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Designing Optimum Salinity, Cycle, and Gas-Water Ratio of Low Salinity Water Alternating Hydrocarbon Gas Injection at "B" Structure in "S" Field

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Abstract
In the last decades, injection of brines with modified ionic composition has been developed to improve oil recovery. low salinity water injection (LSWI) is one of the most prominent enhanced oil recovery (EOR) method which can increase oil recovery better than that other conventional chemical EOR methods. As a result of further studies of LSWI, an idea of combining it with other EOR technique was generated. One of the idea is to combine LSWI with gas injection which is known as low salinity water alternating gas (LSWAG) injection. Applying water alternating gas (WAG) in LSWI process means to inject both low salinity water and gas to the reservoir in order to improve the oil recovery. The presence of flue gas produced during production process leads to the idea of utilizing the produced hydrocarbon gas to be used for injection as pure carbon dioxide (CO_2) gas is considered costly.
In this study, the author proposes the idea of modelling low salinity water alternating hydrocarbon gas (Hydrocarbon-LSWAG) injection using compositional model to identify the effects of Hydrocarbon-LSWAG injection operational parameters and to propose the most optimum Hydrocarbon-LSWAG injection scenario to be applied in the sandstone reservoir at "B" Structure in "S" Field, South Sumatera Province, Indonesia. Reservoir simulations and production forecasts were done using CMG GEM™ Simulator during 15 years of production period starting from 1st January 2021 until 1st January 2036 with preliminary work using CMG WINPROP™ for generating the reservoir fluid compositional model. Series of sensitivity analysis were conducted in this study to identify the effects of operational parameters in modelling Hydrocarbon-LSWAG injection and to determine the most optimum Hydrocarbon-LSWAG injection scenario to be applied at "B" Structure in "S" Field to gain promising oil recovery using two injector wells. Water salinity, number of cycle and gas-water injection duration ratio were varied in order to observe the effects of those parameters to oil recovery factor.
The results of this study show that injection using lower water salinity of 1,800 ppm results in higher oil recovery compared to water salinity of 3,600 ppm. The findings of this study also show that the increasing number of Hydrocarbon-LSWAG injection cycle is neither directly or inversely proportional to the improvement of oil recovery. Furthermore, the resulted recovery factor is higher when the LSWI duration is longer than the hydrocarbon gas injection, in this case, with 1:2 ratio of gas-water injection. The most optimum Hydrocarbon-LSWAG scenario to be applied in "B" Structure of "S" Field is by injecting hydrocarbon gas of 0.25 MMSCFD alternating with low salinity water injection of 1000 BPD with injected water salinity of 1,800 ppm by applying one Hydrocarbon-LSWAG injection cycle for each year with gas-water injection duration ratio of 1:2 which results in 60.01% of oil recovery factor. Therefore, Hydrocarbon-LSWAG is suggested to be applied in "B" Structure of "S" Field for further field development.

Introduction

Low salinity water injection (LSWI) is an emerging enhanced oil recovery (EOR) technique that can increase the oil recovery about 5-20% of original oil in place (OOIP) compared to conventional waterflood (Lager et al., 2008). The main recognized effects of LSWI are the decrease of residual oil saturation and the increase of microscopic sweep efficiency (Rotondi et al., 2014). There is an idea to combine LSWI with gas injection which is known as low salinity water alternating gas (LSWAG) injection. LSWAG injection process means to inject both low salinity water and gas to the reservoir in order to improve the oil recovery. The presence of flue gas produced during production process leads to the idea of utilizing the produced hydrocarbon gas to be used for injection as it is easy to obtain. CO_2 gas is not preferable to be used as it is hard to obtain and expensive. Furthermore, CO_2 injection may trigger pipeline corrosion (Dong et al., 2019). However, there are still limited studies that discuss the performance of Hydrocarbon-LSWAG in prospective field as well as its possible mechanisms in recovering additional oil.
Several objectives that will be achieved in the end of this study are to identify the effects of operational parameters of Hydrocarbon-LSWAG injection that contribute to the enhancement of oil recovery, and to propose the most optimum water salinity, number of cycle and gas-water injection ratio scenario of Hydrocarbon-LSWAG injection based on oil recovery performance through simulation studies. Nevertheless, those objectives are limited to the application in sandstone reservoir at "B" Structure in "S" Field.
Some of the underlying mechanisms of LSWI to promote an additional recovery are known as follows:

a. Fines migration
   Tang and Morrow (1999) reported that LSWI may release fines/clay particles from rock surface which leads into increased water-wetness of the rock. Released fine particles from rock surfaces may block the pore throats and subsequently divert the flow of injected water into unswept pores inside reservoir rock.
b. pH increase
   Lager et al. (2006) explained that pH increase during LSWI is caused by carbonate dissolution and cation exchange process. The formation of OH- components in the liquid phase and may result in higher pH and increases oil recovery.
c. Multicomponent ionic exchange (MIE)
   Lager et al. (2006) stated that MIE releases oil component when positively charged multivalent ion which connects to negatively charged clay surface exchanges with a monovalent ion in injected water. Desorption process of polar oil components from clay surface lead into a more water-wet reservoir rock and tends to provide an additional oil recovery.
d. Electrical double layer (EDL) expansion
   Desorption of oil components from clay surface occurs as a result of salinity reduction which causes the EDL

expansion between clay surface and oil interfaces (Ligthelm et al., 2009). The clay surface becomes more water-wet and form a more stable water film (Nasralla and Nasr-El-Din, 2012).

e. Salting-in effect
RezaeiDoust et al. (2009) found that salting-in effect describes the increase of organic materials solubility inside the aqueous phase when the water salinity is lowered.

Besides all of the mechanisms mentioned above, geochemical reactions that consist of aqueous reactions, mineral dissolution reactions, and cation exchange reactions also become the main factor in affecting oil recovery improvement through LSWI by supplying cations for the ionic exchange process as a result of mineral dissolutions and support wettability alterations mechanism.

LSWI is an EOR method based on wettability alteration from oil-wet to water-wet conditions and WAG is a proven method for improving gas flooding performance by controlling the gas mobility. Therefore, LSWAG injection promotes the synergy between those underlying mechanisms (multicomponent ionic exchange, wettability alteration, improving displacement efficiency, mobility control, etc.) in enhancing the oil recovery (Dang et al., 2014).

Data and Method

1. Methodology

This study was conducted based on the design framework as shown on **Figure 1**.

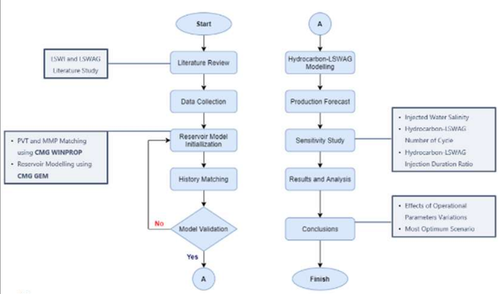

Figure 1: Framework of the Study

In designing the Hydrocarbon-LSWAG injection model, some parameters are assumed to complete the design due to the limitations on experimental data:

a. Clay minerals content is distributed similarly for each grid.
b. Interpolation range of ion exchange $\zeta(Na - X)$ is between 0.9378 and 0.6678 as obtained from the model initialization result.
c. The study is limited to the application in Sandstone Reservoir at "B" Structure in "S" Field.

2. Field Overview

The "S" Field, which is the focus of this study, is located in Kabupaten Ogan Ilir, South Sumatera Province, Indonesia. The field is founded in 1990 with area approximation of 18.25 km^2. Eleven wells are existed in "S" Field with different status that consist of five production wells (B-1, B-3, B-5, T-1, and T-3), an injection well (S-1), two plugged and abandoned wells (T-2 and K-1), and three suspended wells (B-2, B-4, T-4). The 2D map of "S" Field can be seen on **Figure 2**. According to the company, the "S" Field has been producing fluid from four wells and two proven layers since 1992. This field consists of two major structures which are "B" and "T" structures with "B" Structure as the main focus of this study. The cumulative production of "B" Structure is 2.285 MMSTB according to the field status in January 2020. The reservoir of "S" Field is identified as a sandstone reservoir with original reservoir pressure of 1700 psig and a strong water drive reservoir based on material balance analysis. Based on the provided fluid data, the hydrocarbon of this reservoir has an original GOR value of 722 scf/bbl, liquid gravity of 33.4 ºAPI at 60 ºF, and oil viscosity of 0.7342 cP. "B" structure consists of three sand layers including T, G, and K layer. Current productive layers which are used for LSWI implementation in "B" Structure are T and K sand layers. Based on the mineral content analysis data, it shows that the reservoir contains clay minerals especially kaolinite and illite which must be considered for LSWI implementation.

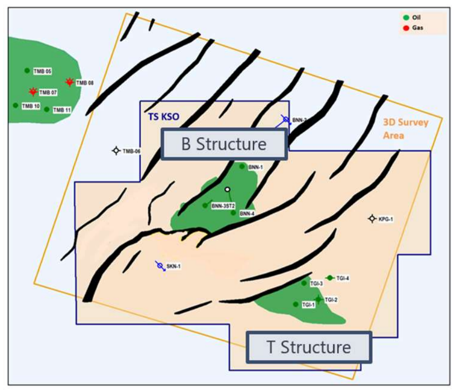

Figure 2: 2D Map of "S" Field

3. PVT Modelling and MMP Determination

In the early process of reservoir modelling, pressure, volume, and temperature (PVT) validation test was conducted by generating a compositional fluid model with C_{7+} as the pseudo-component. In this study, the fluid model was built using CMG WINPROP™ from constant composition expansion (CCE) and differential liberation (DL) tests. The prioritized parameters to be matched in this study are the saturation pressure, gas-oil ratio, relative volume, formation volume factor, and viscosity. Based on the fluid data and phase envelope obtained from this modelling process, the fluid of "B" Structure is identified as light-medium oil.

Minimum miscibility pressure (MMP) is calculated to determine the miscible condition at which the gas is injected to the reservoir. Due to the limited experimental data of "B" Structure in "S" Field, the determination of MMP value is calculated using a correlation proposed by Ghorbani (2013) as the optimum condition for the correlation is fulfilled with the characteristics of "B" Structure. The correlations are shown as follows:

$$\mathrm{MMP} = 44.162 - 4.32\alpha + 0.691\alpha^2 - 0.141$$

$$\alpha = \frac{X_{C2-C6}^{1.68} \times X_{C1}^{0.1}}{(1.8\,T + 32)^{0.5} \times M_{C7+}}$$

$$\beta = Y_{C2+}^{(1.085 + 0.0056 M_{C2+})}$$

This correlation gives MMP value of 1951.27 psi which is identical with the MMP value obtained from cell-to-cell simulation method using CMG WINPROP™ which results in MMP value of 1975 psi with only 1.2% of differences.

4. Reservoir Simulation Modelling

Table 1: Initial Conditions

Parameter	Units	Value
Total Bulk Reservoir	res ft^3	7.954×10^8
Total Pore Volume	res ft^3	1.278×10^8
Total Hydrocarbon Pore Volume	res ft^3	4.951×10^7
Original Oil In Place	std bbl	7.175×10^6
Original Gas In Place	std ft^3	2.365×10^9

Reservoir model initialization was modeled using CMG GEM™ builder format by inputting basic reservoir properties. The initial condition value of the model is obtained with original oil in place (OOIP) of 7.1748 MMSTB. This OOIP value is considered as 2P.

The selected geochemical reactions that are applied in this simulation encompas the aqueous reaction and mineral dissolution or precipitation based on the core flood experiment and PHREEQC Software proposed by Ashraf et al. (2010) in combination with ionic exchange proposed by Dang et al. (2013). The geochemical reactions are as follows:

Table 2: Geochemical Reactions

	Geochemical Reactions
Aqueous Reactions	$H^+ + OH^- \leftrightarrow H_2O$
	$CaHCO_3^+ \leftrightarrow Ca^{2+} + HCO_3^-$
	$NaHCO_3 \leftrightarrow Na^+ + HCO_3^-$
	$MgHCO_3^+ \leftrightarrow Mg^{2+} + HCO_3^-$
	$H^+ + MgCO_3 \leftrightarrow Mg^{2+} + HCO_3^-$
	$H^+ + NaCO_3^- \leftrightarrow Na^+ + HCO_3^-$
Mineral Reactions	$H^+ + \text{Calcite} \leftrightarrow Ca^{2+} + HCO_3^-$
	$H^+ + \text{Dolomite} \leftrightarrow Ca^{2+} + Mg^{2+} + HCO_3^-$
Cation Exchanges	$Na^+ + 0.5Ca - X_2 \leftrightarrow 0.5Ca^{2+} + Na - X$
	$Na^+ + 0.5Mg - X_2 \leftrightarrow 0.5Mg^{2+} + Na - X$

The CEC value was calculated using the equation proposed by Seilsepour and Rashidi (2008) :

$$\mathrm{CEC}\left(\frac{\mathrm{meq}}{\mathrm{kg}}\right) = 628.58 \text{ x fraction clay} + 48.8$$

$$\mathrm{CEC}\left(\frac{\mathrm{meq}}{\mathrm{m}^3}\right) = \mathrm{CEC}\left(\frac{\mathrm{meq}}{\mathrm{kg}}\right) \text{x} \left[\frac{\rho_{\mathrm{rock}}(1-\phi)}{1000}\right]$$

The porosity that being used in the equation is the average porosity of the reservoir by assuming that the porosity value is homogenous for all rock types. The calculated CEC value for LSWI process in this sandstone reservoir is equal to 237 eq/m^3.

After the initialization process of the reservoir model is done, history matching was then conducted using available production history data from three production wells (B-1, B-3, and B-5) from 1992 until 2020 with the reported cumulative oil production of 2.285 MMSTB. The parameters that are used for the history matching of the reservoir model are liquid rate, oil rate, and water rate. Parameters adjustment and refinement during the history matching process were done by modifying the aquifer and water-oil contact (WOC). The history matching process results of cumulative production of the field ("B" Structure) is shown on **Figure 3**.

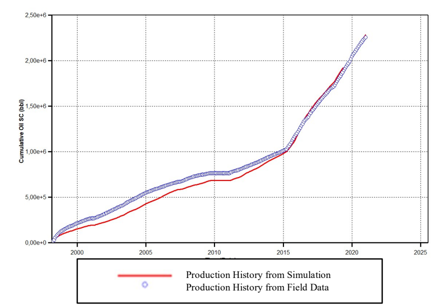

Figure 3: Cumulative Production History Matching

5. Sensitivity Study

The production scenario of this study is forecasted for 15 years of production started from 1st January 2021 to 1st January 2036 to observe the reservoir performance and oil recovery of the field. Production wells that are used are the same as the existing production wells consist of Well B-1, B-3, and B-5. The injection of Hydrocarbon-LSWAG in this study is performed using two injector wells consisting of Well B-4 (suspended well) which begins to inject fluid on 1st January 2022 and by converting Well B-1 into injector well (Convert to Injector or CTI) on 1st November 2027 when the well reaches the economic limit. Several production constraints are applied in this analysis: bottomhole pressure of 100 psi, economic limit of 15 STBD, liquid rate of 546 STBD for Well B-1, liquid rate of 2,342 STBD for Well B-3, and liquid rate of 120 STBD for Well B-5. Those liquid rate constraints are obtained from last production data for each well.

In this study, gas and water injection rates are locked at 1,000 BPD and 0.25 MMSCFD. The water injection rate of 1,000 BPD is obtained from previous study that have been done in this field which concluded that this water injection rate value is the most optimum one. On the other hand, the gas injection rate value of 0.25 MMSCFD is applied based on last gas production data of the field. This decision is made due to the idea that the injected gas used in this study is the hydrocarbon gas produced from the production of the field.

The first analysis to identify the effects of Hydrocarbon-LSWAG injection operational parameters is performed using three comparison studies:

a. Hydrocarbon-LSWAG injection using water salinities of 1,800 and 3,600 ppm are simulated and then being compared with the base case. The number of injection cycle is locked at 1 cycle/year and the gas-water injection duration ratio is locked at 1:1. The composition of the injected water is shown on **Table 3**.
b. Hydrocarbon-LSWAG injection using both injected water salinities of 1,800 and 3,600 ppm are simulated by applying variations in number of injection cycle of 1, 2, and 3 cycles/year. The gas-water injection duration ratio is locked at 1:1.

c. Hydrocarbon-LSWAG injection using both injected water salinities of 1,800 and 3,600 ppm are simulated by applying variations in gas-water injection duration ratio of 1:1, 2:1, and 1:2. The number of injection cycle is locked at 1 cycle/year.

Table 3: Injected Water Compositions

	Components	Concentration 1 (ppm)	Concentration 2 (ppm)
Cations	Na^{+}	662.099	1324.200
	K^{+}	6.720	13.440
	Ca^{2+}	6.013	12.025
	Mg^{2+}	1.238	2.478
	Fe^{3+}	0.292	0.584
	Sr^{2+}	1.680	3.360
	Ba^{2+}	0.159	0.318
Anions	HCO_3^{-}	296.124	592.247
	CO^{2-}	0.000	0.000
	OH^{-}	0.017	0.017
	Cl^{-}	814.981	1629.961
	SO_4^{2-}	10.876	21.752
Total Salinity		**1800.181**	**3600.363**

The time durations for each number of cycles and gas-water injection duration ratios are shown on **Table 4**.

Table 4: Duration for Each Cycle and Gas-Water Injection Ratio

Number of Cycle/Year	1 Cycle Duration (days)	Ratio 1:1 (days)		Ratio 2:1 (days)		Ratio 1:1 (days)	
		Gas	Water	Gas	Water	Gas	Water
1	365.25	182.625	182.625	243.5	121.75	121.75	243.5
2	182.625	91.3125	91.3125	121.75	60.875	60.875	121.75
3	121.75	60.875	60.875	81.167	40.583	40.583	81.167

Number of Cycle/Year	1 Cycle Duration (months)	Ratio 1:1 (months)		Ratio 2:1 (months)		Ratio 1:2 (months)	
		Gas	Water	Gas	Water	Gas	Water
1	12	6	6	8	4	4	8
2	6	3	3	4	2	2	4
3	4	2	2	2.67	1.33	1.33	2.67

The second analysis is done using permutations of sensitivity study simulations with variations of injected water salinity, number of Hydrocarbon-LSWAG injection cycle, and gas-water injection duration ratio.

Result and Discussion

1. Effects of Operational Parameters

The first study is conducted to identify the effects of Hydrocarbon-LSWAG injection operational parameters that consist of water salinity, number of Hydrocarbon-LSWAG cycle and gas-water injection duration ratio on the improvement of oil recovery. This identification was done by conducting comparison studies as explained in the previous section.

The first comparison was done to identify the effects of the water salinity of the injected low salinity water. The comparison was done to compare the oil recovery resulted from the base case without the application of Hydrocarbon-LSWAG injection, Hydrocarbon-LSWAG injection using 1,800 ppm of water salinity, and Hydrocarbon-LSWAG injection using 3,600 ppm of water salinity. The resulted oil recovery comparison is shown in **Table 5** and **Figure 4**. The comparison results show that the injected water salinity of 1,800 ppm gives better result with 4.27 MMSTB cumulative oil production and 59.577% of oil recovery factor with oil recovery factor improvement of 5.04% from the base case. The results indicate that the increasing value of the injected water salinity is inversely proportional to the improvement of oil recovery. In crude oil-brine-rock systems, the water relative permeability will decrease while the oil relative permeability will increase as the rock surface becomes more water-wet as LSWI influenced the shape and the end points of the relative permeability curves. According to the study done by RezaeiDoust, et al. (2009), lowering the injected water salinity increases the organic materials solubility in the aqueous phase and supports the occurrence of wettability alteration. This phenomenon is known as salting-in effect. Injection using lower water salinity also boosts the occurrence of MIE between the organic material on the surface of the mineral and the invading low salinity water. Polar compound desorption from the clay surface makes the reservoir rocks to be more water wet and cause an increase in oil recovery. **Figure 5** shows the comparison between remaining oil saturation distribution using water salinity of 1,800 ppm and 3,600 ppm. It is shown that Hydrocarbon-LSWAG injection using water salinity of 1,800 ppm promotes better sweep efficiency compared to 3,600 ppm.

Table 5: Oil Recovery Comparison of Water Salinity Variations

Water Salinity (ppm)	Number of Cycle (cycle/year)	Gas-Water Injection Duration Ratio	Np (MMSTB)	RF (%)
	Base Case		3.913	54.534
1,800	1	1 : 1	4.27459	59.577
3,600			4.15695	57.938

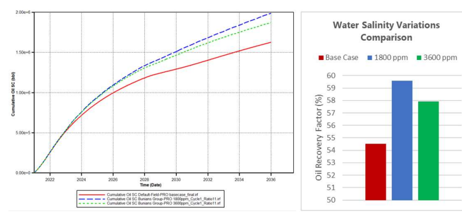

Figure 4: Oil Recovery Comparison of Water Salinity Variations

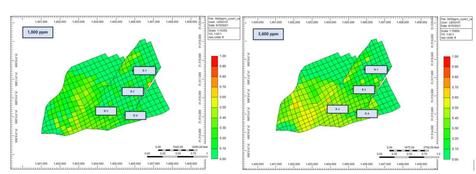

Figure 5: Remaining Oil Saturation Comparison of Water Salinity Variations

The second comparison was done to observe the effect of Hydrocarbon-LSWAG cycle to the oil recovery of the field. The comparison results are shown in **Table 6** and **Figure 6**. For cases with injected water salinity value of 1,800 ppm, the most optimum case is the one with 1 cycle/year (182.625 days of gas injection and 182.625 days of water injection). The case resulted in 4.275 MMSTB of cumulative oil production and 59.577% of oil recovery factor with an improvement of 5.04% from the base case. Nevertheless, the cases with injected water salinity of 3,600 ppm show that the most optimum case is the one with 2 cycle/year (91.313 days of gas injection and 91.313 days of water injection). The case resulted in 4.158 MMSTB of cumulative oil production and 57.959% of oil recovery factor with oil recovery improvement of 3.43% from the base case. Hence, the comparison results show that increase in number of Hydrocarbon-LSWAG injection cycle is neither directly nor inversely proportional with the improvement oil recovery in this field. The observed results show contradictory pattern with most cases that have been found previously. As in most cases, more WAG cycle results in higher oil recovery. Namani and Kleppe (2011) explained that the longer the duration of the cycle, the supporting pressure that drive the production of the field becomes higher as well. This mechanism may optimize sweep efficiency and support oil production. This contradictory study result may lead to the opinion that the effects of cycle number to oil recovery is uncertain and may result in different behavior at different fields caused by the lateral and areal heterogeneity of the reservoirs.

Table 6: Oil Recovery Comparison of Hydrocarbon-LSWAG Cycle Variations

Water Salinity (ppm)	Number of Cycle (cycle/year)	Gas-Water Injection Duration Ratio	Np (MMSTB)	RF (%)
1,800	1	1 : 1	4.275	59.577
	2		4.274	59.574
	3		4.268	59.480
3,600	1	1 : 1	4.157	57.938
	2		4.158	57.959
	3		4.156	57.927

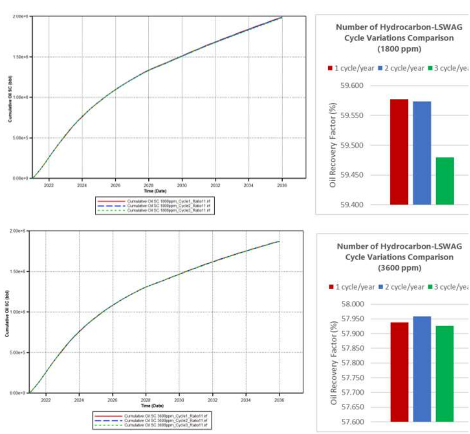

Figure 6: Oil Recovery Comparison of Hydrocarbon-LSWAG Cycle Variations

The third comparison study was done to identify the effects of Hydrocarbon-LSWAG gas-water injection duration ratio to the oil recovery. The results of the third comparison study are shown in **Table 7** and **Figure 7**. The comparison results for both injected water salinity of 1,800 and 3,600 ppm show that the highest oil recovery is obtained from gas-water injection ratio of 1:2 (121.75 days of gas injection and 243.5 days of water injection). The best case for 1,800 ppm water salinity results in 4.306 MMSTB of cumulative oil production and 60.011% of oil recovery factor with 5.48% of oil recovery factor improvement from the base case. Meanwhile, the best case for 3,600 ppm water salinity results in 4.163 MMSTB cumulative oil production and 58.022% of oil recovery factor with 3.489% of improvement from the base case. Therefore, it can be identified that higher oil recovery is obtained in this field when the low salinity water injection duration is twice longer than the duration of hydrocarbon gas injection (gas-water injection duration ratio of 1:2). Longer water injection duration improves the low salinity water performance by increasing the occurrence of mineral dissolutions and ionic exchange reactions. Increase in ionic exchange reactions leads to more oil swept in the reservoir. However, several previous studies found that equal injection duration ratio may also results in better oil recovery as it provides more stable sweep efficiency support. The explanation of different behaviors that were found in different fields regarding injection duration ratio can be related to the fluid composition, injector well locations, and heterogeneity of the reservoir.

Table 7: Oil Recovery Comparison of Gas-Water Injection Duration Ratio Variations

Water Salinity (ppm)	Number of Cycle (cycle/year)	Gas-Water Injection Duration Ratio	Np (MMSTB)	RF (%)
1,800	1	1 : 1	4.275	59.577
		2 : 1	4.221	58.829
		1 : 2	4.306	60.011
3,600	1	1 : 1	4.157	57.938
		2 : 1	4.122	57.453
		1 : 2	4.163	58.022

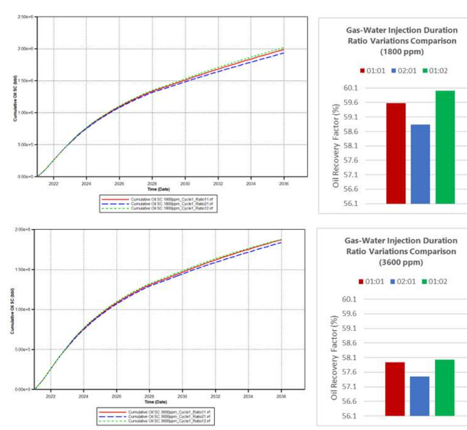

Figure 7: Oil Recovery Comparison of Gas-Water Injection Duration Ratio Variations

2. **Optimum Scenario of Hydrocarbon-LSWAG Injection**

The determination of the most optimum scenario of Hydrocarbon-LSWAG injection is done by conducting permutation sensitivity study of the injection operational parameters. Those parameters consist of water salinity, number of cycles, and gas-water injection ratio. The oil recovery and recovery factor values resulted from the simulations of the proposed sensitivity permutations can be seen in **Table 8**. From the table, it is observed that the highest oil recovery is obtained from scenario number 9 with injected water salinity of 1,800 ppm, 3 cycle/year, and injection ratio of 1:2 (40.58 : 81.17 days). The scenario results in cumulative oil production (Np) and oil recovery factor of 4.31 MMSTB and 60.078% respectively. It means that the scenario has recovery factor value improvement of 5.54% from the base case at which Hydrocarbon-LSWAG is not implemented. Nevertheless, the author suggests to reduce the number of Hydrocarbon-LSWAG injection cycle from 3 cycle/year to 1 cycle/year which indicates that case number 3 is more preferable to be applied. This decision is made by considering that the application of 3 cycles/year may result in higher operational cost and technical difficulties compared to 1 cycle/year. The fact that the oil recovery factors of both scenarios only show 0.067% of difference, which is considered identical, also supports this decision. The comparison between both scenarios is shown in **Figure 8**.

Table 8: Results of Sensitivity Analysis Permutation Scenarios

Scenario	Water Salinity (ppm)	Number of Cycle (cycle/year)	Gas-Water Injection Duration Ratio	Np (MMSTB)	RF (%)
Base Case	-	-	-	3.913	54.534
1	1,800	1	1 : 1	4.275	59.577
2			2 : 1	4.221	58.829
3			1 : 2	4.306	60.011
4		2	1 : 1	4.274	59.574
5			2 : 1	4.227	58.914
6			1 : 2	4.308	60.048
7		3	1 : 1	4.268	59.480
8			2 : 1	4.225	58.887
9			1 : 2	4.311	60.078
10	3,600	1	1 : 1	4.157	57.938
11			2 : 1	4.122	57.453
12			1 : 2	4.163	58.022
13		2	1 : 1	4.158	57.959
14			2 : 1	4.116	57.367
15			1 : 2	4.167	58.080
16		3	1 : 1	4.156	57.927
17			2 : 1	4.122	57.453
18			1 : 2	4.161	57.995

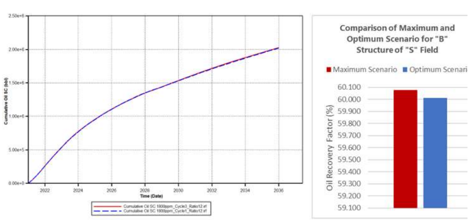

Figure 8: Remaining Oil Saturation Comparison of Water Salinity Variations

As a result, the preferable optimum scenario to be applied in "B" Structure of "S" Field is scenario number 3 with injected water salinity of 1,800 ppm, 1 cycle/year, and injection duration ratio of 1:2 (121.75:243.5 days). The water and gas injection rates are 1000 BPD and 0.25 MMSCFD respectively. This scenario results in cumulative oil recovery (Np) and oil recovery factor of 4.31 MMSTB and 60.01% respectively with oil recovery improvement of 5.47% from the base case.

Conclusions

Based on the results and analysis of this study, several conclusions can be obtained to answer the objectives of this study:

1. According to simulation study results: lowering the injected water salinity improves oil recovery; the number of Hydrocarbon-LSWAG injection cycle in this field is neither directly nor inversely proportional with the improvement of oil recovery; higher oil recovery is obtained from the field when the low salinity water injection duration is twice longer than the duration of hydrocarbon gas injection (gas-water ratio of 1:2).
2. The proposed optimum scenario of Hydrocarbon-LSWAG injection to be applied at "B" Structure in "S" Field is using injected water salinity of 1,800 ppm, applying 1 Hydrocarbon-LSWAG cycle/year, and using gas-water injection duration ratio of 1 : 2 (121.75 : 243.5 days) with water injection rate of 1000 BPD and gas injection rate of 0.25 MMSCFD.

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