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Hydraulic Fracturing Design Considerations for Carbon Capture, Utilization, and Storage (CCUS)

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Abstract

Hydraulic fracturing, a well-established technique in the oil and gas industry, has gained significant attention as a potential method to improve the short- and long-term efficiency of the Carbon Capture, Utilization, and Storage (CCUS) process. Most of the scoping studies on CCUS have centered on the reservoir aspects, such as storage and CO2 movement. Very little has been done evaluating what the fracture designs might look like in this process.

This paper presents a review of the application of hydraulic fracturing in CCUS projects, examining its technical feasibility, fluids, sustaining agents, wellbore orientation, and fracture orientation considerations required to assure its technical and economic success. It will consider rock properties, depleted oil or gas reservoirs conditions, or deep saline aquifers horizons and compressed CO2 supply at the storage site; simulations have been performed using primarily super critical CO2 (scCO2) and conventional fluids to perform the hydraulic fracturing. In addition to the sCO2 usage and proppants required to tail the generated fractures; the wellbore orientation effect in reference to the stress plane is also considered in the paper.

Finally the short- and long-term benefit of the hydraulic fracturing will be evaluated by simulating the CO2 injection behavior.

The review encompasses an analysis of the various key stages involved in CCUS hydraulic fracturing process, starting from the review of rock properties, wellbore orientation, perforation strategy, selection of suitable fluid and propping agents for efficient and safe stimulation of a well candidate. The potential benefits of the proper hydraulic fracturing process implementation will be translated in an enhanced storage capacity and improved injectivity.

The extensive simulations considering the sCO2 as the primary fluid system for fracturing purposes, combined with the wellbore orientation and other parameters will show the direct benefit of the combinations of the hydraulic fracturing and the CCUS processes, including:

- The use of sCO2 and proppants for hydraulic fracturing purposes in CCUS
- The influence of the wellbore and hydraulic fracture orientation in the success of the CCUS process

The paper aims to explore the potential of CCUS in conjunction with hydraulic fracturing to increase the efficiency of CO2 disposal and analyze methods to maximize its effectiveness. It will be beneficial for those contemplating CCUS, complementing other CCUS evaluations to provide a more complete picture of the feasibility as well as technical hurdles that must be overcome to implement this concept.

Introduction

As companies strive to reduce carbon emissions and implement ESG practices, carbon sequestration has attracted a large amount of attention from oil and gas operators, private equity, and other carbon intensive companies. CCUS allows for an operator to inject large volumes of carbon dioxide deep into the ground where it is either permanently stored or used as a secondary recovery method to extract additional oil from a producing field. Federal tax credits for eligible CCUS projects allow for an operator to reduce carbon that would otherwise be released into the atmosphere while making money in the process. However, for these projects to be economic there are a number of critical factors that need to be considered including proximity to emitters, potential risk of groundwater contamination, and rock quality.

Because the 45Q tax credits are based on metric tons of CO2 injected, finding rock that is capable of large injection volumes is crucial for the feasibility of CCUS projects. The requirements for a Class VI carbon sequestration well are extremely stringent on the wellbore design to prevent carbon dioxide from leaking up into the atmosphere or drinking water. Metallurgical requirements include either stainless steel or chromium alloy pipe along with acid resistant cement and nickel or Inconel packers which can significantly impact well costs. With higher permeability rock, less wells will need to be drilled to inject the targeted injection volumes of CO2.

The high quality, readily accessible acreage has begun to see a frenzy of interested parties rushing to piece together as much acreage as possible in an attempt to put together a sizeable package for a profitable project. The expansive Gulf Coast Miocene and Frio sandstones have emerged as the most attractive acreage due to their proximity to a large number of refineries and other sources of CO2, high porosity and permeability, and stratified layers of sand and shale that work together to permanently secure the CO2 in the reservoir. Hundreds of thousands of acres have been purchased along the Gulf Coast which could lead to all of the practical acreage to be gone in the next few years.

Hydraulic fracturing will open up an entirely new realm of CCUS potential. While the Gulf Coast sands are currently seeing the most attention, there are numerous other locations across the United States that present viable opportunities for those seeking a way into CCUS. As the Gulf Coast Miocene and Frio sands become more densely populated, people will need to look to more unconventional approaches. Just as hydraulic fracturing revamped oil and gas production throughout the US, it offers the same opportunity to CCUS projects as it allows operators to pursue locations closer to emitters, cutting down or even avoiding expensive midstream costs. A marginal location with lower permeability could be hydraulically fractured to allow the rock to take on the necessary volumes to make it a viable option. This paper aims to provide an expanded analysis showing how hydraulic fracturing can be used and applied to CCUS.

Injectivity problems in CCUS projects. Potential solutions to address it

An ideal environment to dispose captured and conditioned scCO2 in ground is a bigger vertically contained saline aquifer with a high permeability and higher porosity. The vertical barrier or cap rock is required to avoid the CO2 migration to the upper horizons, contamination of freshwater horizons or the leak of the CO2 to surface throughout existing or induced fissures. If the previously listed requirements are satisfied, and assuming that injectivity into the saline water aquifer is not damaged during the drilling and completions steps, the CO2 disposal could be assured at the required disposal rates and volumes.

Unfortunately, for saline aquifers having the ideal size and permeability (e.g. 1000 mD), the drilling and completion processes can induce injectivity damage. The induced damage as it is going to be proved later, will drastically impact the scCO2 injectivity levels, requiring the implementation of a stimulation service or the placement of a small hydraulic fracture to be able to bypass the damaged zone, restore the injectivity, balance the economics and comply with the government requirements.

In other cases, despite properly planning the placement of the disposal well in an ideal environment, the reservoir permeability of the prospective horizon could much lower than the expected. For these specific condition as in the case of the ideal conditions a more aggressive type of hydraulic fracture would be required to assure the scCO2 injection

Another condition where the hydraulic fracture will be required will be the cases where the aforementioned ideal saline aquifers are located too far from the CO2 generation and capture points. For these conditions, as it will be shown later, a horizontal wellbore completion in low permeability saline aquifers where transverse or multiple longitudinal fractures can be placed to increase the effective injection area and assure adequate injectivity and disposal levels.

As described above for all the possible scenarios to comply with the Class VI permit requirements, a hydraulic fracture will be required to assure the planned injection rate and volumes for commercial-scale geologic CO2 sequestration projects.

Wells architecture and wellbore orientation considerations for CCUS

As in the case of hydrocarbon producer wells, the wellbore and hydraulic fracture orientation is important to maximize the hydrocarbons recovery. For unconventional reservoirs where the permeability of the completed formation is ultra-low, it is necessary to drill the horizontal well aligned with the minimum stress to be able to generate multiple transverse fractures and increase the effective producing area and SRV.

For the case of CO2 injection in low permeability disposal wells, as it is proposed for the case of conventional hydrocarbon producers, the drilling and completion of wellbore could be aligned with the maximum stress. This wellbore orientation will promote the generation of multiple fractures aligned with the maximum stress or the generate longitudinal fractures.

For the case of high permeability CO2 injectors as discussed on this paper, assuming that the reservoir properties are uniformly distributed laterally and vertically, theoretically a vertical wellbore completed in undamaged or minimally damaged formation will permit the injection scCO2 at higher rates; but in the real world, since it is expected to have changes in the lateral and/or vertical reservoir properties; the hydraulic fracturing in high permeability aquifers (e.g. k = 1000 md) is also justified to assure the volumetric CO2 injection at the planned rates as shown in Fig. 1.

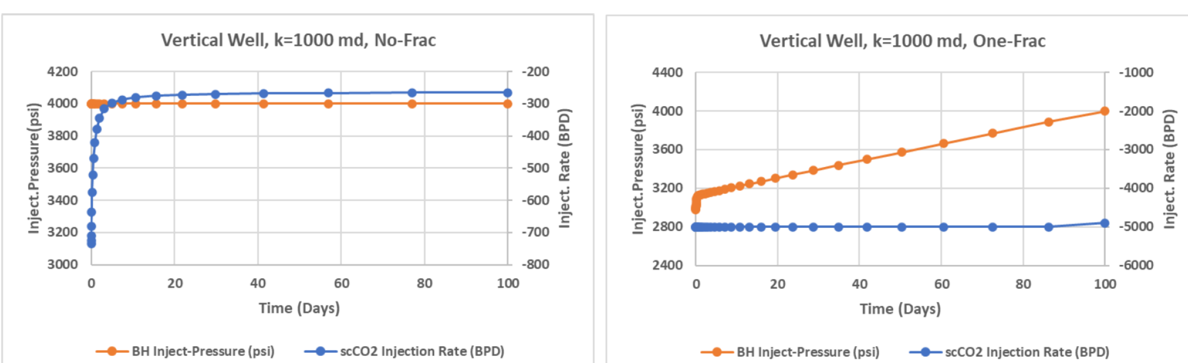


Figure 1—scCO2 Injection estimation for High Permeability (1000 md) Vertical Well, No Frac & Non-Damaged and Fractured

Completion considerations for fracturing in CCUS projects

To comply with the Class VI requirements regarding to the CO2 injectivity levels, assurance of the integrity of cap rock and the integrity of the completion during the life of the well; the completion strategy needs to consider the listed considerations, this is in addition to the requirement to implement a hydraulic fracture stimulation.

As mentioned before and shown in Table 1 the architecture of the wellbore for CCUS is going to be conditioned by the permeability level of the saline aquifer. For high permeability wells a vertical or deviated wellbore could assure the expected injection targets for this kind of projects; but in the case of low permeability reservoirs the drill and completion of horizontal wells will be required to place multiple fractures to assure the expected scCO2 injection levels

Table 1—Completion options for scCO2 injection

Reservoir Permability Level	Wellbore Architecture		
	Vertical Wellbore	Deviated (Slant) Wellbore	Horizontal Wellbore
Low Permeability Saline Aquifer (eg. 15 md)			√
Medium Permeability Saline Aquifer		√	√
High Permeability Saline Aquifer (eg. > 1000 md)	√	√	

To minimize the potential CO2 leakage risk at the level of the wellbore, as shown in Fig. 2, the entire wellbore needs to be cemented using an appropriate cement slurry and placing an acid resistive cement slurry in the lower section of the wellbore where the saline aquifer is located.

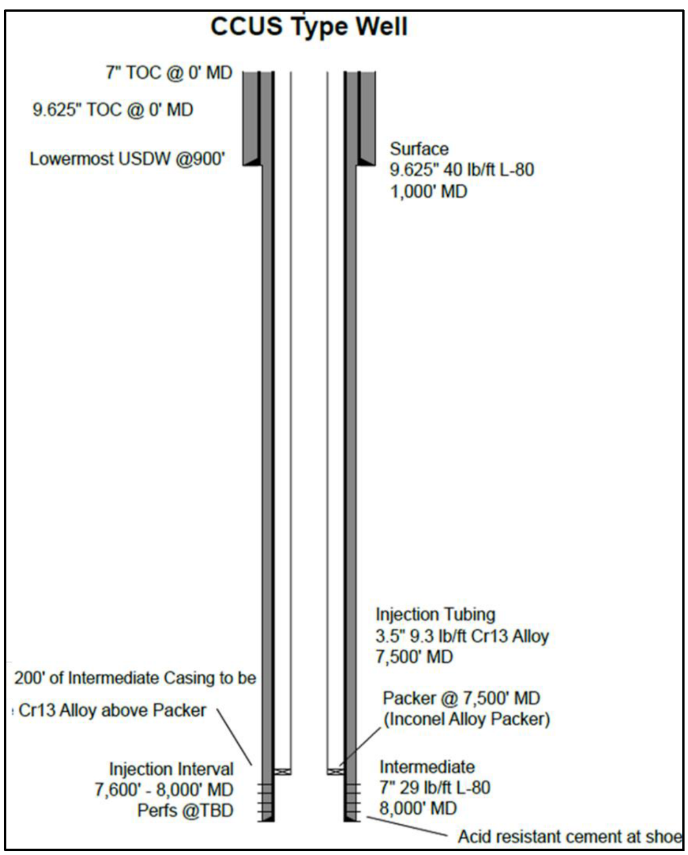


Figure 2—Example completion schematic for scCO2 injection

At the same time due to the corrosiveness of the scCO2, Cr-13 metallurgy should be considered primarily for the casing and tubing system. The size of the tubing considered for the final completion if required needs to be selected based in the expected scCO2 injectivity levels and taking in consideration the hydraulic fracture as potential option to stimulate the well.

Hydraulic fracturing design, fluids, and proppants selection

As documented by others (including Faroughi 2018, Elturki 2021, Fu 2017) for the case of conventional type reservoirs, or Reynolds 2017 for unconventional reservoirs, the implementation of hydraulic fracturing in CCUS projects will increase of the disposal volume of CO2. This paper reviews the different considerations to perform successful hydraulic fracturing treatments in a potential CO2 disposal in conventional saline aquifer reservoirs. Similar to low and high permeability hydrocarbon producer wells, the selection of the fracturing fluid and proppant is important to ensure the transport of the proppant from surface to downhole, to minimize the fracturing fluid leak-off and successfully place a high conductivity proppant pack into the fracture.

Considering the expected high fluid leak-off levels in most prospective saline aquifers and the proppant transport requirements, as well as the formation / fracture face damage reduction, a foam based fracturing fluid system may serve as the optimal fluid system for the stimulation purposes in CCUS projects. The foam generates a thinner filter cake along the fracture face, and this will be translated in a reduced damage of the fracture face by liquid phase system used in combination with N2 or CO2 [Harris 2005].

Considering the purposes of the stimulation and disposal requirements, CO2 in comparison to the N2 may be the best gas-phase to generate the foam system. For this case depending on the specific conditions of the disposal environments, the liquid phase might include a typical slick water, viscoelastic fluids, gelled fluid, or a crosslinked type of fluids as required. If water supply for fracturing purposes is limited or a concern, the saline water from the aquifer may also be used as a base liquid system for the foam generation. In this case the saline water may be viscosified with the proper gelling agents or with viscoelastic systems depending on required properties.

It is proposed that a foam quality between 60% and 80% will generate a more stable foam system, a more viscous fluid, and a system with a superior proppant transport due to the structure of the foam (Figure 3). The foam quality is the ratio of the gas phase volume to the liquid plus gas-phase volume. For example, in a 70% CO2 quality foam, the volume of the liquid phase will 30%.

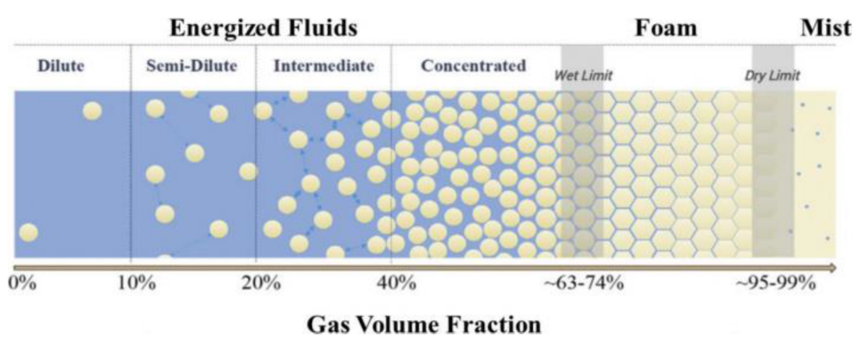


Figure 3—2D illustration of common classification of gas-liquid mixture according to gas volume fraction. Dispersed phase is assumed to be monomodal (Faroughi et al., 2018)

For practical field application purposes, to be able to pump adequate proppant concentrations on surface without affecting the capability of the blender or pumping equipment used for the fracturing operations, the CO2 foam quality needs to be limited to 80%. For example if the planned foam quality if 75%, the proppant concentration to be added in the liquid phase of the foam need to be 4 time higher; this means that to be able to place 4 PPG into the fracture, the proppant concentration in the liquid phase would need to be 16 PPA.

As shown before, the gas phase dispersed into the liquid phase forms a stable and viscous structure, making the foam an effective carrying fluid system for proppant and an excellent system to reduce the fluid loss along the fracture face particularly in high permeability environments such as proposed for CO2 disposal. At the same time, since overall liquid volume is reduced in the foam system, the fracture face damage will be reduced compared with the traditional high viscosity fracturing fluids.

To simulate the use of CO2 foam for stimulate a prospective CO2 disposal saline water aquifer, a base case where the mechanical and reservoir properties proposed by Fu et al, 2017 was used (Table 2). The first fracturing design as shown in Table 2 was performed for a reservoir having a permeability of 15 mD. Alternated designs were also evaluated for a higher permeability case(1000 md) as shown in Table 3. All other key parameters affecting the fracturing process are same for the three designs.

Table 2—Formation tops and rock properties, Low permeability Saline Aquifer

Formation Type	Sandstone	Formation tops (ft)	6400-6500
Thickness (ft)	100	Stress (psi)	4400
Permeability (md)	15	YM (psi)	1.5 e^{+6}
Porosity (%)	15	PR	0.25
Pressure (psi)	4900	Frac. Toughness (psi-in $^{1/2}$)	1000

Table 3—Formation tops and rock properties, High Permeability Saline Aquifer

Formation Type	Sandstone	Formation tops (ft)	6400-6500
Thickness (ft)	100	Stress (psi)	4400
Permeability (md)	1000	YM (psi)	1.5 e^{+6}
Porosity (%)	15	PR	0.25
Pressure (psi)	4900	Frac. Toughness (psi-in $^{1/2}$)	1000

For simplicity, a uniform permeability and mechanical properties have been considered for the entire saline formation.

For the first design where the reservoir permeability is 15 mD, the pumping schedule is shown in Table 4.

Table 4—Pumping Schedule, Low permeability Saline Aquifer (Design 1)

Fluid Type	Flow Rate (BPM)	CO2 Rate (BPM)	Btm Slurry Foam Rate (BPM)	Btm CO2 Quality (%)	Prop Conc (ppg)	Btm Prop Conc (ppg)	Clean Vol (gals)	Btm Clean (gals)	Tage Length (min)	Cumul. Time (min)	Fluid Type	Proppant Type
Main CO2 Foam pad	10	20	30.58	67.3	0	0	6,000	18,346	14.29	14:17	Gel	
Main CO2 Foam slurry	10	20	29.47	69.1	3.3	1.02	3,000	9,693	8.18	22:28	Gel	LD-SP 20/40
Main CO2 Foam slurry	10	19	28.47	70.7	6.9	2.02	3,000	10,230	9.32	31:47	Gel	LD-SP 20/40
Main CO2 Foam slurry	10	17	26.5	70.5	10.2	3.01	3,000	10,179	10.36	42:08	Gel	LD-SP 20/40
Main CO2 Foam slurry	10	15	24.54	69.8	13.3	4.02	3,000	9,922	11.34	53:28	Gel	LD-SP 20/40
Main CO2 Foam slurry	10	14	23.55	70.3	17	5.04	3,000	10,115	12.5	65:58	Gel	LD-SP 20/40
Main CO2 Foam slurry	10	13	22.56	70.5	20.5	6.04	3,000	10,176	13.61	79:35	Gel	LD-SP 20/40
Main CO2 Foam slurry	10	13	22.53	70.5	20.5	6.05	1,500	5,081	6.8	86:23	Gel	LD-SP 20/40
Main CO2 Foam Flush	10	13	22.51	55.6	0	0	2,600	5,854	6.19	92:34	Slickwater	
Shut-in									60	152:34	Shut-in	

For the second and third designs with the higher permeability of 1000 md was considered for the saline aquifer. As expected, for the higher permeability level, a lower volume of foam and proppant is proposed, as in these cases it was only necessary to generate a shorter fracture geometry. The pumping schedule for the two additional designs is shown in Table 5 and Table 6

Table 5—Pumping Schedule, High Permeability Saline Aquifer. Treatment Volume 60% of Design-1

Fluid Type	Flow Rate (BPM)	CO2 Rate (BPM)	Btm Slurry Foam Rate (BPM)	Btm CO2 Quality (%)	Prop Conc (ppg)	Btm Prop Conc (ppg)	Clean Vol (gals)	Btm Clean (gals)	Tage Length (min)	Cumul. Time (min)	Fluid Type	Proppant Type
Main frac pad	10	20	30.58	67.3	0	0	6,000	18,346	14.29	14:17	Gel	
Main frac slurry	10	20	29.49	69.1	3.3	1.02	1,800	5,819	4.91	19:11	Gel	LD-SP 20/40
Main frac slurry	10	19	28.49	70.7	6.9	2.02	1,800	6,142	5.59	24:47	Gel	LD-SP 20/40
Main frac slurry	10	17	26.55	70.6	10.2	3	1,800	6,120	6.21	31:00	Gel	LD-SP 20/40
Main frac slurry	10	15	24.6	69.8	13.3	4.01	1,800	5,969	6.8	37:48	Gel	LD-SP 20/40
Main frac slurry	10	14	23.61	70.4	17	5.03	1,800	6,087	7.5	45:18	Gel	LD-SP 20/40
Main frac slurry	10	13	22.62	70.6	20.5	6.02	1,800	6,128	8.16	53:28	Gel	LD-SP 20/40
Main frac slurry	10	13	22.61	70.6	20.5	6.03	900	3,062	4.08	57:32	Gel	LD-SP 20/40
Main frac flush	10	13	22.6	55.7	0	0	2,600	5,875	6.19	63:44	Slickwater	
Shut-in	0	0	0	0	0	0	0	0	60	123:44	Shut-in	

Table 6—Pumping Schedule, High Permeability Saline Aquifer. Treatment Volume 40% of Design-1

Fluid Type	Flow Rate (BPM)	CO2 Rate (BPM)	Btm Slurry Foam Rate (BPM)	Btm CO2 Quality (%)	Prop Conc (ppg)	Btm Prop Conc (ppg)	Clean Vol (gals)	Btm Clean (gals)	Tage Length (min)	Cumul. Time (min)	Fluid Type	Proppant Type
Main frac pad	10	20	34.44	71	0	0	6,000	20,664	14.29	14:17	Gel	
Main frac slurry	10	20	34.44	73.7	3.3	0.87	1,200	4,560	3.27	17:33	Gel	LD-SP 20/40
Main frac slurry	10	19	33.22	75.2	6.9	1.71	1,200	4,835	3.73	21:17	Gel	LD-SP 20/40
Main frac slurry	10	17	30.77	75.1	10.2	2.54	1,200	4,815	4.14	25:25	Gel	LD-SP 20/40
Main frac slurry	10	15	28.33	74.4	13.3	3.4	1,200	4,691	4.53	29:57	Gel	LD-SP 20/40
Main frac slurry	10	14	27.11	75	17	4.26	1,200	4,793	5	34:57	Gel	LD-SP 20/40
Main frac slurry	10	13	25.89	75.2	20.5	5.09	1,200	4,831	5.44	40:24	Gel	LD-SP 20/40
Main frac slurry	10	13	25.89	75.2	20.5	5.09	600	2,415	2.72	43:07	Gel	LD-SP 20/40
Main frac flush	10	13	25.89	61.4	0	0	2,600	6,730	6.19	49:19	Slickwater	
Shut-in	0	0	0	0	0	0	0	0	60	109:19	Shut-in	

For information purposes, the rate & pressure history, proppant concentration and fracture conductivity are shown in Figs. 4, 5 and 6 only for the first design (Table 4). The simulations indicated that the CO2 foam could be used to generate a fracture and place conductive fracture in a low or high permeability prospective CO2 disposal horizon. For the considered reservoir and stress conditions in the design, the vertical growth of the fracture doesn't appear to compromise the integrity of the cap rock.

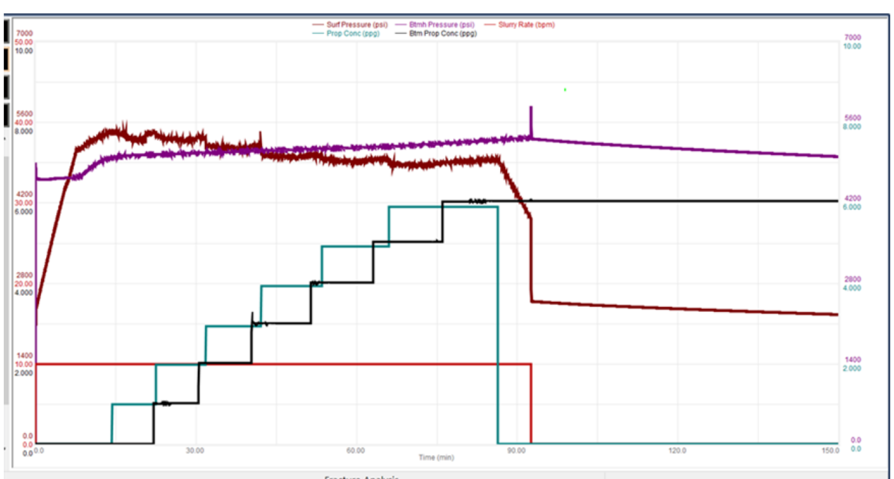


Figure 4—Design-1, Rate and Treatment Pressure History

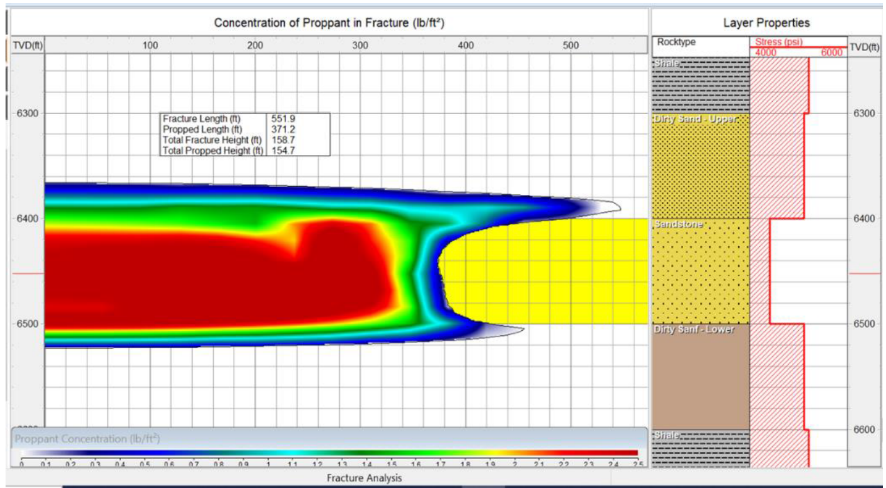


Figure 5—Design-1, Fracture Geometry and Proppant Concentration Distribution

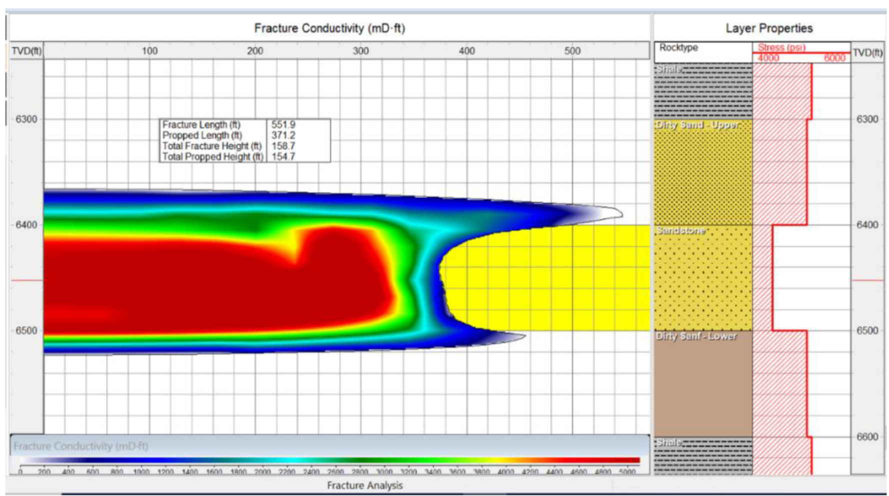


Figure 6—Design-1, Fracture Geometry and Fracture Conductivity Distribution

The fracture geometry for the 3 fracturing designs considered in the paper is showed in Table 7 below.

Table 7—Calculated Fracture Geometry for Design-1, Design-2 & Design-3

	Permeability 15 mD	Permeability 1000 mD	
	a) Design-1	b) Design-2	c) Design-3
Created Length (ft)	552	572	517
Propped Length (ft)	371	314	252
Created Fracture Height (ft)	159	149	142
Propped Fracture Height (ft)	155	140	127

The fluid temperature variation inside the generated fracture at the end of the design-1 is shown in Fig. 7. The Design-1 was selected here because a higher volume of fluid was used in the stimulation and is expected to have a higher temperature drop or thermal effect compared with the two additional designs where the stimulation fluid volume is smaller. As for the case of conventional treatments where a cooler fluid is also used for the stimulations, at the end of the Design-1 pumping process a lower than 78 °F of temperature is observed around the wellbore and this increases gradually along the generated fracture. Considering the initial reservoir temperature of 145 °F, the temperature drop of 67 °F observed here, thermally doesn't induce additional stresses to greatly affect hydraulic fracture growth like in the case steam and water flooding, because the time scale of the thermal convective-diffusion in reservoir rock is much larger than the fracture growth time [Crockett 1986].

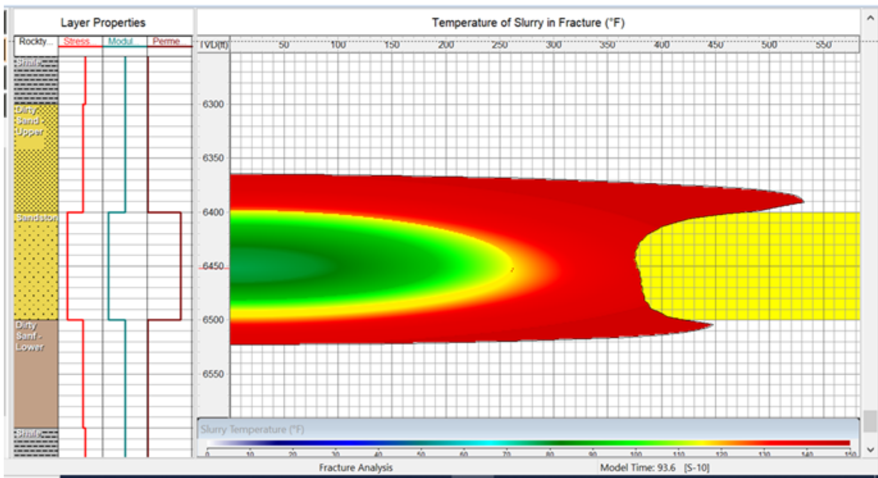


Figure 7—Desing-1, Fracture Geometry and Fluid Temperature Inside Fracture

Although this paper doesn't address the long-term thermal effect of the scCO2 injection over the cap rock stress, depending on the projects as documented by Fu et al. 2017 for the case of CO2 disposal low permeability saline aquifers or Park et al. 2023 for the case of CO2 disposal in depleted reservoirs, the cooldown effect of the long term CO2 injection should be evaluated to predict the generation of thermal fracturing and its impact on the mechanical integrity of the cap rock in the projects. For the case of scCO2 injection in a low permeability aquifer having 7 fractures presented in the paper, the temperature variation around the fractures due to the injection of scCO2 is presented in Fig. 8. The temperature drop in cap rock is not significative after 100 days of injection. Additionally the main temperature drop is constrained to the fractured area

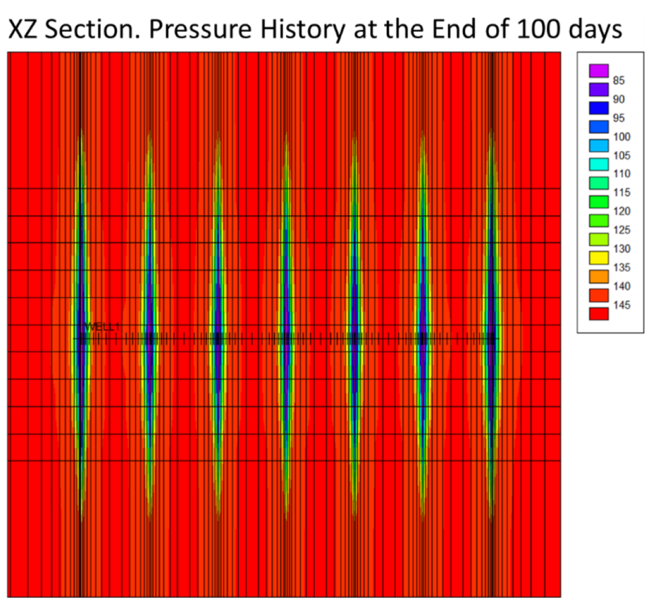


Figure 8—Design-1, Fracture Geometry and Fluid Temperature Inside Fracture

Another visualization of the temperature drops around the fracture in the Y-Z plane is showed in Fig. 9 where the temperature drops around the cap rock area connected by the hydraulic fracture is almost 20 °F after 100 days of scCO2 injection. This temperature drop considering the 1-D strain analytical thermo-elastic solution, the typical thermal dilation coefficient, the YM's and PR of the cap rock considered for the Design-1, will reduce the cap rock stress only in 114 psi. This stress reduction associated thermal effect is still low to be able to affect the integrity of the cap rock

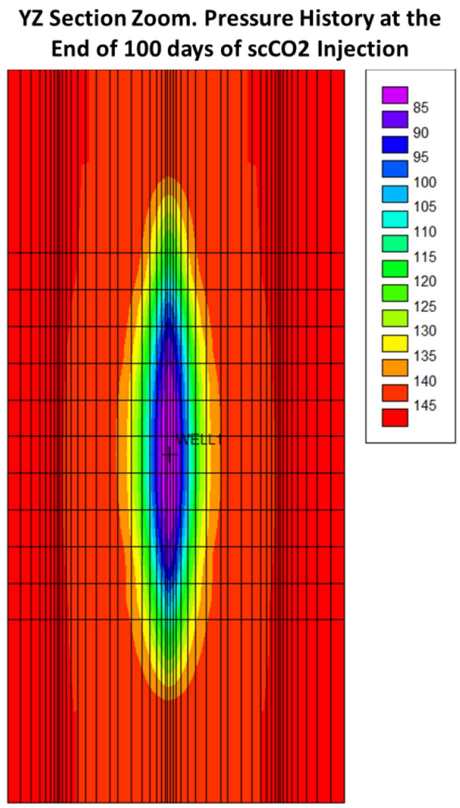


Figure 9—Design-1, Fracture Geometry and Fluid Temperature Inside Fracture

The other main component of the hydraulic fracturing process proper application and particularly to assure the success of a stimulation treatment is the selection of a proppant agent for the specific reservoir conditions and stimulation objectives. The proppant selection is important for conventional hydraulic fracturing of hydrocarbon producers where the variation of the effective stress effect (closure pressure minus reservoir pressure) over time due to the depletion will affect the conductivity of the proppant bed placed inside the fracture. In the case of CO2 disposal projects, the effective stress is not as important because the scCO2 injection is performed at a pressure higher than the reservoir pressure. However, similar to producing wells, fracture/proppant conductivity is still important, in order to create and maintain the required conductivity contrast between reservoir flow capacity and fracture conductivity in the typical high permeability environment selected for scCO2 disposed

Considering the importance of the fracture conductivity in CO2 disposal projects, the selection of the proppant needs to consider the below listed selection criteria:

1. **Particle Size and Shape:** Proppant size and uniform shape or roundness will assure a higher conductivity required for CO2 disposal projects. During scCO2 injection the fluid velocity will be elevated causing non-Darcy pressure drop in the fracture. Larger proppant with uniform shape and size will reduce the impacts of non-Darcy flow (Palisch 2007). A tightly sieved ceramic proppant would be superior to natural frac sand (Fig 10).

2. **Density and Specific Gravity:** The density of the proppant can affect its settling rate in the fracturing fluid and its transport within the fracture. For the case of SC CO@ disposal projects where a foam type fluid is used as carrying fluid, a lower density proppant would be preferred.
3. **Chemical Compatibility:** The proppant selection needs to consider the chemical reaction or compatibility associated to the short- or long-term interaction with scCO2. A high-quality proppant with smooth surface will reduce the impact of chemical reactions.
4. **Higher Conductivity:** Given the need to provide high CO2 injectivity into high flow capacity saline aquifers, the fracture conductivity will need to be as high as practical to create and maintain good conductivity-flow capacity.

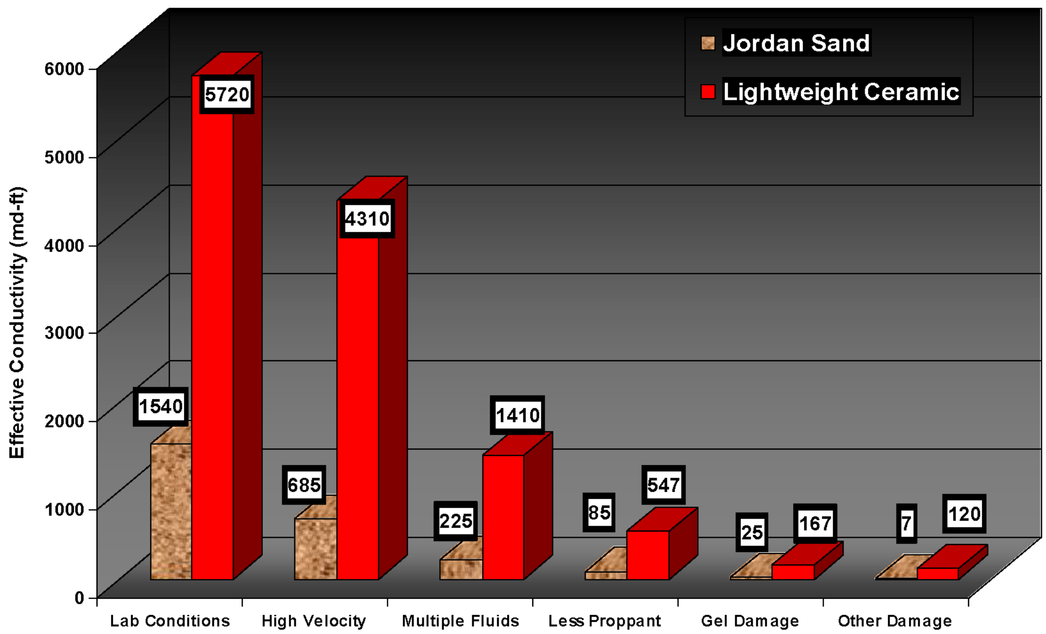


Figure 10—Comparative Conductivity data for sand and premium low density ceramic proppants used in hydrocarbon producer wells after correcting for downhole conditions. The premium ceramic exhibits over 15x the conductivity as a northern white sand.

For the purpose of this work, a premium Low Density Synthetic 20/40 mesh proppant was selected for the treatment and the injectivity estimations done with a reservoir simulator and reported earlier in this paper. However, based in the comparative conductivity data showed in Fig. 11, the use of a single 25 mesh low density advances synthetic proppant could the best sustaining agent to assure a high fracture conductivity at the lower closure pressures typically observed in CO2 disposal project where the hydraulic fracture is required to assure the CO2 injection.

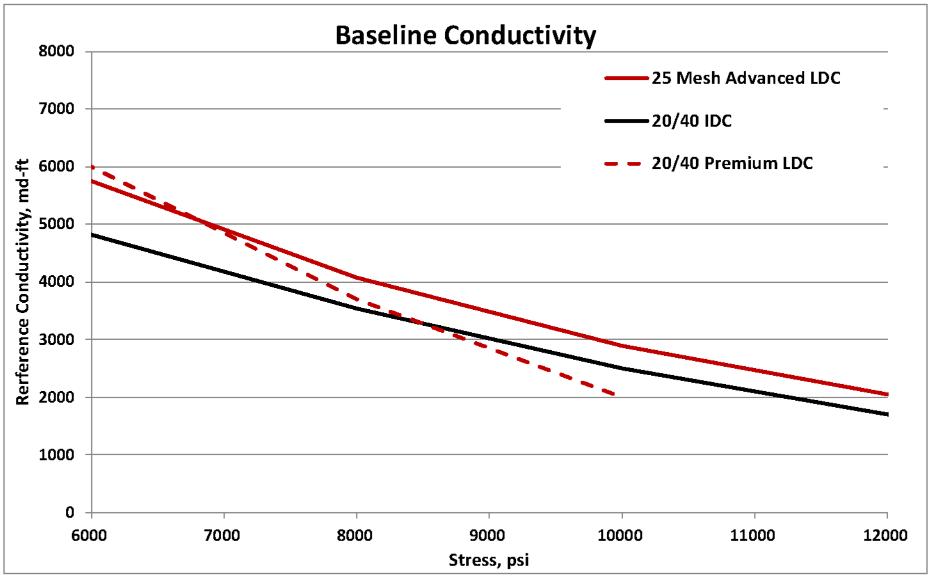


Figure 11—Comparative Conductivity of Low Density 25 Mesh Single Mesh Synthetic Proppant

Evaluation of the hydraulic fracturing for CCUS

The hydraulic fracturing benefits in the injectivity and storage capability of low and high permeability saline aquifers considered in the papers has been done considering the generated fracture geometry and conductivities in each design. For this purpose, the fracture geometry and properties obtained with the fracture simulator has been exported to a reservoir model where the intrinsic fracture properties are considered. The maximum injection pressure for the simualtion purposes was fixed as 4000 psi or 80% of the minimum stress of the upper and lower caps rocks, to avoid the scCO2 migration to upper horizons such as freshwater layer(s) or to surface.

The scCO2 injection rate and Injectivity Index (I-Ix) for the case of an unfractured well having a permeability of 15 md reservoir and skin value of 10 is shown in Fig. 12. As expected, the injection rate and I-Ix for a vertical well completed in this reservoir will be low (0.55 BPD/psi). As shown below to be able to maintain the maximum injection pressure at 4000 psi required to avoid the cap rock breaking, the injection rate needs to be reduced and this will be translated in a poor scCO2 storage capability.

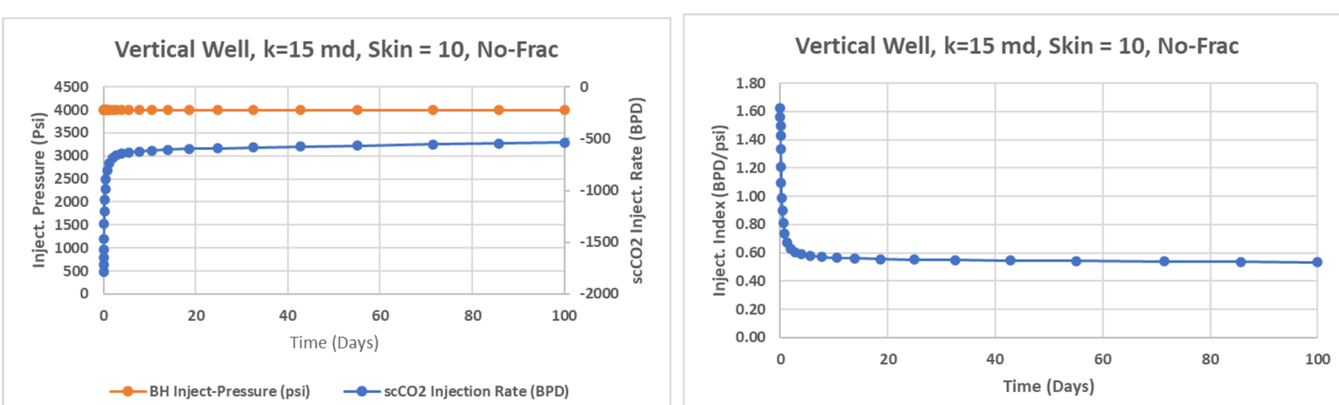


Figure 12—Simulated Injection Rate, Injection Pressure, and Injectivity Index. K = 15 md, Skin = 10, Not fractured

The same simulation has been done for the case of vertical well completed in an undamaged 1000 md reservoir. For the higher permeability level as shown in the Fig. 13 the injection rate also must be reduced to due to the previously fixed injection pressure limitations. Compared with the low permeability case presented before the I-Ix for this case increases to 1.4 BPD/psi or 2.5 times higher than the corresponding 15 md case.

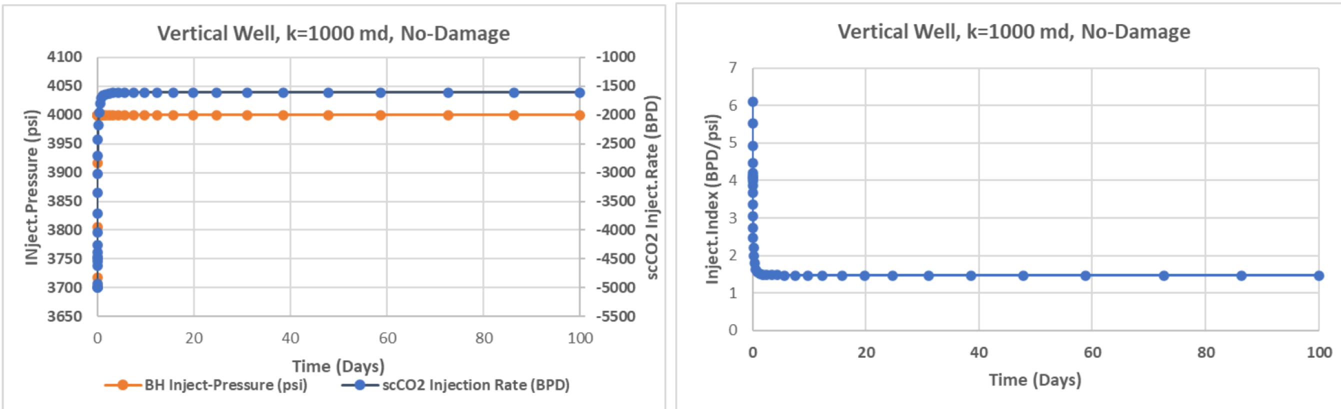


Figure 13—Simulated Injection Rate, Injection Pressure, and Injectivity Index. K = 1000 md, Skin = 0, Not fractured

The simulated previous cases shows that the reservoir permeability and the type of completion limits the long-term injection of the scCO2 or storability and to improve it will require hydraulic fracturing stimulation. Fig. 14 shows the comparative injectivity benefit of a hydraulically fractures vertical well having a permeability of 1000 md.

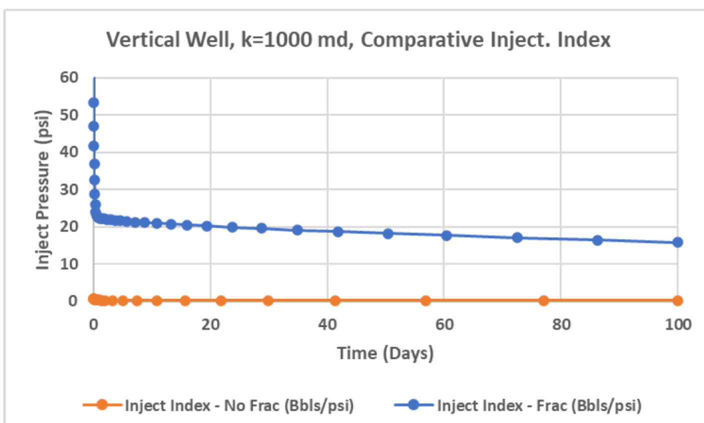


Figure 14—Simulated Injection Rate, Injection Pressure, and Injectivity Index. K = 1000 md, Vertical Well

The fracture geometry loaded to the reservoir simulator to be able to predict the injection rate and I-Ix for the high permeability well is showed in Table 7c. Although the I-Ix increased significatively when the high permeability vertical well is fractured; for a longer and sustained injectivity will be required a change of the completion architecture and the placement of more fractures to improve the scCO2 storage capacity.

For the case of lower permeability reservoir (15 md), it was considered a horizontal completion architecture where the scCO2 injectivity was evaluated placing 1, 4 and 7 transverse fractures. As shown in Figs. 15 and 16, the injection rate, and I-Ix increase substantially due to the hydraulic fracture stimulation. For the case of a reservoir of 15 md, the placement of more than 7 transverse fractures having a geometry and proppant distribution showed in Table 7A and Fig. 6 will improve the injection rate or I-Ix in short or long term.

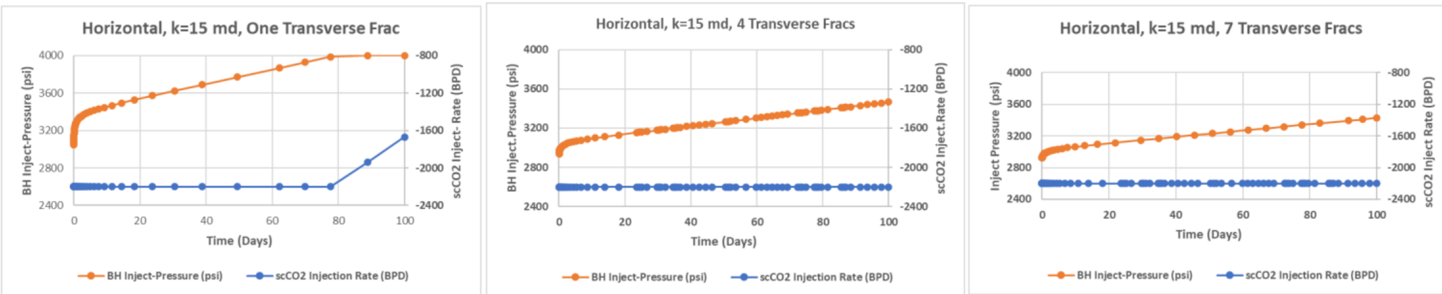


Figure 15—Simulated Injection Rate, Injection Pressure. K = 15 md, with one, 4 and 7 fractures

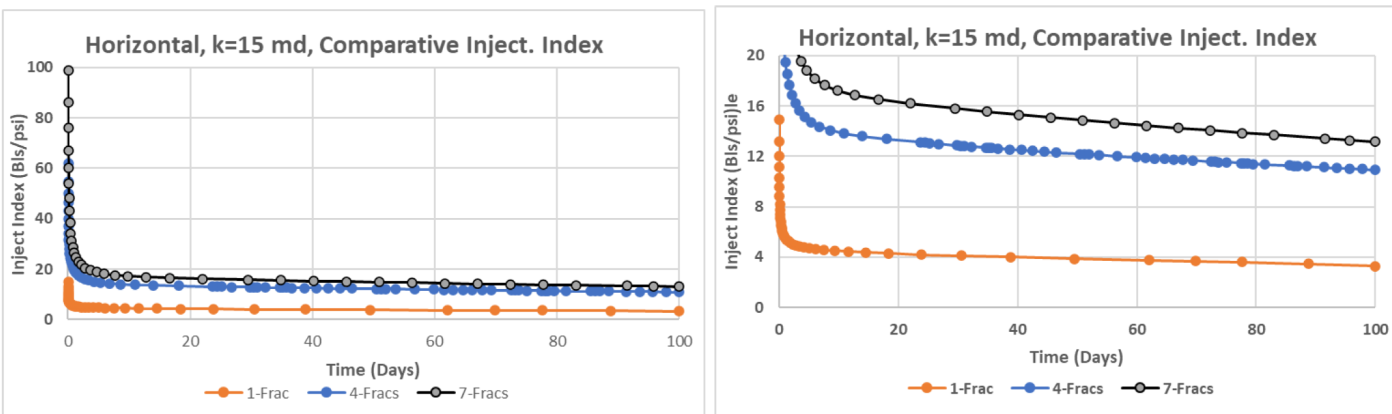


Figure 16—Complete and Expanded Comparative Injectivity for a K = 15 md reservoir and one, 4 and 7 Fractures

An alternative option to improve the injectivity of scCO2 in these low and high perm cases could be to drill and complete the horizontal wellbore aligned with the maximum stress, thereby generating longitudinal fractures. The benefit of this completion option for the case of a 15 md permeability reservoir is showed in Fig. 17 where the placement of 3 longitudinal fractures improves the injection rate of scCO2 and improves the I-Ix as shown in Fig. 18. Although the placement of a smaller number of longitudinal fractures could be economically attractive, when compared to the base cases for this permeability level, the injection rate and I-Ix associated to the placement of transverse fractures are higher.

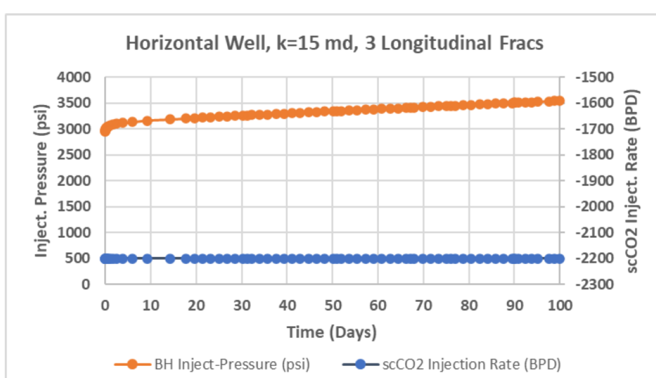
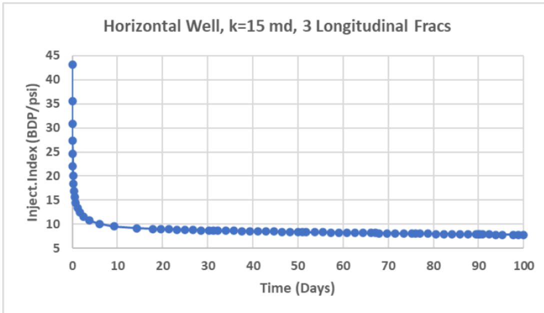


Figure 17—Complete and Expanded Comparative Injectivity for a K = 15 md reservoir and one, 4 and 7 Fractures



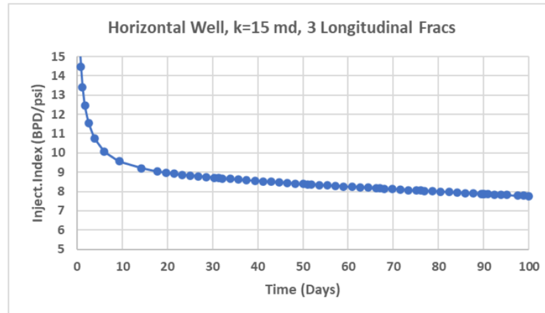


Figure 18—Complete and Expanded Comparative Injectivity for a K = 15 md reservoir and one, 4 and 7 Fractures

For additional reference, the reservoir pressure distribution at the end of 100 days of scCO2 injection for the low permeability formation where 7 transverse fractures have been placed is shown in Fig. 19. As discussed before, the reservoir pressure (2900 psi initially) will increase in time. The required time to reach the maximum injection pressure to reach 4000 psi fixed as maximum injection pressure to avoid the cap rock breaking will depend on the size of the saline aquifer selected for the CO2 disposal purposes

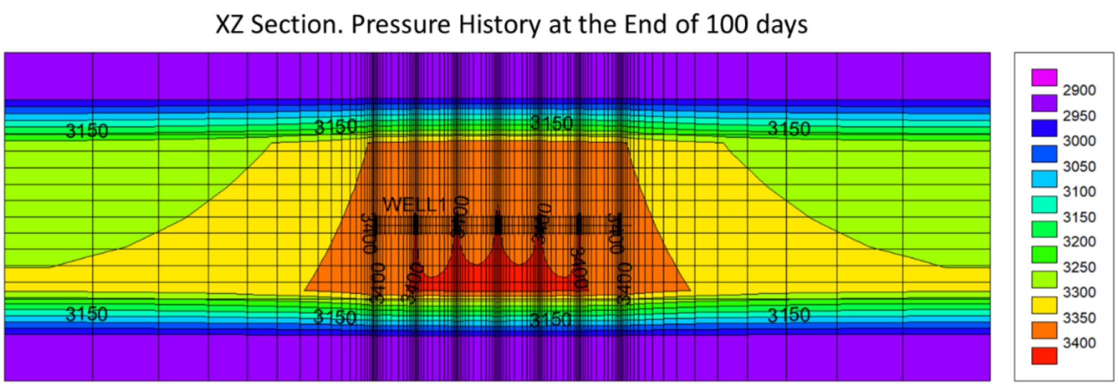


Figure 19—Complete and Expanded Comparative Injectivity for a K = 15 md Fractured Formation

Conclusions

1. scCO2 injection in both low and high permeability saline water aquifers is analyzed in this paper to consider techniques to improve the injectivity and storability of CO2.
2. For high permeability saline aquifer where the preferred option could be to drill and complete a vertical or deviated wellbore, the results show hydraulic fracturing could be required to increase the effective injection area around the wellbore and to bypass any deeper damage induced during the drilling or completion of the wellbore.
3. The wellbore architecture, wellbore orientation aligned with the maximum stress and the generation of longitudinal fractures will not assure higher injectivity level for saline aquifers having 15 md permeability, but this option could be also good for higher permeability levels if their completion architecture permits this type of stimulation
4. Due to the metallurgy of the completion used in CO2 disposal wells, the use of acid stimulation in high permeability saline aquifers could be an option, but the corrosiveness of the acid system may compromise the integrity of the completion.
5. Due to its structure, minimum damage and proppant carrying capability, CO2 foam may be the preferred fluid system to be used to fracture scCO2 injector wells.
6. Although the effective stresses acting over the proppant bank during the life of the scCO2 disposal project will be low compared to the standard production wells, to create an adequate conductivity

contrast in high permeability saline aquifers and accommodate the high injection rates required, a high-quality low density ceramic proppant will be required. An advanced Low-Density Single Mesh Proppant may also be beneficial to reduce non-Darcy effects and maintain long term injectivity. Natural sand may not assure an adequate conductivity contrast and its quality could be affected in time by CO2 injection.

7. The cap rock integrity was superficially discussed in the paper but as shown in the paper the cooldown effect must be a part of the evaluation process to check the stress sensitivity with the typical temperature drops observed in typical field applications.

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Nomenclature

scCO2,	Super critical CO2
Cr-13,	Chrome 13
K,	Permeability in millidarcies
ppg,	Pounds per gallon
YM,	Youngs Modulus, psi
PR,	Poisson Ratio
I-Ix,	Injectivity Index
Inject.,	Injectivity
SRV,	Stimulated Reservoir Volume

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