Suitability of depleted gas reservoirs for geological CO_2 storage: A simulation study

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Abstract

Hydrocarbon reservoirs, particularly depleted gas formations, are promising geological sites for carbon dioxide (CO_2) storage. Although there have been many studies on the storage aspects of gas reservoirs, suitability of these formations in terms of fluid types such as dry, wet, condensate have not been properly addressed at the reservoir level. In this study, an attempt was made to evaluate different gas reservoirs in order to provide an insight into their storage capabilities. A dynamic numerical simulation was done to simulate CO_2 injection in a synthetic but realistic model of a geologic formation having dry, wet or condensate gas. The obtained results at particular conditions revealed that the condensate gas medium offers a good storage potential, favorable injectivity and reasonable pressure buildup over a long period of time, whilst dry gas formations were found to be the least favorable sites for storage among gas reservoirs. A sensitivity analysis was done to evaluate the injection rate and permeability variation of different media during and after storage. It was indicated that the storage behavior of gas reservoirs is sensitive to the injection rate and selection of an optimum injection rate may help to achieve a good storage capacity in condensate gas systems. The results also highlighted that CO_2 immobilization in gas reservoirs after injection is enhanced due to the reduction of permeability, while no heterogeneity effect was observed under different permeability realizations.

Keywords: CO_2 storage, depleted gas reservoirs, numerical simulation, trapping mechanisms

1. Introduction

Capturing of Carbon dioxide (CO_2) from the combustion of fossil fuels and injection it into subsurface geologic formations for permanent storage has been widely recognized as one of the reliable strategy to reduce the amount of CO_2 emission into the atmosphere. Deep saline aquifers, depleted oil and gas reservoirs, and coal-bed seams are possible sites for CO_2 storage.[1] However, depleted oil and gas reservoirs are often the best options as they already hosted hydrocarbon for thousands of years. These petroleum fluids systems are generally divided into five categories of black oil, volatile oil, condensate gas, wet gas, and dry gas. Out of these categories, gas reservoirs which are classified into dry, wet and condensate gas bearing formations[2, 3] have gained the attention of many researchers in recent years as a better place to store CO_2 compared to oil reservoirs due to the high compressibility of gas.[4, 5]

For instance, Gorgon Carbon Dioxide Injection project in Australia has been initiated and is in its construction phase for deployment of CO_2 in a gas field**.** [6]

There have been many studies carried out to show the potential of injecting CO_2 into dry gas[7-15] and condensate gas reservoirs[4, 16-19] using numerical modeling techniques. According to these studies, the success of a CO_2 storage practice is linked to the injection strategy, reservoir characteristics and operational parameters. For instance, Oldenburg *et al.*[15] studied the storage by focusing on physical processes associated with injections through a numerical simulation. The results obtained indicated that injection allows additional production of methane during or after injection. Jikich *et* al.[9] numerically considered the effects of the injection strategy and operational parameters on CO_2 storage. They concluded that injection after field abandonment can provide a better recovery compared to injection at early stages. In a similar study, Al-Hashami *et al.*[7] showed that CO_2 solubility in brine is favorable to delay the breakthrough time and CO_2 injection at later stages will be more effective in terms of methane production. Polak and Grimstad.[12] developed a numerical approach to evaluate CO_2 storage in the Atzbach-Schwanenstadt gas field of Austria. They found a quick breakthrough of CO_2 which could ultimately limit production. They also reported that the reservoir pressure stabilizes after the stoppage of injection and only 10% of injected CO_2 dissolves in the immobile reservoir water during 1500 years with leakage from other wells. Feather and Archer.[8] numerically analyzed the factors favorable to enhance natural gas recovery by carbon dioxide injection for storage purposes. They considered well types, permeability, reservoir geometry, injection timing, and injection rate in their modeling. They found that vertical wells, reservoir geometry and low permeable isotropic homogeneous reservoirs are favorable for a successful storage job. Pamukcu *et al.*[14] focused on numerical modeling to predict the short term (less than a decade) system performance of CO_2 injection in the In-Salah gas field. The indicated that CO_2 can reach the northern part of the gas field in 2010 and spread out over an area including production wells in 2015. Khan *et al.*[10] illustrated the potential of CO_2 storage in natural gas reservoirs. Their simulation results indicated that optimal timing of injection and different injection rates might be favorable to control the breakthrough of CO_2. Khan *et al.*[11] performed numerical simulation to maximize enhanced gas recovery in a natural gas reservoir by storage of CO_2 and H_2S. They concluded that CO_2 breakthrough at the production well occurred faster than the breakthrough of mixed CO_2–H_2S injection. Kühn *et al.*[13] carried out a comprehensive assessment of the EGR potential of the Altmark field and concluded that proper usage of storage capacity can mitigate the risk of leakage during EGR and CO_2 storage. Similarly, studies carried out on condensate gas reservoirs are emphasizing the potentials of these geological formations as a suitable site for CO_2 storage. For instance, Azin *et al.*[16] analyzed partial depleted gas reservoirs for CO_2 storage. They suggested a scheme for storage purposes by selecting an optimum pressure or injection of a high volume of gas at the early stage of injection for a suitable gas recovery. Barrufet *et al.*[4] evaluated the storage capacity of depleted condensate gas reservoirs and aquifers by considering formation types, level of CO_2 purity and injection schedules. They concluded that CO_2 injection recovers complete condensate which makes these reservoirs a better place for storage compared to aquifers due to overall compressibility. Shen *et al.*[18] investigated CO_2 storage in nearly depleted gas reservoirs. They concluded that CO_2 sinks into the bottom of the gas cap and stores permanently when gas recovery by CO_2 displacement and condensate re-vaporization processes take place. Narinesingh and Alexander[17] showed that the injection pressure increases in high condensate recoveries due to the re-vaporization of the condensate drop-out. According to Yuan *et al.*[19], a fast condensate recovery and CO_2 storage can be achieved by combining the processes of enhanced recovery and storage at the early stage of the field development.

Although the above studies confirmed the feasibility of dry and condensate gas reservoirs for CO_2 storage, there have been very limited number of researches assessing these reservoirs for sequestration. This might be due to the complexity of key storage aspects of these reservoirs such as injectivity, storage capacity, trapping mechanisms, and containment which have not been fully understood.[20] For instance, some gas reservoirs may cause loss of injectivity, over pressurization or less CO_2 immobilization as the mixture of CO_2 with the residual gas may change the properties of CO_2 and gas mixture.[15, 18, 21-23] In the meantime, CO_2 mixing with resident gas depends on reservoir geometry, anisotropy, heterogeneity, injection rate, time of injection, rock or fluid properties, and diffusion which can only be studied through numerical modeling. In this paper, a 3D numerical model was built for gas reservoirs based on the modified Peng-Robinson equation of state to explore their feasibility of a long-term CO_2 storage.

2. Methodology

2.1 Numerical simulation

Numerical simulations were performed by the help of Eclipse simulator which is an advanced industry standard finite difference flow simulator developed by Schlumberger Limited. It is a major tool used for compositional modeling of enhanced recovery processes and CO_2 storage. As mentioned earlier, injection after field depletion is the best scenario to sequester CO_2 with a better residual recovery.[9, 17] Hence, simulation was run for a long term-storage to investigate the compositional impact of different gas types on the storage of depleted gas reservoirs.

In the first step, compositions of dry, wet and condensate gas at the depleted stage were taken from the literature.[22] Adisoemarta et al.[22] used these compositions to calculate the compressibility factor for storage purposes in depleted gas reservoirs. In the data preparation stage by Adisoemarta *et al.*[22], the hydrocarbon components were normalized to 1.0 mole and the components were analyzed to find the median composition for each category of gas reservoirs. Table 1 gives the normalized median compositions of each category of gas reservoirs used for the purpose of this study.

Table 1. Mole composition of typical reservoir fluids in depleted gas reservoirs expressed as the mole fraction of hydrocarbon components[22]			
Components	Dry gas	Wet gas	Condensate (50psi)
CO2	0.0001	0.0001	0.0001
C1	0.9661	0.9002	0.2477
C2	0.0267	0.0475	0.0527
C3	0.0051	0.0203	0.0541
C4	0.0020	0.0102	0.0770
C5	0	0.0041	0.0667
C6	0	0.0035	0.0734
C7+	0	0.014	0.4282
Total	1	1	1

Dry gas has a significant concentration of methane (C1) whilst the wet and condensate gases have a remarkable amount of heptane's-plus fractions (C7+). There are no phase changes in dry and wet gases and, therefore, a median dry and wet gas compositions can be considered as the compositions of gas at depleted reservoir conditions. This, however, is not the case for retrograde gas, which undergoes a phase change at the reservoir condition. For the purpose of this study, depleted condensate gas compositions at the pressure of 50 psi was taken into consideration. This compositional gas data and the depletion pressure are favorable because the pore pressure depletion of gas reservoirs is large.[24]

Three different compositions representing three different gas types, as given in Table 1, were used to evaluate the suitability of gas reservoirs and describe the behavior of CO_2 once mixed with residual gases. A 0.0001 mole fraction from butane component of each gas was picked to introduce CO_2 in the modeling. The black oil PVT analysis by the PVTi module of Eclipse at the reservoir temperature of 220 ^{o}F was carried out to confirm the gas type and generate properties of each gas type including critical pressure, critical temperature, acentric factor together with z-factor and binary coefficients. These properties are essential inputs to govern the fluid properties for modeling the storage site. Figure 1 shows the phase diagrams of considered gases, which confirms the fluid type with reference to the temperature condition, position of critical point, and the envelop size as reported by McCain Jr[2] and Terry and Rogers[3].

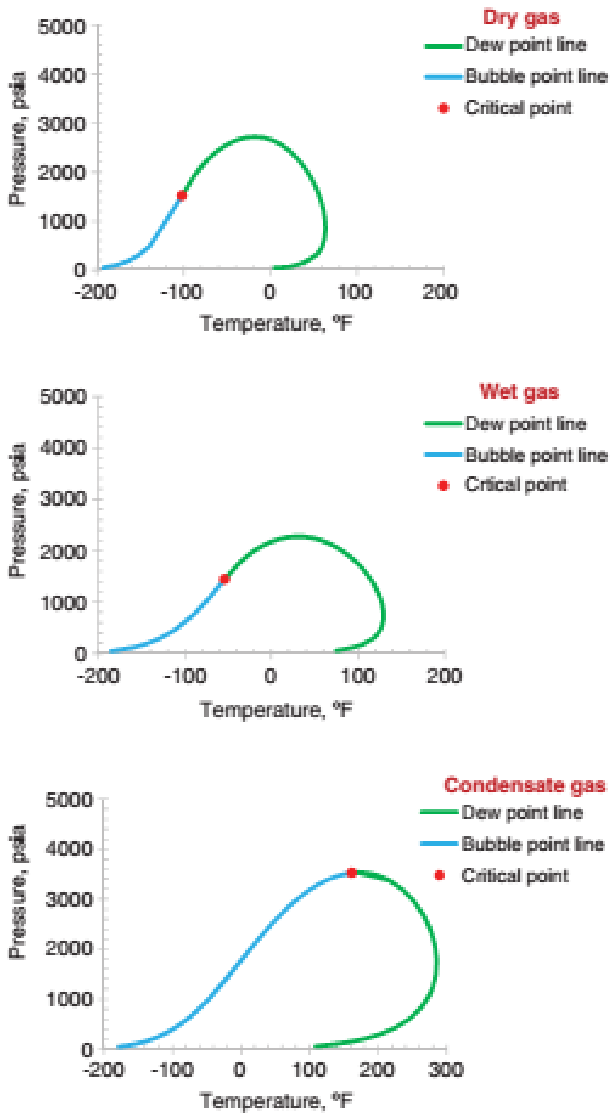


Figure 1. Phase diagram of dry gas (top), wet gas (middle) and condensate gas (bottom)

2.2 Modeling Approach

The GASWAT option of the Eclipse E300 simulator was used to model the storage of CO_2 in depleted gas reservoirs which is capable of solving the gas and brine phase equilibrium based on the adaptive implicit approach.[8, 25, 26] This method was applied to each gas type (dry, wet, and condensate) considering all essential parameters and modeling procedures. However, modeling the condensate liquid was not an easy task due to the limitation of GASWAT. As a result, modeling was solely done on the compositional effects (i.e., equilibrium between hydrocarbon rich and CO_2 rich phases) of different gas types on CO_2 storage. As a result, the total injected CO_2, total stored CO_2, and pressure buildup against time was predicted through this modeling.

In the modeling process, properties of gas, water and carbon dioxide (i.e., critical pressure, critical temperature, acentric factors and binary coefficients) were generated by the PVTi module of the Eclipse at reservoir conditions and CO_2 was separated for being traced individually. During simulation, solubility of CO_2 in water was determined by the Peng-Robinson Equation of State (PR-EOS) (see Eq. 1), according to the modification proposed by Soreide and Whitson.[27] Soreide and Whitson[27] modified the expression $\alpha^{1/2}$ for the water component and expressed it by Eq. (2) which includes salinity (c_s) of brine and reduced temperature, T_r, in the calculations. In fact, the Soreide and Whitson approach adds a temperature dependency behavior to the aqueous phase binary interaction coefficients. The solubility of gas was treated by the original Peng Robinson EOS.[26]

$$\left[P + \frac{A}{V_M(V_M + B) + b(V_M - B)}\right](V_M - B) = RT \tag{1}$$

In the above equation, P is the pressure (psia), V_M is the molar volume (cu ft/lb-mole), R is the gas constant (10.732 psia.cu.ft/lb. mole), T_R is the temperature (^oF), A and B are the mixture-specific constants which are a function of temperature and composition. The coefficient A is defined based on the mole fraction, binary interaction coefficients, critical temperature and critical pressure.

$$\alpha^{\frac{1}{2}} = 1 + 0.4530\left[1 - \left(1 - 0.0103c_s^{\ 1.1}\right)T_r\right] + \left[0.0034(Tr^{-3} - 1)\right] \tag{2}$$

Although CO_2 displaces the resident gas by the miscible displacement process, and available gases will be mixed over time by the molecular diffusion, when the CO_2 diffusion coefficient at reservoir conditions is less than 10^{-6} m^2/sec, the effect of diffusion on the gas mixing and CO_2 dispersion can be ignored.[7, 28] Considering the importance of diffusion on the mixing, the molecular diffusion was introduced and considered as part of the analysis.[29-31] This diffusion ensures that gas interblocks diffusive flows by defining the diffusivity input for each component[25] which is obtained using Eqs. (3) and (4)

$$J_i = -y \frac{D_i \partial y_i}{\partial d} \tag{3}$$

$$F_{ig}^{diff} = T_D D_{ig} (S_g b_g^m) \Delta y_i \tag{4}$$

In Eq. (3), x is the total molar concentration (mol m^{-3}), J_i is the flux of component i per unit area (mol m^2 s^{-1}), D_i is the diffusion coefficient of component I (m^2 s^{-1}), and $\partial y_i/\partial_d$ is the molar concentration gradient of component i in the direction of flow (mole fraction). These diffusion coefficients are used in the simulator module to obtain the gas interblock diffusive flows expressed by Eq. (4). In Eq. (4), F_{ig} is the interblock diffusive flow (mol/hour), T_D is the diffusivity (m^2/s), and y_i is the vapor mole fractions, S_g is the gas saturation (fraction), and b_p^m is the molar density of gas (mol/m^3).

The relative permeability of water and gas (CO_2) was determined based on the approach presented by Oak.[32] The relative permeability curves obtained are shown in Figure 2, having 69% of initial gas saturation, 40% of trapped gas saturation and 31% of connate water saturation. It was then apparent that hysteresis effects are strong in the gas relative permeability only. One may say that these data were generated for a brine-nitrogen gas system under a low pore pressure condition[32] and may not be suitable for a CO_2 system. It should be noted that this data has already been used to study the hysteresis of relative permeability in saline aquifers[33], and the value of residual gas saturation at 40% is within the range of experimental values presented by Bennion and Bachu.[35] GASWAT modeling is used in order to model gas (CO_2)/aqueous phase equilibriums for CO_2 storage in depleted gas reservoirs by utilizing the relative permeability and capillary pressure data of water and gas (CO_2) phases. Pure CO_2 injection was made in water zone. Considering this facts, combinations of gas and water relative permeability of CO_2 injection in aquifer which are taken from Juanes et al., 2006 was utilized to quantify the effect of different gas type in residual form on CO_2 storage performance.

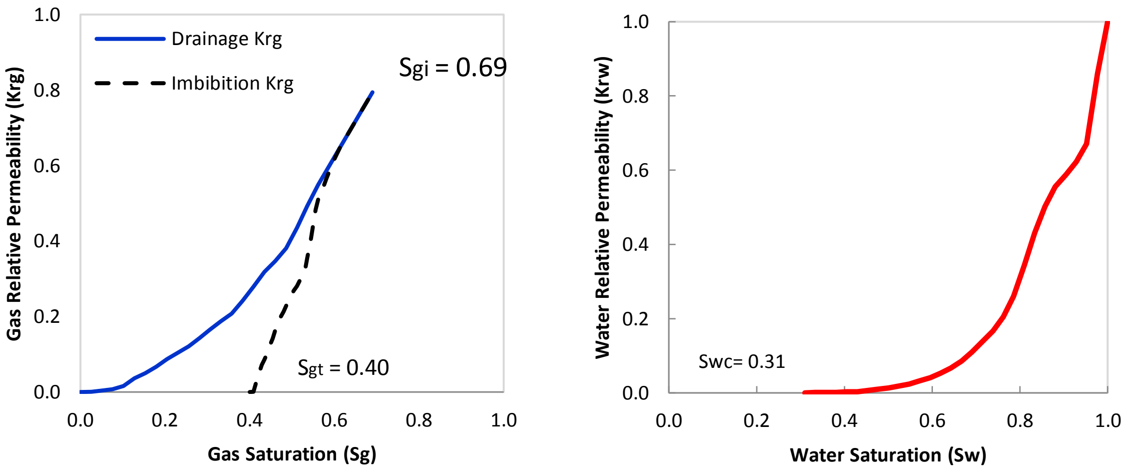


Figure 2. Relative permeability curves used in the CO_2 simulations, generated from the data by Oak.[32] for a water-wet Berea sandstone[33].

The most important parameter quantifying the significance of hysteresis is the trapped gas saturation (S_{gt}) after a flow reversal (from drainage to imbibition), which can be used to relate trapped (residual) gas saturation to the maximum gas saturation (S_{gmax}). The common relative permeability hysteresis models often used for the trapping modelling is the one proposed by Land.[36], which formulates the Land Model as given in Eqs (5-6).

$$S_{gt} = \frac{S_{gi}}{1 + CS_{gi}} \tag{5}$$

Where

$$C = \frac{1}{S_{gt,\max}} - \frac{1}{S_{g,\max}} \tag{6}$$

In this model, S_{gi} is the initial gas saturation at the flow reversal and C is the Land trapping coefficient computed from the bounding drainage and imbibition relative permeability curves. The bounding drainage and imbibition curves obtained from the experimental data indicated that the Land trapping coefficient, C, can be approximately equal to 1. $S_{gt,max}$ is the maximum trapped gas saturation linked to the imbibition curve where $S_{g,max}$ is the maximum gas saturation.

Capillary forces and relative permeability affects will contribute in residual trapping[36]. According to Spiteri and Juanes.[34], capillary pressure effects are negligible during numerically simulating field-scale displacements in case, when the characteristic capillary length is much smaller than the grid resolution. Juanes et al. [33] also found that their numerical predictions are insensitive to the options of the hysteretic or nonhysteretic capillary pressure curves, while emphasized on accounting CO_2 trapping in the relative permeability model for evaluation of the distribution and mobility of CO_2 in the formation.[33] Thus, we assumed ignored capillary pressure data in the simulations presented here.

A relative permeability hysteresis model characterizes the scanning curves during imbibition and drainage cycles. In this paper, the hysteresis model developed by Killough.[37], were utilized in which the gas relative permeability along a scanning curve, such as the one shown in Figure 3 is determined by using the expression given in Eqs (7,8). For a given value of Sg_{imax}, the trapped critical saturation and the relative permeability for a particular gas saturation, S_g, on the scanning curve is calculated by using the expression given in Eqs. (7-8).[33]

$$k_{rg}^{i}(S_g) = k_{rg}^{ib}(S_g^*)\frac{k_{rg}^{d}(S_{gi})}{k_{rg}^{d}(S_{gi,\max})} \tag{7}$$

Where,

$$S_g^* = S_{gt,\max} + \frac{(S_g - S_{gt})(S_{gi,\max} - S_{gt,\max})}{S_{gi} - S_{gt}} \tag{8}$$

In the above equations, k^{d}_{rg} and k^{ib}_{rg} represent the bounding drainage and imbibition curves, respectively. $S_{g,max}$ is the maximum gas saturation, and $S_{gt,max}$ is the maximum trapped saturation, associated with the bounding imbibition curve.

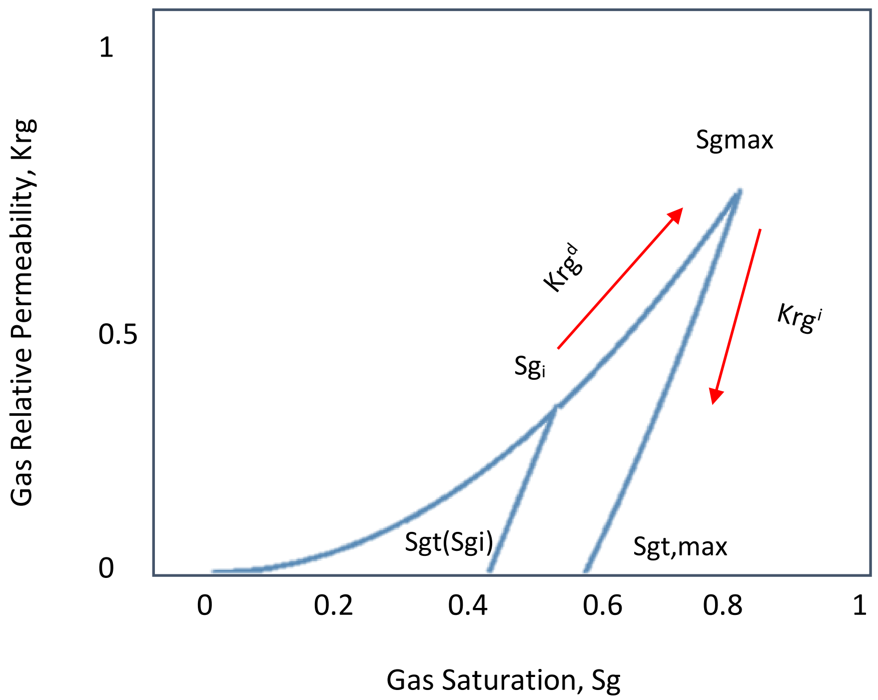


Figure 3. Parameters involved in the evaluation of the Land Trapping model[33]

2.3. Model Description

In view of huge time required for running a three-dimensional simulation, a 3D Egg model was utilized for evaluating the long-term injection of CO_2 into dry, wet and condensate gas reservoirs. The "Egg Model", is a synthetic static reservoir model consisting of an ensemble of 101 relatively small three-dimensional permeability realizations,[38] built by considering three permeability realizations. The grid dimension of the model was modified from the smaller to bigger size going up to 3937 ft in a horizontal XY plane with a thickness of 200 ft (i.e., 7 layers) for a thorough evaluation of heterogeneity,[39, 40] time-scale of convective mixing, plume size and degree of CO_2 stored.[41] To ensure the presence of supercritical CO_2, the top depth of the first layer out of seven layers was set at 13000 ft. However, zero dip angle considered to neglect the effect of gravity segregation. Water was also present at the gas-water contact depth of 13190 ft. A single injection well was located in middle grid and perforated in last three layers to made pure CO_2 injection in water phase at a rate of 100MScf/day. However, major portion was occupied by residual gas phase which would help to quantify the effect of different gas type on CO_2 storage. The lateral boundaries are at average distance of from the injection well to have impact on the CO_2 plume evolution.

The model had a porosity and channel permeability of 0.30 and 800 mD, respectively. The permeability in XYZ directions was similar (isotropic). Figure 4 displays the permeability distribution in the model where the X-Y plane has 3600 grid blocks in each direction. The major portion of the model had a low matrix permeability (40 mD) with a high permeability meandering channels in unconsolidated sandstone layers. This high heterogeneity would help to evaluate the gas mixing as heterogeneity and reservoir aspect ratio directly affect the mixing[42] while low permeability is an important factor to enhance hysteresis and capillary effects.[43, 44] This model description used in link with generated PVT data for different gas types to evaluate CO2 storage performance. Details of the properties and parameters used in the model are listed in Table 2.

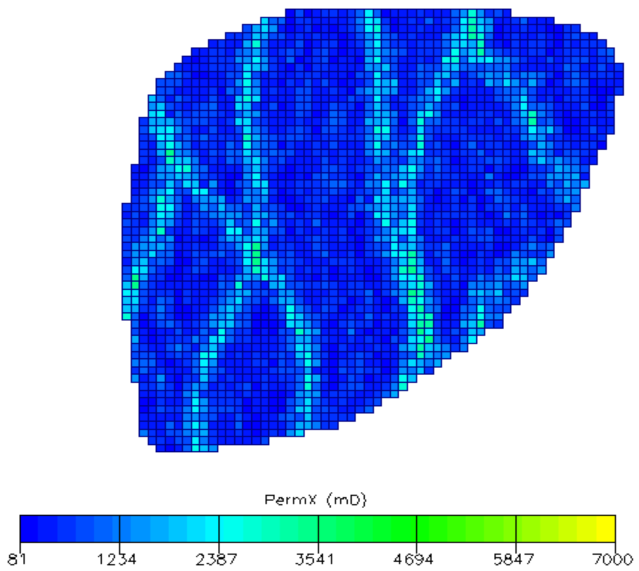


Figure 4: Top view of the egg shaped reservoir model displaying a typical structure of high-permeability meandering channels (800 mD) in a low permeability blue background matrix (<40 mD)

Table 2: Reservoir and fluid properties used in this study

Symbol	Variable	Value	Field Units
N	Grid blocks	25200	
	Active blocks	18553	
L	Length	1200	**feet**
W	Width	1200	**feet**
H	Thickness	200	feet
D_{top}	Depth at the top of the injection well	13000	feet
α	Dip degree	0	
ϕ	porosity	30	%
K	Channel permeability	800	mD
D	Molar concentration gradient of component	CO_2 1.72 10^{-5} C_1 1.61 10^{-5} C_2 4.30 10^{-6} C_3 4.30 10^{-6} C_4 4.30 10^{-6} C_5 4.30 10^{-6} C_6 1.20 10^{-5} C_{7+} 1.40 10^{-6} Liquid 10^{-10}	m^2/sec
Cr	Rock compressibility	2×10^{-7}	
S_{wc}	Connate water saturation	31	%
P_{ini}	Initial reservoir pressure	50	psi
S	Salinity	15000	ppm
Temp	Temperature	220	ºF
Q_g	Gas injection rate	100	MScf/day
S	Skin	0	
PV	Initial pore volume	6.6	Billion tons (Bt)
xCO_2	CO_2 mole fraction	1	Mole fraction
Pmax(inj)	Maximum injection pressure	4500	psi
T	Injection time Simulation time	5 1000	years years

2.4. Initial conditions for simulation

During the simulation, the volumetric gas reservoir was assumed to be at the end of the gas production. There were only brine and gas phases in the reservoir before CO_2 injection having pressure of 50 psi and a gas-water contact at a particular datum depth of 13150 ft. The temperature was assigned to be 220 ^oF, while the initial gas saturation at the depleted stage for dry, wet and condensate gas cases were respectively 0.19. 0.14, 0.11 fractions. Prior to CO_2 injection, the remaining gas at the depleted condition pressure of 50 psi was different in various media. Thus, relative permeability data for residual gas phase is not required by GASWAT module. During injection phase, drainage relative permeability data of CO_2 and water phases is used as injection is a drainage process. At the time of storage process, imbibition relative permeability data of CO_2 and water phases is acquired by GASWAT module. Therefore, significant residual trapping is occurred after injection stops when water displaces CO2. [33]. Owing to this, relative permeability hysteresis data by Juanes et al. (2006) [33] accounting for CO_2 trapping was considered for predicting the distribution and mobility of CO_2 in the formation after injection stops. A well was considered for the injection of pure CO_2 (i.e., 100 mole percent of CO_2) under a maximum sustainable pressure of 4500 psi at a rate of 100MScf/day for 5 years. A skin equal to zero was considered near the well bore of the injection well. To investigate the long-term storage of CO_2 in the gas reservoirs, the simulation was run for 1000 years.

3. Results and Discussions

Quantifications of the storage aspects for formation reservoirs with different gas compositions at particular conditions was evaluated in this study. Considering the simulation conducted, it can be safely say that the results obtained are realistic since the actual protocol adopted to carry out the simulation covers all possible factors included in the realistic modeling of dry, wet and condensate gases compositions.

In order to investigate the interaction between different kinds of gases and CO_2, three simulation cases were generated and named as dry-base, wet-base and condensate-base. Moreover, the effect of the injection rate and heterogeneity during storage was also evaluated. These three cases are neglecting the CO_2-water-rock reaction for precipitation and dissolution during injection due to the limitation of the simulator[25] and low reactivity of sandstone reservoirs.[45]

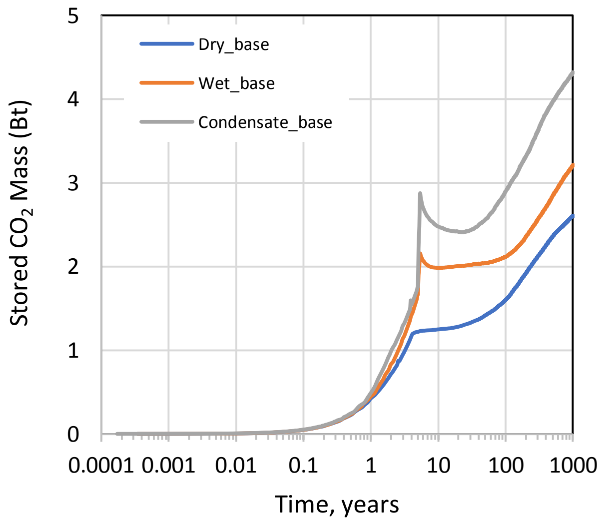
3.1. Temporal evolution of CO_2 in different phases

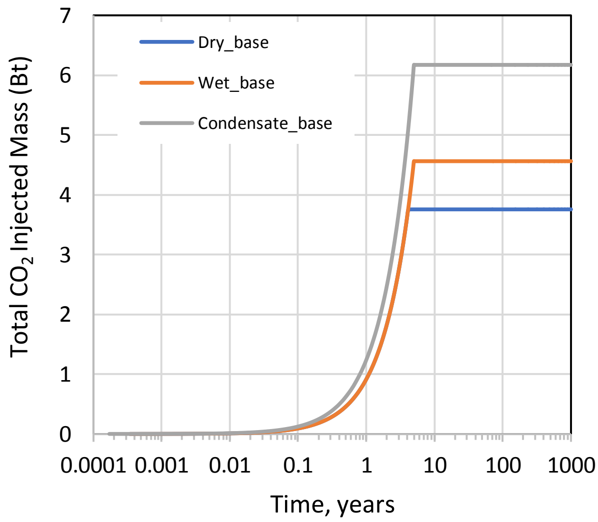
As mentioned earlier, there are four major trapping mechanisms for CO_2 storage in a gas reservoir. When CO_2 is injected into a gas reservoir, initially displaces the brine and gas, mixes with the resident gas and flows upwards by the buoyant force because it is less dense than water. During this process, a fraction of CO_2 is capillary trapped as the residual CO_2 saturation in narrow pore throats in a short-term scale. In a longer term, a significant amount of CO_2 dissolves in brine and forms an immobilized dissolved phase. The dissolved CO_2 can form $H_2CO_3(aq)$, HCO_3^-, and CO_3^{2-} by interacting with brine which can change the pore geometry due to the dissolution and precipitation of minerals in the reservoir. Some fractions of CO_2

are also transformed into stable carbonate minerals (mineral phase) for the permanent storage, but this mechanism was not taken into consideration during simulation by GASWAT E300. During and after injection, trapping mechanisms play their role to store (immobilize) the injected CO_2, depending on the characteristics of the storage medium.[46] Figure 5 (a) indicates that the mass of CO_2 storage in different gas mediums start to increase slowly till the injection period of 5 years which is aligned with earlier study[47]. Once injection stops, mass of CO_2 stored due to the residual and dissolution trappings starts to decline for few years, but sharply increases after that. Figure 5 (a) confirms that that the residual trapping and dissolution trapping play crucial roles to achieve a favorable CO_2 storage capacity. Condensate gas, which has the maximum residual and dissolved CO_2 saturations, shows the maximum storage capacity during and after injection as discussed earlier[22] Comparison of the dry base, wet base, and the condensate base cases shows that the storage medium with condensate gas has significant impact on the total storage capacity due to favorable residual and dissolution trapping. This may indicate that high a compressible fluid like condensate gas is favorable to immobilize large fraction of CO_2 in the form of residual and dissolved phases. Comparing the total injected mass of CO_2 in Figure.5 (b), it can be seen that that the maximum mass of CO_2 was injected in the condensate base case and the least amount belongs to the dry base case. The total amount of injected CO_2 in all three cases was different ranging from 3.75 billion tonnes (Bt), 4.50 Bt, and 6.16 Bt for dry, wet and condensate base cases respectively owing to the effect of the bottom-hole injection pressure and pressure distribution in the reservoir. It seems that condensate gas with a lower remaining gas at the depleted pressure would be more beneficial for enhancing the well injectivity by permitting more CO_2 to flow into the reservoir. It might be due to the high compressibility of condensate gas at the depleted stage compared to dry and wet gases because condensate gas at 50 psi is 1.1 times more compressible than condensate at 500 psi for wet and dry gases.[23]

The pressure buildup due to CO_2 injection is generally not a limiting parameter but must not exceed the fracture initiation pressure of formations.[47] In this study, the maximum injection pressure was monitored in dry, wet and condensate gas media upon injection as shown in Figure 5(c). Looking at this figure, it can be concluded that the pressure reaches its maximum value in the dry base case but stays at its lowest magnitude in the condensate base case regardless of the huge mass of CO_2 which was injected and stored in the condensate gas formation. This behavior of pressure in different gas mediums can be attributed to the compressibility level of these gases. Figures 6 shows the percentage of CO_2 in different phases over time for all three cases of gas reservoirs.

As it is seen in this Figure, initially a large amount of CO_2 resides in the reservoir, while some amounts are residually trapped and dissolved at the early stage of injection. As injection continuous, the amount of supercritical CO_2 increases at the end of injection after 5 years in which 38.2%, 42.5% and 65% of CO_2 is trapped in dry, wet and condensate cases, respectively. Residual and dissolved trapping are not significant and within the range of 8-20% in a short-term geological sequestration of CO_2. Moreover, the potential of residual phase trapping is less than the dissolution in the base case of wet and condensate gases for a short-term scenario. As time passes, the capillary phenomenon becomes significant resulting in the increase of residual phase while dissolution takes place with a slow rate, enhancing CO_2 residual trapping and dissolution in brine. On the other hand, CO_2 in the supercritical phase is reduced as time passes. At the end of 1000 years, the residual trapping becomes the main mechanism of trapping and more than half of total CO_2 injected is trapped. In a short or long term scenario, the amount of supercritical CO_2 is significant in the condensate gas medium while it is very minor in a dry gas reservoir. However, all gas types show a great potential for residual trapping relative to dissolution trapping in a long-term and the free CO_2 phase is residually trapped and decrease with time. Comparatively, the condensate gas reservoir offers a significant immobilization in residual and dissolution phases (65.2%) during shut-in period till 1000 years. Nevertheless, the pressure and molecular diffusivity play a major role in the gas mixing, which can be attributed to the interactions of CO_2 with gas components and remaining gas saturation as explained earlier. It was also revealed that components other than methane might enhance the residual and dissolution mechanisms as methane solely support more dissolution compared to CO_2, O_2, SO_2, H_2S, and N_2.[49] However, the dry base case doesn't show any significant dissolution trapping even in the presence of high huge methane. Although, the high percentage of supercritical phase in condensate base case relative to others is a favorable option for injection and storage, it may initiate leakage due to its long term contact with the caprock[50, 51]. Table 3 summarizes the material balances (total injected CO_2, stored CO_2 and maximum pressure buildup) of dry base, wet base, and condensate base cases.





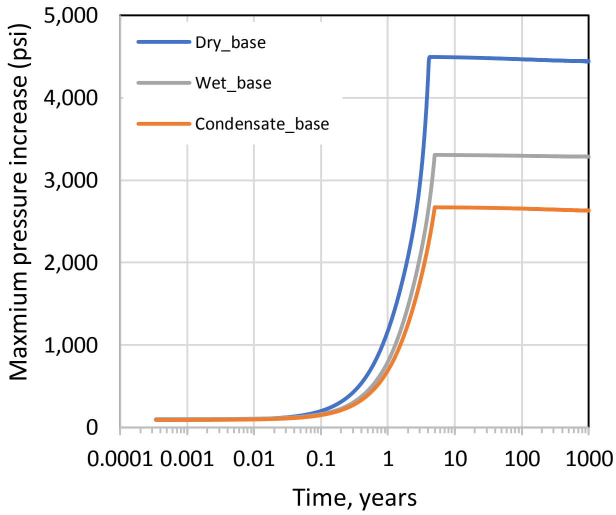


Figure 5. (a) Comparison of gas mediums for total mass of CO_2 stored at different time intervals; (b) The total injected CO_2 mass vs time; (c) The maximum pressure buildup vs time

Generally, the condensate gas type has a high compressibility and as such it offers a larger storage capacity compared to dry and wet gas type[22, 23] as also evident in Figure 6. A similar conclusion was made by Sobers *et al.*[23], where the large storage capacity of condensate gas reservoirs was attributed to the phase behavior of the condensate gas-CO_2 mixture[23], good injectivity due to a high compressibility, low remaining gas, and small amount of methane mole fractions. Although the effect of the condensate liquid was not included in the analysis of this study due to the limitation of GASWAT, it seems that it could further enhance the storage space[23] and recovery by re-vaporization.[17]

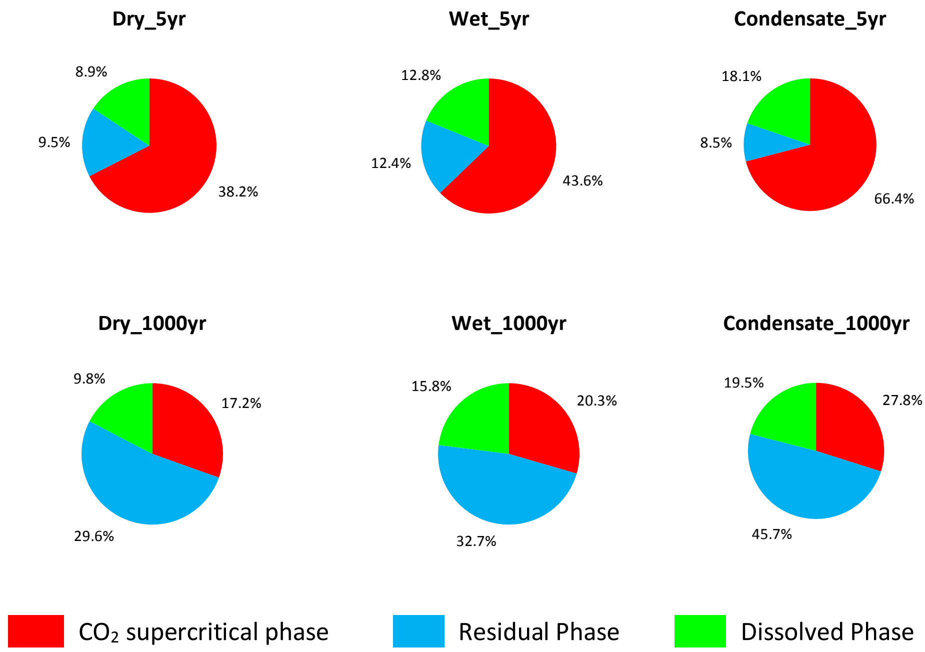


Figure 6. Percentage of CO_2 in different phases after 5 years and 1000 years in dry gas, wet gas and condensate gas reservoirs

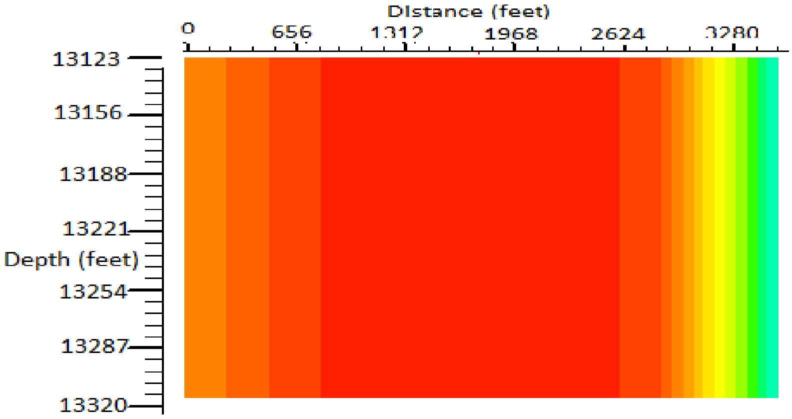
Table 3: Summary of the gas type effect on cumulative injected CO_2, total stored CO_2, and maximum pressure buildup

Case	Gas Type	CONSTRAINTS		Inj. Rate (MScf/D)	Cum. CO_2 Injected (Bt)	CO_2 amount in 1000 years (Bt)			Maximum pressure buildup, psi
		BHP (psia)	Inj. Time (years)			Supercritical free phase	Stored CO_2 as Residual phase	Stored CO_2 as Dissolved in brine	
Base Case	Dry	5000	5	100	3.75	1.14	1.96	0.65	4496
	Wet	5000	5	100	4.55	1.34	2.16	1.05	3307
	Condensate	5000	5	100	6.16	1.84	3.03	1.29	2671

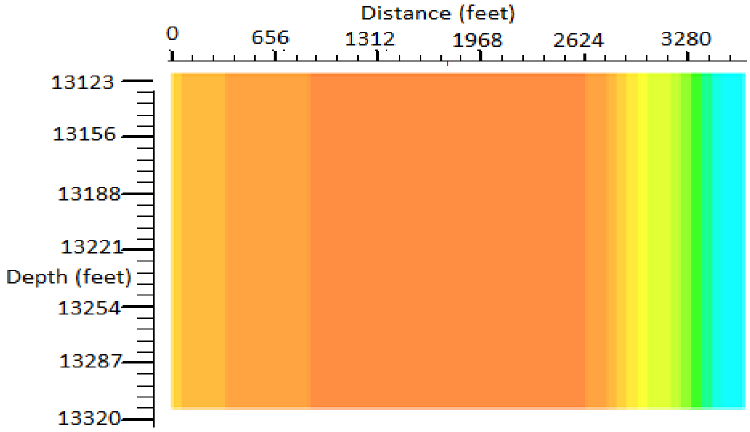
3.2. Spatial evolution of CO_2 mixing

Pressure built up near the injection well was expected during injection, resulting in generation of a high saturation region near the wellbore which smoothly depleted towards the reservoir. This build-up slowly decreases after the stoppage of injection in 5 years for all base cases (dry, wet, condensate), although gas mixing may play an important role in this reduction. According to Oldenburg[28], gas mixing in the medium increases with pressure, which depend on rock and fluid properties, may result in different compositions of CO_2 phases. This is clearly observed in Figures 7 and 8 which are demonstrating the maximum pressure build up near the injection well and CO_2 saturation in the reservoir, respectively. Overall, the results obtained from saturation and pressure build up are aligned with what was shown in Figure 5. Figure 9 shows the distribution of CO_2 mixed with gas in the top layer of the model for all three cases after 5 and 1000 years.

Dry base



Wet base



Condensate base

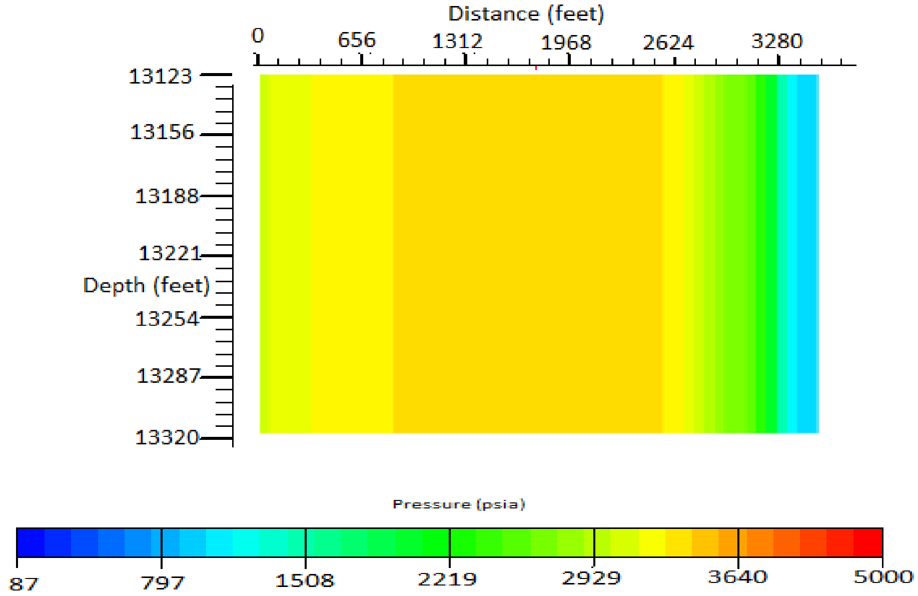
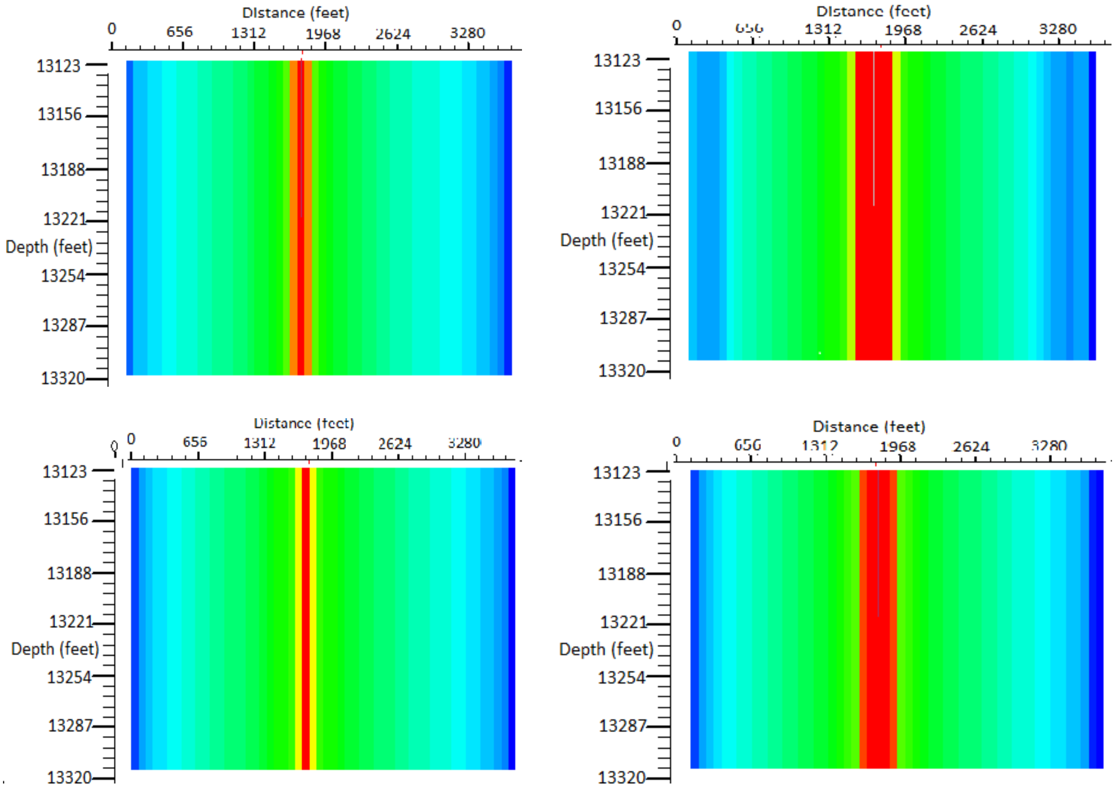


Figure 7. Cross section view of the reservoir for maximum pressure build at the end of 1000 years near the wellbore in dry base, wet base, and condensate base cases



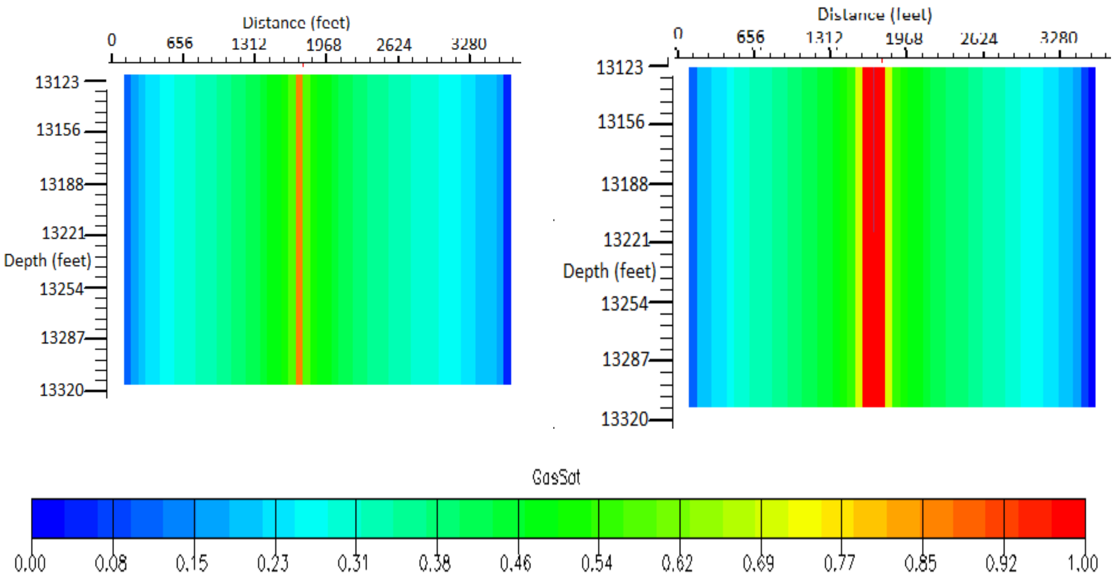
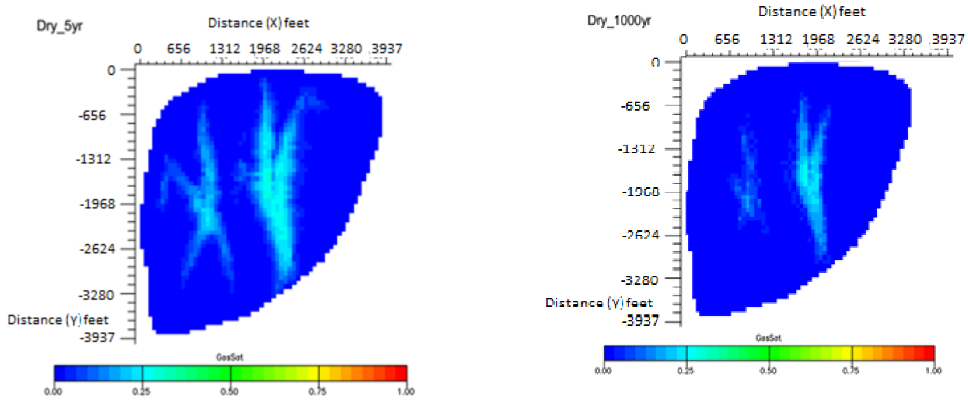


Figure 8. Cross section view of the reservoir for CO_2 saturation distribution near the wellbore in the dry base (top), wet base (middle), and condensate base (bottom) cases after 5 years (left) and 1000 years (right) of storage. Red strip shows the high gas saturation near the wellbore

The contours shown in Figures 8 and 9 indicates that once injected, CO_2 quickly moves away from the injection site into the high permeable area and slowly spreads into the surrounding low permeable portions. The fraction in the blue zone is very small after displacing the remaining gas during the first 5 years in all three base cases. During the whole process in three cases, the low permeable and high heterogeneous areas are holding a low saturation over a short to long term period of time.



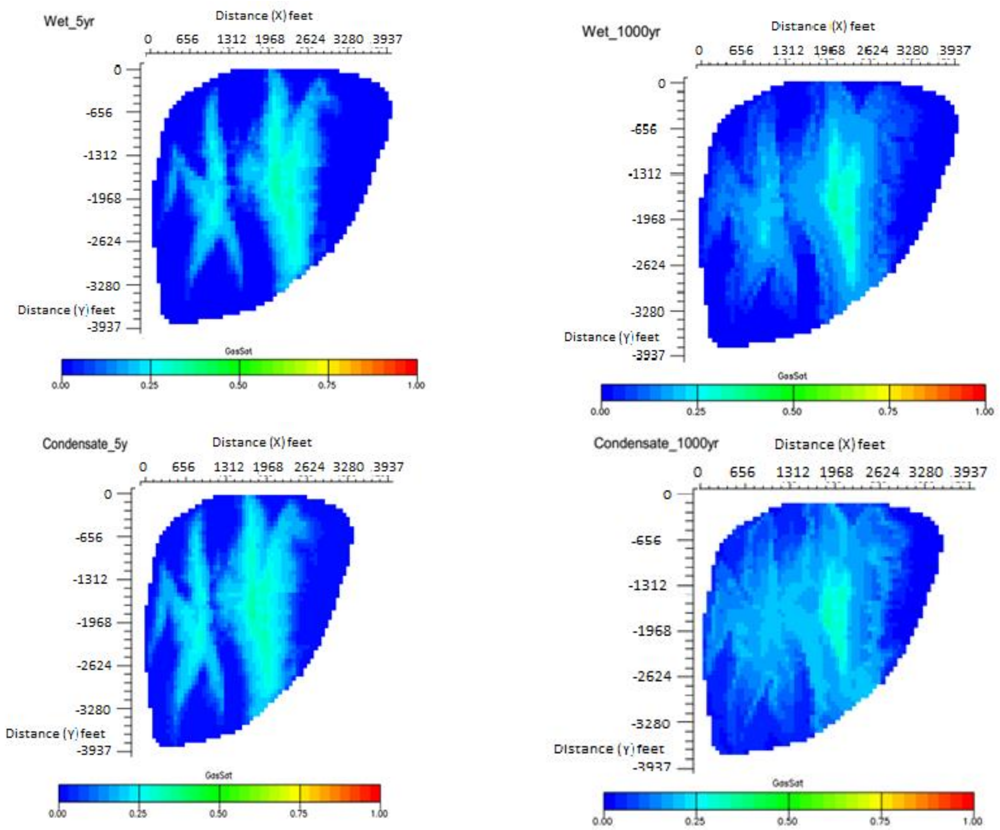


Figure. 9: CO_2-gas distribution in k=1 at 5 years (well shut-in time), and 1000 years for dry gas, wet gas and condensate gas

On the other hand, the spatial distribution of gas-CO_2 saturation in the high permeable channels is high. Comparatively, the total gas saturation including remaining gas and CO_2 supercritical phase after 5 years is huge which starts to decrease as we get closer to 1000 years. The same phenomenon was observed in the dry and wet gas reservoirs over a short to long term period. However, the thermal and capillary effects posed after injection on the caprock integrity[52] in these types of gas reservoirs must be evaluated before getting any further conclusions.

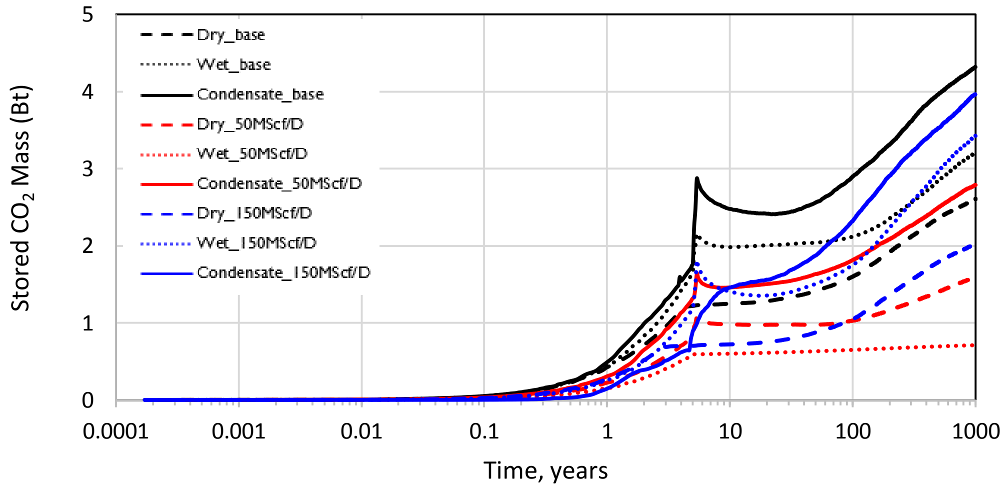
4. Sensitivity analysis

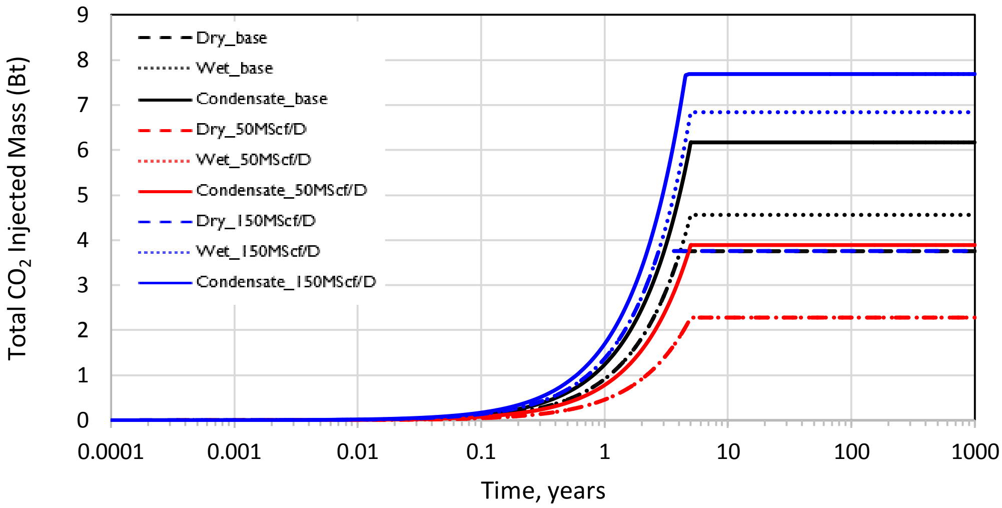
The model built in this study was based on three types of gas compositions which may have different impacts on the mechanism of CO_2 storage, but there are few important parameters such as injection rate and heterogeneity which may vary from case to case, offering different storage potential for the rese upon injection. In this section, these two parameters were evaluated and their impacts on the overall performance of the gas reservoirs were reported.

4.1. Injection Rate

Injection rate plays an important role in achieving a desired CO_2 volume and having a certain mixture of CO_2 with gas. However, it should be noted that in gas reservoirs, injectivity might be affected by the presence of the residual gas (methane).[28, 53] There have been many studies in which trapping mechanisms, especially capillary trapping, suppressed at a high injection rate.[54-57] Considering these facts, a low (50 MScf/D) and high injection rates (150 MScf/D) were selected and compared to evaluate different gas reservoirs against the variation of injection rate. The results obtained from running the numerical model for 5 and 1000 years indicated that at a low injection rate of 50MScf/D, the storage capacity of the dry gas medium is more than the wet gas case but less than the condensate gas system. The storage potential of the dry gas reservoir at the high injection rate seems to be the lowest and that of the condensate gas would be the highest similar to the base case. Thus, it was concluded that storage potential is sensitive to the gas type. At different rates, the condensate gas medium shows a high potential compared to other two cases if the mass of CO_2 stored is compared. This highlights the fact that an optimum injection rate may help to achieve a good capacity in condensate gas systems. Figure 10a shows the amount of CO_2 stored in different gas reservoirs at low and high injection rates.

As it is seen in Figure 10b, the total amount of CO_2 injected increases gradually at early stages (after 5 years) and stabilized once injection stops. However, the total injected CO_2 is low in the dry and wet gas systems compared to the condensate gas medium at the low injection rate. A very similar trend exists at the high injection rate, but the amount of CO_2 injected was clearly lower than the low injection rate as shown in Figure 10b. It worth to mention that a large amount of CO_2 is injected at a high injection rate in the wet and condensate gas cases compared to the wet base and the condensate base cases. On the contrary (see Figure 10a), lesser amount of CO_2 was stored in these two gas systems through residual and dissolution trappings at the high injection rate of 150 MScf/D compared to the results obtained from the injection rate of 100 MScf/D. This might be related to the effect of high injection rate which suppresses the residual trapping and dissolution trapping potentials[55,56] and as such a huge amount of CO_2 appears under supercritical condition.





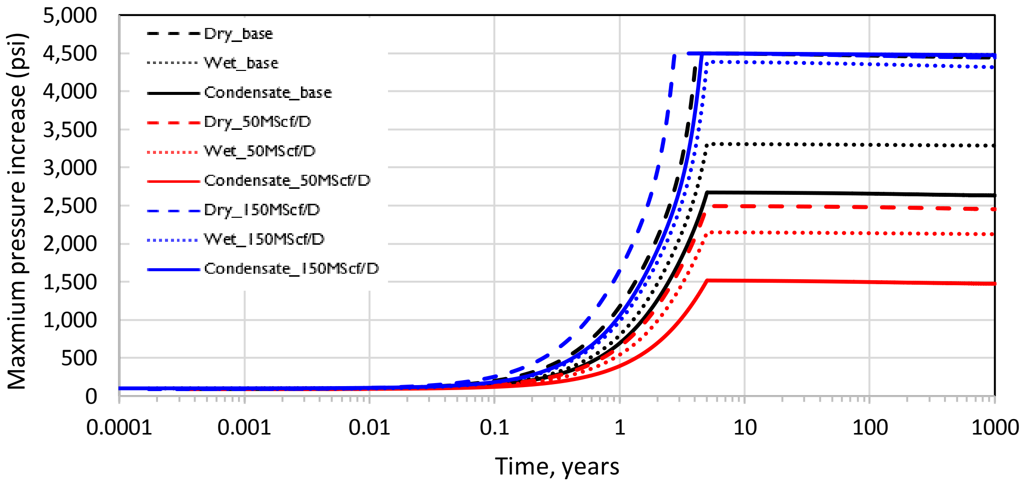


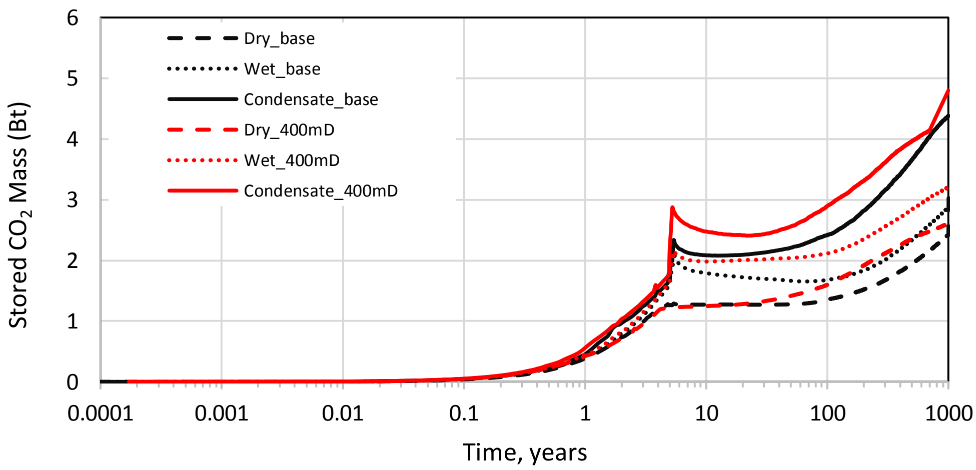
Figure. 10: (a) Comparison of gas mediums for total mass of CO_2 stored at different time; (b) The total injected CO_2 mass vs time; (c) The maximum pressure buildup vs time at different injection rates (50 MScf/D, 100 MScf/D and 150 MScf/D)

It was also found that the trends of pressure build up in the gas mediums slowly increases up until the end of injection periods[47], regardless of injection rate chosen. The trend of pressure increase in at a low injection rate is similar but quantitatively less than the one observed in bases cases. The most important observation was the pressure build up at a high injection rate which was maximum for all gas formations approaching to the pressure build up observed at 5 years in the dry base case (see Figure 10c). Thus, it could be concluded that selection of an appropriate gas medium plays an important role to achieve a favorable storage potential with lesser mobile CO_2 and lower pressure build up.

4.2. Heterogeneity

Heterogeneity may have impacts on the multiphase flow of CO_2-brine[58] and can be expressed in terms of permeability variation.[28] The storage capacity is linked to heterogeneities and porosity, whilst injectivity is related to petrophysical properties such as permeability. [59] To analyze the effect of permeability, numerical simulation was run by considering the channel permeability of 400 mD by multiplying reduction factor to the base cases (dry, wet and condensate). The results obtained which are shown in Figure 11a revealed that the trends of CO_2 storage through residual and dissolution trappings is quantitatively similar to the trends of the bases case in all gas systems up until the end of the injection period. Once injection stops, the amount of CO_2 stored in the case with the permeability of 400 mD gradually increased and becomes more than that of the base case for all gas systems due to favorable residual and dissolution trappings as reported in Table 4. The total amount of storage in dry, wet, and condensate gas mediums was around 2.87 Bt, 3.37 Bt, and 4.80 Bt, respectively after 1000 years. This increase in the amount of CO_2 storage after injection in the channel permeability case could be related to hysteresis and capillary effects which are changed by the variation of permeability.[43, 44]

The results of total injected CO_2 and pressure increase in 400 mD case for all gas systems are almost similar to the base case from start of the injection till 1000 years as depicted in Figures 11b and 11c. Table 3 reports the effect of gas type on the cumulative injected CO_2, total storage of CO_2, and maximum pressure buildup. However, 400 mD and 800 mD channel permeability values are representative of good quality reservoirs. It seems that the reduction of permeability does not have a remarkable impact on the total injected CO_2 and pressure build up during and after injection. This reduction in permeability doesn't affect the storage potential of CO_2 during the injecting period and more CO immobilizing was observed after injection due to the significant role of residual and dissolution trappings.



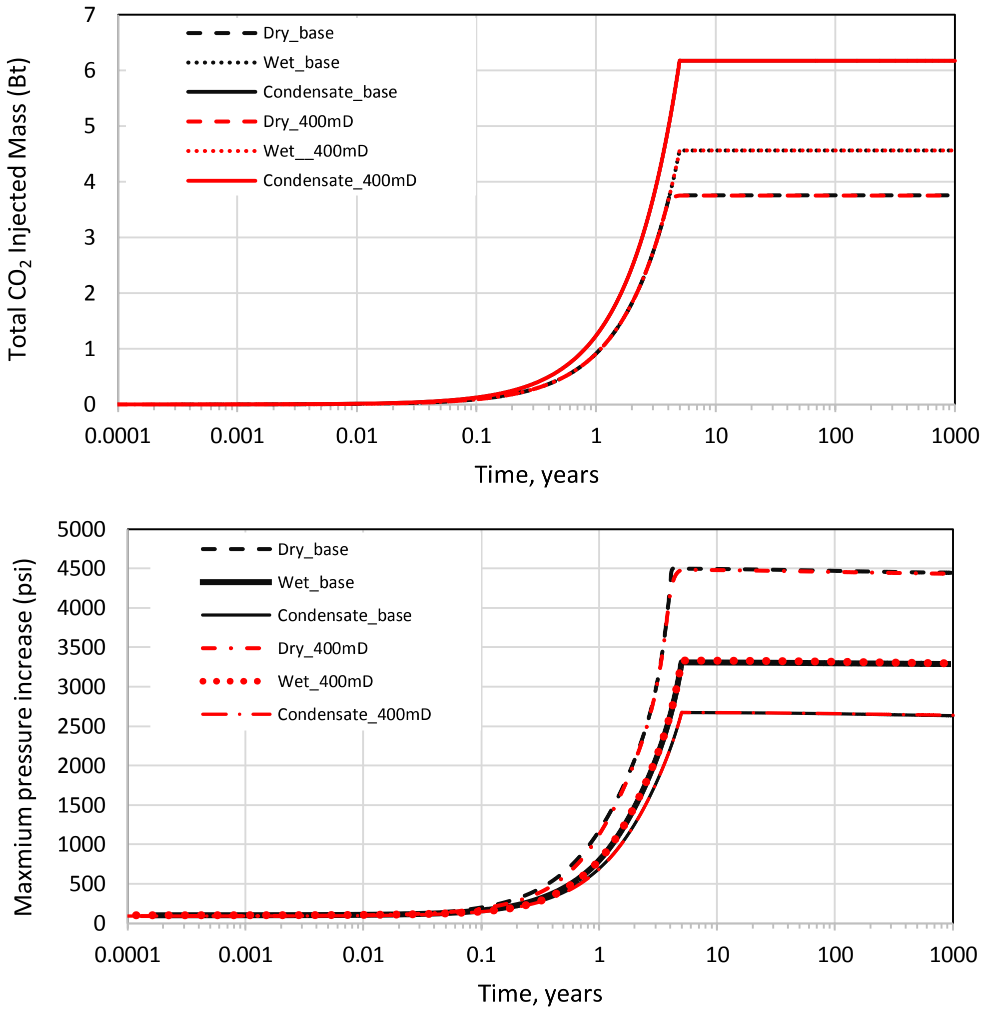


Figure. 11. (a) Comparison of gas mediums for total mass of CO_2 stored at different time for bases case and case_400mD; (b) The total injected CO_2 mass vs time for bases case and case_400mD; (c) The maximum pressure buildup vs time for bases case and case_400mD

Table 4: Comparing the effect of the gas type on cumulative injected CO_2, total stored CO_2, and maximum pressure buildup

Case	**Gas Type**	**CONSTRAINTS**		**Inj. Rate (MScf/D)**	**Cum. CO_2 Injected (Bt)**	**CO_2 amount in 1000 years (Bt)**			**Maximum pressure buildup**
		BHP (psia)	Inj. Time (years)			Supercritical free phase	Stored CO_2 as Residual phase	Stored CO_2 as Dissolved in brine	
Base Case	Dry	5000	5	100	3.75	1.14	1.96	0.651	4496
	Wet	5000	5	100	4.55	1.34	2.16	1.05	3307
	Condensate	5000	5	100	6.16	1.84	3.03	1.29	2671
400mD	Dry	5000	5	100	3.75	0.88	2.20	0.67	4481
	Wet	5000	5	100	4.56	1.19	2.30	1.07	3328
	Condensate	5000	5	100	6.17	1.37	3.30	1.50	2670

To assess CO_2 injection into heterogeneous media, two different permeability realizations were considered, as shown in Figure 12, and simulations were run under the same conditions as before. The average channel permeability in these two realizations was 913 mD and 798 mD. The values of permeability in different directions are given in Table 5. As discussed earlier, the heterogeneity factor is related to the gas mixing upon CO_2 injection. Figure 13 shows the results obtained from two different permeability realizations governing the behavior of CO_2 injection.

From Figure13, similar trends for the cumulative amount of CO_2 stored and injected are observed during and after injection in all gas systems which are almost the same trends obtained from the base case. However, little fluctuation in the cumulative amount of CO_2 stored was observed for both permeability realizations (R1 and R2) after the injection period which could be related to the effect of heterogeneity on residual and dissolution trappings. Looking at Table 6, the obtained results for permeability realizations are almost similar to the base case under similar injection conditions. It was then concluded that heterogeneity may not have a significant impact on the storage mechanism of CO_2 in dry, wet and condensate gas systems. However, the permeability variation such as 400mD (see Figure 11) or the one close to a poor-quality storage medium (<10 mD) may offer different storage potentials under certain conditions.

Table 5: Permeability values in different directions in the given realizations

Permeability Realization	**K_h (mD)**	**K_v (mD)**	**K_z (mD)**	**K_{avg} (mD)**
R1	1300	1310	130	913
R2	1140	1140	114	798

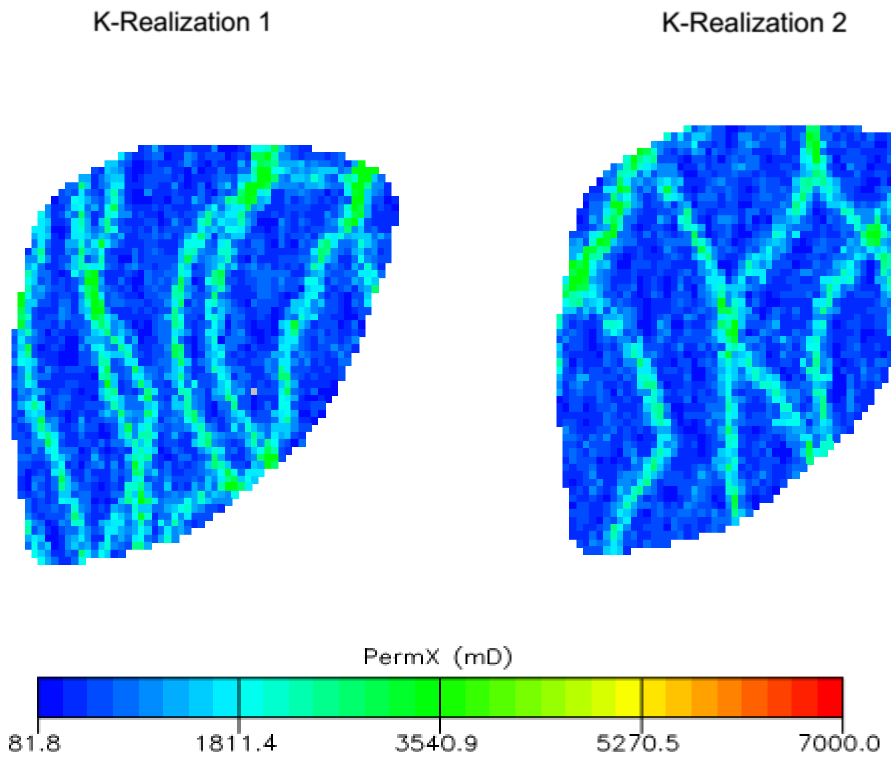


Figure 12. Reservoir models displaying the typical structure of high-permeability meandering channels in a low permeability background for permeability realizations

Table 6. Comparing the effect of gas type on cumulative injected CO_2, total stored CO_2, and maximum pressure buildup

Case	**Gas Type**	**CONSTRAINTS**		**Inj. Rate (MScf/D)**	**Cum. CO_2 Injected (Bt)**	**CO_2 amount in 1000 years (Bt)**			**Maximum pressure buildup**
		BHP (psia)	Inj. Time (years)			Supercritical free phase	Stored CO_2 as Residual phase	Stored CO_2 as Dissolved in brine	
Base Case	Dry	8000	5	100	3.75	1.14	1.96	0.651	4496
	Wet	8000	5	100	4.55	1.34	2.16	1.05	3307
	Condensate	8000	5	100	6.16	1.84	3.03	1.29	2671
R1	Dry	8000	5	100	3.78	1.15	1.97	0.66	4497
	Wet	8000	5	100	4.58	1.35	2.17	1.06	3309
	Condensate	8000	5	100	6.20	1.86	3.04	1.30	2673
R2	Dry	8000	5	100	3.72	1.13	1.95	0.64	4495
	Wet	8000	5	100	4.52	1.33	2.15	1.04	3304
	Condensate	8000	5	100	6.21	1.85	3.05	1.31	2670

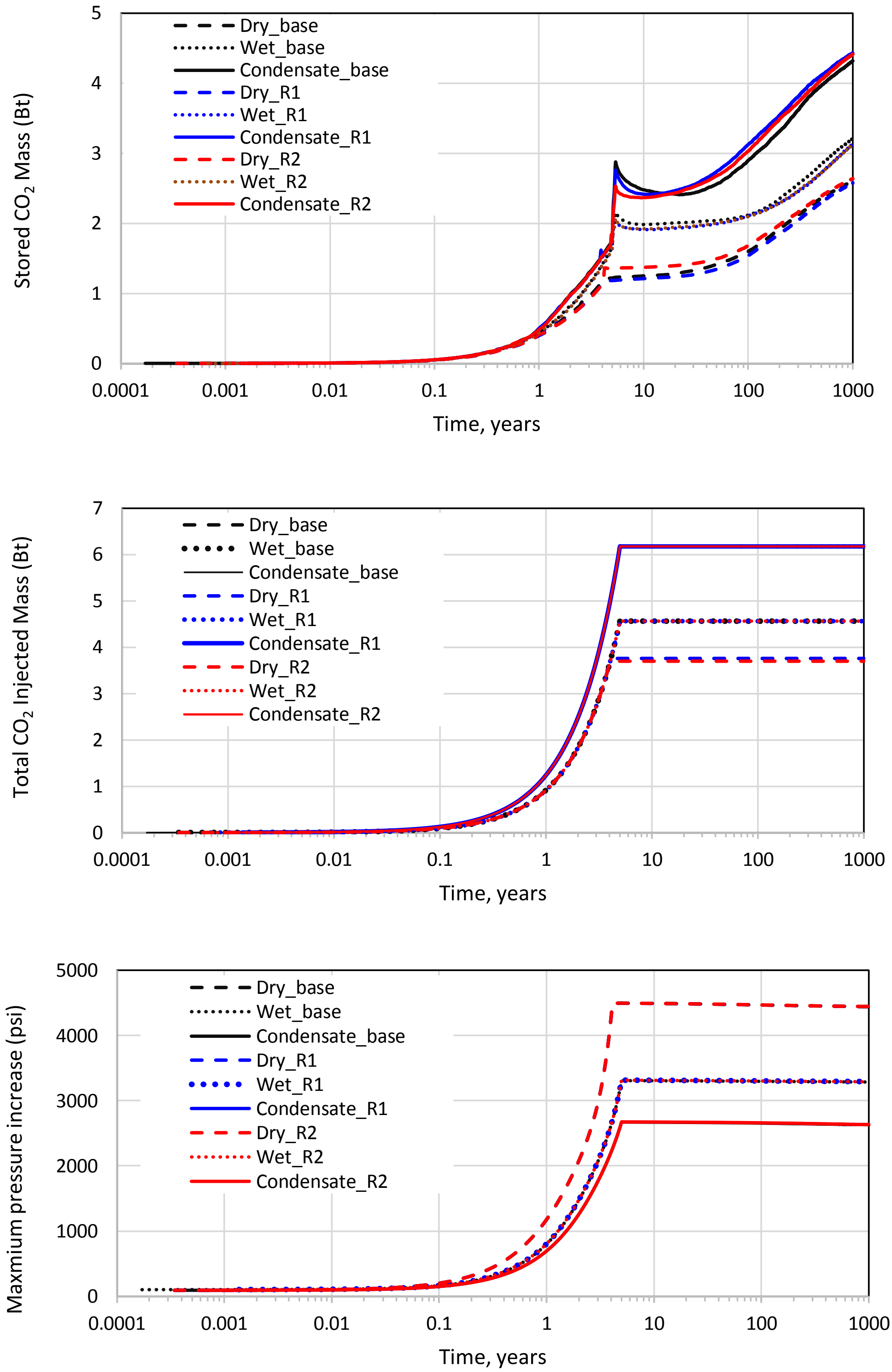


Figure 13: Comparing the amount of CO_2 stored in different gas formations based on two permeability realizations

5. Conclusions

A numerical model was built in this study for gas reservoirs to evaluate the long-term storage of CO_2 in gas reservoirs by considering representative compositions of dry, wet and condensate gases. It appears that gases reservoirs have a good potential for CO_2 immobilization in a long-term, but the condensate gas formations would be the best among all three. This could be attributed to the slight remaining gas volume, phase behavior of the condensate gas-CO_2 mixture, good injectivity, and lesser amount of methane mole fractions present in the medium.

A sensitivity analysis was performed to evaluate the variation of the injection rate and heterogeneity on CO_2 storage. It was found that the gas medium storage behavior is sensitive to the injection rate. Selection of an optimum injection rate could help to achieve a high storage potential in gas reservoirs, particularly in condensate gas mediums. Particularly, a high injection rate would also be beneficial for wet gas media to provide a good storage capacity. The results obtained also revealed that reduction in the permeability of the storage site enhances the overall storage capacity by boosting the residual and dissolution trappings after the injection period. Finally, it was concluded that the medium with condensate gas is a more favorable place for storage compared to mediums with dry gas and wet gas.

Nomenclature

k	Permeability
μ	Fluid viscosity
c_r	Formation compressibility
ϕ	Porosity
F_{pni}^{c}	Flow rate component in a phase (p=o, w, g)
T_{ni}	Transmissibility between cells n and i
y_p^c	Mole fraction of component c in phase p
k_{rp}	Relative permeability of phase
S_p	Saturation of phase p
b_p^m	Molar density of phase p
μ_p	Viscosity of phase p
dP_{pni}	Potential difference of phase p between cells n and I, given by
CO_2	Carbon dioxide
N_2	Nitrogen
O_2	Oxygen
SO_2	Sulfur dioxide
H_2S	Hydrogen sulfide
P	Pressure
V_M	Molar volume
R	Gas constant
T	Temperature
A, B	Mixture-specific functions of T and composition with the mixing rules
T_r	Reduced temperature
C_s	Salinity
bq_i	Soreide and Whitson constants
J_i	Flux of component i per unit area
D_i	Diffusion coefficient of component I,
$\partial y_i/\partial_d$	Molar concentration gradient of component i.
F_{ig}	Interblock diffusive flow

T_D	Diffusivity, the analogue of transmissibility for diffusive flow
y_i	Vapor mole fractions.
S_g	Gas saturation
S_{gi}	Initial gas saturation
C	Land trapping coefficient
$S_{g,max}$	Maximum gas saturation
$S_{gt, max}$	Maximum trapped gas saturation
K^d_{rg}	bounding drainage curve
K^{ib}_{rg}	bounding imbibition curves
BScf	Billion standard cubic feet
Bt	Billion tones

Acknowledgment

This work was funded by Curtin Sarawak Research Institute (CSRI) of Curtin University Malaysia under the grant number CSRI-6015. We also acknowledge Schlumberger Malaysia for providing Petrel tool and Eclipse compositional simulator.

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