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Evaluation of the Impact of Water Injection on CO_2 Dissolution and Migration Characteristics during Sequestration

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Abstract

This work investigates CO_2 dissolution and migration in a homogeneous aquifer through a vertical well at different water injection rate and ascertains the amount of CO_2 sequestered into the subsurface. Numerical simulation was done with Computer Modelling Group (CMG) simulator and builder used to write the dataset and validated with GEM.WINPROP was used to predict the thermodynamics properties using the Peng-Robinson 1978 EOS and sensitivity studies carried out with three different water injection rate (25, 50 and 75m^3/day) and compared to a base condition of no water injection. Result indicates that after 196 years, mobile CO_2 gas cap formation was at the top of the formation with a saturation of 0.99 and length of 558.4753m, 75604384 moles of CO_2 dissolved and 18547034 moles of CO_2 trapped without water injection above the CO_2 injector. For 25m^3/day of water injected, there was a 54 % decrease in the length of gas cap saturation, 17% decrease in the CO_2 dissolved and 28% decrease in the CO_2 trapped when compared with the base case model without water injection. 50m^3/day scenario of water injected had 93% decrease in the length of gas cap saturation, 39% decrease in the CO_2 dissolved, and 63% decrease in the CO_2 trapped. Also, 75m^3/day of water injected above the CO_2 injector shows no zone of mobile supercritical CO_2 formed at the top of the structure with 50% decrease in the CO_2 dissolved and 64% decrease in the CO_2 trapped .Result reveals that most of the injected CO_2 were completely dissolved in water and less trapped at different rate of water injection.

Keywords: *Water Injection, CO_2 Dissolution, Migration, Solubilized, Sequestration.*

INTRODUCTION

The constant exploitation of fossil fuels as sources of energy inexorably raises greenhouse gas (GHG) emissions in the atmosphere and eventually leads to the proliferation of global warming. The reduction of these GHG emissions has become vital, and it is getting major attention globally due to its environmental repercussions. The main component of the GHGs accountable for the cumulative harmful influence on the environment is CO_2 (Ding et al., 2018). Thus, the decrease in this anthropogenic CO_2 output cannot be overemphasised. Carbon capture technology is one possible way to lower the amount of CO_2 that heavy industries emit (Ding et al., 2018; Li et al., 2013; Pereira et al., 2017). The captured CO_2 is then stored and sequestered underground (Burton et al., 2009; Ganjdanesh and Hosseini, 2017; Mijic et al., 2014; Mutailipu et al., 2019). Geologic storage as a greenhouse gas mitigation approach will be workable only if long-term, secure containment of CO_2 can be assured. Among the different methods for CO_2 sequestration, subsurface saline aquifers are considered the most viable because of the massive, porous, and permeable formation in sedimentary basins globally, as these have the largest potential for CO_2 sequestration compared to others. According to Jiang (2011), there exist four distinct methods of trapping in saline aquifers: structural trapping, capillary trapping, solubility trapping, and mineral trapping. At typical subsurface temperature and pressure conditions in the terrestrial crust, separate-phase supercritical CO_2 is less dense than the aqueous phase. Accordingly, when CO_2 is injected into a saline aquifer, it will experience an upward buoyancy force, tend to collect beneath a caprock, and migrate towards shallower depth whenever appropriate permeable pathways, like fractures, faults, or improperly abandoned wells, are available (Nordbotten et al., 2005; Pruess, 2008; Celia et al., 2008). As the CO_2 plume expands out under a caprock, it will become partially immobilised by capillary forces (Kumar et al., 2005). The interfacial tension between CO_2 and the formation, traps CO_2 in an irreducible gas saturation state, preventing it from leaving the pores (capillary trapping). Solubility trapping in saline aquifers isolates the accumulated CO_2 below the caprock from the environment as it progressively dissolves

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into the brine over time. The dissolved CO_2 reacts chemically with the minerals in the formation and finally converts into solid carbonate minerals, which are precipitated in the pore space, known as mineral trapping. While mineral trapping is encourage, formation minerals has different reactivity to salinity concentration which decides CO_2 trapping and sequestration (Kinate et al.,2024)

Among these, solubility trapping is seen to be a more reliable and secure method in the medium to long term, and it also meets the characteristics needed for mineral trapping (Alcalde et al., 2018). CO_2 dissolution acts as a gateway towards eventual fixation of CO_2 as carbonates of poor solubility, and it generates a slight rise in aqueous phase density, thereby reducing concerns regarding upward buoyant flow. The transformation from free gas to trapped gas, dissolution into the aqueous phase, and precipitation of solid carbonates increase storage security, and the accompanying quantitative characteristics of CO_2 inventories and characteristic durations involved are of major practical significance (IPCC, 2005). It is widely known that both residual and mobile CO_2 will progressively dissolve into the groundwater; this gives great storage security, but CO_2 is relatively weakly soluble in groundwater, and density diffusion-driven dissolution occurs on lengthy time scales relative to plume migration (Macminn et al., 2010). Many investigations have been made on the density-driven convection for CO_2 solubility trapping in saline aquifers (Wang et al., 2022; Mahyapour et al., 2022). In contrast to much of the past studies, which have concentrated on CO_2 dissolution by natural convection, this paper analyses the technical possibility of speeding the dissolution of CO_2 in aquifers using water injection.

METHODOLOGY

Simulator and Data

Computer Modelling Group (CMG) was used for simulation and the input data with properties presented are presented in Table 1 – Table 6

Table 1. Grid properties data (Kinate et al.,2024)

Properties	Value
Grid Top	1200m
Grid thickness	5m
Permeability (I, J and K)	100 millidarcies
Porosity	0.13
Rock compressibility	5.4e-7 per kPa
Reference pressure for rock compressibility	11800 kPa

Table 2. Data for GEM fluid model creation(Kinate et al.,2024)

Component	Mole fraction
CH_4	0.999
CO_2	0.001
Reservoir temperature for GEM fluid model	50°C

Table 3. Brine properties (Kinate et al.,2024)

Property	Value
Water density	1020kg/m^3
Water compressibility	4.4e-7 per psi
Reference pressure	11800kPa

Table 4. Water relative permeability data(Kinate et al.,2024)

Sw	krw	krow
0.2	0	1
0.2899	0.0022	0.6769
0.3778	0.018	0.4153
0.4667	0.0607	0.2178
0.5558	0.1438	0.0835
0.6444	0.2809	0.0123
0.7	0.4089	0
0.7333	0.4855	0
0.8222	0.7709	0
0.9111	0.95	0
1	0.9999	0

Table 5. Gas relative permeability data (Kinate et al.,2024)

Sg	krg	krog
0.0006	0	1
0.05	0	0.88
0.0889	0.001	0.7023
0.1778	0.01	0.4705
0.2667	0.03	0.2963
0.3556	0.05	0.1715
0.4444	0.1	0.0878
0.5333	0.2	0.037
0.6222	0.35	0.011
0.65	0.39	0
0.7111	0.56	0
0.8	0.9999	0

Table 6. Model initialization data (Kinate et al.,2024)

Properties	Value
Temperature	60°C
Reference pressure	11800 kPa
Datum depth	1200m
Water gas contact	1150m
CO_2 fraction	0.001
CH_4	0.999

Simulation Process

This study was implemented with numerical simulation using Computer Modelling Group (CMG) and Builder for writing the dataset and validated with GEM. A homogeneous aquifer model of dimensions 100 x1x25 (2500 grid blocks) and block width of 10ft was developed. The model was populated with petrophysical, grid and rock properties with the data in Table 1.Fresh water and carbon dioxide (critical pressure, critical temperature, acentric factors and binary interaction coefficients), and the Peng-Robinson 1978 EOS was applied for estimation of CH_4 properties using WINPROP. A fluid model was developed and comprises of supercritical CO_2 and CH_4 in proportion of 0.001 and 0.999 (Table 2) with PR 1978 selected as the EoS for thermodynamic properties. The CH_4 component was treated as the trace component to have a tiny trace of CH_4 present as residual gas in the aquifer to add some compressibility to the system. Li-Nghiem's model was used for the calculation of Henry's constant for gas solubility in brine. The created fluid model was imported into the component section of GEM data file. Data in Table 3 were used in defining the brine properties. Relative permeability data in Table 4 and 5 were used to define the relative permeability curves and the model was initialized using the data in Table 6. Water-Gas contact was set at 1150m above the reference depth which gave a model fully saturated with brine. Gas cap was initialized with supercritical CO_2 fraction of 0.001 and CH_4 fraction of 0.999 respectively as stated in Amadichuku et al.(2023). An injector well 'CO2_INJECTOR' was completed in three layers at the bottom of the model at 1298m, 1299m and 1300m as adopted in Kinate et al.,(2024). Pure supercritical CO_2 was injected at a maximum, constant surface gas rate of 10000m^3/day with a bottomhole injection pressure limit of 44500kPa for 4years followed by 196years of equilibration (no injection). With the base case model established, a water injection well, 'WATER_INJECTOR' at a shallower depth than the CO_2 injector was located in grid block 1 1 5 to 1 1 8 and sensitivity studies were conducted at three different fresh(no saline) water injection rate of 25m^3/day, 50 m^3/day, and 75m^3/day respectively. The aquifer model with only CO_2 injector and Aquifer model with both CO_2 and water injectors are presented in the appendix. The simulation work flow is shown in figure 1

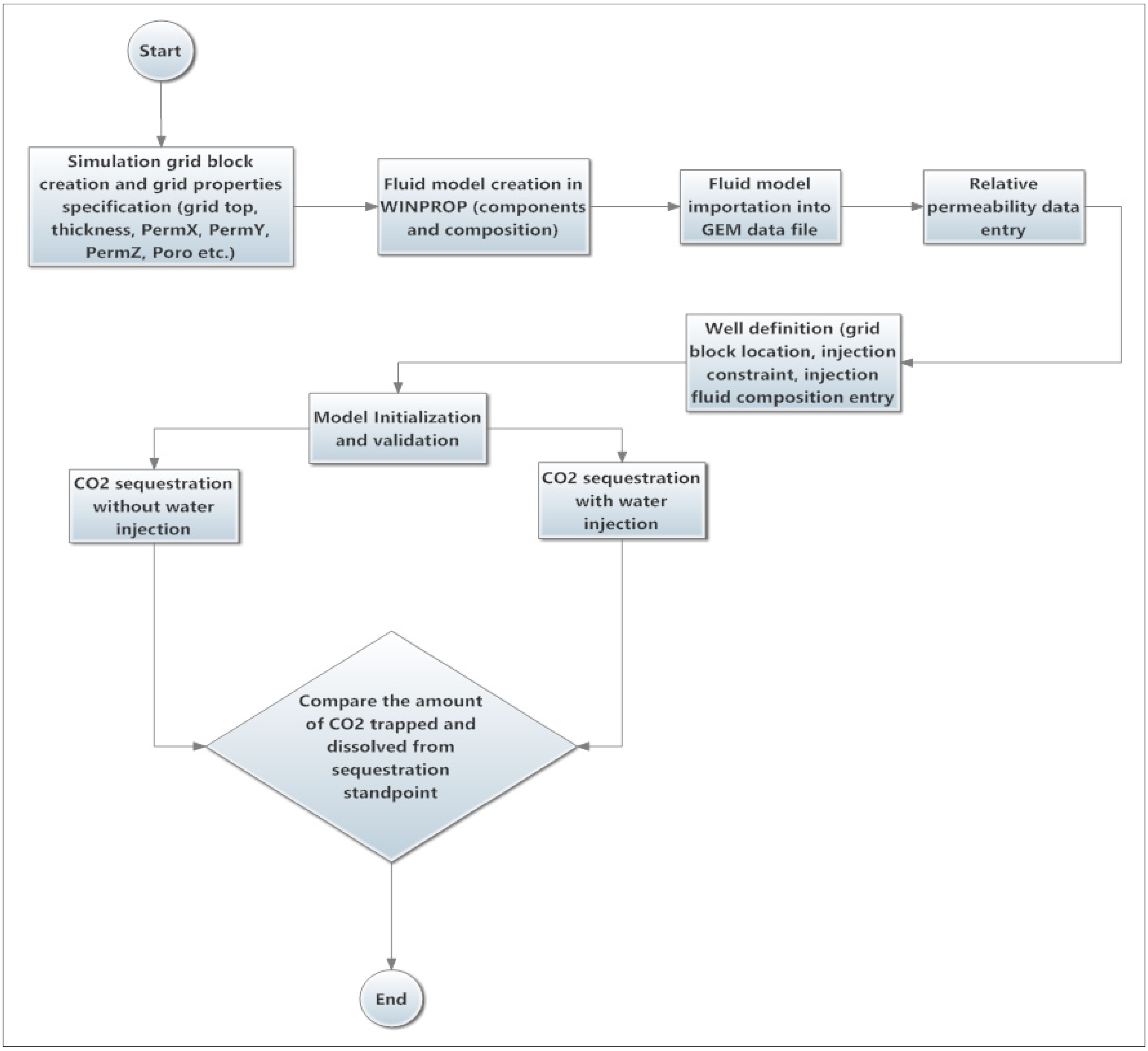

Figure 1. Simulation workflow

RESULTS AND DISCUSSION

Base Case CO_2 Solubility Model Without Water Injection

Figure 2 shows the model of CO_2 migration in saline aquifer with no water injection for CO_2 dissolution enhancement. The model simulates the injection of CO_2 for 4years and migration of the injected CO_2 plume under the effect of natural buoyancy during the next 196 years. The injected CO_2 migrate laterally during the injection phase under the influence of pressure provided by the injection well. During the post-injection, the lateral expansion of the plume ceased and CO_2 migrate upward to form a gas cap at the top of the structure. More of the CO_2 dissolved in brine as evidenced by the high concentration of CO_2 at the bottom of the aquifer. After 196 years, there was formation of a gas cap of mobile CO_2 at the top of the formation with a saturation of 0.99 and length of 558.4753m.

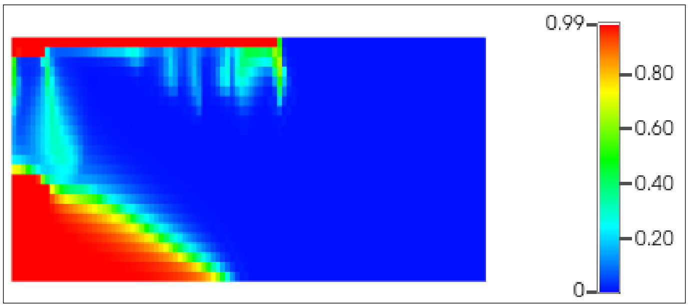

Figure 2. CO_2 migration in saline aquifer without water injection

The amount of CO_2 trapped and dissolved after 200years for when only CO_2 was injected for 4years without water injection is shown in figure 3. Result shows that during the injection period, 28111450 moles of CO_2 were structurally trapped. For post-injection phase, the amount of CO_2 trapped structurally increases slightly before declining and constant at 18547034moles due to the onset of CO_2 solubility trapping mechanism. During the injection phase, 30021050moles of CO_2 was solubilized in water while during the post-injection period, CO_2 solubility trapping mechanism gave 75604384moles of CO_2 in water. Less amount of CO_2 was trapped as compared with the higher moles dissolved with time.

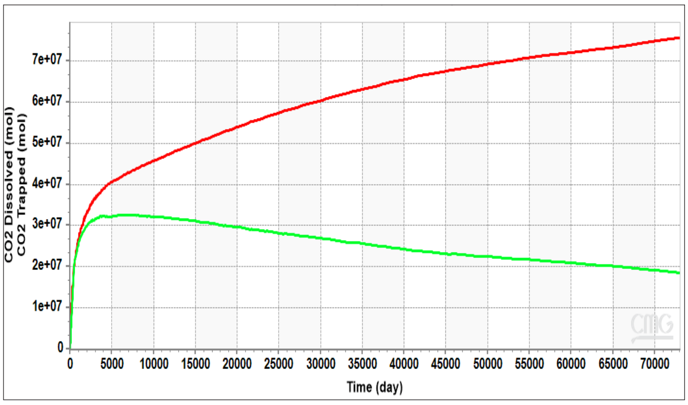

Figure 3. CO_2 trapped and dissolved without water injection

Water Injection Rate of $25m^3$/Day

CO_2 migration characteristics in saline aquifer when $25m^3$/day of water was injected above the CO_2 injector for 6months is presented in figure 4. The injected CO_2 migrate laterally during the injection phase under the influence of pressure provided by the injection well. For Post-injection, the lateral expansion of the plume ceased and more of the CO_2 dissolved in brine as evidenced by the high concentration of CO_2 at the bottom of the aquifer. After 196years of CO_2 migration under natural buoyancy with $25m^3$/day of water injected, a lower gas cap of mobile CO_2 was formed at the top of the structure when compared with without water injection. The gas cap saturation has a length of 258.5576m.

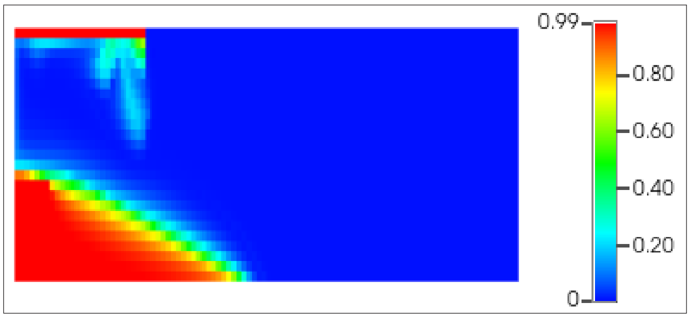

Figure 4. CO_2 migration characteristics in saline aquifer with $25m^3$/day water injection rate

The amount of CO_2 trapped and dissolved after 200years for when CO_2 was injected for 4years and water injected at the rate of $25m^3$/day for 6months above the CO_2 injector is presented in figure 5. Less of the CO_2 moles are structurally trapped compare the higher dissolved in water. Result shows that during the injection period, 20294074moles of CO_2 were structurally trapped.For Post-injection, the amount of CO_2 trapped structurally increases slightly and declined to 13350654 moles due to the onset of CO_2 solubility trapping mechanism. During the injection phase, 23520362 moles of CO_2 was solubilized in water while during the post-injection period, CO_2 solubility trapping mechanism gave 63114912 moles of CO_2 in water.

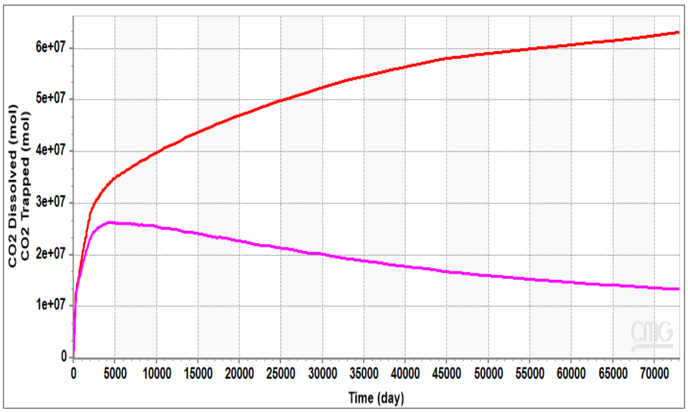

Figure 5. CO_2 trapped and dissolved with $25m^3$/day water injection

Water Injection Rate of $50m^3$/Day

The CO_2 migration characteristics in saline aquifer when

$50m^3$/day of water was injected above the CO**2** injector for 6months is shown in figure 6. The injected CO_2 also migrate laterally during the injection phase under the influence of pressure provided by the injection well for no water injection and when $25m^3$/day of water was injected above the CO_2 injector. However, with $50m^3$/day of water injected above the CO_2 injector, a thin zone of gas cap of mobile supercritical CO_2 was formed at the top of the structure with a length of 37.40061m.

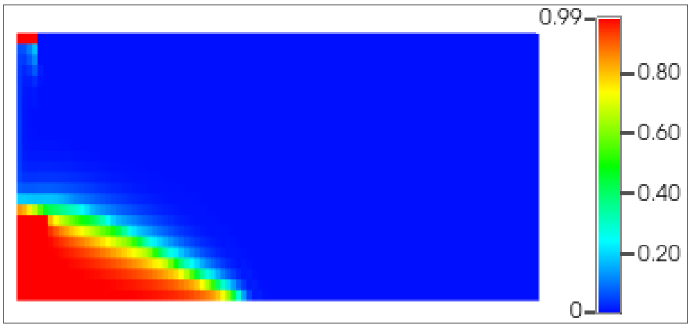

Figure 6. CO_2 migration characteristics in saline aquifer with $50m^3$/day water injection rate

The amount of CO_2 trapped and dissolved after 200years for the case in which CO_2 was injected for 4years and water was injected at the rate of $50m^3$/day for 6months above the CO_2 injector is shown in figure 7. The amount of CO_2 dissolved in water and trapped decrease rapidly with time when compared with case of no water injection and that of water injection rate of $25m^3$/day. Not much was trapped compare to the mount dissolved. Result shows that during the injection period, 10713185 moles of CO_2 were structurally trapped. For post-injection, the amount of CO_2 trapped structurally increases slightly and declined to 6820270 moles due to the onset of CO_2 solubility trapping mechanism. During the injection phase, 13739760 moles of CO_2 was solubilized in water while during the post-injection period, CO_2 solubility trapping mechanism gave 46310500 moles of CO_2 in water.

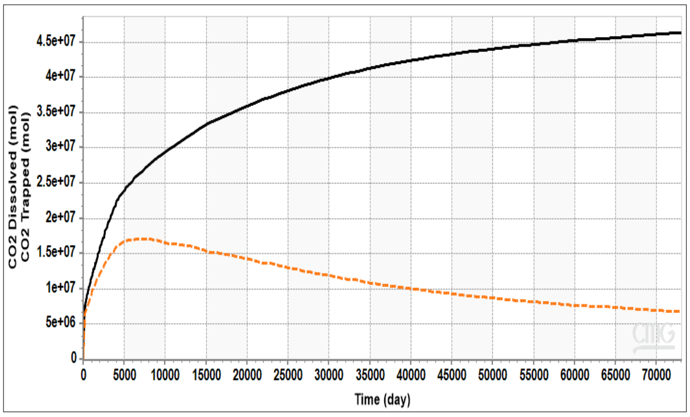

Figure 7. CO_2 trapped and dissolved with $50m^3$/day water injection

Water Injection Rate of $75m^3$/Day

The CO_2 migration characteristic in saline aquifer when $75m^3$/day of water was injected above the CO_2 injector for 6months is presented in figure 8. The injected CO_2 migrate laterally during the injection phase under the influence of pressure provided by the injection well for without water injection and when $25m^3$/day and 50 m^3/day respectively of water was injected above the CO_2 injector. However, with $75m^3$/day of water injected above the CO_2 injector, no zone of mobile supercritical CO_2 was formed at the top of the structure. All the injected CO_2 were completely dissolved in water. This scenario was quite favorable from a sequestration standpoint because fractures in the cap rock would not conduct any CO_2 to upper formations and eventually, the atmosphere.

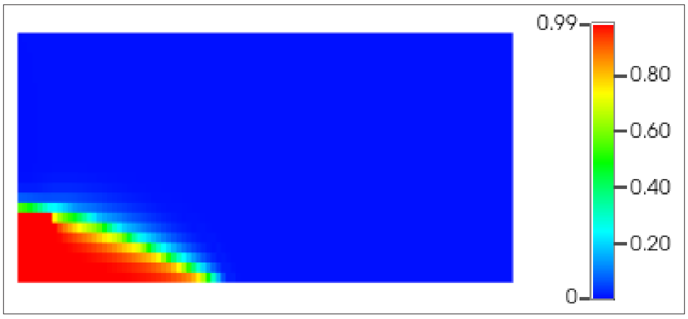

Figure 8. CO_2 migration characteristics in saline aquifer with $75m^3$/day water injection rate

Figure 9 shows the amount of CO_2 trapped and dissolved after 200years for the case in which CO_2 was injected for 4years and water was injected at the rate of $75m^3$/day for 6months above the CO_2 injector. CO_2 dissolved in water and the amount of CO_2 structurally trapped was less compared to the $50m^3$/day water injection rate. Result shows that during the injection period, 5984155 moles of CO_2 were structurally trapped. Post-injection shows that the amount of CO_2 trapped structurally increases slightly and declined to 6712214.5moles due to the onset of CO_2 solubility trapping mechanism. During the injection phase, 8128458.5moles of CO_2 was solubilized in water while during the post-injection period, CO_2 solubility trapping mechanism gave 38128952moles of CO_2 in water.

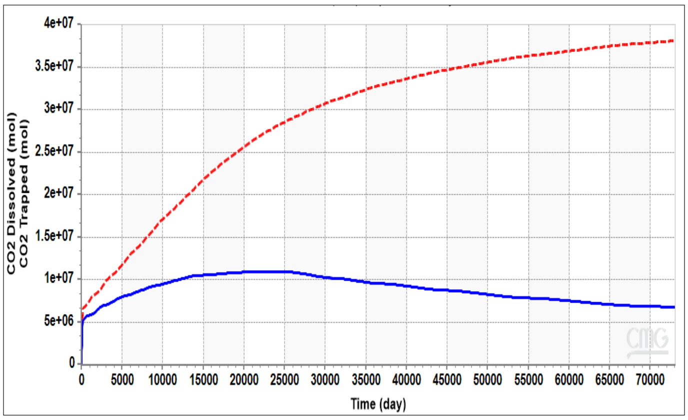

Figure 9. CO_2 trapped and dissolved with $75m^3$/day water injection

CONCLUSION

This work analyzed the influence of different water injection rates of 25 m^3/day, 50 m^3/day and $75m^3$/day on CO_2 dissolved and trapped in a homogeneous aquifer through numerical simulation. The scenario of no water injection was compared to different water injection rates for trapping and dissolution of CO_2 and the following conclusion drawn:

i. CO2 dissolved decreases with increase in water injection rate

ii. CO2 trapped decreases with increase in water injection rate

iii. The gas cap saturation length decreases with increase in water injection rate.

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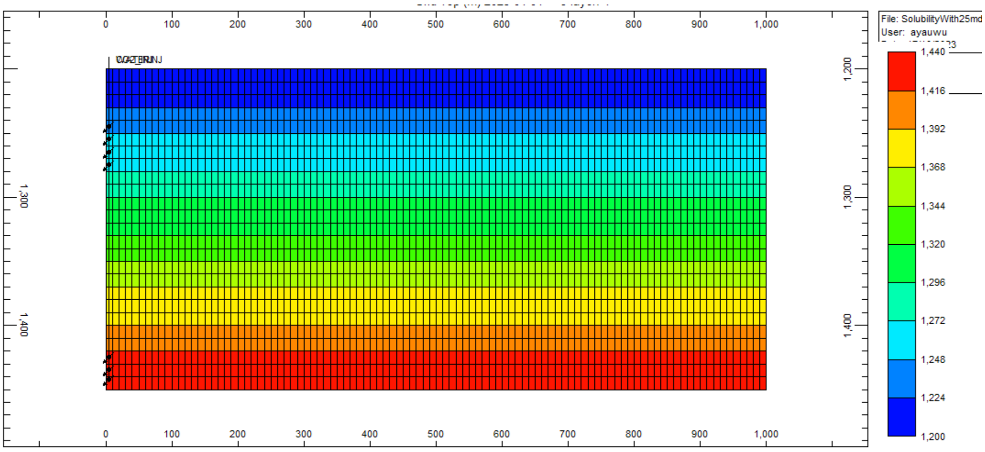
APPENDIX

Aquifer model with only CO2 injector



Aquifer model with both CO2 and water injectors