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Geological CO_2 Storage Supports Geothermal Energy Exploitation: 3D Numerical Models Emphasize Feasibility of Synergetic Use

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Abstract

Geological storage of CO_2 in deep saline aquifers is considered as option for reducing anthropogenic greenhouse gas emissions into the atmosphere. Most often the same aquifers might allow for provision of geothermal energy potentially resulting in a competitive situation. Within the frame of the present study we evaluated the feasibility of synergetic utilisation of a reservoir suitable for both, CO_2 storage and geothermal heat exploitation, by 3D numerical simulations of simultaneous CO_2 and brine (re-) injection and brine production. Based on structural and petrophysical data from a prospective storage site in the North East German Basin different scenarios were investigated taking into account reservoir permeability anisotropy and varying flow related descriptions of existing faults. Simulation results show that for an isotropic horizontal permeability distribution synergetic use is feasible for at least 30 years. Nevertheless, permeability anisotropy and open faults do have an impact on the CO_2 arrival time at the brine production well and should be taken into account for implementation of a synergetic utilisation in the study area.

Keywords: CO_2 storage; saline aquifer; brine production; geothermal heat provision; synergy

1. Introduction

Geological storage of the greenhouse gas carbon dioxide (CO_2) in deep saline aquifers is on the one hand viewed as a promising measure for mitigating the adverse impact of increasing anthropogenic emissions on the global climate-change but on the other hand also linked to several risks as any technology. Especially large-scale pressure build-up as a result of CO_2 injection, potentially with substantial impact even 100 km away from the injection zone is associated with the risk of cap rock fracturing, reactivation of existing faults or induced seismicity [1-3]. Further major concern is that pressurization may force displaced brines to migrate along leakage pathways from the storage formation

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into shallow groundwater reservoirs with potable water resources [4]. To prevent overpressurisation and associated risks in saline aquifers the extraction of formation water from the storage reservoir by active brine production concurrent to CO_2 injection has been shown to be a potential strategy [5-6]. Even with passive water production which requires that aquifer pressure exceeds the hydrostatic pressure near the production well, the pressure build-up in the formation can be significantly reduced especially in the near-well area [7]. Birkholzer et al. [8] introduced the concept of "impact-driven pressure management (IDPM)", a method for local pressure relief via targeted brine extraction in particular at discrete geological features with a higher risk potential such as critically stressed faults to prevent (re-)activation. In addition to risk mitigation brine-extraction volumes can be significantly reduced and the extracted brine volume must not necessarily be equal to the injected CO_2 volume to achieve a pressure relief. If not re-injected into the storage formation or another neighbouring high-permeable formation, the extracted brine can for instance be used for freshwater production or geothermal heat provision [9]. However, the use of geothermal brines from low-enthalpy systems (temperature below 100°C) is not always economically profitable, whereby the technical infrastructure required for geological CO_2 storage may support heat exploitation, if the same reservoir is for instance used synergetically by both technologies. This might also prevent competitive situations, since the same aquifers most often allow for geothermal heat provision and geological CO_2 storage.

We therefore decided to investigate the feasibility of synergetic reservoir utilisation of a deep sandstone reservoir located in the Northeast German Basin (NEGB) suitable for both, CO_2 storage and/or geothermal heat exploitation. By this means, and to avoid disposal of native brines above the surface, an injection strategy was developed taking into account concurrent brine production for geothermal heat provision and its re-injection into the storage formation together with the CO_2. Based on structural and petrophysical data from the prospective storage site in the NEGB and in order to assess a conceptual synergetic utilisation, large-scale numerical flow simulations at regional scale (about 42 km x 42 km) coupled to heat transfer were carried out using the TOUGH2-MP simulator [10]. Different scenarios were investigated considering existing faults as open and closed, respectively, as well as anisotropy of the reservoir permeability to account for preferred flow directions resulting from a heterogeneous facies distribution in the storage formation.

1. Study Area

The prospective CO_2 storage site Beeskow-Birkholz is located in the southeastern part of the German state of Brandenburg in the NEGB (Figure 1). The potential storage horizon is part of a saline multi-layer aquifer system of Mesozoic age characterized by an anticline structure that extends in west-northwest and east-southeast direction. This Mesozoic anticline developed due to salt tectonic movements of the deeper-lying Upper Permian Zechstein [11]. The northeastern and southwestern boundaries of the study area are confined by the Fuerstenwalde Guben and Lausitzer Abbruch fault systems. The Detfurth formation sandstone of the Middle Bunter with a formation top located at a depth of about 1,080 m and an average thickness of 23 m was chosen to evaluate the feasibility of a synergetic reservoir utilisation, since it offers the greatest thickness of three permeable formations situated in the Middle Bunter potentially suitable for both, CO_2 storage and/or heat provision. The underlying permeable sandstone formation of the Middle Bunter is separated from the Detfurth formation by a sealing unit consisting of mudstones with a thickness of 60 m. The cap rocks overlying the Detfurth formation are multi-barrier seals made up of mudstones and anhydrite. For a more detailed stratigraphic description of the study area, the reader is referred to Tillner et al. [12].

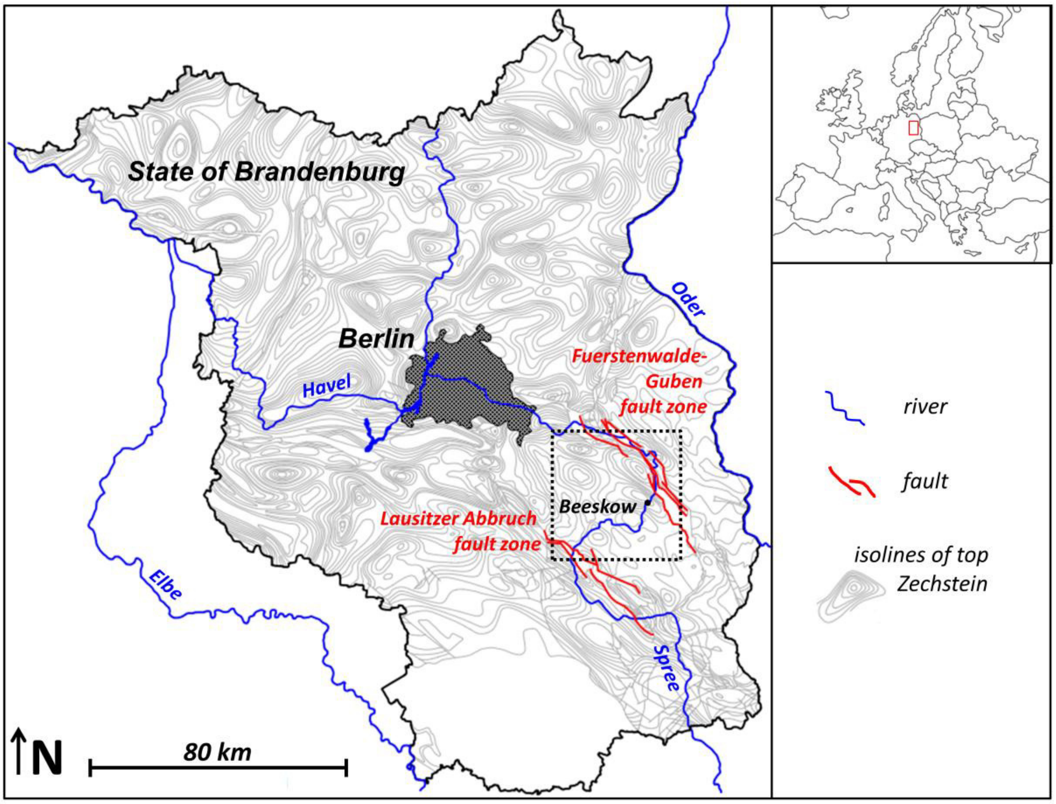

Figure 1: The Beeskow anticline formed due to halokinetic movements in the underlying Zechstein salts, whereby the outlined rectangle indicates the location of the study area. Isolines of top Zechstein and fault trends were derived from Beer and Stackebrandt [13], the outline of the states of Brandenburg and Berlin as well as the rivers from Stackebrandt and Manhenke [11].

2. Methodology

3.1. Numerical model setup, parameterization and applied simulator

Within the scope of this study a static 3D geological structural model of the Detfurth formation as the target reservoir for heat exploitation and CO_2 storage with an areal size of 42 km x 42 km was implemented using the Petrel software package [14]. In addition to the Detfurth formation sandstone the model includes four major fault zones, representing the Fuerstenwalde Guben and Lausitzer Abbruch fault systems in the northeastern and southwestern part of the study area. Therefore, layer boundary, fault data and petrophysical data derived from well logs carried out in the frame of previous hydrocarbon campaigns (former German Democratic Republic, unpublished data [12]) was used for model implementation and parameterisation. A depth and thickness correction was further performed based on geological and structural maps derived from Stackebrandt and Manhenke [11, 12]. Subsequent to the model gridding in Petrel the structured hexahedral grid is transferred to the reservoir simulator TOUGH2-MP/ECO2N [10, 12, 15] to perform the coupled thermal-hydraulic multiphase flow simulations. Porosity and permeabiltity values of the Detfurth formation are 23 % and 400 mD, respectively. For the low-enthalpy reservoir with a reservoir temperature at the top of the anticline of approximately 45 °C [16] a geothermal gradient of 30 °C/km was applied resulting in an average reservoir temperature of 50 °C [12]. For calculating heat transfer within the coupled thermal-hydraulic simulations, heat conductivity, heat capacity and rock density of the Middle Bunter were adapted from Scheck [17]. Heat exchange with the rocks underlying the Detfurth formation and the overlying cap rock was not taken into account. The selected pressure regime is hydrostatic with an initial pressure of approximately 10.8 MPa at the top of the Detfurth anticline at a depth of 1,080 m. According to the available borehole data the salinity of the Detfurth formation was set to 250,000 mg/l. All four lateral model boundaries were assumed to be open for fluid flow only (Dirichlet boundary condition) by implementing a boundary element volume multiplier of 100. A heat-transfer boundary condition was not applied.

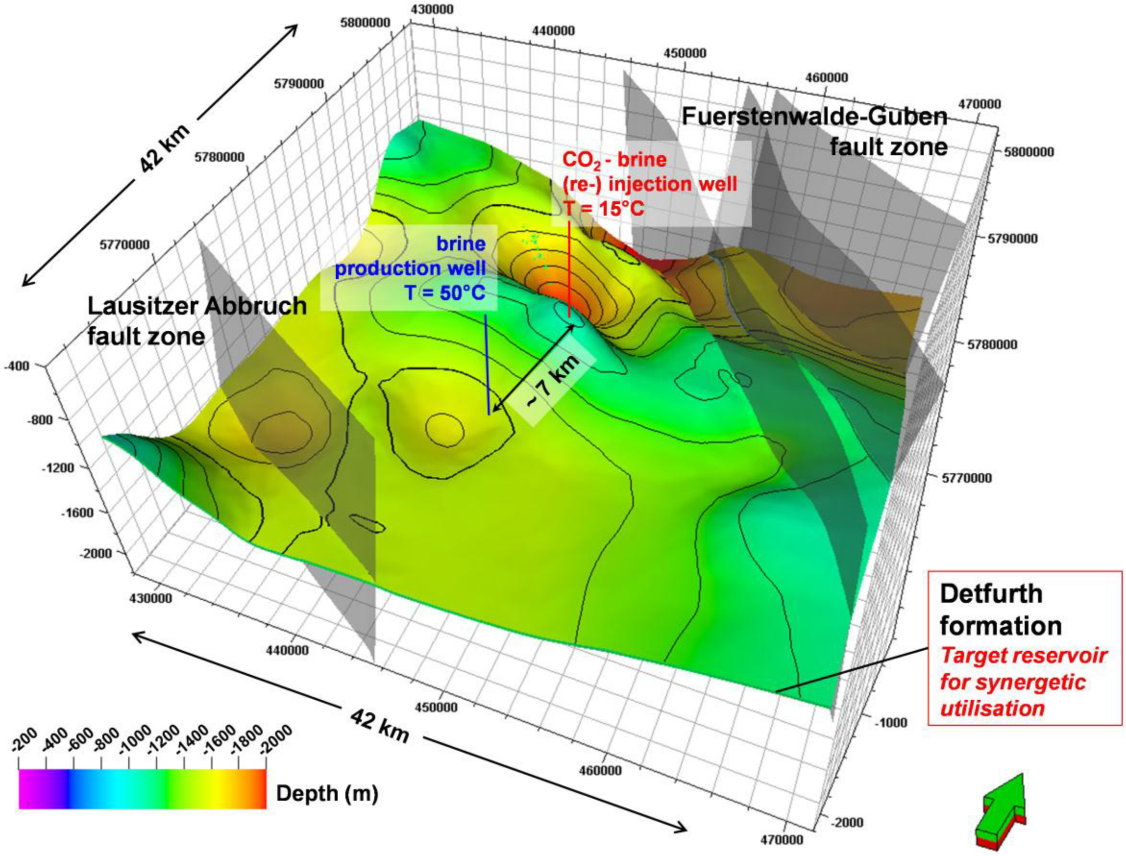

Figure 2: 3D geological model of the Detfurth formation sandstone of the Middle Bunter. A synergetic utilisation based on simultaneous CO_2 and brine injection into the top of the anticline (red) and brine production at the southwestern flank (blue) is evaluated.

3.2. Scenario analysis and injection/production scheme

In the present feasibility study for synergetic reservoir utilisation, five different simulation scenarios were applied considering different flow-related fault descriptions as well as permeability anisotropy to simulate higher permeable facies in different directions (Table 1). In all five scenarios the anticline system is developed by two wells, whereby a vertical injector is located at the top and a vertical producer in the southern flank of the west-northwest, east-southeast orientated anticline at a distance of about 7 km in order to delay CO_2 arrival time. In Scenarios 1 and 2 annual amounts of 1.7 Mt/CO_2 and 0.65 Mt/brine are injected simultaneously into the Detfurth formation for a time span of 20 years using the same well. Although the maximum storage capacity of the Detfurth formation is estimated with about 34.5 Mt/CO_2 [18] which is reached after 20 years of injection, a total injection period of 100 years was simulated for Scenario 3 in order to determine the time the CO_2 requires to arrive at the central fault zone. For geothermal heat provision the equal quantity of brine injected is simultaneously extracted at the production well. Due to temperature losses in the production well, a fluid temperature loss from 50 °C (bottom hole temperature) to 45 °C at the production well head was assumed. Hence, a temperature difference of about 30 °C remains at the surface for heat provision. Within the described scenarios brine is re-injected into the storage reservoir with a temperature of approximately 15 °C (bottom hole temperature; Figure 2).

Table 1. Investigated scenarios with applied permeability anisotropy, fault description and simulation time.

Scenario	Faults	Permeability anisotropy		Simulation time
		X:Y	X:Z	
1a	open for cross-flow	2:1	3:1	20 years
1b	closed			
2a	open for cross-flow	1:2	1.5:1	
2b	closed			
3	open for cross-flow	1:1	3:1	100 years

4. Simulation Results

In all five investigated scenarios the injection well bottom hole pressure starts to increase almost immediately after the start of injection and reaches a first peak of 20.2 MPa (Scenarios 1a and 2a), 18.1 MPa (Scenario 3) and 20.1 MPa (Scenarios 1b and 2b) 2 hours after (Figure 3).

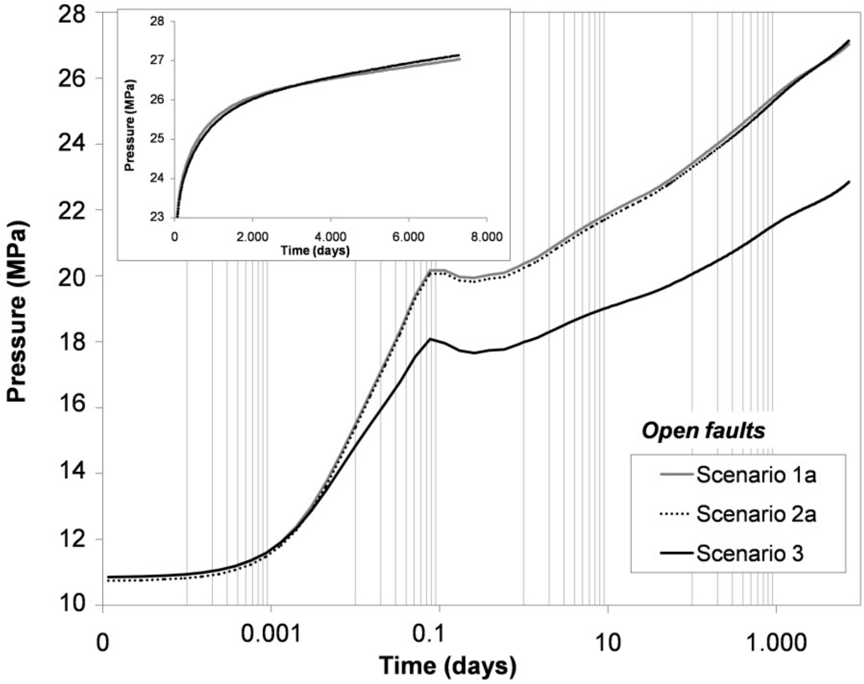

Figure 3: Injection well bottom hole pressures for Scenarios 1a, 2a and 3.

Until the end of injection after 20 years, the bottom hole pressure increases by 149 % (16.2 MPa relative) at the injection and by 5 % (0.8 MPa relative) at the production well in Scenario 1a, where four open faults and a permeability in x-direction twice the permeability in y-direction was assumed. In Scenario 1b, where all fault zones were assumed to be closed, pressure build-up was correspondingly higher with an bottom hole pressure increase of 161 % (17.4 MPa relative) at the injector and 13 % (2.1 MPa relative) at the producer until the end of injection (20 years). A comparison between Scenario 2a and 2b, investigating the reverse case with a permeability in y-direction twice the permeability in x-direction, shows that the bottom hole pressure increase after 20 years of utilisation is again slightly lower in the open fault case (Scenario 2a) with 152 % (16.4 MPa relative) and higher in the closed fault case (Scenario 2b) with 160 % (17.3 MPa relative), respectively (Figure 4). Comparing the two scenarios with open fault descriptions it becomes obvious that the pressure rises steeper in Scenario 1a with a higher permeability in x-direction until about eight years of injection and production than in Scenario 2a. From eight years on and until the end of the simulation after 20 years the pressure build-up at the injection is higher in Scenario 2a with a higher permeability in y-direction (Figure 3). The pressure development in the two scenarios with closed faults (Scenario 1b and 2b) is identical in the first 400 days of simulation and starts to rise steeper in Scenario 1b until the end of the simulation (20 years). Nevertheless, pressure build-up is only 1 % higher after 20 years in Scenario 1b compared to Scenario 2b (Figure 4). For an isotropic horizontal permeability distribution in the Detfurth formation (Scenario 3) the overall smallest total pressure increase of about 110 % (12 MPa relative) at the injection and compared to Scenario 1a, a slightly higher pressure increase of 7 % (1.1 MPa relative) at the production well can be observed after 20 years of simulation (Figure 3).

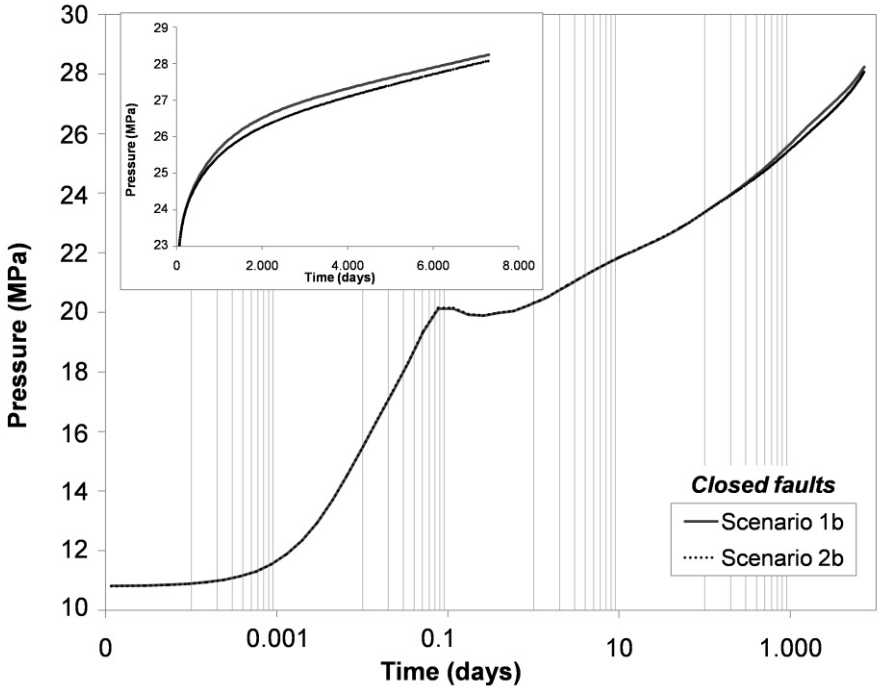

Figure 4: Injection well bottom hole pressures for Scenarios 1b and 2b.

The pressure difference plot between the two scenarios with open faults, Scenario 2a and 1a as well as with closed faults, Scenario 2b and 1b shown in Figure 5, generally illustrates that the pressure build-up in north-south direction is larger if a permeability ratio of x:y=1:2 was assumed and correspondingly higher in east-west direction for a permeability ratio of x:y=2:1. Nevertheless, for the case with faults closed for cross-flow it becomes obvious that the pressure build-up in a radius of 8 km from the injection well in north-south direction is reduced by approximately 0.24 MPa and increased in east-west direction by 0.27 MPa in average.

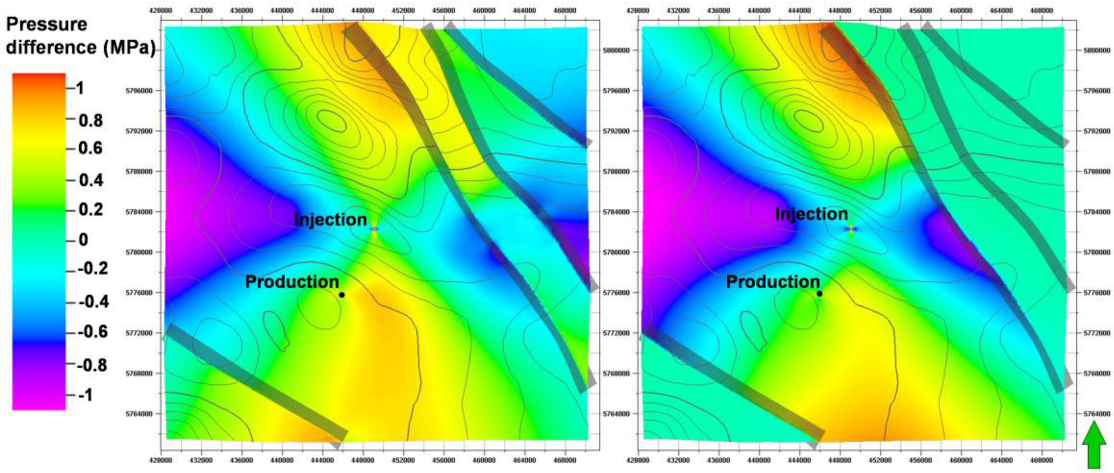

Figure 5: Pressure difference plots between Scenarios 2a and 1a (left) and 2b and 1b (right). Positive values denote a higher pressure in Scenario 2a (2b), negative values a higher pressure in Scenario 1a (1b), respectively.

In all scenarios investigated the CO_2 plume expands along the orientation of the anticline in west-northwest and east-southeast direction. The greatest extent of the CO_2 plume can be observed in Scenario 1a with 19.2 km in the longitudinal and 8.6 km in the transverse direction (Figure 6) after 20 years of simulation. The CO_2 plume does neither reach the central fault in the east nor the production well at the flank of the anticline. The remaining distances are 600 m and 880 m, respectively (Figure 7). In Scenario 1b the plume is 1.8 km smaller with a total length of approximately 17.4 km and at a distance of 3.4 km and 900 m to the central fault and the producer, respectively. For the Scenarios 2a and 2b with a permeability ratio of x:y=1:2 the CO_2 plume arrives at the production well after 19 years (Scenario 2a) and 20 years (Scenario 2b) of simultaneous (re-) injection and production. Open faults (Scenario 2a) allow the CO_2 plume to migrate at least 800 m closer to the central fault compared to the closed fault case (Scenario 2b). In longitudinal direction the plume has an extent of 16.7 km (Scenario 2a) and 15.9 km (Scenario 2b). With 9.7 km (Scenario 2a) and 9.5 km (Scenario 2b) the extent in the transverse direction is significantly larger compared to Scenario 1. For an isotropic horizontal permeability distribution in the Detfurth formation (Scenario 3), the extent of the CO_2 plume is approximately 19 km in east-west direction along the orientation of the anticline and 6.4 km in north-south direction. Both, production well and central fault zone remain unaffected by the plume and are still at a distance of 2.7 km and 2.0 km, respectively (Figure 7). After 32 years the CO_2 plume reaches the central fault zone and after 59 years of synergetic reservoir utilisation the second major fault in northeast direction. After 67 years of simulation the CO_2 plume arrives at the production well at the flank of the anticline (Figure 6). In all investigated scenarios the CO_2 that dissolves in the formation fluid migrates approximately 500 m ahead of the outer extent of the gaseous CO_2 plume and arrives one year earlier at the production well and central fault zone.

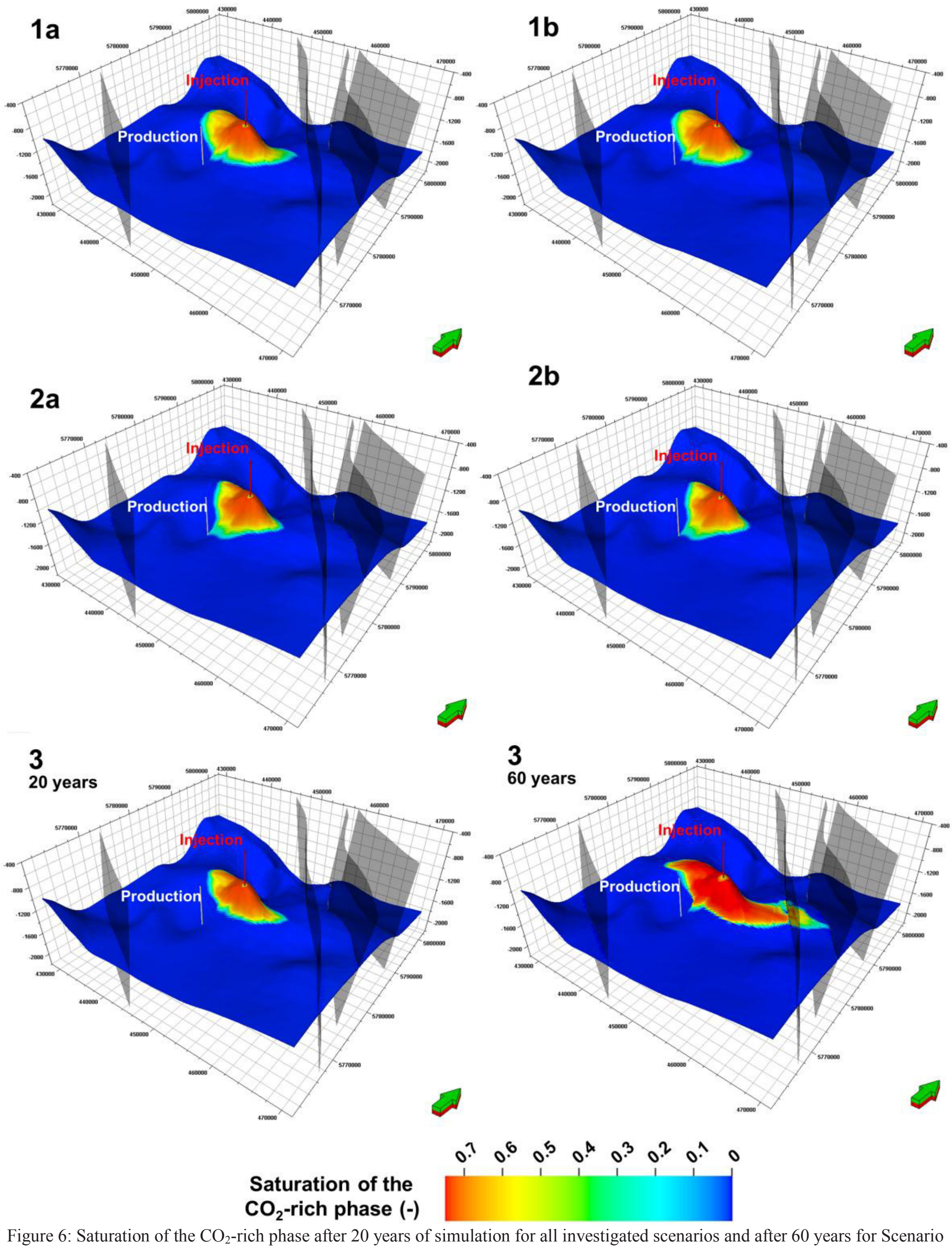

Figure 6: Saturation of the CO_2-rich phase after 20 years of simulation for all investigated scenarios and after 60 years for Scenario 3.

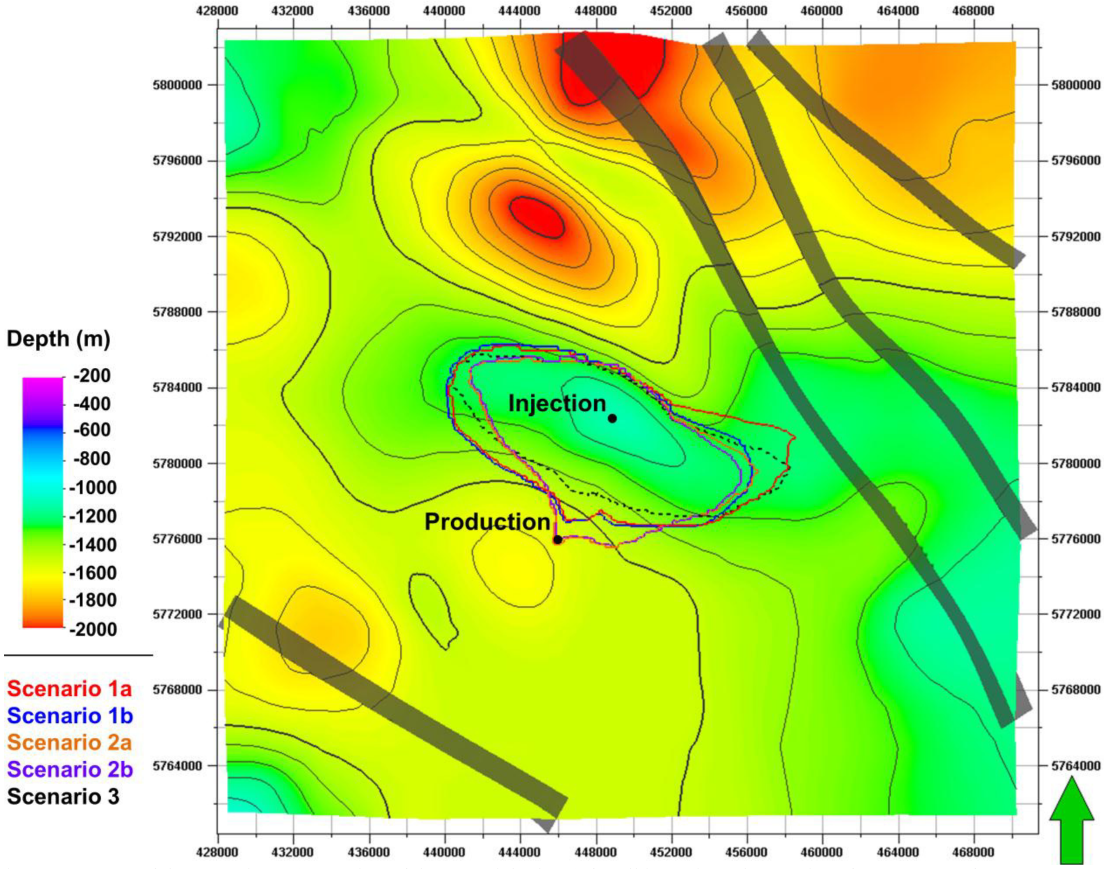

Figure 7: Extent of the CO_2 plume (saturation of the CO_2-rich phase) for all investigated scenarios after 20 years of concurrent CO_2 and brine (re-)injection and brine production.

In Scenarios 1a and 1b the cold water front that develops around the injection well elongates in east-west direction and is far from reaching the production well with a remaining distance of 7 km after 20 years. Beyond a radius of 1.4 km in east-west direction and about 1 km in north-south direction the average reservoir temperature is at the initial state of 50 °C. The production well also remains unaffected by the cold water front around the injector in both Scenarios 2a and 2b, but on contrary to Scenarios 1a and 1b it elongates in north-south direction. The average reservoir temperature is at the initial state of 50 °C beyond a radius of 1.38 km in north-south direction and 1 km in east-west direction (Figure 8). For an isotropic horizontal permeability distribution within the Detfurth formation (Scenario 3) the temperature decrease develops almost radially symmetrical around the injector with a radius of 1.1 km after 20 years. After 100 years of simulating synergetic utilisation the radius of the temperature decrease around the injection well increases to 2.0 km but does still not affect the production well.

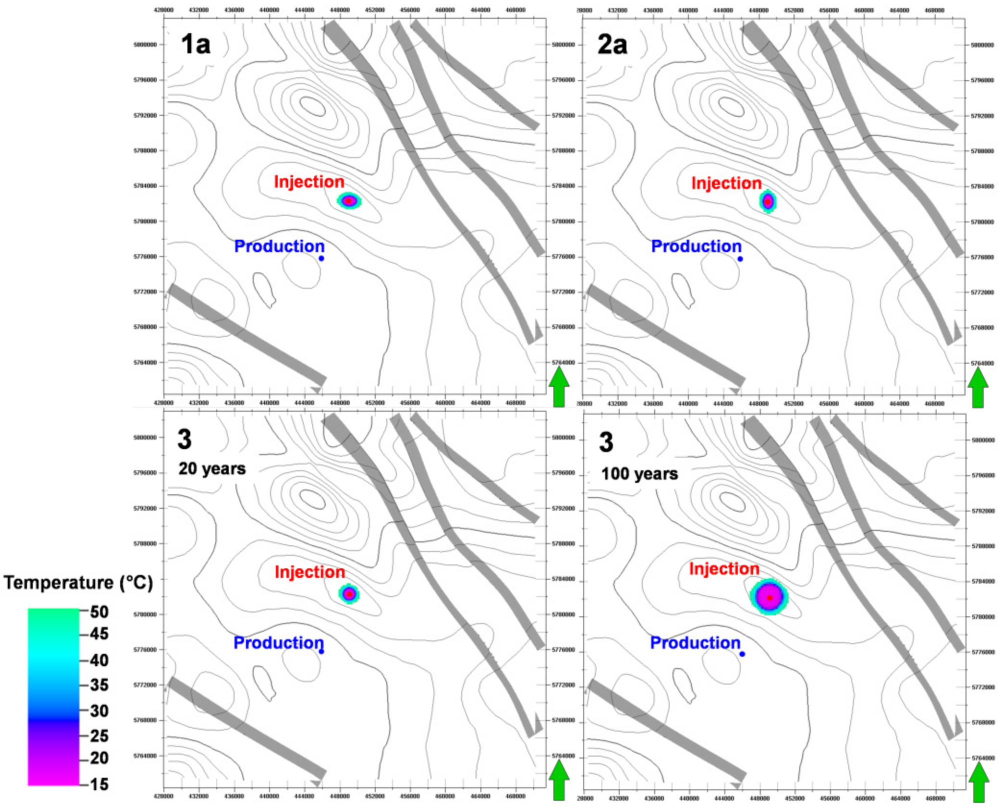

Figure 8: Extent of the cold water front (T<50°C) developing around the injector due to brine re-injection at 15°C. Scenarios 1a, 2a and 3 after 20 years of simulation and Scenario 3 after 100 years of simulation are plotted.

In Scenario 1a, brine mainly migrates out of the model domain through the western and eastern boundaries (relative water mass change of 0.22 % and 0.14 %), whereas the amount of brine migrating out of the system via the eastern boundary is significantly reduced in Scenario 1b with faults closed for cross-flow (relative water mass change of 0.01 %). Here, an even larger quantity of brine is forced to migrate out of the system via the western as well as the southern boundary compared to Scenario 1a. In Scenario 2a brine migrates mainly out of the model domain through the southern and northern boundaries. For the case with faults closed for cross-flow (Scenario 2b), less brine migrates through the northern and southern boundaries. Brine migration rate slightly increases at the western boundary, whereas brine migration via the eastern boundary approaches zero. In Scenario 3, the relative water mass increases mainly in the western and southern boundary elements by 0.2 % and 0.16 % after 20 years of simulation, respectively, indicating that the displaced brine is predominantly migrating out of the system in southwest direction (Figure 9).

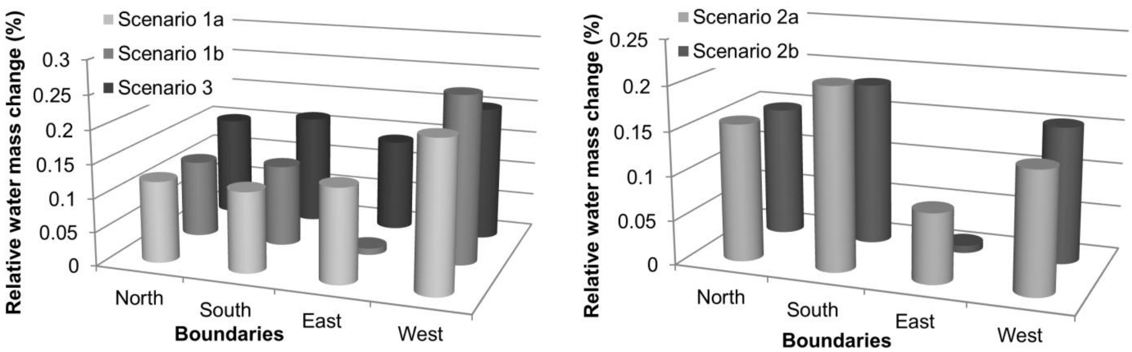

Figure 9: Relative water mass change at the northern, southern, eastern and western boundary elements for all investigated scenarios after 20 years.

5. Discussion and Conclusions

In the present study we investigated the feasibility of synergetic utilisation of a deep saline sandstone formation for geothermal heat exploitation and geological CO_2 storage by concurrent CO_2 and brine injection and brine production from the same reservoir. The results demonstrate that the competitive character between both technologies can be neglected and for how many years a synergetic reservoir utilisation can be realized in the chosen study area. First, a regional-scale 3D model was implemented based on structural and petrophysical data from a prospective CO_2 storage site in Northeast Germany. Different scenarios considering existing faults as either open or closed as well as anisotropy of the reservoir permeability to account for preferred flow directions within the storage formation due to facies heterogeneity were thereby investigated and evaluated. CO_2 is injected concurrent with cycled brine into the top of an anticline structure at 15 °C and brine produced for heat provision at the flank in a distance of 7 km at 50 °C.

Numerical modelling results show that for an isotropic horizontal permeability distribution and a permeability ratio of x:y=2:1 representing a higher permeable facies in east-west direction, neither the dissolved nor gaseous CO_2 arrives at the brine production well after an operational period of 20 years. The maximum distance between the CO_2 plume and the production well after 20 years of simulation of 2.7 km was observed for an isotropic lateral permeability distribution, whereas for a permeability ratio of x:y=2:1 the CO_2 plume extends slightly more towards the production well located at the southwestern flank due to topographic effects. Nevertheless, in both cases synergetic use would be feasible for at least 20 years and even 30 years for the isotropic lateral permeability distribution. The reverse case with a permeability ratio of x:y = 1:2 representing a higher permeable facies in north-south direction was implemented to represent a worst-case for this feasibility study, since the producer is located in that direction. Simulation results show that the production well is affected by the dissolved CO_2 after 18 years of synergetic reservoir utilisation with closed faults and after 19 years, if faults are assumed to be open, which would limit a synergetic use to that time span. A layered heterogeneous permeability could additionally delay the CO_2 arrival time at the brine production well [19], but was not considered in the present study.

The propagation of the cold-water front developing around the injector does not exceed a maximum radius of 1.4 km after 20 years for all scenarios. Even after 100 years of simultaneous injection and production a remaining distance of 5 km between the outer extent of the cold-water front and the producer can be observed. Nevertheless, an injection period of 100 years would exceed the maximum storage capacity (which is reached after 20 years) and was simulated to determine whether only geothermal heat provision can be realized for an even longer time period, which is the case.

The bottom hole pressure at the injection increases by a maximum of 161 % after 20 years when closed faults and a permeability anisotropy are assumed, and by a minimum of 110 % for open faults and an isotropic permeability distribution. With the selected production rates at the brine producing well a significant reduction of reservoir pressure was not achieved, since the quantity of injected CO_2 exceeds the quantity of cycled brine by more than two and a half times. However, at high-risk areas, such as critically stressed faults, pressure can be relieved by targeted brine production as presented by Birkholzer et al. [8]. A steep pressure rise directly after the start of injection can also be reduced by a stepwise injection rate increase. As expected, the displaced brine is mainly migrating out of the modelling domain in direction of the higher horizontal permeability. Reservoir compartmentalization due to closed faults leads to an increased brine migration rate towards the other boundaries and should be taken into consideration for alternative production well placements.

The results of our modelling demonstrate that a synergetic utilisation of a saline aquifer in the NEGB is generally feasible and the competitive character between geothermal exploitation and CO_2 storage can be neglected, if suitable reservoir management strategies involving production and re-injection of formation fluids are employed. Furthermore, our modelling results show that geothermal heat provision from deep low-enthalpy formations may become feasible for at least 30 years, if supported by the technical infrastructure required for geological CO_2 storage as successfully demonstrated in our case study for the Middle Bunter at the Beeskow-Birkholz anticline in Eastern Germany. However, detailed knowledge on site geology, transmissibility of existing faults as well as facies distribution in the storage formation is of uttermost importance for the successful implementation of a synergetic reservoir utilisation concept. CO_2 that arrives at existing faults may not impose problems as these faults are impermeable in vertical direction and only open for cross-flow. Fault permeability should therefore be determined prior to reservoir utilisation by hydraulic testing. Cycling the CO_2 arriving at the production well, may also support geothermal exploitation of the reservoir beyond the named limitations, if an anisotropic lateral permeability is assumed. However, geochemical processes such as corrosion of well casings and completions, pumps and pipelines have to be considered while applying this procedure. Salt precipitation due to cooling during production and above surface are still problems of geothermal systems using saline formations and were not specifically addressed as a limiting factor for the presented synergetic utilisation concept in this study. Further studies will integrate new borehole data and 3D seismics to extend the facies distribution model of the reservoir in order to optimize the production well placement.

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