Model Investigation of Low Salinity Brine Injection on Gas-Condensate Recovery in a Sandstone Reservoir: Effect of Calcium and Sodium Ions

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Abstract:- There are many technical challenges associated with the recovery of valuable condensates from gas-condensate reservoirs. While some condensates are immobile far from the production well, others can accumulate close to the producer wellbore area. As a result, such valuable condensates are either not produced or, in some cases, their accumulation might choke the production well, lowering gas productivity. Maintaining reservoir pressure has long been a means of dealing with this problem. This, however, only functions as a temporary solution because the drop-out and immobile condensate production continues unabated. In this study, the effect of injecting brine into a gas-condensate reservoir at various concentrations was examined using a numerical simulation approach. It was found that changing two cations (Ca^{2+} and Na^+) concentrations could improve gas-condensate recovery at an injection rate of 490.8 m³/d (3000 bbl/d). According to this simulation research, the optimised range of sodium ion concentration fell between 0.013 and 0.026 mol/L, with 0.013 mol/L (300 ppm) being the optimum value. Additionally, the low salinity brine injection should have a Ca^{2+} content greater than 0.0029 mol/L (116 ppm). It was also observed that changes in salinity had a negligible influence on gas recovery. Thus, if recovering lost condensate is of priority, then this recovery strategy is highly recommendable.

Keywords:- Condensate Banking; Low Salinity Water Injection; Ion Exchange; Condensate Recovery, Reservoir Geochemistry.

I. INTRODUCTION

The decline of a gas-condensate reservoir pressure below dew-point pressure results in the drop-out of valuable heavy-ends of a produced gas, called condensates, throughout the reservoir (Fan *et al*., 2005). The drop-out of these valuable components occur in reservoir zones both near and farther from the producer well (Fan *et al*., 2005). Below the critical condensate saturation, condensate formed in areas farther from the producer well remains immobile due to capillary forces acting on the fluid (Fan *et al*., 2005; Rahimzadeh *et al*., 2016). Hence, these fluids are trapped in the pores or pore throats of the reservoir rocks until the condensate saturation build-up can overcome the

gas-condensate reservoir's critical condensate (oil) saturation. Therefore, the condensate formed in most part of the reservoir is lost to production unless a depletion strategy is implemented (Fan *et al*., 2005). This phenomenon happens to even rich gas-condensate reservoirs with substantial liquid dropout.

However, near the producer well, the situation is different. Once the bottomhole pressure falls below the dew-point pressure, a near wellbore pressure sink forms (Fig. 1). As gas is drawn into the pressure sink, liquid condensate drops out (Amani and Nguyen, 2015). After a brief transient period, enough condensate accumulates that its mobility becomes significant. When this happens, the gas and the mobile condensate compete for flow paths. This often ends up reducing flow rate, gas, and condensate production, or even choking the reservoir (Fan *et al*., 2005). The decreased gas mobility due to the condensate accumulation around the producer well is termed condensate blockage or condensate banking.
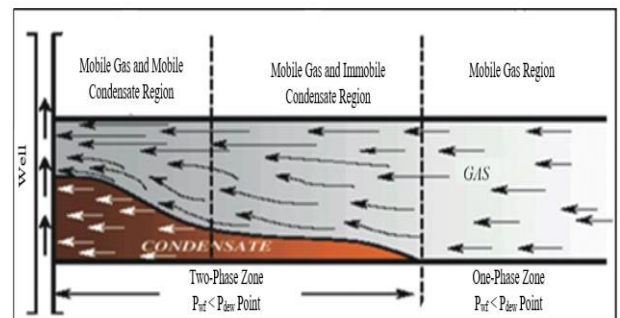

Fig. 1: Near Wellbore Condensate Formation
(Amani and Nguyen, 2015)

Over the years, large productivity losses in gas-condensate reservoirs have been documented due to this phenomenon. The Arun field, a high-volume gas-condensate reservoir in Indonesia, saw a 50% loss in productivity due to condensate drop-out (Afidick *et al*., 1994). This phenomenon also resulted in a poor primary recovery of 10% at the Cal Canal field in California (Amani and Nguyen, 2015). The Cupiagua field in Columbia, the Karachaganak field in Kazakhstan, and the North field in Qatar are all huge gas-condensate reservoirs that have suffered from this phenomenon (Sayed and Al-Muntasheri, 2016).

Some of the conventional methods that have been proposed to increase gas-condensate production include gas cycling, methanol treatment, waterflooding, gas injection, and hydraulic fracturing (Hassan *et al*., 2019). However, because the critical condensate (oil) saturation is left unchanged and the condensate banking continues to form as production moves forward, most of them serve as temporary measures with little lasting impact (Amani and Nguyen, 2015; Hassan *et al*., 2019). The modification of a reservoir's wettability with brine can significantly affect the critical oil saturation of oil reservoirs (Webb *et al*., 2003; McGuire *et al*., 2005). As a result, it is expected that brine salinity, especially low brine salinity, can aid in condensate recovery by reducing the critical condensate saturation and enabling the previously immobile condensate to become mobile.

II. RESOURCES AND METHODS USED

This section illustrates the main steps taken to obtain the fluid and rock properties to conduct the simulation studies. These included condensate fluid modelling, compositional reservoir modelling, and reservoir geochemical modelling.

A. Condensate Fluid Modelling
To create the gas-condensate fluid model, fluid compositions given by Kenyon (1987) was used to build an Equation of State (EOS) model using Peng Robinson (PR). The PR EOS model was then tuned against experimental data of Constant Composition Expansion (CCE), Constant Volume Depletion (CVD), and reservoir saturation pressure (P_{sat}). Fig. 2 shows the typical phase envelope obtained.
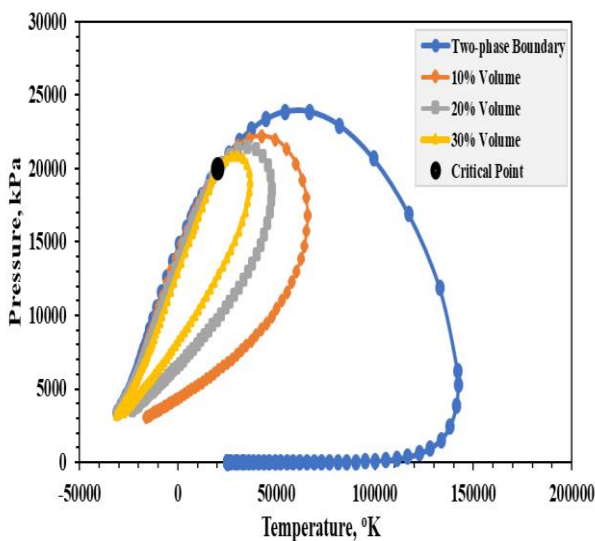

Fig. 2: Two-Phase Envelope for Fluid Model

As shown in Figs. 3 and 4, an improvement is achieved to match the experimental CCE and CVD data by modifying the critical pressure, critical temperature, omega parameters, and interaction coefficient of the heavier components during the regression procedure. Figs. 3 and 4 respectively show comparisons between the experimental and actual parameter values for the fluid with regards to the liquid volume from the CVD data and the relative oil volume from the CCE data. The comparison, which had an R squared value of 0.98, clearly shows that the simulated fluid behaves in a way that is compatible with the fluid in the actual reservoir.
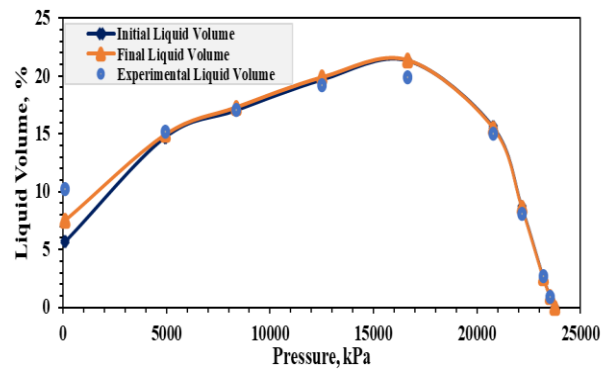

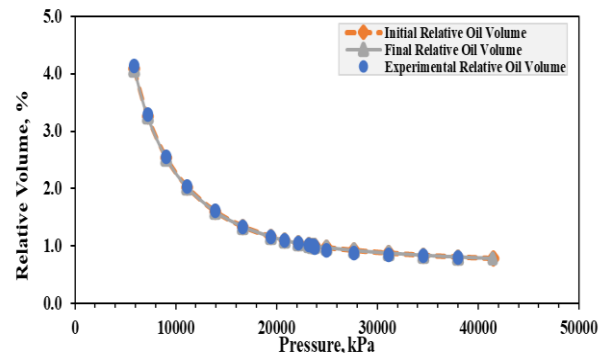Fig. 3: Liquid Volume Match for CVD Data

Fig. 4: Relative Oil Volume Match for CCE Data

B. Compositional Reservoir Modelling
To undertake the analysis, a cartesian compositional reservoir grid model was built. A total of nine (9) grid blocks were used in the I and J-directions and 4 grid blocks in the K-direction. The injector well was constrained by an injection flow rate of 490.8 m³/d (3,000 stb/d) and the producer well constrained by a surface gas rate of 175,565 m³/d (6,200,000 ft³/d) with a minimum Bottom Hole Pressure (BHP) of 3,447.38 kPa (500 psi).

a) Input Data
Table 1 presents the reservoir properties and laboratory relative permeability end-point data used to construct the reservoir model. Also, the plot of the resultant relative permeability versus water saturation used for this study is illustrated in Fig. 5. This shows the relative permeability curves for high brine salinity (set #1) and low brine salinity (set #2).

Parameter	Value
Reference pressure, kPa	24476
Reference depth, m	2286
Water-Gas phase contact depth, m	2286
Permeability, Layer 1, mD	13
Permeability, Layer 2, mD	40
Permeability, Layer 3, mD	20
Permeability, Layer 4, mD	150
Grid Thickness, m	15
Porosity, %	13
Initial Water Saturation, %	24
Top of Reservoir Sand, m	2286
Swcon	0.16
Soirw	0.3
Sorg	0.124
Sgcon	0
krocw	0.8
krgcl	0.556

Table 1: Reservoir Properties and Relative Permeability
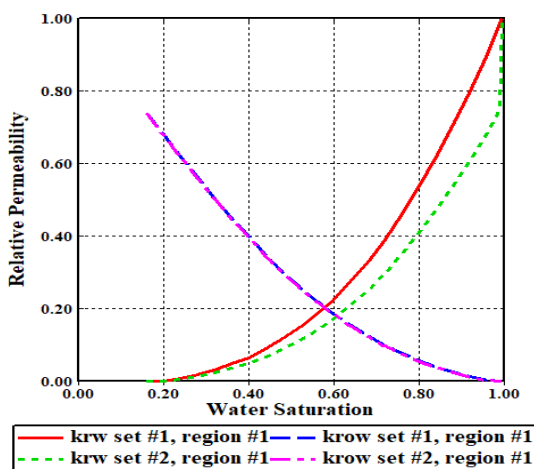End-Point Data (Kenyon, 1987; Ali, 2014)

Fig. 5: Relative Permeability Curves

b) Brine Water Analysis

The laboratory analysis of the formation water, sea water, and low saline brine used in this study are presented in Table 2.

	Formation Water (FW) (mol/l)	Sea Water (SW) (mol/l)	Low Salinity Brine (LSB) (mol/l)
Na^+	1.32622	0.45011	0.01326
Ca^{2+}	0.14794	0.01299	0.00148
Mg^{2+}	0.01746	0.04451	0.00018
Cl^-	1.67773	0.52513	0.01661
SO_4^{2-}	0.00089	0.02401	0.00001
K^+	0.00562	0.01006	0.00006
HCO^{3-}	0.000118	0.00000	0.00000

Table 2: Composition of Salt (Fjelde *et al*., 2012)

c) Boundary and Initial Conditions

Bottom hole pressure (BHP) and well flow rates were specified as input restrictions for the boundary conditions. To perform interpolation for salinity values between predetermined limits, the initial brine composition and measured relative permeability for the brine injections were defined and used.

d) Wettability Alteration Modelling

By altering the relative permeability curves in Fig. 5, the impact of wettability alteration could be predicted. One set of the relative permeability curves (set #1) was made to represent the high saline brine injection, and the other set (set #2) was made to represent the low saline brine injection. In this work, the interpolant for the two relative permeability curves was the ion equivalent fraction of Ca^{2+}. The usage of equivalent fraction of Ca^{2+} as an interpolant has been reported to provide a good match with experimental data (Dang *et al*., 2013). This helped to mimic the change in wettability expected. Since the interpolant, Ca^{2+}, signified the amount of Ca^{2+} that had been absorbed on the clay mineral surface, its release would have an impact on how the clay mineral's wettability changed. It was conditioned that high brine salinity relative permeability curve was to be used if the equivalent fraction of the interpolant (Ca^{2+}) was less than or equal to 0.19, else a low brine salinity curve was to be used if the equivalent fraction of the interpolant was larger than or equal to 0.4. An interpolation was applied between the two curves for values in the range of 0.19 and 0.4.

III. RESULTS AND DISCUSSION

The research focused on the possibility of injected brine salinity leading to higher condensate recovery. The results and discussions are presented in four main sections: (1) gas-condensate reservoir modelling and validation, (2) effect of injected water salinity changes on gas-condensate recovery, (3) effect of sodium, and calcium ions concentration on gas-condensate recovery, and (4) effect of the concentration changes on the reservoir geochemistry.

A. Reservoir Modelling and Validation

The reference case simulation was a primary depletion run for 7,305 days (20 years) and Table 3 shows the recovery results obtained. Similar observation was made by Ali (2014) in his study.

Parameter	Value
Gas Recovery Factor (%)	86.95
Condensate (Oil) Recovery Factor (%)	32.24
Field Production Time (Years)	20

Table 3: Reference Case Recovery

For validation purpose, the production data obtained was therefore compared to that of Ali (2014) and the result presented in Fig. 6. A good match was observed between the two data with an R squared value of 0.98.
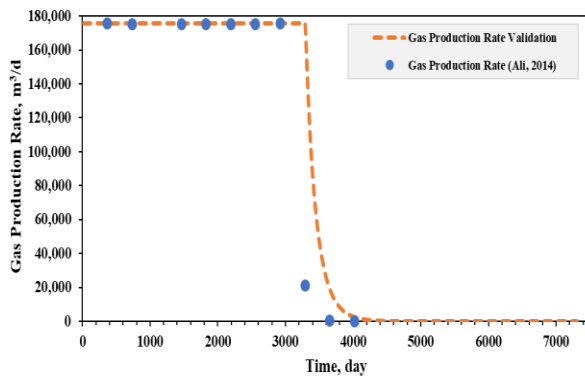

Fig. 6: Reference Case Gas Rate Validation

B. Effect of Injected Water Salinity on Condensate Recovery

Using the salinity analysis already presented in Table 3, an initial brine injection was carried out. Table 4 displays the results of the initial brine analysis. The injection of low salinity brine was expected to increase condensate recovery through pressure maintenance and wettability modification. Switching from freshwater to seawater injection and low-saline brine injection, only resulted in an increase in the recovery factor by about 4.2 % and 3.2 %, respectively. Table 4 makes it clear that the pressure maintenance was mostly responsible for the increase in recovery, with the anticipated change in wettability having little to no impact. Since the difference in condensate recovery between the water injection (scenario 2) and the low salinity brine injection (scenario 4) was only a 3.3% increment. Between the low saline brine and sea water injection scenarios, the cumulative condensate recovery difference was just 2.23%.

	Scenario	Total Salinity (mol/L)	Recovery Factor (%)		Cumulative Recovery		Cumulative Water Injected (m³*10³)	Water Injection Rate (m³/d)
			Condensate	Gas	Condensate (m³*10³)	Gas (m³*10⁶)		
1	Reference Case	0	32.2	86.95	170.4	15.2	0	0
2	Water Injection	0	70.1	98.72	420.4	17.6	3484.2	490.8
3	Sea Water (SW) Injection	1.1	73.2	98.84	450.4	19.5	3484.2	490.8
4	Low Salinity Brine (LSW) Injection	0.03	72.5	98.81	440.1	19.5	3484.2	490.8

Table 4: Initial Salinity Analysis

This finding seems to support the notion that gas-condensate recovery is unaffected by low saline brine injection, especially at that concentration as observed in the work of Zheng (2012). The determination of the various salt component concentrations, in accordance with Dang *et al*., (2015), is one of the controllable parameters that can influence the design of a low salinity waterflood scenario. The condensate recovery may therefore be improved by changing the concentrations of principally Ca^{2+} and Na^+ in the low salinity water design. Therefore, utilizing the findings from the low saline brine injection (scenario 4 in Table 4) as the base case, additional analysis was done for this work to determine the impact of the specific salt components on the condensate recovery.

C. Effect of Injected Brine Sodium and Calcium Ion Concentrations on Condensate Recovery

a) Effect of Sodium Ion (Na^+) Concentration on Recovery
   Table 5 and Fig. 7 show the effect of Na^+ concentrations in the injected brine on gas-condensate recovery. Reducing the Na^+ concentration below the initial concentration of 0.013 mol/L (300 ppm) led to a reduction of the condensate recovery factor (from 72.46% to 72.45%). As the Na^+ concentration was increased from 0.013 to 0.026 mol/L, the recovery factor increased to 72.46%. However, when the concentration was increased beyond 0.026 mol/L, the condensate recovery started reducing. This reduction continued until it stabilised at a concentration of 0.25 mol/L (5747 ppm). This could be because increasing Na^+ concentration in the injected water prevents the desorption of Na^+ from the reservoir rock surface (Katende and Sagala, 2019). Without any desorption, there is no replacement by divalent ions and hence, no added recovery rather a reduction in recovery. The gas recovery was however, not affected when the Na^+ concentration was reduced beyond the 0.013 mol/L. When the concentration increased beyond 0.0714 mol/L the gas recovery started reducing from the initial 98.81% recovery. From the study it can be concluded that, to enhance condensate recovery, the sodium ion concentration should be within 0.013 and 0.026 mol/L with the optimum concentration being at 0.013 mol/L (300 ppm).

| Scenario | Concentration | | Recovery Factor (%) | | Cumulative Recovery | |
	(mol/L)	(ppm)	Condensate	Gas	Condensate (m^3*10^3)	Gas (m^3*10^{12})
1	0.00018	4	72.45	98.81	440.8	6868.7
2	0.00044	10	72.45	98.81	440.8	6868.7
3	0.0022	50	72.45	98.81	440.8	6868.8
4	0.013	300	72.46	98.81	440.9	6868.8
5	0.02	460	72.46	98.81	440.9	6868.8
6	0.026	600	72.46	98.81	440.9	6868.8
7	0.04	920	72.44	98.81	440.7	6868.8
8	0.0714	1609	72.39	98.81	440.4	6868.8
9	0.12	2759	72.14	98.80	438.9	6867.9
10	0.15	3448	71.94	98.79	437.7	6867.2
11	0.19	4368	71.76	98.78	436.6	6866.5
12	0.25	5747	71.66	98.77	436.0	6866.3

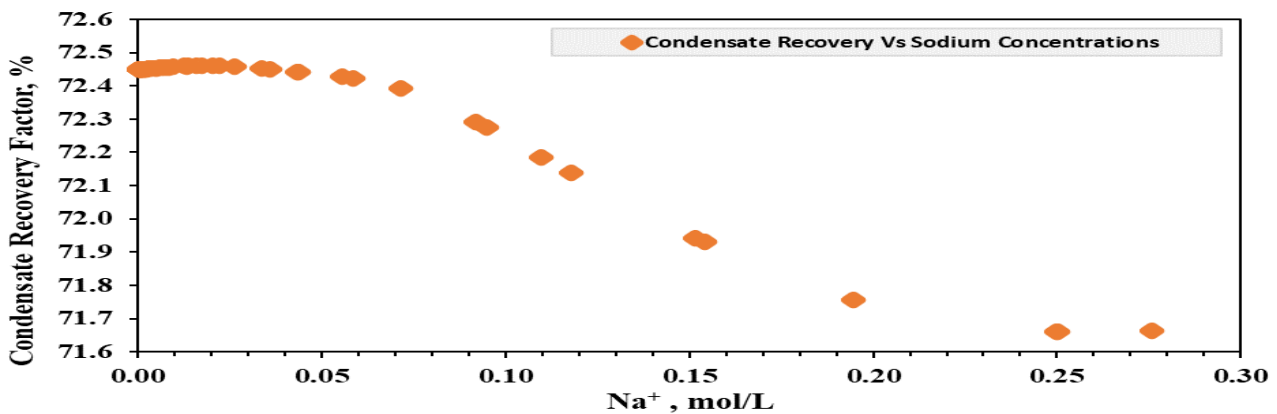Table 5: Impact of Sodium Ion Changes on Recovery

Fig. 7: Impact of Na^+ Concentrations on Condensate Recovery Factor

b) Effect of Calcium Ion (Ca2+) Concentration on Condensate Recovery

The impact of calcium ion concentrations on gas-condensate recovery is presented in Table 6 and Fig. 8. Both condensate and gas recovery were unaffected by lowering the calcium ion concentration below the baseline concentration of 0.0029 mol/L. However, a gradual increase in condensate recovery was seen when the concentration increased to 0.0068 mol/L. The condensate recovery factor increased from 72.47% to 86.7%, representing a 16.4% increment, when the Ca^{2+} concentration was increased from 0.0068 to 20.98 mol/L. The Ca^{2+} concentration increment however, had little impact on gas recovery. Increasing the concentration beyond 0.037 mol/L saw a gradual increment in the gas recovery from 98.81% to 99.26%. Unlike the changes in Na^+ concentration, Ca^{2+} concentration increment has been shown to enhance gas-condensate recovery.

| Scenario | Concentration | | Recovery Factor (%) | | Cumulative Recovery | |
	(mol/L)	(ppm)	Condensate	Gas	Condensate (m^3*10^3)	Gas (m^3*10^{12})
1	0.0000998	4	72.46	98.81	440.9	6868.7
2	0.00025	10	72.46	98.81	440.9	6868.7
3	0.00126	50	72.46	98.81	440.9	6868.7
4	0.0029	116	72.46	98.81	440.9	6868.7
5	0.0068	273	72.47	98.81	440.9	6868.7
6	0.037	1483	72.69	98.81	442.3	6868.7
7	0.086	3447	72.84	98.82	443.2	6869.6
8	0.467	18717	73.57	98.85	447.6	6871.3
9	1.089	43647	74.61	98.98	453.9	6873.8
10	3.869	155069	78.23	98.99	476.0	6881.7
11	9.009	360720	82.21	99.13	500.2	6890.8
12	20.98	840000	86.68	99.26	572.4	6900.2

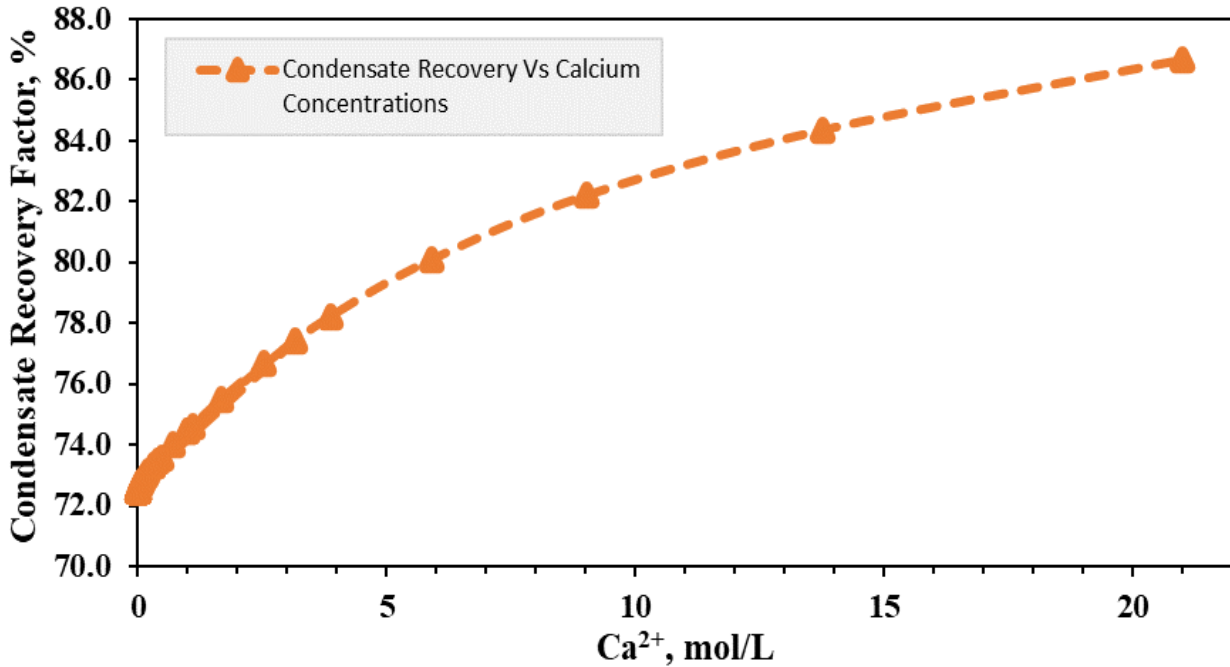Table 6: Impact of Calcium Ions on Recovery

Fig. 8: Impact of Ca²⁺ Concentration on Condensate Recovery Factor

c) Impact of Brine Injection on Condensate Saturation
Changes in calcium ion concentration was observed to have influence on condensate saturation. Fig. 9 shows the impact of Ca^{2+} at selected concentrations. As the Ca^{2+} concentration increased from 0.0075 to 12.5 mol/L (300 ppm to 500 Kppm) at a constant injection rate of 490.8 m^3/d (3 Mstb/day), it was discovered that the average condensate saturation also reduced from 0.046 to 0.019 (representing about 58.7% reduction). This reduction in average condensate saturation at the constant injection rate could be due to reduction of the critical condensate saturation. This was because the addition of extra Ca^{2+} disrupted the already stable ionic equilibrium at the rock-water-condensate interface, lowering the critical condensate saturation (Sheng, 2014). This assertion is backed by low salinity brine studies by Sheng (2014); Dang *et al*. (2015) and Katende and Sagala (2019).
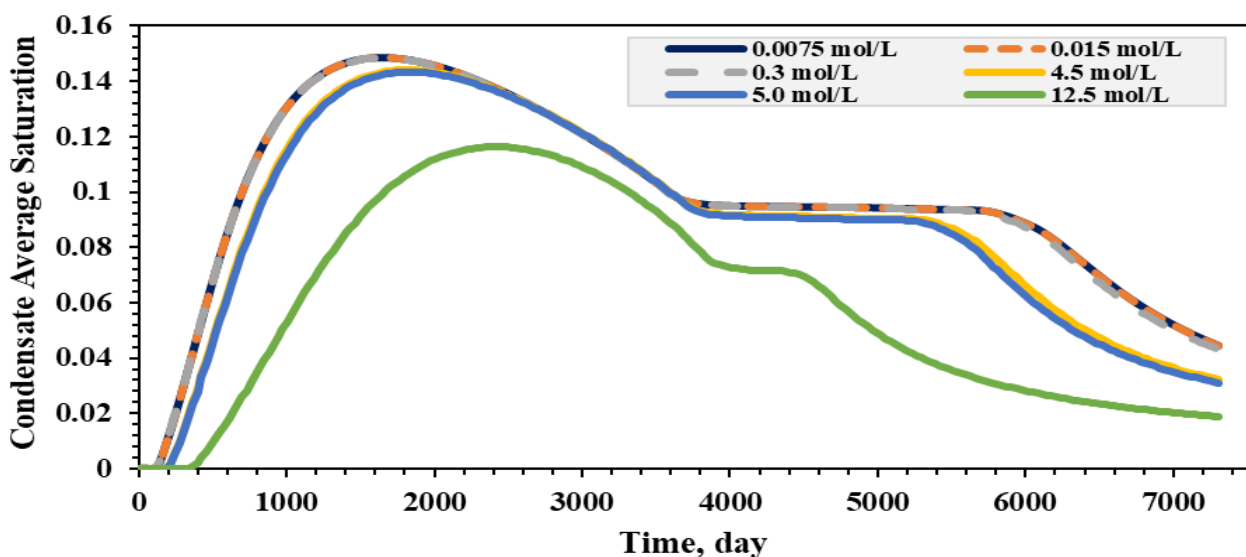

Fig. 9: Impact of Ca²⁺ ion concentration changes on Condensate Saturation

A.

D. Effect of the Concentration Changes on The Reservoir Geochemistry

According to the literature surrounding the low saline brine injection, the ions on the rock surface are disturbed whenever a reduced saline brine is injected into the reservoir (Lager *et al*., 2008). To measure the impact on the reservoir geochemistry, the equivalent fraction of the ions on the reservoir rock surface was recorded. It is reported that low saline brine often leads to a higher Ca^{2+} equivalent fraction and a lower Na^+ equivalent fraction (Sheng, 2014; Dang *et al*., 2015; and Katende and Sagala, 2019). The Ca^{2+} and Na^+ equivalent fractions in the reservoir grid blocks from the injector to the production well at the same time step are shown in Figs. 10 and 11 respectively. It is evident that as the Ca^{2+} ion concentration was increased from 0.015 mol/L to 12.5 mol/L (600 ppm to 500 Kppm), the Ca^{2+} fraction on the rock surface increased while the Na^+ fraction decreased. In Fig. 11, the low Na^+ equivalent fraction at the injector well resulted from the release of the sodium ions on the rock surface into the injected brine within the reservoir pore space, which contained fewer sodium ions. During this period, the Ca^{2+} in the injected brine replaced the released sodium ions on the rock surface increasing the Ca^{2+} equivalent fraction (Fig. 10). This increased Ca^{2+} fraction on the rock surface led to the destabilisation of the rock-connate water-condensate equilibrium state allowing the bounded condensate to become mobile. The increase in Ca^{2+} fractions and decrease in the Na^+ fractions confirmed the desorption and adsorption of Na^+ and Ca^{2+} respectively on the rock surface which is associated with the low saline brine process. This agreed with the prevailing hypothesis that when low saline brine is introduced into a reservoir, ion exchange occurs, replacing the cations bounded to the polar oil (condensate) component with divalent cations in the injected brine (Lager *et al*., 2008). This would then lead to higher oil recovery since the bond between the cations on the reservoir rock surface and the polar oil components is disturbed due to the introduction of the unbounded cations from the injected brine (Sheng, 2014; Katende and Sagala, 2019)
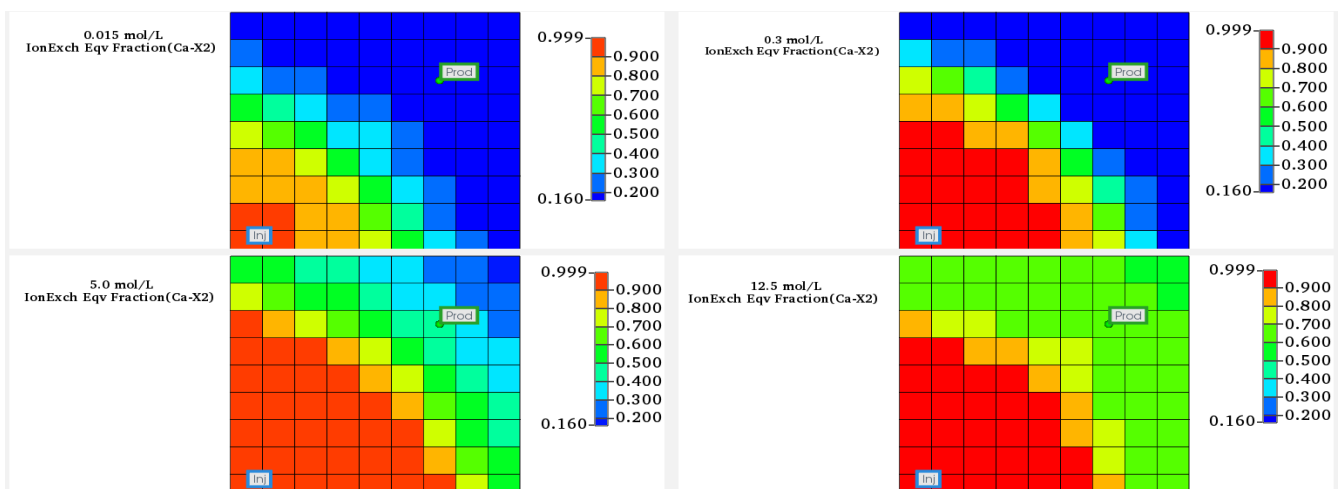

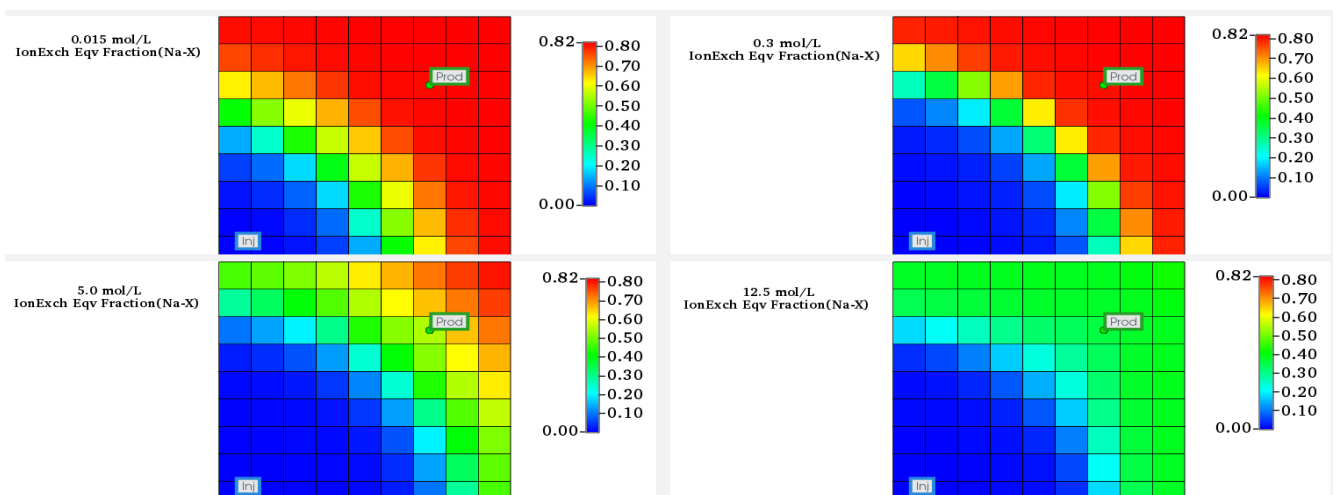Fig. 10: Calcium Ion Equivalent Fraction

Fig. 11: Sodium Ion Equivalent Fraction

IV. CONCLUSION

This paper has shown the ability of injected brine salinity changes to recover more condensate while at the same time reducing the condensate saturation. It was realised that to improve upon gas condensate recovery the optimised range of Na^+ concentration in the brine should be 0.013 mol/L (300 ppm) with Ca^{2+} concentration also been greater than 0.0029 mol/L (116 ppm). With these conditions, condensate recovery factor improved from 32.2% to 86.7%. at an injection rate of 490.8 m^3/d (3000 bbl/d). With increasing gas prices, this recovery mechanism could serve as a means of enhancing recovery from existing gas-condensate reserves.

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