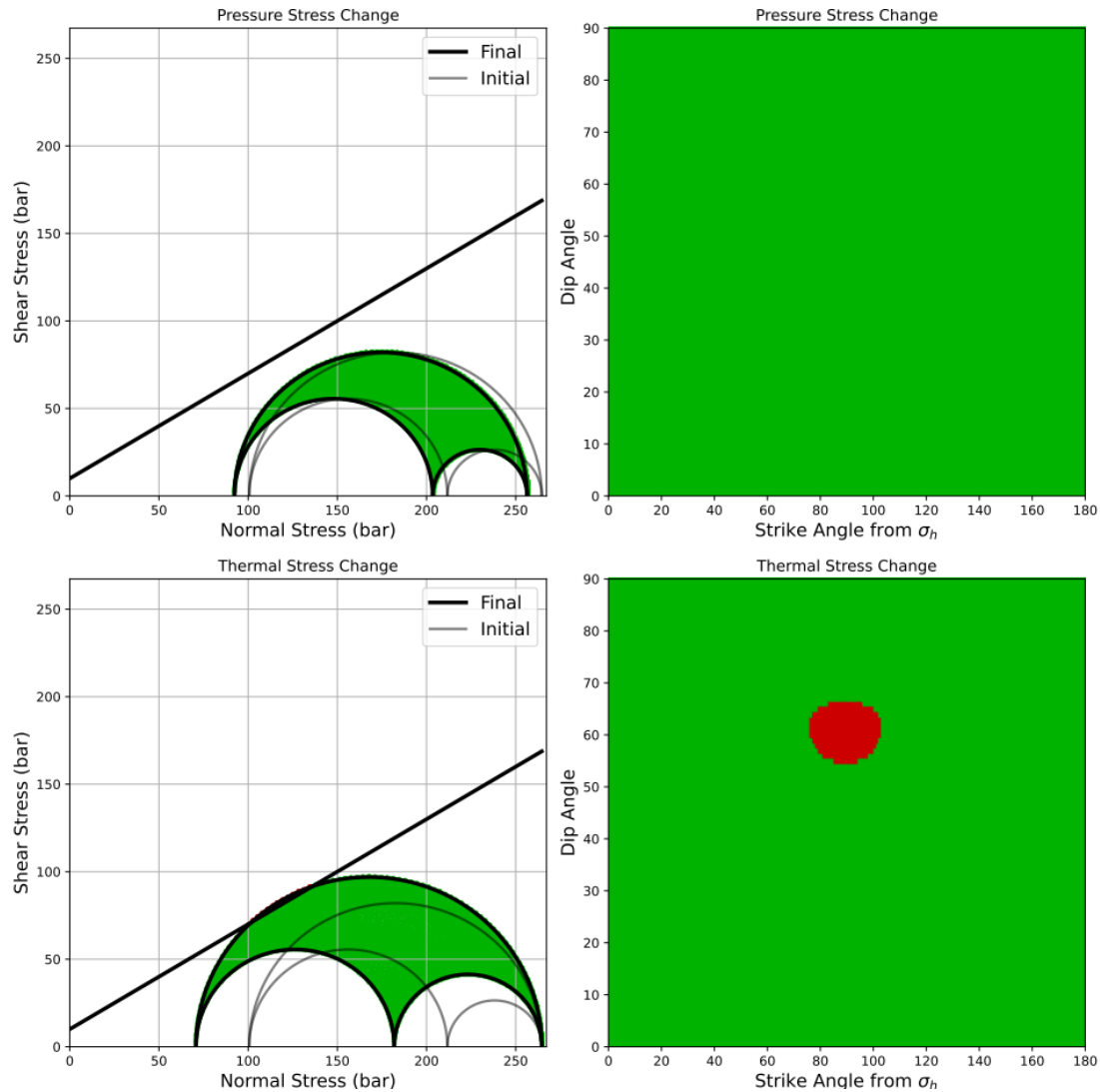


Figure 6-10: Mohr circle (left) and critical fault orientation (right) plots for the bottom reservoir due to only pressure changes (top) and only temperature changes (bottom) in isolation, for a point 0 m from the injection well.

Some shear failures were also predicted at 250 m away from the injection well in only the bottom reservoir. For distances >500 m, no additional shear failures were predicted in either reservoir.

The production well had no cooling near the well, so no thermal stress was acting to induce shear failure in those simulations. In general, the pressure is reducing around the well, though some extreme scenarios do show pressure increases in the reservoir. However, those pressure increases are small enough that no shear failure was predicted near the production well at any distance.

The results can be visualized using the value of μ_{max} versus distance from the well (defined in section 6.1.1). A summary of the evolution of μ_{max} as a function of distance away from the well for all the permeability cases of Section 4.1 is shown in Figure 6-11. The cases with the largest μ_{max} values are also the cases that showed the largest pressure change in the respective reservoirs. In the top reservoir, the scenario that had only the top reservoir in the injection well (bottom reservoir absent in injector) showed the largest pressure and stress

changes in the top reservoir. In that extreme case, shear failure could occur at distances more than 500 m away from the well. Then, for the bottom reservoir, the case where the bottom reservoir was laterally discontinuous and only present in the injection well resulted in very large pressure and stress changes across the entire bottom reservoir. In that case, the pressure increase was high enough to induce shear failure very far away from the well (>1000 m) as thermal impact did not reach so far away from the well.

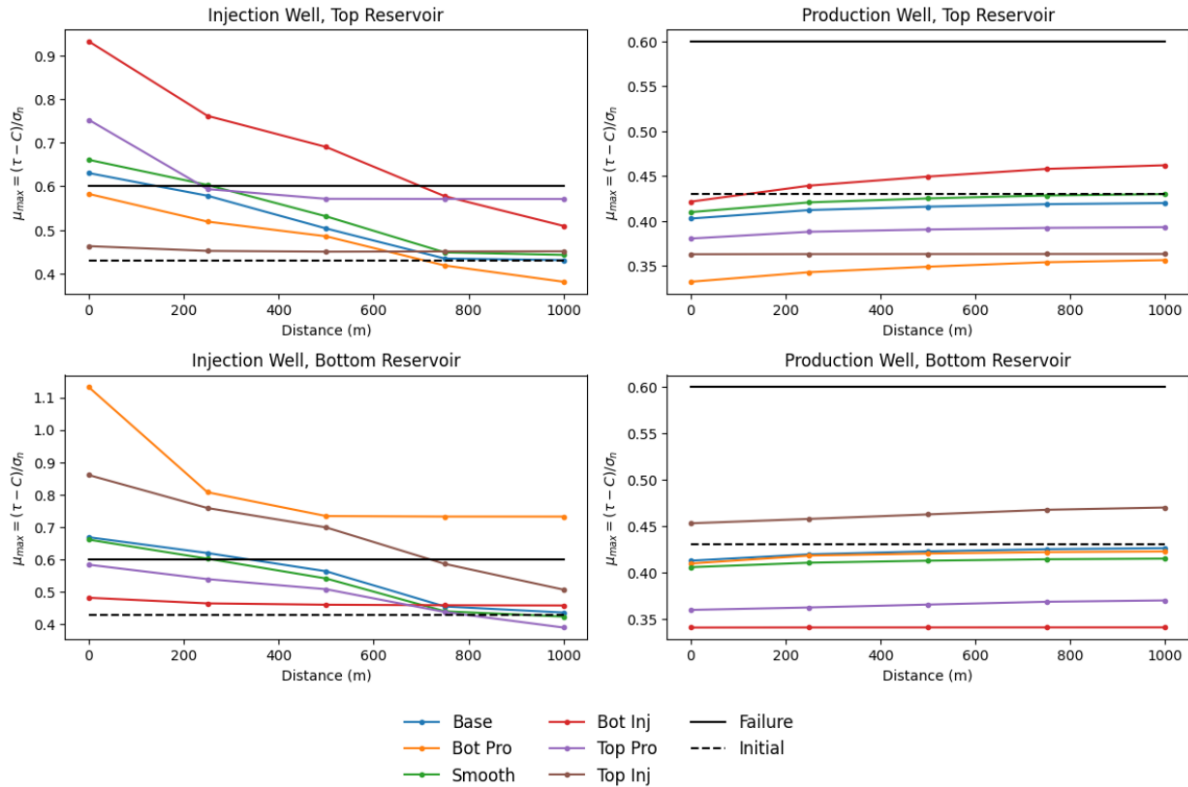


Figure 6-11: Evolution of μ_{max} as a function of distance away from the injection well (left) and production well (right) for the top reservoir (top) and bottom reservoir (bottom). The failure envelope slope ($\mu = 0.6$) is shown by a black line and the initial stress state is shown by the dashed black line in each subfigure.

Figure 6-12 shows the stress changes and critical fault orientations for the worst case (Bot Pro) scenario where the bottom reservoir is absent in the production well. The extensive pressure changes in the top reservoir can lead to shear failure very far away from the well. It is also, however, important to note that the predicted downhole pressure changes in the injection well for that scenario were greater than 80 bar in the simulation. That situation would possibly exceed permitted maximum injection pressure values. In general, injection pressure monitoring is a good check to ensure that a situation like that does not happen in practice.

6.3.1.3 Thickness variations

The pressure change profile plots for the variable reservoir thickness scenarios are repeated in Figure 6-13. The most extreme case was the discontinuous bottom reservoir case only present in the injection well (Bot Pro, from the previous section). For review, the thickness of the bottom reservoir at the production well varies in the simulations: $h_0=50$ m, $h_1=33.3$ m, $h_2=16.7$ m, and $h_3=0$ m. The case h_0 is also the base case repeated from the previous section.

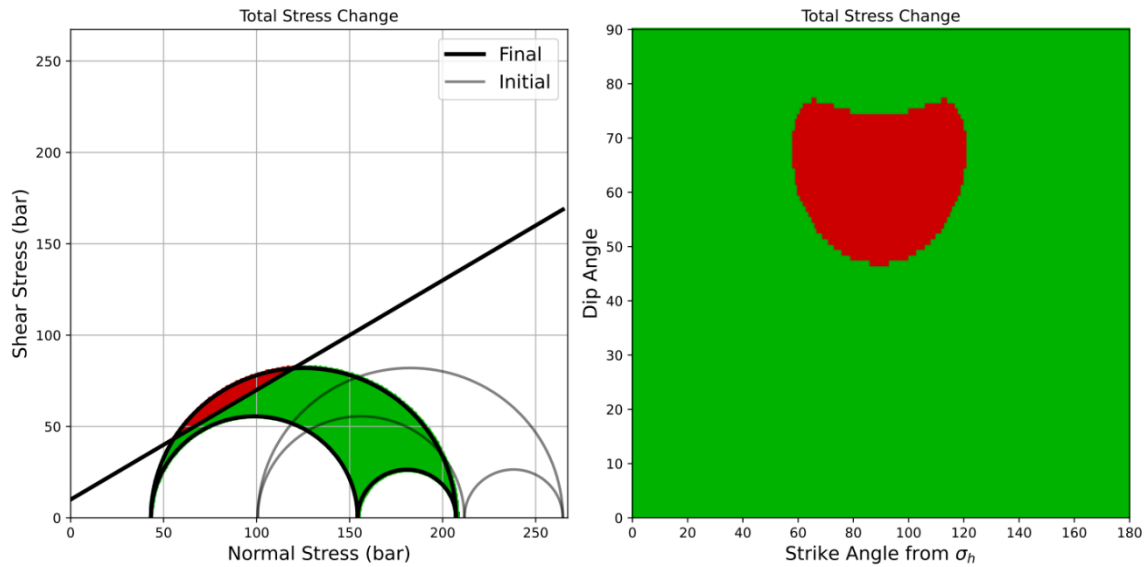


Figure 6-12: Mohr circle (left) and critical fault orientations (right) for a distance of 1000 m away from the injection well in the bottom reservoir of the discontinuous bottom reservoir production case (Bot Pro) where the reservoir was only present in the injection well.

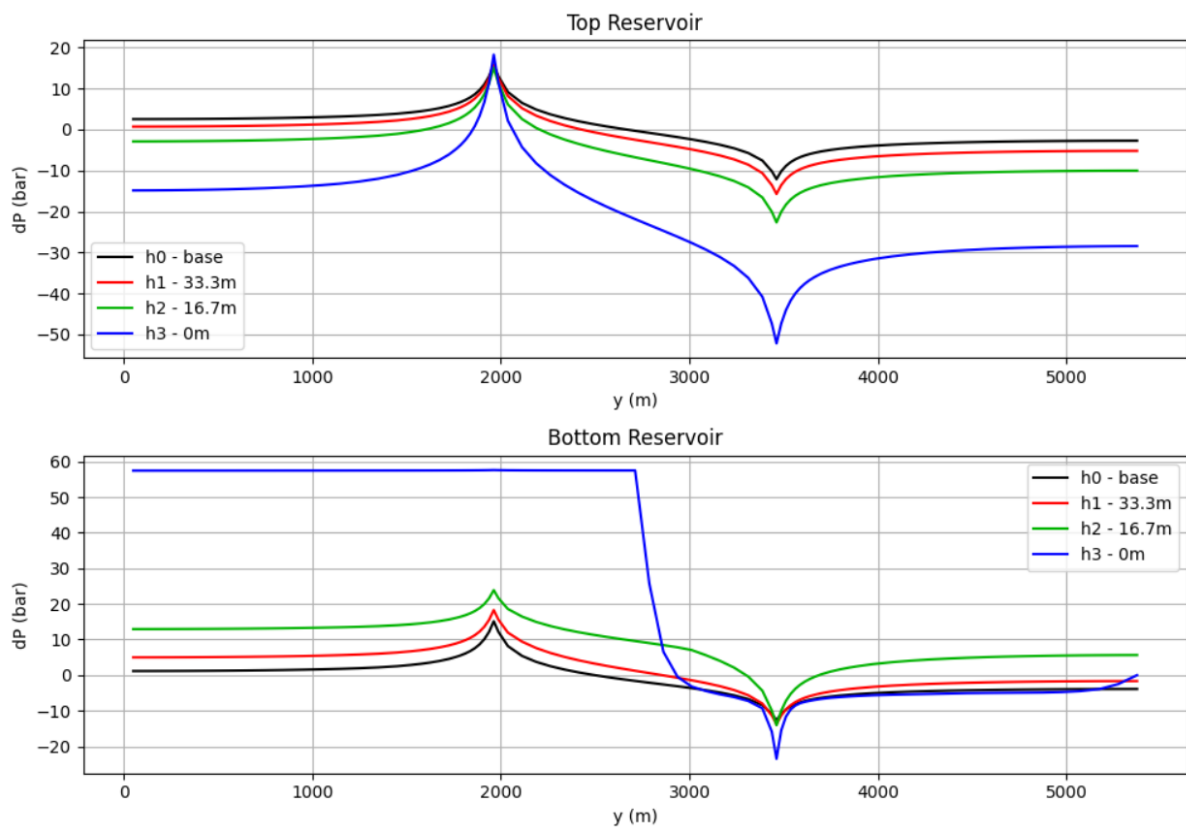


Figure 6-13: Pressure change profile plots for the variable bottom reservoir thickness scenarios.

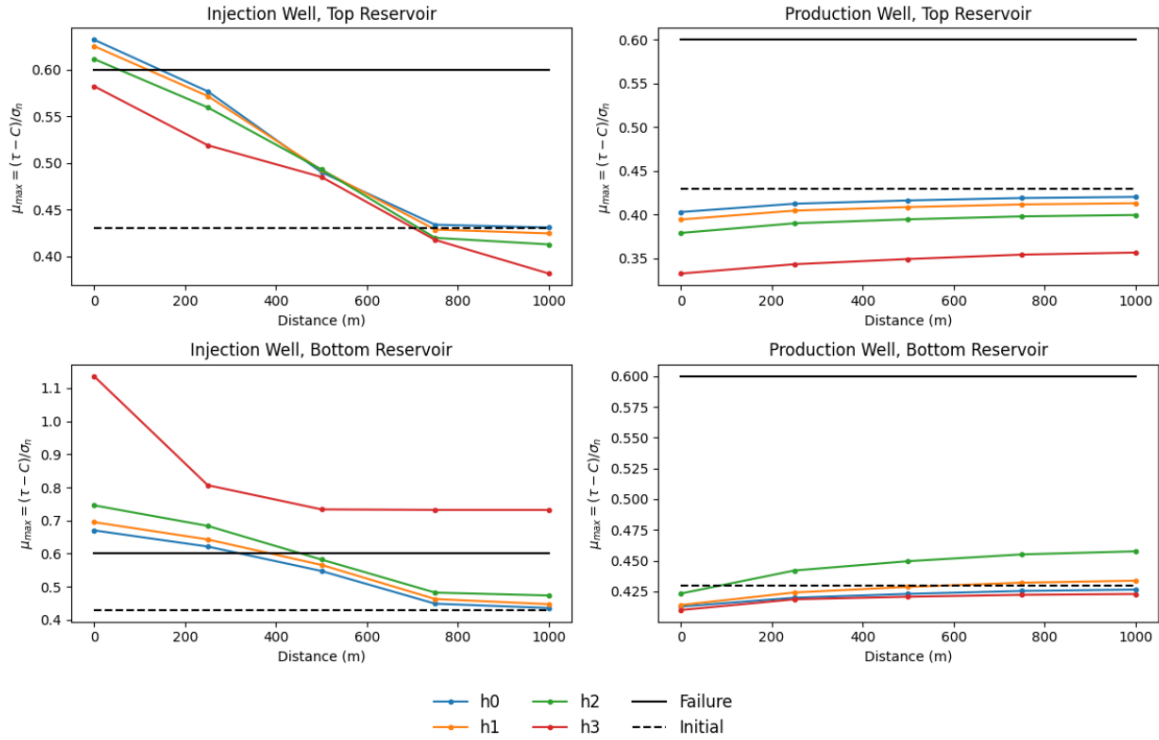


Figure 6-14: Evolution of μ_{max} as a function of distance away from the injection well (left) and production well (right) for the top reservoir (top) and bottom reservoir (bottom). The failure envelope slope ($\mu = 0.6$) is shown by the solid black line and the initial stress state is shown by the dashed black line.

The plots of μ_{max} are shown for the variable thickness simulations in Figure 6-14. The discontinuous layer case from the previous permeability analysis represents, again, the most extreme case. The estimated distance of shear failure in the bottom reservoir goes from <400 m to ~500 m as the thickness decreases. So, the takeaway from this plot is that reducing reservoir thickness can result in slight increases in pressure and shear failure away from the well. But having some connection to additional aquifer volume (especially to the production well) ensures that the lateral reach is limited and that a situation like seen in the discontinuous layer case does not occur.

Figure 6-15 and Figure 6-16 show the stress change situation 250 m away from the injection well in the bottom reservoir for the base case and 13.3 m (h2) case, respectively. The fault orientation plot shows that for vertically dipping faults, the strike angle for a critical fault can increase an additional 10° due to the increase in pressure effect. So, in the base case, a fault oriented 60° from σ_h may not slip, but in case the reservoir thickness is reduced shear failure may be induced on that fault.

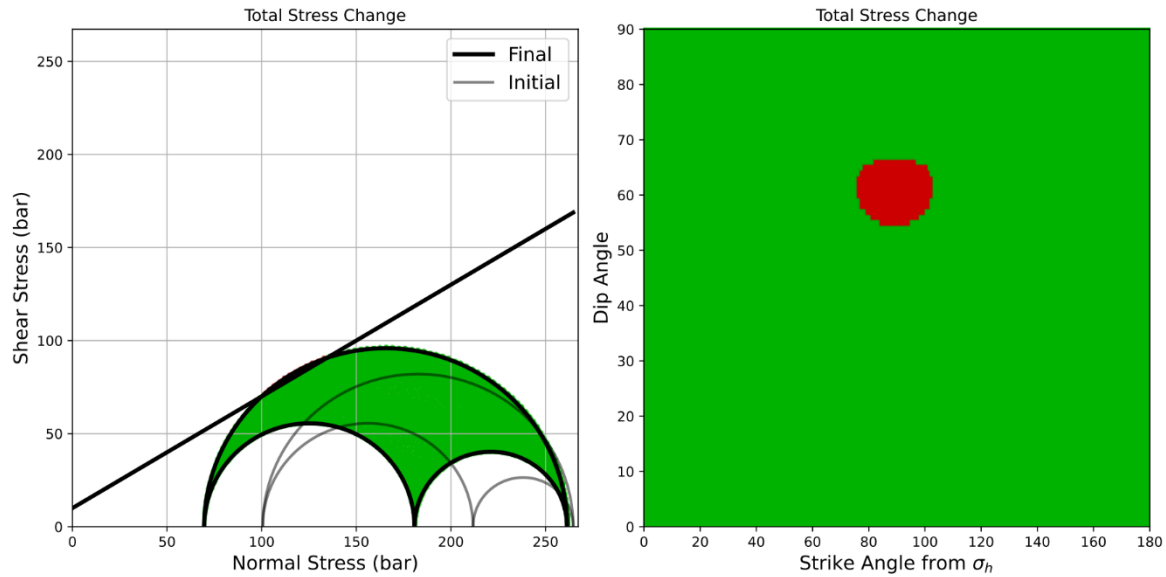


Figure 6-15: Mohr circle (left) and critical fault orientations (right) for a distance of 250 m away from the injection well in the bottom reservoir of the base case simulation (h_0).

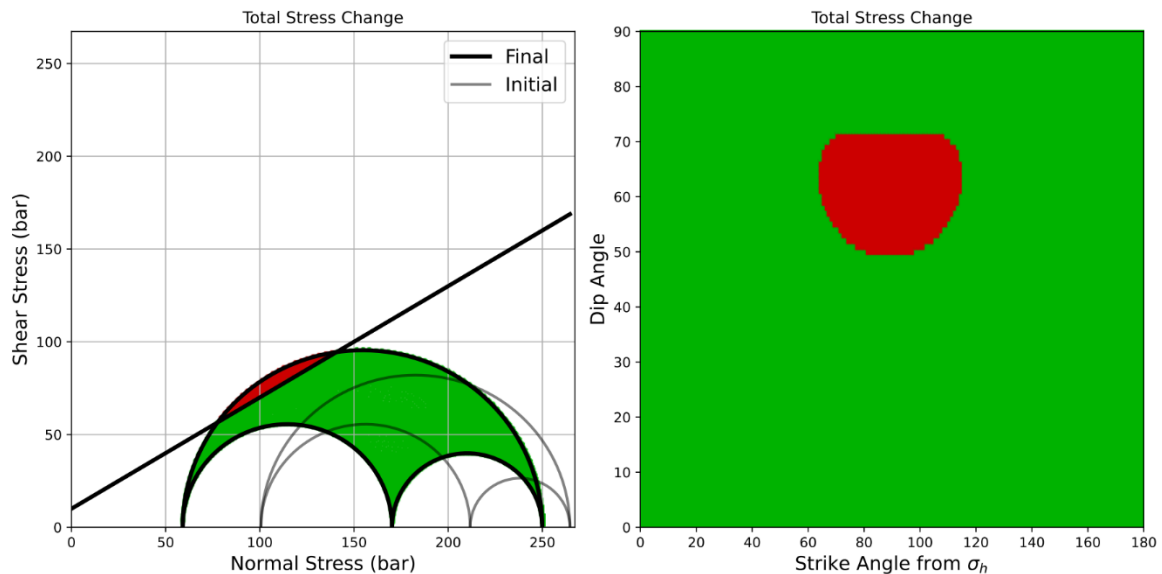


Figure 6-16: Mohr circle (left) and critical fault orientations (right) for a distance of 250 m away from the injection well in the bottom reservoir of h_2 simulation where the bottom reservoir was 13.3 m thick near the production well.

6.3.1.4 Compositional model

The compositional model cases investigated involved brine mixing in an isothermal setting. The pressure differences associated with the extreme brine/fresh water mixing case compared to a base case were about 5 bar. That pressure change without temperature changes is not high enough to induce shear failure in the parameter space tested in these scenarios.

6.3.1.5 Temperature variations

In the thermal variation experiments, 3 different thermal gradients were tested: 20°C/km, 30°C/km, and 40°C/km. The injection temperature was held constant. Therefore, greater cooling was seen in the warmer scenarios as the gradient affected the *in situ* reservoir temperatures. The scenarios revealed only small pressure differences between scenarios –

fluid viscosity/density changes were determined to be the main driver for pressure differences. The temperature profile plots for the 3 temperature scenarios are shown in Figure 6-17.

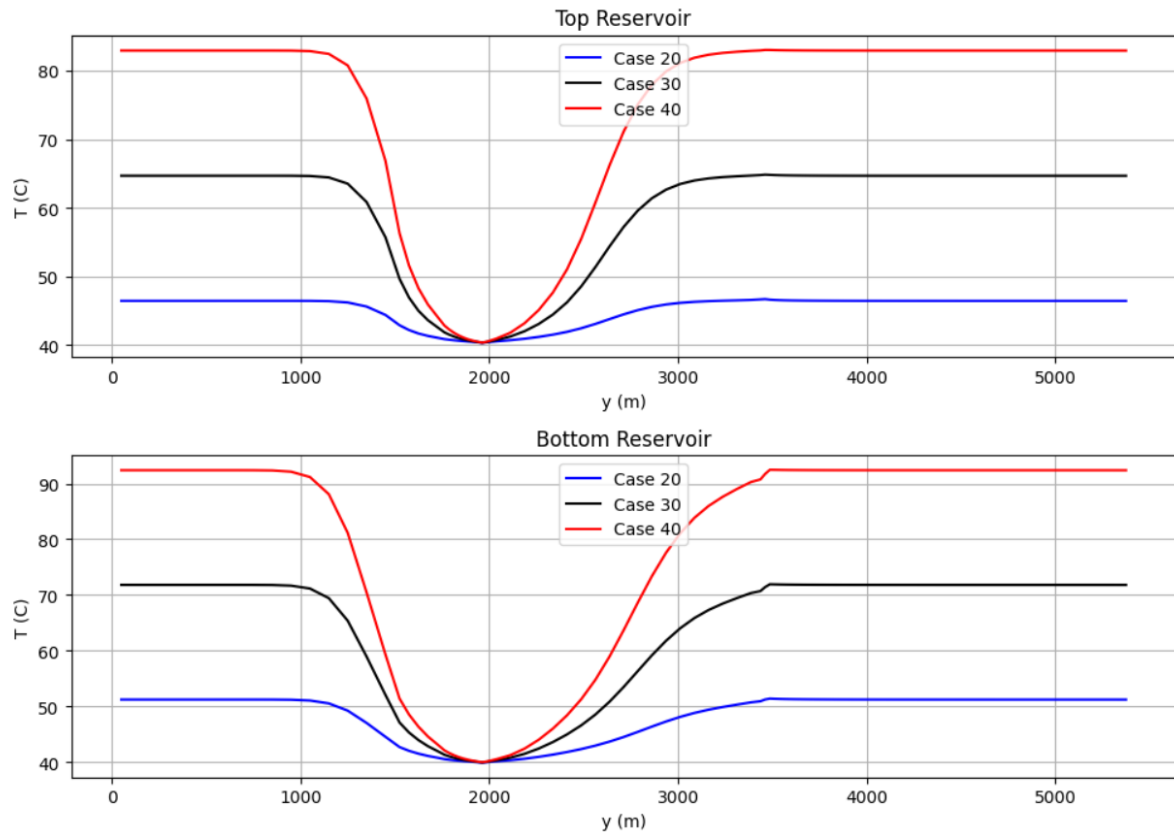


Figure 6-17: Temperature profile after 30 years for the top (top) and bottom (bottom) reservoirs in the thermal gradient variation analysis.

The plots of μ_{max} are shown for the variable temperature simulations in Figure 6-18. The additional cooling has a noticeable impact on the extent of the shear failures. The dT values from the simulations ranged from $\sim 11^{\circ}\text{C}$ ($20^{\circ}\text{C}/\text{km}$ case) to -52°C ($40^{\circ}\text{C}/\text{km}$ case). As an example, consider the bottom reservoir near the injection well (bottom-left plot). A distance of 250 m away from the well is within the cooling front of all the simulations, but the dT is low enough in the lower temperature model that shear failure is not induced. However, the two higher thermal gradient models do show a possibility of shear failure. The plots of the Mohr circles and critical fault angles are shown in Figure 6-19 to Figure 6-21.

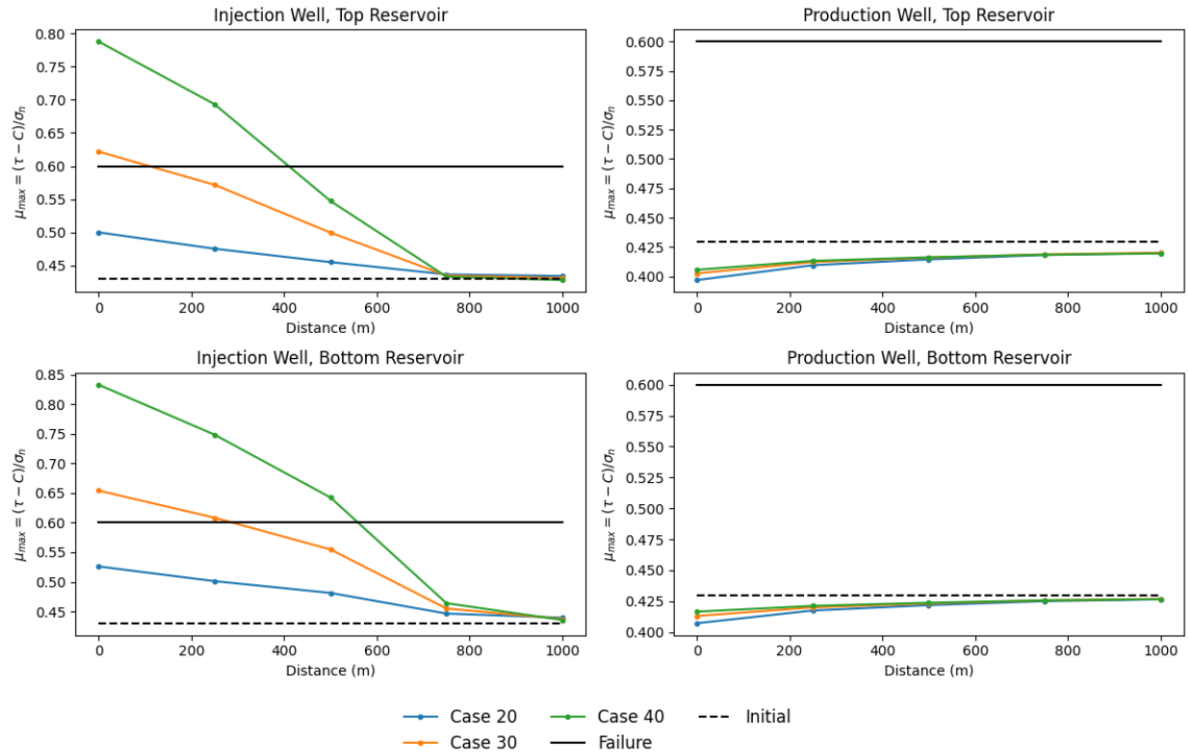


Figure 6-18: Evolution of μ_{max} as a function of distance away from the injection well (left) and production well (right) for the top reservoir (top) and bottom reservoir (bottom) for the temperature gradient scenarios after 30 years of production. The failure envelope slope ($\mu = 0.6$) is shown by the solid black line and the initial stress state is shown by the dashed black line.

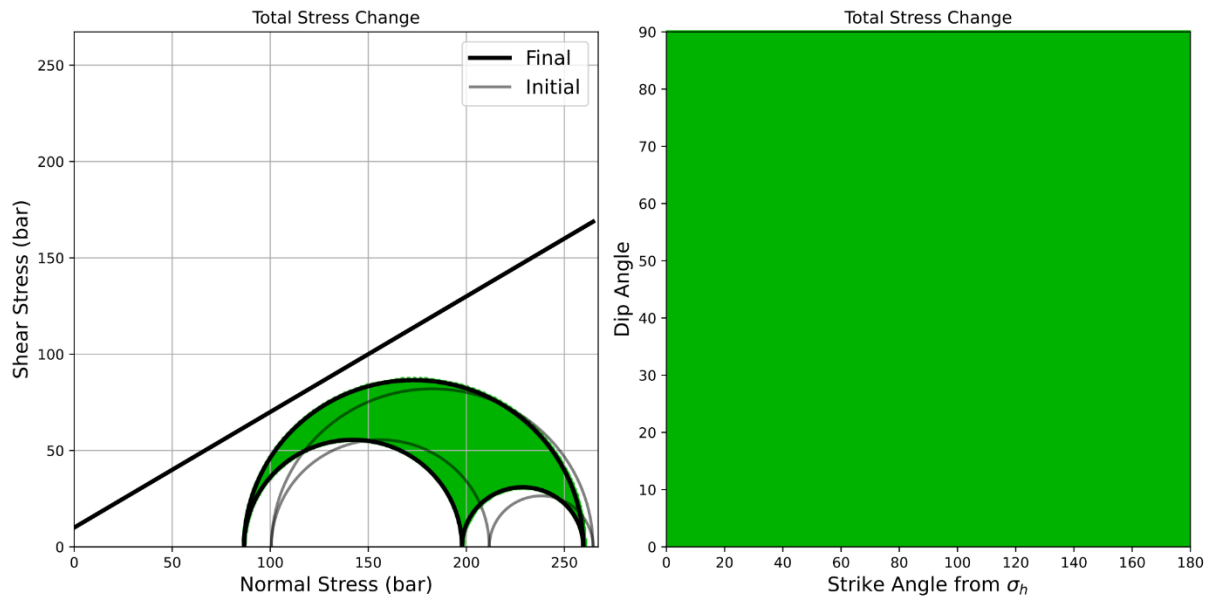


Figure 6-19: Mohr circle (left) and critical fault orientations (right) for a distance of 250 m away from the injection well in the bottom reservoir of the 20°C/km simulation.

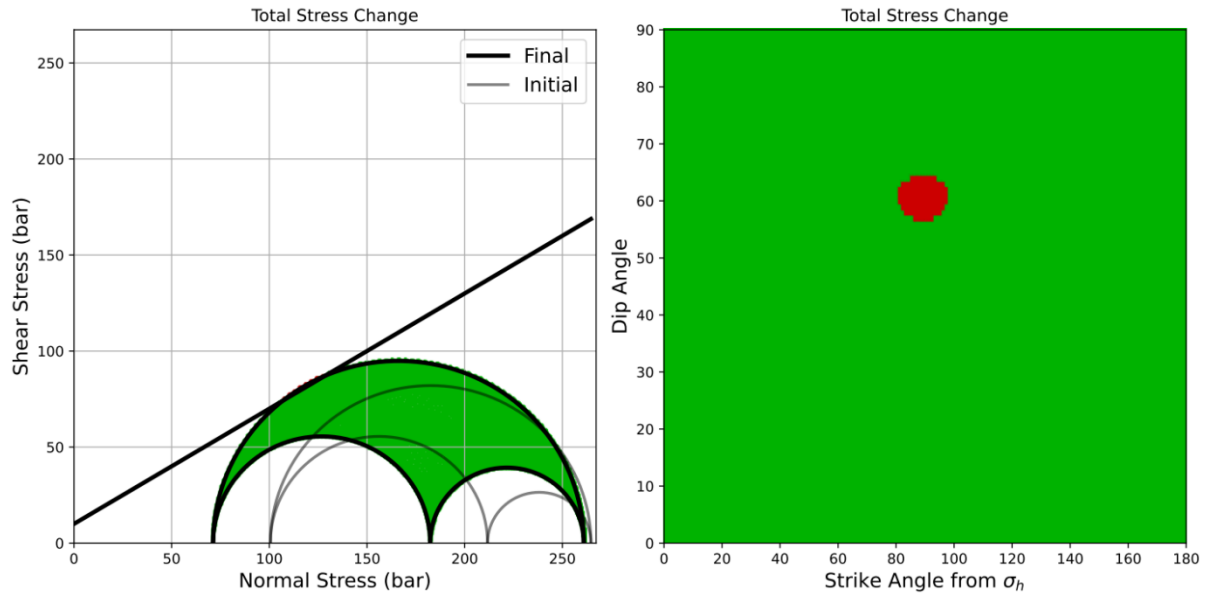


Figure 6-20: Mohr circle (left) and critical fault orientations (right) for a distance of 250 m away from the injection well in the bottom reservoir of the 30°C/km simulation.

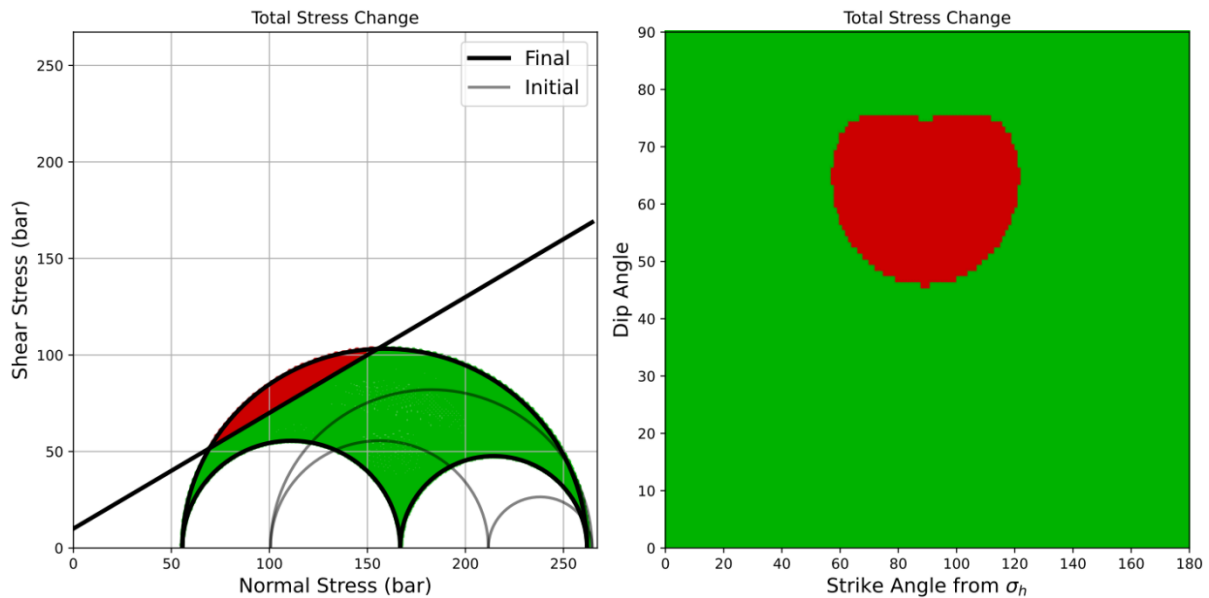


Figure 6-21: Mohr circle (left) and critical fault orientations (right) for a distance of 250 m away from the injection well in the bottom reservoir of the 40°C/km simulation.

The main conclusion from the thermal analysis is that cooling-induced stress changes can be significant, especially at higher dT values. The exact extent of the stress changes depends heavily on material parameters (Young's modulus, Poisson's ratio, and the coefficient of thermal expansion). In certain instances, like in the presence of critically oriented faults, it may be prudent to avoid large temperature changes (or at least limit the magnitude of the temperature change) by increasing injection temperature.

6.3.1.6 Completion investigation

For the well completion investigations, the well radius investigation showed a very small (<1 bar) impact on reservoir pressures and temperature changes were non-detectable. So, there

was no real change compared to the base case. This analysis focuses on changes induced by well trajectory (horizontal section) in the lower reservoir. The pressure profiles from the horizontal completion scenarios are repeated in Figure 6-22. The lower permeability case (blue) had no additional horizontal well length, but the permeability of the lower reservoir was reduced from 265 mD to 50 mD. Then in the purple (Both Low Perm) case, horizontal sections were placed in both wells to simulate a case that may happen in an actual project.

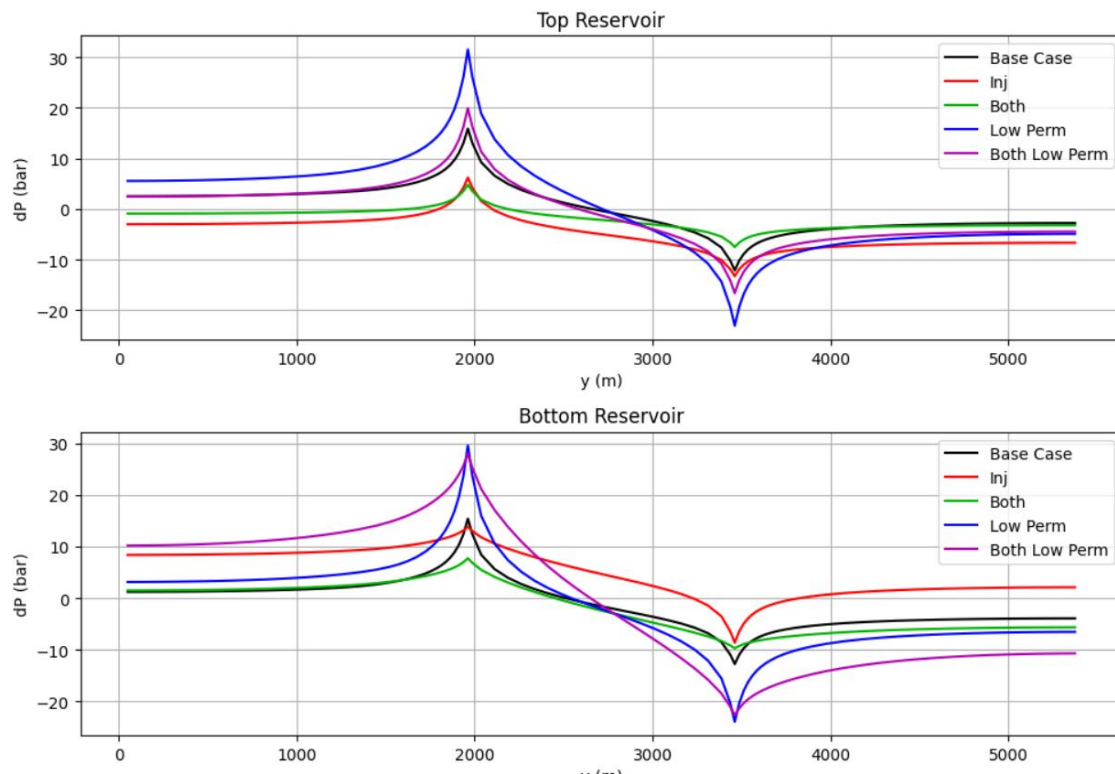


Figure 6-22: Pressure change profile results from the horizontal completion scenarios for the top reservoir (top) and bottom reservoir (bottom).

In addition to pressure changes, the horizontal completion scenarios also resulted in different cooling levels for each simulation as the fractions of flow to each reservoir section changed (Figure 6-23). A greater proportion of flow in a reservoir resulted in a greater degree of cooling in that reservoir and reduced cooling in the other. We repeat the downhole pressure plots as well here in Figure 6-24 as the horizontal completion perhaps could mask the effect on the reservoir pressure in the downhole pressure. This can be observed in the lower permeability scenarios. The addition of horizontal completions in both wells does work to reduce the dP seen in both wells (~10-20 bar depending on the well), however, the pressure (especially far-field pressure) change in the bottom reservoir is elevated due to a higher percentage of injection being directed toward a lower permeability reservoir. Since more fluid is directed to that reservoir, there is also additional cooling in that reservoir. This could result in an increased likelihood of shear failures on faults intersecting that reservoir (Figure 6-25).

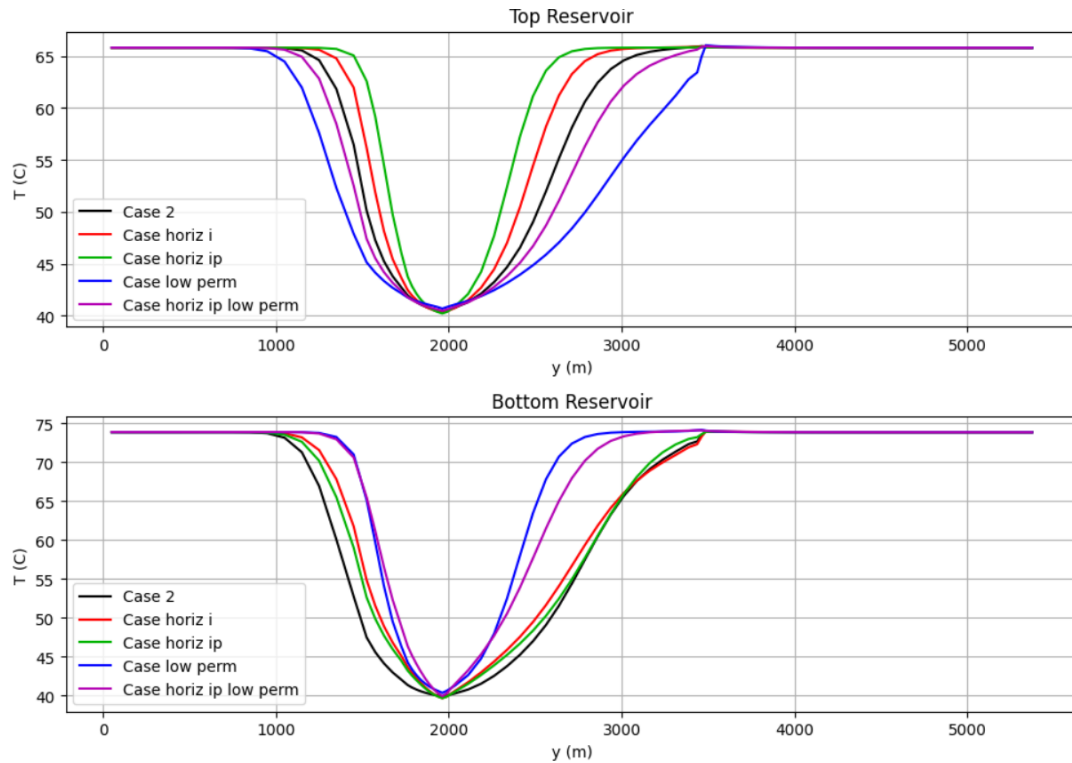


Figure 6-23: Temperature profile after 30 years for the top (top) and bottom (bottom) reservoir in the horizontal completion analysis.

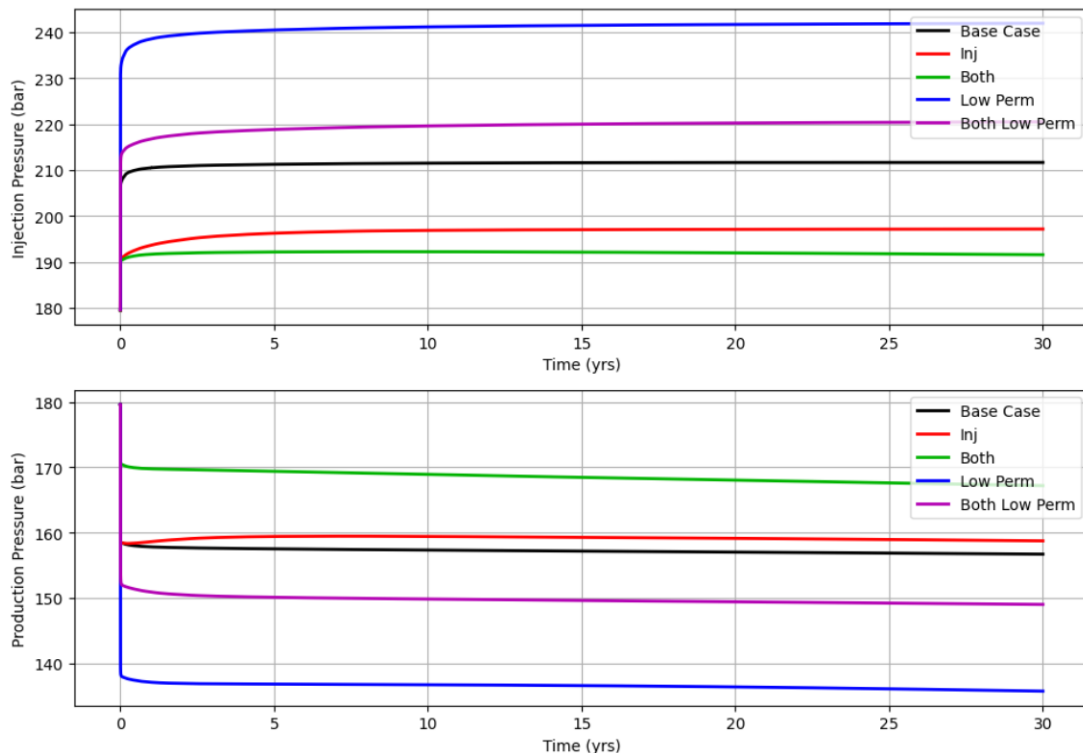


Figure 6-24: Downhole pressure for the injection well (top) and production well (bottom) for the horizontal completion scenarios.

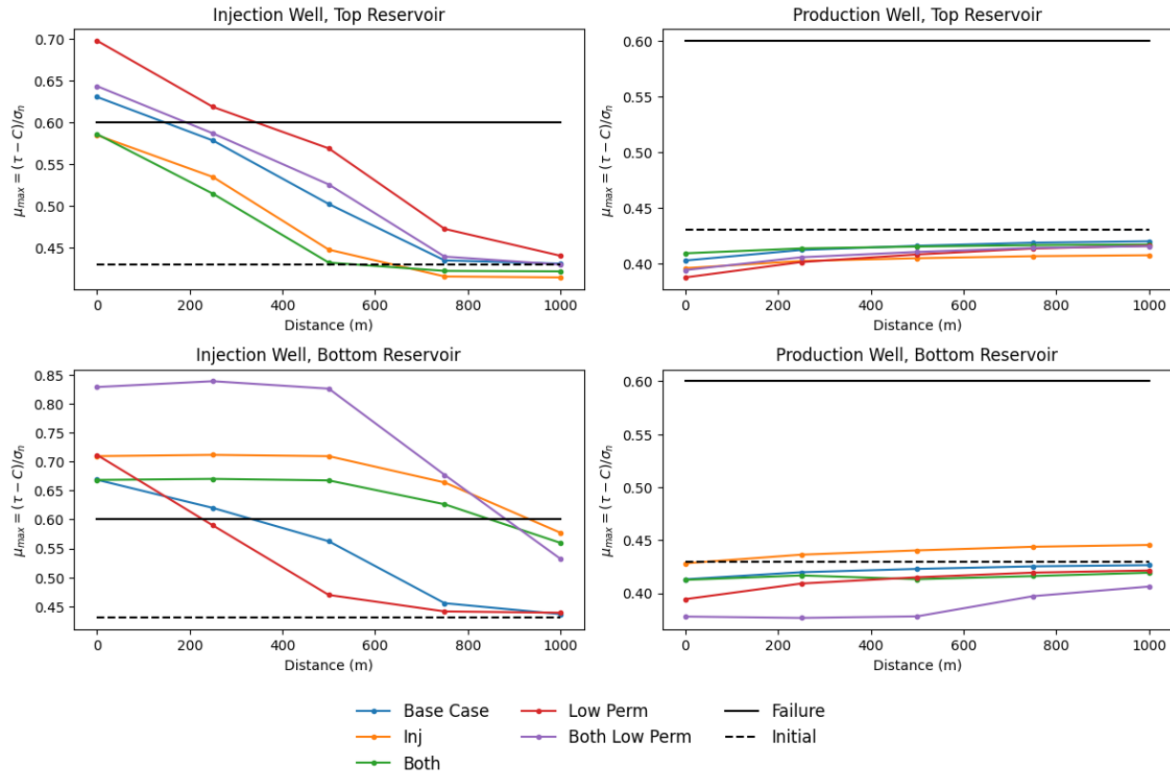


Figure 6-25: Evolution of μ_{max} as a function of distance away from the injection well (left) and production well (right) for the top (top) and bottom reservoir (bottom) for the horizontal completion scenarios after 30 years of production. The failure envelope slope ($\mu = 0.6$) is shown by the solid black line and the initial stress state is shown by the dashed black line.

6.3.1.7 Skin scenarios

Recall from Section 4.6, the cases with uniform skin (same skin in both reservoirs in one well) showed significant changes in wellbore pressure and near well (skin zone) pressure, but very little change in flow imbalances or reservoir pressures. As such, the basic potential for shear failure is also not dramatically changed. The changes in the maximum friction factor μ_{max} are seen in Figure 6-26. In contrast, the cases with large skin differences in a single well (e.g., top reservoir has negative skin and bottom reservoir has positive skin) showed the largest changes in flow contributions per reservoir and the largest pressure differences. The result is that those simulations also show the highest number of shear failures by a Mohr-Coulomb criterion. Figure 6-27 displays a summary of the results for cases with non-uniform skin: the cases with a large contrast have the highest μ_{max} values in the reservoir with negative skin.

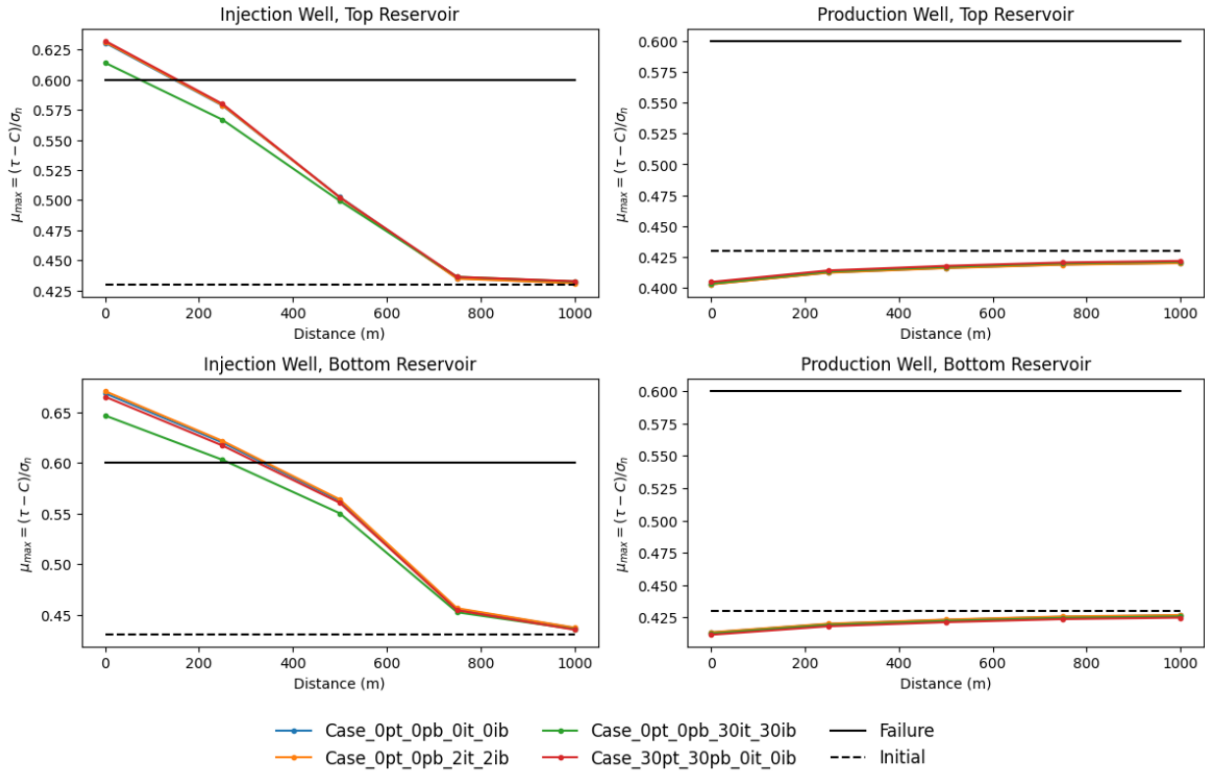


Figure 6-26: Evolution of μ_{max} as a function of distance away from the injection well (left) and production well (right) for the top reservoir (top) and bottom reservoir (bottom) for the equal skin scenarios after 30 years of production. The failure envelope slope ($\mu = 0.6$) is shown by the solid black line and the initial stress state is shown by the dashed black line.

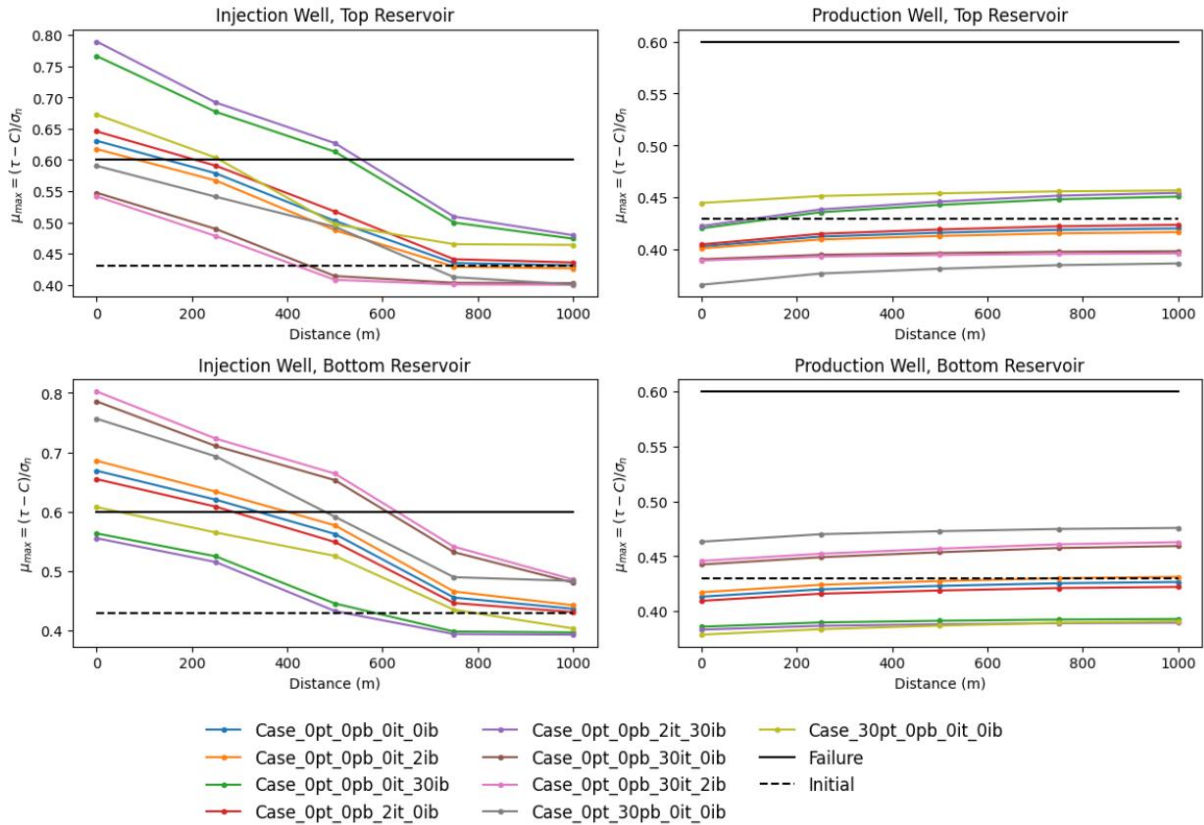


Figure 6-27: Evolution of μ_{max} as a function of distance away from the injection well (left) and production well (right) for the top reservoir (top) and bottom reservoir (bottom) for the unequal skin scenarios after 30 years of production. The failure envelope slope ($\mu = 0.6$) is shown by the solid black line and the initial stress state is shown by the dashed black line.

6.3.1.8 Conclusions for the analytical approach

The simulations of Chapter 4 were analyzed for direct pore pressure and thermal stress effects analytically. Shear failure is possible for critically oriented faults near the injection well even in the Base Case scenario. However, the stress drops quickly away from the wellbore and failures are not expected at more than about 200 m away from the well in that case. This enforces the idea of injecting away from known critically oriented faults. The exact conditions that can lead to shear fault reactivation are situation dependent, but a few conclusions can be drawn from this analysis for commingled production scenarios:

- Discontinuous reservoirs/compartments with no hydraulic connection to larger reservoirs or the production well, present the highest likelihood of shear fault reactivation (even at large distance away from the injection well).
- Conditions that lead to over-injecting into an aquifer can result in overpressurization of that aquifer and an increased likelihood of shear fault reactivation (e.g., large negative skin with a relatively low permeability or long horizontal drilling in very low permeability reservoirs).
- Cooling effects can be significant. As such, in elevated risk situations, it is important to have a good hand on material parameters that can affect the thermal stress (i.e., Young's Modulus, Poisson's ratio, coefficient of thermal expansion).

Table 6-2: Overview of scenarios (and their description) for Section 6.3.1 and corresponding simulation results indicating maximum μ values at the injection well for the top and bottom reservoir. Values in red indicate fault reactivation.

Scenario name	Description	Max. μ (top)	Max. μ (bottom)
Base Case	Base case scenario	0.63038	0.66872
Top Pro	Discontinuous TOP reservoir in PRODUCTION well	0.75235	0.58405
Top Inj	Discontinuous TOP reservoir in INJECTION well	0.46300	0.86049
Bot Pro	Discontinuous BOTTOM reservoir in PRODUCTION well	0.58253	1.13158
Bot Inj	Discontinuous BOTTOM reservoir in INJECTION well	0.93201	0.48211
Smooth	Smooth permeability variation in bottom reservoir	0.66076	0.66133
h0	Uniform reservoir thickness (50 m) in both wells	0.63226	0.67035
h1	Bottom reservoir 33.3 m thick at production well	0.62540	0.69524
h2	Bottom reservoir 16.7 m thick at production well	0.61157	0.74603
h3	Bottom reservoir 0 m thick at production well	0.58244	1.13605
Case 20	Thermal gradient 20°C/km	0.50022	0.52609
Case 30	Thermal gradient 30°C/km	0.62190	0.65441
Case 40	Thermal gradient 40°C/km	0.78763	0.83339
Inj	Horizontal completion in Injection well	0.58464	0.70947
Both	Horizontal completion in both wells	0.58587	0.66836
Low Perm	Lower permeability bottom reservoir (NO horizontals)	0.69757	0.71156
Both Low Perm	Lower permeability bottom reservoir (BOTH wells with horizontal completion)	0.64324	0.82877
Case_Opt_0pb_0it_0ib	Base case scenario with 0 skin for all reservoirs	0.63077	0.66911
Case_Opt_0pb_0it_2ib	Scenario with 0 skin in the production well, 0 skin at the top reservoir in the injection well, and a skin of -2 in the bottom reservoir in the injection well	0.61750	0.68579
Case_Opt_0pb_0it_30ib	Scenario with 0 skin in the production well, 0 skin at the top reservoir in the injection well, and a skin of -2 in the bottom reservoir in the injection well	0.76640	0.56361
Case_Opt_0pb_2it_0ib	Scenario with 0 skin in the production well, a skin of -2 at the top reservoir in the injection well, and 0 skin in the bottom reservoir in the injection well	0.64576	0.65491
Case_Opt_0pb_2it_30ib	Scenario with 0 skin in the production well, a skin of -2 at the top reservoir in the injection well, and a skin of 30 in the bottom reservoir in the injection well	0.78963	0.55554
Case_Opt_0pb_30it_0ib	Scenario with 0 skin in the production well, a skin of 30 at the top reservoir in the injection well, and 0 skin in the bottom reservoir in the injection well	0.54748	0.78563
Case_Opt_0pb_30it_2ib	Scenario with 0 skin in the production well, a skin of 30 at the top reservoir in the injection well, and a skin of -2 in the bottom reservoir in the injection well	0.54184	0.80246
Case_Opt_30pb_0it_0ib	Scenario with 0 skin at the top reservoir in the production well, a skin of 30 at the bottom reservoir in the production well, and with 0 skin in the injection well	0.59061	0.75650
Case_30pt_0pb_0it_0ib	Scenario with a skin of 30 at the top reservoir in the production well, 0 skin at the bottom reservoir in the production well, and with 0 skin in the injection well	0.67274	0.60789

6.3.2 Thermo-Hydro-Mechanical reservoir simulation approach

The analysis of the previous section was performed as a fast semi-analytical technique to evaluate direct pore pressure and thermal stress effects for fault reactivation likelihood. Those analyses neglected potential elastic (stress transfer) effects and Poisson (out-of-plane) effects in the effective stress development in the solid skeleton. To that end, coupled Thermo-Hydro-Mechanical (THM) simulations were performed using open-DARTS for the Base Case (semi-

open) model and for the Bot Pro simulation from the permeability cases in Chapter 4.1. The ‘Bot Pro’ case was chosen from the fault reactivation analysis as it was the simulation with the highest likelihood of induced shear reactivation.

6.3.2.1 Methodology

Open-DARTS v1.1.1 was leveraged for this portion of the study. This version features a THM simulation capability that is not present in v1.1.3 (version used for the reservoir simulations earlier in this report). The capability utilizes a nucleus of strain concept to compute geomechanical displacements and stresses throughout the domain. The approach is outlined in Saifullin et al. (2024) and based on earlier work by van Wees et al. (2019), Munoz and Roehl (2017), and the seminal work of Mindlin (1936). The poroelastic and thermoelastic displacements due to the pressure and temperature changes (from initial conditions) are computed for every cell in the numerical grid. In theory, the nucleus of strain concept itself is a mesh-free method that allows for computation of displacements at any location – aligned with the numerical grid or not. Even points outside the grid are possible. In such an approach, the poro- and thermoelastic effects even outside of the direct pore pressure and thermal strain areas can be computed. In practice in open-DARTS, the reservoir model blocks act as both strain sources (nuclei) and as evaluation points. This could be thought of as a type of semi-analytical geomechanical model. One obvious simplification is that the approach requires uniform and isotropic medium material properties (Young’s modulus, Poisson ratio, Biot coefficient, and coefficient of thermal expansion).

In the approach, the scalar displacement potential of a location is given by the function (equation 32):

$$\Phi = -\frac{C_m V \Delta \chi}{4\pi r} \quad (32)$$

Where χ is the primary variable (pressure or temperature), r is the radius to a nucleus of volume V where the change in primary variable takes place. C_m is a compaction coefficient defined by equation 33:

$$C_m = \begin{cases} \frac{(1+\nu)(1-2\nu)}{E(1-\nu)}, & \chi = P \\ \alpha, & \chi = T \end{cases} \quad (33)$$

The gradient of the potential field gives the displacement vector ($\nabla_I \Phi = u_I$) where $I \in [1,3]$ are the Cartesian coordinate directions. The displacement in direction I of an observation point can be expressed as the sum of all the contributions from the numerical grid (equation 34):

$$u_I = -\frac{C_m}{4\pi} \sum_{e=1}^N \Delta \chi G_I \quad (34)$$

Where e ranges from 1 to the number of numerical grid cells N and the geometric gradient contributions are given by equation 35:

$$G_I = \int_{V_e} \nabla_I \frac{1}{r} + C_v \int_{V_e} \nabla_I \frac{1}{r'} + 2z_e \int_{V_e} \nabla_I \nabla_z \frac{1}{r'} \quad (35)$$

Where the first integral term in the equation represents the infinite-space solution and the last two integral terms are used for the semi-infinite half space correction associated with the free surface at $z = 0$ (ground surface). All the terms are integrated over the volume of the cell (V_e).

The double gradient term is the Hessian, r' is the distance to the nucleus of strain image above ground ($-z$), and the coefficients $C_v = 3 - 4\nu$ and z_e (depth of the element) ensure stress reduces to zero at the ground surface.

The above equations are implemented in open-DARTS v1.1.1 and are used to compute the pressure- and thermal-related displacements in the domain. The displacements are used to calculate the induced stress changes from an initial state.

6.3.2.2 Simulation setup

The THM simulations required a coarser grid resolution to run. The determination of the mechanical effects required a computation where the effect of every cell's pressure and temperature changes are used to inform the displacement results of every numerical cell. The Base Case models from Chapters 3 and 4 have about 120000 numerical cells. The run time of the production scenarios varied based on some convergence conditions but, generally, was around 1-2 minutes on the VITO Linux computing cluster. For the THM numerical model a grid with about 40000 blocks was set up. The details of the numerical THM grid compared to the original grid are presented in Table 6-3. The lower number of grid blocks was achieved by reducing the discretization level around the edges of the model and in the over- and underburdens. The runtime of the THM simulation depends on the discrete times the geomechanical calculations are carried out. They are performed 11 times: 0 (initialization), 1 day, 50 days, 200 days, 1 year, 2 years, 7 years, 12 years, 17 years, 22 years, and 30 years. The total simulation run time was 22 hours (Coarse THM model) and 24 hours (Bot Pro case).

Table 6-3: Description of grid discretization of the THM grid compared to the original grid. Log - the top and bottom numerical grid sections had logarithmic spacing (refining toward the reservoir) for a total of 300 m each for over- and underburden.*

	Model	Original	Totals	THM	Totals
X	Nx	15,27,15	57	5,27,5	37
	Dx	100,75,100	5025 m	300,75,300	5025 m
Y	Ny	15,5,10,19,10,5,15	79	5,5,10,19,10,5,5	59
	Dy	100,50,25,75,25,50,100	5425 m	300,50,25,75,25,50,100	5425 m
Z	Nz	10,1,4,1,10	26	6,1,4,1,6	18
	Dz	Log*,50,50,50,Log*	900 m	Log*,50,50,50,Log*	900 m
Total # Cells		117078		39294	

The initial stress state is taken to be the same as in the section on fault reactivation and depth dependent. That is σ'_V is determined from the lithostatic gradient, $\sigma'_H = 0.8 \sigma'_V$, and $\sigma'_h = 0.38 \sigma'_V$ (van Wees et al., 2014 – see Section 6.3).

6.3.2.3 Results Coarse THM model

The pressure and temperature results of this Coarse THM model and the Base Case model (presented in Section 3.4.3) are nearly identical. The pressure change and temperature profiles along the centerline are shown in Figure 6-28 and Figure 6-29 and are compared to the Base Case semi-open model from the previous analyses. The pressure and temperature results are the same, though differences in discretization do affect the thermal results along the gradients. The peak pressure change for the top reservoir at the injection well is 15.8 bar in the Coarse THM model and 15.9 bar in the Base Case model.

Since the model is assumed linear elastic, the pressure and temperature stress results can be viewed independently and superimposed for a total effect. Pressure acts hydrostatically on all principal stress directions. However, due to the constrained nature of the boundary value problem (and the reservoir underground), deviatoric (or poroelastic) effects are seen resulting from Poisson ratio effects. Taking the injection well, for example, the pressure increase induces tensile stresses (reduction of compressive stress) in all directions. However, the elastic coupling (Poisson effect) resists the volumetric expansion caused by the pressure increase, thus generating deviatoric stresses. In the half-space problem with a free surface at $z=0$, this manifests itself as a larger stress change in the vertical direction than in the horizontal directions. Figure 6-30 displays the pressure change due to injection/production after 30 years of production and injection and the corresponding components of the change in the stress tensor due to those pressure effects. The ~15.2 bar overpressure results in stress changes of 9.4 bar (vertical), 8.5 bar (y-direction), and 7.4 bar (x-direction).

Figure 6-31 displays the Mohr circle shift at the injection well (left) and production well (right) for the stress states plotted in Figure 6-30. The injection well stress state shifts left toward shear failure and the production well shifts right due to pressure reduction around the well.

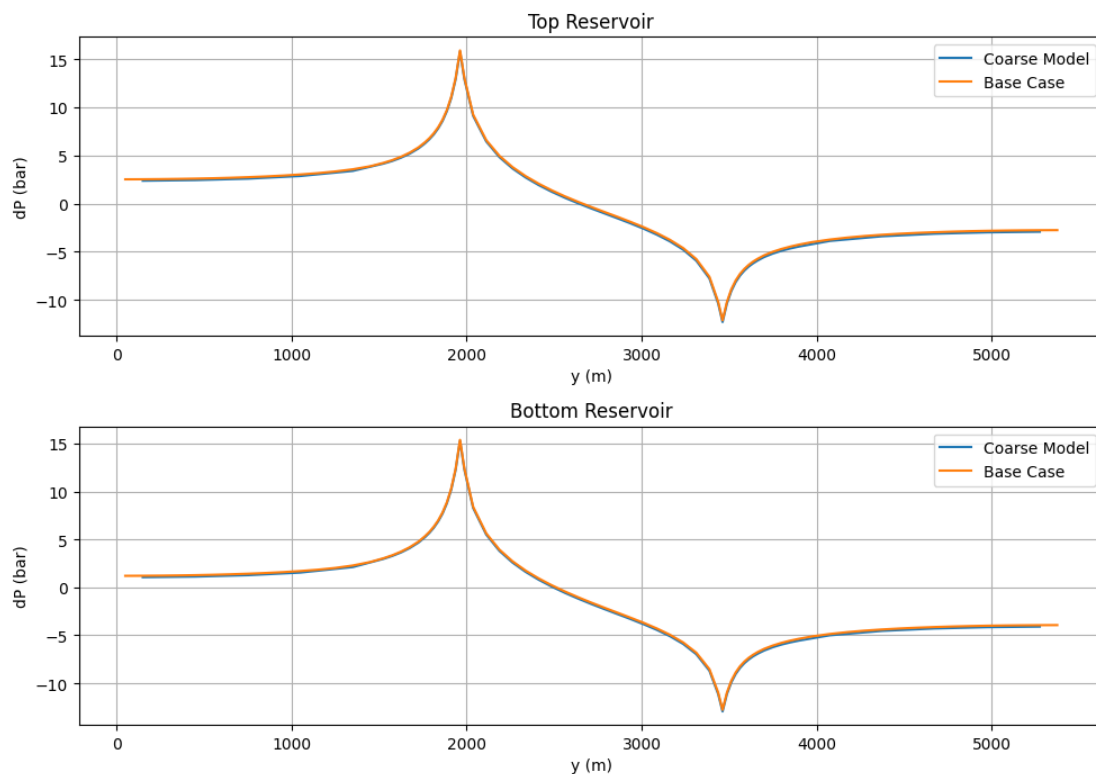


Figure 6-28: Pressure change profile along centerline for Coarse THM model compared to Base Case semi-open model after 30 years of operations.

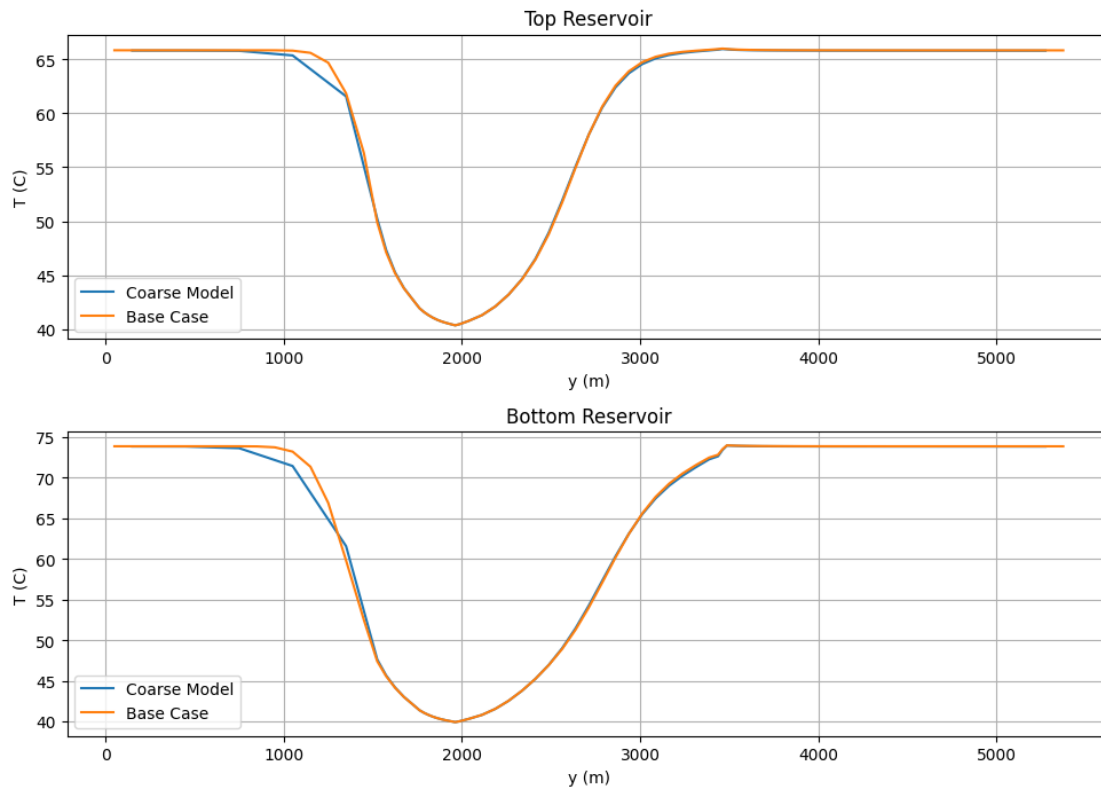


Figure 6-29: Temperature profile along centerline for Coarse THM model compared to Base Case semi-open model after 30 years of operations.

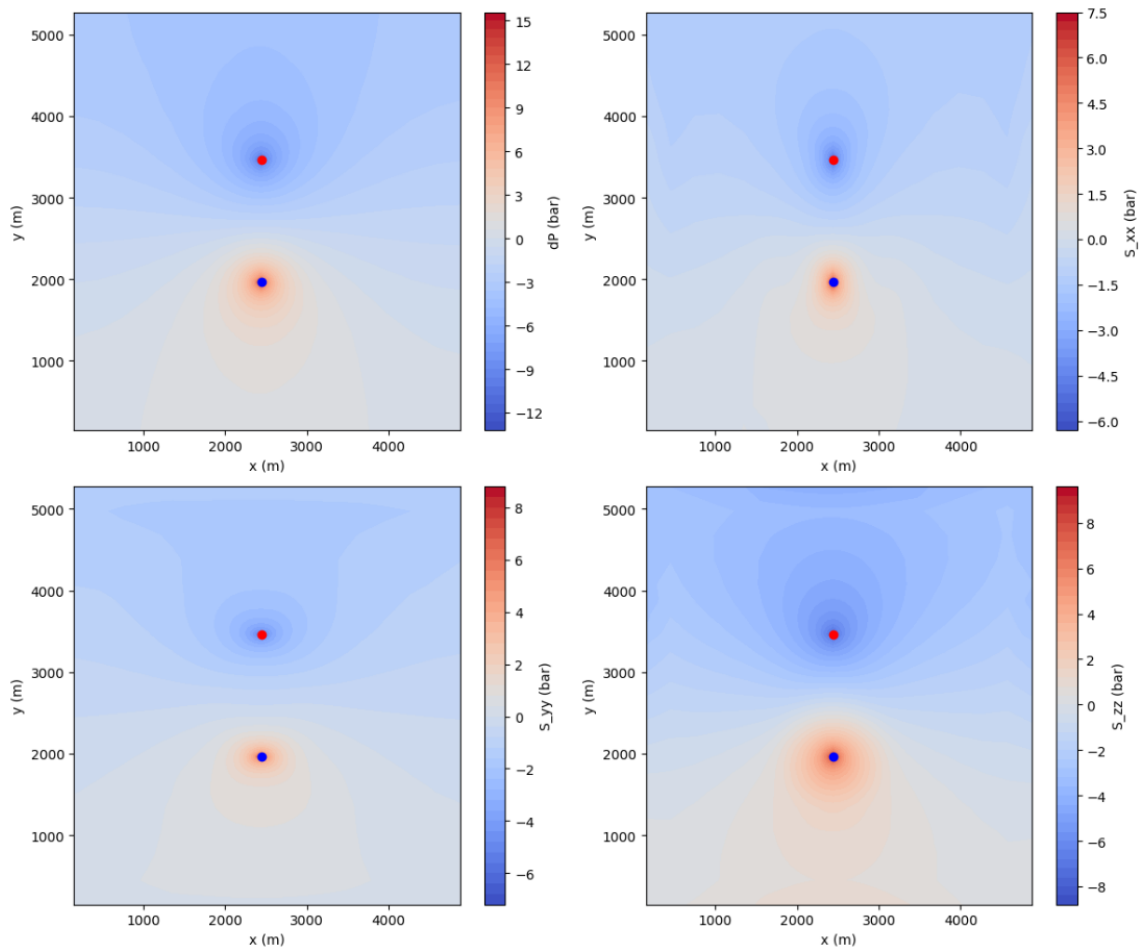


Figure 6-30: Coarse THM model pressure change (in bar – top left) after 30 years from initial state and stress changes (bar) for each axial direction shown in the plane of the bottom reservoir. Negative stress change is compression and positive stress change is tension. The location of the injection well is shown in blue and the production well in red.

Meanwhile, Figure 6-32 displays the temperature change (top left) after 30 years and the associated thermoelastic stress changes from the initial state due to production. From the previous section, the expected thermoelastic stress change for a 33°C temperature reduction (assuming horizontal plane strain conditions) would be about 28 bar. However, due to the thermoelastic effects and effect of the free surface at ground level, the expected stress changes are 24.4 bar (vertical) and ~10.4 bar in both the x- and y-directions. A deviation in these results compared to the previous section, is the development of stress change in the vertical direction. That result is strongly affected by the free surface boundary condition. If the reservoir is deep enough, then hydrostatic stress changes are possible (effectively an infinite medium). If the reservoir is very near the surface, then stress changes trend toward zero in the vertical direction and the ground is free to movement. Actual reservoirs lie somewhere between. The overburden resists some vertical displacement associated with the temperature change at depth and thus, changes develop in the vertical and (through Poisson effects) horizontal stresses.

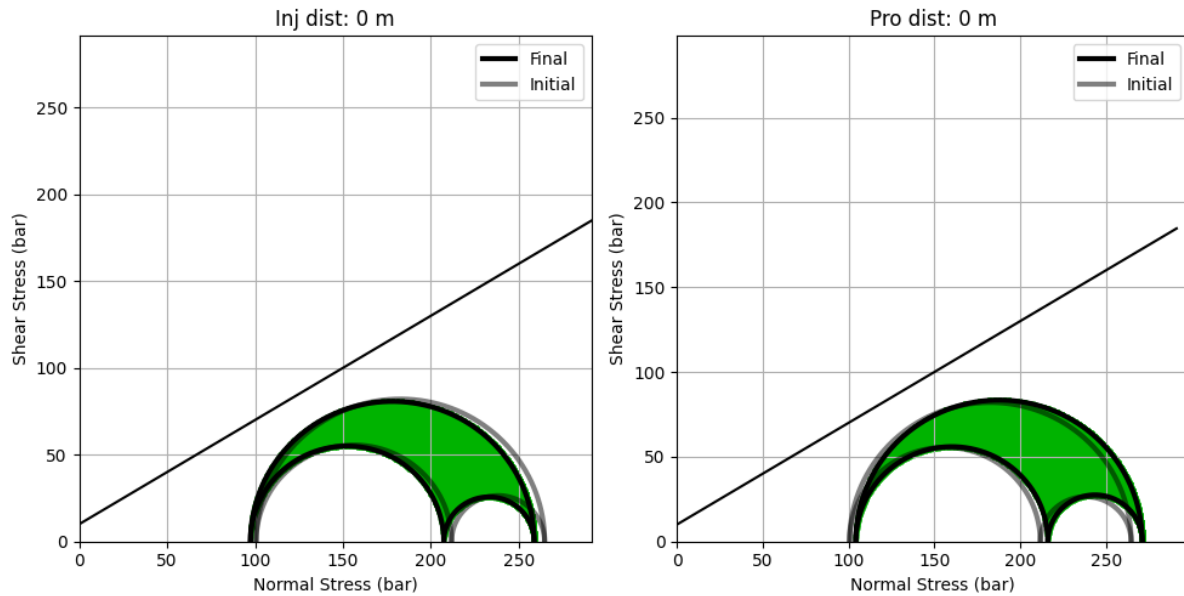


Figure 6-31: Pressure-induced Mohr circle shift for the bottom reservoir at the injection well (left) and production well (right) for the coarse THM model after 30 years.

Figure 6-33 displays the equivalent Mohr circle diagrams for the thermally related stress changes shown in Figure 6-32. The cooling-related thermal contractions induce tensile stress changes near the injection well and shift the Mohr circle toward the origin. The production well displays no temperature change, so the circle is unshifted. Since the vertical component shifts more than the horizontal components around the injection well, differential stress decreases and hence the radius of the circle is reduced. This result contrasts with the plane-strain assumption results of the previous section (Section 6.3.1) where σ_V was assumed unchanged and the changes in the horizontal stress components were greater.

The combined thermo-hydro-mechanical stress change results for the bottom reservoir from the top view are shown in Figure 6-34. The peak stress changes in each direction are 17.8 bar (x), 19 bar (y), and 33.7 bar (z). The equivalent Mohr circle diagrams are displayed in Figure 6-35 for the position (model block) of the injection well (left) and production well (right) in the bottom reservoir. The Mohr circle plots show that in this case, no shear failure is expected in the Coarse THM model (which has the same properties as the Base Case).

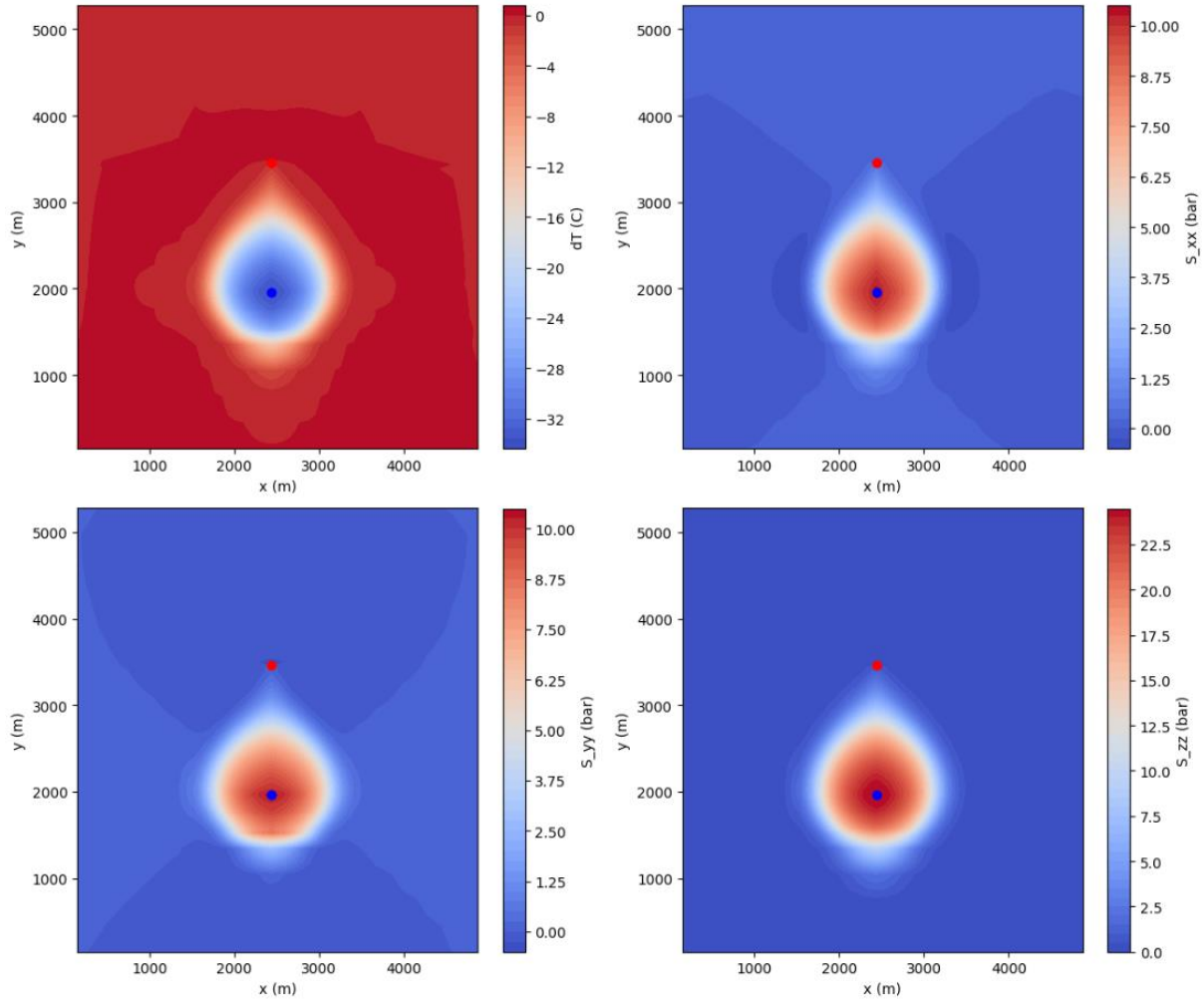


Figure 6-32: Coarse THM model temperature change (in °C – top left) after 30 years from initial state and stress changes (bar) for each axial direction shown in the plane of the bottom reservoir. Negative stress change is compression and positive stress change is tension. The location of the injection well is shown in blue and the production well in red.

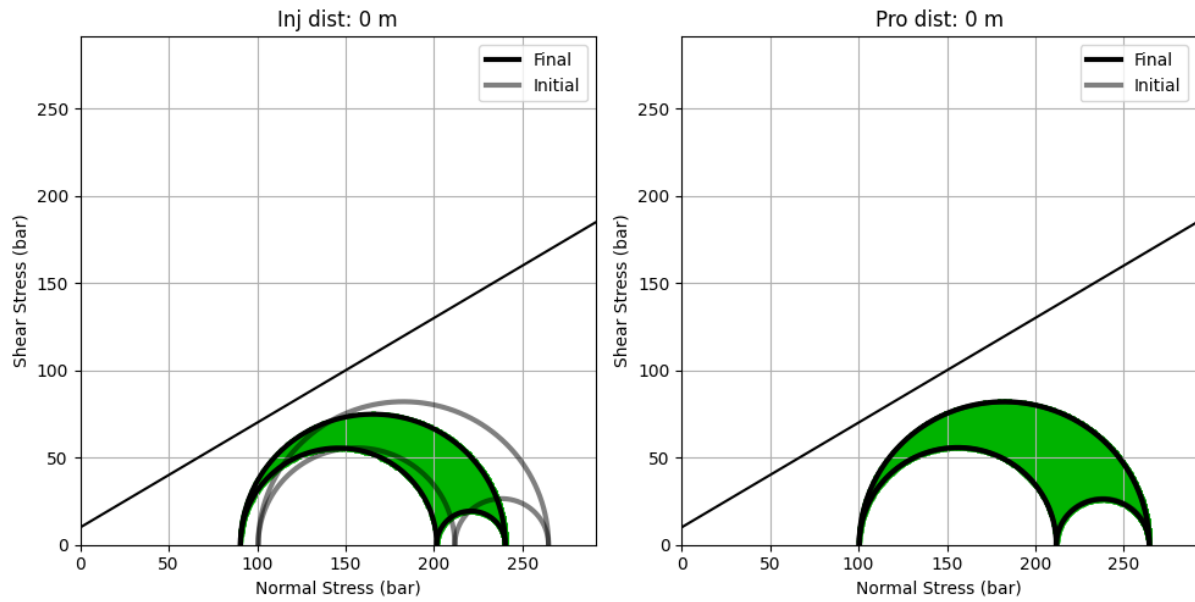


Figure 6-33: Temperature-induced Mohr circle shift for the bottom reservoir at the injection well (left) and production well (right) for the coarse THM model after 30 years.

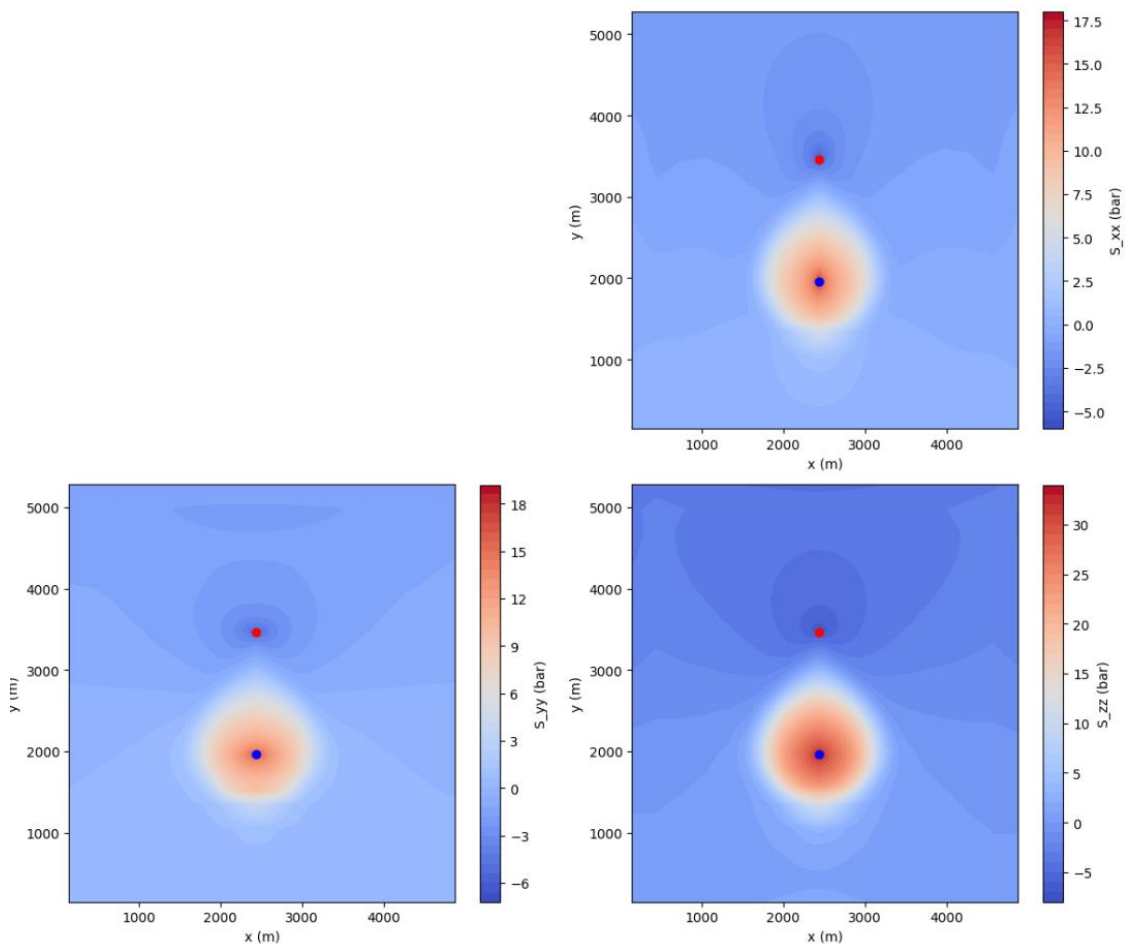


Figure 6-34: Coarse THM model combined thermo-hydro stress change (bar) results after 30 years from initial state for each axial direction shown in the plane of the bottom reservoir. Negative stress change is compression and positive stress change is tension.

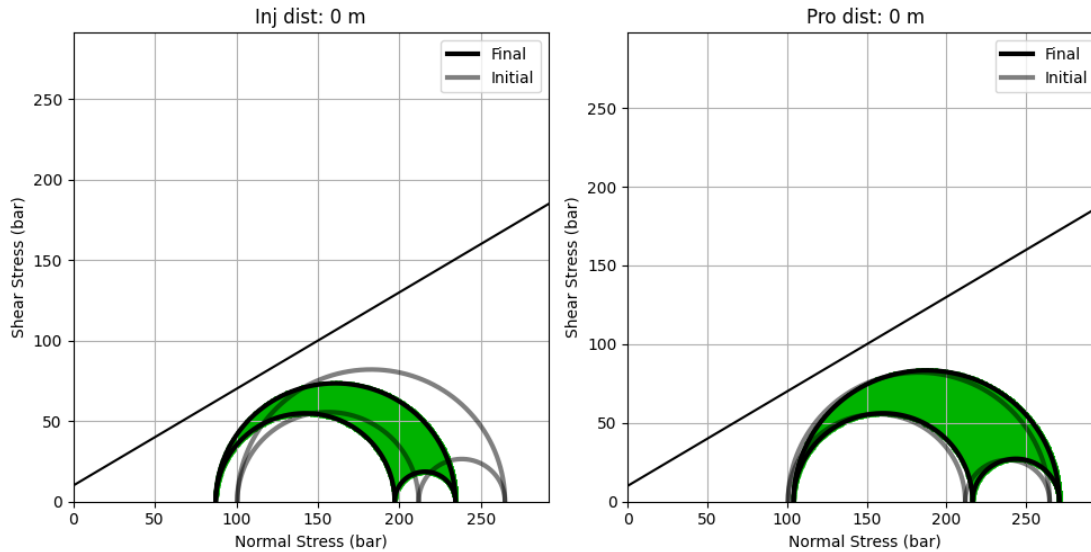


Figure 6-35: Combined thermo-hydro-induced Mohr circle shift for the bottom reservoir at the injection well (left) and production well (right) for the coarse THM model after 30 years.

6.3.2.4 Results laterally discontinuous bottom reservoir case (Coarse Bot Pro)

The laterally discontinuous bottom reservoir scenario from the permeability study presented in Section 4.1 had the largest μ_{max} value of any case tested in the shear fault reactivation study, so could be considered the extreme case of this study. Injection-related pressure increases of nearly 60 bar developed in the bottom reservoir where present and resulted in extensive shear failures predicted in that reservoir. The analysis of the previous section (6.3.1.2) using the geomechanical model of DARTS is repeated here for the Coarse Bot Pro case.

The coarser grid slightly affects the pressure and temperature result of the simulation. The results of laterally discontinuous reservoir simulations are affected by the total volume of the 'compartment' of the reservoir. The semi-open boundaries utilized an extra volume of $1e8 \text{ m}^3$ per side boundary element (x and y sides) for blocks of 100 m (x) x 100 m (y). The Coarse Bot Pro model has edge elements of 300 m (x) x 300 m (y), so a slightly larger volume per element would be required to precisely match the pressure response. Figure 6-36 shows the pressure change profile along the centerline for the original Bot Pro permeability model and the Coarse Bot Pro model from the THM study. The pressure results differ in both reservoirs. The bottom reservoir was the more critical reservoir (higher chance of shear failure) in the fault reactivation study. In the coarser model, the maximum pressure in the bottom reservoir is 69.5 bar and in the finer model, the pressure is 57.6 bar. The temperature results of the models are shown in Figure 6-37 and are similar.

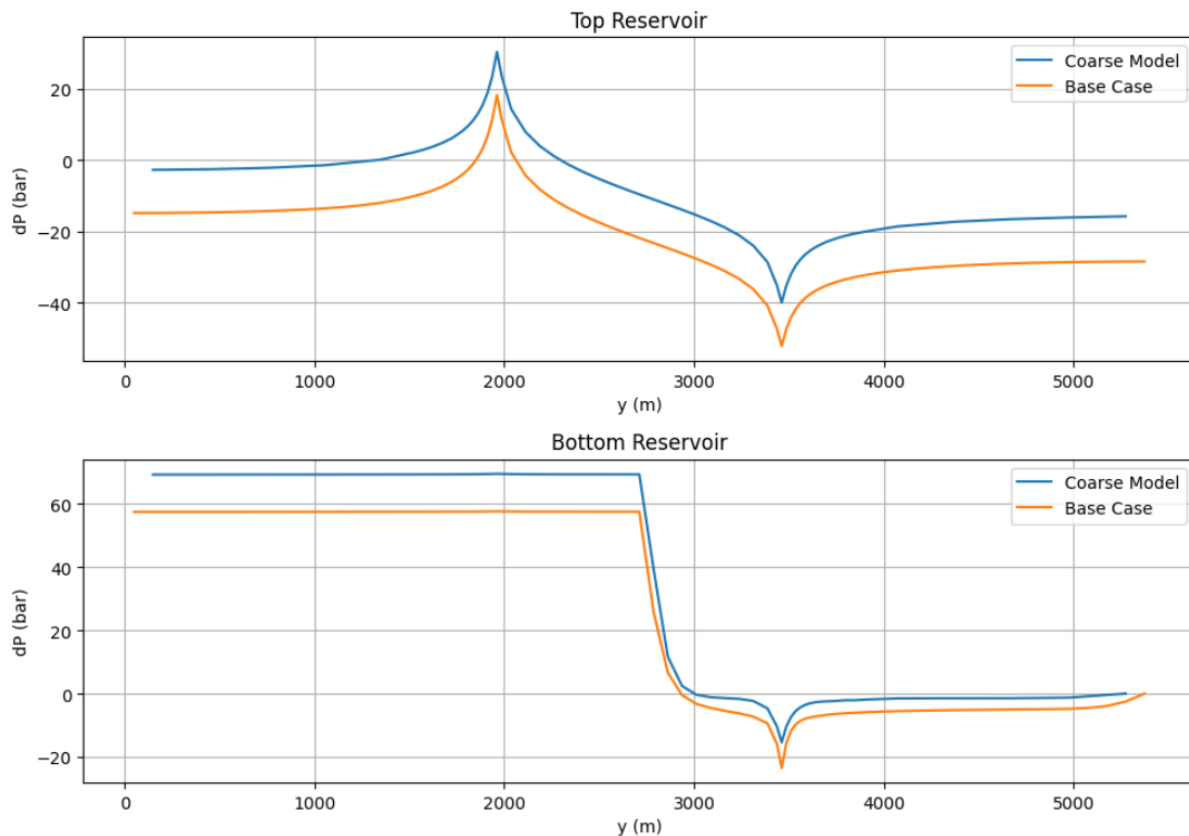


Figure 6-36: Pressure change profiles along centerline comparing the Coarse THM Bot Pro model with the original semi-open Bot Pro permeability model after 30 years.

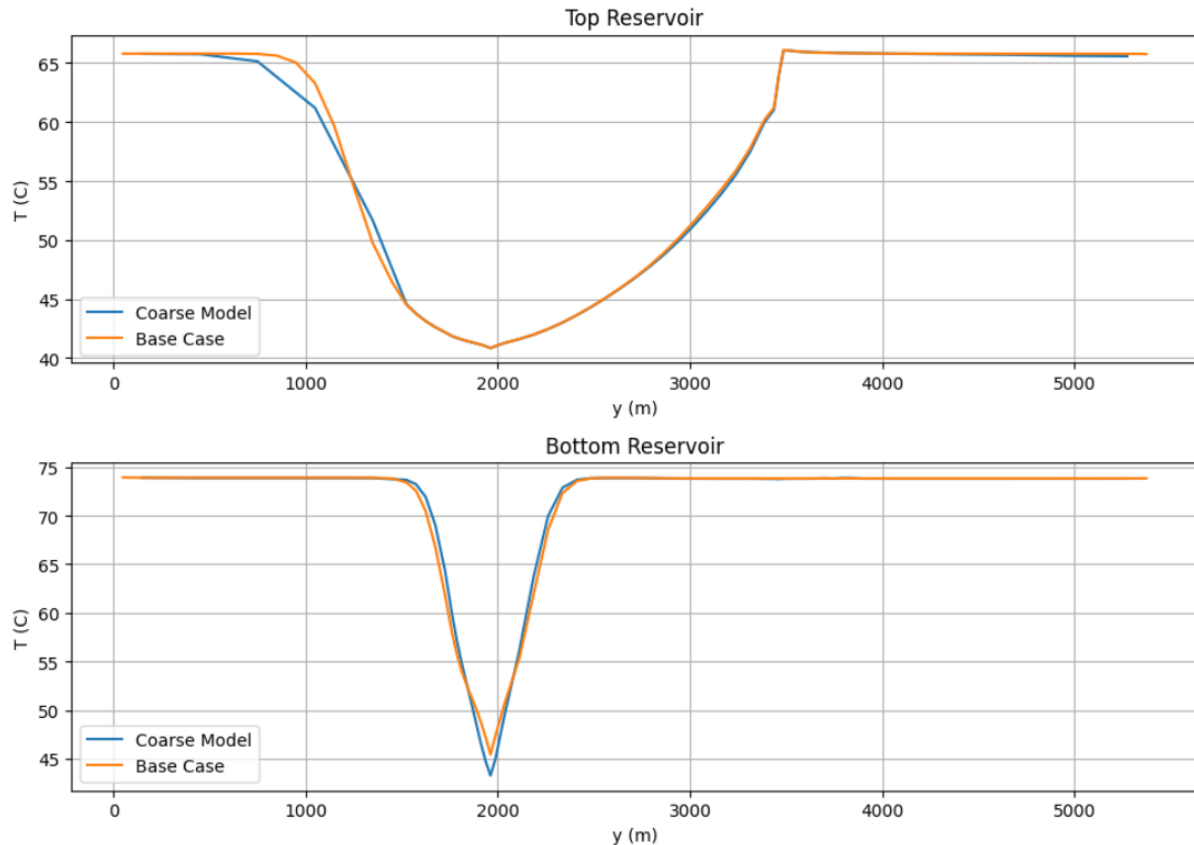


Figure 6-37: Temperature profiles along centerline comparing the Coarser THM Bot Pro model with the original semi-open Bot Pro model after 30 years.

The primary result of the different pressure responses in the models will be a slight shift of the Mohr circle toward the origin in the Coarse THM Bot Pro model simulation compared to the finer original Bot Pro model. Concerning thermal stress, the extent of the cooled region is greater (approximately 1.5 km toward the production well vs ~500 m toward the production well) in the top reservoir vs the bottom reservoir. However, since the injection temperature is fixed at 40°C, there is a larger temperature change in the bottom reservoir (~30°C vs ~25°C). Figure 6-38 shows the Mohr circle results for the top reservoir in the block containing the injection well (left) and production well (right) for the Coarse Bot Pro simulation. Again, similar to above, the shift in the vertical component of the stress tensor toward the origin is the greatest - going from initially $\sigma_V = 233$ bar to $\sigma_V = 209$ bar ($\Delta\sigma = 24$ bar), while the shift in horizontal components is smaller ($\Delta\sigma = 14$ and 13 bar). No shear failures are predicted for the failure envelope with a slope of $\mu = 0.6$ and a cohesion $C = 10$ bar. Even if the cohesion were reduced to zero, the shifted circle still falls slightly inside the failure envelope.

The Mohr circle results for the bottom reservoir are shown in Figure 6-39. The nearly 70 bar pressure change in the reservoir around the injection well shifts the stresses significantly toward the origin ($\Delta\sigma_V = -63$ bar, $\Delta\sigma_H = -25$ bar, $\Delta\sigma_h = -23$ bar). The rest of the shift is due to thermal effects. However, again, the largest $\Delta\sigma$ occurs in the vertical direction, so the radius of the circle also shrinks as it moves toward the origin. The result is, again, no predicted shear failures by the Mohr-Coulomb criterion.

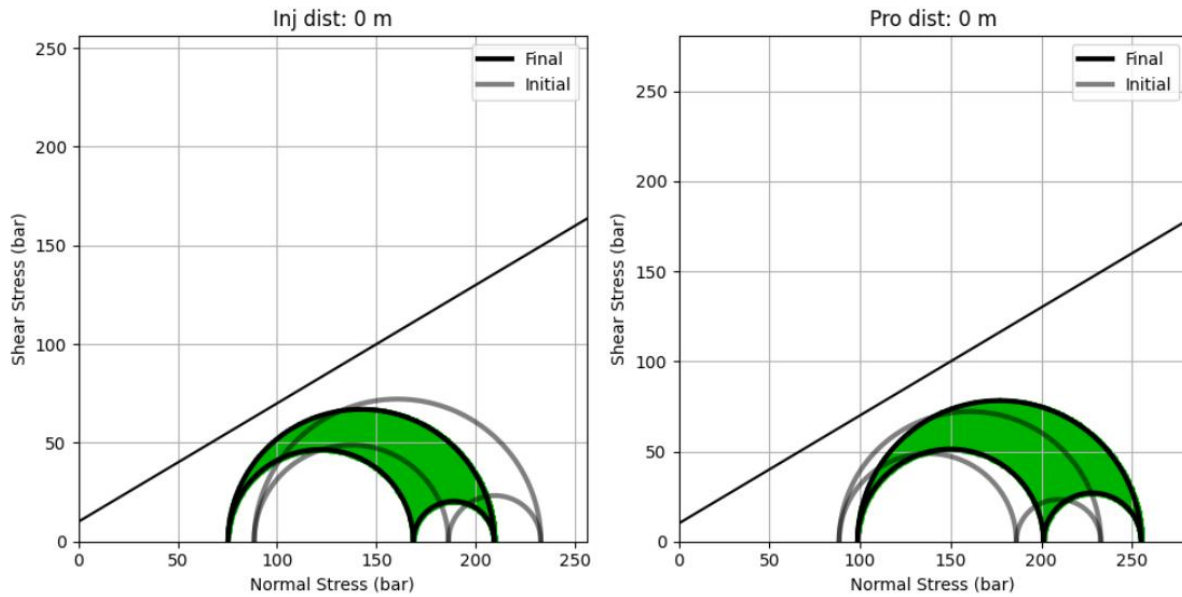


Figure 6-38: Mohr circle results at the injection well (left) and production well (right) for the top reservoir in the Coarse Bot Pro THM simulation after 30 years.

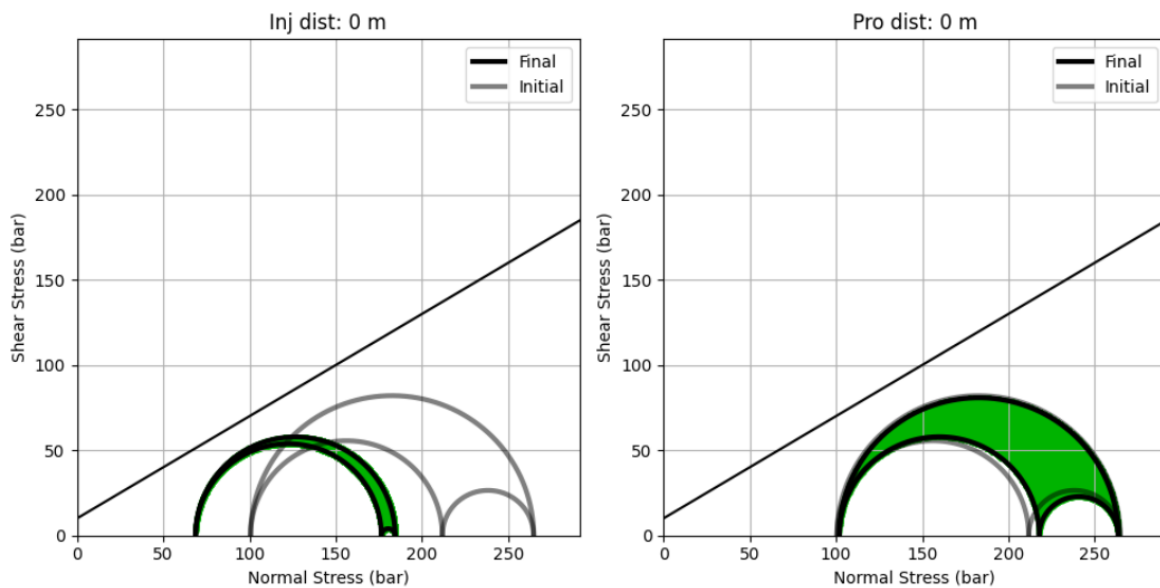


Figure 6-39: Mohr circle results at the injection well (left) and production well (right) for the bottom reservoir in the Coarse Bot Pro THM simulation after 30 years.

6.3.2.5 THM modelling discussion

Neither of the THM models tested here predict shear failure, including the extreme Bot Pro simulation from the permeability study where the bottom reservoir is absent in the production well. This does not necessarily mean that the situation is always safe from induced shear failure. However, this model can help to understand some of the fundamental physics in play and to understand the areas to improve in future models. These results of the THM analysis help to highlight the stabilizing effects of hydrostatic stress changes (pressure or temperature related) in a homogeneous half-space. The vertical component of the stress tensor sees larger magnitude changes whereas changes in the horizontal direction are smaller (due to the presence of a free surface at $z=0$ and the Poisson effect that redistributes stress

anisotropically). This is true even in thermal stress analysis. Additional effects that are not accounted for in these THM models that could result in additional shear failures could include: different initial stress states (especially a strike-slip setting where a horizontal stress is greater than the vertical stress), strong stiffness differences between reservoirs and the associated arching effect (this can cause greater shifts in horizontal stress components or smaller shifts in vertical thermal stress (as in the previous chapter)), inelastic behaviors such as plasticity, or localized stress concentrations/rotations that could occur due to layer thinning/pinching or nearby fault discontinuities. The nucleus of strain approach is well documented and accurate; however, the simplifications of such a mesh-free method do average out many details and may underestimate differential stresses that could be critical to induced shear failure.

6.3.3 Conclusions and comparison between the analytical and THM approach

Two different approaches were utilized to assess the likelihood of fault reactivation. The approaches are both based on a linear elastic solid skeleton assumption. The first approach leveraged a uniaxial reservoir deformation assumption to determine if direct pore pressure or thermal stresses would induce stress change magnitudes large enough to result in shear reactivation. It is a common first order approach to estimate stress changes due to production related temperature and pressure changes in a reservoir. That analysis showed that, for many scenarios (including the Base Case), some shear reactivation on critically oriented structures could be expected.

The second approach utilized the built-in THM capability in the simulator open-DARTS leveraging the semi-analytical nucleus of strain concept. The main advantage of the second approach is that stress transfer (through Poisson effects and poro/thermo-elasticity) are accounted for natively, though the many domain and material assumptions limit the applicability of the technique. The THM model did not predict shear failure in either the Coarse THM model (Base Case properties) or the Coarse Bot Pro model that had the largest likelihood of induced shear failure in the uniaxial stress change analysis (analytical approach).

The combination of the two analyses indicates that the uniaxial direct pore pressure assumption is more conservative and predicts more shear failures at a given production-related temperature and pressure change scenario. That is largely due to the assumption that the vertical component of the thermal stress is unchanged (free deformation vertically). This is true if overburden is very soft or the reservoir is very close to the surface. The THM nucleus of strain approach allows for stress transfer effects and shows that some vertical stress change is possible, even thermal stress. However, details such as varying material stiffness (soft overburden) are also neglected and result in a less conservative analysis.

6.4 Assessment of the impact of unbalanced flow on subsidence and uplift

6.4.1 Analysis procedure

The subsidence analysis followed a semi-analytical procedure. The numerical model results from Chapter 4 were taken as input into the surface displacement calculations by the nucleus of strain concept (Mindlin & Cheng, 1950) to estimate potential elastic deformations at the surface. Specifically, the equation (36) as presented in Geertsma (1973) to represent the pressure-dependent surface motion at a given location as:

$$u_{zp}(r, 0) = \frac{(1 - \nu)}{\pi E} \frac{D}{(r^2 + D^2)^{\frac{3}{2}}} \Delta P * V \quad (36)$$

Where V is the volume of a nucleus, ΔP is the pressure change, $r = \sqrt{x^2 + y^2}$ is the radial distance from the underground nucleus, and D is the depth of the nucleus. We denote the pressure component of the displacement with the subscript P . A decrease in pressure results in downward surface motions (subsidence) whereas an increase in pressure results in upward motion (uplift or tumescence).

The thermal displacements at the free surface were first derived by Sen (1951) (equation 37):

$$u_{zT}(r, 0) = \frac{\alpha(1 + \nu)}{\pi} \frac{D}{(r^2 + D^2)^{\frac{3}{2}}} \Delta T * V \quad (37)$$

where the subscript T is used to indicate thermal displacement, α is again the linear coefficient of thermal expansion, and ΔT is the temperature change. From the equations, one can derive that positive changes in temperature result in expansion of the rock and upward motion, while a decrease in temperature results in contraction and subsequent subsidence. The material parameters of E , ν , and α were taken to be the same as in the section on fault reactivation (Section 6.3).

The main objective of this analysis is to assess if and to what extent reservoir parameter variations may lead to changes in uplift and/or subsidence compared to the Base Case. The above relationships assume that the subsurface volume that affects surface displacements is imbedded in an *elastic semi-infinite half-space*. This is obviously an idealization, so the magnitude of the displacements could be subject to errors. However, these relationships are best viewed as sound first-order estimates of ground surface displacements and can be confidently applied to understand the physical processes at play that can result in surface displacements due to geothermal production/injection. This can help to identify situations where problematic surface displacements can occur compared especially to the Base Case scenario.

6.4.2 Overview of results

The subsidence analysis was applied to each case from Chapter 4 to calculate the surface displacement. The primary result is a contour plot of the surface deformation after 30 years as shown in Figure 6-40. The green center line represents the path for subsidence profile plotting (similarly to the pressure profiles from Chapter 4). An example of the surface displacement profile is shown in Figure 6-41 (top). The total displacement is the cumulative effect of the pressure changes and temperature changes at the surface.

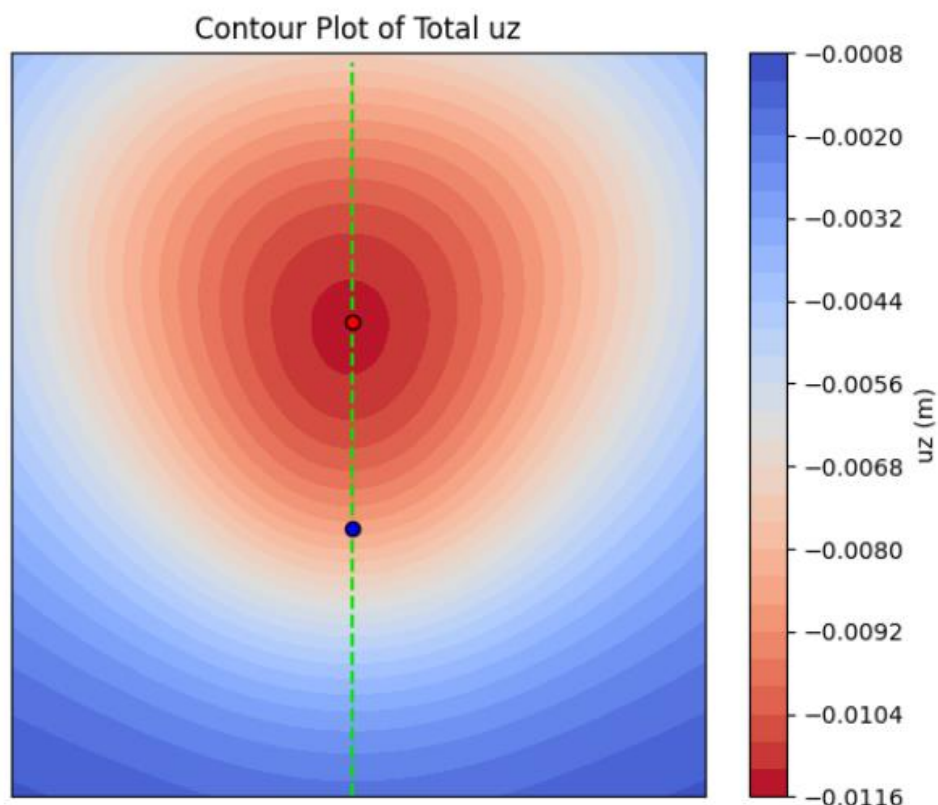


Figure 6-40: Example of a contour plot showing total surface displacement after 30 years, with indication of the position of production (red) and injection (blue) well. The dashed green line shows the position of the surface displacement profile.

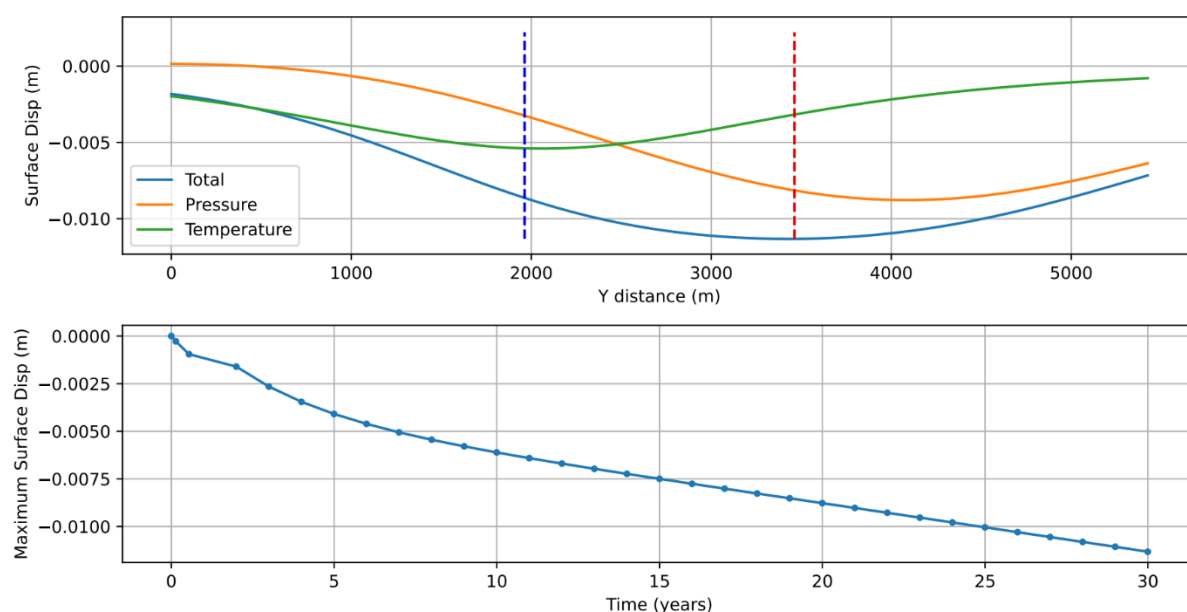


Figure 6-41: Surface displacement profile plots (top) as a result of pressure change, temperature change, and total displacement at the end of the 30-year simulation. The bottom plot shows the maximum subsidence value over time. The vertical dashed lines indicate the position of the production (red) and injection (blue) well.

6.4.3 Permeability variations

It is useful to compare the total surface displacement profiles after 30 years for all the permeability cases together as shown in Figure 6-42. The profiles reveal uplift around the injection well, which is primarily caused by high pressures developing due to the discontinuous reservoir cases. It is worth noticing (as mentioned earlier and shown in Figure 4-8) that those simulations represent extreme cases where the downhole pressure response may exceed the maximum permitted injection pressure. The peak subsidence magnitudes in the worst-case discontinuous layer scenarios can be around 4-8 times greater than those seen in the Base Case.

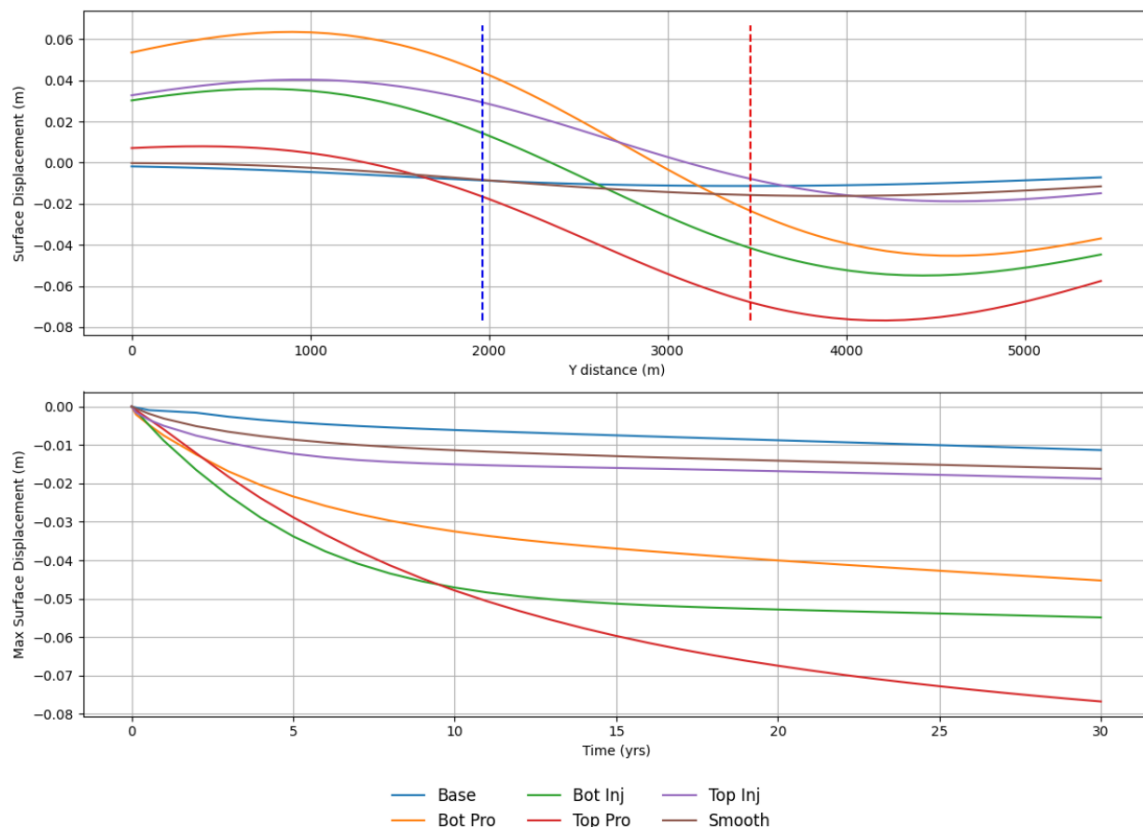


Figure 6-42: Subsidence profiles (top) and maximum subsidence (bottom) for 30 years for the permeability scenarios.

6.4.4 Thickness variations

Figure 6-43 shows the surface displacement profiles and maximum subsidence over time for the variable thickness scenarios. Recall that the extreme cases h0 and h3 represent the Base Case and Bot Pro case (bottom reservoir absent in the production well) from the permeability investigations. The thickness of the bottom reservoir in the other cases is 33.3 m and 16.7 m (h1 and h2, respectively). The initial pressure investigations revealed that having some connectivity between the wells greatly reduced the pressure differences that could build in the reservoirs. This effect can be observed in the predicted surface displacement results as well.

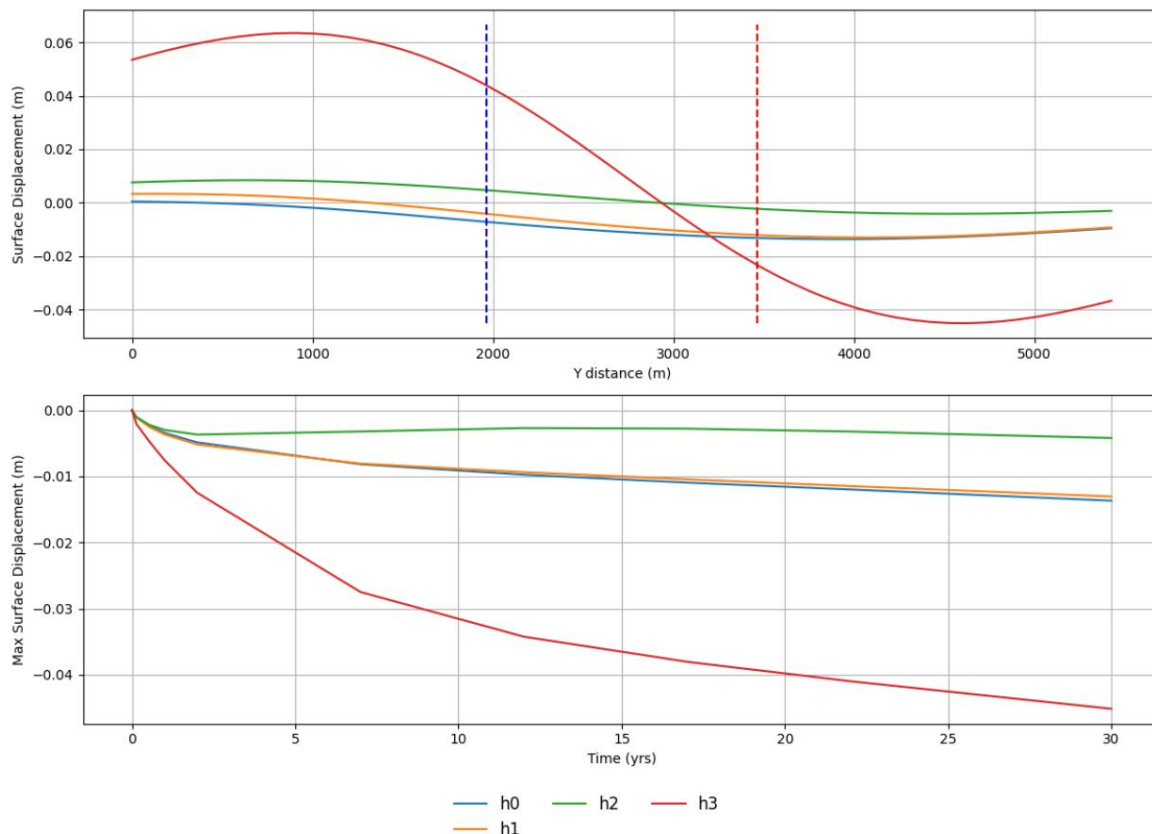


Figure 6-43: Subsidence profiles (top) and maximum subsidence (bottom) for 30 years for the variable thickness scenarios.

One of the observations from the results of the variable thickness simulations is the competition between thermal- and pressure-induced surface displacements. Even though the h2 case (in terms of reservoir thickness) is similar to h3 (16.7 m vs 0 m thickness at production well), the maximum subsidence over time is far smaller. The breakdown of the surface profiles at different times for total, pressure-, and temperature-related displacements are shown in Figure 6-44. Figure 6-45 repeats the reservoir flow balancing plot. The balance in the reservoir flows does not reach an equilibrium until about 15 years of simulation time. Initially, there is more injection in the bottom reservoir, but after a few years, the top reservoir receives more injection. This effect is reflected in both the pressure responses and the thermal-displacement response. The subsidence effect due to pressure peaks after about 2 years, then begins to reduce as injection into the top reservoir serves to increase pressure in that reservoir and limit the subsidence values. However, the additional cooling in the top reservoir results in acceleration of cooling-related subsidence. This scenario is an example demonstrating the ability to mitigate or limit subsidence effects through changes in reservoir flow balancing (the resulting reservoir pressures should of course kept within acceptable limits with regards to other hazards (such as seismicity)).

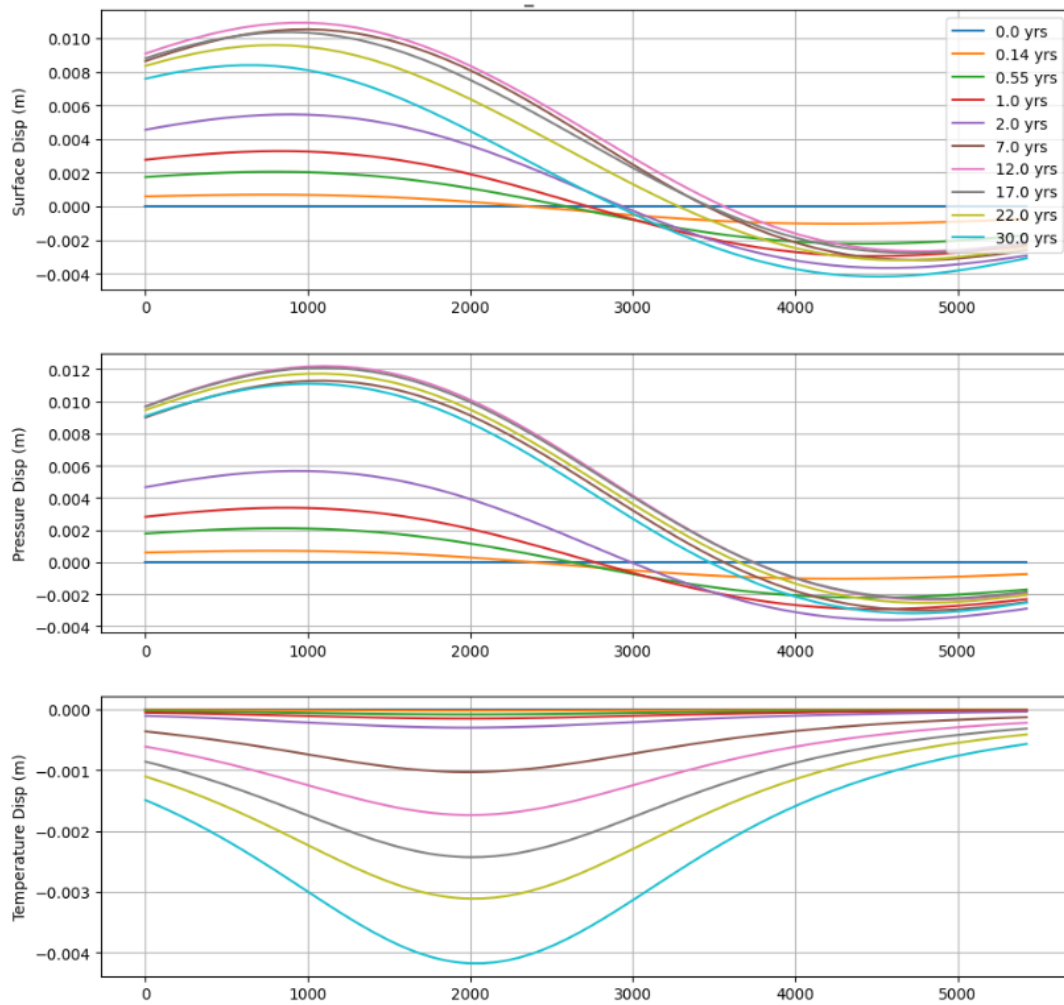


Figure 6-44: Total surface displacements (top), pressure-related displacements (middle), and temperature-related displacements (bottom) profile plots over time for variable thickness case h2.

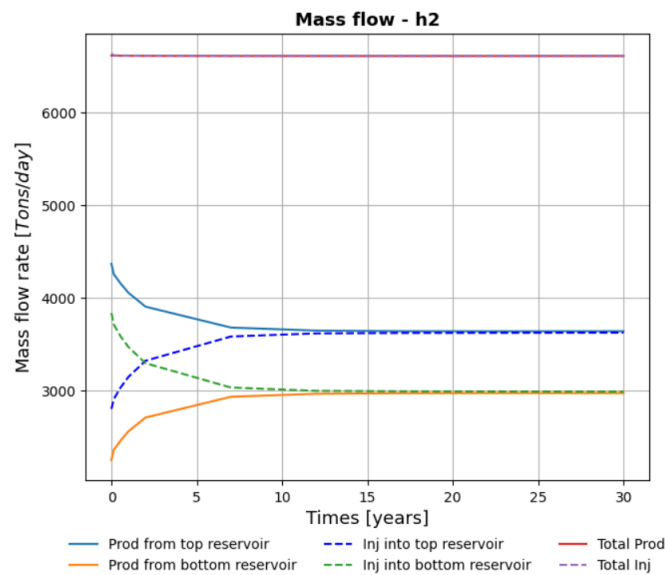


Figure 6-45: Mass flows per reservoir for the variable reservoir thickness scenario h2 (16.7 m thick bottom reservoir near production well).

6.4.5 Compositional model

As in Section 4.3, thermal effects were ignored in the brine mixing simulations. Fluid properties were a function of salinity only. The effects of the mixing of fluids of different salinity (density and viscosity) do have an impact on the surface displacements, but the results indicate that those represent only 2nd order effects. The summary of results for surface displacements is shown in Figure 6-46. The COMP6 model was the Base Case (with thermal effects considered) and highlights the importance of those effects both in fluid properties and in thermal stresses that could cause surface displacements.

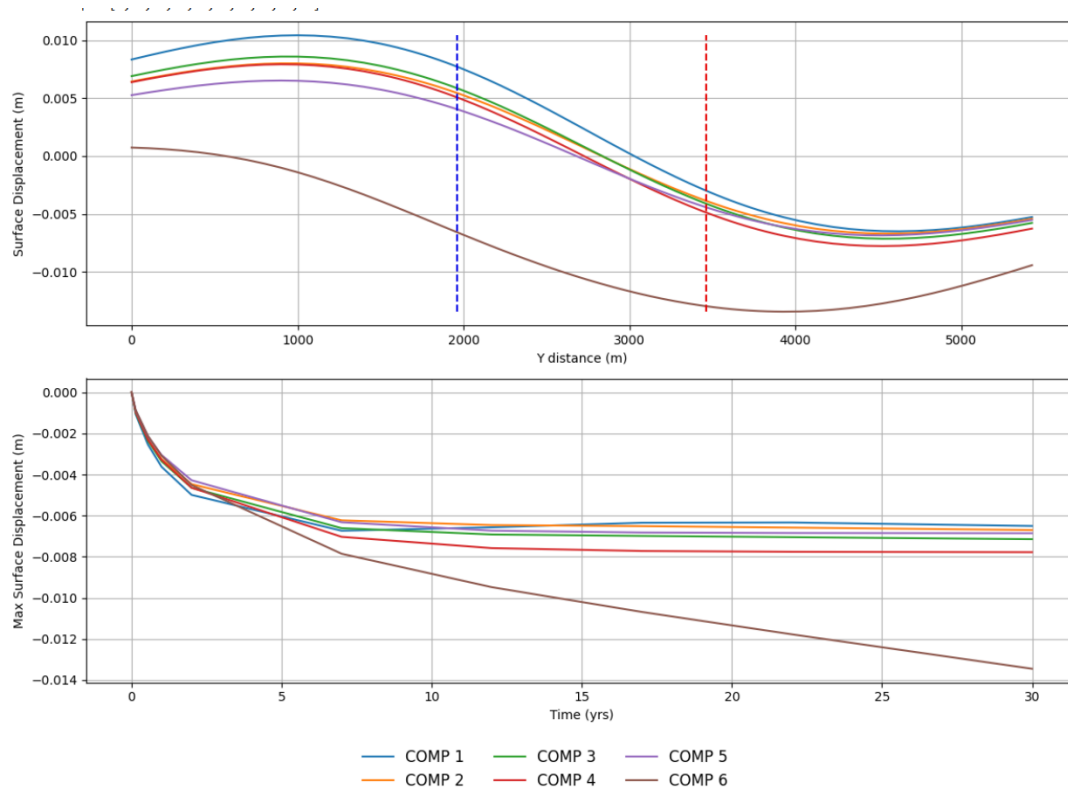


Figure 6-46: Subsidence profiles (top) and maximum subsidence (bottom) for 30 years for the brine mixing scenarios.

6.4.6 Temperature variations

Figure 6-47 displays the surface displacement results for the variable thermal gradient cases. The pressure responses in the simulations were nearly identical, so these plots highlight the difference that more extreme dT scenarios can cause in surface subsidence. The main effect is, indeed, subsidence as additional cooling further contracts the reservoir rock over time and leads to increased subsidence values.

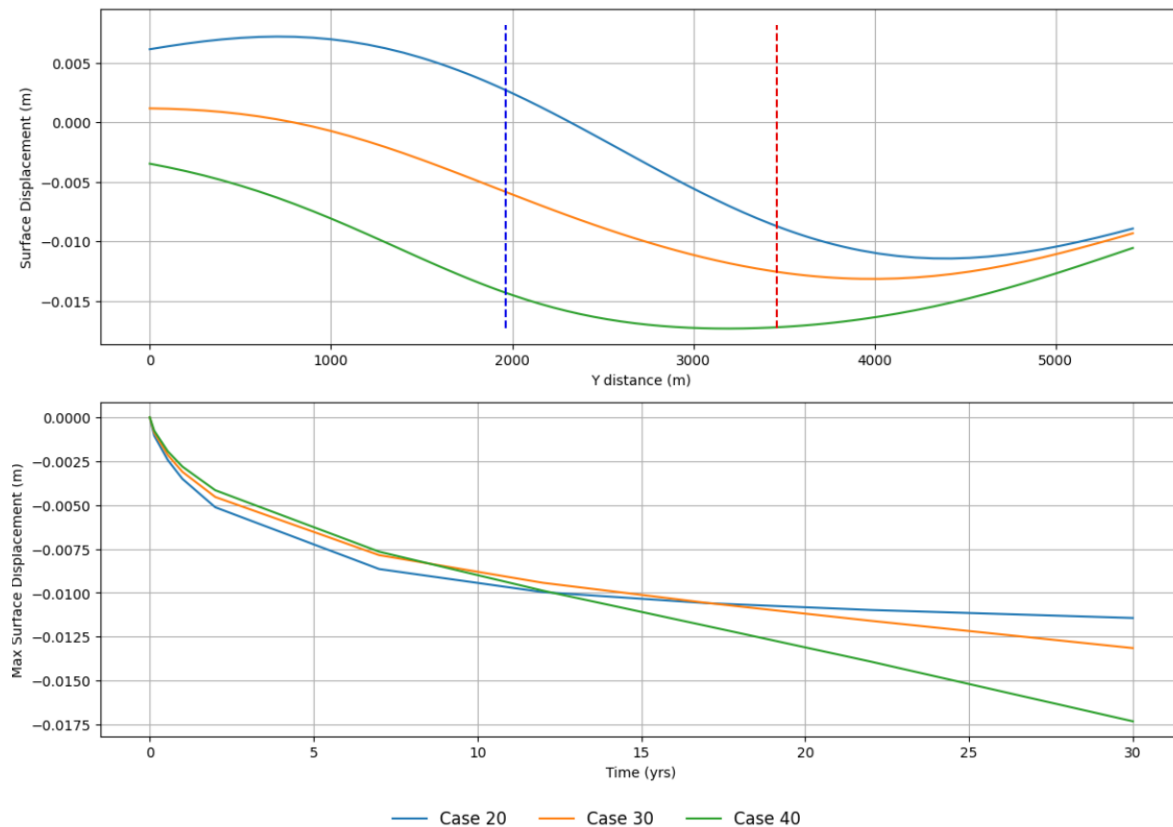


Figure 6-47: Subsidence profiles (top) and maximum subsidence (bottom) for 30 years for the variable temperature scenarios.

6.4.7 Completion investigation

The results of the horizontal completion scenarios for surface displacements are shown in Figure 6-48. In those simulations, the effects of horizontal completion in the bottom reservoir do have an impact on subsidence values, but those results are perhaps muted by the additional depth of the reservoir. That is, the deeper a reservoir is, the less effect that pressure changes in that reservoir have on surface displacement. Simulations presented in Section 4.5 demonstrated that pressure changes could be relatively significant (~10 bar) in the bottom reservoir for the lower permeability case with horizontal completions. The additional cooling resulting from more fluid flow also compounded the stress effects. However, in the subsidence result, the overpressure and cooling have opposite effects. Therefore, the total effect on surface displacement is reduced.

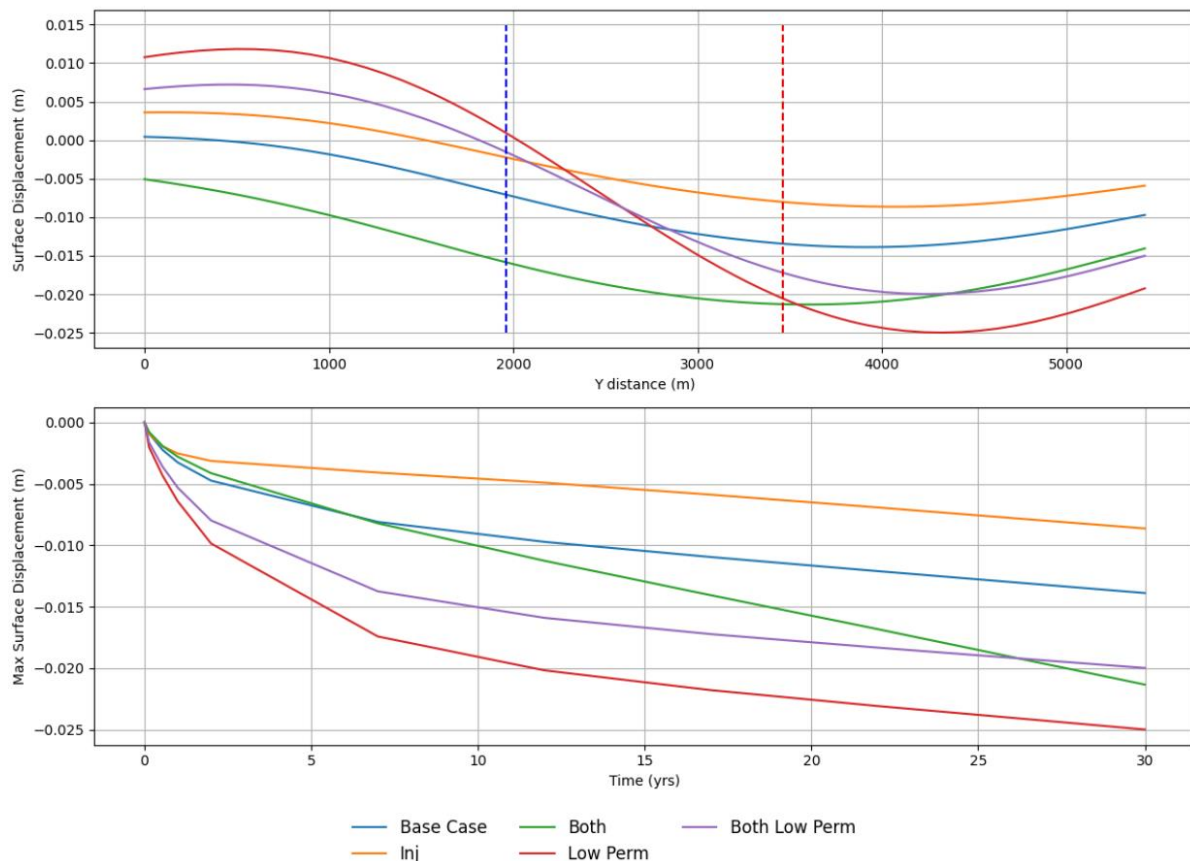


Figure 6-48: Subsidence profiles (top) and maximum subsidence (bottom) for 30 years for the horizontal well completion scenarios.

6.4.8 Skin scenarios

Figure 6-49 shows the surface displacement results for the uniform skin cases, where skin in a well was the same for both reservoir sections (positive or negative). Similar to the results assessing fault reactivation in the previous section, those cases result in very little pressure change in the reservoir and, thus, very little change in surface displacement values.

Figure 6-50 shows the results for the simulations with non-uniform skin (different skin value for different reservoir sections in the same well). The results show three distinct groups. The middle group comprises the Base Case and the two simulation cases with small positive skin values. The top and bottom groups are cases with strong negative skin in opposite reservoirs in opposite wells, i.e., skin in top of production well AND bottom of injection well, or skin in top of injection and bottom of production well. The net effect of those outcomes is very close in the subsidence result. The conclusion is that high values of skin can affect subsidence through flow redistribution and the creation of more extreme pressure changes.

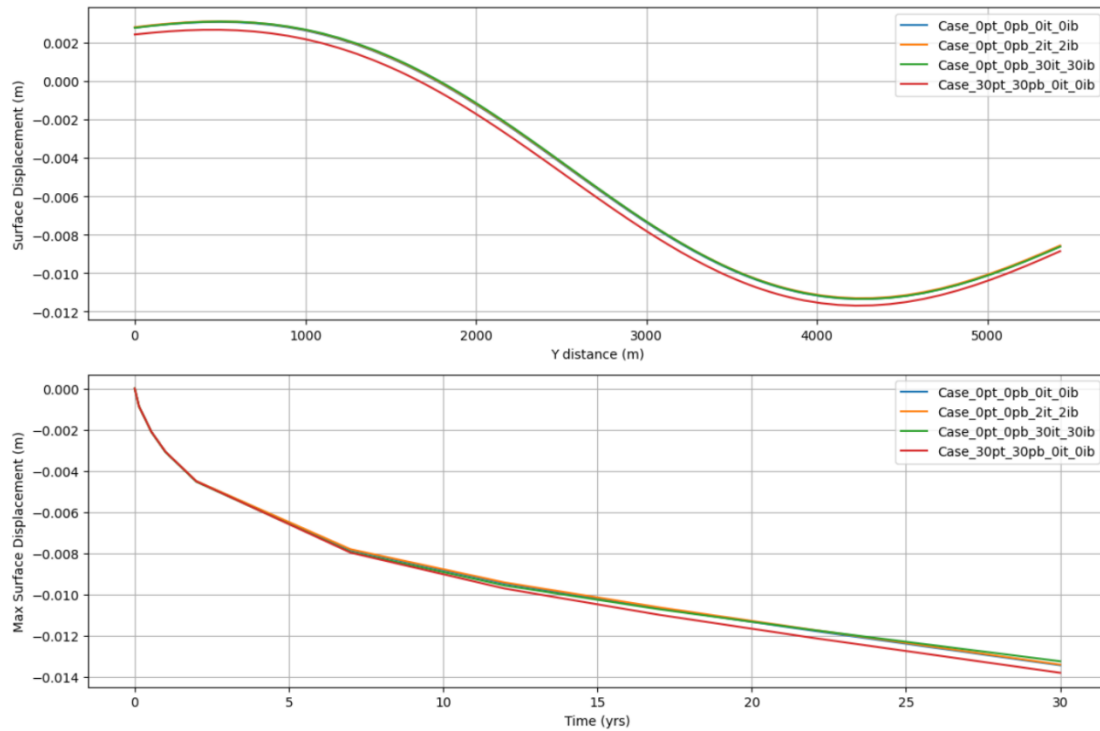


Figure 6-49: Subsidence profiles (top) and maximum subsidence (bottom) for 30 years for the uniform well skin scenarios.

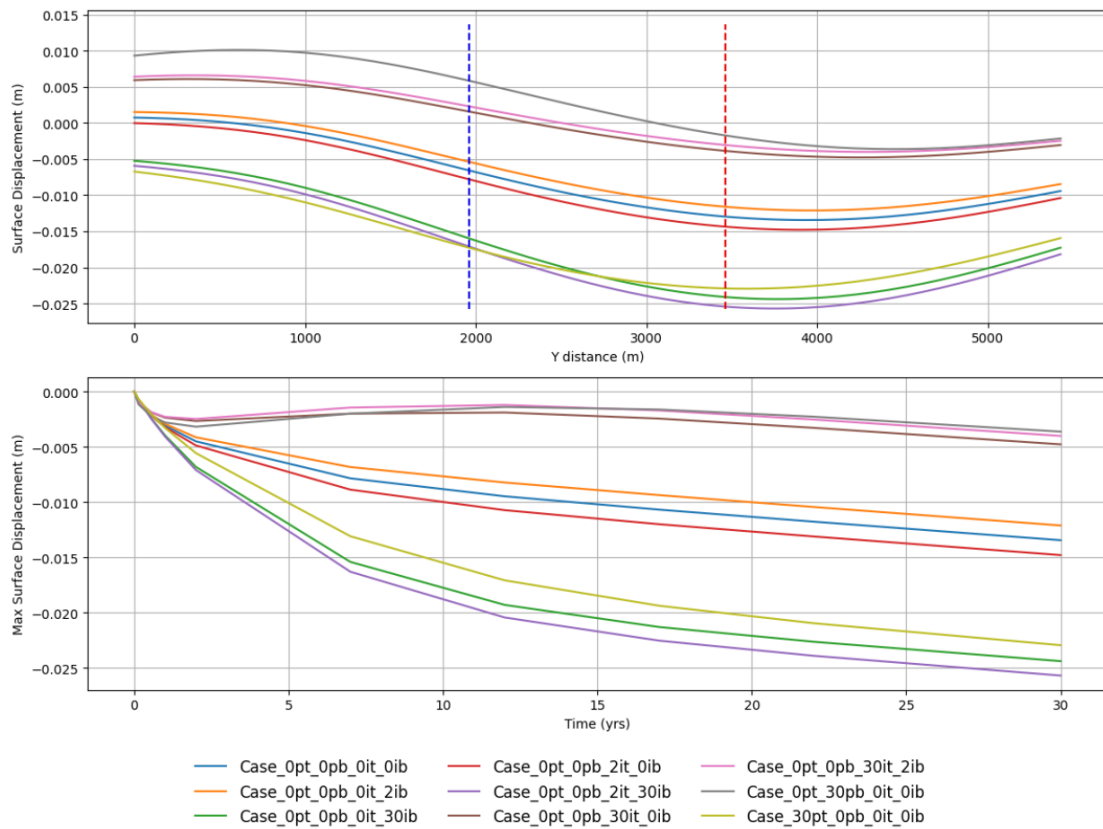


Figure 6-50: Subsidence profiles (top) and maximum subsidence (bottom) for 30 years for the non-uniform well skin scenarios.

6.4.9 Conclusions

The nucleus of strain concept was used to estimate surface displacements due to subsurface temperature and pressure changes. A few conclusions from the results of this section are:

- Flow redistribution can lead to increases in pressure and temperature change after 30 years, compared to the Base Case.
- The cases of extreme flow redistribution lead to the highest values of subsidence and uplift.
- The estimated magnitudes of the surface displacements are on the order of cm in the worst case scenarios.
- Material properties of both the reservoir and immediately overlying rocks should be investigated in cases where the likelihood or impact of subsidence is high.

Table 6-4: Overview of scenarios (and their description) for Section 6.4 and corresponding simulation results indicating maximum uplift and subsidence.

Scenario name	Description	Max subsidence (m)	Max uplift (m)
Base Case	Base case scenario	-0.01388	0.00045
Bot Pro	Laterally discontinuous BOTTOM reservoir in PRODUCTION well	-0.04526	0.06357
Bot Inj	Laterally discontinuous BOTTOM reservoir in INJECTION well	-0.05487	0.03590
Top Pro	Laterally discontinuous TOP reservoir in PRODUCTION well	-0.07673	0.00796
Top Inj	Laterally discontinuous TOP reservoir in INJECTION well	-0.01879	0.04034
Smooth	Smooth permeability variation in bottom reservoir	-0.0162	-0.00019
h0	Uniform reservoir thickness (50 m) in both wells	-0.01367	0.00041
h1	Bottom reservoir 33.3 m thick at production well	-0.01305	0.00329
h2	Bottom reservoir 16.7 m thick at production well	-0.00419	0.0084
h3	Bottom reservoir 0 m thick at production well	-0.04516	0.06352
COMP1	Top reservoir – fresh water; bottom reservoir – 0.02 mol salt	-0.0067	0.00802
COMP2	Top reservoir – fresh water; bottom reservoir – 0.05 mol salt	-0.0065	0.01044
COMP3	Top reservoir - 0.008 mol salt; bottom reservoir – 0.025 mol salt	-0.00714	0.0086
COMP4	Top reservoir – 0.016 mol salt; bottom reservoir – 0.016 mol salt	-0.00778	0.00793
COMP5	Fresh water both reservoirs	-0.00686	0.00653
COMP6	Base Case	-0.01345	0.00074
Case 20	Thermal gradient 20°C/km	-0.01143	0.00720
Case 30	Thermal gradient 30°C/km	-0.01315	0.00117
Case 40	Thermal gradient 40°C/km	-0.01732	-0.00347
Inj	Horizontal completion in Injection well	-0.00864	0.00362
Both	Horizontal completion in both wells	-0.02133	-0.00507
Low Perm	Lower permeability bottom reservoir (NO horizontals)	-0.02498	0.01183
Both Low Perm	Lower permeability bottom reservoir (BOTH wells with horizontal completion)	-0.01998	0.00722
Case_0pt_0pb_0it_0ib	Base Case scenario with 0 skin for all reservoirs	-0.01345	0.00074
Case_0pt_0pb_2it_2ib	Scenario with 0 skin in the production well, and a skin of 2 in the injection well	-0.01342	0.00075
Case_0pt_0pb_30it_30ib	Scenario with 0 skin in the production well, and a skin of 30 in the injection well	-0.01326	0.00089

Case_30pt_30pb_0it_0ib	Scenario with a skin of 30 in the production well, and 0 skin in the injection well	-0.01382	0.00039
Case_0pt_0pb_0it_2ib	Scenario with 0 skin in the production well, 0 skin at the top reservoir in the injection well, and a skin of 2 in the bottom reservoir in the injection well	-0.01212	0.0015
Case_0pt_0pb_0it_30ib	Scenario with 0 skin in the production well, 0 skin at the top reservoir in the injection well, and a skin of 2 in the bottom reservoir in the injection well	-0.0244	-0.00525
Case_0pt_0pb_2it_0ib	Scenario with 0 skin in the production well, a skin of 2 at the top reservoir in the injection well, and 0 skin in the bottom reservoir in the injection well	-0.0148	0
Case_0pt_0pb_2it_30ib	Scenario with 0 skin in the production well, a skin of 2 at the top reservoir in the injection well, and a skin of 30 in the bottom reservoir in the injection well	-0.0257	-0.00594
Case_0pt_0pb_30it_0ib	Scenario with 0 skin in the production well, a skin of 30 at the top reservoir in the injection well, and 0 skin in the bottom reservoir in the injection well	-0.00478	0.00607
Case_0pt_0pb_30it_2ib	Scenario with 0 skin in the production well, a skin of 30 at the top reservoir in the injection well, and a skin of 2 in the bottom reservoir in the injection well	-0.00402	0.00658
Case_0pt_30pb_0it_0ib	Scenario with 0 skin at the top reservoir in the production well, a skin of 30 at the bottom reservoir in the production well, and with 0 skin in the injection well	-0.00363	0.0101
Case_30pt_0pb_0it_0ib	Scenario with a skin of 30 at the top reservoir in the production well, 0 skin at the bottom reservoir in the production well, and with 0 skin in the injection well	-0.02295	-0.00674

6.5 Assessment of the impact of unbalanced flow on operations

6.5.1 Assessment of well integrity

Well integrity is the practice of ensuring a well is designed, constructed, and operated in such a way to prevent uncontrolled release of reservoir fluid beyond the primary well barrier envelope. The well integrity concerns the wellhead components and the casings above the production liner shoe (Figure 6-51). The reservoir completions are therefore not considered part of the well integrity workflow.

The main issues on well integrity for operational geothermal systems are related to: (i) corrosion, (ii) burst and collapse, and (iii) erosion. The effects of commingled production on well integrity seem to be not distinctly different from single reservoir systems. Based on this study as well as operational experience, no new corrosion drivers due to commingling of different aquifer fluids in geothermal systems typical for the Netherlands (low-enthalpy, matrix-permeable, clastic, sedimentary systems at depth of approximately 1500–3000 m) were identified (Section 4.7). If the well engineering is done properly, the material selection will be based on the most aggressive fluid, considering fluid chemistry and temperature. Microbiological Induced Corrosion (MIC) potential is also not considered to differ in commingled operations, unless very shallow oxygen-rich waters are mixed, which we do not consider part of this study. Nonetheless, the lower sections of the well where lower turbulence flow is expected are considered more sensitive to MIC.

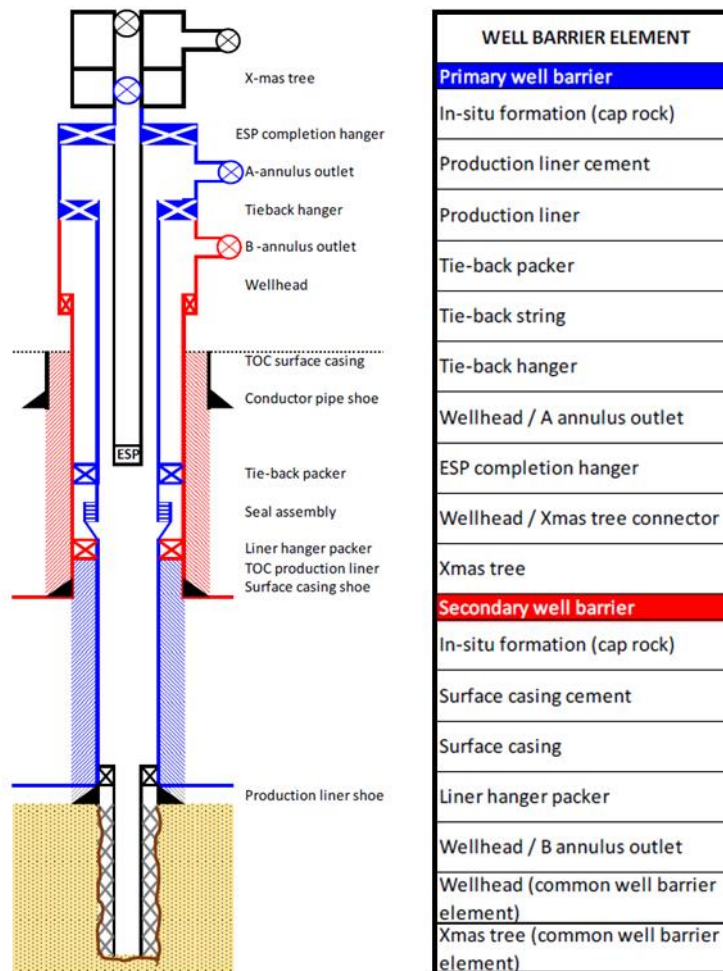


Figure 6-51: Well barrier schematics after Geothermie Nederland (2021)

For burst and collapse well integrity envelopes, the wall thickness is normally designed for the heaviest load case. For the production well, the casing collapse strengths are based on a worst-case pressure drawdown as internal pressure across the production well with a maximum hydrostatic external pressure. For the injector, the casing burst strengths are based on the maximum allowable injection pressure and a minimum hydrostatic pressure gradient. These load cases for commingled reservoirs are not different from the load cases of a single reservoir, however it might be possible that the maximum injection pressure window, casing wall thickness or maximum drawdown provides flow capacity limits for a multiple reservoir production plan versus a single reservoir production plan and this needs to be considered by the production and well engineering as part of the detailed well design.

In summary, based on this study and operational experience, no direct impact of commingled production (e.g., crossflow) is expected on well integrity, as these processes occur below the primary well barrier envelope. Provided that well design, material selection, and load-case assessments are properly engineered for the maximum operating conditions, commingled operations shall not introduce additional hazards compared to single-reservoir systems.

6.5.2 Assessment of the impact on productivity and injectivity

In commingled geothermal systems, if reservoirs are hydraulically connected, crossflow may occur, which ultimately may lead to fluid mixing. For the considered commingled system in the Netherlands, crossflow via the reservoir is not expected, given the presence of a shale layer (e.g., the Rodenrijs Claystone) preventing hydraulic connection between the Berkel and Delft Sandstone members. Nonetheless, based on operational experience, crossflow is expected to occur within the wellbore section during stand-still periods as a result of unbalanced flow within a commingled production system (Figure 6-52).

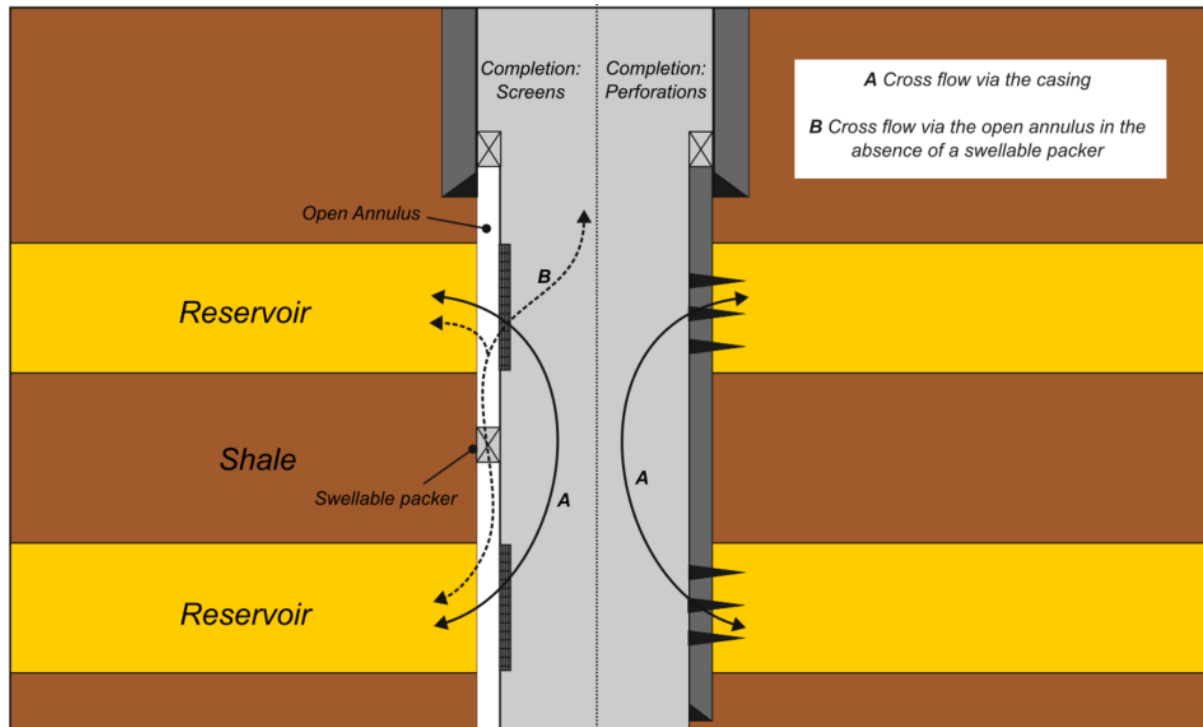


Figure 6-52: Completion designs in geothermal wells potential inter-wellbore cross flow types. Note the shale in between the two reservoirs is assumed to be fully impermeable.

Geochemical modeling of brine interactions in Dutch geothermal systems (Section 4.7) shows that fluid circulation can lead to degassing and minor, negligible pH changes, occasionally causing precipitation of carbonates or sulphides. For the Berkel and Delft Sandstone brines, limited deposition of Al-phases or clay minerals cannot be excluded, particularly where cooled brine re-enters the reservoir. However, even when mixing occurs with more acidic and saline formations (e.g., the Triassic Buntsandstein), the overall scaling tendency does not significantly change (Section 4.7).

Thermal and chemical contrasts between fluids (*i.e.*, differences in temperature, salinity, and oxygen content) also influence fluid properties such as viscosity and density, thereby affecting flow distribution between zones (Sections 4.3, 4.4, 4.7). Cooler injection fluids are denser and more viscous, requiring higher pressures to maintain flow rates, which may concentrate flow in warmer, lower-viscosity reservoirs and accelerate thermal breakthrough in more permeable intervals (Section 4.4). Similarly, high-salinity fluids increase density and promote gravitational segregation, potentially enhancing crossflow between zones of differing pressure or elevation (Sections 4.3, 4.7). These effects, however, are marginal (in the order of a few percent) and, in practice, remain within the operational limits of the system.

In summary, crossflow in commingled geothermal systems as a result of unbalanced flow can influence injectivity and productivity by redistributing flow between reservoirs and promoting chemical or physical processes such as scaling, corrosion, erosion, or skin development. However, geochemical simulations indicate that even when mixing brines of differing compositions (e.g., varying pH) (Sections 4.3, 4.7), the overall scaling tendency remains largely unchanged compared to brines of similar composition. Similarly, thermal or salinity contrasts between the fluid could affect flow preferred reservoirs, but, in reality, this effect is marginal (Sections 4.3, 4.4, 4.7).

6.6 Conclusions on the impact of unbalanced flow

6.6.1 Lower operational limit

The lower operational limit defines the threshold below which further pressure depletion may cause the reservoir to underperform (*i.e.*, requiring higher drawdowns to sustain production) and may increase the likelihood of triggering geomechanical hazards, such as surface subsidence and fault reactivation (Sections 6.2, 6.3, 6.4).

Within this project, subsidence effects have been evaluated as a result of geothermal production using a semi-analytical workflow (see Section 6.4), where the subsidence effect has been quantified based on modelled vertical displacements at the surface. Overall, the modelling results demonstrate that geothermal operations induce changes in reservoir pressure and temperature within the producing intervals. As a consequence of continuous production, the reservoir experiences some degree of compaction due to depletion. However, this effect is minor, with cumulative surface displacements around 1 cm over 30 years for the Base-Case scenarios (Section 6.4.9). Theoretical scenarios, representing pressure responses that would likely fall outside of the (no longer used) 0.135 bar/m operational guideline (SSM, 2020) on the upper side or are significantly over the maximum drawdown of the ESP (> 60 bar) on the lower side, are also tested (Section 6.3). Even in these theoretical cases, the resulting peak subsidence magnitudes were only 4–8 times higher than in the Base-Case, corresponding to a total subsidence of <8 centimeters (Section 6.3).

The effect of unbalanced flow between reservoirs is also investigated. Subsidence appears to be mitigated when flow distribution between reservoirs is better balanced, provided that reservoir pressure remains within acceptable limits for other hazards (*e.g.*, fault reactivation) (Section 6.3). Injection temperature is found to influence subsidence through thermal contraction (Section 6.4.6). Rock cooling due to cold-water injection increases compaction over time; however, enhanced subsidence becomes noticeable only when the temperature difference between in situ reservoir temperature and injection fluid temperature (ΔT) exceeds $\sim 40^{\circ}\text{C}$ (max. 1.75 cm after 30 years). For smaller temperature differences, thermal effects on subsidence remain limited.

Similarly, well skin effects are found to have a comparable impact on pressure and subsidence (Section 6.4.6). When variable skin factors are applied to individual wells within each reservoir, higher skin values promote stronger local pressure gradients, leading to greater but still limited subsidence through flow redistribution (max. 1.4 cm after 30 years).

Extreme reservoir depletion (> 150 bar) could, in theory, lead to higher subsidence rates and potential fault reactivation. The Groningen gas field in the northern Netherlands serves as an illustrative example: decades of gas production caused reservoir depletion, likely eventually resulting in compaction and surface subsidence of over 40 cm, and ultimately induced seismicity, which persists despite the cessation of production (NAM, 2021). However, this is not the case in the current typical Dutch geothermal systems, given that the produced fluid is

(almost) entirely reinjected, ensuring mass-balance and, importantly, reservoir depletion is limited by the maximum drawdown of the ESP (< 60 bar). Therefore, in practice, only marginal depletion is expected in the worst-case scenario.

Simulations conducted within the context of this study (Section 6.4) indicate that even under the most extreme, theoretical geothermal production scenarios (e.g., discontinuous reservoirs) where the associated pressure decline would be over the maximum drawdown of the ESP (> 60 bar), subsidence after 30 years remains limited to only a few centimeters (maximum of ~ 7 cm). Furthermore, the geomechanical analysis (Section 6.3) indicates that no fault reactivation near the production wells is expected under any tested scenario. However, this analysis did not include depletion-related reactivation as maximum pressure drawdowns in the geothermal scenarios tested here are less (10-50 bar) than those reported in Groningen for traditional depletion related activation are > 150 bar (Xin et al., 2025).

Although simplified, the results of this study suggest that, at the conditions applied in the models, that after 30 years subsidence is limited to maximum 3 cm in scenarios within the effective operational window and < 8 cm for the theoretical cases (Section 6.4). While it is difficult to define an exact lower pressure boundary for safe operations based solely on this study, the findings indicate that typical pressure drops expected during geothermal operation (i.e., limited by maximum drawdown of the ESP, < 60 bar) are unlikely to pose significant geomechanical changes that can lead to significant geohazard potential (Sections 6.3, 6.4). In geothermal systems, where production and injection largely maintain mass balance and/or pressure drop is limited to the maximum drawdown of the ESP (< 60 bar), reservoir depletion is typically not a major concern; therefore, the upper operational limit often becomes the more critical boundary to control.

6.6.2 Upper operational limit

The upper boundary of the operational window defines the pressure threshold beyond which further pressure increase may increase the likelihood of inducing fault reactivation or compromising the seal integrity of the reservoir system. This limit is generally more relevant for the injection well, as the injected fluid volume and temperature are the main drivers of the resulting pressure field.

In terms of pressure, in practice, the upper operational limit is strongly governed by the maximum allowable injection pressure (as specified in the project permit in the Netherlands). In the Netherlands, the State Supervision of Mines (SSM) has established a guideline limit for the maximum wellhead pressure at the top of the reservoir, based on a stress gradient of 0.135 bar/m. This value corresponds to an estimate of the minimum horizontal stress in the sealing formations and serves as a conservative constraint to prevent seal breaching, thus potential vertical fluid migration. This gradient applies when the temperature difference (ΔT) between the injected and the reservoir fluids is $\leq 40^\circ\text{C}$. However, at the time of writing, this holistic approach is being replaced by a more refined, geology-dependent, and location-specific method that would allow for partial fracturing in the sealing layer (SSM, 2025). For example, in the case where the reservoirs are highly permeable, the upper limit of the operational window can possibly be increased as higher injection rates, with similar injection pressure, can be accommodated within the reservoirs (Figure 6-2). For discussion purposes, we will assume here a simplified maximum injection gradient of 0.135 bar/m, which follows from the (now disused) protocol for the calculation of injection pressures by SSM (2020).

Numerical simulations presented in Chapter 3 indicate that, under Base Case conditions with balanced production and injection in both reservoirs, the pressure increase near the injector remains below 20 bar. Pressure peaks at the wellbore and drops rapidly as lateral distance to the well increases, such that shear failure of critically stressed faults is not expected beyond

~200 m from the well (Section 6.3.1). Over a 30-year operational period, fault reactivation is only observed in scenarios when faults are critically oriented and close to failure under the initial stress field (Section 6.3). This indicates that when injection occurs within approximately 200 m of a fault (or less), the upper operational limit should be adjusted towards the hydrostatic gradient to reduce the likelihood of fault reactivation after 30 years.

The simulations also reveal that discontinuous reservoirs with limited hydraulic connectivity on the production side are most likely to experience shear reactivation (Section 6.3.3). This condition can also apply to single-layer reservoirs. The shear reactivation potential is further increased by unbalanced flow between reservoirs, where over-injection into one reservoir can potentially lead to faster-than-expected cold front propagation and localized overpressures, while operating within the operational window. This condition may occur when there are strong contrasts in permeability or skin between the two reservoir intervals (Sections 6.3.2 and 6.3.3).

Thermal effects also play a role in the upper operational limit: cooling of the formation induces thermoelastic contraction, which can modify the local stress field around the injector, increasing the likelihood of shear failure (Section 6.3.2.3). The magnitude of this effect depends on the thermal and elastic properties of the rock (Section 6.3.1.5) and the difference between the formation and injection temperature. The largest difference in temperature tested in this work was about 50°C which, for the material parameters used, was enough to induce cooling-related shear failure in critically oriented fractures near the well. Cooling effects may be more pronounced when horizontal completions are used, as they typically deliver a higher volume of colder fluid to the formation over a larger contact area (Section 6.3.1.6).

7 DEFINITION OF MITIGATION AND PREVENTION MEASURES FOR MINIMIZING HAZARDS

7.1 Introduction

Both the lower and upper operational limits define the pressure range within which geothermal production and injection can occur without increasing the likelihood of inducing adverse mechanical or hydraulic responses. The lower limit is constrained by the potential for reservoir depletion, which may ultimately lead to subsidence and, in extreme cases, fault reactivation, while the upper limit is controlled by the likelihood of overpressurization, seal integrity loss, and fault slip due to injection-induced stress changes. However, in reality, as the lower operational limit is effectively strongly controlled by the maximum drawdown of the ESP (in the order of 60 bar), significant reservoir depletion is constrained (Section 6.4). Similarly, as the upper operational limit is effectively governed by the maximum permitted injection pressure in practice, overpressurization and seal integrity loss as a result of commingled production are also typically constrained (Section 6.4).

However, even when operating within the effective operational window, there are events that could occur due to unbalanced flow in commingled geothermal systems that could increase the likelihood of triggering geohazards: (i) *faster-than-expected cold front propagation*, or (ii) *accelerated reservoir depletion* in one of the reservoirs. Nevertheless, except for the theoretical cases (i.e., scenarios where the pressure drop is larger than the maximum drawdown pressure of the ESP or where the injection pressure is larger than the maximum permitted injection pressure), across the realistic scenarios (i.e. scenarios operating within the actual, effective operating window) evaluated by this study, the results remain well within safe operational margins (Sections 6.3, 6.4, 6.5).

With respect to the lower operational limit, the predicted subsidence for both the realistic and theoretical scenarios is minor, particularly when compared to subsidence associated with hydrocarbon production (e.g., Groningen gas field) (Section 6.4). Therefore, based on scenarios evaluated in this study, the effect of *accelerated reservoir depletion* as a result of unbalanced flow in commingled production systems that operate within the (effective) operational window is marginal. Based on these results and noting that significant reservoir depletion is constrained by the maximum drawdown of the ESP, no adjustment to the (effective) lower operational limit is currently warranted. However, depletion-induced seismicity has not been explicitly assessed within this study and cannot be fully captured through a Mohr–Coulomb approach. Such mechanisms could, in principle, reduce the effective operational window, warranting continued monitoring and conservative operation near depletion conditions.

Conversely, the upper operational limit is more sensitive to reservoir conditions and operational behavior. Although fault reactivation is limited under Base Case conditions (Section 6.3.1), the limit may need to be constrained toward the hydrostatic gradient in cases of unbalanced flow. This may occur within the effective operational window when the produced volume from multiple isolated reservoirs is reinjected primarily into a single reservoir due to poor connectivity, lower permeability, or skin effects, resulting in *faster-than-expected cold front propagation*.

The impact of unbalanced flow on operations, however, seems to be marginal (Section 6.5). No direct impact of commingled production (e.g., crossflow) is expected on well integrity, as these processes occur below the primary well barrier envelope. Provided that well design, material selection, and load-case assessments are properly engineered for the maximum operating conditions, commingled operations shall not introduce additional hazards compared

to single-reservoir systems. Furthermore, crossflow in commingled geothermal systems as a result of unbalanced flow can influence injectivity and productivity by redistributing flow between reservoirs and promoting chemical or physical processes such as scaling, corrosion, erosion, or skin development. However, geochemical simulations indicate that even when mixing brines of differing compositions (e.g., varying pH) (Sections 4.3, 4.7), the overall scaling tendency remains largely unchanged compared to brines of similar composition. Similarly, thermal or salinity contrasts between the fluid could affect flow preferred reservoirs, but, in reality, this effect is marginal (Sections 4.3, 4.4, 4.7). Nevertheless, Section 7.2 presents different well design and operational strategies to mitigate increasing the likelihood of unwanted geomechanical responses as a result of unbalanced flow in a commingled production system while staying within the effective operational window.

In Section 7.3 the event of *faster-than-expected cold front propagation* as a result of unbalanced flow in the commingled production system while staying within the effective operational window is addressed in a bow-tie analysis for fault reactivation and induced seismicity. In Section 7.4 *accelerated reservoir depletion* as a result of unbalanced flow in the commingled production system while staying within the effective operational window is addressed in a bow-tie analysis for subsidence.

7.2 Well design and operational mitigation strategies

In cases where strong reservoir heterogeneities are present within one or both reservoirs, and significant pressure contrasts are anticipated within each reservoir (e.g., due to limited hydraulic connectivity), maintaining partial hydraulic communication between reservoirs can be beneficial (i.e., hydraulic communication via the wells), as it promotes pressure equilibration and reduces stress concentration at layer interfaces. Crossflow in commingled geothermal systems can influence injectivity and productivity by redistributing flow between reservoirs and promoting chemical or physical processes such as scaling, corrosion, erosion, or skin development. Completion design should account for potential erosion due to crossflow, for instance through the use of cement or swellable packers to isolate reservoir zones (Figure 6-52). While crossflow can aid in pressure equilibration, over time it may lead to uneven injectivity and a gradual decline in system productivity. Furthermore, additional completion controls could be employed in the well design to manage flow distribution and maintain wellbore integrity/stability. Potential mitigation strategies include:

- Installation of swellable packers to restrict undesired crossflow through the annulus between the blind liner and open borehole in the section between the different reservoirs completed by e.g., slotted liner or wire wrap screen.
- Cemented casing sections at selected intervals (e.g., across impermeable layers) to achieve localized zonal isolation with selective perforated production zones.

The choice of completion strategy should be guided by location-specific reservoir characterization and field data.

Subsequently, after the well is drilled and completed, Production Logging Tools (PLT) and fiber-optic monitoring systems, such as Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) can be deployed to track flow behavior along the wellbore and assess the contribution of each reservoir interval, and guide potential follow-up interventions if required.

To monitor injectivity and productivity behavior, Operators should actively manage injection temperature and flow rate, as well as more in general brine composition. Continuous monitoring enables early detection of compatibility issues or performance decline, allowing for adaptive adjustments to the operational strategy.

In cases involving large differences ($\Delta T > 40^\circ\text{C}$) between production and injection temperature, thermal cooling effects may significantly alter the local stress state near the injector. Under such conditions, additional mitigation is required, as thermal contraction may increase the likelihood of fracturing or fault reactivation. Similarly, if the injector is located near a known or suspected fault zone, a site-specific geomechanical assessment and mitigation plan should be developed prior to starting up operations. Based on the assessment an adjustment of the operational parameters to decrease likelihood of unwanted geomechanical response can be achieved either by lowering the injection flow rate (and hence the injection pressure, or the cooled area of the fault plane after 30 years) or, if thermoelastic effects are significant, by reducing the temperature difference (ΔT) between the injected and reservoir fluids (Section 6.3) to ensure staying within the operating window. In extreme scenarios where the injection rate cannot match the production rate due to the maximum injection pressure, adding an additional injection well may be considered.

7.3 Bow-tie analysis for fault-reactivation and induced seismicity

The central event identified in this bow-tie is relatively *faster-than-expected propagation of the cold front* within one of the reservoirs while operating a commingled production system within effective operational window (Figure 7-1). The propagation is assumed to be relatively faster than modeled for the permit application (e.g., Seismic Hazard and Risk Analysis or SHRA).

Threats

Three primary threats are identified as potential precursors to relatively faster-than-expected cold-front propagation in one of the reservoirs:

- Well clogging or flow obstruction (Section 4.6), reducing effective injectivity and altering the pressure distribution in one of the reservoirs leading to relatively faster-than-expected propagation of the coldfront in the other reservoir.
- Large permeability contrast between the reservoirs (Section 4.1), which can concentrate injection flow in the most permeable reservoir and accelerate the cooling front relative to the modeled forecast.
- Thin or absent reservoir in the injector interval (Section 4.2), which can localize fluid entry into one of the reservoirs and induce faster-than-expected propagation of the coldfront.

This process may potentially lead to localized stress redistribution and thermal contraction within the reservoirs, potentially triggering reactivation of a nearby fault and, in extreme cases, leading to felt seismic events at surface within 30 years of production (Section 6.3). Although this phenomenon is not unique to commingled systems, the presence of multiple reservoirs with variable permeability can influence the rate, and spatial extent and geometry of thermal propagation within one of the reservoirs.

Prevention Barriers

A range of preventive measures can mitigate these threats before the event occurs:

- Installation of screens to minimize well clogging and maintain uniform flow distribution.
- Installation of sleeves to ensure even reservoir flow distribution.
- Well workovers (chemical or mechanical stimulation) to restore injectivity and balance flow between reservoirs.
- Flow rate adjustment based on SHRA outcomes to maintain stable pressure evolution in the reservoir by adjusting the operational window.
- Drilling of additional injector(s) to distribute injection volumes and prevent excessive local cooling.
- Deployment of production monitoring tools to monitor reservoir behavior in real time.

These preventive measures can be deployed during the operational phase, however, the installation of screens and/or sleeves should be considered in the design phase. An overall production philosophy that considers these different prevention barriers should be addressed early in the development phase.

Mitigation Measures

If faster-than-expected cold front propagation does occur, several mitigation strategies can be applied to reduce the likelihood or impact of induced seismicity:

- Reduce injection rate to relieve pressure buildup and thermal stress on the fault.
- Decrease the temperature contrast (ΔT) between injected and in situ reservoir fluids to limit thermal contraction effects.
- Perform an SHRA and implement a traffic light system (TLS) for operational decision-making.
- Deploy real-time continuous seismic monitoring to detect early signs of microseismic activity and adjust operations proactively.
- Evacuate or restrict access in case of elevated seismic risk to ensure public safety. In the unlikely scenario of a foreseen seismic event, enhance structural resilience at the surface through building reinforcement and emergency planning where applicable.

Consequence

If not properly mitigated, faster-than-expected cold front propagation in one reservoir as a result of unbalanced flow in a commingled production system operating within the effective operational window may increase the likelihood of inducing felt seismic events caused by fault slip triggered by thermally induced stress changes after 30 years of production (Section 6.3). While the results of the evaluated scenarios indicate that fault reactivation is limited under normal operational conditions (*i.e.*, when operating within the effective operational window) (Section 6.3), continuous monitoring and adaptive management remain essential to ensure safe long-term operation.

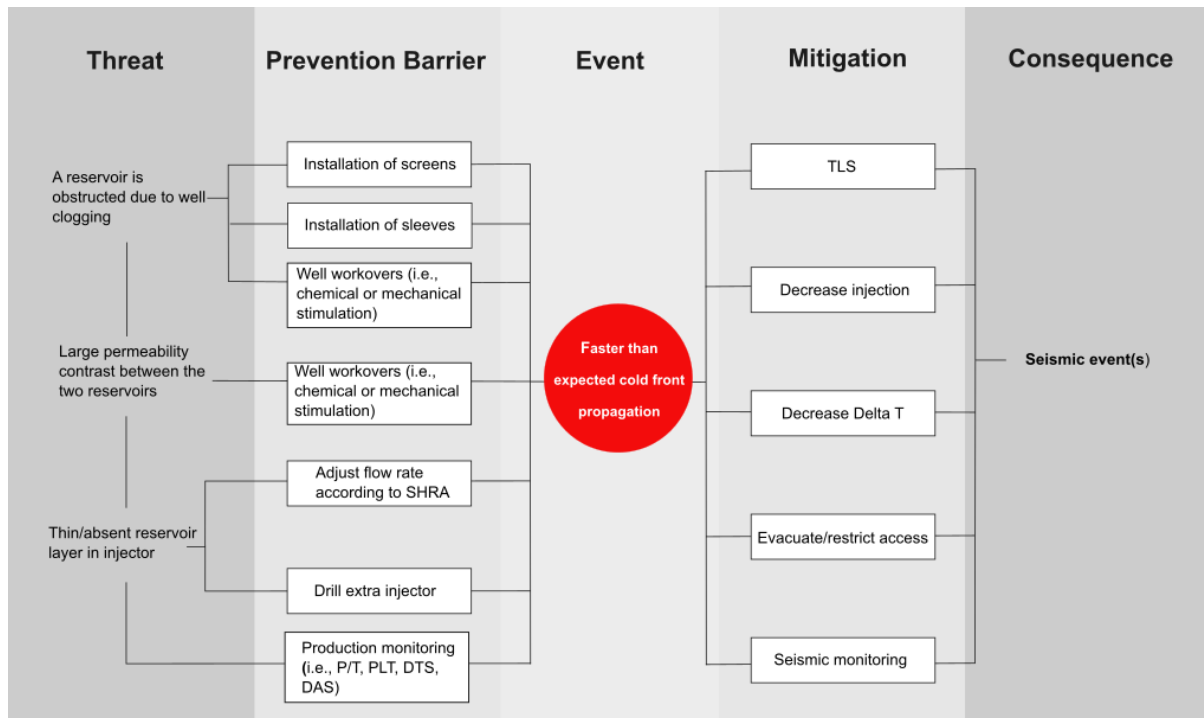


Figure 7-1: Bow-tie for fault reactivation and induced seismicity.

7.4 Bow-tie analysis for subsidence

The central event considered in this analysis is *accelerated reservoir depletion* of one of the reservoirs, which can occur when pressure decline progresses unevenly within the reservoirs due to production and injection imbalance in a commingled production system while operating within the effective operational window (Figure 7-2). In commingled systems, this may result from restricted flow in one of the reservoirs due to large permeability contrasts and/or absence of both reservoirs at the producer due to lateral facies variation. Accelerated depletion leads to reservoir compaction, which, in turn, can potentially cause surface subsidence.

Threats

Three main threats are identified as precursors to accelerated depletion:

- Flow zone obstruction (Section 4.6), due to well clogging, which can reduce the effective production or injection area and cause localized pressure drops in one of the reservoirs.
- Large permeability contrast (Section 4.1), between reservoirs, leading to disproportionate fluid withdrawal and uneven pressure depletion between the reservoirs.
- Thin or absent productive reservoir (Section 4.2), at the producer, concentrating production in limited intervals and increasing drawdown in the other reservoir.

Prevention Barriers

Preventive measures focus on maintaining stable reservoir pressure distribution and avoiding localized depletion. Key barriers include:

- Installation of screens to prevent clogging and maintain even flow distribution.
- Well workovers (chemical or mechanical stimulation) to restore flow capacity and minimize differential depletion.
- Flow-rate adjustment based on SHRA to keep pressure drawdown within the operational window.
- Drilling of an additional producer to redistribute extraction and reduce localized stress on individual wells.

Together, these measures aim to preserve hydraulic balance between the two reservoirs and mitigate excessive compaction. These preventive measures can be deployed during the operational phase, however, the installation of screens and/or sleeves should be considered in the design phase. An overall production philosophy that considers these different prevention barriers should be addressed early in the development phase.

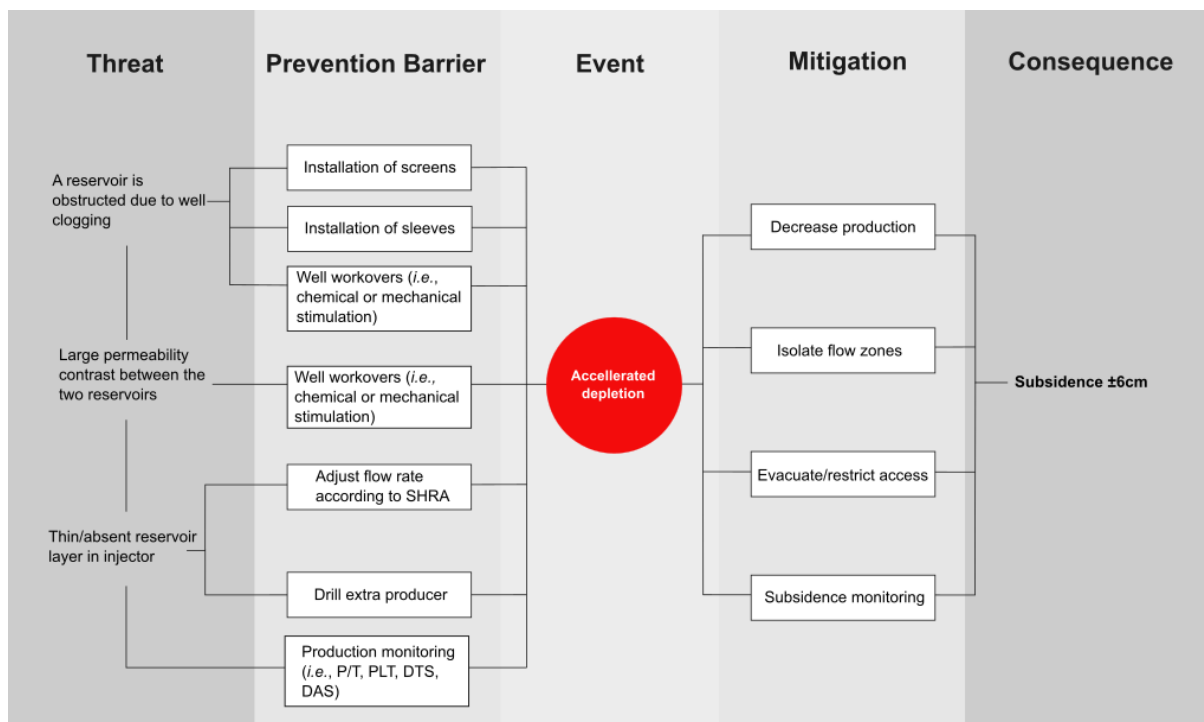


Figure 7-2: Bow-tie for subsidence.

Mitigation Measures

If accelerated depletion and compaction do occur in one of the reservoirs, several mitigation strategies can limit the resulting surface effects:

- Reduce production temporarily to allow reservoir pressure to stabilize.
- Isolate specific flow zones within a reservoir showing excessive depletion to restore pressure equilibrium.

- Relocate or restrict access in localized zones at the surface that experience higher subsidence rates as a precautionary measure. In the unlikely scenario of a subsidence higher than 6-7 cm, enhance structural resilience at the surface through building reinforcement and emergency planning where applicable.
- Implement continuous subsidence monitoring (e.g., InSAR, GNSS-stations) to track ground movement trends and inform adaptive management.

Consequence

If left unmitigated, accelerated reservoir depletion can lead to surface subsidence, typically within a few centimeters (± 6 cm) over long-term operational (~ 30 years) periods (Section 6.4). While such deformation is minor compared to cases like the Groningen gas field, continuous monitoring and adaptive control remain essential to ensure safe and sustainable geothermal operation.

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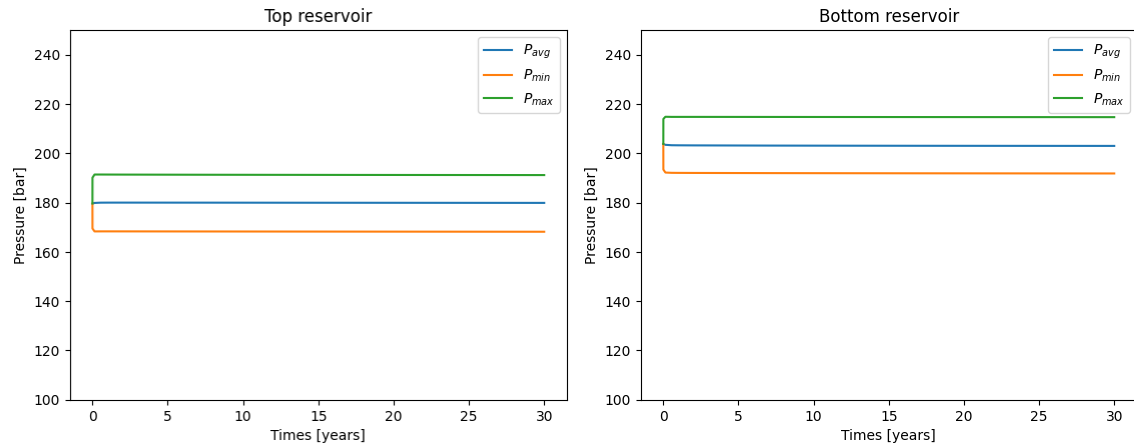
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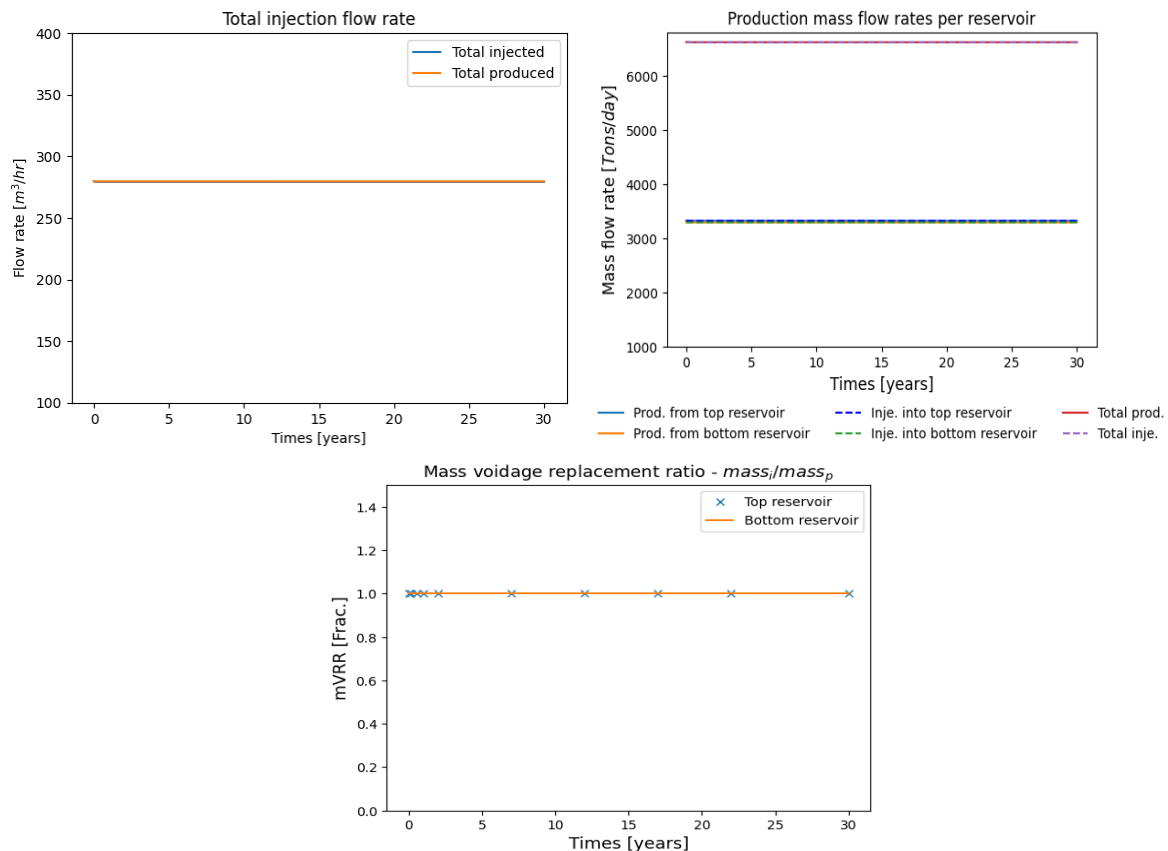
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ANNEX A: ADDITIONAL RESULTS FOR THE BASE CASE

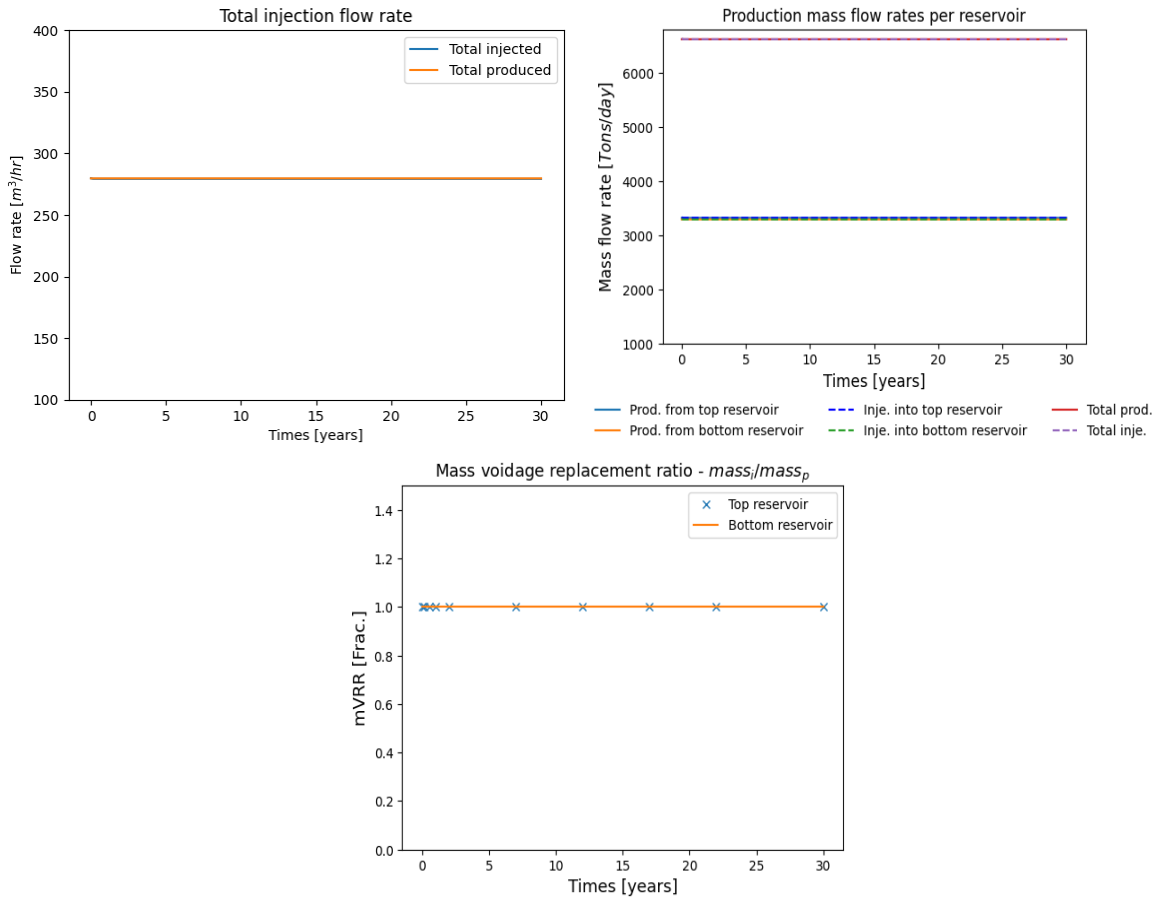
A.1 Minimum, maximum and average pressure for bottom and top reservoir when injection temperature (69.5 °C) is similar to reservoir's temperature. – Closed-system. The plots show that when the injected water has the same temperature that produced water there is not pressure reduction due to replacement of hot water by colder and denser water.



A.2 Homogeneous case - Closed system: Volume flow rate (upper-left), mass flow rates (upper-right) and mass voidage replacement ratio (bottom) when reservoir layers have the same properties as the bottom reservoir as well as the same temperature. Mass voidage replacement ratio is equal to 'one' both in early and late times.



A.3 Homogeneous case – Semi-open system: Volume flow rate (upper-left), mass flow rates (upper-right) and mass voidage replacement ratio (bottom) when reservoir layers have the same properties that the bottom reservoir in the base case as well as the same temperature. Mass voidage replacement ratio is equal to ‘one’ both in early and late times.



ANNEX B: INPUT DATA FOR CHEMICAL MODELLING

Berkel+Delft (LSL-GT-01)

Dissolved solids

Parameter		Concentration	Unit	Remark
pH		5.97		Measured on surface sample
HCO ₃ ⁻		170.	mg/l	
CO ₃ ²⁻	<	2.5	mg/l	
Cl ⁻		60000.	mg/l	
SO ₄ ²⁻	<	1.7	mg/l	
Al ³⁺		350.	µg/l	
Ba ²⁺		27000.	µg/l	
Ca ²⁺		420.	mg/l	
K ⁺		280.	mg/l	
Mg ²⁺		770.	mg/l	
Na ⁺		34000.	mg/l	
Sr ²⁺		300.	mg/l	
FeT		33.	mg/l	
density		1.0727	Kg/m ³	Measured on surface sample

Gasses

Parameter	Concentration	Unit	Remark
GWR	0.9894	Nm ³ /m ³	
density	0.791	kg/Nm ³	
gas content	0.730	kg/kg brine	At 1bar, 15°C
opening pressure	128.79	bar	Start pressure of degassing
opening temperature	22.6	°C	
final pressure	1.	bar	Final pressure of degassing
H ₂	0.000	mol%	
H ₂ S	0.000	mol%	
CO ₂	3.871	mol%	
N ₂	1.933	mol%	
CH ₄	92.858	mol%	
C ₂ H ₆	0.981	mol%	
C ₂ ⁺	0.357	mol%	

Buntsandstein (BRI-GT-01)

Dissolved solids

Parameter		Concentration	Unit	Remark
pH		6.01 - 6.05		Measured on surface sample
HCO ₃ ⁻		8.12	mg/l	
CO ₃ ²⁻	<	10.	mg/l	
Cl ⁻		78000.	mg/l	
SO ₄ ²⁻		330.	mg/l	
Al ³⁺	<	500.	µg/l	
Ba ²⁺		4200.	µg/l	
Ca ²⁺		5900.	mg/l	
K ⁺		630.	mg/l	
Mg ²⁺		900.	mg/l	
Na ⁺		43000.	mg/l	
Sr ²⁺		356.	mg/l	
FeT		76.	mg/l	
density		1.087 - 1.082		Density of flashed water @15°C

Gasses

Parameter		Concentration	Unit	Remark
GWR		1.0748	Nm ³ /m ³	
density		0.806	kg/Nm ³	
gas content		0.799	kg/kg brine	At 1bar, 15°C
sampling pressure		250.5	bar	
sampling temperature		83	°C	
opening pressure		162 – 175	bar	Start pressure of degassing
opening temperature		24	°C	
pressure		1.	bar	Final pressure of degassing
H ₂		0.000	mol%	
H ₂ S		0.000	mol%	
CO ₂		3.871	mol%	
N ₂		1.933	mol%	
CH ₄		92.858	mol%	
C ₂ H ₆		0.981	mol%	
C ₂ ⁺		0.357	mol%	

Rotligend (Slochteren) (AMS-01)

Dissolved solids

Parameter		Concentration	Unit	Remark
pH		5.47		Measured on bh 1.01 at 20°C
HCO ₃ ⁻		84.	mg/l	
CO ₃ ²⁻	<	1.5	mg/l	
Cl ⁻		110000.	mg/l	

Annex B: Input data for chemical modelling

SO42-	<	1300.	mg/l	
Al3+	<	100.	µg/l	
Ba2+		27000.	µg/l	
Ca2+		4600.	mg/l	
K+		450.	mg/l	
Mg2+		690.	mg/l	
Na+		59000.	mg/l	
Sr2+		130.	mg/l	
FeT		50.	mg/l	
density		1.1217	g/cm3	Measured on bh 1.01 at 15°C and 1bar

Gasses

Parameter	Concentration	Unit	Remark
GWR	0.442	Nm3/m3	
density	0.884	kg/Nm3	
gas content	0.348	kg/kg brine	At 1bar, 15°C
opening pressure	269.17	bar	Start pressure of degassing
opening temperature	20	°C	
pressure	1.52	bar	Final pressure of degassing
H2	0.000	mol%	
H2S	0.000	mol%	
CO2	3.918	mol%	
N2	4.210	mol%	
CH4	86.792	mol%	
C2H6	1.328	mol%	
C2+	3.752	mol%	

ANNEX C: OVERVIEW OF MODELED SCENARIOS

Scenario name	Description	Chapter
Base Case – closed	Base Case scenario with closed boundaries	3.4 Commingled production response considering properties of the base case
Base Case – semi-open	Base Case scenario with semi-open boundaries (volume of boundary cells set to 1e8 m ³)	3.4 Commingled production response considering properties of the base case
Bot Pro	Laterally discontinuous bottom reservoir in production well	4.1 Impact of permeability variation between producer and injector
Bot Inj	Laterally discontinuous bottom reservoir in injection well	4.1 Impact of permeability variation between producer and injector
Top Pro	Laterally discontinuous top reservoir in production well	4.1 Impact of permeability variation between producer and injector
Top Inj	Laterally discontinuous top reservoir in injection well	4.1 Impact of permeability variation between producer and injector
Smooth	Scenario with homogeneous permeability in the top reservoir, and a smooth linear permeability variation between injector and producer in the bottom reservoir	4.1 Impact of permeability variation between producer and injector
h0	Base Case scenario (semi-open boundaries) with uniform reservoir thickness (50 m) in both wells, but with 3 cell layers per reservoir	4.2 Impact of thickness variation between producer and injector well
h1	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 33.3 m thick at production well)	4.2 Impact of thickness variation between producer and injector well
h2	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 16.7 m thick at production well)	4.2 Impact of thickness variation between producer and injector well
h3	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 0 m thick at production well), which is the same as scenario Bot Pro	4.2 Impact of thickness variation between producer and injector well
h4	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 33.3 m thick at injection well)	4.2 Impact of thickness variation between producer and injector well
h5	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 16.7 m thick at injection well)	4.2 Impact of thickness variation between producer and injector well
h6	Scenario with constant thickness of the top reservoir (50 m) and decreasing thickness of bottom reservoir (bottom reservoir 0 m thick at injection well), which is the same as scenario Bot Inj	4.2 Impact of thickness variation between producer and injector well
COMP 1	Scenario with fresh water in the top reservoir and salt water in the bottom reservoir (molar fraction of 0.02, roughly equivalent to 120 g/L)	4.3 Impact of density and viscosity variations due to brine mixing
COMP 2	Scenario with fresh water in the top reservoir and salt water in the bottom reservoir (molar fraction of 0.05, roughly equivalent to 270 g/L)	4.3 Impact of density and viscosity variations due to brine mixing
COMP 3	Scenario with salt water in the top reservoir (molar fraction of 0.008, roughly equivalent to 50 g/L) and salt water in the bottom reservoir (molar fraction of 0.025, roughly equivalent to 150 g/L)	4.3 Impact of density and viscosity variations due to brine mixing
COMP 4	Scenario with salt water in both reservoirs (molar fraction of 0.016, roughly equivalent to 100 g/L)	4.3 Impact of density and viscosity variations due to brine mixing
COMP 5	Scenario with fresh water in both reservoirs, with the thermal property variation of water ignored	4.3 Impact of density and viscosity variations due to brine mixing
COMP 6	Scenario with fresh water in both reservoirs, accounting for the thermal property variation of water (= Base Case)	4.3 Impact of density and viscosity variations due to brine mixing
Case 20	Scenario with a thermal gradient of 20°C/km and a surface temperature of 10°C	4.4 Impact of temperature differences

Annex C: Overview of Modeled Scenarios

Case 30	Scenario with a thermal gradient of 30°C/km and a surface temperature of 10°C, equivalent to the Base Case (semi-open boundaries)	4.4 Impact of temperature differences
Case 40	Scenario with a thermal gradient of 40°C/km and a surface temperature of 10°C	4.4 Impact of temperature differences
Base Case	Base Case scenario with a wellbore diameter of 8 ½" in both wells in both reservoir sections (vertical) (semi-open boundaries)	4.5 Impact of well completion differences
r1 (Inj)	Scenario with a wellbore diameter reduced to 5 ½" in the lower reservoir section in the injection well and a diameter of 8 ½" in the production well (both reservoir sections)	4.5 Impact of well completion differences
r2 (Pro)	Scenario with a wellbore diameter reduced to 5 ½" in the lower reservoir section in the production well and a diameter of 8 ½" in the injection well (both reservoir sections)	4.5 Impact of well completion differences
r3 (Both)	Scenario with a wellbore diameter reduced to 5 ½" in the lower reservoir section in both wells	4.5 Impact of well completion differences
horiz1 (Inj)	Scenario with a 500 m long horizontal section in the bottom reservoir of the injection well	4.5 Impact of well completion differences
horiz2 (Both)	Scenario with a 500 m long horizontal section in the bottom reservoir of both wells	4.5 Impact of well completion differences
horiz3 (Both Low Perm)	Scenario with a 500 m long horizontal section in the bottom reservoir of both wells with a reduced reservoir permeability of 50 mD	4.5 Impact of well completion differences
low perm vertical wells (Low Perm)	Scenario with vertical sections in both reservoirs in both wells, but with reduced permeability in the bottom reservoir of 50 mD	4.5 Impact of well completion differences
Case_Opt_Opb_0it_0ib	Base Case scenario with 0 skin for both wells in all reservoir sections (semi-open boundaries)	4.6 Impact of skin factor differences
Case_Opt_Opb_0it_2ib	Scenario with 0 skin for the production well, 0 skin in the top reservoir section in the injection well, and a skin of -2 in the bottom reservoir section in the injection well	4.6 Impact of skin factor differences
Case_Opt_Opb_0it_30ib	Scenario with 0 skin for the production well, 0 skin in the top reservoir section in the injection well, and a skin of 30 in the bottom reservoir section in the injection well	4.6 Impact of skin factor differences
Case_Opt_Opb_2it_0ib	Scenario with 0 skin for the production well, a skin of -2 in the top reservoir section in the injection well, and 0 skin in the bottom reservoir section in the injection well	4.6 Impact of skin factor differences
Case_Opt_Opb_2it_2ib	Scenario with 0 skin for the production well and with a skin of -2 for the injection well	4.6 Impact of skin factor differences
Case_Opt_Opb_2it_30ib	Scenario with 0 skin for the production well, a skin of -2 in the top reservoir section in the injection well, and a skin of 30 in the bottom reservoir section in the injection well	4.6 Impact of skin factor differences
Case_Opt_Opb_30it_0ib	Scenario with 0 skin for the production well, a skin of 30 in the top reservoir section in the injection well, and 0 skin in the bottom reservoir section in the injection well	4.6 Impact of skin factor differences
Case_Opt_Opb_30it_2ib	Scenario with 0 skin for the production well, a skin of 30 in the top reservoir section in the injection well, and a skin of -2 in the bottom reservoir section in the injection well	4.6 Impact of skin factor differences
Case_Opt_Opb_30it_30ib	Scenario with 0 skin for the production well and with a skin of 30 for the injection well	4.6 Impact of skin factor differences
Case_Opt_30pb_0it_0ib	Scenario with 0 skin in the top reservoir section in the production well, a skin of 30 in the bottom reservoir section in the production well, and with 0 skin in the injection well	4.6 Impact of skin factor differences
Case_30pt_Opb_0it_0ib	Scenario with a skin of 30 in the top reservoir section in the production well, 0 skin in the bottom reservoir section in the production well, and with 0 skin in the injection well	4.6 Impact of skin factor differences
Case_30pt_30pb_0it_0ib	Scenario with a skin of 30 for the production well and with skin 0 for the injection well	4.6 Impact of skin factor differences
PERM1	Average permeability scenario of the specific case	5 Commingled production in a specific geological case in the Netherlands
PERM2	High permeability scenario of the specific case	5 Commingled production in a specific geological case in the Netherlands
PERM3	Low permeability scenario of the specific case	5 Commingled production in a specific geological case in the Netherlands

Annex C: Overview of Modeled Scenarios

PERM0	Scenario with Base Case properties applied to the specific case	5 Commingled production in a specific geological case in the Netherlands
Coarse THM model	Base Case scenario (semi-open boundaries) on a coarser grid (reduced level of discretization along the edges of the model and in over- and underburden)	6.3.2 Thermo-Hydro-Mechanical reservoir simulation approach
Coarse Bot Pro model	Bot Pro scenario with laterally discontinuous bottom reservoir in production well (semi-open boundaries) on a coarser grid (reduced level of discretization along the edges of the model and in over- and underburden)	6.3.2 Thermo-Hydro-Mechanical reservoir simulation approach

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