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Simulation of Reinjection of Non-Condensable Gas-Water Mixture into Geothermal Reservoirs

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ABSTRACT

Injection of non-condensable gases (NCG) into geothermal reservoirs can be used to reduce greenhouse gas emissions, providing reservoir pressure support and possibly improve reservoir permeability. First, we review existing field trials of NCG reinjection in geothermal fields. We then use numerical reservoir modelling to assess the effect of NCG reinjection on energy recovery, understand permanent trapping, and forecast potential NCG breakthrough into production wells.

This modelling study was conducted to assess the feasibility of using water-NCG mixture injection into a geothermal reservoir. Although the different NCG species from geothermal systems have moderate solubility in water, formation of gas phases at lower pressures and/or the shallow subsurface requires careful consideration of the rate and composition of NCG. This is to assess the potential risk of growing into fingers that may lead to an early breakthrough or potentially leakage to the surface. In order to investigate the influence of injected NCG concentrations and determine the spatial distribution of NCG's, a four gas version of the TOUGH2 reservoir simulator was used. This version of TOUGH2 can handle non-isothermal flow of multiphase, multicomponent reacting flows of mixtures of water, H_2S, CO_2, N_2 and CH_4.

Modified version of the benchmark geothermal reinjection model was constructed with initial conditions of a liquid-dominated geothermal system. The paper describes a series of numerical modelling scenarios to investigate the effects of NCG-water injection on steam production. Possible fluid paths and distribution of gas components were investigated to estimate the NCG storage capability of a reservoir and to identify potential breakthrough and leakage events. The results obtained show that the effects of injection depend on the reinjection well pattern and recharge conditions. The risk of leakage to the surface is very limited since the injected NCGs remains in the liquid phase.

1. INTRODUCTION

Reinjection is an environmentally friendly method of waste water disposal. It helps with reservoir recharge, pressure support and can be used to manage subsidence. However, reinjection of geothermal water can also cause problems, e.g., premature thermal breakthrough, groundwater contamination and leakage of reinjected fluid to the surface. Therefore careful reinjection strategies need to be in place to provide an appropriate steam field management (Kaya, Zarrouk, et al., 2011; Rivera Diaz et al., 2016).

Geothermal fluid contains variable quantities of NCG, consisting primarily of CO_2, H_2S, and trace quantities of some other gases (e.g. NH_3, H_2, N_2 and CH_4). Depending on the fluid source, the fraction of the NCG can vary from less than 0.2% to greater than 25% by weight of the geothermal fluid (Özcan and Gökçen, 2010), e.g. at Ohaaki, New Zealand, the CO_2 content of well discharges is up to 6 wt% (Grant, 1977). CO_2 is the most dominant gas, which is ~90 % of the total NCGs by volume (Bertani and Thain, 2002), while H_2S constitutes ~2 to 3%, and the other gasses constitute the remaining volume. The presence of NCG, in particular CO_2 and H_2S, in geothermal fluids often presents a challenge as these are associated with corrosion, calcite deposition, reduced power plant efficiency, and health, safety, and environmental risks (DiPippo, 2012).

The global average of NCG emission values from geothermal power production was 122 gCO_2/kWh in 2001, based on a survey accounting for more than 50% of the total installed capacity worldwide. The average value in the United States was 106 gCO_2/kWh in 2002), in New Zealand was 123 gCO_2/kWh (in 2012), in Iceland was 34 g/kWh (in 2013), and in Italy was 330 gCO_2/kWh (in 2013); the most extreme reported values of 900 to 1,300 gCO_2/kWh are from power plants located in the Menderes and Gediz grabens in Turkey. Fairly high values have also been reported in some power plants from Mount Amiata, Italy, and Ngawha, New Zealand (ESMAP, 2006).

In recent years, reinjecting NCG into geothermal reservoirs is receiving increasing interest from the geothermal industry to minimize the emission of the greenhouse gas into the atmosphere. The presence of CO_2 in reservoir fluid lowers the flash point pressure of the mixed fluid and promotes boiling. This induces the formation of a gas phase in the geothermal reservoir help maintain higher total reservoir pressure. The NCG could be injected in the form of gas dissolved in water or as supercritical fluid. A brine-NCG mixture enhances residual trapping and avoids risk of gas leakage from the reservoir. There is also lower risk of salt precipitation due to formation dry-out (Hamidreza et al., 2015). However, the breakthrough of CO_2 and cold-water can reduce the lifetime of the geothermal production wells. To understand the migration and impact of injected gases in the reservoir and forecast the effects on the reservoir pressure, production enthalpy and the potential breakthrough of reinjection fluid to the production wells, numerical reservoir simulation studies are required.

NCG reinjection has been applied to geothermal reservoirs in few fields including: Hijiori (Yanagisawa, 2010); Ogachi (Kaieda et al., 2009); and Hellisheidi (Alfredsson and Gislason, 2009); Coso (Nagl, 2010; Sanopoulos and Karabelas, 1997) and Puna (Richard, 1990). At Hijiori, Ogachi, and Hellisheidi, CO_2 was dissolved in water at very low concentrations (0.01 to 3 % by weight) prior to injection.

This work investigates the possible impacts of reinjection of water-CO_2-H_2S mixture in two-phase liquid-dominated geothermal reservoirs using modified versions of an idealized numerical model developed by Kaya and O'Sullivan (2006) as a representative case study. Various reinjection scenarios were applied to see the effect of pure water and water-NCG mixture in a geothermal reservoir, in particular on the longevity of the resource with regard to steam production. Possible pathways of injected fluid were investigated in order to identify potential breakthrough and leakage risks. Adsorption behavior of CO_2-H_2S-water mixtures was investigated to understand the NCG storage capability of a reservoir. Different injection rates of water-NCG mixture were tested along with the geothermal water. The breakthrough of CO_2 was also monitored since higher gas (CO_2) production can result in lower power recovery due to higher parasitic load needed to remove these gases from the power plant condenser. Numerical experiments were carried out for various boundary conditions such as closed side boundary, hot side recharge and warm side recharge.

The injection of NCG gases will promote water-rock interactions when water flows through a permeable reservoir matrix. A growing number of experiments and numerical simulation studies are being conducted to explore the mechanisms and reactions prevalent in rock- CO_2-H_2S-water environments (Passarella et al., 2015; Sonney and Mountain, 2013). These chemical reactions result in different precipitation, dissolution and rock alteration assemblage that can change the porosity and permeability of the original rock matrix (Saldaña et al., 2016). Coupled flow and reactive transport modeling is not considered in this study. However, the effect of chemical reactions between NCG and rock minerals that could potentially contribute to mineral trapping of NCG was considered by including gas holding capacity through Langmuir adsorption): Gas holding capacity is a measure of the amount of gas that can be held by a unit volume of reservoir rock at a particular pressure and temperature.

When the NCG’s are co-injected with water, it mainly dissolves in the aqueous phase, but the pressure drop during production induces formation of a supercritical gas-like phase that has a much lower viscosity and density than the dissolved NCG. This may cause a rise of gas components to the surface with the effect of buoyancy forces. The use of the TOUGH2 equation of states (e.g. EOS2, EOS4 and EWASG) make it possible to simulate flow of water and a separate gas component, such as water-air for EOS4, water-CO_2 for EOS2, and choice of one type of NCG (air, CO_2, CH_4, H_2 or N_2) for EWASG in order to represent multicomponent systems and their temperature and pressure dependent gas dissolution. However, implementing one gas component of NCG is not adequate for monitoring the distribution of NCG injected into a reservoir, especially in the shallow vadose zones that mainly contains air.

In this study, we employ a modified version of the ECBM-TOUGH2 equation of state (Zarrouk and Moore, 2009), which was originally developed for modelling enhanced coalbed methane (ECBM). ECBM-TOUGH2 incorporates gas properties from the equations of EWASG (Battistelli et al., 1997) and EOS11(Zarrouk, 2008) and can handle non-isothermal multiphase flows of water and CO_2, N_2, H_2S and CH_4 gas compositions together. Representation of NCG trapping is also possible using adsorption parameters. ECBM-TOUGH2 has been used on several test problems and the model results have been compared with results from existing commercial packages (Moore and Zarrouk, 2011; Zarrouk, 2008; Zarrouk and Moore, 2009). The model has been used successfully in the assessment of the potential of several CBM fields in New Zealand and overseas. For visualisation and post processing, TIM (Yeh and Croucher, 2013) and PyTOUGH software (Florian Wellmann et al., 2012) were used.

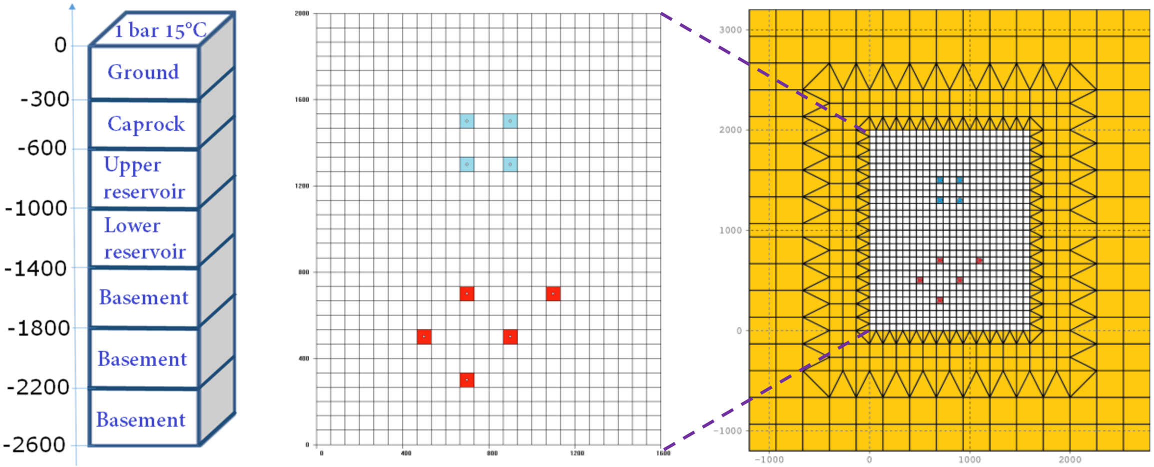
2. MODELLING OF WATER-NCG MIXTURE REINJECTION

The purposes of this study are to investigate the effect of NCG-water injection on overall heat recovery in a geothermal reservoir, and to observe the flow of NCG within the reservoir in order to assess the potential risk of early breakthrough or potential leakage to the surface. Experiments were carried out by using the following three types of model structure:

- 1D model: A natural state was derived for a 1D column model (Figure 1a) with an input of heat and mass at the base and atmospheric conditions (1 bar, 15°C and a 0.996 bar partial pressure of N_2) at the top. The 1D column model was used to obtain a representative 2-phase temperature and pressure profile of a geothermal system (Kaya and O'Sullivan, 2006).
- 3D closed model: The result of 1-D natural state model provided initial conditions for the 3D numerical model (Figure 1b) and small amount of inputs of heat and mass were injected at the base. The vertical grid structure, topmost boundary conditions, and rock properties of the 1D model was incorporated into this model.
- 3D large model: The 3D closed model was extended (yellow area) to test the effect of lateral warm recharge by adding an outer zone outside the reservoir (Figure 1c).

The vertical and areal grid structure of the 3D closed model are shown in Figure 1a and b. The areal extent of the layers is 1.6km × 2.0km. The vertical extent is 2.6km and includes 7 layers corresponding to the ground water system and a cap-rock, upper and lower reservoir, and basement rock. To achieve a representative behaviour of a 2-phase liquid dominated geothermal reservoir, various aspects of production parameters and model design of reservoir were investigated; e.g. deliverability of the production wells with DELV and DELG well types (AUTOUGH2, 2008), cut-off pressure, productivity index, maximum steam flow, reservoir permeability, relative permeability curves, and residual saturation. For some of the model settings, the simulations did not run for long enough due to problems with numerical convergence. By numerical experimentation, a stable model which can simulate long term behaviour under various reinjection conditions and exhibit characteristic behaviour of a liquid dominated reservoir system during production was obtained. Based on the result of these numerical experiments; the parameters shown in Table 1 were chosen to be used in the models.

Laboratory and field experiments (Kaieda et al., 2009; Passarella et al., 2015) demonstrated that a large amount of NCG can be stored in the reservoir rock through mineral dissolution and precipitation. This trapping mechanism can be mathematically represented through either chemical or physical adsorption of the NCG on the rock matrix. . Chemical adsorption (chemisorption) is permanent and requires the inclusion of all chemical species and products in the model (Saldaña et al, 2016), this can be complecated and time consuming for a large scale numercial reservoir model. This is best modeled using the TOUGHReact version of TOUGH2 (Saldaña et al, 2016).



(a) (b) (c)

Figure 1. Grid structure of a) 1D model, b) 3D closed model, c) 3D large model, and areal location of production (red) and injection (blue) wells.

Physical adsorption on the other hand is reversible, simpler to implement and do not require the use of the detailed chemistry of all the minerals involved in the reactions. There are two types of physical adsorptions implemented in different versions of the TOUGH2 reservoir simulator (Zarrouk, 2008); the first is the Freundlich (linear) adsorption and the second is the Langmuir (non-linear) adsorption, both types adsorptions are a function of the partial pressure of the given gas component. In this work we used laboratory experimental data from (Passarella et al, 2015) to calibrate the Langmuir adsorption parameters (Langmuir volume (VL) and Langmuir pressure (PL)). Although the Langmuir adsorption is reversible and the Langmuir adsorption parameters are temperature dependent (isotherms) we feel it is a reasonably simple approximation given that the NCG holding capacity of the reservoir rock is very small compared to coal (Zarrouk and Moore, 2009). At the same time amount of NCG injected is relatively small and the reservoir pressure around the reinjection wells will not decline significantly with time, hence the gases will not desorb.

A dipole injection and production configuration was used. Locations of production (red) and reinjection wells (blue) are shown in Figure 1b. An exploitation period of 50 years was chosen. Both upper and lower reservoir layers are open to production through 5 production wells. However, reinjection is only applied into the upper reservoir layer. Injection scenarios include two cases of reinjection rate (130 and 215 kg/s). Reinjection of water-NCG mixture (2.5% by mass of CO_2 and 0.06% H_2S) as well as water-only reinjection cases were presented.

Table 1. Parameters used in the model

Rock Parameters		
Matrix density (kg/m^3)		2650
Specific heat (J/kg ^{o}C)		1000
Thermal Conductivity (W/m ^{o}C)		1.7
Layers	Permeability (mD)	Porosity (%)
Ground layer	6	10
Caprock	0.25	5
Reservoir	17.5	5
Basement	0.25	5
Relative Permeability	Corey Curves: Slr : 0.6 Svr : 0.05	

CO_2 Langmuir isotherms	VL (cc/g) 5.0 PL(bar) 200.0
H_2S Langmuir isotherms	VL (cc/g) 0.001 PL(bar) 44.1
Relative Permeability	Corey Curves Slr : 0.6 Svr : 0.05
Reinjection Temperature	170 °C
Separator pressure	8 bar abs
Well deliverability (DELG) parameters	
Productivity Index (m^3)	1.00E-12
Maximum steam rate (kg/s)	15
Cut off pressure (bar)	Upper reservoir : 21.8
	Lower reservoir : 50.0

Production was represented by wells on deliverability. The deliverability of the production wells has the form given in Equation 1, where q_m is the mass flow, PI is the productivity index, k is the absolute permeability, ν_f is the kinematic viscosity of the fluid, p is the reservoir pressure and $p_{cut\text{-}off}$ is the trigger pressure at which the well stops flowing. Both DELV and DELG options were tried but it was decided to use DELG, which allows a discharge proportional to the pressure above some cut-off pressure value, due to its allowance to have more control on production parameters. Various cut-off pressure values were tried in both feed zones of the production wells. Since the reservoir pressure is higher at the deeper layers, a higher cut-off pressure value was assigned to these layers in order to prevent a larger pressure difference (between reservoir pressure and cut-off pressure) at the deeper zones (Table 1).

$$q_m = PI \frac{k}{\nu_f}(p - p_{cut-off}) \tag{eq. 1}$$

3. RESULTS

3.1. 3D closed model

In the 3D closed model, it is assumed that recharge outside the lateral boundaries of the model is negligible and the sides of the model are treated as no-flow boundaries. The model uses the parameters given in Table 1. Based on the 1D model, a mass flux of 6.5×10^{-7} kg/s.m^2 was assigned from the base of the model with an enthalpy of 1765 kJ/kg. Initial conditions obtained by using 1D model and used in the 3D closed model are shown in **Table 2**. Two reinjection rates were investigated with and without the NCG's.

Table 2. Initial conditions used in the model reservoir layers

Layers	Pressure, bar	Temperature, °C
Upper Reservoir	70.8	281.8
Lower Reservoir	99.1	310.3

Figure 2 shows steam and NCG production flow rates for the 3D closed model, for no rejection, and reinjection of mixed NCG-water at the rates of 130 and 215 kg/s. It can be seen from this figure that, for the overall production period, the higher the reinjection rate results in the higher long term steam production. Figure 2 also shows that after the first five years of production, NCG breakthrough occurred at the production wells and NCG production continued with an increasing flow rate. This is due to the short distance (shortest distance is 600m) between the production and reinjection wells. Since high reinjection rates consist of higher NCG concentrations, the NCG production rate is highest for the 215kg/s "water+NCG" injection case. According to the figure, after about 50 years of reinjection, the NCG flow rate at production wells is as high as 8% of the produced steam for the 215kg/s reinjection case, and 5% for the 130kg/s reinjection case.

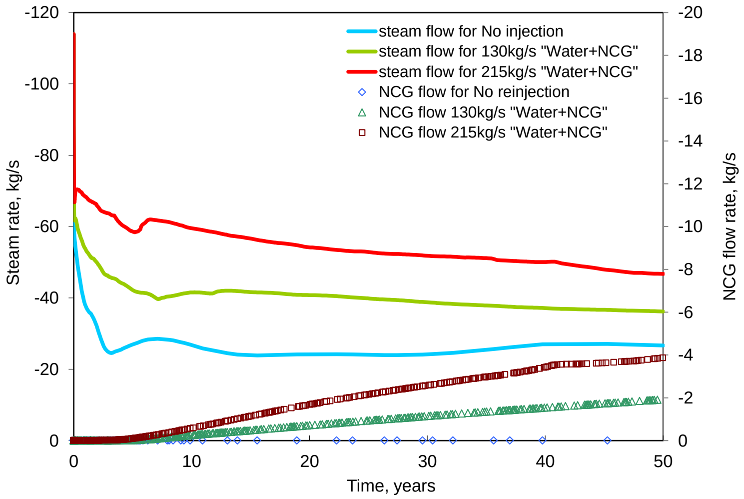


Figure 2 Steam and NCG production rates for no reinjection, and the 130 and 215 kg/s water-NCG mixture injection cases

Figure 3 compares the "water+NCG" reinjection case with the water-only reinjection case. From Figure 3, the addition of 2.5% NCG into reinjected water causes a slightly higher steam production rate for the first five years of the production than for the water-only reinjection case. However, the amount of produced steam starts to decrease later on and a significant drop occurs in the long term. The reason for this drop is the deliverability option used to represent the mass flow from the production wells (DELG) allows a declining flow rate in all production wells with time as the reservoir is depleted. For the DELG option, production occurs with a specified cut-off pressure and productivity index. Under a certain cut-off pressure, having a high rate of NCG production causes a drop in the steam production.

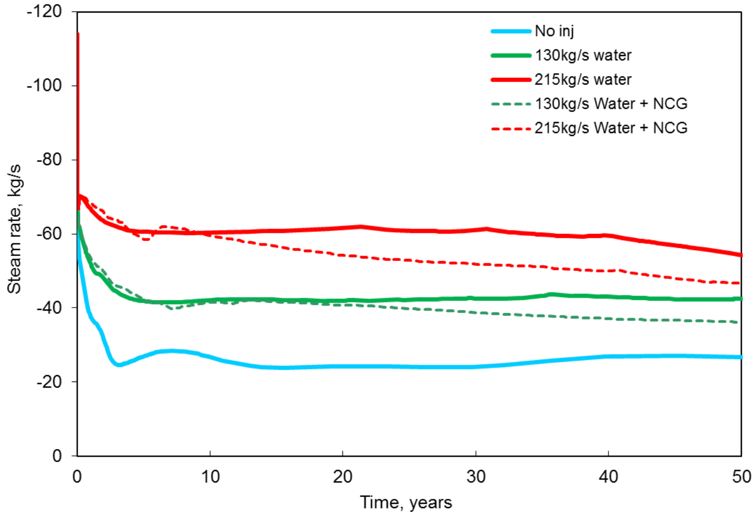


Figure 3. Comparison of steam production rates for water-only and water-NCG mixture reinjection cases.

In order to understand whether the difference visible in Figure 3 (between water-only and water-NCG mixture reinjection cases) comes from additional mass of NCG or from the overall effect of the reaction of water with NCG and the deliverability option used to represent the mass flow from the production wells, a different combination of NCG concentrations and water was tested for the same rate of reinjection;. e.g. for the reinjection rate of 130kg/s two different combinations were tried, *"water+NCG"* represents injection of 126.67 kg/s water, 3.25 kg/s CO_2, and 0.08 kg/s H_2S. The other combination considers a proportion of 2.5% NCG as additional to the total water rate; e.g. *"130kg/s water"+NCG* represents rates of 130 kg/s water, 3.25 kg/s CO_2 and 0.08 kg/s H_2S. The results showed that there is no significant difference in steam production rates and NCG flow distribution in the reservoir between these cases (**Figure 4**) due to the small amount of additional mass of NCG.

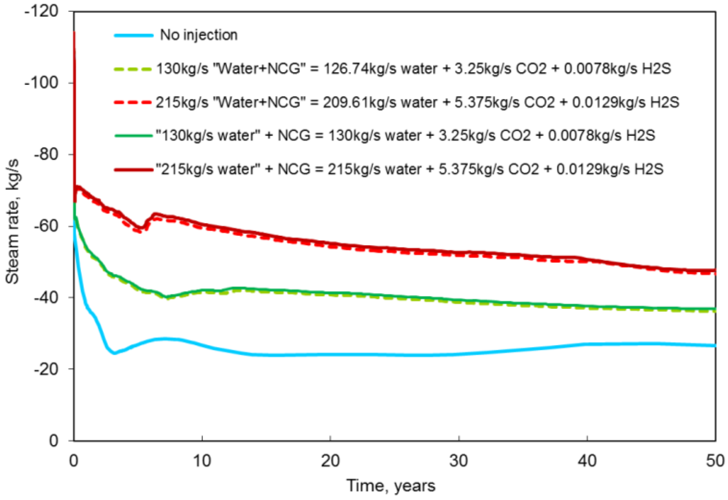


Figure 4. Effect of water-NCG mixture proportions on steam production rate

Figure 5 shows the areal distribution of the mass fraction of CO_2 in the gas phase for layer 3 and layer 4 and the vertical cross-section view along line A-A'. It can be seen from this figure that, at the high rate of reinjection, CO_2 diffuses into a large area. Injected NCG also flows vertically: A larger rate of flow is visible in the lower reservoir layer (Layer 4) due to its permeability, as well as a smaller amount of flow to the low permeability caprock (layer 2), and to the ground layer with the effect of buoyancy. Since the fraction of NCG is less in the *"215 kg/s Water" + NCG* case than in the *"215 kg/s Water + NCG"* and causes a slightly higher pressure support due to additional mass, *"215 kg/s Water" + NCG* case causes less propagation of NCG horizontally and vertically.

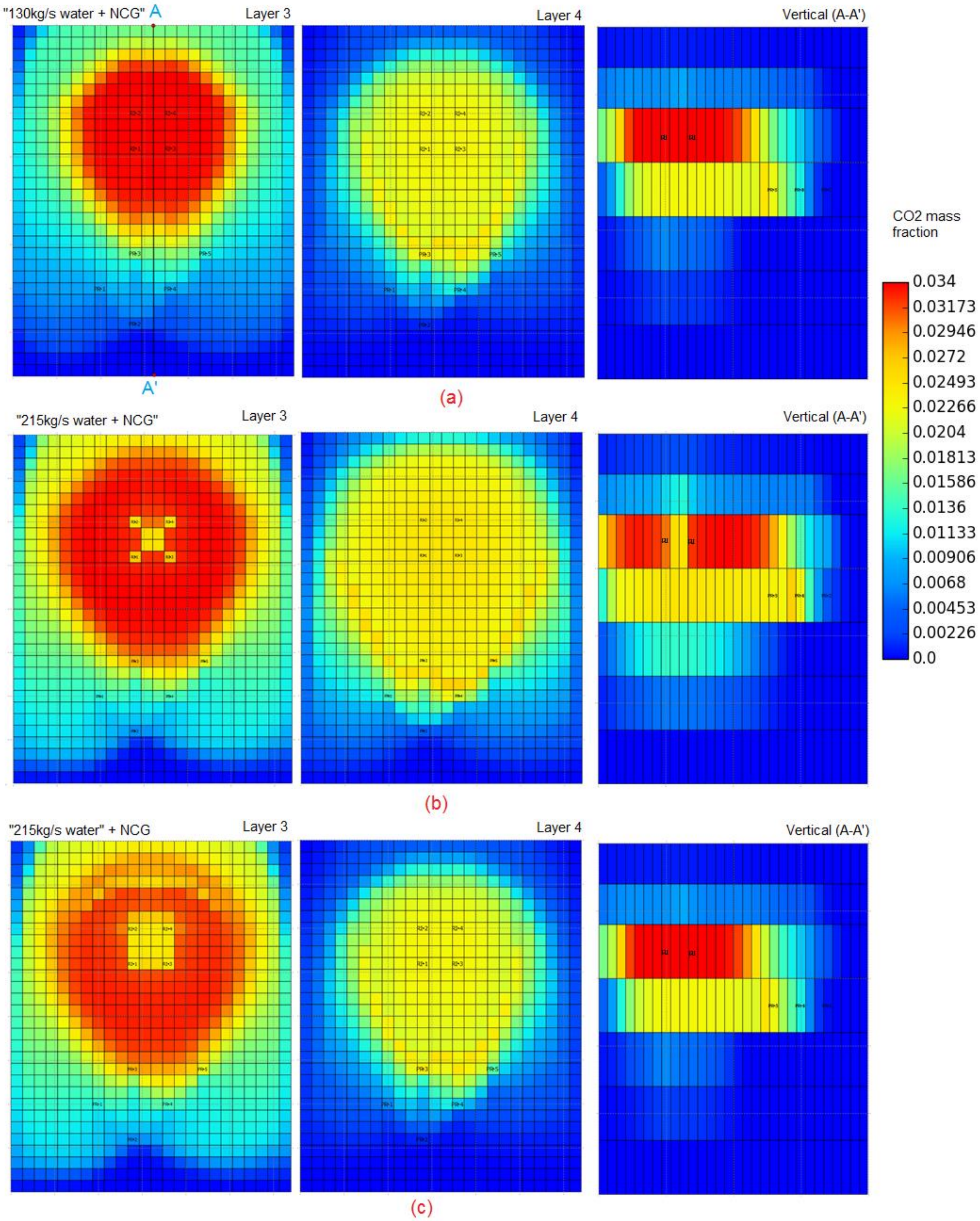


Figure 5. CO_2 mass fraction at Layers 3 and 4 and a vertical cross-section through A-A' for (a) 130kg/s *"water + NCG"* (b) 215kg/s *"water + NCG"* mixture reinjection (c) *"215kg/s water +NCG"*, on the 50th year

In order to investigate the effect of reinjection depth on the production capacity of the reservoir, a deep reinjection case was considered. **Figure 6** compares the shallow (injection into Layer 3- upper reservoir) and deep (injection into Layer-5 basement) reinjection cases. **Figure 6** shows that, for the low rate of reinjection case (130kg/s), shallow reinjection provides a good pressure support, and allows a higher rate of steam production than the deep reinjection case. For the high reinjection rate (215kg/s) case, although injecting into the deeper level gives a significantly smaller steam production rate than shallow reinjection initially, after 25 years of production, the deep reinjection starts to show better support of steam production than the shallow reinjection case.

NCG flow rates at production wells are compared for shallow and deep cases of water-NCG mixture reinjection in **Figure 7**. Results show that deep reinjection allows less production of NCG.

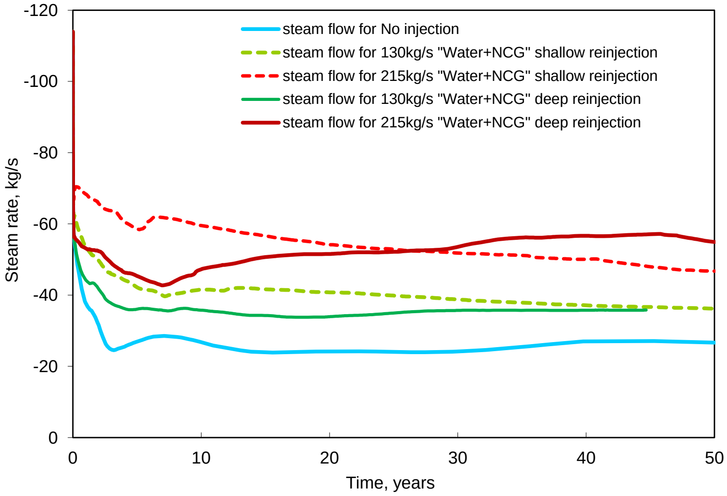


Figure 6. Comparison of steam production for shallow and deep reinjection of water-NCG mixture

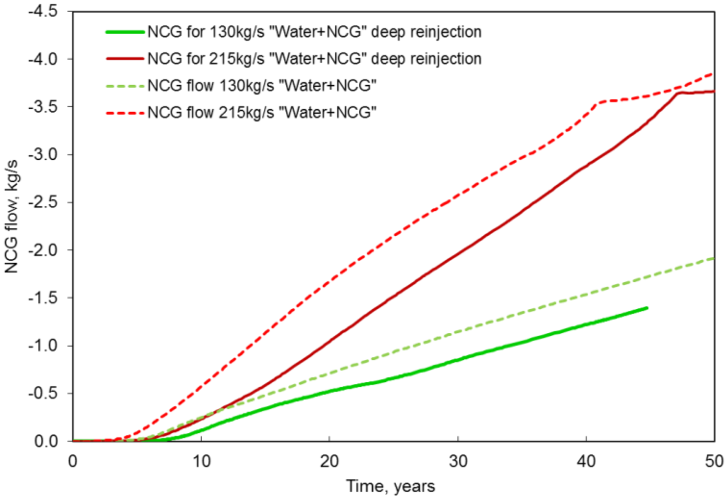


Figure 7. Comparison of NCG flows for shallow and deep reinjection of water-NCG mixture

3.2. Side-Recharge

3.2.1. Hot Side Recharge

Lateral recharge is important in geothermal reservoirs (Kaya and O'Sullivan, 2006; Kaya, O'Sullivan, et al., 2011). To examine the effect of a lateral hot recharge, an effectively infinite outer zone was implemented by using recharge boundary conditions at the side boundaries of the outer zone of the 3D closed model. The initial conditions that were used with the Model 3D were used again in this case. To obtain recharge equivalent to the infinite boundary model, recharge wells were assigned to the outermost blocks by using the RECH option (AUTOUGH2, 2008). The mathematical formula for this option is given in Equation 2. The RECH option used here allows extra recharge to enter the system through the side boundaries, in proportion to the pressure drop. This option also keeps the enthalpy of the recharge fluid the same as the initial enthalpy. So that if the block is initially hot, then hot fluid enters the system.

$$q_m = A(p - p_o) \quad \text{(eq. 2)}$$

Here, q_m is the mass flow rate, A is the recharge coefficient, p is the block pressure, and p_0 is the initial block pressure. The recharge coefficient values depend on the size and permeability of the outermost grid-blocks. The flow can be either into or out of the boundary block. If it is an inflow, the enthalpy is assumed to be at the original block value corresponding to the initial state (p_0, T_0).

As can be seen from Figure 8, in the cases of no-reinjection and 130kg/s *"water+NCG"* reinjection, the hot recharge model produces more steam than the laterally closed model, while for the 215kg/s *"water+NCG"* reinjection case, the laterally closed model produces more steam. This indicates that a considerable amount of recharge comes from the large outer zone blocks, and high rate of reinjection supresses the hot boundary recharge. Figure 9 shows that, in the presence of hot lateral recharge, NCG production rates are lower for both reinjection cases. This is because production fluid is mostly replenished by the side recharge, rather than reinjected fluid, and this slows the arrival of reinjected NCG to the production wells (Figure 10).

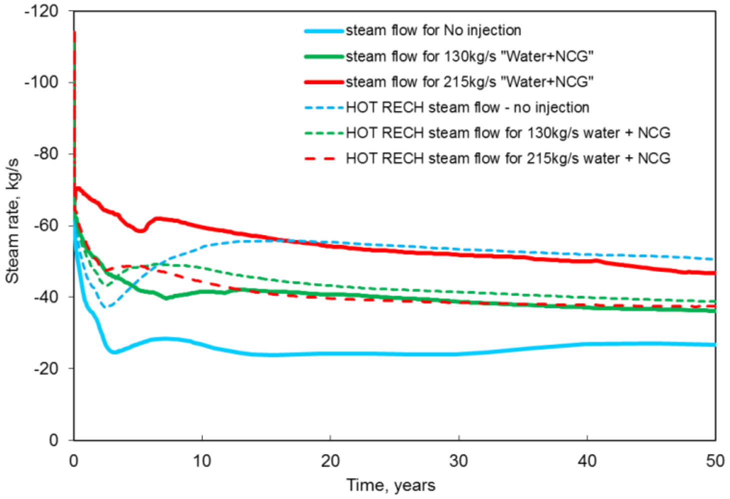


Figure 8. Steam production rates for the closed model and hot recharge model

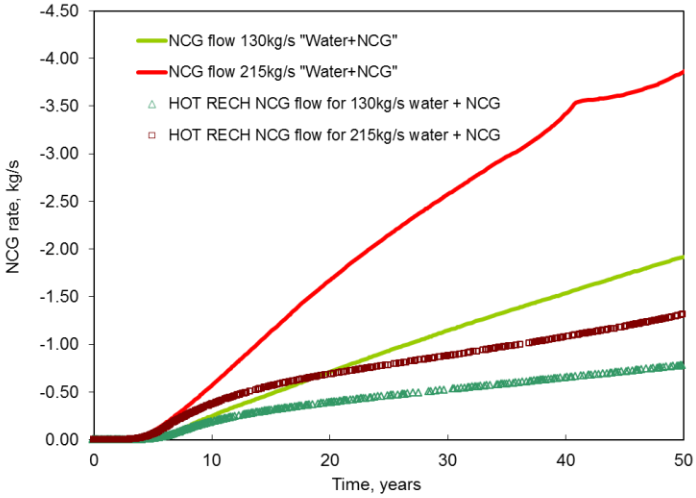


Figure 9. NCG production rates for the closed model and hot recharge model

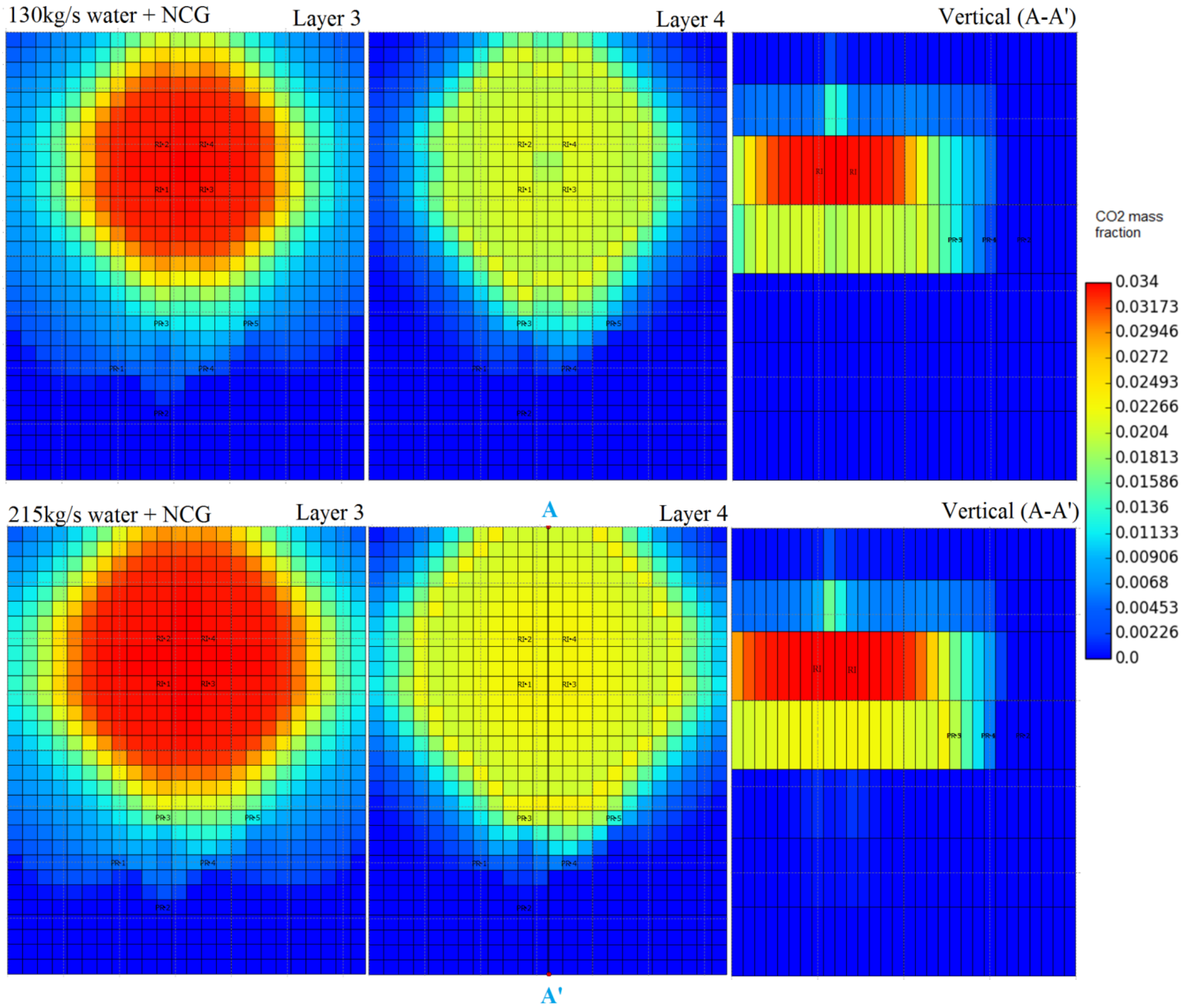


Figure 10. Areal and vertical distribution of CO_2 mass fraction at layer 3 and layer 4 for the hot side recharge model at the 50th year.

3.2.2. Warm Side Recharge

In this model, we consider the additional case where the side recharge is warm rather than hot. To explore the effect of warm lateral recharge, the grid used for the 3D closed model was enlarged by adding an outer zone 1.2km wide. This model is called 3D large model. The grid structure of this model is shown in Figure 1c. The white area in this figure is the grid used for the 3D closed model, and the surrounding area shows the enlarged section.

Because the temperature gradient in geothermal areas can be up to 200°C/km or more (Garcia-Estrada et al., 2001), we assumed a temperature gradient for the outermost grid blocks of 150°C/km. For the white area in Figure 1c, the temperature profile is the same at that used in 3D closed model. For the blocks in between, the temperature values were obtained by interpolation between the temperature profiles of the inner (white) and outermost blocks. We also included recharge boundary conditions at the outside of the 1.2km outer zone: The mass flow into the boundary blocks is given by Equation 2.

Figure 11 compares steam production rates of the no reinjection case for the 3D closed model and the hot and warm side recharge models. Because it provides high enthalpy recharge to the production wells, the higher temperature lateral recharge results in a higher steam production rate.

Figure 12 shows that in the warm side recharge model, for the water-only injection case, the higher rate of reinjection increases the steam production. Addition of NCG into the reinjection fluid increases the steam production due to an increased enthalpy at the early stages, however in the long terms suppresses the steam production because of the decrease in the total mass production (**Figure 13**). NCG production starts and increases with time. **Figure 14** show that the presence of warm recharge decreases the amount of NCG breakthrough as compared to the laterally closed model. The higher rate of reinjection increases the size of the zone that is invaded by the reinjected NCG (Figure 15) and causes a larger drop in steam production.

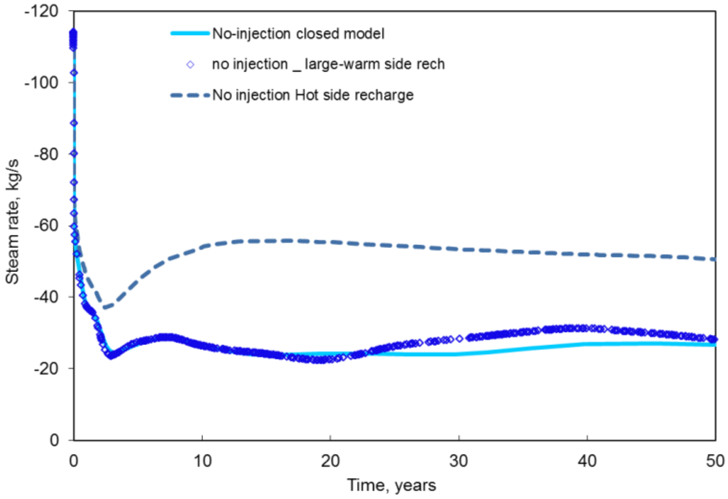


Figure 11. Steam production rates for the no reinjection case for the 3D closed model and hot and warm side recharge models

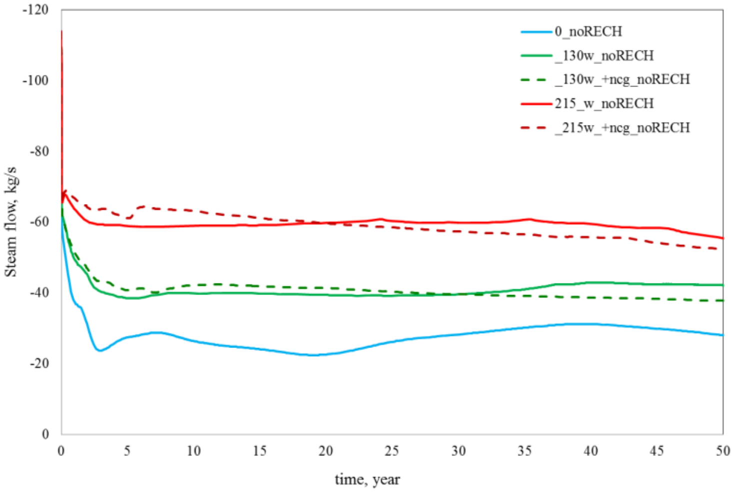


Figure 12. Comparison of steam production of water-only and water-NCG mixture reinjection cases for the warm side recharge model

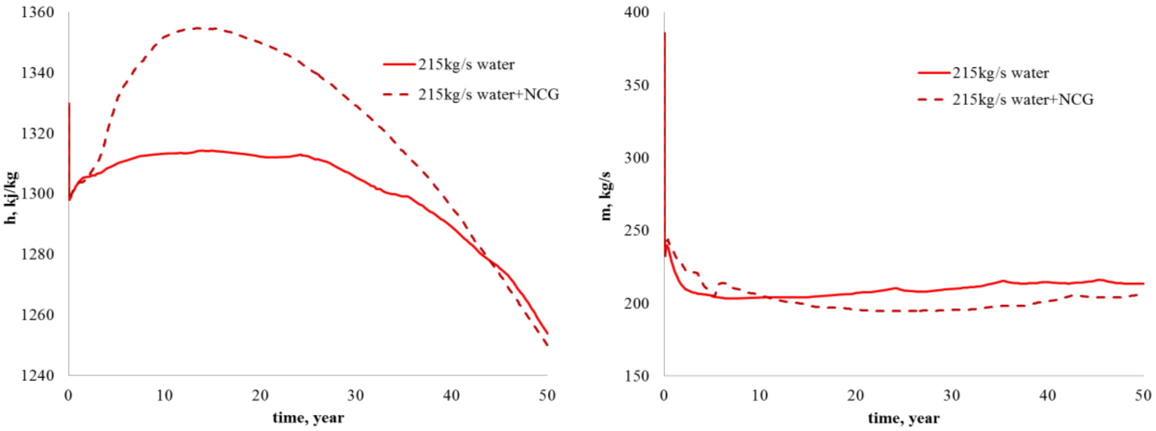


Figure 13. Comparison of enthalpy and total mass production of 215kg/s water-only and 215kg/s water-NCG mixture reinjection cases for the warm side recharge model

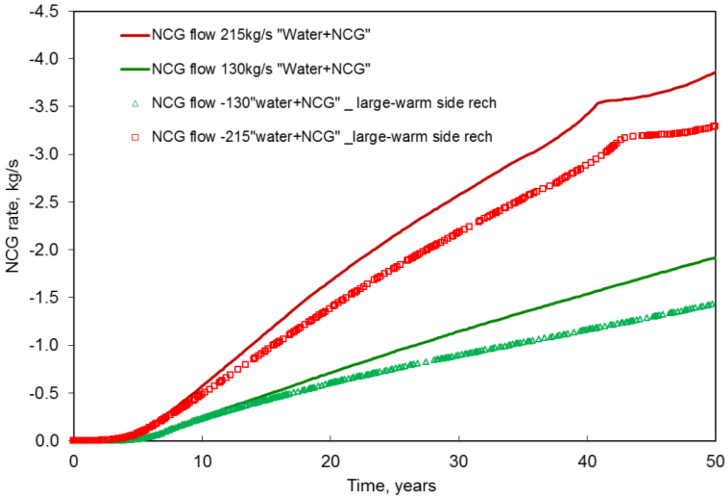


Figure 14. Comparison of NCG production rates for the laterally closed model (3D closed model) and the warm side recharge model.

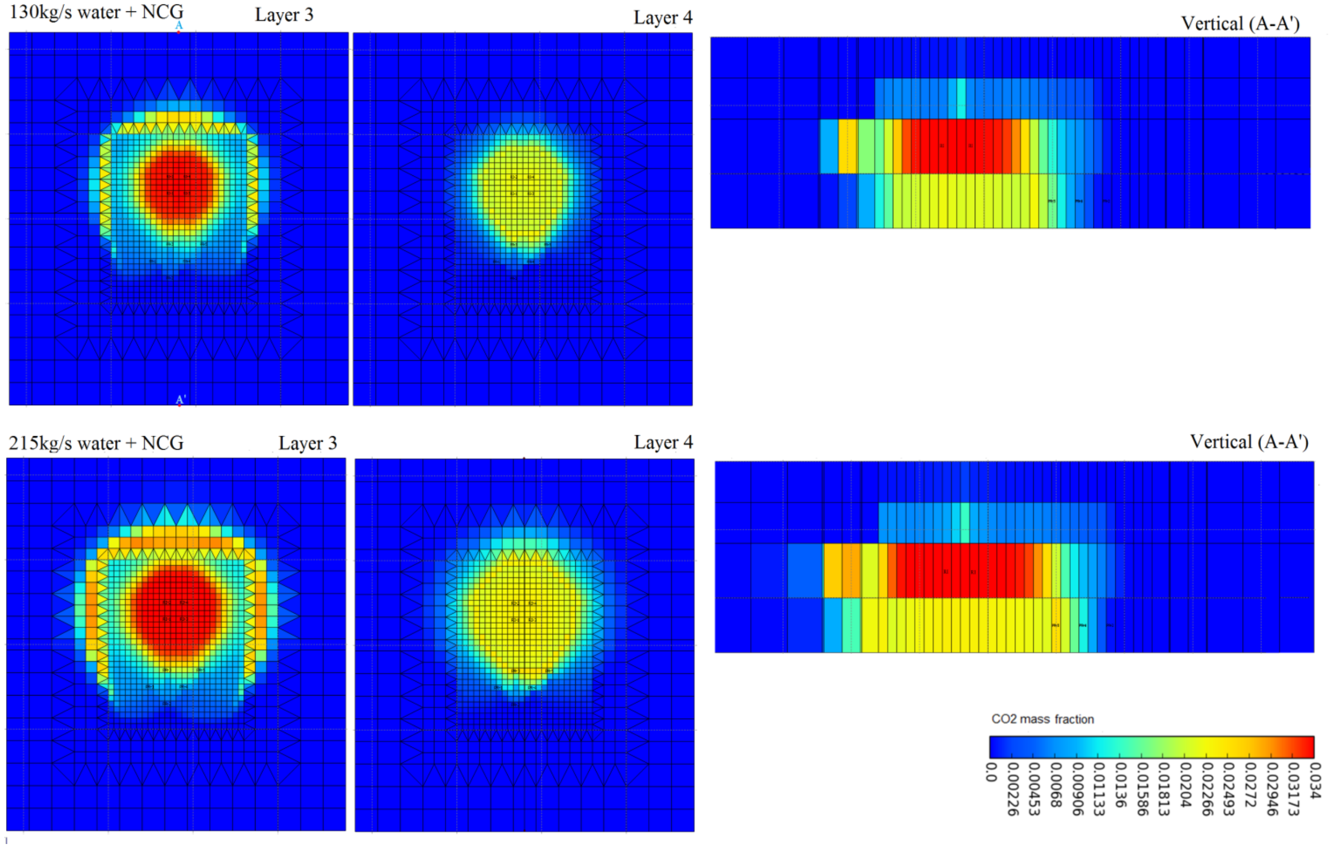


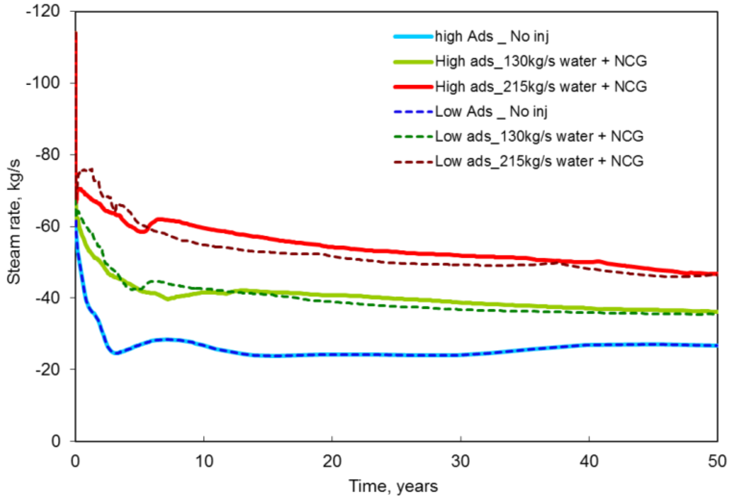
Figure 15. Areal and vertical distribution of CO_2 mass fraction at layers 3 and 4 for the warm side recharge model at the 50th year

3.3. Adsorption

Injected NCG can be trapped by a variety of mechanisms in the reservoir (especially solubility trapping, mineral trapping). The amount of gas held by the rock is represented by adsorption isotherms (maximum gas holding capacity) (Zarrouk and Moore, 2009). In this section, the effects of different NCG holding capacity values were investigated by using high and low adsorption capacities. The 3D closed model and the initial conditions that were used with that model were used again in this case.

The high adsorption case was represented by using the adsorption isotherms belonging to Gore lignite with a VL of 5.0 cc/g, and PL of 20.0 MPa for CO_2 holding capacity; here, VL is the volume that represents adsorption capacity and PL is the pressure at half of that volume. These high adsorption parameters were only assigned to the reservoir rocks (layers 3 and 4). For the low adsorption case, a VL of 0.001 cc/g, and PL of 4.25 MPa were used. For H_2S, values of 0.001 cc/g VL and 4.41 MPa PL were used for both (the high adsorption and low adsorption) cases.

Figure 16 compares steam production rates for the high and low adsorption capacity cases. The figure shows that, although, initially, low adsorption of NCG causes a higher steam flow, in the long term, the high adsorption case results in higher steam production. If NCG is held by reservoir rock with a high adsorption capacity, less NCG flow occurs at the production wells (Figure 17).



	VL, cc/g	PL, bar
CO_2 - High Adsorption	5	200
CO_2 - Low Adsorption	0.001	44.1
H_2S -Adsorption	0.001	44.1

Figure 16. Steam production rates for high adsorption (solid lines) and low adsorption (dashed lines).

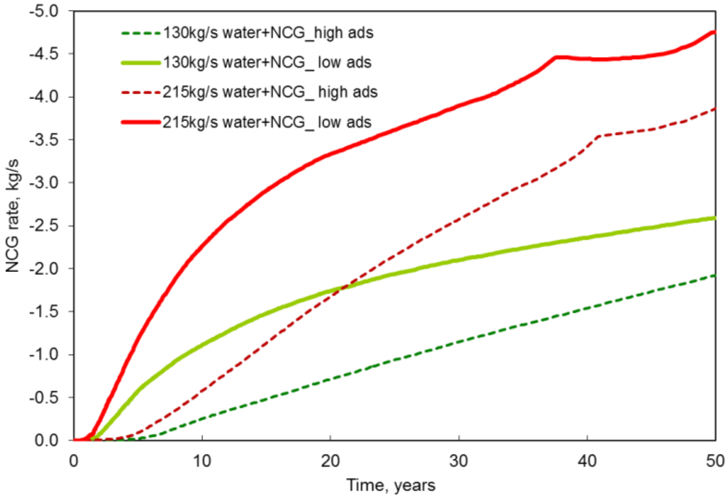
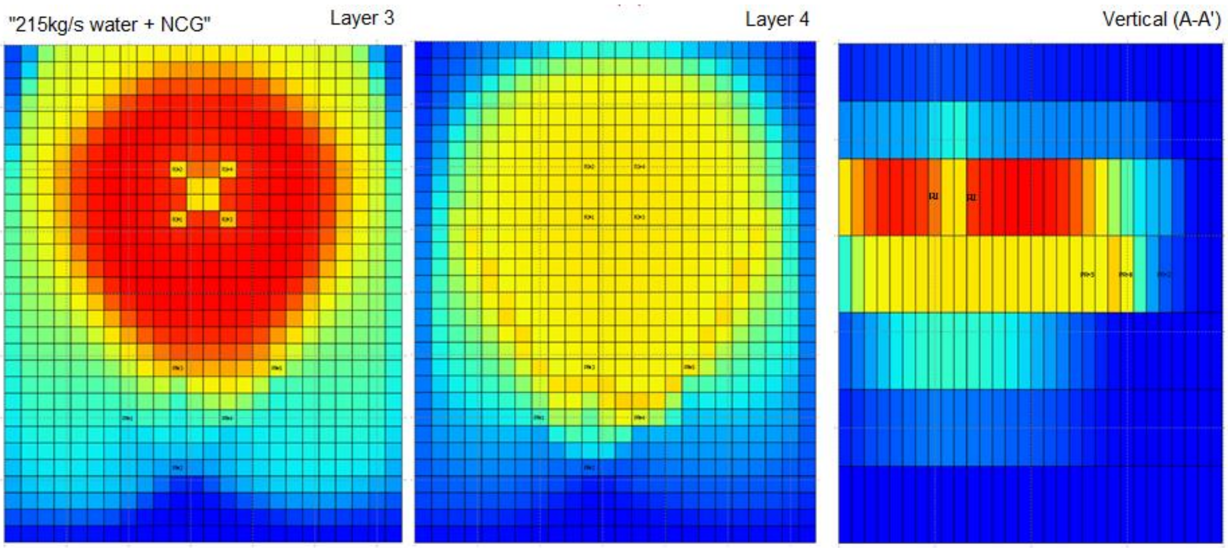
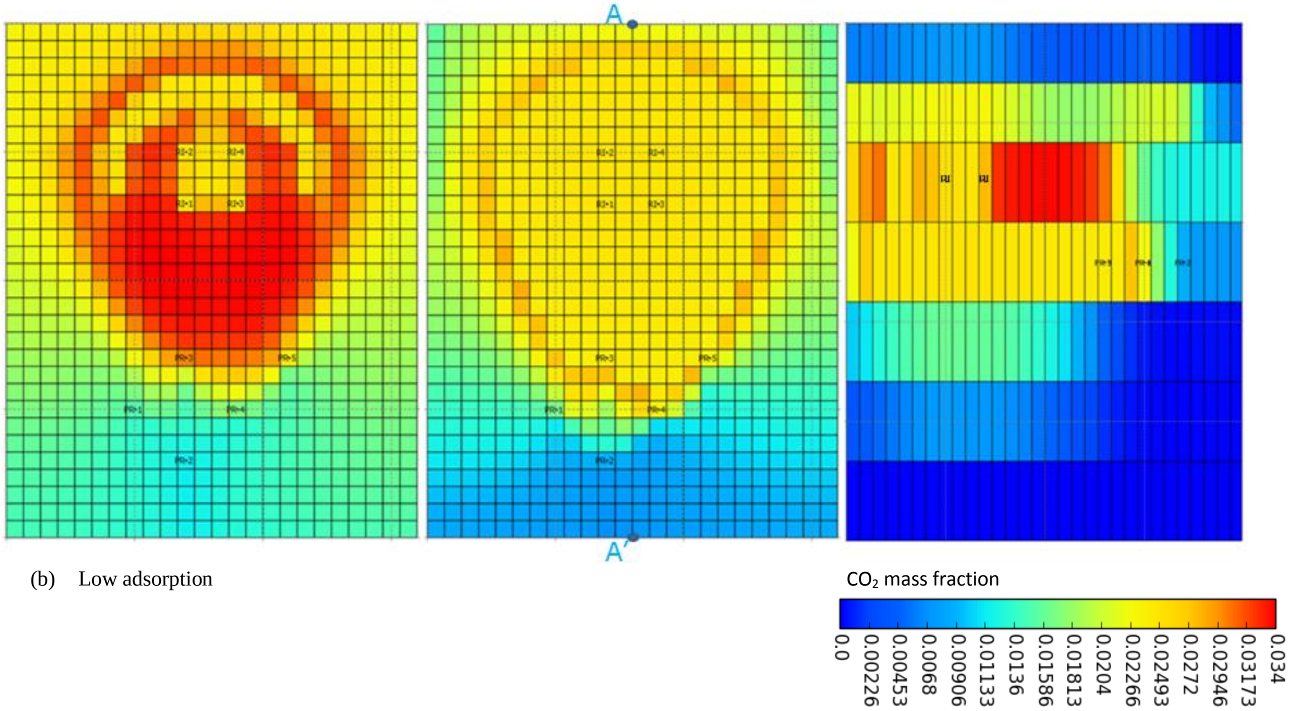


Figure 17. NCG flow rates for high adsorption (solid lines) and low adsorption (dashed lines).

The CO_2 mass fraction distributions in the reservoir layers (layers 3 and 4) and on a vertical cross-section after 50 years of production are given in Figure 18. In general, all scenarios give similar patterns of CO_2 distribution. It can be seen that, for the case of high adsorption, the reservoir layers hold a larger amount of CO_2.



(a) High adsorption



(b) Low adsorption

Figure 18. CO_2 mass fraction distribution for a) high and b) low adsorption at the 50th year for "215kg/s water+NCG".

4. CONCLUSION

A simultaneous NCG and water reinjection for a high temperature geothermal reservoir has been modelled by using a set of idealised 3D closed models representing various boundary conditions, reservoir and production parameters under several reinjection scenarios. This work provides a critical insight into how to better design a NCG and water injection system under various operating conditions. The model of the system was developed by using the ECBM version of the TOUGH2 reservoir simulator (Zarrouk and Moore, 2009), which enables the representation of combination of different NCG and also includes the NCG trapping by using adsorption parameters. The overall results of the modelling show that:

- Water-NCG mixture reinjection into geothermal systems can lead to an increase on the reservoir pressure and might promote boiling at the early times of production, but it causes a drop in steam production rate in the long term, since the NCG reaches to the production wells and NCG flow rises steadily with time. The injected CO_2 flows mainly in the reservoir layers, with a small amount of CO_2 flowing upward through the cap-rock.
- When side recharge implemented, NCG production from production wells decreases, because some portion of the production fluid comes from NCG-free recharge fluid.

- NCG trapping was represented by using a high adsorption capacity. Numerical simulation shows that when NCG holding capacity is high, NCG flow from production wells is low, due to holding a higher NCG mass fraction in the reservoir.

This modelling study could be extended further by including a larger model with a different well pattern (intermixed or peripheral). Various topography conditions can be included to see its effect on the convection of NCG in the reservoir. Flowing bottom-hole pressure dependence on both total rate and mixture enthalpy can be included for production wells on deliverability.

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