Geologic Containment - Theory and Methods

Sources: Ramirez and Aguilera (SPE 171626-PA, 2016), Fragoso et al. (SPE 189784-MS, 2018; SPE-195822-MS, 2019); Bao (URTeC: 3723651, 2022); Jacobs (SPE-0616-0028-JPT, 2016); Jacobs (SPE-0519-0037-JPT, 2019).

It is well known how oil, condensate and dry gas were generated starting about 90 million years ago (late Cretaceous) in the Eagle Ford shale. It is also well known through the drilling bit that fluids distribution over geologic time have remained in the windows where they were generated, e.g., there is oil shallower in the structure, condensate in the middle and dry gas is even deeper. Differences in burial depth, temperature, and vitrinite reflectance have been used by geoscientists to explain this unique distribution. A similar inverted fluid distribution occurs in other unconventional reservoirs (e.g., Duvernay shale in Canada).

With the ultimate goal to improve oil recovery from the Eagle Ford shale, Ramirez and Aguilera (2016) performed a 1 million-years+ simulation with a dual porosity/dual permeability model having hydrocarbons distributed in an inverted order. The idea was trying to understand the factors that controlled fluid migration and distribution in the Eagle Ford shale. The studied controlling parameters were porosity, permeability, pore throat aperture (rp35) and spacing between natural fractures. Results showed that fluids in the matrix remained with approximately the same original distribution. This led to their theory of geologic containment. The theory supported the use of H&P to improve oil recovery in the Eagle Ford shale (Fragoso et al., 2018), and supports our present hypothesis that utilization and storage of CO_2 (an important part of CCUS) can be carried out safely in the Eagle Ford shale and similar types of shale reservoirs around the world.

Figure 1 shows simulation results at different times (0, 10000, 50000, 100000 and 214000 years) that led to the geologic containment theory. **Figure 1** presents the base case but there are other cases published by Ramirez and Aguilera (2016) that consider various controlling parameters such as porosity, permeability, pore throat aperture (rp35) and spacing between natural fractures. "The initialization started with single phase oil at the top, condensate in the middle and dry gas at the bottom. Once the model was initialized, it was run for one million years without touching it and the phases were allowed to separate naturally. The conclusion was reached that contacts did not change in any significant way (i.e., approximately the same dry gas-condensate contact and approximately the same condensate-oil contact remains throughout the one million years)" (Ramirez and Aguilera, 2016).

A hypothesis advanced by the GFREE group with respect to lack of leaks during gas injection is supported by geological containment shown in **Figure 1**. A second hypothesis is that as H&P proceed with CO_2, more methane (originally in-place or from previous H&P) is removed from the reservoir. It follows that if CO_2 is injected during H&P, it can be contained (stored) in the shale reservoir without leaks. Potentially this is very positive from the point of view of Carbon Capture, Utilization and Storage (CCUS) as discussed later.

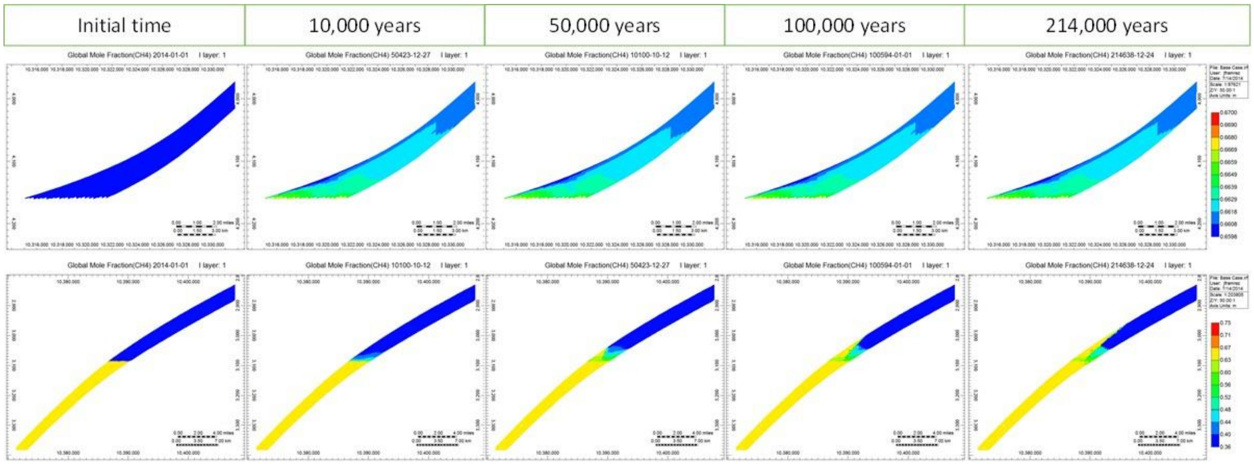

Figure 1—Global mole fraction (methane) for the base case. The dry gas–condensate contact is in the upper half of the graph, and the condensate–oil contact is in the lower half of the graph. Dark blue in upper half represents a global mole fraction (CH_4) equal to 0.6599. After 10000 years, a darker shade of blue is only at the top of the structure above a lighter blue color, indicating a global mole fraction (CH_4) of 0.6629. The color scale is different in the lower half of the graph. At time zero there is a clear separation (representing condensate-oil contact), between oil shown in dark blue (CH_4 global mole fraction is 0.36) and condensate shown in yellow (CH_4 global mole fraction is 0.67). There is a light blue color (CH_4 global mole fraction is 0.48) indicating at 10000 years with very slight increase up to 214000 years. However, in general, the contacts remain approximately constant through time, corroborating that there is geologic containment (Ramirez and Aguilera, 2016).

Figure 2 shows in a cross-section mode how the CO_2 global mole fraction increases in the shale reservoir during H&P CO_2 injection at different times (0, 61, 67, 87, 120 and 146 months). The cross section at time zero is dark blue, corresponding to a global mole fraction (CO_2) equal to 0.0039. After the beginning of H&P CO_2 injection, a lighter shade of blue is shown at 61 months. As the H&P CO_2 injection process goes on, more CO_2 remains in the reservoir. The global mole fraction (CO_2) in the shale reservoir increases continuously as highlighted by the different colors: cyan (67 months), green (87 months), yellow (120 months) and light orange (146 months). The color scale in the right-hand side of **Figure 2** provides the values of the CO_2 global mole fraction. After 146 months, there is a large amount of CO_2 stored in the reservoir. The same global mole fraction analysis was used in **Figure 1** to demonstrate geological containment in the Eagle Ford shale. Since natural gas been geologically contained since the Cretaceous (90 Ma), it is reasonable to anticipate that the injected CO_2 will remain stored in the shale reservoir without any leaks. Notice that the dates in the figure are shown to maintain continuity and to be consistent with the pilot data.

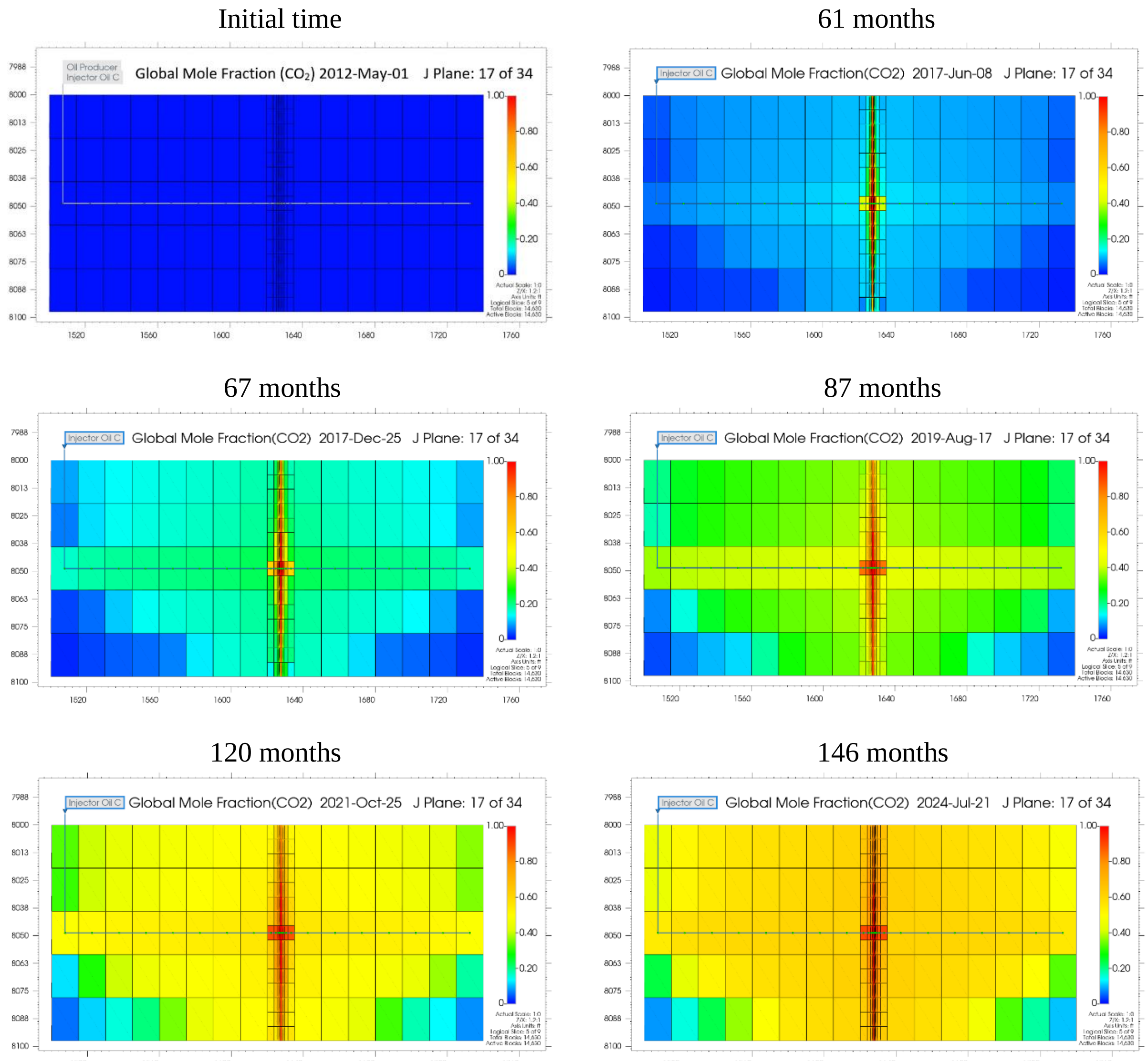

Figure 2—Cross-section figures (CO_2 global mole fraction) from the initial time to the last stage of H&P CO_2 injection (146 months).

This hypothesis is verified by simulation results. **Figure 3** shows the continuation of the cross-section presented in **Figure 2** using the global mole fraction at the end of continuous CO_2 injection when average reservoir pressure reaches an imposed safe value not to exceed the initial reservoir pressure (6000 psi) to avoid any potential leakage. The color at the end of continuous CO_2 injection (161 months) in **Figure 3** is in darker orange, compared to **Figure 2** at the end of H&P CO_2 injection (146 months). This indicates that the CO_2 storage amount is gradually increasing with continuous CO_2 injection. **Figure 4** shows results when the well is shut in for 5 years after reaching an average reservoir pressure of 6000 psi. This is the type of result that can be anticipated under conditions of geologic containment: Safe CO_2 storage without any leakage. Although the color around the perforation blocks is fading, the reason is that CO_2 in those blocks with higher CO_2 concentration transfers to the adjacent blocks with lower CO_2 concentration.

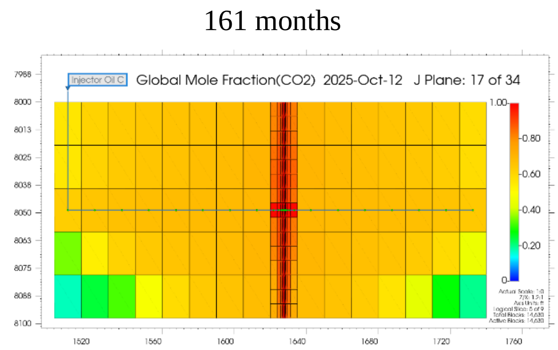

Figure 3—Cross-section figure (CO_2 global mole fraction) at the end of continuous CO_2 injection (when average reservoir pressure reaches initial 6000 psi).

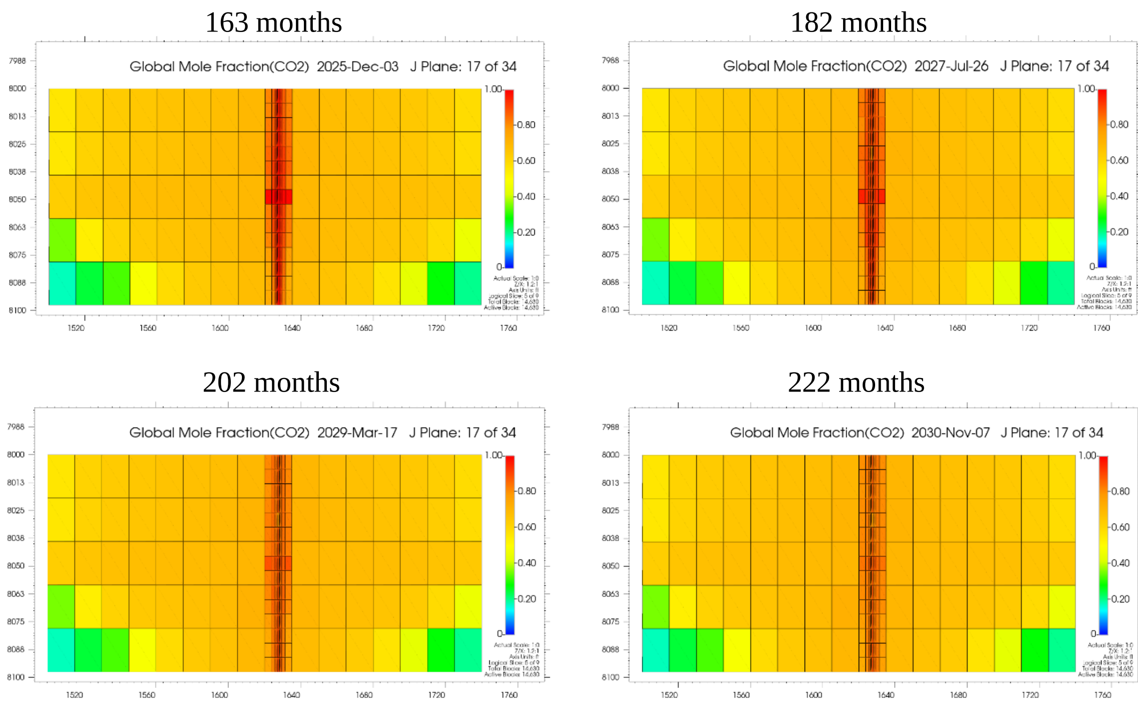

Figure 4—Cross-section figures (CO_2 global mole fraction) after the well is shut in for 5 more years to evaluate the effect of geologic containment.

Theoretically by the end of the project, CO_2 will remain safely in the shale reservoir without any significant leaks. In practice, this will be monitored by the operator during the life of the H&P CO_2 injection project by recording reservoir pressures and keeping a balance of the injected and produced CO_2 during each cycle of the project. The hypothesis with respect to lack of leaks is supported by the geological containment theory explained in Figure 1 (Ramirez and Aguilera, 2016; Fragoso et al., 2018). Based on the reservoir simulationr, H&P CO_2 injection and production in the same hydraulically fractured horizontal well of the Eagle Ford shale leads to a total injection of 13 cycles x 4.1 MMscf/day x 21 day/cycle = 1.1 billion scf by the end of the forecast 144 months. In practice, the length of the H&P projects could change based on economic considerations. **Figure 5** shows a summary explaining why the probability of any leakage from the hydraulically fractured horizontal well(s) is small.

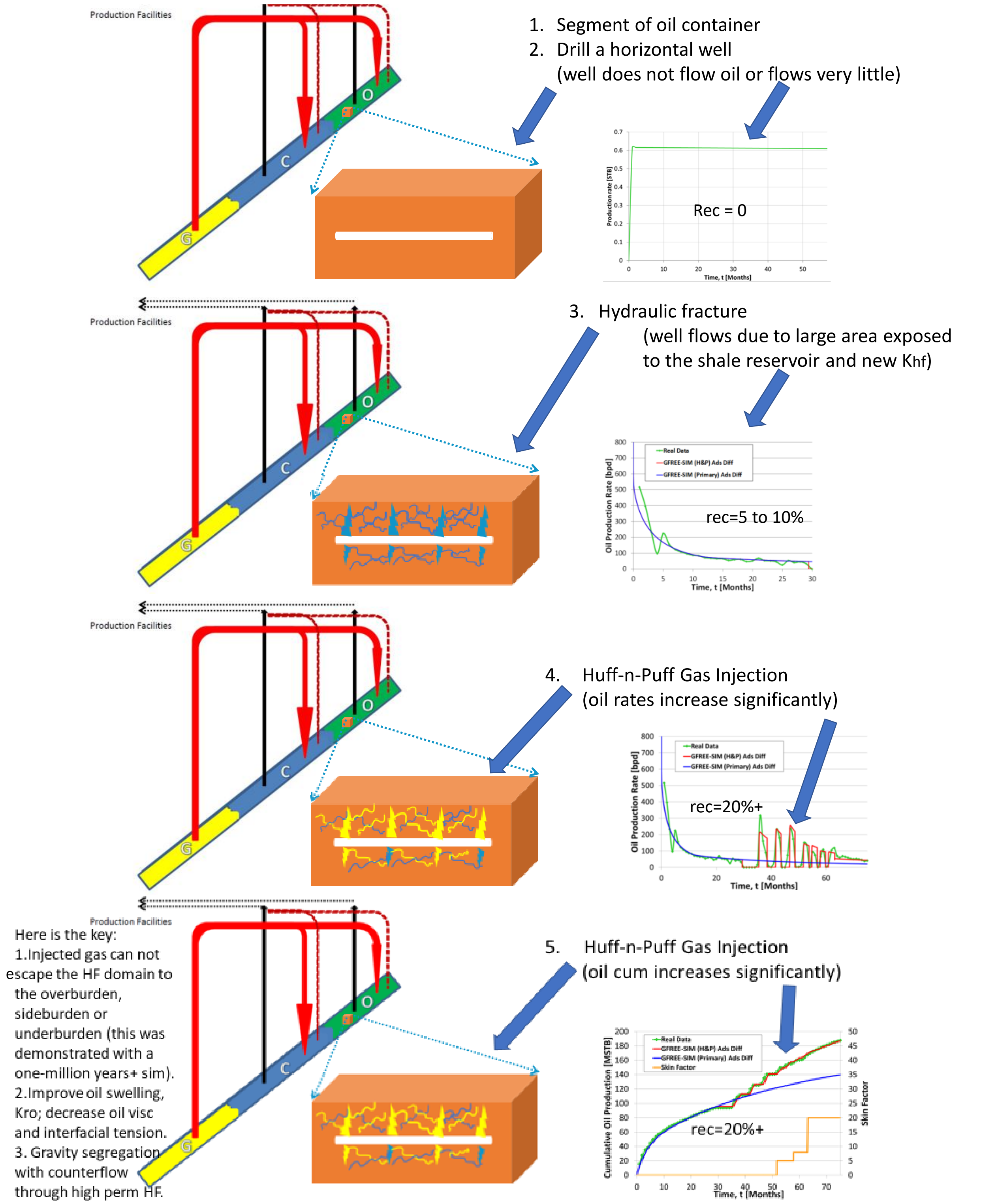

Figure 5—From drilling to hydraulic fracturing to primary production to H&P gas injection. Conceptual model for gas injection in shale oil (O) and condensate (C) containers is not to scale. HF = hydraulic fracture. K_{hf} = permeability of HF (adapted from Fragoso et al., 2018, 2019). The final stage would be continuous injection of CO_2 until reaching the initial reservoir pressure.

The simulation results on the upper right-hand side of **Figure 5** show that the horizontal well without hydraulic fracturing flows very small amounts of oil (0.6 BOPD) resulting in a recovery close to zero. Subsequently, following hydraulic fracturing, the well recovers between 5 and 10% of the OOIP in the simulation model, which is what is actually reported in the literature for Eagle Ford primary oil recovery. Next the oil recovery increases to more than 20% when H&P gas injection is implemented. Once the economic limit of the H&P project is reached, the horizontal well(s) can be used for injecting continuously CO_2 until reaching the initial reservoir pressure.

Based on our GFREE research, we had previously anticipated “hundreds of injection wells and hundreds of production wells, that would be suitable EOR candidates in the Eagle Ford” (Jacobs, 2016). This is certainly proving to be a realistic prediction. Jacobs (2019) has indicated more recently that "in a recent quarterly earnings statement, EOG said it continues to see "strong results" from around 150 EOR wells, more than a third of which were converted in 2018. Analysts and engineering consultants have found about 100 other wells in the Eagle Ford that several other operators have converted into H&P injectors".

Thus, if we assume 1000 H&P injection wells, then 1.1 trillion scf of CO_2 would be injected during the H&P life of the projects. Our hypothesis is that the injected CO_2 will remain in the reservoir safely stored. And there are many more shale reservoirs with geologic containment throughout the world. Thus, the potential for CO_2 Utilization and Storage via H&P CO_2 injection is significant. This hypothesis will require testing and corroboration via pilot wells.