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ON THE FATE OF THE FRACTURING FLUID AND ITS IMPACT ON LOAD RECOVERY AND WELL PERFORMANCE

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ON THE FATE OF THE FRACTURING FLUID AND ITS IMPACT ON LOAD

RECOVERY AND WELL PERFORMANCE

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MEWBOURNE SCHOOL OF PETROLEUM AND GEOLOGICAL ENGINEERING

BY

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DEDICATION

To my family, friends and teachers

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First and above all, I praise God, Almighty for providing me this opportunity and granting me the capability to proceed successfully. This thesis appears in its current form due to the assistance and guidance of several people. I would therefore like to offer my sincere thanks to all of them

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Abstract

The complexity of the shale system coupled with the mystery of low fracturing fluid recovery has puzzled many researchers. Field reports from hydraulic fracturing operations performed on shale formations have highlighted the low recovery of the fracturing fluid. Despite the low recovery observed in field reports, neither the fate nor the impact of these trapped fluids is well-understood. The shale membrane behavior was observed in the drilling operations and the application of low salinity water flooding. Therefore, first objective was to incorporate chemical osmosis in the modeling of hydraulic fracture cleanup which could better simulate the physical phenomena and might resolve the enigma of the impact of the elongated shut-in time on the well performance. The combination of the large surface area, the mild reactive nature of shale and the massive trapped volume of fracturing fluids raises a question on the impact that geochemical interactions have on load recovery, well performance and reservoir characteristics, which was the second objective of this study. The third objective was the development and implementation of an experimental workflow to investigate the impact of fluid salinity and rock mineralogy on the spontaneous imbibition of slick water. Quantifying the formation strength loss due to water soaking was also investigated.

In this study, a reservoir simulator capable of simulating the chemical osmosis and the concentration gradient driven flow is used to mimic the hydraulic fracture cleanup stage along with well performance. The significance of the chemical osmosis on load recovery and the salinity of the produced water is pointed out by simulating the same model with and without the osmotic flow. Sensitivity analysis for the effect of membrane efficiency, salinity contrast between the fracturing fluid and the formation brine, the

reservoir temperature, natural fracture spacing, organic volume and shut-in time on load and gas recovery is reported along with the relevancy factor of every parameter.

For the Geochemical Coupling, a fit-for-purpose model is built where a hydraulic fracture stage is modelled using LG-LR-DK model. The initial conditions are simulated by injecting the fracturing fluid, then shutting-in the well to allow the fluids to be soaked into the formation. Different relative permeability sets are used for high and low salinity water since the fluid's mobility is affected by its salinity. Actual connate water composition from Haynesville shale is used to study the impact of connate composition on geochemical coupling. The formation mineralogy and fracturing fluid composition impact on gas and load recovery is investigated.

The introduction of the oxygenated, low salinity, fracturing fluid to a reducing environment would definitely catalyze both precipitation and dissolution reactions depending on the formation mineralogy. The dissolution and precipitation rates show a positive correlation with the carbonate content of the rock. Interestingly, the incorporation of the dependence of relative permeability on ion exchange and fluid salinity might reveal the fate of the fracturing fluid. Overestimation of both gas and load recovery is observed when geochemical coupling is neglected. In addition, sea water shows an enhanced performance suggesting a good alternative fracturing fluid. In addition, better performance is observed for less saline connate water cases. The carbonates reactions outweigh the clays reactions in most cases. Also, treating carbonates as only calcite results in more reactions compared to the dolomite case. Sensitivity analysis suggests that the concentration of SO_4, K and Na ions in the fracturing fluid, and illite and calcite mineral content of the rock, along with the reservoir temperature are the main key factors affecting well performance. It is worth noting that the salinity contrast between the injected fluid and the formation brine shows a negative correlation with well performance.

Regarding the Experimental Investigation, Samples from Woodford and Caney outcrops in the Unites States of America were obtained. Spontaneous imbibition, contact angle and interfacial tension measurements were conducted for these samples using slickwater with an added KCl weight percentage of 0, 5, and 10. Both the rock-water-gas and the rock-water-oil systems were examined. The formation softening was quantified by recording the rock mechanical parameters before and after the imbibition and soaking tests. The results were analyzed in terms of the capillary suction characteristics for each formation.

According to the experimental results, a positive relationship was observed between water salinity and imbibition in Caney formation. However, the opposite was observed for Woodford samples. The formation mineralogy was identified to be the major factor in this surprising reversal of wettability. Similar trends were observed for the recovery of both oil and gas where the low salinity imbibition yielded a higher recovery factor for the Caney formation samples and a lower recovery factor for Woodford. In addition, the formation softening results suggest that water salinity and formation mineralogy should both be considered in the selection of the proper fracturing fluid. Interestingly, the high the salt content the water had, the more softening was observed in Woodford samples and the less softening in Caney formation. This study provides insights into the water dynamics in ultra-low permeability reservoirs. The formation mineralogy is a key factor for properly describing the water dynamics whether in fracturing treatments or in low salinity flooding projects. The low salinity flooding does not always imply better hydrocarbon recovery, as we observed in carbonates-rich samples. The wetting characteristics are directly related to the capillary suction and clay content.

In conclusion, the incorporation of the geochemical coupling and Chemical Osmosis in simulating fracturing fluid dynamics, and their impact on load recovery and well performance, is essential. Careful selection of a fracturing fluid optimized for specific formation mineralogy will enhance well performance

Chapter 1: Introduction

1.1 Shale Reservoirs

Shale reservoirs are considered as unconventional resources due to both their ultra-low permeability and production performance characteristics. The development of theses reservoirs caused a Paradigm shift on the Petroleum Industry as shown in **Figure** 1.1 and 1.2. However, only four countries are producing commercially from these reservoirs. In the case of shale gas activity, it can clearly be seen that the United States tops the world production with more than 35 Bcf/d, then Canada and China with minimal production compared to the US. This is attributed to the advances in fracturing and completion schemes that enabled economic development of these kinds of reservoirs.

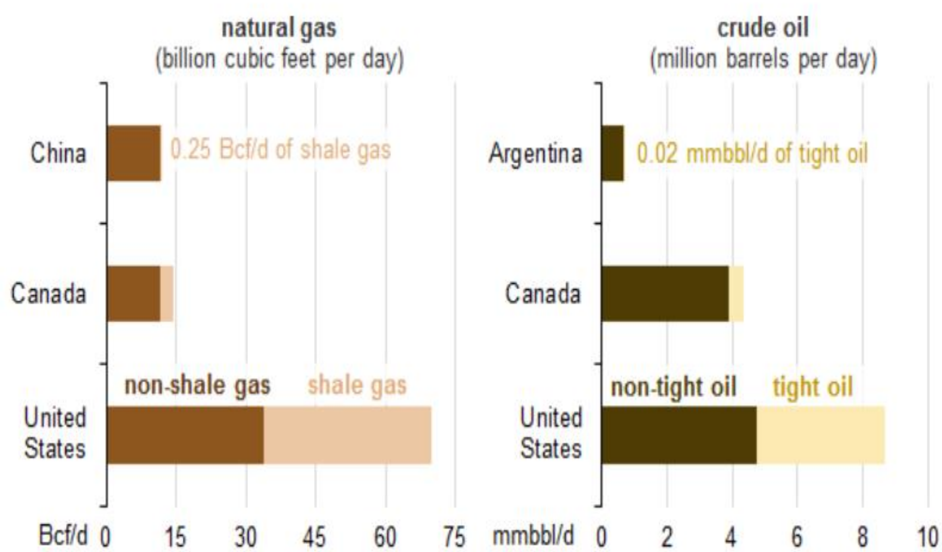


Figure 1.1 the production of the only four Countries producing commercially from shale (Aloulou, 2015)

A glance at the different contributors to gas production on the US reveals interesting trends on both the current and the projected portions. While, a steady production is projected for most of the contributors, namely tight gas, lower 48 onshore conventional, lower 48 offshore, coalbed methane and Alaska, a prompt increase in the shale gas portion is expected. This projection is also evident from the constant decrease in gas imports and constant increase in gas exports as shown in **Figure** 1.3.

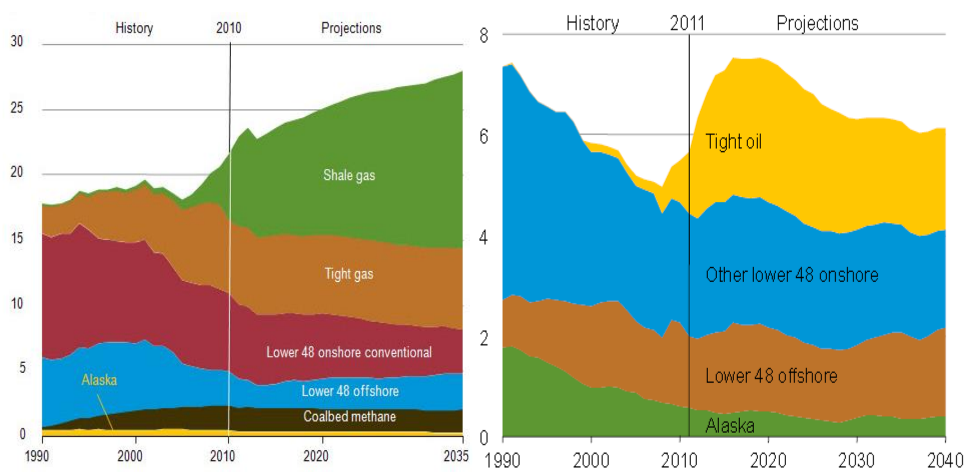


Figure 1. 2 Oil (MMBPD) and Gas Production (TCF) from shale reservoirs in USA (EIA, 2014)

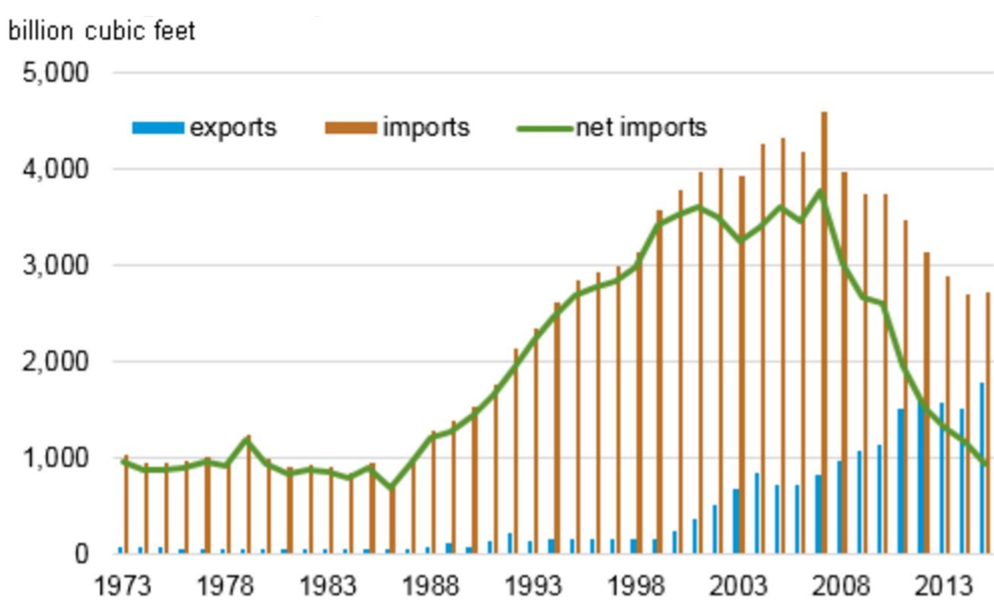


Figure 1. 3 the US Natural gas imports and exports

1.2 Shale Characteristics

Shale is a clay-rich rock which contains variable content of clay minerals and organic matter. This rock contains different pore sizes which have fractional wettability and host different kinds of fluids. In addition, the Nano-scale pores and adsorption add more ambiguity to the nature of these rocks.

1.2.1 Pore size

Nelson, (2009) reported an interesting diagram representing the length scale of sandstones, tight sandstones and shales along with some molecule diameters as shown in **Figure** 1.4. Knowing that the length scale of shale pores is comparable to the diameter of molecules raises a lot of questions regarding the applicability of the current thermodynamic models in predicting the phase behavior of the resident fluids.

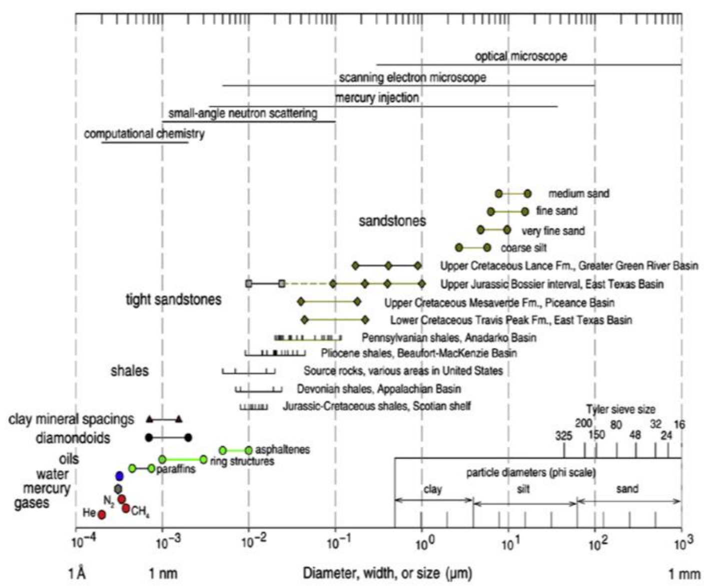


Figure 1. 4 comparison for the length scale of different formations pore size and molecules along with the optimum measuring method on the top (Nelson, 2009)

One approach was to modify the critical properties of fluids to account for the pore proximity effect (Alharthy et al. 2013), however, to the best of the author knowledge, this contradicts with the definition of the phase as a “homogeneous system” considering that the length scale of the shale pores is comparable to the diameter of the fluid molecules (Jin and Firooabadi et al. 2015).

Another feature is the heterogeneity of the pore size down to the nano-scale in the clays interlayers and natural fractures in shale fissures. This spectrum of pore sizes makes the proper modelling of the shale medium more challenging. Triple and quadruple porosity models were developed to account of this heterogeneity. Fakcharoenphol et al. (2013) used triple porosity model with organic and inorganic matrix along with natural fractures to study the impact of shut-in time on early well performance. Considering two types of matrix enabled defining different wettability and adsorption properties for the organic and the inorganic pores. **Figure** 1.5 presents the improvements introduced by implementing the triple porosity model over the dual one.

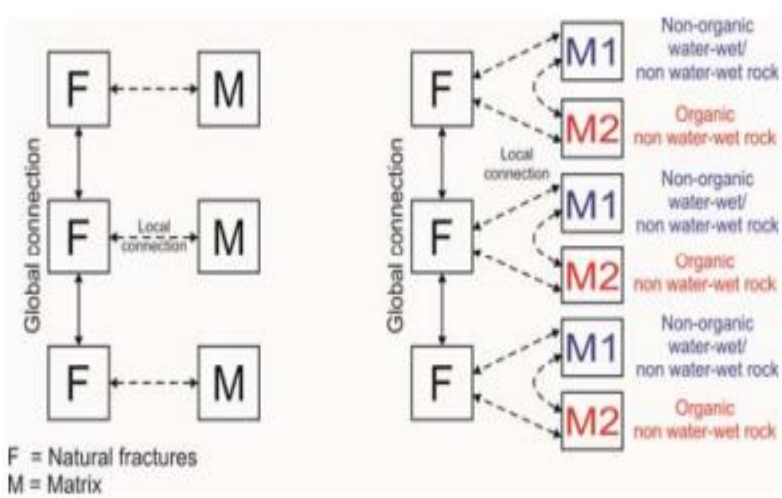


Figure 1. 5 Comparison between Dual (left) and triple (right) porosity models (Fakcharoenphol et al., 2013)

Towards better modelling of the shale medium, He et al. (2016) represented a quadruple model where the matrix is divided to non-organic matter, porous kerogen and clay minerals. This division entails further understanding of gas transport and storage in shale pores with free, desorbed, adsorbed and dissolved gas introduced.

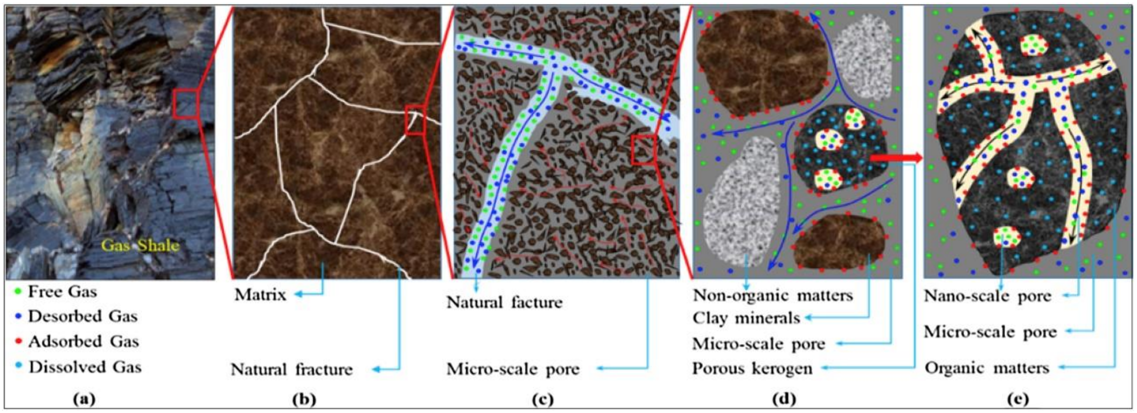


Figure 1. 6 Quadruple Porosity model (He et al. 2016)

1.2.2 Organic matter and clay content

Shale reservoirs are self-sourced reservoirs. The organic content of shale rock can be characterized by the total organic content (TOC). The well-known Van Krevelen type curve classifies the organic matter based on H/C and O/C atomic ratios. Vitrine reflectance (R0%) is used as a quantitative measure of the thermal maturity which directly impacts and correlats with hydrocarbon generation as shown in the **Figure** 1.7. Several studies and models have been proposed to account for the complexity of the organic matter and its impact on initial calculations and production performance.

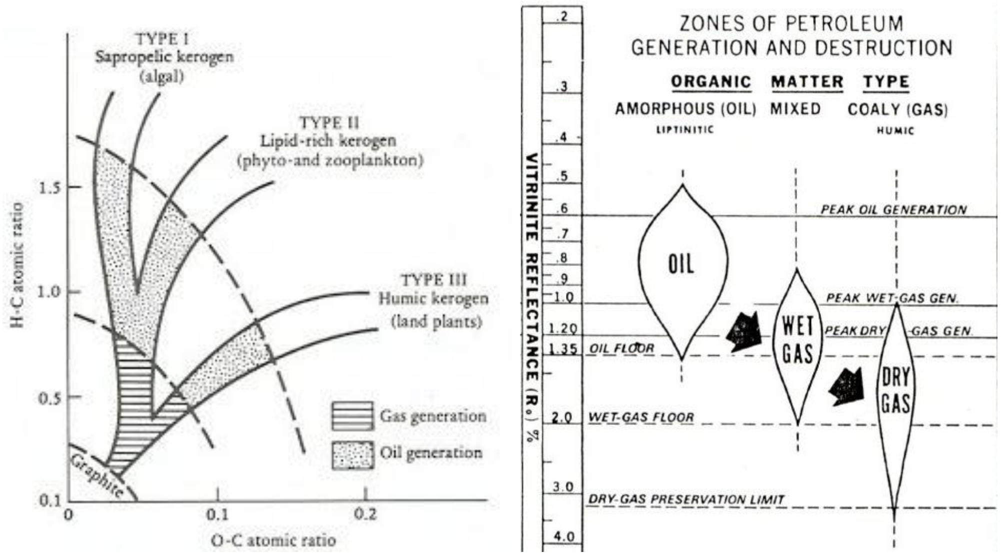


Figure 1. 7 Van Krevelen diagram(left) and Vitrinite Reflectance (R_0%) and hydrocarbon generation (right) (Dembicki, 2009)

Clay minerals and structure affect both the shale petrophysical and development plan. While clay swelling is one of the challenges faced during well completion, gas adsorption in the clay interlayers is one of uncertainties reported during initial gas in place calculation. The common structure of a clay is constructed from SiO_4^- tetrahedrons and $Al(OH)_3^-$ octahedrons. These sheets are interbedded by interlayers capable of storing water molecules, oxygen molecules and exchangeable cations. In addition, the recrystallization of the montmorillonite to illite is usually accompanied by micro cracks which highly impact shale conductivity.

1.2.3 Wettability and adsorption

Wettability determines which fluid will adhere to the surface achieving a balance between the interactions forces between the crude oil and minerals. Describing shale reservoirs as water or oil-wet reservoirs is inacceptable oversimplification of the system. However, Shale pores have different wettabilities and most of them are mixed. Rylander et al.

(2013) reported mixed wettability in Eagle ford pores where the organic pores are considered oil-wet and the mineral pores are water-wet. However, there is still active debate conceptually if the polar hydrocarbons molecules displace the water film around the mineral pores or adheres to the mineral surface through water film.

The electrical charge imbalance on the surfaces of both organic matter and clay particles leads to fluid adsorption onto these surfaces. There are two kinds of adsorption experienced in Shale: gas adsorption in organic pores and water adsorption on clay particles. Gas adsorption is more tangible at high pressures as indicated from Langmuir isotherm.

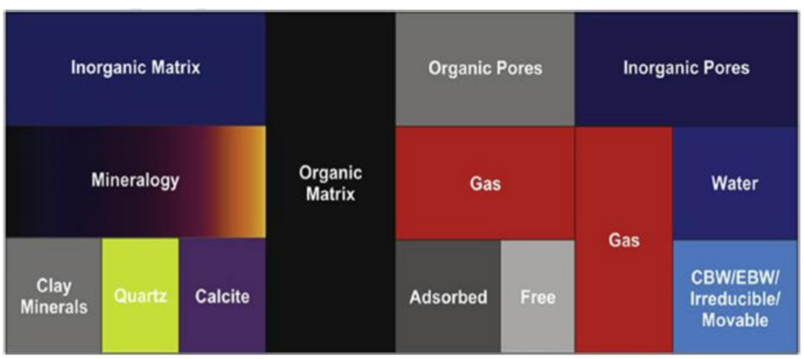


Figure 1. 8 Schematic representations of different shale constitutions (Dyrka, 2015)

1.2.4 Mineralogy

Clays, carbonates, quarts and feldspars are the main constituents of the shale matrix. While Eagle ford is considered a carbonates-rich shale reservoir, several shale reservoirs exhibit a wide spectrum of heterogeneous composition. Diaz et al. (2013) tried to correlate the shale mineralogy with both the reservoir and Completion quality using a ternary diagram. Algahtani et al. (2012) investigated the acoustic and mechanical properties of different organ-rich shale reservoirs with respect to the mineralogy. Besides, the quartz content of shale is used qualitatively as a measure of the rock brittleness which determines the appropriate completion scheme.

1.3 Hydraulic fracture

The hydraulic fracturing technique is one of the stimulation techniques that involves pumping massive amounts of fracturing fluid to overcome the tensile strength of the rock and create the fracture. Then, proppants are distributed across the fracture to maintain the fracture open. After that, the proppant laden fluid is displaced from the wellbore in the flush stage (Sash, 2015). This techniques was first introduced in the petroleum industry in 1947 and commercially in 1950 (king, 2010).

Formation damage bypass and Recovery acceleration were the main reasons for the implementation of this technique in the conventional reservoirs. Therefore, the ultimate recovery from these kinds of reservoirs is the same for with and without stimulation cases as indicated in **Figure** 1.9. However, the Flow rate is enhanced with stimulation due to larger contact area with the reservoir.

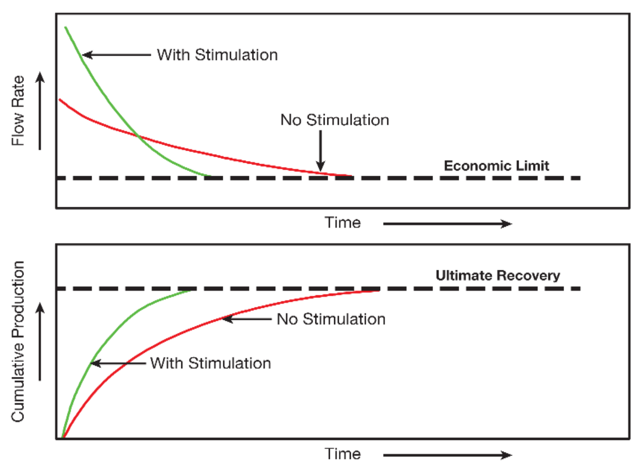


Figure 1. 9 the stimulation impact on the well performance and ultimate recovery in the conventional reservoirs (EPT, 2015)

The recent advances in the hydraulic fracturing techniques have unlocked the potential of the tight formations as indicated in **Figure** 1.10. As, the reservoir contact grew to the order of millions m^2, the permeability economic limit for oil and gas reservoirsdecreased to micro and nano darcy levels. The coupling between multistage fracturing and horizontal well technology has resulted in a massive contact area between reservoir and wellbore which enabled the economic production from ultra-low permeability reservoirs. That coupling marked the dawn of the shale boom in the USA.

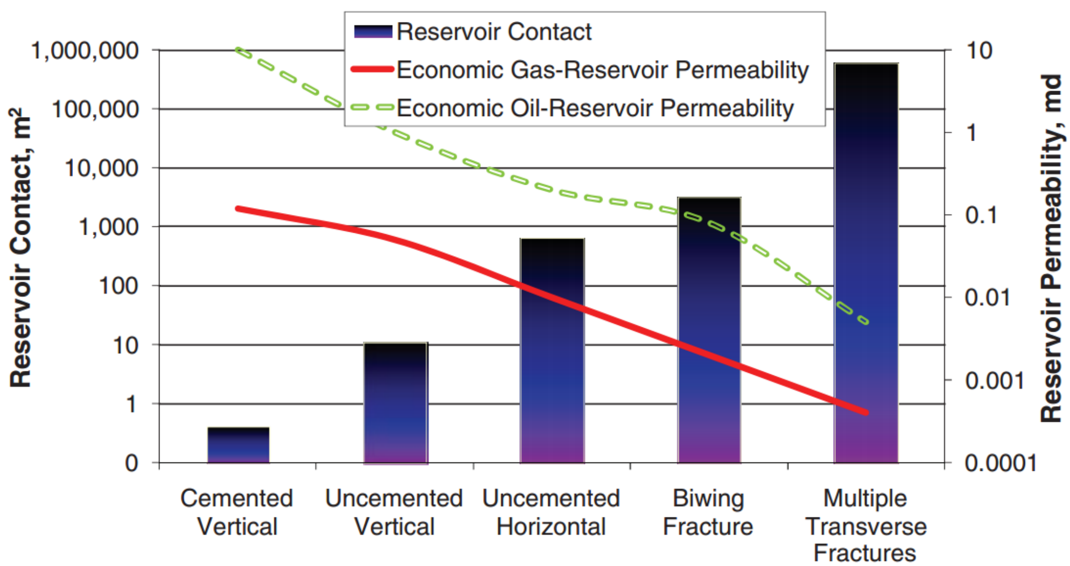


Figure 1. 10 the Economic Gas and Oil Permeability as A function of the Reservoir Contact (Vincent, 2013)

1.3.1 Fracturing Fluid

The viscosity, the carrying capacity and the clean-up properties are the main criteria for choice of the fracturing fluid. The selection of the proper fracturing fluid depends on both the treatment parameters and the formation characteristic as presented in **Figure** 1.11. While the implementation of slick water in low-perm, brittle formations with high injection rates is more prone to develop a complex fracture network, the coupling between the low injection rate and gel-based fluid in high-perm ductile formation is more likely to result in Bi-wing fracture.

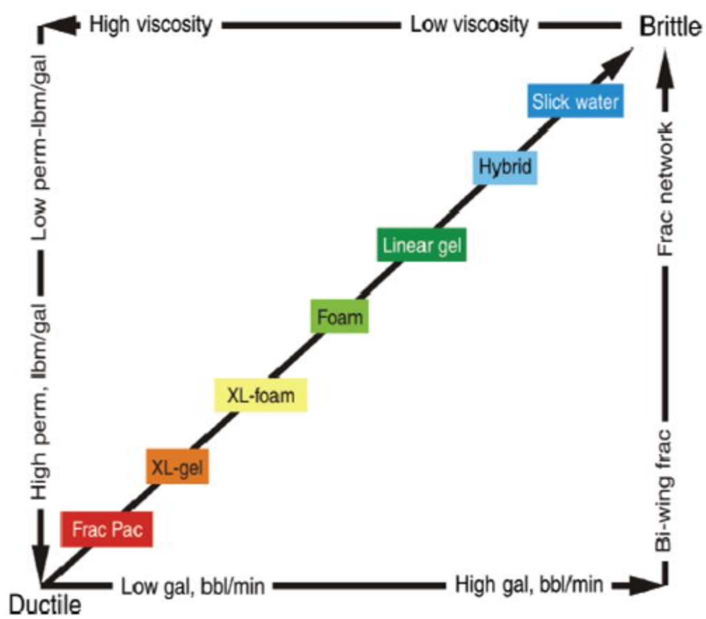


Figure 1. 11 the relation between the Injection rate, the formation permeability, fracture geometry, fluid viscosity formation strength and fracturing fluid type (Chong et al. 2010).

The evolution of the fracturing technology has resulted in the shale revolution as indicated in **Figure** 1.12 where the number of fracture treatments per year roared to more than 100,000 and the Average Job size became more than 5 Million gallon. The observed increase in the average job size in 2000 might be explained by the introduction of slickwater as a fracturing fluid which entails pumping of massive amounts of the fracturing fluid to compensate for its poor carrying capacity. However, there are many benefits for the use of slick water including cost saving, complex fracture network and less formation damage (Palisch, 2010). These characteristics nominate the use of slickwater for the treatment of shale reservoirs. However, the risk of fracture containment and complex hydrocarbon flow should be considered in the design. Interestingly, the simple formulation of slick water, water with low concentration of friction reducer or linear gel, allows the reuse of flow back fluids which lessens the environmental footprint and eases the paucity of water for the successive treatments.

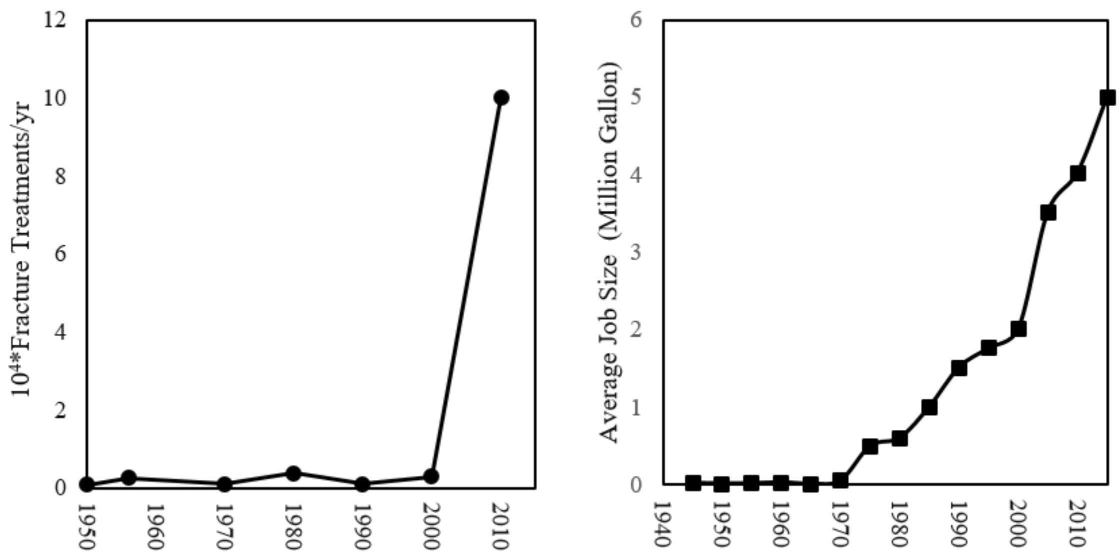


Figure 1. 12 Timeline for the Number of the Fracture Treatment Performed and the Average Job Size (Modified after Perry, 2011)

The mystery of the fate of the fracturing fluid has puzzled many researchers. Field reports from hydraulic fracturing operations performed on shale formation have highlighted the low recovery of the fracturing fluid (King, 2010). The complexity of the fracture developed in shale, the shale activity and the heterogeneity of the shale system add more degrees of complexity to the cleanup process compared to the conventional, less complex reservoirs. Literature has attributed the low load recovery to either trapping into the natural or created micro-fractures or imbibition into the matrix. However, the impact of these fluids on well performance is not well-understood.

1.3.2 Fracturing Geometry

The fracture geometry predication and modelling was the focus point of many research studies (Brady et al. 1992; Warpinski et al. 1993; Xu et al. 2010; Weng et al. 2011; McClure, 2012; Kresse et al. 2013 and Ouchi et al. 2015). The modelling of the hydraulic fracture propagtion started with the 2-D models where one of the fracture dimensions was held constat. While both PKN and GDD models assume constant fracture height, the fracture width is proportional to the fracture height in PKN and fracture length in GDD. Moreover, GDD predicts wider and shorter fractures compared to PKN for the same treament size,fluid and formation properties (shah, 2014). Apart from the fracture-wing shape, the Penny shaped fracture (Radial model) assumes circular fracture shape where the maximum width is in the center. While the pressure required to extend the fracture decreases with treatment time for GDD and Radial model, the PKN model predicts the pressure to increase with the treatment time (Brady, 1992) as shown in **Figure** 1.13.

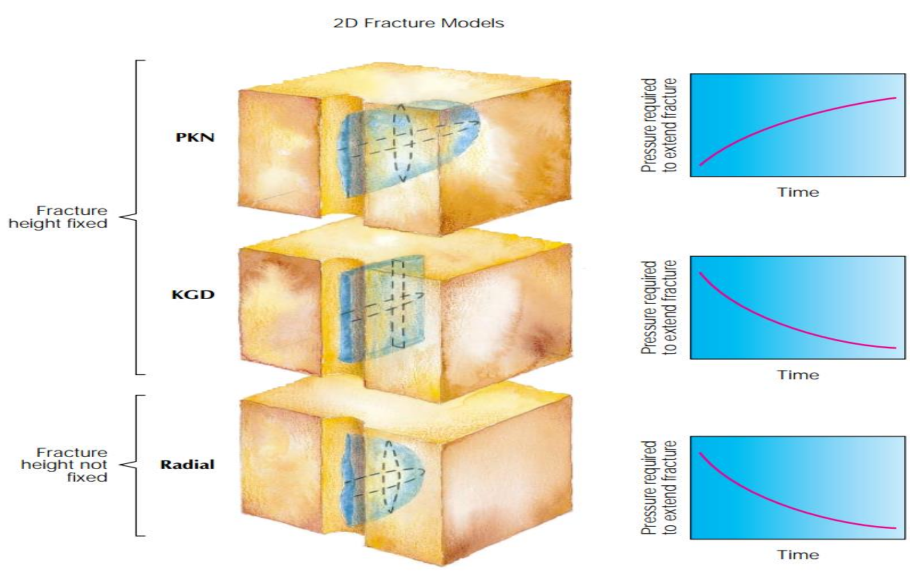


Figure 1. 13 PKN, KGD and Radial fracture models (Bradly, 1992)

The removal of the constant fracture height constraint from PKN model assumptions resulted in the generation of the Pseudo-3-D models family for fracture propagation. Interestingly, there are tangible differences in the fracture geometry developed by this family models. This difference results from the way the models deal with the fracture cells.

Xu et al. (2010) developed the Wiremesh model. The key improvement from this model is the ability to predict both the wing like fractures and the development of a Hydraulic Fracture Network (HFN). The fracture propagates first as a wing fracture, then the development of an HFN depends on the differential stress in the fracture. Further developments have been introduced in the unconventional fracture model (UFM) (Weng et al. 2011) where complex fracture network propagation in naturally fractured formations was simulated. Interestingly, this model accounts for the impact of fracture interactions, multiple fracture placement, stress shadow effect and the proppant transport on the generated geometry.

Counting on the displacement discontinuity method (Olson, 2004), McClure (2012) managed to simulate the interactions between the propagating hydraulic fracture and the existing natural fractures and study the seismicity induced during the injection stage. However, his model necessities the prior knowledge of the new fractures. Ouchi et al. (2015) implemented the nonlocal continuum theory of Peridynamics to model fracture propagation. Their model overcome the shortage of McClure's model as it is capable of modelling the propagation of multiple non-planar fractures without specifying the direction of the fracture in advance. Also, they investigated the interactions between the hydraulic fracture and the natural fracture in terms of the differential stress and the approaching angle as shown in **Figure** 1.14

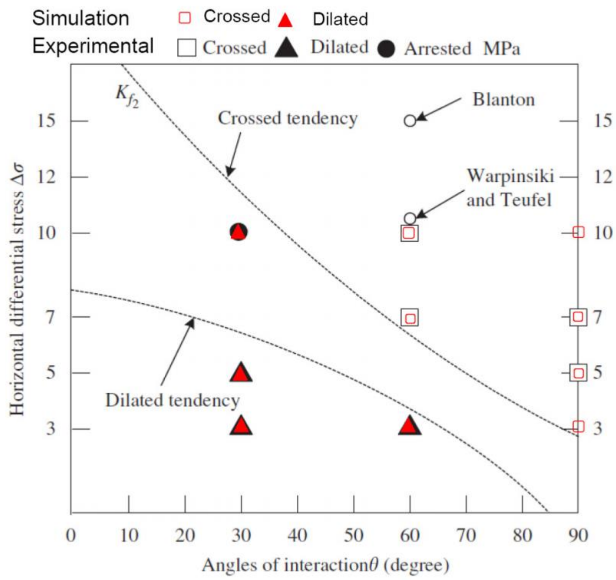


Figure 1. 14 Diagnostic map for the interactions between the hydraulic fracture and the nature fracture along with the experimental and simulation cases results (Ouchi, 2015)

1.4 The Fate of the Fracturing Fluid

In one of the early studies investigating the impact of the trapped fracturing fluid on well performance, Holditch (1979) studied the impact of capillary pressure, relative permeability and matrix permeability on the cleanup stage and, in turn, well performance. Also, the relation between drawdown and capillary pressure was investigated. He pointed out that well performance is hindered if the capillary pressure outweighs the drawdown pressure.

The impact of fracture conductivity on the fracture fluid cleanup and well performance was the focus of Soliman and Hunt (1985)'s numerical investigation. In addition, they studied the pressure build up response after flow back. They conclude that the cleanup stage requires higher fracture conductivity than the production stage. Moreover, they reveal the vital role of the matrix capillary pressure on cleanup in depleted reservoirs.

Iqbal and Civan (1993) simulated both the leak-off and cleanup stage to study the fracture face skin effects on both load recovery and performance of hydraulically fractured wells. They used a three-dimensional two-phase simulator. They highlighted the importance of considering both the permeability damage in the invaded zone and the decreased gas relative permeability in the partially saturated matrix in the hydraulic fracture design.

Bennion et al. (1994) studied the relation between water blocking and reservoir characteristics. They claim that the water desaturated reservoirs, those where the initial water saturation is lower than the critical water saturation, would mostly suffer from water blocking due to the trapping of drilling or workover fluids. Moreover, they recommended the use of non-aqueous fluids or alcohol to both enhance and accelerate the cleanup according to their experimental results.

The impact of the Geomechanics coupling on the modelling of the fracture cleanup was introduced by Settari et al. (2002). Their study involved an investigation of water blockage at the field scale using a case study form the Bossier play. The key findings form their study were the equal importance of the Geomechanics coupling in the production stage and in the drilling and completion stages. The combination of water blockage and permeability reduction would greatly impair well productivity. In addition, they conclude that the extended shut-in time has limited impact on both load and well recovery.

Slick water invasion can be described by **Figure** 1.14. In the initial state, the gas resides in the pores' center, with water saturation less than the connate water saturation. During hydraulic fracturing, slick water invades the pore as shown in stage B. In the production stage, gas starts to break through the invaded water from the center of the pore leaving behind imbalanced conditions with over and under-saturated pores. After that, the salt diffuses from the formation brine to the trapped slick water. Finally, the equilibrium conditions are achieved by the osmosis and capillariy driving forces, sucking the fluid deeper into the formation.

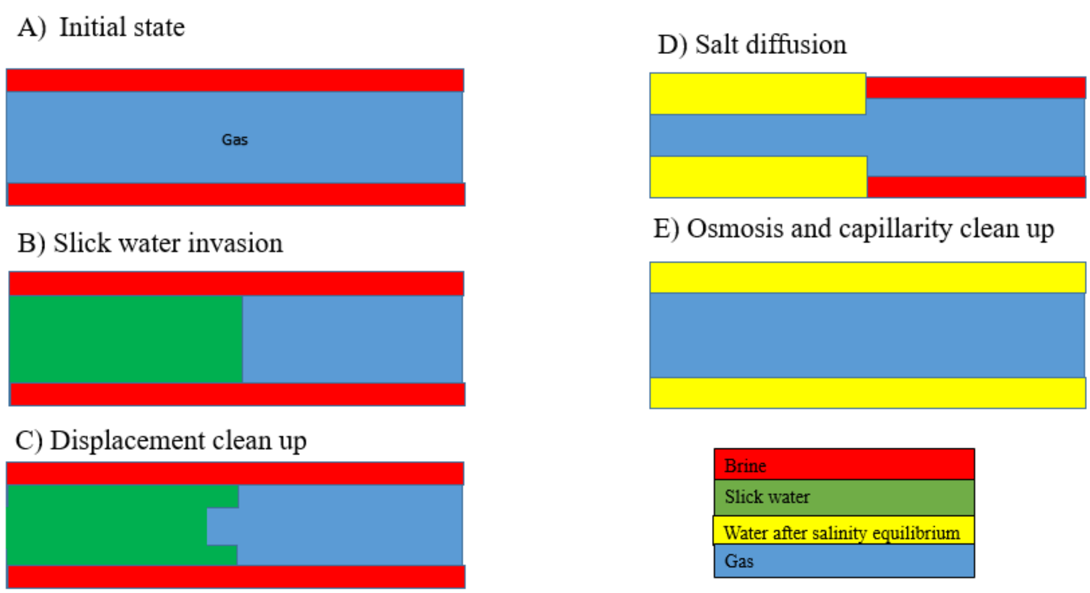


Figure 1. 15 Conceptual pore sacle for the slick water invaion and cleanup

1.4 Thesis Design

The rest of this thesis is organized as follows. The second chapter discusses the coupling of the osmosis pressure and the impact of the different parameters on the early well performance and load recovery. The third chapter presents the impact of the geochemical coupling on the fate of the fracturing fluid and, in turn, well performance. The fourth chapter experimentally investigates the impact of salinity on slick water dynamics. Finally, the fifth chapter summarizes the findings and the recommendations from this study.

Chapter 2: Numerical Investigation of the Osmotic Flow Impact on Load Recovery and Well Performance

2.1 Introduction

The fracturing job involves the injection of high volumes of the fracturing fluid at a pressure high enough to overcome the formation fracture pressure. The proppant injected with the fracturing fluid is responsible for keeping the fracture open when the injection pressure is relieved. Post-treatment performance starts with a flow back period which is dominated by water production, followed by a shut-in time while the invaded fluids are soaked up further from the flooded fracture face, and finally production, where the gas flow dominates as indicated in Fig. 2.1.

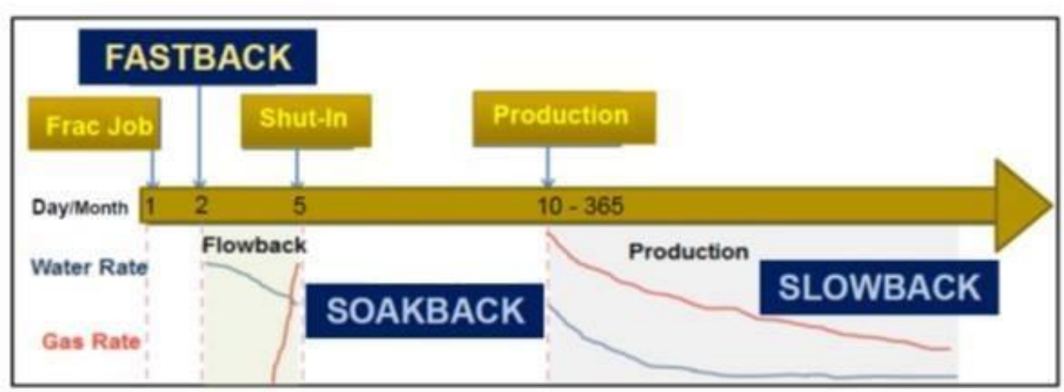


Figure 2. 1 Production stages after hydraulic fracture [Alkouh et al. 2014].

The long exposure of the matrix to highly pressurized fluids results in larger and deeper invasion. Therefore, the sooner the flow back period starts, the better the load recovery will be. During the flow back period, the production is initiated due to fluid displacement by the draw down pressure. This draw down should be sufficient to overcome capillarity holding the fluid and sidestepping the excessive proppant flow back. Therefore, load recovery is expected to be lower in depleted and tight reservoirs.

The capillary and osmosis suction begin with the fracturing process itself, which means that it is bolstered by the fluid filtration during the fracturing process, detracted by production during the flow back period and act on its own the shut-in time. The salinity contrast between the fracturing fluid and formation brines along with the membrane efficiency of the rock determine osmotic pressure, which might range from negligible value in permeable formation to several hundred psi in some types of shale. Moreover, the characteristic small size in the pores of these reservoirs intensifies the capillary suction. There is a trade-off among shut-in time, initial gas rate and load recovery. The effect of the shut-in time has been the focus point for many research studies [Fakcharoenphol et al. 2013; Bertoncello et al. 2014; Settari et al. 2012 and sharma and Agrawal, 2014].

The slow back stage start at the end of shut-in time and last to the end of the well lifetime. Fracturing fluid evaporation constitutes most of the load recovery during this stage. It is worth mentioning that high fluid flow velocities are mandatory for the evaporation mechanism to be effective in cleaning up the fracturing fluids.

The focus of this chapter is to numerically investigate the impact of the parameters controlling the osmatic pressure on load recovery and well performance. Firstly, the methodology is reported, then the essence of the osmatic pressure coupling is presented, after that the sensitivity analysis results for the impact of membrane efficiency, salinity contrast, natural fracture spacing, organic volume, Temperature and Shut-in time. Finally the conclusion summarize the main findings and results.

2.2 Methodology

The simulator used was developed by Fakcharoenphol et al. (2013). It is a 2-D sector model where the hydraulic fracture is represented explicitly with modified properties orthogonal grids to account for the fracture higher conductivity. A triple porosity model is implemented to represent the formation where natural fracture network, organic matrix and non-organic matrix are the main component. Further details about the simulator are provided in the work done by Fakcharoenphol et al., (2013). The relative permeability sets and capillary pressure for natural fractures, non-organic matrix and organic matrix are reported in **Figure** 2.3 and 2.4.

Simulation scenarios are performed to quantify the effect of salinity contrast, membrane efficiency, temperature, organic volume, shut-in time and natural fracture spacing on both gas recovery and load recovery. After that, the relative effectiveness of the different parameters on gas and fluid recovery are presented through the relevancy factor.

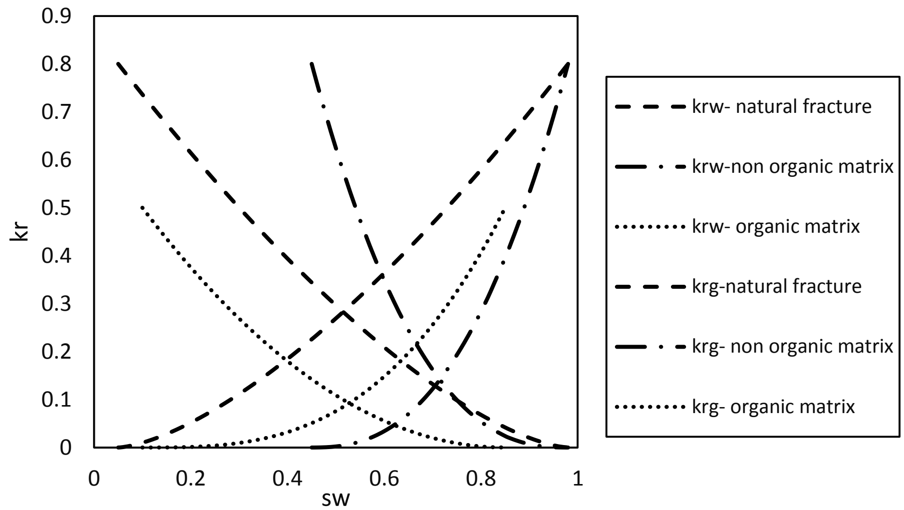


Figure 2. 2 Rock properties: Relative permeability.

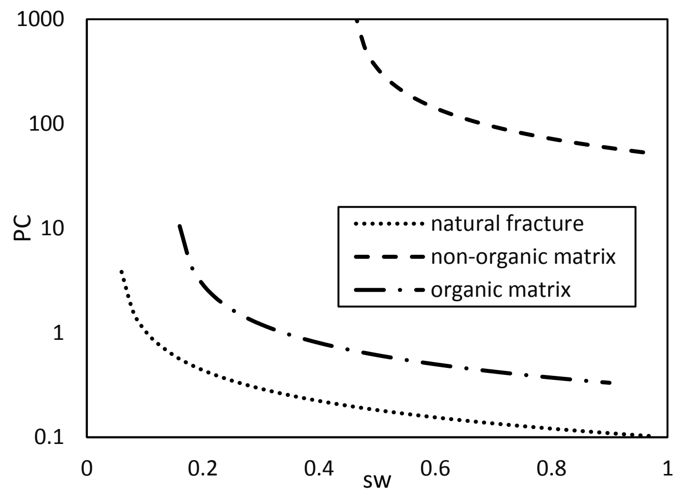


Figure 2. 3 Rock properties: Capillary Pressure.

2.3 Results and Discussion

2.3.1 Osmosis flow

Similar to the capillary pressure which is driven by wettability of the formation, the pore radii and interfacial tension, osmotic pressure depends on formation membrane efficiency, salinity contrast and temperature. Given that most of the current fracturing operations are performed using slick water, which is composed mainly from low salinity water compared to formation brine, this high salinity contrast coupled with the shale membrane characteristics might cause a pressure difference that is comparable to the one resulting from capillary pressure and in some cases even higher.

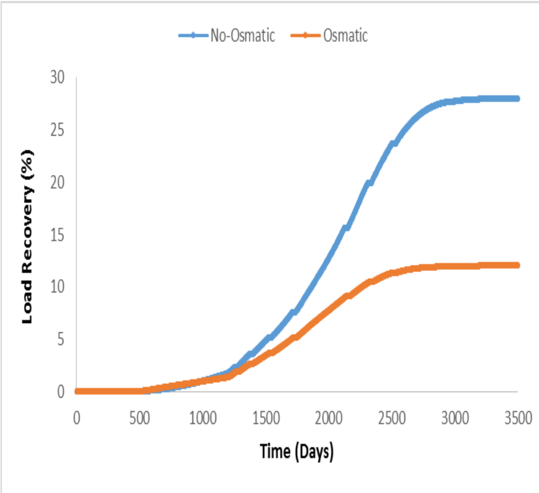
The osmotic pressure, π, is estimated using the following equation [Marine et al. 1981]:

$$\pi = \frac{RT}{v} \ln\left(\frac{a_1}{a_2}\right) \tag{1}$$

Where

a1, a2	water activity of the fracturing fluid and the formation brine respectively
R	Universal gas constant
T	Temperature
v	Partial molar volume

The imbibition of the fracturing fluid further into the formation during shut-in time depends on the suction pressure provided by capillary osmosis pressure. **Figure** 2.4 reports the simulation results obtained with and without considering the chemical osmosis. The lower load recovery observed considering the osmotic flow is a direct result of the additional suction pressure provided which, in turn, reinforces the imbibition of the fracturing fluid either away from the wellbore or into the formation matrix. Subsequently, lower fracturing fluid flows back to the wellbore. Moreover, the salt diffusion between the low salinity fracturing water and high salinity formation brine explains the lower salt production obtained when the chemical osmosis is implemented in the model



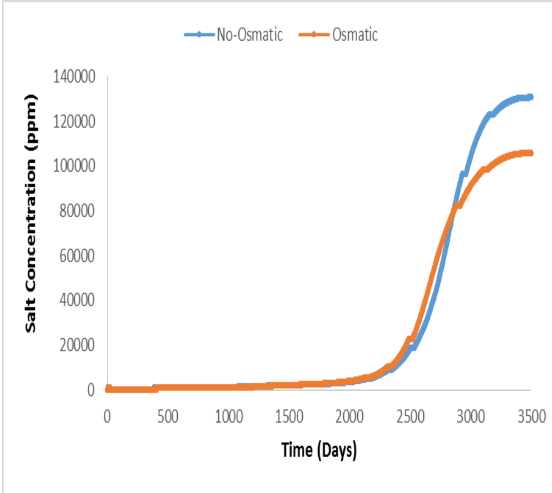


Figure 2. 4 : water load recovery and salt concentration (ppm) vs time (Days) with and without osmosis

2.3.2 Membrane Efficiency

The efficiency of a membrane is the ratio between the theoretical osmotic pressure and the actual induced pressure. It is presented by the reflection factor, σ, which can range from 1 for a perfect membrane and 0 for a non-ideal membrane (Schlemmer et al. 2002). The membrane efficiency of shale depends on its morphology, compaction, and mineralogy. **Figure** 2.5 shows the effect of membrane efficiency on gas production rate and recovery. It is evident that the effect on the ultimate gas recovery is negligible. However, the gas rate peaks at higher values for higher membrane efficiency. The high membrane efficiency, the faster is the natural fracture cleans up and the better is the gas conductivity to the wellbore. This is better explained in **Figure** 2.6, which represents load recovery for different membrane efficiencies. Note, the low load recovery of 7% observed for an ideal membrane compared to the 19% load recovery observed for a 0.2 membrane efficiency. The prompt decrease in load recovery with the increase in the membrane efficiency is a direct result of the enhancement of fracturing fluid imbibition into the matrix. The ultra-low permeability of the matrix coupled with the relative permeability hysteresis due to imbibition-drainage cycles highly curtail the production of the imbibed fracturing fluid. Therefore, the mystery of the fate of the fracturing fluid might be resolved by considering the entrapment of the osmotic-driven imbibed fluid into the matrix. It is worth mentioning that the load recovery can be almost tripled by tuning membrane efficiency. Therefore, incorporating chemical osmosis is highly recommended when simulating fracturing fluid dynamics.

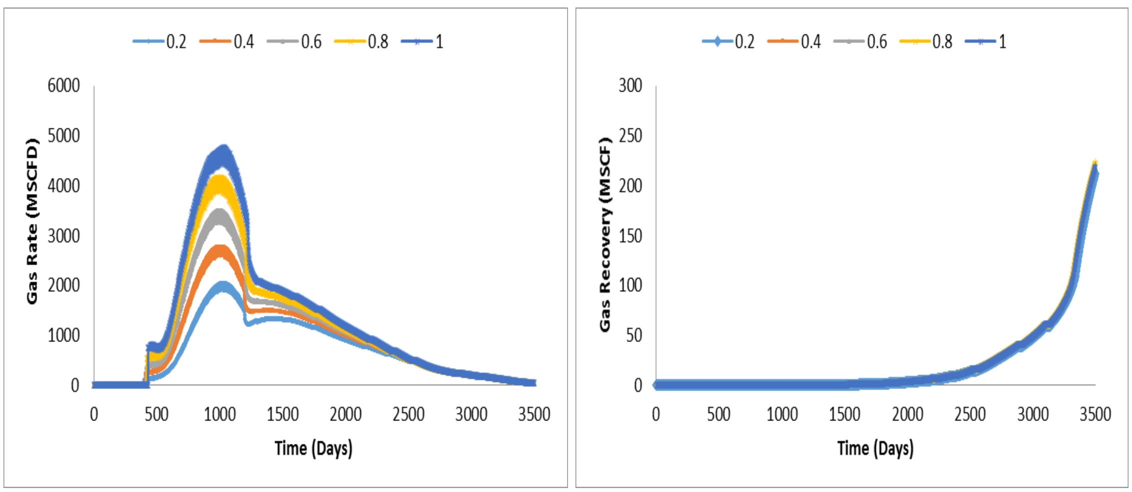


Figure 2. 5 Gas flow rate (MSCFD) and Gas Recovery (MMSCF) vs. Time (Days) for Membrane efficiency of 0.2, 0.4, 0.6, 0.8 and 1.

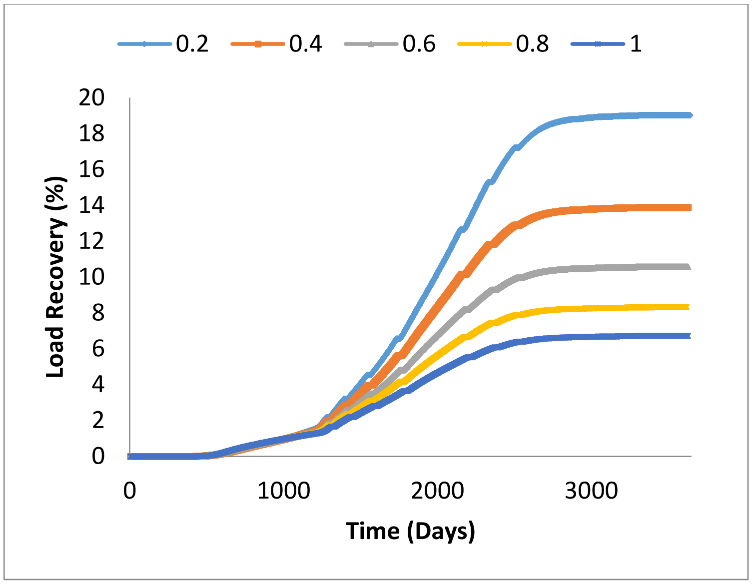


Figure 2. 6 Load Recovery vs. Time (Days) for Membrane efficiency of 0.2, 0.4, 0.6, 0.8 and 1

2.3.3 Salinity Contrast

The introduction of the slick water application was the key parameter for the technical and economic development of shale reservoirs. The most common slick water system used is fresh water with a friction reducer (10pptg) (Palisch et al. 2008). Therefore, salinity of the slick usually does not exceed 1000 ppm while formation brine salinity can range from 50,000 to 175,000 ppm. This salinity contrast between slick water and formation brine activates a concentration gradient driven flow similar to the hydraulic flow which is driven by the hydraulic gradient. It is clear that the interactions between the fracturing fluid and the rock will highly affect the fluid dynamics along with the properties of the rock such as permeability, wettability and porosity. However, these interactions are not considered in this study and it will be addressed in the future. According to the simulation results shown in **Figure**. 2.7, the impact of the different salinity contrasts on gas rate and recovery is insignificant. However, these findings might be misleading considering that the simulator is incapable of simulating the geochemical interactions between the fluid and the rock or their effects on both the rock and fluid properties. Therefore, the coupling between geochemical, reservoir and fracture propagation simulator is recommended to fully comprehend the fate of the fracturing fluid. On the other hand, the results shown in **Figure** 2.8 present the load recovery for five different salinity contrasts. These results are consistent with the previous claims of concentration gradient driven flow, since the high salinity contrast results in a high contrast between the activity of the fracturing fluid and that of the formation brine, which increases the osmotic pressure according to equation [1]. Subsequently, this additional pressure will suck the fluid away from the wellbore and reduce load recovery.

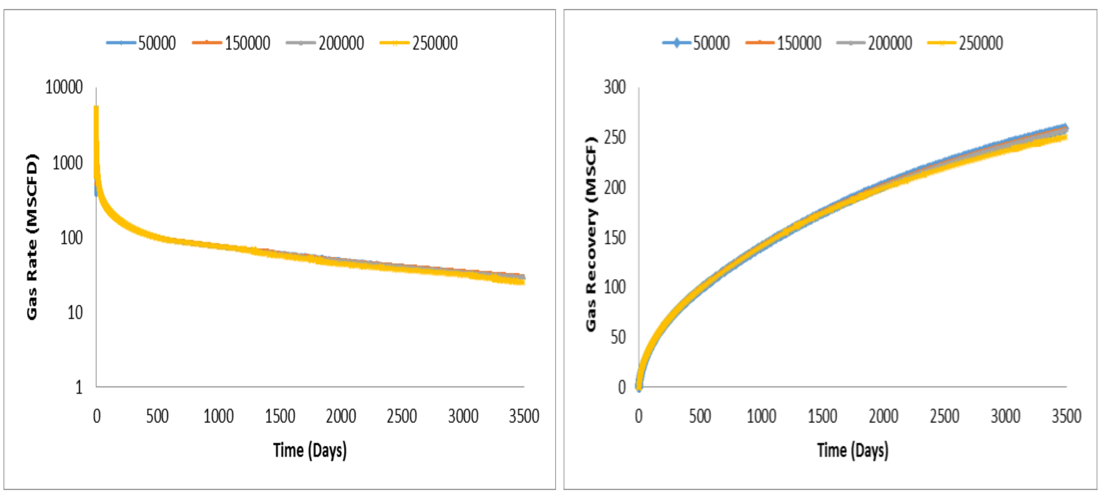


Figure 2. 7 Gas flow rate (MSCFD) and Gas Recovery (MMSCF) vs. Time (Days) for salinity contrast of 50,000, 100,000, 150,000, 200,000 and 250,000

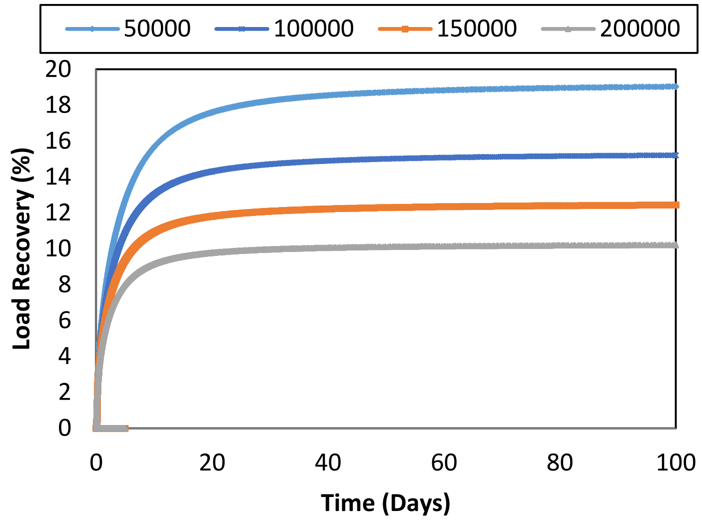


Figure 2. 8 Load Recovery vs. Time (Days) for salinity contrast of 50,000, 100,000, 150,000, 200,000 and 250,000.

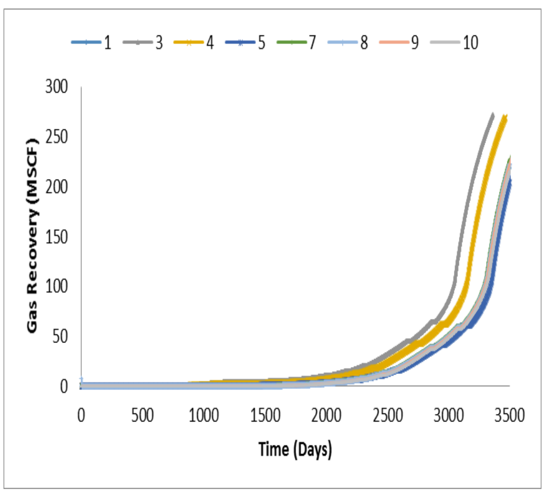
2.3.4 Natural Fracture Spacing

Shale reservoirs are characterized by an ultra-low permeability in the range of nanodarcy. Therefore, the development of these reservoirs is not possible without the presence of the natural fractures (Walton and Mclennan, 2013). These natural fractures play a vital role during the fracture propagation stage, production stage and even in the design of secondary derive techniques for shale reservoirs. During fracture propagation, the intersection between these micro natural fractures and the main hydraulic fractures results in a very complex fracture geometry, which, in turn, provides a massive contact area between the matrix and the wellbore and maximizes the stimulated reservoir volume. Besides, it provides high permeability pathways connecting the undeveloped regions to the main fracture in the production stages. Several simulation scenarios are performed with natural fracture spacing ranging from 1 to 10 ft. The simulator we used requires the explicit values for the shape factor which was estimated using the following equation (Ramierez et al., 2007).

$$\sigma = 4\left[\frac{1}{l_x^2} + \frac{1}{l_y^2} + \frac{1}{l_z^2}\right] \tag{2}$$

Where lx, ly, lz are the matrix block dimensions (ft.)

The simulation results for the gas rate and recovery are shown in **Figure**. 2.9. The gas rate peak increases with the decrease in the fracture spacing. However, the impact of fracture spacing on ultimate gas recovery after 10 years of production is still insignificant. Note that these gas recovery trends will level off after prolonged production time and the difference among them will become clearer. Interestingly, the separation in the load



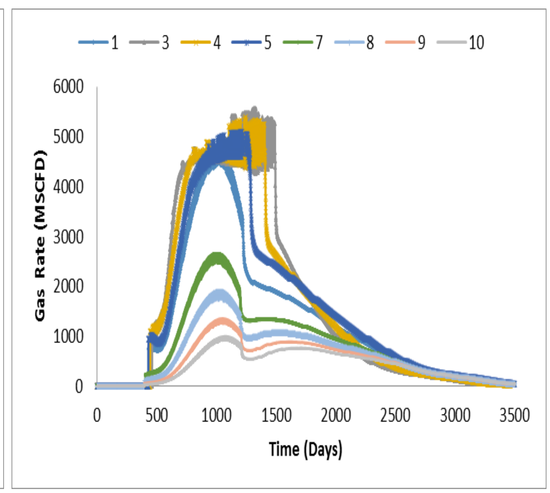


Figure 2. 9 Gas flow rate (MSCFD) and Gas Recovery (MMSCF) vs. Time (Days) for natural fracture spacing of 1, 3, 4, 5, 7, 8, 9 and 10 ft.

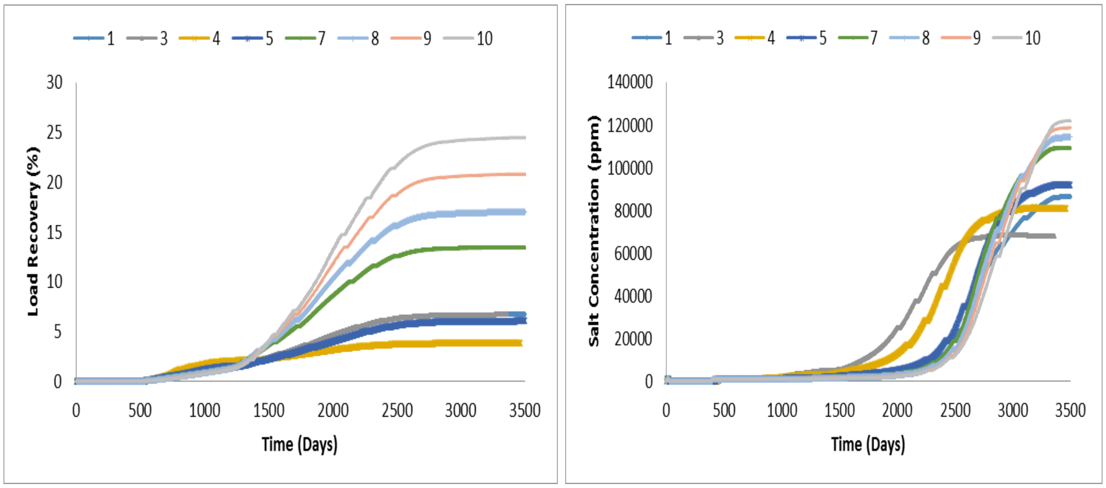


Figure 2. 10 Load Recovery and Salinity Concentration vs. Time (Days) for natural fracture spacing of 1, 3, 4, 5, 7, 8, 9 and 10 ft.

recovery trends and salt concentration in the produced water are clearer as **Figure**. 2.10 shows. The increase the natural fracture spacing results in less fluid to be imbibed into the matrix and, subsequently, higher load recovery. Similarly, the more natural fractures the formation has, the less diffusion between the fracturing fluid and the formation brine occurs and in turn, the less salt concentration is observed in the produced water.

2.3.5 Organic Volume

Shale is self-sourced reservoir. Therefore, the Total organic Content (TOC) of the formation is one of the petrophysical measures of the formation potential for hydrocarbon prospects. While a TOC (wt % of rock) less than 0.5% is considered as non-source, reservoirs with TOC more than 2% are excellent prospects for exploration. **Figure** 2.11 reports the simulation results of different scenarios with organic volume ranging from 0.1 to 20 %. The impact of the organic volume on both gas rate and load recovery is minor. The non-water wet and the relatively bigger pores characteristics observed in the organic pores might explain the minimal impact of the organic volume on load recovery.

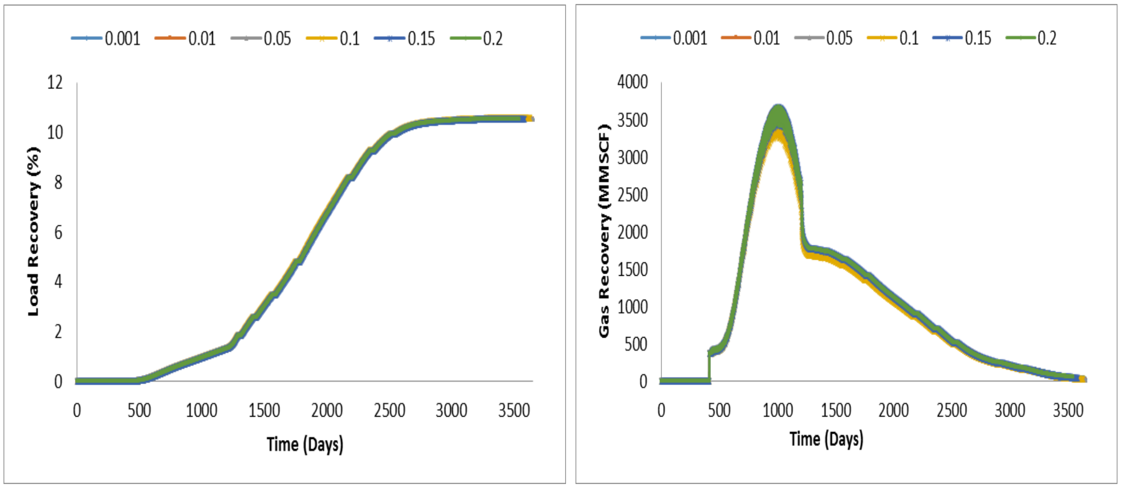


Figure 2. 11 Load Recovery and Gas Flow Rate (MSCFD) vs. Time (Days) for organic volumes of 0.001, 0.01, 0.05, 0.1, 0.15 and 0.2

2.3.6 Reservoir Temperature

The temperature contrast between the fracturing fluid and reservoir temperature might produce induced stress which will create micro fissures enhancing the hydrocarbon recovery (Fakcharoenphol et al. 2012). The simulation results for different reservoir temperature are presented in **Figure** 2.12. While the decrease in the gas peak with the increase in reservoir temperature is observable, the increase in load recovery is insignificant. The observed inverse relationship between the gas peak and the temperature is a direct result of the positive relationship between the temperature and the gas formation volume factor. Therefore, the effect will be more tangible in the gas (compressible fluid) and marginal in the liquid (slightly compressible fluid). It is worth mentioning that the simulator we used does not account for the temperature induced stresses.

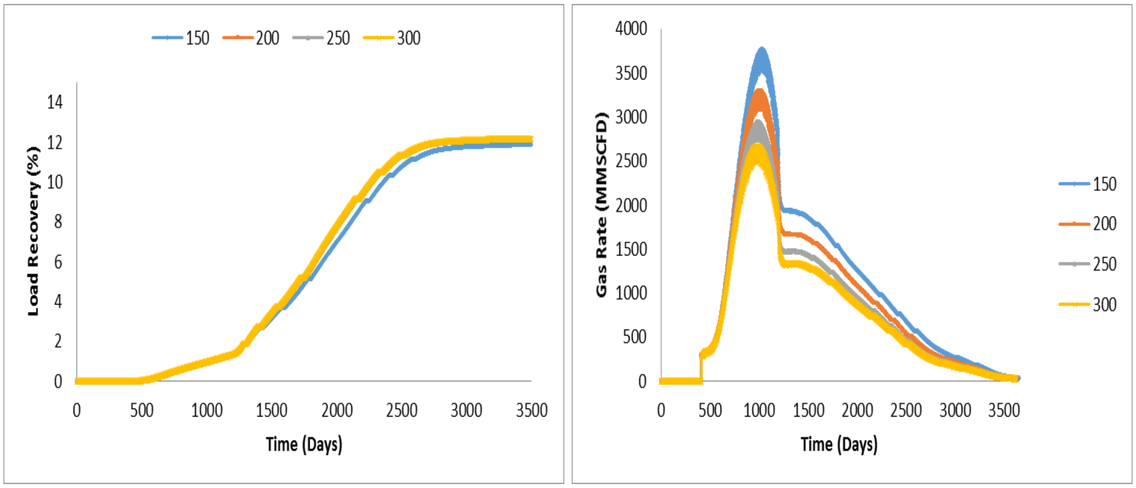


Figure 2. 12 Load Recovery and Gas Flow Rate (MSCFD) vs. Time (Days) for different Reservoir Temperatures

2.3.7 Shut-In time

There is still a debate among the researchers about the impact on the shut-time on gas recovery. The simulation results suggest an inverse relationship between shut-in time and load recovery, which is consistent with the literature (Bertoncello et al. 2014 and Fakcharoenphol et al. 2013). However, there is an improvement in the gas flow rate with the increase in shut-in time, which allows the fracturing fluid to be sucked deep into the formation and, subsequently, desaturate the flooded natural fracture. However, the extended shut-in time will not have that of a strong effect on the gas flow rate as shown in **Figure** 2.13 (right side), where the gas rate peaks at around 5000 MSCFD for all the scenarios with a little increase in the production plateau for higher shut-in time.

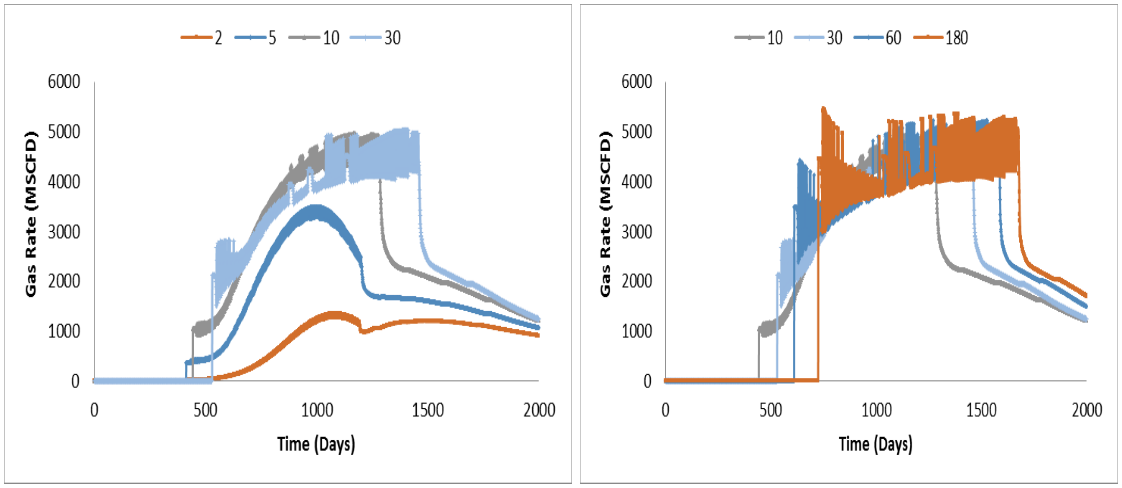


Figure 2. 13 Gas flow rate (MSCFD) vs. Time (Days) for shut-in time of 2, 5, 10, 30, 60 and 180 days.

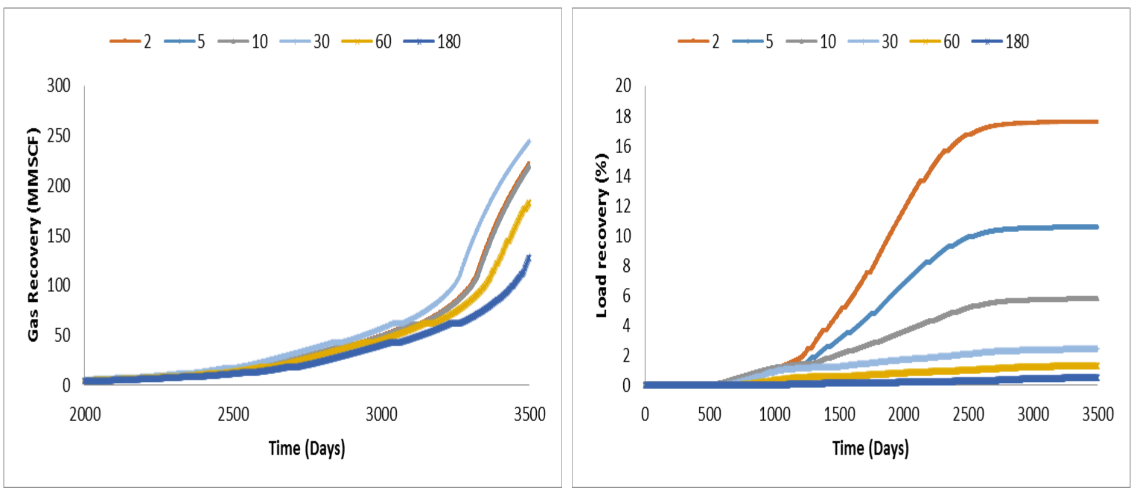


Figure 2. 14 Cumulative Gas recovery (MMSCF) vs. Time (Days) for shut-in time 2, 5, 10, 30, 60 and 180 days

Surprisingly, the effect of the extended shut-in time on gas recovery is detrimental as shown in Fig. 2.13 (left side) which contradicts with Zanganeh et al. (2015)'s claims. The effect of the shut-in time on load recovery is tangible as shown in Fig. 2.14. The low load recovery observed during the case of longer shut-in time can be explained by capillary and osmotic suction of the fracturing fluid deeper in the formation. Subsequently, a larger surface area is available for the water into be imbibed in the ultra-low permeability matrix. Consequently, a glance at the presented **Figure 2.14** leads to the conclusion that the efficient shut-in time would be one month.

2.4 Conclusion

The work presented in this chapter is a parametric numerical investigation of the incorporation of the impact of chemical osmosis on the modelling of fracturing fluid dynamics and well performance. According to the presented results, the incorporation of chemical osmosis in the modelling of fracturing fluid dynamics and well performance is essential. Moreover, the additional pressure resulting from the salinity contrast between the fracturing fluid and the formation brine is one of the parameters neglected in commercial reservoir simulators while it might account for the fate of the fracturing fluid. Interestingly, the dependence of the Load recovery on the osmotic flow parameters is critical. Load recovery triples by just tuning the membrane efficiency. The extended shut-in time curtails both the load and the gas recovery. Therefore, according to the simulation results, one month shut-in time is recommended. The natural fractures act as highways connecting unstimulated regions to the main hydraulic fracture. Therefore, their density is one of the critical parameters controlling both gas and water recovery. On the other hand, the salinity of the recovered fluids is highly dependent on the mixing between the low salinity fracturing fluid and the high salinity formation brine, which, in turn, depends on the salt diffusion coefficient and the imbibed volume from the fracturing fluid.

Chapter 3: The Impact of the Geochemical Coupling on the Fate of Fracturing Fluid, Reservoir Characteristics and Early Well Performance in Shale Reservoirs.

3.1 Introduction

The dawn of the shale boom is marked by the coupling between the multistage hydraulic fracture technique and horizontal drilling technology, where the massive exposure created between wellbore and formation's matrix outweighs its ultra-low permeability. However, this entails massive leaked volumes of fracturing fluid which neither their fate nor impact is well investigated. King (2010) reported that the recovery of fracturing fluid in shale reservoirs is in the order of 10 - 50%. This percent varies with shale characteristics and treatment parameters as shown in **Figure 3.1**.

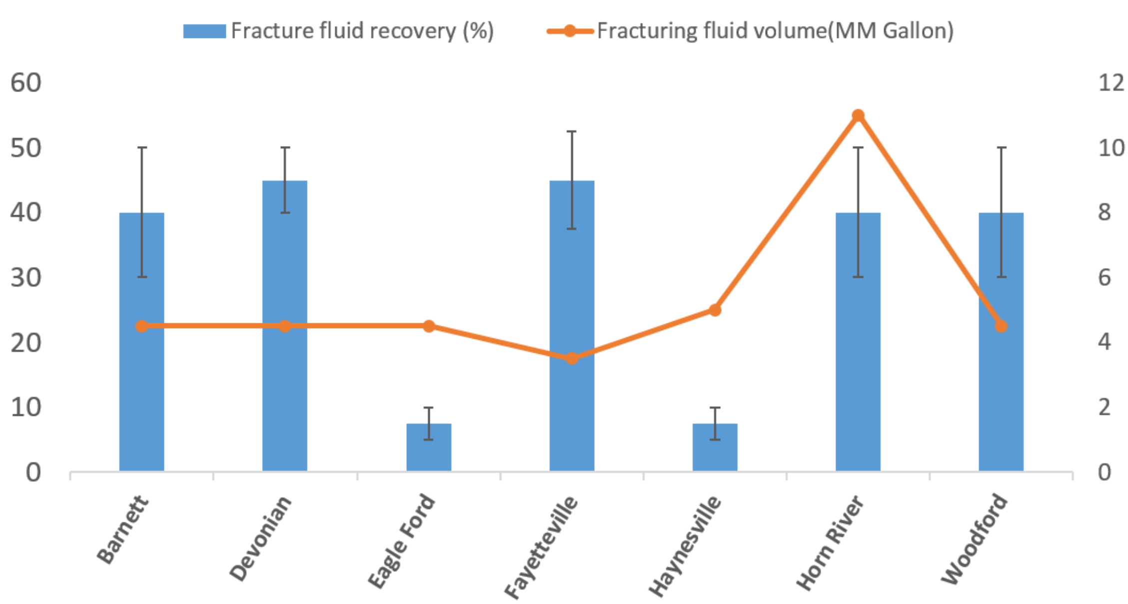
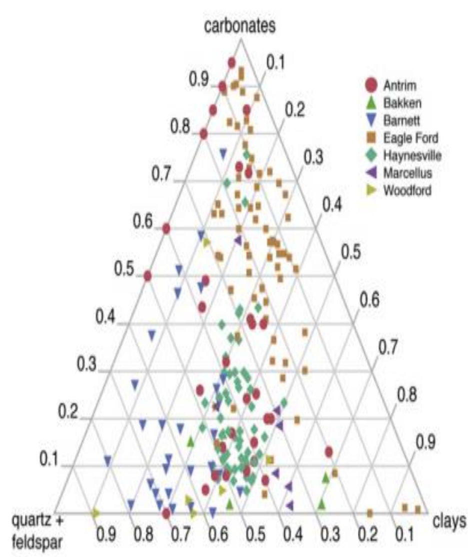


Figure 3. 1 Load recovery (%) and fracturing treatment volume (MM Gallon) for the main shale producing plays in United States. (Adapted from King, 2015)

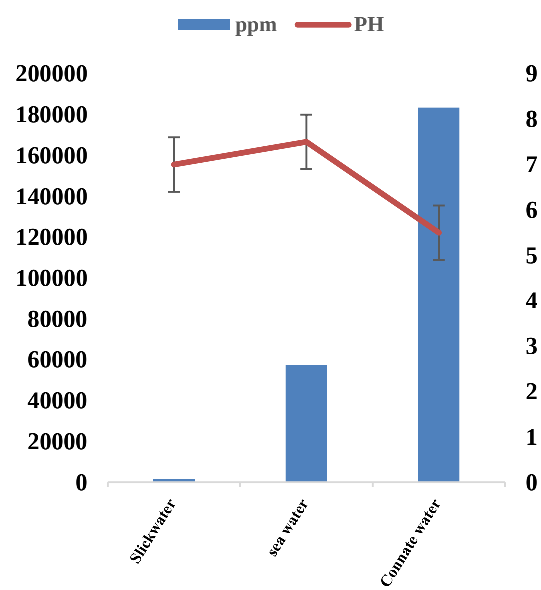
The fate of the fracturing fluid is a multi-facet topic. Therefore, it was the focus point of many research studies. Mehana and El-Monier (2015) studied the essence of incorporating chemical osmosis on load recovery. Fakcharoenphol et al. (2013) investigated the impact of shut-in time on well performance and load recovery. Agrawal and Sharma et al. (2013) considered liquid loading inside the fracture and its impact on load recovery and fluid entrapment. Le et al. (2012) explored the impact of capillary suction on fracture dynamics and well performance. Mahadevan et al. (2007) examined the potential of water evaporation as a cleaning mechanism of trapped fluids. Shaoul et al. (2012) investigated the various damage mechanisms resulting from fracture propagation and fluid dynamics. Gdsaki et al. (2010) reported the impact of both fracture conductivity and matrix permeability on load recovery and well performance.

The introduction of oxygenated, low salinity and neutral-pH Slickwater to a reduced, active and heterogeneous system like shale would disturb the system equilibrium. The resulting interactions involve the geochemical reactions like aqueous, ion exchange and rate controlled reactions in addition to physiochemical reactions like clay swelling. Akrad et al. (2011) investigated the impact of these interactions on reservoir characteristics experimentally, where they reported conductivity and strength loss for various shale samples after exposure to slick water. While conductivity loss directly impacts well performance, formation softening endangers prolonged production life time (Das et al., 2014). Therefore, selection criteria of the proper fracturing fluid should take into account these interactions.

The heterogeneity of shale composition is documented as shown in **Figure 3.2a**. The composition of the samples is spread all over the ternary diagram among three main components, Carbonates, Clays and Quartz. While both carbonates and clay minerals are considered reactive minerals with a fast reaction rate, Quartz is considered inactive for the lifetime of a well. The differences among sea water, connate water and slick water in terms of salinity and pH are highlighted in **Figure 3.2b**. The incompatibility between injected water and formation brine would definitely stimulate scale deposition which can severely curtail flow capacity and reservoir performance. In addition, the pH contrast stimulates more geochemical reactions to achieve the lost equilibrium. It is important to note that sea water salinity averages between the other two, but, with a relatively higher pH value.



(a)



(b)

Figure 3. 2 (a) The mineralogy of samples from the main shale producing plays (b) comparison among the connate, slick and sea water in terms of salinity and pH. (Schreiber and Chermak, 2013)

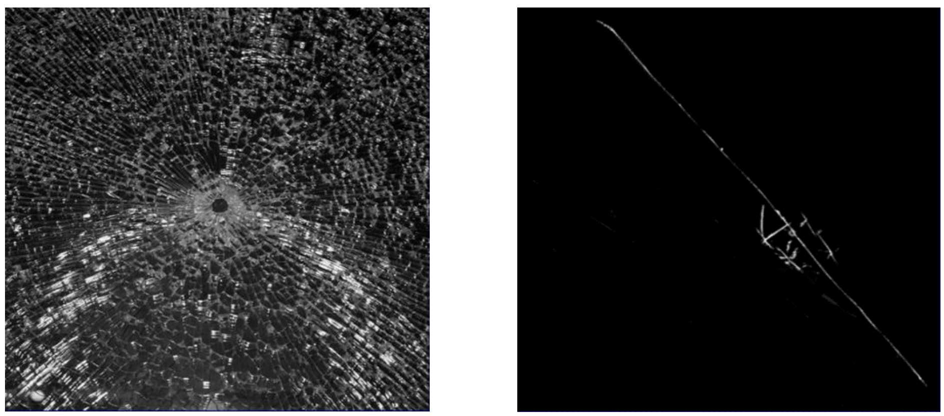
In this paper, we present the findings of our study, implementing the geochemical coupling and its impact on fluid mobility, and, as a result, on the recovery of both gas and fracturing fluid. We start by presenting the methodology, where we describe the model used and the geochemical interactions incorporated in it. Afterwards, we discuss the results in terms of well performance, as well as mineral dissolution and precipitation under various scenarios. A sensitivity study is also reported to highlight the key factors to be considered in the fracturing fluid selection criteria.

3.2 Methodology

The coupling between reservoir model and geochemical interactions entails the implementation of an efficient approach where both the computational cost and precision is optimized. The following subsections illustrate the methods used.

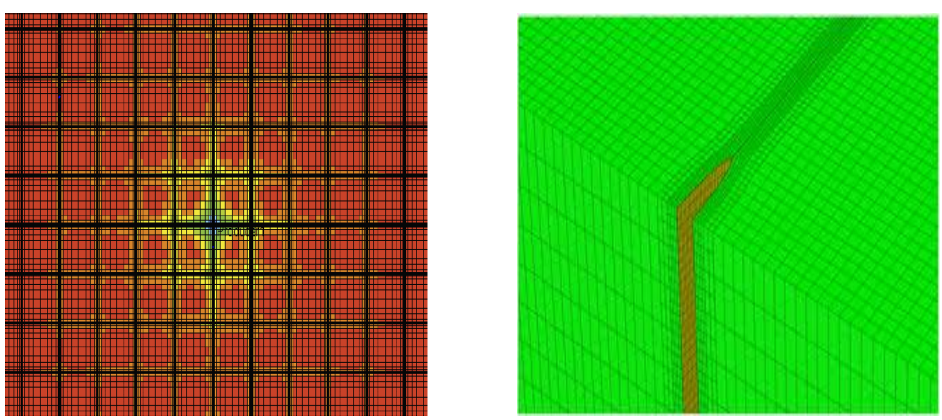
3.2.1 Reservoir Modelling

The complexity of the hydraulic fracture geometry observed in shale reservoirs makes the proper modelling of hydraulically fractured wells more challenging. Marin (2015) presented the analogy shown in **Figure** 3 between the conventional and unconventional fracturing. While the conventional planar fractures are sufficient to stimulate wells in Darcy domain, the unconventional fractures are crucial in the development of nanodarcy shale plays as illustrated in **Figure 3.3**. However, the explicit modelling of highly unstructured permeable fractures embedded in ultra-tight matrix is both computationally expensive and highly prone to numerical error. Fortunately, Cipola et al., (2010) presented an efficient approach in terms of computational cost and accuracy to account for both the conductivity enhancement and fracture complexity. This approach is based on LS-LG-DK model where the Stimulated Reservoir Volume (SRV) is modelled through a network of orthogonal primary and secondary fractures. **Figure 3.4** presents a comparison between Explicit Hydraulic Fracture (EHF) and SRV using LS-LG-DK.



(a) (b)

Figure 3. 3 Analog comparison between (a) unconventional fracturing and (b) conventional planar fracture (Martin, 2015).



(a) (b)

Figure 3. 4 Schematic illustration of the SRV using (a) LS-LG-DK and (b) EHF.

A hydraulic fracture stage is simulated using CMG-GEM-GHG module. The reservoir characteristics are presented in the **Table 3.1**. Different relative permeability sets are adopted for low and high salinity fluids as shown in **Figure 3.5**. The relative permeability data for high salinity was adopted from data reported in literature for tight reservoirs because of limited data availability for shales. The low salinity relative permeability limit was defaulted by CMG based on the cation exchange. The software interpolates relative permeability at each step depending on the estimated ion exchange and the corresponding change in water composition. The fluid leak-off and entrapment is simulated by injecting the fracturing fluid, shutting the well for one month to allow the fluids to be soaked in and starting the production. The selection of one month shut-in period was recommended by Mehana and El-Monier (2015) where both hydrocarbon and slickwater recovery are optimized.

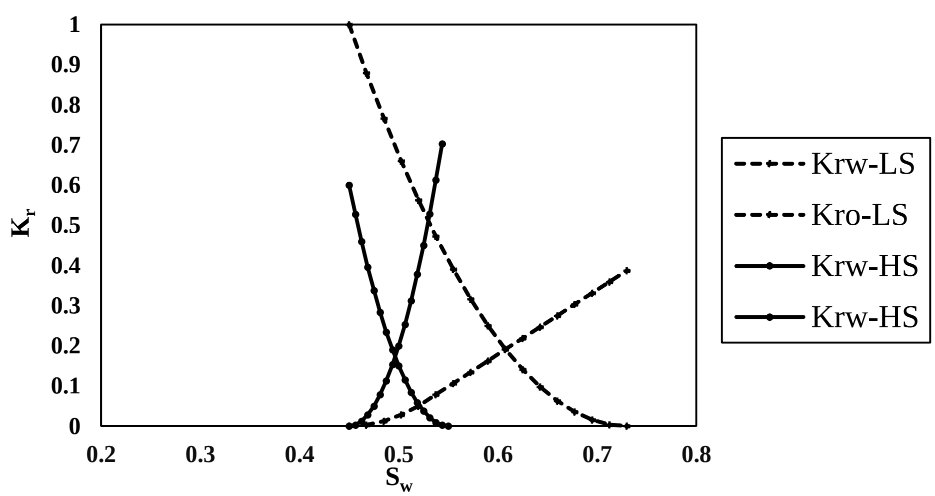


Figure 3. 5 Relative permeability sets for low and high Salinity water.

Table 3. 1 Input Parameters for Reservoir Simulation

Parameter	**Value**
Model Dimensions	420x420x100 ft.
Reservoir Pressure	5000 psi
Matrix Porosity	7%
Natural Fracture Porosity	1%
Matrix Permeability	150 nd
Fracture Conductivity	4.13 md-ft.
Reservoir Temperature	250 F
Natural Fracture Spacing	10 ft.
Shut-in time	1 month

3.2.2 Geochemical Interactions

Nghiem et al. (2004) developed a fully-coupled Geochemical EOS Compositional simulator. This simulator was developed initially to investigate the CO_2 sequestration process in a field-scale. Various modifications, extensions and additions have been incorporated to properly present the aqueous phase behaviors and geochemical modeling. Interestingly, the simulator became capable of modelling the intra-aqueous, rate-controlled and ion exchange reactions. Consequently, it was used mechanistically to model the impact of low salinity water flooding on recovery factor. In this study, the applications of this model are extend to include the impact of the trapped fracturing fluid on reservoir characteristics.

The geochemical interactions considered in this study include ion exchange, aqueous and mineral reactions. All these reactions are reversible, and are controlled by the activity of products and reactants as shown in reaction (1). However, the geochemical modelling of incompatible water in heterogeneous porous media entails various permutations to determine the least energy path.

$$n_A\, A + \; n_B B \overset{K_{react}}{\Longleftrightarrow} n_c\, c \tag{1}$$

The kinetics of mineral reactions include the chemical equilibrium constant, activation energy and specific surface area. The equilibrium constant determines the reaction speed and depends on the products and reactants activity. However, the activation energy and the surface area are characteristics of each mineral and the accurate database is still under investigation. The database used in this study is adopted from Nghiem et al. (2004) and it is presented in **Table 3.2**. Both Quartz and K-feldspar minerals are considered non-reactive minerals at reservoir conditions within the well lifetime as their reactions are very slow and require high activation energy.

The cation exchange capacity represents the total amount of exchangeable cations that can be adsorbed on the negatively charged mineral surface. Consequently, both clay minerals and organic matter are expected to have higher capacity, in this regard, compared to carbonates and quartz. While clay surface charge is controlled by the ion substitution, the organic matter charge is pH dependent. Therefore, the fracturing fluid ion composition and pH highly affect stability and structure of surface-charged minerals.

In addition, the exchange reactions might explain the impact of water salinity on wettability alterations of reservoir matrix. Consequently, the lower the water salinity is, the more water-wet the matrix becomes. With this in mind, the impact of water salinity on both the relative permeability end point and curvature could be estimated and, in turn, the interpolations between the low and high salinity relative permeability sets will be tied to the cation exchange reactions

Table 3. 2 Geochemical Modelling Database

Mineral	Area (m^2/m^3)	Activation Energy (J/mol)	Log K_{eq} ($mol/(m^2s)$) at 25 °C
Kaolinite	17600	62760	-13.18
Illite	26400	58620	-14
Calcite	88	41870	-8.79
Dolomite	88	41870	-9.22
Quartz	7128	87500	-13.9
K-Feldspar	176	67830	-12

Table 3. 3 Ion Exchange Reactions and Constants (Luo et al. 2015)

Exchange Reactions	Exchange Constant (100°C)
$Ca^{2+} + 2NaX \longleftrightarrow 2Na^{+} + CaX_2$	11.31
$Mg^{2+} + 2NaX \longleftrightarrow Na^{+} + MgX_2$	7.25
$H^{+} + NaX \longleftrightarrow Na^{+} + HX$	10

Slickwater is simply water with low concentrations of either friction reducer or linear gel (Palish at al. 2008). The detailed chemical analysis of slick water is adopted from King (2015). The salinity and ion concentration of the connate water is a formation-specific property. The chemical analysis of a Haynesville shale connate water sample and another typical connate water are listed in **Table 3.4**. Also, sea water composition is presented as it is analyses for use as a fracturing fluid.

3.2.3 Sensitivity analysis

A sensitivity analysis for the impact of slick and sea water compositions, mineral content and reservoir temperature on load and gas recovery was performed using CMOST (CMG sensitivity analyses module). The Design of Experiment (DOE) approach was used to generate sensitivity runs to explore the impact of variations in these properties to overcome the computation cost required for one-parameter-at-a-time sampling technique. The factorial design reduces the number of runs needed by allowing several factors to change simultaneously. Afterwards, the appropriate analysis of variance (ANOVA) estimates the parameter impact on the output.

The Response Surface Methodology (RSM) correlates the input parameters with the responses (output) by a proxy model where the original reservoir simulation model is replaced by a linear or quadratic form proxy model. Additionally, more tornado diagrams display the main effects and the associated interactions.

Table 3. 4 Chemical Analysis of Slick, Connate and Sea Water (Fjelde et al., 2012).

Ions	Slick water	Connate water	Sea water	Haynesville
HCO_3^-	49	354	12	-
Ca^{++}	29	19040	650	26040
$SO4^{--}$	5	350	2290	-
Mg^{++}	3	2439	1110	1460
Na^+	80	59491	10352	18400
Cl^-	30	102060	18379	71102
K^+	984	-	600	310
$CO3^{--}$	640	-	-	-
Ba^{+2}	1	-	-	-
Fe^{+2}	1	-	-	-
B^{+3}	120	-	-	-
Si^{-4}	2	-	-	-
Total	1944	183734	33393	117312

3.3 Results and Discussions

The outcome from the implementation of the methodology discussed above is presented as follows. We first show the impact that geochemical interactions have on mineral dissolution and precipitation, and, as a result, on well performance; the impact of neglecting geochemical coupling is also discussed in this section. We then investigate the impact of connate water composition followed by the impact of rock minerology on productivity. At the end, we highlight the results of the sensitivity analysis and the relative impact of various parameters.

3.3.1 Mineral Dissolution and Precipitation

The disturbance of the chemical equilibrium, by introducing slick or sea water, stimulates the geochemical reactions to regain the lost equilibrium. Interestingly, the direction of the reversible chemical equilibrium reactions is controlled by the relative availability of the reactants and the products to hold the equilibrium in single-reaction controlled systems. However, in heterogeneous systems like porous media where the chemical equilibrium is the outcome of the various mineral, aqueous and ion exchange reactions, the path to the lowest energy state will determine the direction of the reactions. Subsequently, this entails various permutations and arrangement to determine the equilibrium state path.

Surprisingly, the load and gas recovery resulting from the implementations of sea water as fracturing fluid surpasses those from slickwater. The detailed dissolution and precipitations reactions are presented in **Figure 3.6**. It is evident that a higher reaction rate is reported in the case of sea water injection. While dolomite precipitation and calcite dissolution is observed for slick water, the reverse is reported for the case of sea water. This behavior could be attributed to the availability of the “Ca^{++}” and “Mg^{++}” cations in sea water compared to slick water. Note that negligible reactions are observed in clay minerals in both cases. The reaction kinetics for carbonates, and its thermodynamic characteristics, explain the higher mineral reactivity detected for carbonates compared to clay minerals.

Load and gas recovery results for these cases are shown in **Figure 3.7**. The depressed load and gas recovery for slick water could be attributed to the relatively limited mobility compared to the sea water case. On the other hand, ignoring geochemical coupling results in overestimation of both gas and load recovery.

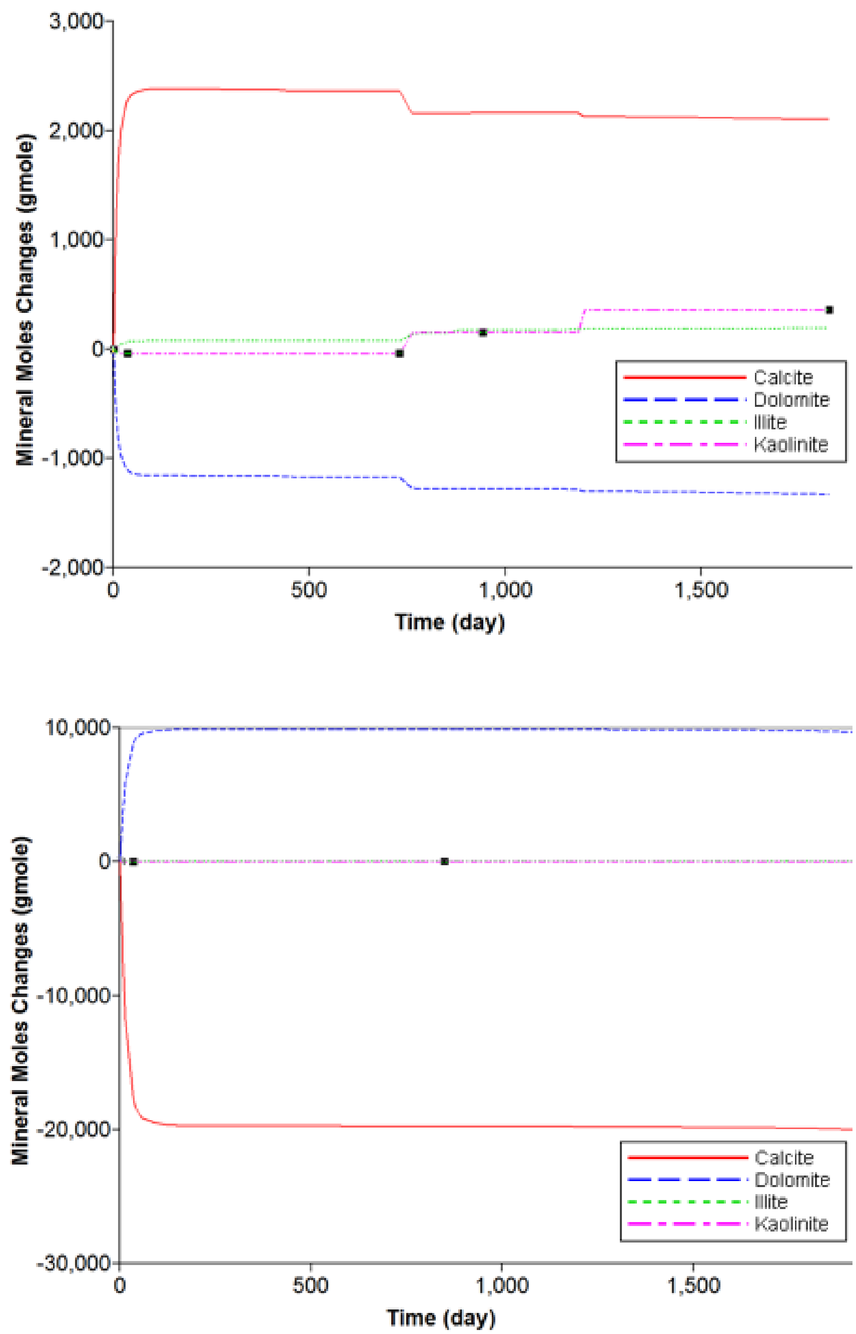
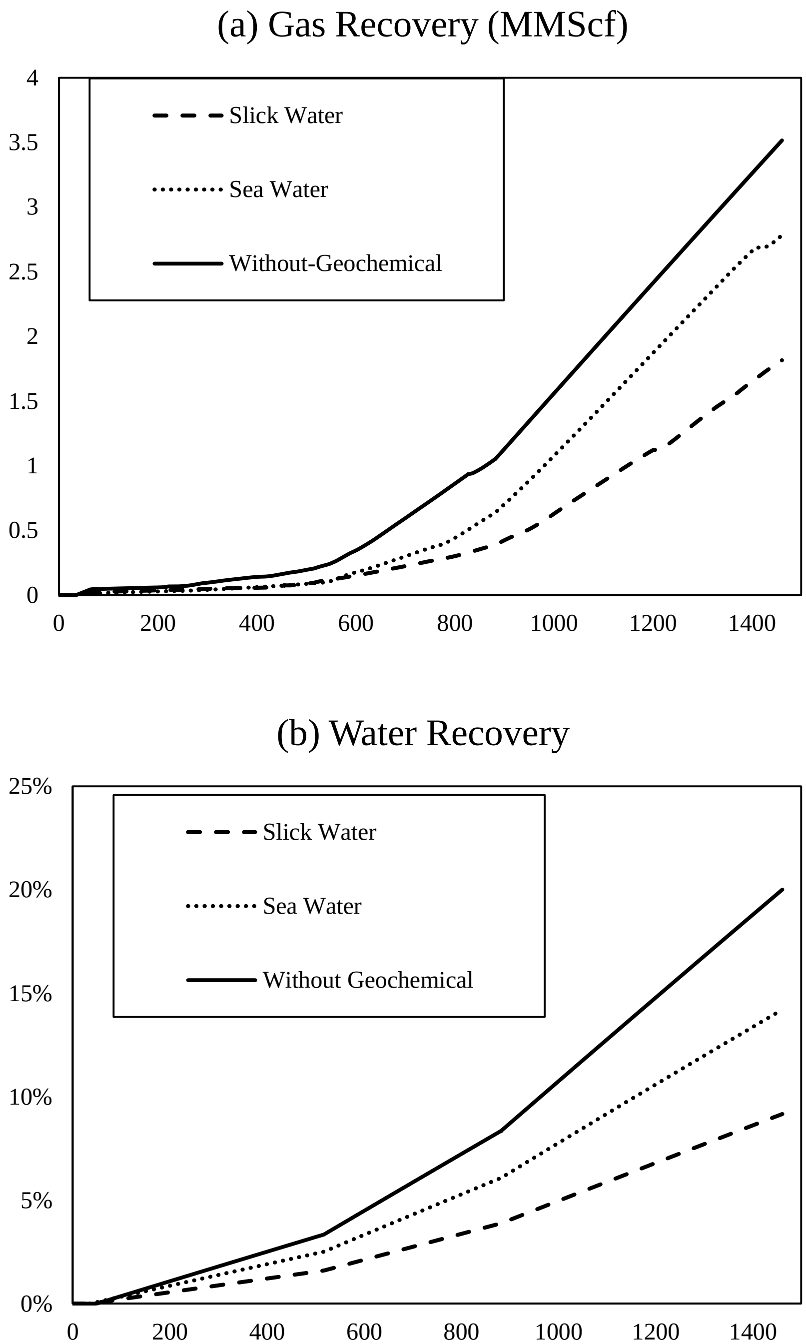


Figure 3. 6 The mineral content change (gmole): a) slick water and b) sea water



(a) Gas Recovery (MMScf)
4
3.5
3
2.5
2
1.5
1
0.5
0
0
200
400
600
800
1000
1200
1400
Slick Water
Sea Water
Without-Geochemical
(b) Water Recovery
25%
20%
15%
10%
5%
0%
0
200
400
600
800
1000
1200
1400
Slick Water
Sea Water
Without Geochemical

Figure 3. 7

3.3.2 The Impact of Connate Water Composition

The connate water salinity and composition is a formation-specific attribute where various equilibrium reactions between the rock and water change the connate water to a highly saline and dense fluid. Therefore, the longer the water resides or migrates in porous media, the more saline the water would get. The salinity of the connate water associated with hydrocarbon accumulation ranges from 20 to more than 300 g/L.

According to the simulation results presented in **Figure 3.8a**, a dramatic change is observed for the slick water case using connate water composition of Haynesville compared to the base case discussed in the previous section. While the dolomite dissolution is diminished, the Kaolinite dissolution and Illite precipitation became more tangible. Additionally, a higher cumulative gas recovery is observed for Haynesville as reported in **Figure 3.9a** for both slick and sea water cases. While the load recovery for the slick water case does not exhibit any dependence on the connate water salinity as shown in **Figure 3.9b**, more recovery is observed for the Haynesville case when sea water is used.

The mineral reactions reported in **Figure 3.8b** show similar results to what has been observed for the base case. It's worthwhile to mention that the relatively less saline connate water of Haynesville has stimulated more clay minerals reactions. While the clay content change is in orders of tens in the base case, it is in order of hundreds in Haynesville case. In addition, a slight increase is reported in both the calcite dissolution and dolomite precipitation.

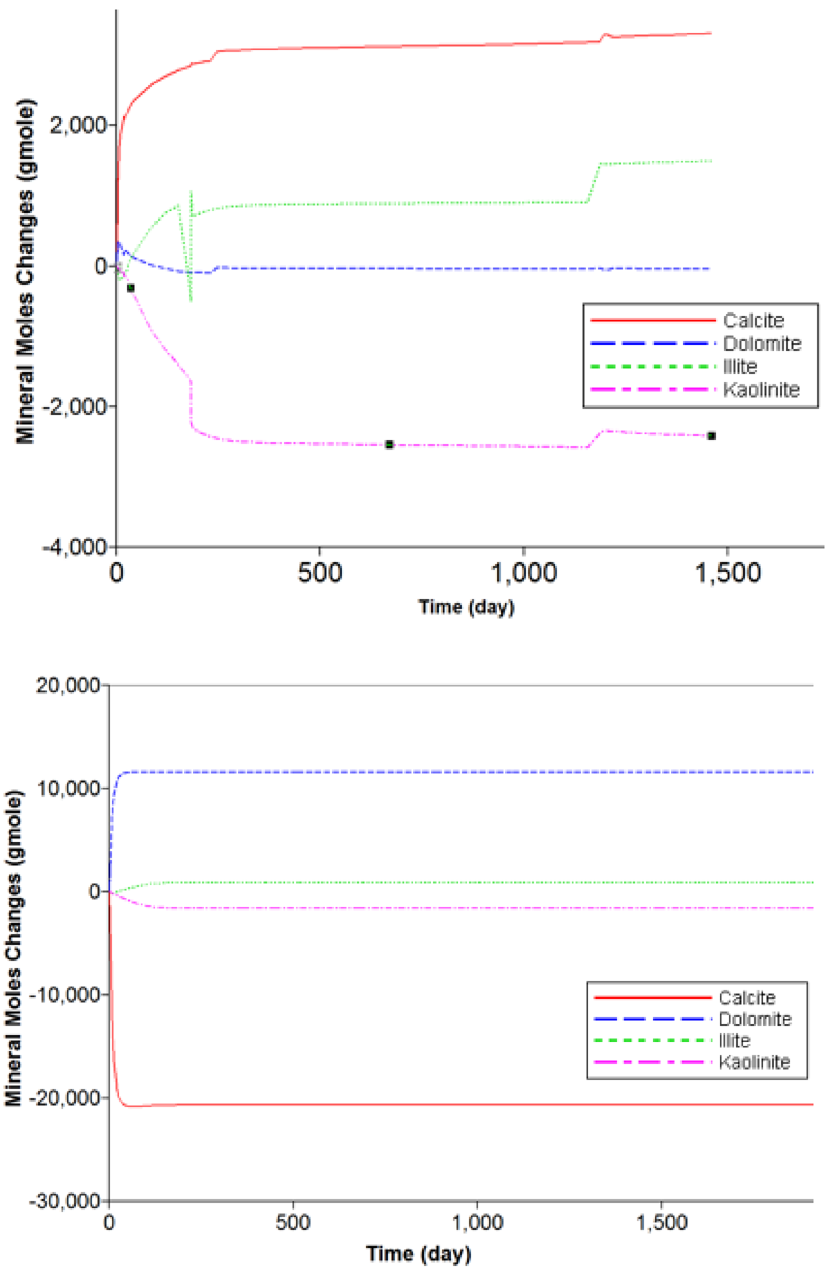


Figure 3. 8 The mineral content change (gmole) using Haynesville Connate water composition: a) slick water and b) sea water

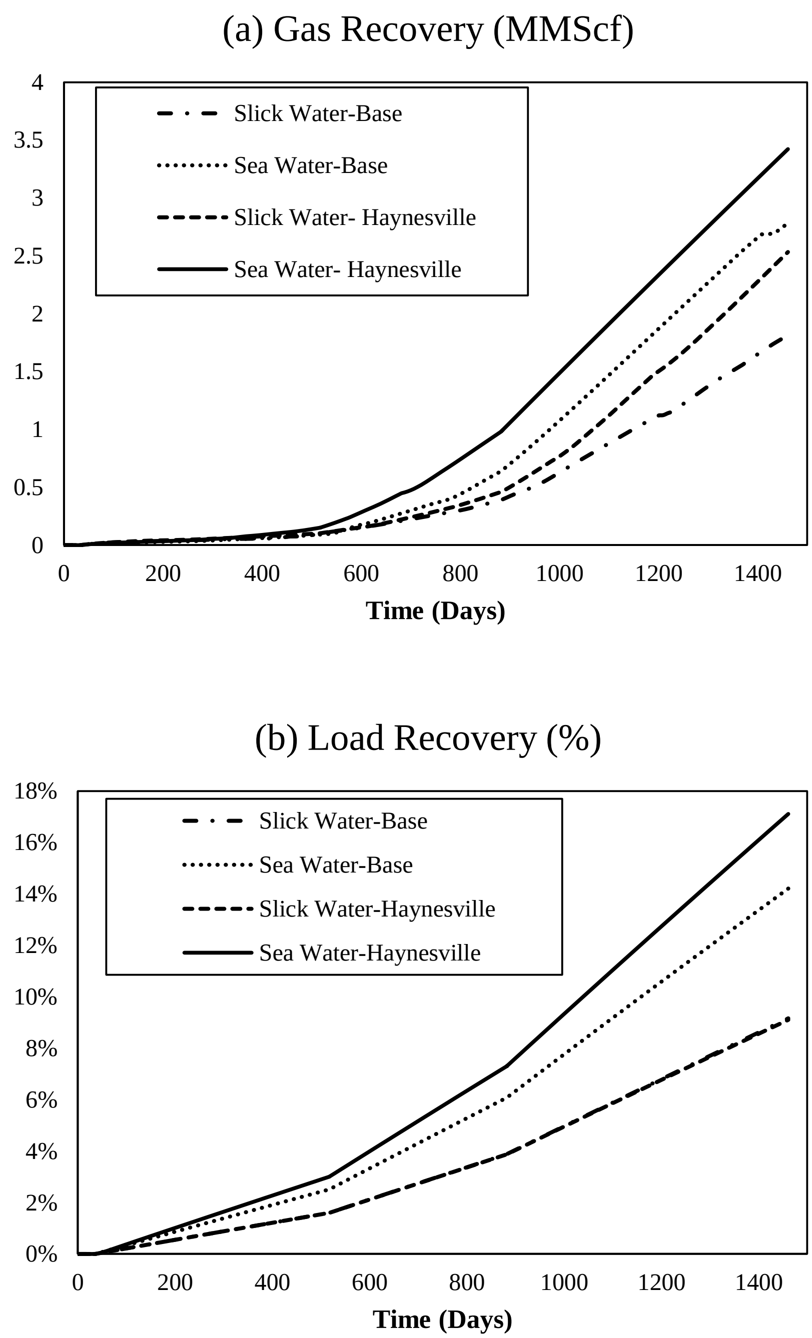


Figure 3. 9 Stimulated Well Performance using Haynesville Connate water composition: a) Gas Recovery b) Load Recovery.

The salinity contrast between the injected water and connate water is a key factor controlling the geochemical interactions and their impact on well performance. Lower salinity contrast leads to an enhanced well performance as it can be seen in the case of Haynesville, which has a low saline connate water compared to the base case. In addition, better performance was reported for sea water compared to slick water.

3.3.3 The Impact of Carbonate Minerals Types

The simulation results suggest that carbonate reactions are more pronounced than clay reactions. Therefore, in this section, we discuss extent to which the carbonate mineral type affects both geochemical reactions and well performance. The main carbonate minerals are calcite ($CaCO_3$) and Dolomite ($CaMg(CO_3)_2$). While the pervious scenarios involved equal mineral content of calcite and dolomite at 15% each, this section involves two cases; one with the calcite as the sole carbonate mineral and one with the dolomite instead.

Figure 3.10 presents the simulation results for the dolomite case. It is evident that the geochemical reactions are depressed when sea water is injected and, subsequently, better gas and load recovery are reported for this scenario in **Figure 3.12** compared to both the calcite case as well as the base case. On the other hand, comparable results to the base case are reported for slick water injection when it comes to mineral reactions as highlighted in **Figure 3.10a**.

When dolomite is taken out of the picture, calcite shows high reactivity with sea water and very minimal interactions with slick water as shown in **Figure 3.11**. In the case of slick water, this has no impact on load and gas recovery as shown in **Figure 3.12**. In the case of sea water, the lower reactivity in the dolomite case results in higher gas and load recovery compared to the calcite case. In both cases, sea water is the preferred injection fluid compared to slick water. Clearly, slick water is activating dolomite reactivity, probably due to the absence of Mg^{++} ions in the aqueous. Sea water, however, is activating the dissolution of calcite, where a tangible precipitation is observed, leading to lower recovery.

3.3.4 Sensitivity Analysis Results

The heterogeneity observed in shale composition and injected water composition demands a sensitivity analysis to estimate the relative importance of various parameters on both the load and gas recovery. This section will displays the sensitivity results for both sea and slick water as fracturing fluid for the base case.

The input parameters selected include mineral content, injected water composition and reservoir characteristics. **Table 3.5** presents the upper and lower limit of the input parameters. The total number of simulations is reduced from 2^{13} to 72 by using the DOE and the factorial design options in CMOST. According to the simulation results, a proxy model was generated to represent the actual reservoir simulation model. In addition, a tornado plot is generated to represent the relative importance of the various factors (the positive effect means positive correlation between the input parameters and the objective output and vice versa).

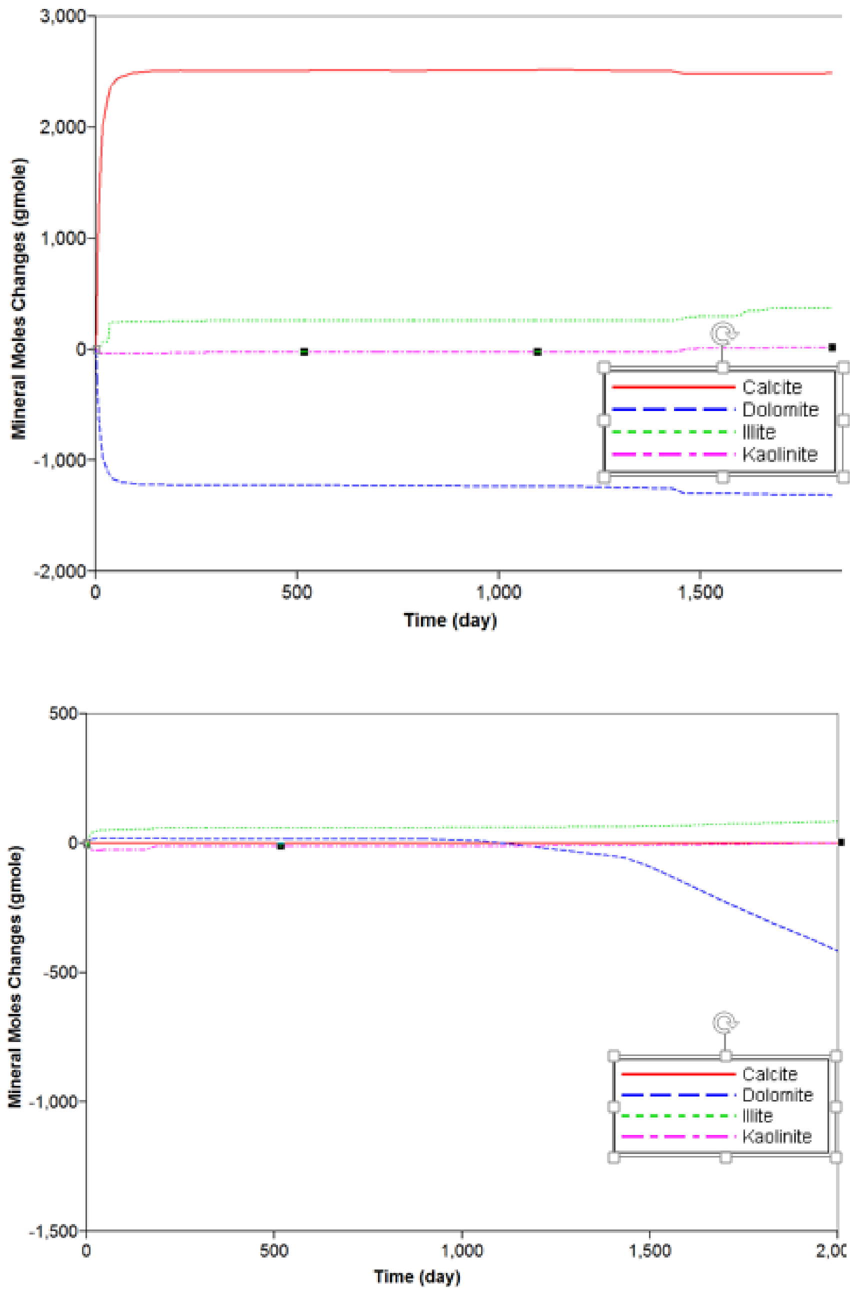
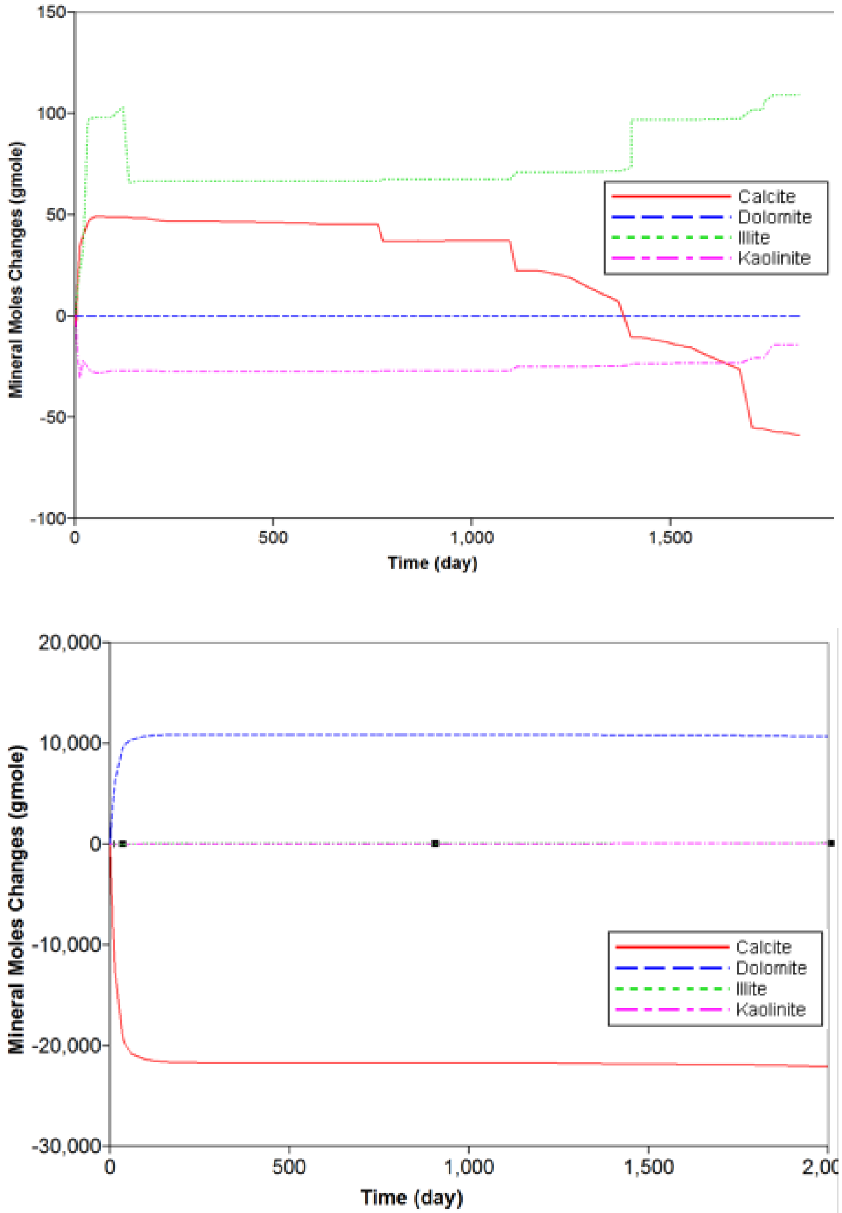


Figure 3. 10 The mineral content change (gmole) using dolomite as the sole carbonates mineral: a) slick water and b) sea water



(a) **(b)**

Figure 3. 11 The mineral content change (gmole) using calcite as the sole carbonates mineral: a) slick water and b) sea water

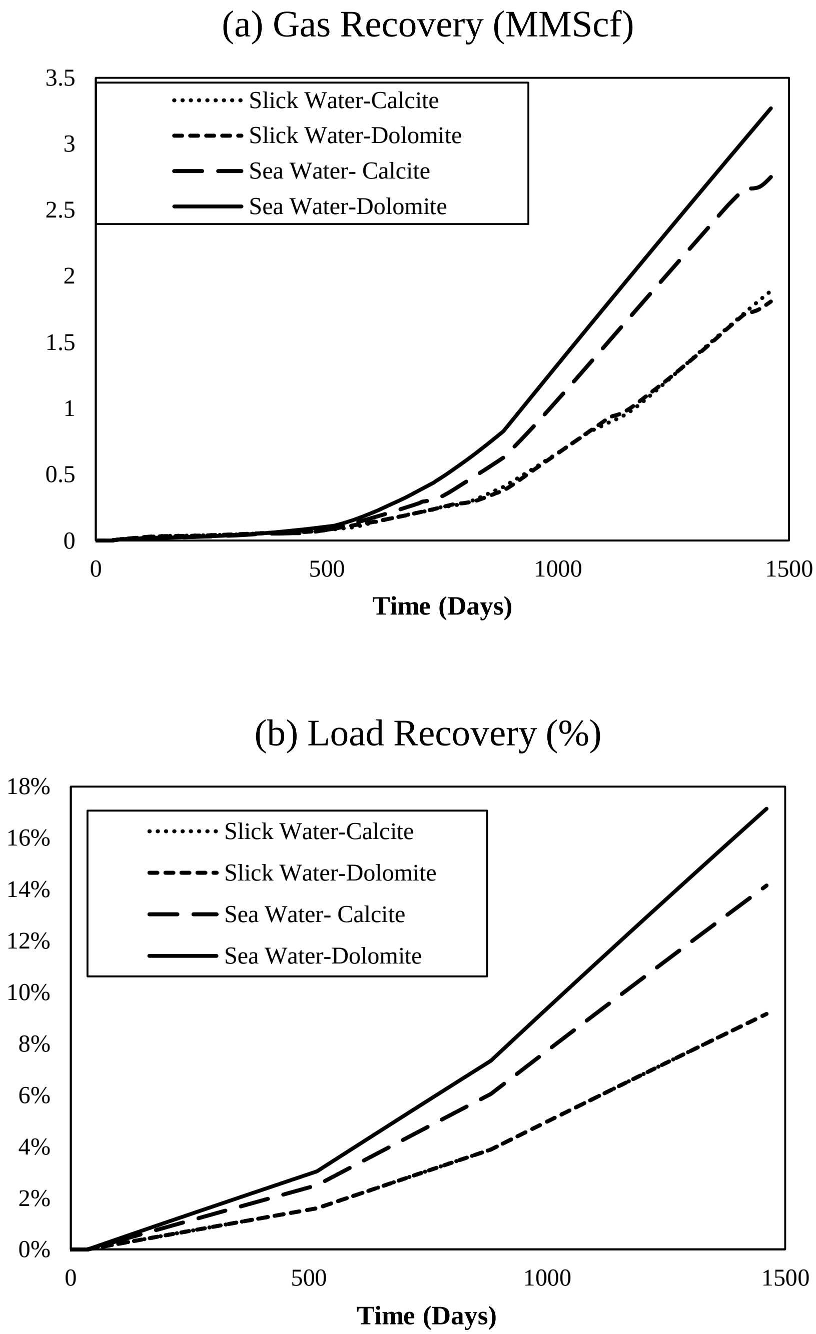


Figure 3. 12 Stimulated Well Performance with Calcite and Dolomite as the only Carbonates mineral: a) Gas Recovery b) Load Recovery

According to the sensitivity results for slick water base case shown in **Figure 3.13**, gas recovery depends mainly on the concentration of K^+ and SO_4^{-2} and illite content. Equally important, load recovery is positively correlated with reservoir temperature and K^+ concentration, and negatively correlated with SO_4^{-2} concentration and illite content. On the other hand, the sea water base case results presented in **Figure 3.14** suggest a positive correlation between both gas and load recovery and the concentration of SO_4^{-2} and Na^+. Surprisingly, the increase in reservoir temperature has shown to positively affect water recovery and negatively affect gas recovery in the case of sea water injection.

Table 3. 5 The upper and lower limit for the sensitivity analysis input parameters

Parameter	Slick Water			Sea Water		
	Base	Lower limit	Upper limit	Base	Lower limit	Upper limit
Ca^{+2} (Mole/L)	0.000724	0.000543	0.000904	0.000299	0.000225	0.000374
Cl^- (Mole/L)	0.000846	0.000635	0.001058	0.5184	0.3888	0.648
H^+ (Mole/L)	9.9216*E-7	7.44E-07	1.24E-06	9.92E-11	7.44E-11	1.24E-10
HCO_3^- (Mole/L)	0.01638	0.01229	0.0205	0.01065	0.007989	0.01332
K^+ (Mole/L)	0.02517	0.01888	0.03146	0.04566	0.03425	0.05708
Mg^{+2} (Mole/L)	0.000123	9.26E-05	0.000154	0.4567	0.3377	0.5629
Na^+ (Mole/L)	0.00348	0.002609	0.004349	0.02384	0.01788	0.0298
SO_4^{-2} (Mole/L)	5.21E-05	3.90E-05	6.51E-05	0.011534	1.15E-02	1.92E-02
T (F)	250	187.5	312.5	250	187.5	312.5
Calcite	0.15	0.1125	0.1875	0.15	0.1125	0.1875
Dolomite	0.15	0.1125	0.1875	0.15	0.1125	0.1875
Illite	0.15	0.1125	0.1875	0.15	0.1125	0.1875
Kaolinite	0.15	0.1125	0.1875	0.15	0.1125	0.1875

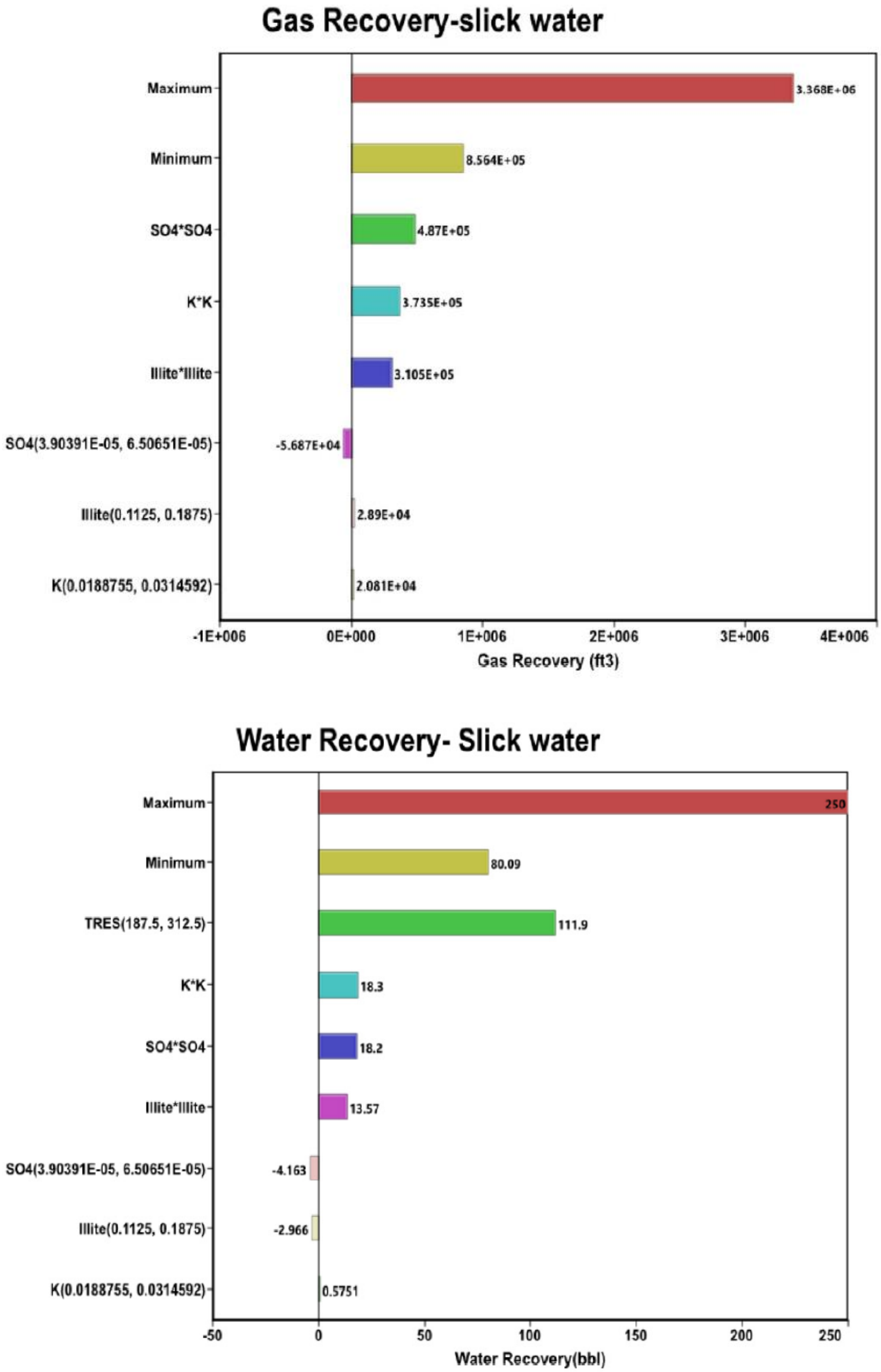
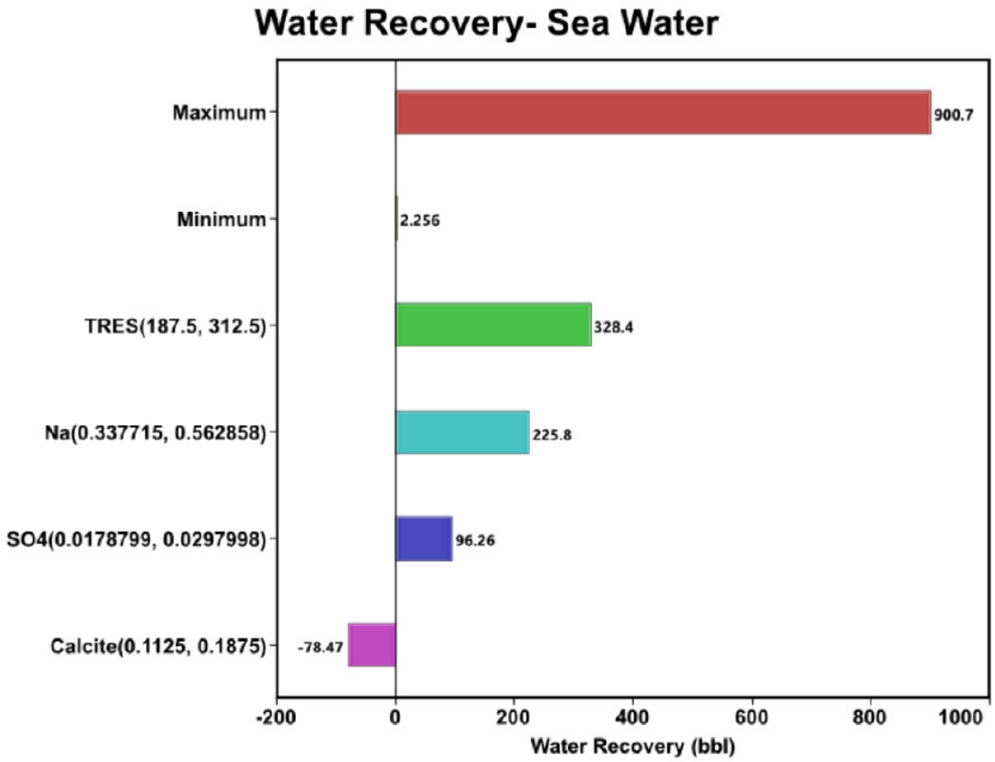


Figure 3. 13 The effect estimates of the main parameters for slick water as fracturing fluid



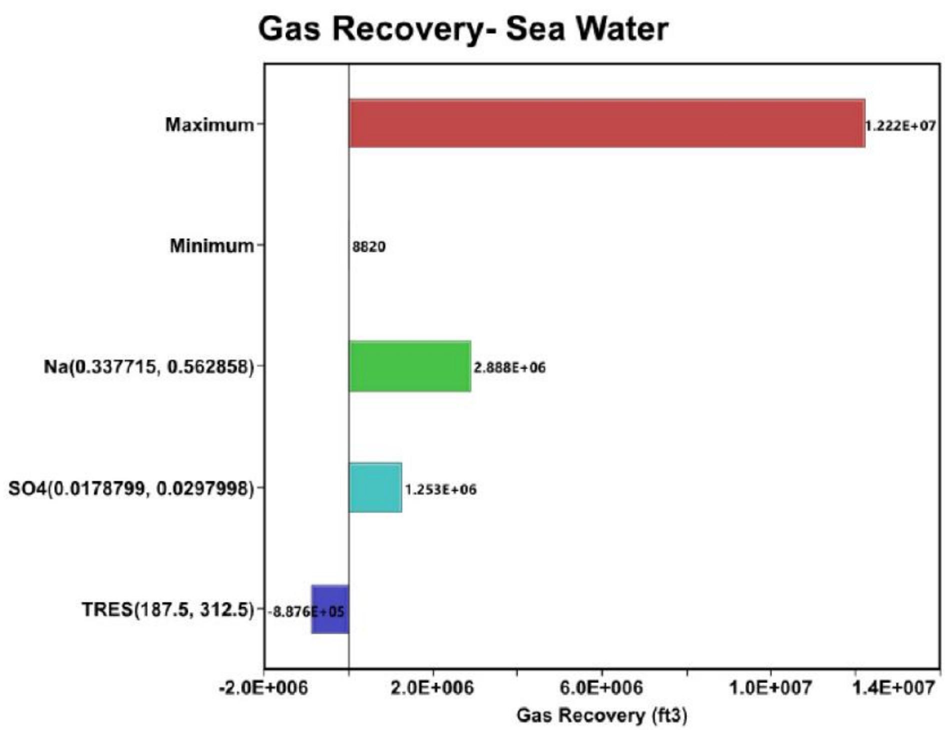


Figure 3. 14 **the effect estimates of the main parameters for Sea water as a fracturing fluid**

3.4 Conclusions

The findings presented in this paper support the following conclusions:

- Neglecting geochemical coupling results in overestimation of both load and gas recovery.
- Sea water, as a fracturing fluid, consistently results in higher load and gas recovery compared to slick water. In fact, the salinity contrast between the injected fluid and the formation brine correlates negatively with well performance.
- Clay mineral interactions are minimal in most cases studied compared to carbonate mineral interactions. The highest amount of clay interactions are observed in the case of slick water injection into the lower-salinity-connate-water case of Haynesville.
- Sea water encourages calcite dissolution while slick water interaction with dolomite is evident.
- Sensitivity analysis suggests that the concentration of SO_4, K and Na ions in the fracturing fluid, and illite and calcite mineral content of the rock, along with the reservoir temperature are the main key factors affecting well performance.

Chapter 4: Experimental study of the Slick Water Imbibition in Shale: The Impact of Water Salinity and Rock Mineralogy.

4.1 Introduction

The dynamics of slick water was the focus of many studies that tried to reveal the key factors controlling the performance and the entrapment of these fluids. **Figure** 4.1 reports the water use in Hydraulic Fracturing operations in the main shale plays in the United States. While 21-24 million liters of water are used to complete a well in Woodford shale, less than 3 million per well are needed for the Permian basin.

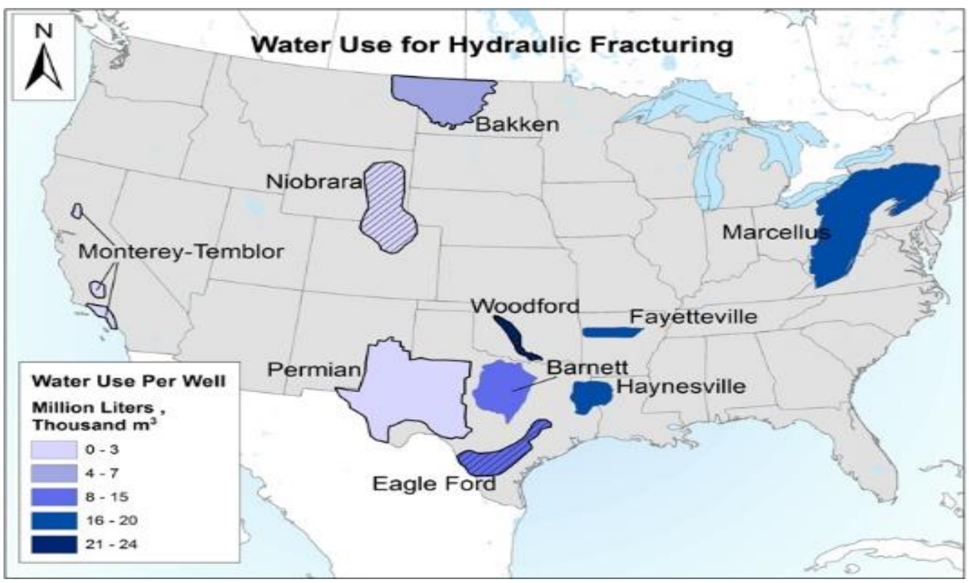


Figure 4. 1 The amount of water required to frac a well in different shale formations in US (Kondash and Vengosh, 2015)

This massive amounts of fracturing fluids raise a lot of questions about the environmental footprints of both the trapped fluids and the high-salinity water flowing back. Besides, the role the trapped fluids play in influencing well performance, formation strength and reservoir characteristics needs further experimental investigations. Therefore, this chapter focuses on developing an experimental workflow to study the impact of fluid salinity into the spontaneous imbibition on two shale formations, Woodford and Caney. Besides, a comprehensive study of the impact of water salinity on oil recovery and formation strength is reported.

4.2 Methodology

4.2.1 Rocks

Outcrops from Woodford and Caney formations were collected. Six groups, namely K, D, T, E, W and C, with mineralogy were prepared. The mineralogy of the samples was measured using the FTIR technique and presented in **Table 4.1** and the detailed mineralogy in **Table 4.2**. While the Woodford samples turned to be Dolomite rich, the Caney samples were Quartz and clay rich. **Figure 4.2** presents the ternary diagram of the samples mineralogy. The dimensions of the cubic samples are presented in **Table 4.3** along with the dimensions of the cylindrical samples in **Table 4.4.**

Table 4. 1 the mineralogy of the samples used

	Carbonates	Quartz and Feldspar	Clays
K	21	56	23
D	58	23	19
T	51	30	19
E	51	26	23
W	3.343	58.243	37.37
C	57.84	24.755	17.405

Table 4. 2 FTIR detailed Mineralogy for the samples used

	Calcite	Dolomite	Anhydrite	Siderite	Aragonite	Quartz	Orthoclase Feldspar	Oglioclase Feldspar	Albite	Illite	Kaolinite	Chlorite	Mixed Clays
K	0	3	4	9	3	55	1	0	0	22	1	0	0
D	3	47	2	6	0	14	5	0	4	11	0	0	8
T	4	38	3	6	0	16	8	6	0	8	1	2	8
E	1	41	2	6	1	15	5	2	3	9	2	1	11
W	0	0	1	3	0	43	15	0	0	31	1	0	5
C	4	47	1	5	0	19	6	0	0	0	0	0	17

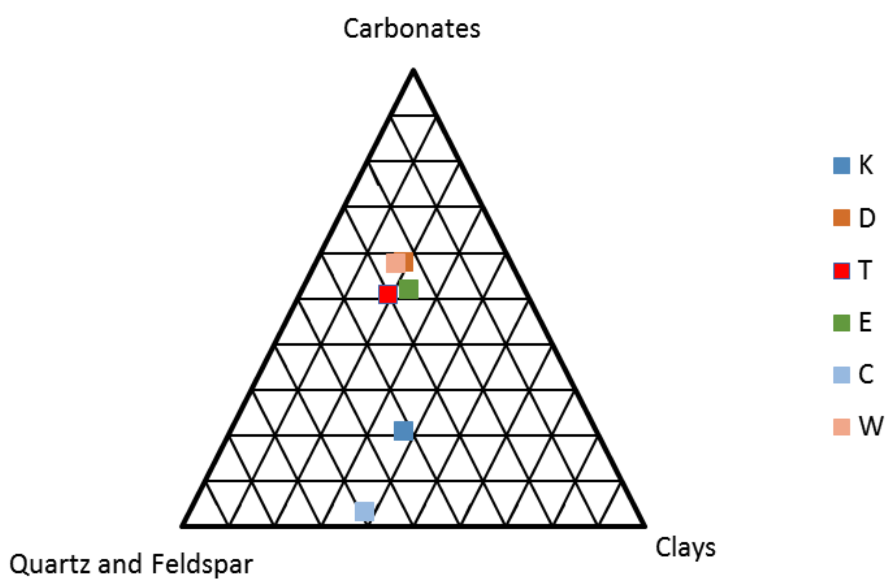


Figure 4. 2 **Ternary Diagram for the mineralogy of the samples used**

Table 4. 3 Dimensions of the Cubic samples

	Sample ID	L	W	H
K	4	26.1	25.17333	25.19667
	1	24.69333	24.62667	25.39333

Table 4. 4 Dimensions of the cylindrical samples

	Sample ID	D (mm)	L (mm)
D	0	44.95	25.4
	1	44.96	25.4
	2	45.17333	25.4
	3	45.16	25.4
	4	42.66333	25.4
T	2	38.03	25.4
	3	37.86333	25.4
E	0	41.05333	25.4
	1	41.45	25.4
	2	41.56667	25.4
	3	41.44333	25.4
	4	40.74	25.4
	5	41.31333	25.4

4.2.2 Fluids

Slick water samples were prepared with different salinities. Solutions with KCl concentrations of 0, 5 and 10 % weight were prepared. 2-Acrylamido-2-methylpropane sulfonic acid was used in 0.1% concentration as a friction reducer. The density of the fluids are reported in **Figure 4.3.**

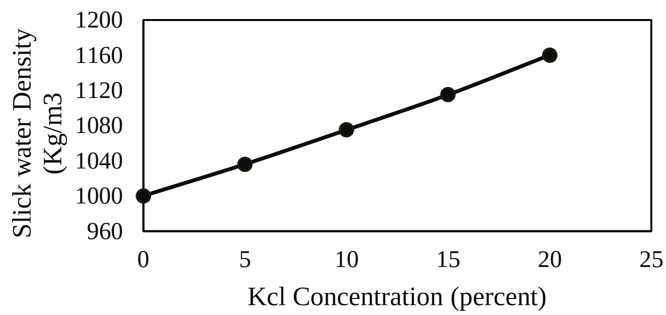


Figure 4. 3 The slickwater density relation with the Kcl Concentration added

4.2.3 Equipment

4.2.3.1 Imbibition setup

The imbibition of the slick water was mentored by recording the weight gain of the samples immersed in the fluid. The weight gain was recorded by connecting the scale to the PC for data acquisition shown in **Figure** 4.4

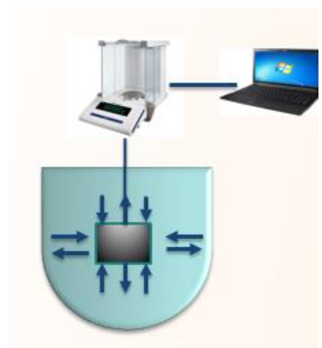


Figure 4. 4 the spontaneous imbibition setup

4.2.3.2 Surface tension measurements

The surface tension between slick water and air and interfacial tension between oil and slick water are measured by the One Attention Theta device from shown in **Figure** 4.5

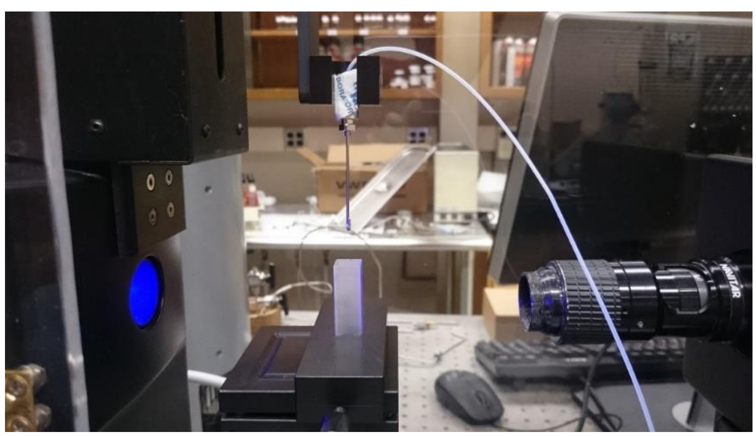


Figure 4. 5 **theta device for interfacial tension measurement (manual)**

4.2.3.3 Amott Cell

The Amott cell was used to mentor oil recovery from the decane-saturated samples immersed on water with different KCl Concentrations as shown in **Figure** 4.6. Samples from Woodford and Caney formation were placed on the amott cell where the spontaneous imbibition of water displaced oil out of the core. Being less dense than the water, the displaced decane accumulates at the top of where a graduated tube is used to measure the displaced volume. However, timely photos were taken and analyzed using ImageJ software for better accuracy.

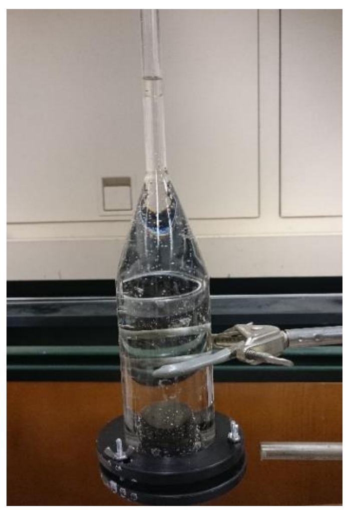


Figure 4. 6 Amott cell for Oil recovery

4.2.3.4 Saturation Cell

A saturation cell was built to saturate the samples used in the amott cell as shown in **Figure** 4.7. A Vacuum pump was connected to a cold trap to protect the pump from liquid flow. Then, the cold trap was connected to an accumulator containing the dried samples. From the other end, the accumulator was connected to an Isco pump. After drying the samples for one day in the oven at a Temperature 80 °C. The samples were placed in the accumulator where vacuum was applied for 24 hours. Decane was then injected using the Isco pump and the samples were kept under a pressure of 200 psi for one week.

Figure 4. 7 Saturation Cell

4.2.3.5 Contact angles

The contact angles were measured as indication of wettability conditions of the system. The images was processed by imageJ software as shown in **Figure** 4.8. Polished surfaces from Woodford and Caney formation were used where the water/ air and water /decane contact angles were measured at ambient conditions. A constant volume syringe was used to avoid the dependence of contact angle on drop size.

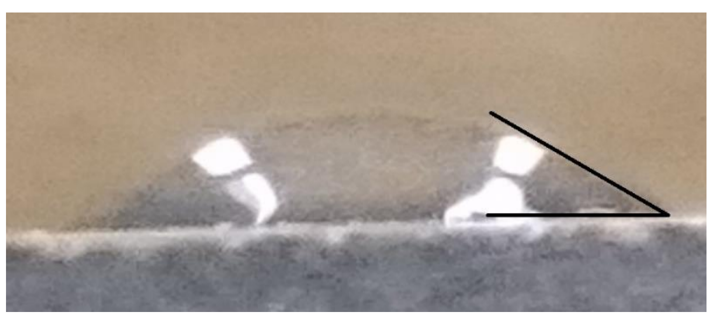


Figure 4. 8 contact angle measurement with image J software

4.3 Results and Discussion

4.3.1 Interfacial tension

Interfacial tension is one of the key factors influencing capillary suction potential. The results presented in **Figure** 4.9 were obtained by analyzing the pendent drop shape. It is evident that the water-decane interfacial tension has a higher dependency on the KCl concentration compared to the surface tension between water and air. While a decrease of 3 dyne/cm was observed in the water-air surface tension for an increase in KCl concentration from 0 to 15%, five folds that decrease is reported for the case of water-decane interfacial tension.

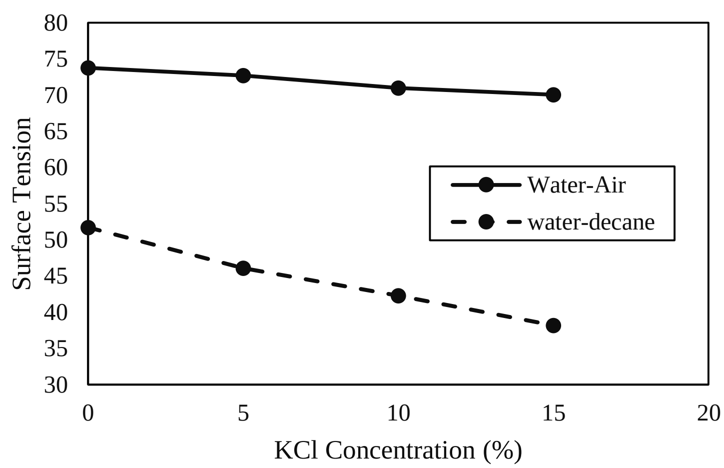


Figure 4. 9 **Surface and Interfacial tension as a function of the KCl Concentration**

4.3.2 Contact angles

The relation between contact angle and water salinity is one of the active research areas. Seyma and Firoozabadi, (2013) reported non-monotonic behavior for the contact angle between oil and water on quartz and mica surfaces with the salt molarity in the aqueous phase. However, monotonic trends are reported for both Woodford and Caney samples. Here, this attributed to the wide range of molarity explored by Aslan et al. (2016). Therefore, comparing the results in the salinity range explored, similar trends are observed for Woodford samples. However, opposite behavior is reported for Caney samples. This is attributed to the clay content of the Caney samples. The impact of clay content on the contact angles is a part of the future work of this study. The direct relationship between the salt concentration and contact angles in Caney samples explains the better performance reported for low salinity water. Bearing in mind, the negative relationship between the contact angles and capillary pressure.

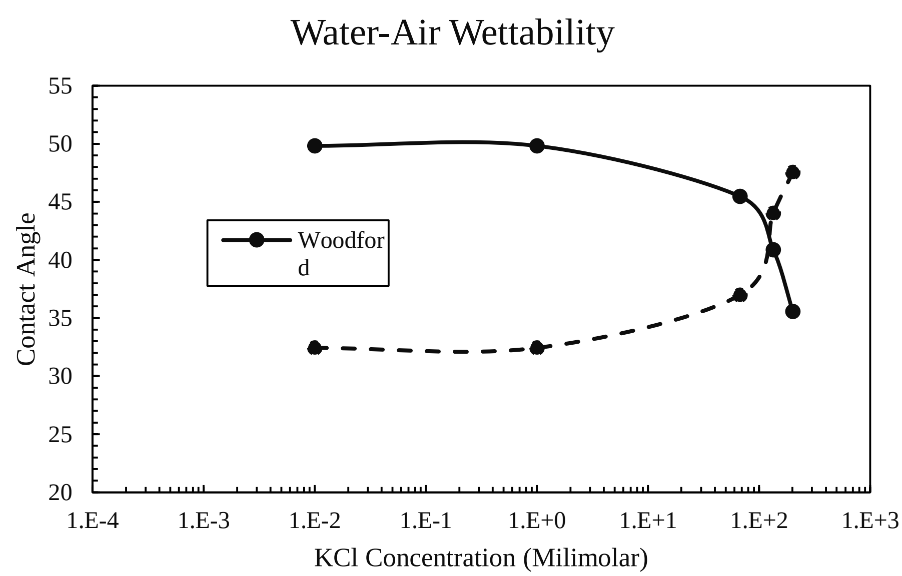


Figure 4. 10 water-Air Contact angle measurements versus KCl Concentration(molar)

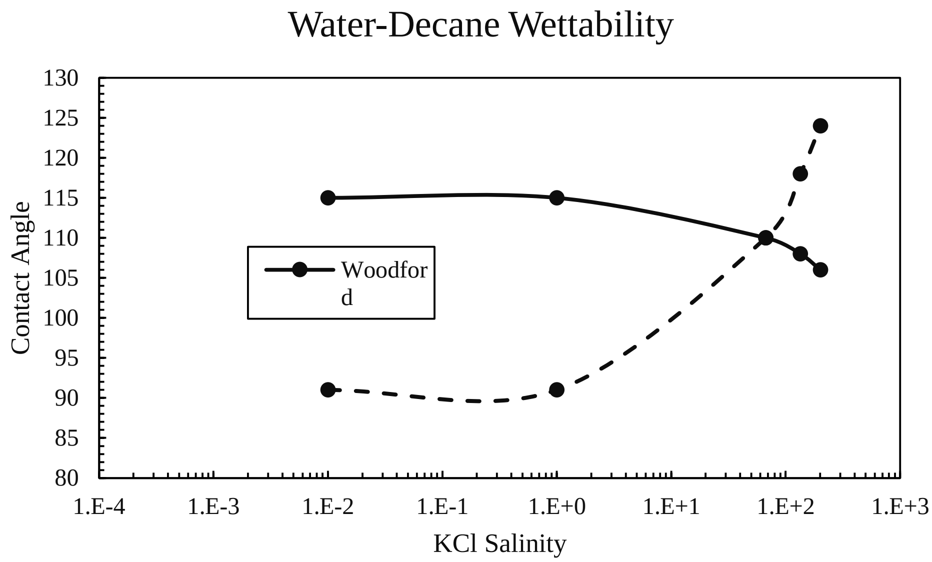


Figure 4. 11 Water-Decane Contact angles versus KCl Concentration (molar)

4.3.3 Compressive strength

The compressive strength of the formation is one of the key factors affecting the prolonged productivity of the well. The introduction of slick water to the formation would stimulate different interactions affecting the formation strength. The impact of slick water salinity is reported in **Figure** 4.12. While no significant change is observed in the Woodford samples, Caney samples exhibit notable increase in the compressive strength with KCl concentration. The monotonic increase in compressive strength in Caney samples is attributed to the ability of KCl to suppress clay swelling which is the main cause of formation softening. The non-monotonic behavior observed in Woodford samples is attributed to heterogeneous rock-fluid interactions.

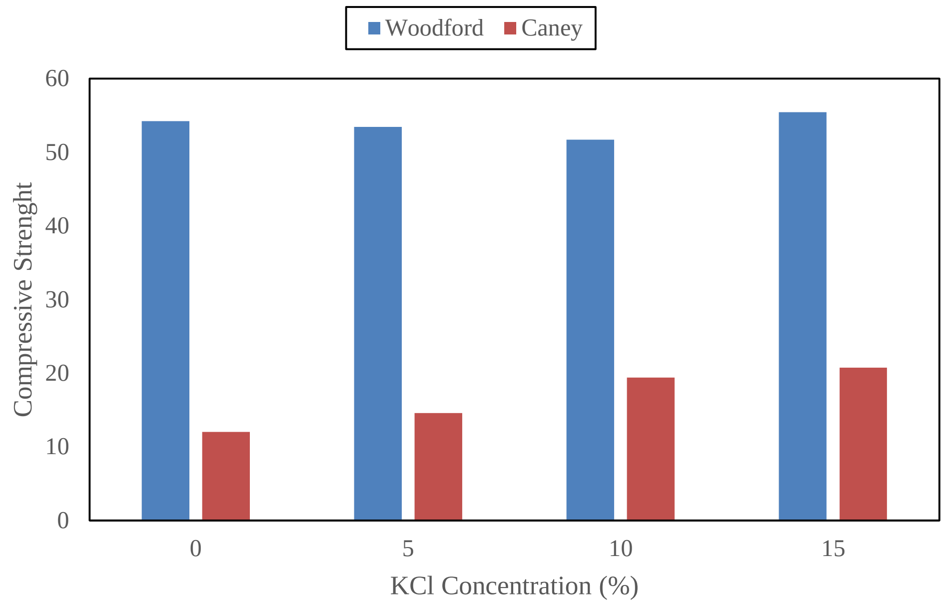


Figure 4. 12 Compressive strength of the Caney samples versus KCl concentration

4.3.4 Oil recovery

Inconsistent results are reported in the literature about the impact of the water salinity on the displacement and the recovery of hydrocarbons. There is still active debate about the microscopic impact of water salinity on mineral wettability and about the formation mineralogy and wettability. The findings from this study are reported in **Figure** 4.13. Surprisingly, opposite trends are observed for the two formations. While an increase in imbibition is observed for low salinity water in Caney formation, a reduction in imbibition occurs Woodford samples. This behavior is also attributed to the clay content of Caney samples where low-salinity water stimulates more clay interactions.

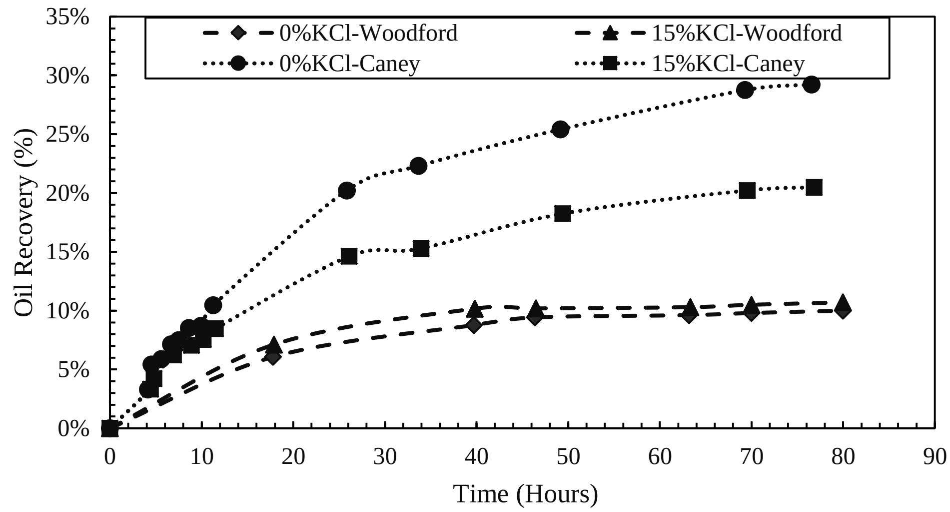


Figure 4. 13 Oil recovery versus time for Woodford and Caney samples.

4.3.5 Water –Air Imbibition

Several sets of counter-current imbibition tests were performed on air-saturated samples. The results spectrum for cubic and cylindrical samples are reported in **Figure** 4.14 and 4.15. A clear correlation was observed between the illite content of the samples and the impact of salinity on imbibed volume; the increase in illite content resulted in a larger contrast between the imbibition results for various salinity conditions. Surprisingly, this led to a reversal of trends between the Woodford and Caney samples as presented in **Figure** 4.15. This is also explained in terms of capillary pressure derived from the wettability and imbibition measurements. A higher imbibition rate correlates with a higher capillary pressure value as observed in **Figure** 4.16.

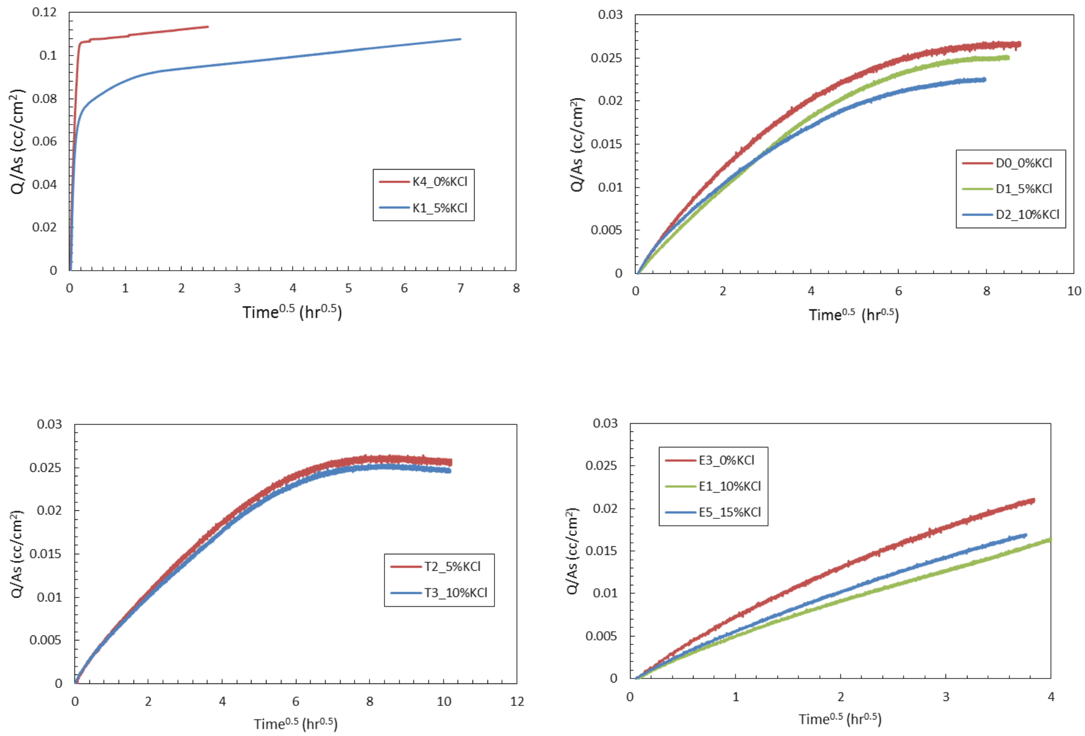


Figure 4. 14 Slickwater-air imbibition of K, D, T, E samples: volume imbibed per surface area versus square root of time.

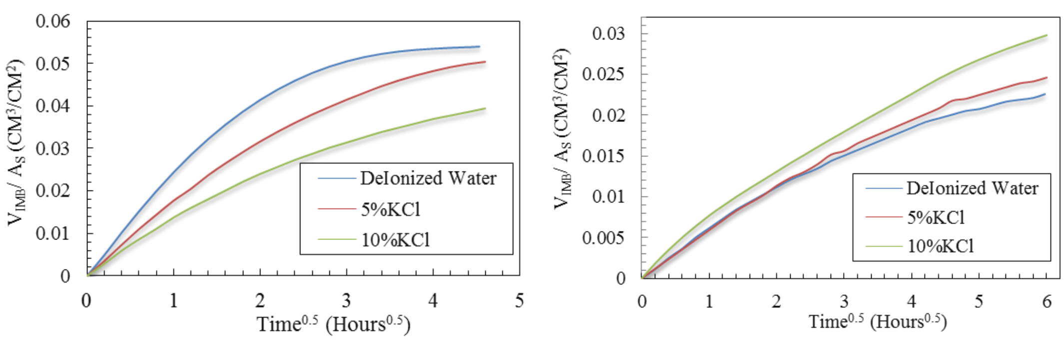


Figure 4. 15 **Slickwater -Air Imbibition for Cubic Samples: Caney (left) and Woodford (right)**

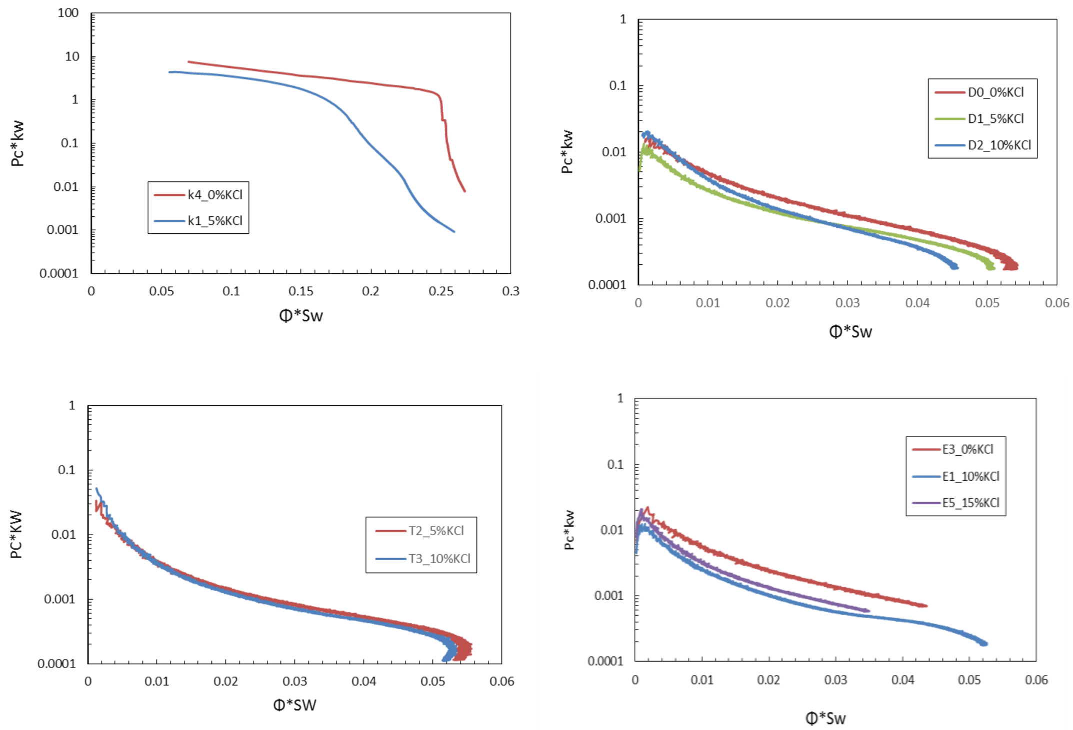


Figure 4. 16 Samples sauction potential: Capillary pressure multiplied by sample permeability versus water volume imbibed

4.4. Conclusion

An extensive experimental study was presented to investigate the impact of water salinity on shale formations' imbibition and strength characteristics. The following conclusions could be drawn:

- Non-monotonic and opposite behaviors are reported for the impact of the water salinity on shale formation wettability. Positive relationship between the contact angle and the KCl concentration is observed for Caney and a negative one for Woodford.

- Tangible increase in the compressive strength of Caney formation was reported with the increase in KCl concentration. However, a non-monotonic trend was observed for Woodford samples
- Better performance was observed for low salinity water in the case of Caney samples and the opposite for Woodford samples in terms of oil recovery
- The spontaneous imbibition could be a quantitative technique to quantify the capillary suction characteristics of the formation
- The illite content of the samples turned out to be the key factor controlling spontaneous imbibition of the samples and revealing the different behaviors observed

Chapter 5: Conclusion

The work presented in this study aims to provide a better understanding of the fate of the fracturing fluids and the role it plays in the well performance. The following conclusions could be drawn

- The incorporation of the chemical osmosis in the modelling of the fracturing fluid dynamics and well performance is inevitable.
- The additional pressure resulted from the salinity contrast between the fracturing fluid and the formation brine is one of the parameters neglected in commercial reservoir simulator while it might account for the fate of the fracturing fluid.
- Sea water, as a fracturing fluid, consistently results in higher load and gas recovery compared to slick water. In fact, the salinity contrast between the injected fluid and the formation brine correlates negatively with well performance.
- Sea water encourages calcite dissolution while slick water interaction with dolomite is evident.
- Non-monotonic and opposite behaviors are reported for the impact of the water salinity on the shale formation wettability. Positive relationship between the contact angle and the KCl concentration is observed for Caney negative one for Woodford.
- Tangible increase in the compressive strength of Caney formation was reported with KCl concentration increase. However, the non-monotonic trend was observed for Woodford samples

- Better performance was observed for low salinity water in case of Caney samples and the opposite for Woodford samples in terms of oil recovery
- The illite content of the samples turned to be the key factor controlling spontaneous imbibition of the samples and revealing the different behaviors observed

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