Study of the fractures effect on the capacity and security geological storage of the CO_2 in hydrocarbon reservoirs

DJEBBAS Faycal, ZEDDOURI Aziez, KHELIFA Cherif

Abstract**—** Mitigation climate change requires reducing the emissions of CO_2 in the atmosphere, according to the actual scenario, the emissions of CO_2 will be doubled in the horizon of 2050 to reach more than 50 milliards tones of CO_2 per year, and we will get 1000 ppm in the end of 21st century, to keep the warming climate below 02°C we MUST keep the CO_2 concentration at 450 ppm.

Carbon Capture and Storage (CCS) is in the focus of interest of a growing scientific community due to its potential contribution to mitigate global warming, deep saline aquifers and oil & gas reservoirs are considered to be one of the most attractive options for reducing CO_2 emissions in the atmosphere and have been practiced in different locations worldwide. Algeria is one of the most advanced countries in this kind of projects, where the project of In Salah is the world's largest onshore CO_2 storage project, this project was started in 2004 with a storage capacity of 1 million tons of CO_2 stored per year.

Natural fractures have a large impact on the fluid flow through a reservoir and the modeling of natural fractures is important in the context of CO_2 storage for two primary reasons. Firstly, fracturing of the cap rock possibly due to increased injection pressure may lead to the unwanted leakage of CO_2. Secondly, and particularly for tight reservoir formations, fractures represent critical fluid flow pathways and constitute a large fraction of the total storage volume.

Keywords**—** CO_2 geological storage, greenhouse gas, capacity storage, cap rock sealing, fractured reservoir.

I. Introduction

CARBON Capture and Storage (CCS) in the geological formation could contribute significantly to reductions in atmospheric emissions of greenhouse gases (IPCC, 2005); several possible sites for injection include deep saline aquifers, depleted oil and gas reservoirs are attractive options to be best location to store the CO_2, injecting CO_2 into the adjacent aquifer of oil and gas reservoirs can provide additional pressure support for the developing hydrocarbon reservoir and improved the ultimate hydrocarbon recovery.

The successful of the geological CO_2 storage project depends on the successful of the trapping mechanisms of injected CO_2 in the subsurface; four trapping mechanisms have been identified: structural, capillary (residual CO_2 trapping), dissolution (solubility trapping), chemical (mineral trapping), and the trapping contribution of the four mechanisms as function of time is plotted in thee below figure

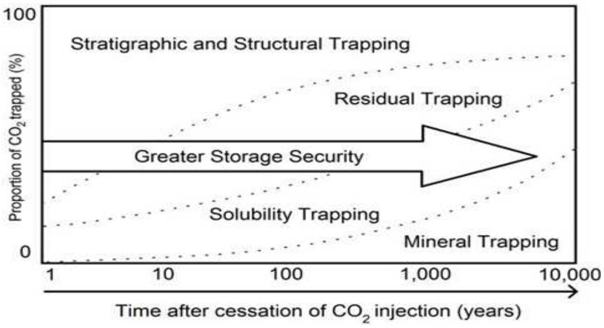

Fig.1: Trapping CO_2 mechanisms vs. time

The above stated trapping mechanisms ensure the capacity and the security of the stored CO_2, this paper presents comparative study between homogenous and fractured reservoirs to define the principal factors affecting the storage capacity and the risk associated with the presence of the fractures in natural fractured reservoirs.

II. Flow of CO_2 in the Subsurface

The main concerns of this study are the capacity and security of the stored CO_2 during the operational phase of geological CO_2 sequestration, in the initial time (<50 years) during which CO_2 is being injected into the subsurface. During this time frame, the CO_2 exists as separate-phase fluid, displacing the residual hydrocarbon in case of hydrocarbon reservoir (considered as EOR project) or brine (in case of deep saline aquifer) away from the injection well, over long time a significant fraction of the CO_2 dissolves into the resident brine that eventually, in the time frame of thousands of years can form minerals if favourable geochemical conditions exist [3]. Thus we are primarily considering the fate of the separate-phase CO_2 in a pressure-driven system during the initial injection period. This time period is considered to have the lowest 'storage security' because of the potential for the CO_2 to escape if favourable leakage pathways exist [3].

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Deep, geological formation such as depleted oil-gas reservoirs and saline aquifers are located at a depth such that the injected CO_2 would exist in a dense phase as a supercritical fluid. The supercritical region of CO_2 shown in the below figure

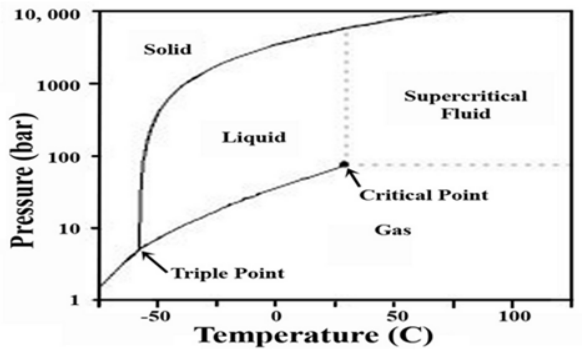

Fig. 2: CO_2 behaviour as a function of pressure and temperature (Critical point is at 31.1 C and 7.34 MPa), obtained from IPCC WGIII, 2005

These temperature and pressure conditions generally are found at depths greater than 800m. At these depths, the density of CO_2 ranges from 200 kg/m3 to 900 kg/m3, depending on the temperature and pressure conditions, as shown in the follow figure, we see that increased pressure has the effect of increasing density, while increasing temperature decreases CO_2 density. For the range of conditions found in the subsurface of continental basins, CO_2 is always less dense than the resident brine. The viscosity of CO_2 also varies with depth in a similar manner, ranging from 3.95×10-5 Pa.s to 7.11×10-5 Pa.s. CO_2 will have lower viscosity than resident brine for the temperatures and pressures that exist at depth, ranging from 5 to 40 times less viscous than brine

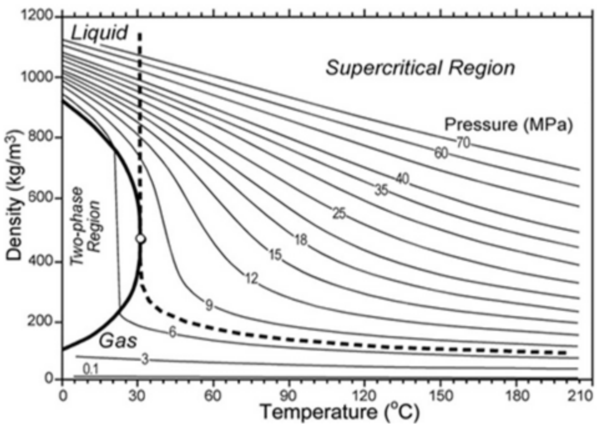

Fig. 3: Density of CO_2 [kg/m3] as function of temperature (obtained from Bachu, 2003)

Given these typical bounds on CO_2 properties, geological CO_2 sequestration will involve injecting a fluid into the subsurface that is less dense and less viscous than the resident fluid. Therefore, the injected CO_2 will rise to the top of the formation due to buoyancy forces with the gravity override enhanced due to viscous instability. This is generally considered an unfavorable scenario because CO_2 will have the tendency to escape vertically if leakage pathways exist through the confining layer especially in the natural fractured reservoirs case. If CO_2 escapes upward out of the injected formation, it can leak into overlying formations and possibly all the way to surface if suitable pathways exist. Also, viscous instability will cause the CO_2 to slip past the brine in a relatively thin layer just beneath the confining layer. This means that very little of the formation thickness will be filled with CO_2, and the areal extent of the plume will be large

III. Potential for CO_2 Leakage

If CO_2 leaks through the confining layer, there is the potential for CO_2 to infiltrate other geological formations and contaminate resources such as drinking and irrigation water or hydrocarbon reservoirs. CO_2 that reaches the surface could cause harm to humans and ecosystems, as has already occurred in the vicinity of natural CO_2 leaks. And, of course, leakage to the atmosphere defeats the purpose of CO_2 injection. Thus, when evaluating the long-term storage potential of a particular formation, possible leakage pathways should be identified and evaluated for their leakage potential.

Tow leakage mechanism are possible, the first one is in diffuse manner through the cap rock formation but it consider as unlikely because of the high thick (~100m) and impermeable of the confining layer and the capillary pressure preclude CO_2 from penetrating, the second leakage mechanism is through high permeability pathway such as (faults, fractures or wellbore) [2].

IV. Trapping mechanisms

The trapping mechanisms for CO_2 sequestration in deep saline aquifers are: (1) structural trapping, (2) solubility trapping, (3) residual trapping, and (4) mineral trapping. Structural trapping occurs due to the presence of structural closure and a seal in the form of an impervious cap rock, an unconformable surface or a sealing fault. Solubility trapping occurs due to dissolution of CO_2 into the aquifer brine at the prevailing conditions of pressure, temperature and salinity. Convective currents get established as the denser brine rich in CO_2 settles to the bottom part of the aquifer and the lighter brine with lesser CO_2 concentration tries to rise to the top of the aquifer. The process continues until a steady state is reached in the system. In active aquifers the CO_2-rich brine is displaced continually by fresh brine, thus promoting further dissolution of CO_2. Residual trapping is a consequence of a hysteresis effect in the relative permeability of the CO_2-rich gas phase that can occur due to reversal of the saturation direction. Mineral trapping is a consequence of conversion of injected CO_2 into ions and minerals caused by chemical equilibrium and mineral reactions. Although this is a long duration process it is considered to be the most secure trapping mechanism.

V. METHODOLOGIES FOR ESTIMATING CO_2 STORAGE CAPACITY

The estimation of the CO_2 storage capacity plays an essential role in the evaluation, analysis, prediction of future performance, and making decisions regarding development of CO_2 storage project, this key parameter is very complicate and depends on the nature of the storage location, in deep saline aquifers is very complex because of the trapping mechanisms that act at different rates are involved, and at time, all mechanisms may be operating simultaneously. Estimation of the CO_2 storage capacity in depleted (or produced) oil and gas reservoirs is straightforward and is based on recoverable reserves, reservoir properties and in situ CO_2 characteristics, Bachu and Shaw (2003, 2005) and Bachu et al. (2007) used the original gas in place (IGIP) at standard conditions and the gas recovery factor to calculate the theoretical mass storage capacity for CO_2 at in situ conditions for gas reservoirs. The principle methods for predicting CO_2 storage capacity are the volumetric method and the material balance method, the volumetric method is based on geological data to define the reservoir area1 extent, core and log data to define the reservoir rock properties and distribution of fluids inside the reservoir. The volumetric method provides a sketchy estimate, however, the material balance method is based on pressure-production data for estimating the initial gas in-place and the simplest method is to plot P/Z vs. Gp and extrapolate to zero-pressure.

VI. SALINE AQUIFERS STORAGE CAPACITY

In the saline aquifers the four trapping mechanisms stated above need to be taken into consideration when estimating storage capacity, the structural and residual trapping mechanisms are referred as the most important storage mechanisms in storing CO_2 in saline aquifers, the CO_2 will get trapped in the pore spaces and become more predominant after the cessation of the carbon dioxide injection, depending of the injection location, if we inject in aquifers adjacent to hydrocarbon reservoir (oil-gas) like In salah in Algeria project the CO_2 injected will migrate to the gas reservoir and replace the produced gas. However, if the aquifer is not adjacent to hydrocarbon reservoir, the storage capacity will be high but the storage will not be secure due to the uncontrolled CO_2 migration, contrary to previous case where the finale geological structure storage location (hydrocarbon reservoir) is known during the production period.

According to the above explanation it is obviously that we use the volumetric method to estimate the storage capacity of the deep saline aquifers and material balance equation to evaluate the storage capacity for hydrocarbon reservoir.

VII. VOLUMETRIC METHOD

Volumetric method uses porosity (∅), area (A), thickness (h) and storage efficiency (E), as in (10). The storage efficiency factor (E) accounts for: fraction of the saline aquifer formation appropriate for CO_2 storage $(h_{net} / h_{total} = 0.25 - 0.80)$ fraction of saline aquifer that satisfies minimum porosity and permeability requirements for injection $(h_{net} / h_{gross} = 0.25 - 0.75)$, Fraction of total porosity that is interconnected $(\phi_{effective} / \phi_{total} = 0.60 - 0.95)$, areal displacement efficiency $(E_A = 0.50 - 0.80)$, vertical displacement efficiency $(E_I = 0.60 - 0.90)$, fraction of net aquifer thickness contacted by CO_2 as a result of CO_2 buoyancy compared with the in situ water $(E_g = 0.20 - 0.60)$, pore-scale displacement efficiency $(E_d = 0.50 - 0.80)$, reflecting the achievable degree of saturation for saline aquifers with these efficiency related factors. By using an array of values for these parameters, various types of saline aquifers could be represented

$$E = (A_n / A_t)(h_n / h_g)(\phi_e / \phi_t ot) E_A E_I E_g E_d \tag{1}$$

$$V_{CO2} = Ah\phi E \tag{2}$$

The above equation can be quick and simple calculation method when limited data is available, however, when more data is available the equation can be reformulated as

$$M_{CO2} = V_r \frac{N}{G} E \phi \tilde{n} \tag{3}$$

Where V_r is the bulk volume of the aquifer and N/G is the net to gross ratio, E is the efficiency factor and was assumed to be 2 %.

VIII. GAS-OIL RESERVOIRS CAPACITY STORAGE

A. *Material balance method - Homogenous Reservoirs*

As explained previously the starting point to calculate the CO_2 storage capacity is the Material Balance method with different assumptions, Chi-Chung Tseng et al. [6] assume that the pore volume of the reservoir is unchanged during gas production and CO_2 injection, this assumption is valid only for low pressure completely seal off “volumetric” gas reservoir.

$$G_i B_{gi} = (G_i - G_p + G_{CO2}) B_g + W_e \tag{4}$$

However, in oil reservoir case or if the reservoir initially has abnormally high formation compressibility, as observed in some high pressure gas reservoirs, the rate of pressure drop may increase with gas production. This is due to the fact that the compaction of the reservoir rock will provide pressure support at the high pressure level. In the present study we apply the Material Balance method to estimate the volume capacity storage of the oil-gas reservoir destined for CO_2 Enhanced oil recovery (EOR) and storage project, of course, the starting of any CO_2 storage project should not be before 40-50 % of hydrocarbon recovery (may be less for oil reservoir), at this stage of development the total hydrocarbon pore volume should be known and highly accurate, but it will be not the total mass storage capacity due to the irreversibility phenomenon of the petrophysical parameters (porosity, compressibility,…). The material balance equation of the homogenous reservoirs with taking into consideration all sources of expansion (formation expansion, connate water expansion) and water influx from associated aquifer can be expressed as:

Gas Reservoir

$$G_i(B_g - B_{gi}) + G_{CO2}B_{g/CO2} + W_e + \Delta V_w + \Delta V_p = G_p B_{g/CO2} + W_p B_w \tag{5}$$

Oil Reservoir

$$N_i(B_o - B_{oi}) + G_{CO2}B_{o/CO2} + W_e + \Delta V_w + \Delta V_p = N_p B_{o/CO2} + W_p B_w \tag{6}$$

B. Material balance method - Fractured Reservoirs

The internal architecture of fractured reservoirs is more complex than that of homogenous reservoirs. This stems precisely from the presence of an additional network of fractures in the porous medium, which results from tectonic forces which have “broken” the rock. The presence of the fractures in the oil-gas reservoirs can be advantage for hydrocarbon recovery but disadvantage for CO_2 geological storage project. The material balance equation for the fractured reservoirs with taking into consideration the dual feature (dual porosity-permeability) of the formation and all sources of expansion (formation expansion, connate water expansion) and water influx from associated aquifer can be expressed as:

Oil Reservoir

$$F = N_1 + N_2 \frac{E_{02}}{E_{01}} + G_{CO2}B_{o/CO2} + W_e - W_p B_w \tag{7}$$

Where E_{01} represents the net expansions of the original oil phase in matrix system and E_{02} is the net expansion of the original oil-phase in the fracture network and expressed as:

$$F = N_p \left[B_o + (R_p - R_s)B_g\right] \tag{8}$$

$$E_{01} = N_1\left[B_o - B_{oi} + (R_{si} - R_s)B_g + \left(\frac{C_w S_{wi} + C_m}{1 - S_{wi}}\right)\Delta P B_{oi}\right] \tag{9}$$

$$E_{02} = N_2\left[B_o - B_{oi} + (R_{si} - R_s)B_g + \left(\frac{C_w S_{wi} + C_f}{1 - S_{wi}}\right)\Delta P B_{oi}\right] \tag{10}$$

Where N_1 is OOIP in the rock matrix and N_2 is OOIP in the fractures C_m and C_f represent the compressibility of the rock matrix and the average compressibility of the fractures. From the previous equations we derive that the theoretical storage capacity of the homogenous and fractured reservoirs are not same.

Gas Reservoir

All the formulation applied for oil reservoirs are valid for gas reservoir with appropriate changes of G instead of N and FVF factor.

IX. MODELING METHODOLOGIES

A. Model geometry

Mathematically the oil in place in the fractured and homogenous reservoirs is not the same as shown in. (5) and (7). In this study, simple reservoir model is built to evaluate the storage capacity and flow behaviour of the CO_2 stored in the homogenous and fractured reservoir. The both models have same dimension with the presence of the fractures properties in the fractured reservoir model as shown below tables.

Table 1: Homogenous reservoir data

Parameter	Unit	value
ΔX **Δ**Y **Δ**Z	ft	2000×1000×250
Pi	psia	4910
Tres	°F	208
Pb	psia	3536
POR	%	29
Kx,Ky,Kz	md	10,10,0.1
Co	1/psi	0.0000197

Table 2: Fractured reservoir data

Parameter	Unit	value
ΔX **Δ**Y **Δ**Z	ft	2000×1000×250
Pi	psia	4910
Tres	°F	208
Pb	psia	3536
PORM	%	29
PORF	%	0.01
Kxm,Kym,Kzm	md	10,10,0.1
Kxf=Kyf=Kzf	md	10.10.90.20.20

B. Dynamic data

We used compositional model with two wells (oil producer well and gas injector well), the initial reservoir pressure was considered as the pressure constraint storage (to be safe and below of the hydraulic fracture pressure of the reservoir), the dynamic model data is shown in the below table

Table 3: Dynamic model data

Parameters	Unit	Value
Pinj	psia	6000
BHP	psia	5000
Pb	psia	4500
Q_{CO2} Max	MSCF	2000
Qo Max	STB	2000

The geometry of the reservoir is shown in below figures

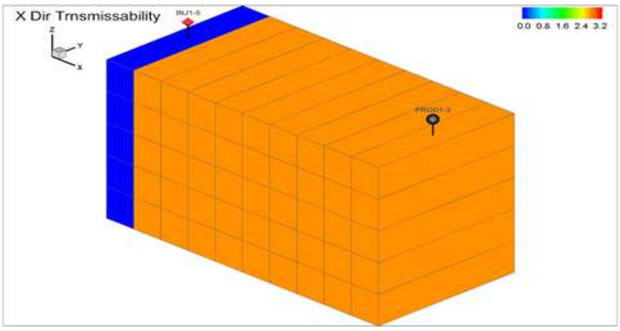

Fig. 4: 3-D simulation grid of homogenous reservoir

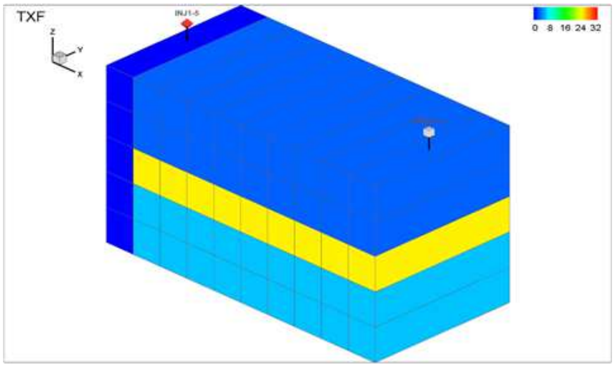

Fig. 5: 3-D simulation grid of fractured reservoir

X. Results

To get consistency in our study the fractured model has same properties as the homogenous model with adding fracture properties as shown in the above tables. Initially the reservoir is filled of oil and the injection of the CO_2 is starts with the production startup to be used as EOR mode.

The theoretical storage capacity (expressed initially by the produced volume at standard conditions, Bchu and Shaw (2003, 2005) and Bachu et al. (2007)) is higher in the homogenous reservoir than the fractured reservoir

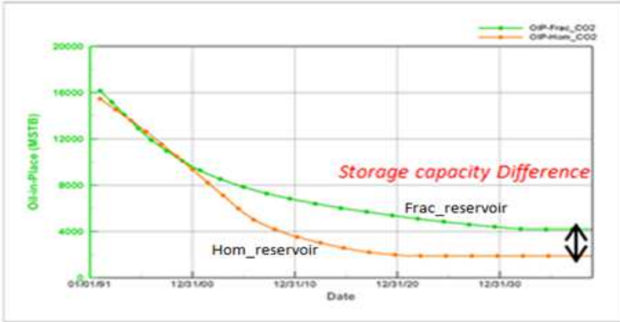

Fig. 6: Capacity storage difference between fractured and homogenous reservoir

A. Homogenous reservoir

To confirm the real storage capacity of our homogenous reservoir the below curve show the difference between the injected and produced CO_2 gas

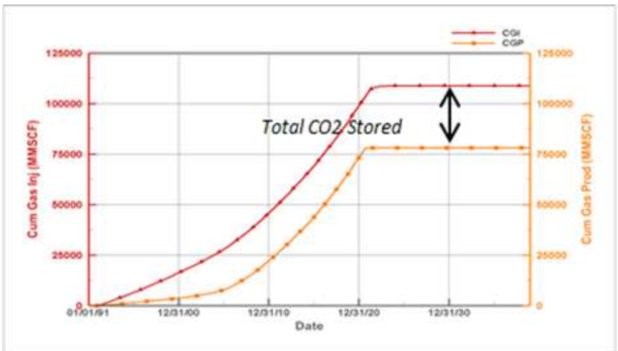

Fig. 7: Total CO_2 stored in homogenous reservoir

The total CO_2 stored in the homogenous reservoir expressed as:

$$TOTAL_{CO2stored} = TOTAL_{CO2injected} - TOTAL_{CO2produced} \quad (12)$$

According to the simulation results we have:

$$TOTAL_{CO2stored} = (108.7-78)10^{9} = 30.710^{9}\,SCUF$$
$$= 30.710^{9} \times 0.510^{-3} = 15.35\,MMRB$$

As stated above, the BHP limit is above the bubble pressure to be sure that all produced gas is coming from the gas injected CO_2 (NO dissolution gas is produced), and the initial oil FVF is Boi = 2.066 rb/stb.

The cumulative oil produced from the homogenous reservoir is:

$$COP_{RB} = COP_{STB} B_{oi} \quad (13)$$
$$COP_{RB} = (15.4-1.9)\times 2.066 = 27.89\,MMRB$$

In order to determine the compressibility of the CO_2 used in our study we need to calculate the Oil-CO_2 compressibility multiplier factor $MCF_{oil\text{-}CO2}$

$$MCF_{Oil-CO2} = \frac{TotalCO2stored_{RB}}{COP_{RB}} = \frac{15.35}{27.89} = 0.5$$

The compressibility of the oil of our study is19.7 10^{-6}, which it means that the CO_2 injected is more compressible two times than the oil in place.

$$C_{CO2} = (19.710^{-6} \times 2 = 39.410^{-6} (1/psi)$$

B. Fractured reservoir

As stated above the matrix blocks of the fractured reservoir used in our study have same homogenous reservoir properties with adding of course the fracture properties and the both models have same dimensions.

The results of our models show that the storage capacity of the fractured reservoir is less than the homogenous reservoir as shown in the below figure.

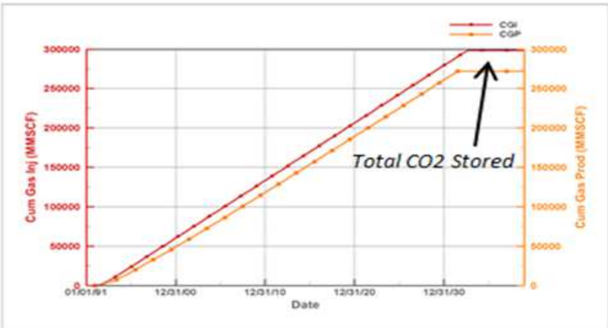

Fig. 8: Total CO_2 stored in fractured reservoir

Using same calculation methodology used with the homogenous reservoir previously, the total CO_2 stored in the fractured reservoir of our study is

$$TOTAL_{CO2stored} = (298.2 - 271.8)10^9 = 26.410^9\,SCUF$$
$$= 26.410^9 \times 0.510^{-3} = 13.2MMRB$$

From the previous plots we deduce that the gas injected in the fractured reservoir preferred flowing through the fractures than the matrix blocks which it means that the big amount of the oil stay in the matrix, the diffusivity phenomena between the fracture and the matrix block is the main exchange mechanism governing the production process of the fractured reservoirs, in order to increase the capacity storage of the fractured reservoir it should improving the recovery oil remained in the matrix blocks.

As stated by many authors the recovery of 1STB of oil required 5-10 MSCUF of CO_2 and during the EOR projects the half (~1/2) of the injected CO_2 will be left in the reservoir (pre-CCS), once the reservoir will be abandoned (no more oil or gas production) the geological storage operation will start and the key parameter governing the capacity of the reservoir will be the pressure which it limited by the security of the project (maximum injection pressure), this value should be less than the minimum pressure value that can allow the CO_2 escaping through the weak point in our system (cap rock or down hole of the abandoned wells) and the presence of the fractures in the system will accelerate the arrival of the CO_2 to this weak points.

The behaviour of the capacity storage of the fractured reservoir is different than the homogenous reservoir, as shown in the below plots

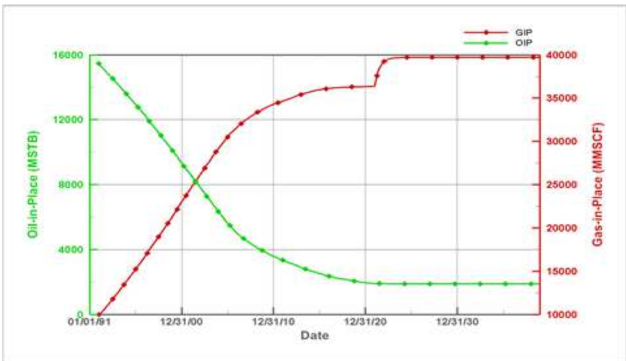

Fig. 9: homogenous reservoir storage capacity behaviour

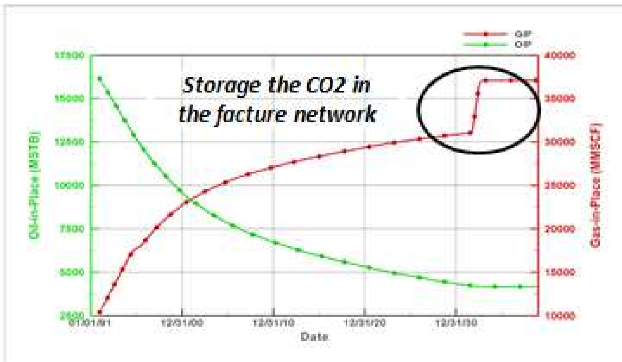

Fig. 10: fractured reservoir storage capacity behaviour

As shown in the previous plots, the amount of the CO_2 stored after stopping the production is higher in the fractured reservoir than the homogenous reservoir but it does not represent the total CO_2 stored, as explained previously that the half of the CO_2 injected during the EOR process will be left in the reservoir and of course the presence of the fractures in the fractured reservoir affect negatively in the capacity storage which can deduced from the big amount of the produced gas in the fractured reservoir than the homogenous reservoir, according to the simulation results during the EOR process it means before shut in the producer the homogenous reservoir stored around 12.8 MMRB of CO_2 and the fractured reservoir stored around 9.2 MMRB of CO_2 (the ratio of the homogenous reservoir capacity storage to the fractured reservoir is around 1.4), after the stopping of the production and starting the geological storage operation which it limited as mentioned previously by the maximum injection pressure, the mount of the CO_2 stored in each reservoir is around 2.15 MMRB in the homogenous reservoir and around 4 MMRB, according to this results we deduce that the fractured reservoir has capacity storage higher than the homogenous but in reality this figures represent the fracture degree of the reservoir because this amount of CO_2 is stored in the fractures, from this analysis we deduce that the storable volume of the CO_2 in the abandoned hydrocarbon reservoirs is related to the hydrocarbon recovery factor and this last parameter is higher in the homogenous reservoirs than the fractured reservoirs especially when the CO_2 is used as EOR mode [18].

XI. Discussion

According to the previous results and analysis we note that the storage capacity of the homogenous reservoirs is higher than the fractured reservoirs due to the dual feature of the fractured reservoir, where the presence of the fractures in the formation helps the CO_2 to flow through the less resistant path.

The difference in the storage capacity between the fractured and homogenous reservoirs is coming principally from the exchange physical mechanisms between the fracture and the matrix, where the diffusion phenomenon is the main exchange mechanism.

Sensitivity cases have been done in our model to check the effect of the injection pressure on the storage capacity of both reservoirs, as shown in the following figures, the increasing of the injection pressure in the homogenous reservoir provides more available space to store more CO_2 due to the increasing of the hydrocarbon recovery and the effect of the pressure increase in the compressibility of the CO_2 and reduce the storage time, however in the fractured reservoir the increasing of the pressure help to accelerate the CO_2 breakthrough which it means increasing in the amount of the injected and produced CO_2 (cycling of the gas through the fractures) and reduce the storage time this indicates that the pressure constraint is more limiting for injection periods.

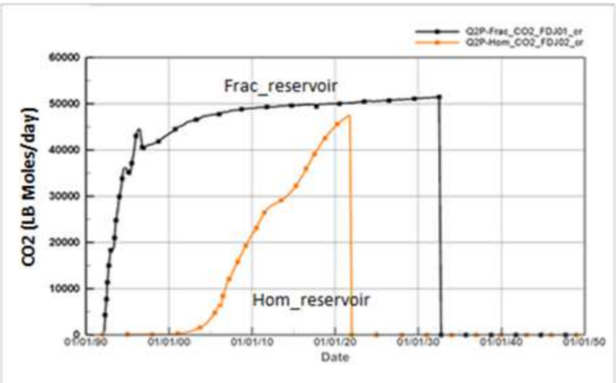

Fig. 11: CO_2 Breakthrough time

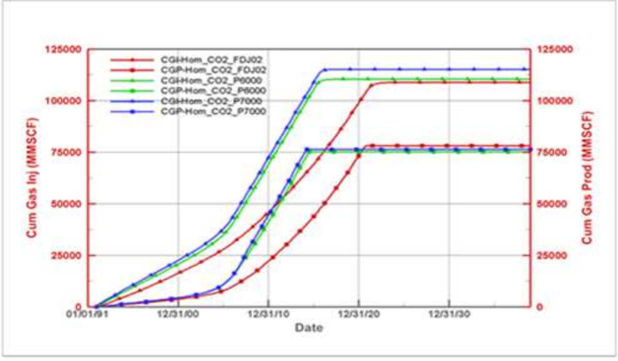

Fig. 12: Effect of the limit injection pressure in storage capacity (homogenous reservoir)

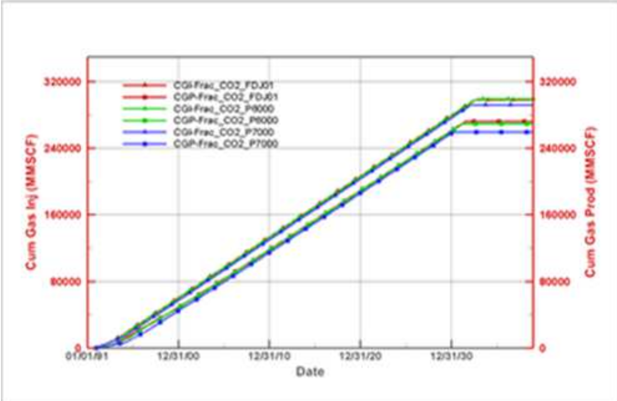

Fig. 13: Effect of the limit injection pressure in storage capacity (fractured reservoir)

XII. Gas-Oil reservoirs security storage

The CO_2 storage project depends on the successful of trapping mechanisms in porous rocks in the subsurface. The trapping mechanisms have been identified to be structural, residual, solubility, and mineral trapping. They reflect the mutual influence of geological environment and physical flow processes on the overall storage process. The impact of fractures on fluid flow is challenging to quantify due to (1) the complexity and varying nature of fractures, (2) their representation in grid meshes for fluid flow simulation, (3) the correct mathematical description of the physical processes, and (4) the computationally demanding solution of the governing equations. For tight gas reservoirs and low permeable cap rock structures, where the permeability is controlled by fault and fractures, a good characterization of the fracture network is essential. It is important to know: (a) the spatial distribution of faults and fractures, (b) their orientation, (c) their conductivity and (d) their overall contribution to effective permeability.

The fractures have always been regarded as potential escape routes for CO_2, which could damage the prospective storage ability of a specific storage site [14]. Fractures have low storage and high permeability values compared to the matrix. These high permeabilities of the fractures could potentially allow CO_2 to migrate quickly through the cap rock or down hole of abandoned wells to the surface or to neighboring aquifers. Local pressure increase caused by CO_2 injection can also lead to hydro fracturing in the vicinity of wells.

In salah project in Algeria is considered as world's largest onshore CO_2 storage project in the worldwide, a lot of monitoring technologies are applying to avoid any leakage of the CO_2 stored in the formation, after injecting around 2.5 million tons of CO_2 (at end of 2008) the results of the plume development suggest a NW migration (Rinrose et al., 2009). These results agree with satellite InSAR (Interferometric Synthetic Aperture Radar) data interpretation (ground surface deformation - Vasco et al. 2008) and the CO_2 breakthrough at an old appraisal well (Kb-5) located 1.3 km from the Kb-502 injector. Tracer analysis confirms the Kb-502 origin of the CO_2. Surface deformation measurements (up to 20 mm near Kb-502) are coherent with both injection of CO_2 and gas production. They may reflect on first approximation the reservoir permeability distribution.

The breakthrough at Kb-5 occurred between two well-head inspections (August 2006 and June 2007). At least, the CO_2 migration trend is fully consistent with major faults and fracture network orientations as shown in the below MAP.

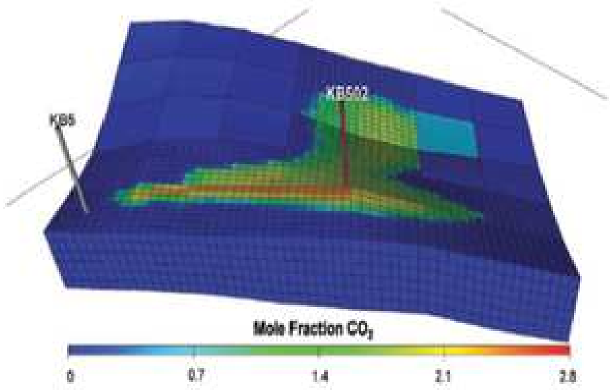

Fig. 14: Impact of the fracture conduit between Kb-5 and Kb-502 in salah project

XIII. Conclusion

The regulation of the CO_2 storage projects is still immature, in our present study we used two reservoir model, homogenous and fractured hydrocarbon reservoirs in order to evaluate the capacity and security storage of the CO_2, according to the previous results and analysis we note that the capacity storage of the CO_2 in the fractured reservoirs is less than in the homogenous reservoir.

For any CO_2 storage project the main leakage risks are driven by (1) Legacy wellbore integrity (2) Cap-rock integrity and (3) CO_2 plume migration direction, understanding CO_2 plume development requires high-resolution data for reservoir characterization and modeling, in In salah project the CO_2 plume migrate 1.3 km from KB-502 to KB-5 in NW direction with a period of two years (about three times faster than would have occurred with an homogenous cylindrical plume), the migration in this direction is consistent with the preferred conductive fracture orientation identified from image-log analysis, geological model and rock mechanical studies, reservoir modeling shown in the previous figure show that a corridor, with a permeability of 1-4 Darcy, gives a consistent match to the breakthrough observation. The high permeability corridor appears to correspond to a subtle fault (at the limit of seismic resolution).

The surface deformation data indicates plume migration has probably also occurred to the east of the observation well, probably following another zone of enhanced permeability.

Understanding CO_2 flow in fractured rock involves complex coupled processes and many challenges. However, by integrating difference data sources and using available modeling tools we are able to make plausible predictions of short-term CO_2 migration in the reservoir, and these insights help to build confidence in the long-term performance assessments.

Nomenclature

V_{CO2T}	Volume CO_2 trapped
Ø	Porosity
Sw	Water saturation
Pc	Capillary pressure
I	Injectivity
Ci	Compressibility (i= w (water), p (pores))
E	Displacement efficiency,
Gi	Gas in place
Bi	FVF Formation volumetric factor, i=o (oil), g (gas)
We	Water influx
G_{CO2}	Gas CO_2 Injected
Rs	Dissolution gas oil ration
MCF	Multiplier compressibility factor
COP_{RB}	Cumulative oil produced, reservoir barrel
BSCUF	Billion standard cube feet
MMRB	Million reservoir barrel

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