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Compositional Reservoir Simulation Study for Gas Cap CO2 Injection Plan in the A-1 Layer of "Jupiter" Field

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Abstract. The "Jupiter" field is located in South Sumatera with Talang Akar Formation as the main reservoir and consists of Layers A, B, and C. Layer A is divided into three sub-layers (A-1, A-2, and A-3). In the previous research in Layer A, some development wells and water injection wells had been planned (Farah, S. N., 2016) and used as a Base case. Then the Base case was added with four CO_2 injection wells (immiscible and miscible) in the oil zone of the A-1 Layer (Ma'roefi, Rambu Muhammad., 2019). This study will simulate with gas cap CO_2 injection to compare with CO_2 injection in the oil zone and only focuses on the A-1 sub-layer. The method used in this study was reservoir simulation using CMG GEM Version 2012 simulator. The best scenario was determined by sensitivity of the best injection pattern, the best rate, and the best injection pressure. Based on the simulation results, it is shown that the injection pattern is not so affecting in determining the success of gas cap CO_2 injection, the optimum variety of injection rate is 2570 MSCFD, and the optimum pressure is 679 psi. Scenario III-B is more optimum than the best immiscible scenario and would be more optimum if usage of the miscible CO_2 scenario, which could give the recovery factor 9.23%.

***Keywords**: CO_2 Injection, Gas Cap, Recovery Factor, Reservoir Simulation*

INTRODUCTION

The "Jupiter" field is located in South Sumatera with Lower Talang Akar Formation as the main reservoir. This field contains Layers A, B, and C. The original oil in place (OOIP) total from layers A, B, and C is 76.01 MMSTB with a number of cumulative production (until day 4140) reaches 9.25 MMSTB, and the recovery factor is 12.2%. The biggest OOIP is sub-layer A-1, 30.32 MMSTB, with a number of cumulative productions reaches 5.298 MMSTB, and the recovery factor is 9.9%. Therefore, this study will focus on sub-layer A-1 [1].

Ma'roefi, Rambu Muhammad (2019) has carried out a scenario in the form of a base case plus four miscible CO_2 injection wells in the A-1 layer in the oil zone with a number injection rates is 2300 MSCFD. The total wells in this scenario are seven production wells, six water injection wells, and four CO_2 injection wells. The results of this scenario are the number of cumulative productions is 10.61 MMSTB, and the recovery factor of Sub-layer A-1 is 35.01% [2].

Based on the previous scenario—CO_2 injection in the oil zone—then will be tried to inject CO_2 in the gas cap zone with various variations of well pattern, injection rate, and injection pressure. CO_2 injection in the gas cap zone of the A-1 sub-layer is supported by screening criteria, which show that the immiscible CO_2 injection can be applied to the A-1 sub-layer of the "Jupiter" Field. CO_2 injection in the gas cap zone is a kind of secondary recovery in the form of pressure maintenance with a hypothesis able to increase the recovery factor by varying patterns, rates, and injection pressures. It is expected to increase the production time of sub-layer A-1 in the "Jupiter" Field.

The secondary recovery method, like water and (or) natural gas injection into the reservoir to raise and (or) maintain the pressure, potentially act as driving the water and (or) gas to replace oil [2,4]. This helps to maintain higher production rates and extend the productive life of the reservoir. The standard practice is injecting natural gas into the gas cap or over the oil zone and inject the water under oil-water contact. Oil recovery at the end of the primary recovery and secondary recovery phases is generally in the range of 20-40 percent of OOIP, in some cases, recovery

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can be lower or higher [10]. Tzimas et al. have reported a slightly higher recovery range of 35-45 percent of OOIP at the end of secondary recovery in the North Sea oil reservoir [9].

Producing oil with CO_2 injection in the gas cap is draining oil with the secondary recovery phase from three phases of oil recovery [7]. CO_2 injection has two main advantages: (1) increase recovery, and (2) reduce atmospheric emissions from CO_2 [3,9]. This study will be a focus on the recovery of oil using CO_2 injection in the gas cap. When a gas cap is already in a reservoir, or when a gas cap is formed by the segregation process during primary production, gas injection helps to maintain reservoir pressure while pushing and directing oil to the production well. This process is in line with the increasing oil-water contact (OWC) when water is injected into the aquifer, which is under the oil zone [5].

METHODOLOGY

This study was conducted at UPN "Veteran" Yogyakarta Simulation Reservoir Modeling Laboratory and used the CMG GEM Version 2012 simulator. The steps were data preparation, data processing, initialization, history matching, and prediction. CO_2 injection scenarios on the gas cap were carried out by sensitivity to the injection location, injection rate, and injection pressure.

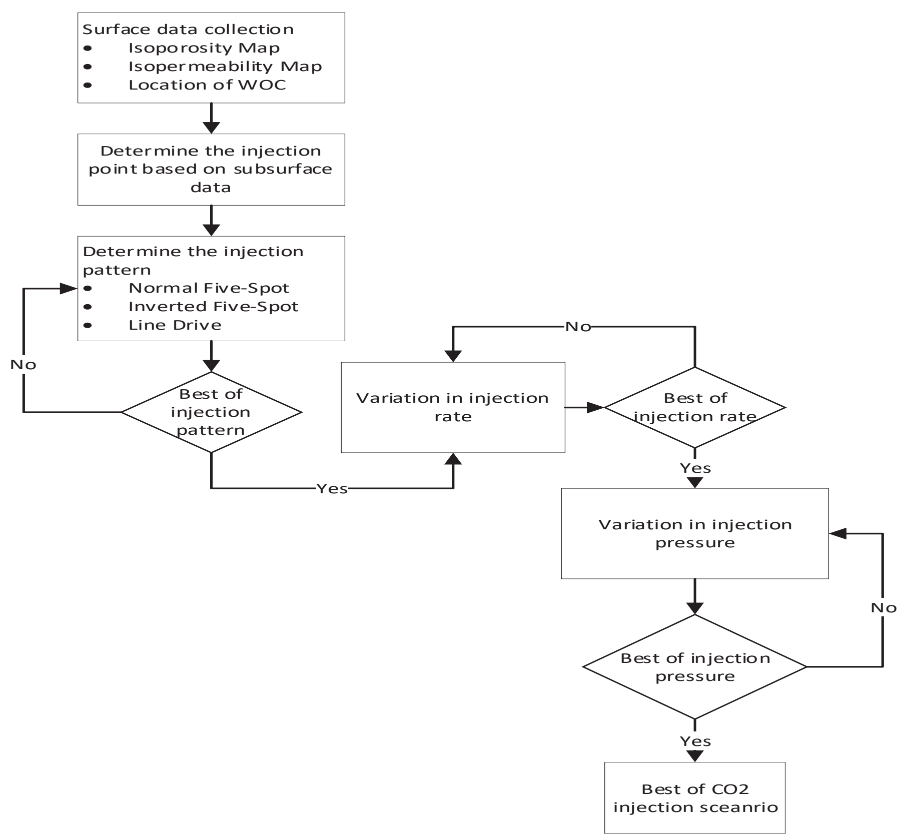

FIGURE 1. Flowchart of CO_2 Injection in Gas Cap

The systematic description of the simulation stages can be described as follows:

1. Collect and identify subsurface parameters, including the distribution of porosity, permeability distribution, and gas-oil contact (GOC).
2. Determine the injection point based on the isoporosity and isopermeability map above the GOC or in the gas cap zone.
3. With the same injection rate, various injection patterns in order to obtain the best injection well patterns.
4. With the best pattern, the CO_2 injection rate is varied to obtain the optimum injection rate.
5. With the optimum injection rate, the CO_2 injection pressure is varied to obtain the optimum injection pressure.

It is running CO_2 injection in the gas cap zone scenario by combining the best injection pattern, rate, and pressure as the best scenario that can provide the maximum recovery factor value.

RESULT AND DISCUSSION

Screening Criteria for “Jupiter” Field A-1 Sub-layer

To develop the A-1 sub-layer in the “Jupiter” Field was carried out to study in 2017 to review the EOR criteria to be applied. Screening criteria are based on Taber [8], the results of the screening criteria based on the study are Sub-layer A-1 "Jupiter" field has three EOR methods that can be applied, including: chemical injection (Alkaline or ASP), immiscible CO_2 injection and miscible CO_2 injection. The results of the screening criteria are used as a reference for conducting this CO_2 injection simulation study. After screening the criteria, the next stage is to predict the best scenario for the sub-layer A-1 "Jupiter" field.

Basecase: Twelve Production Wells + Six Water Injection Wells

Base case for sub-layer A-1 in the “Jupiter” field is carried out by producing wells from the end of the history matching (day 3500) until day 9404. The cumulative oil production in Base case is 7.83 MMSTB, and the recovery factor is 25.85%.

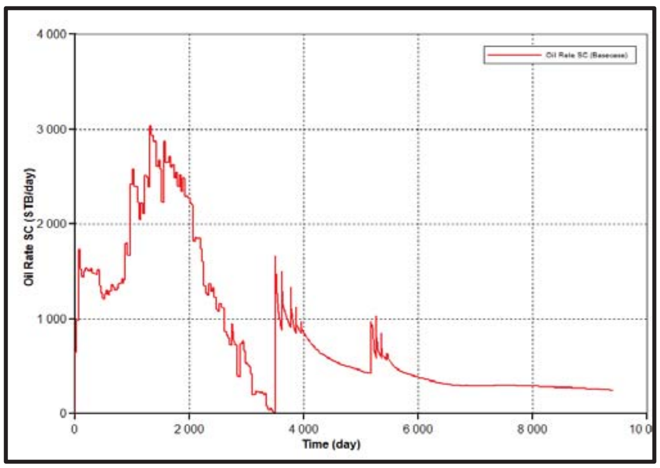

FIGURE 2. Prediction of Oil Production Rate of “Jupiter” Field A-1 Sub-layer (Base case)

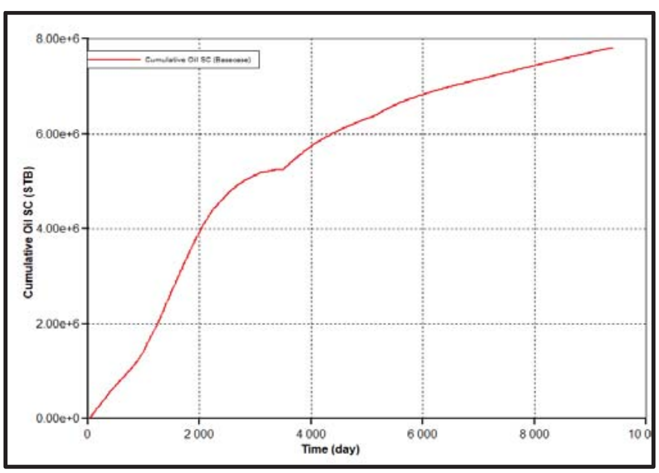

FIGURE 3. Prediction of Cumulative Oil Production for “Jupiter” Field A-1 Sub-layer (Base case)

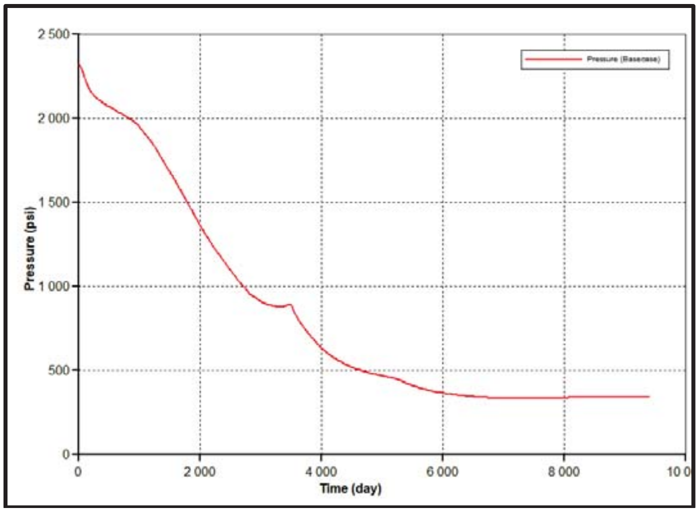

FIGURE 4. Pressure Prediction of "Jupiter" Field A-1 Sub-layer (Base case)

The Scenario I: Base Case + One CO2 Injection Well in Gas Cap (J-INJCO2)

Determining the location of the CO_2 injection well looks at the permeability distribution and the depth above the GOC with the same injection rate for each well, namely 3000 MSCFD. Injection of CO_2 can maintain pressure and even increase the pressure of the reservoir. The results of injection pattern sensitivity in **FIGURE 5** show that the optimum injection pattern is patternless with the number of injection wells only one.

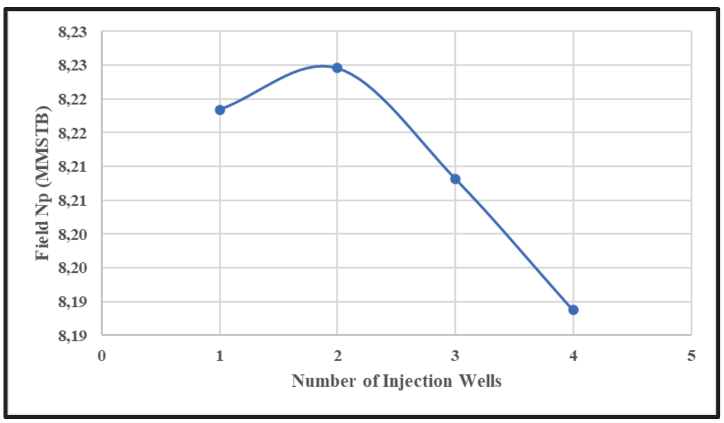

FIGURE 5. CO_2 Injection in Gas Cap Pattern Sensitivity

TABLE 1. The **se**nsitivity of CO_2 Injection in Gas Cap Patterns on "Jupiter" Field with Number of Injection Rate is 3000 MSCFD and BHP 2307 psi

Scenario	Injection Pattern	Number of Injection Well	Cumulative Oil Production MMSTB
I-A	Patternless	1	8.22
I-B	Patternless	2	8.22
I-C	Line Drive	3	8.21
I-D	Inverted Five Spot	4	8.19

Scenario I-A is more optimum than the other Scenario I. The cumulative oil obtained from the I-A scenario is 8.22 MMSTB, with a number of recovery factors is 27.13%. Variation of injection patterns in Scenario I shows that the pattern is not so influential in determining the success of CO_2 injection in the gas cap. This is because CO_2 injection in the gas cap with a pattern is not at the optimum injection point, and each addition of injection wells will cause GOR to increase GOR from 2764.66 cuft/bbl to 3478.36 cuft/bbl, which affects the age of a production well.

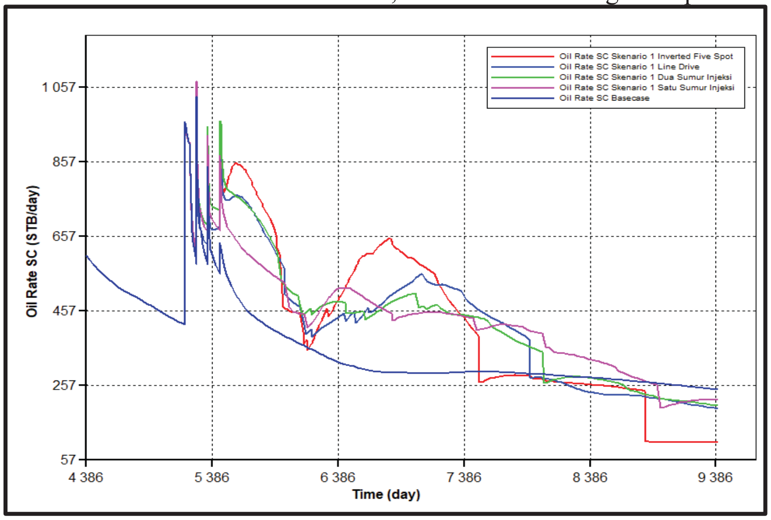

FIGURE 6. Oil Production Rate Prediction of "Jupiter" Field A-1 Sub-layer (Scenario 1)

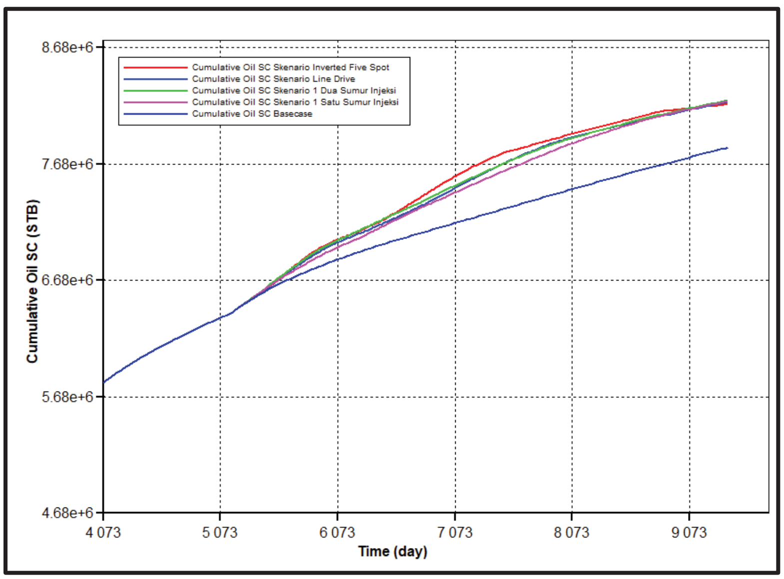

FIGURE 7. Cumulative Oil Production Prediction of A-1 Sub-layer "Jupiter" Field (Scenario 1)

Scenario II: Scenario I-A + Injection Rate Turn into 2570 MSCFD

In Scenario II, the injection rate will be changed by sensitivity. The cumulative oil until day 9404 for each injection rate is as in **TABLE 2**. The sensitivity results in **FIGURE 8** show that the optimum injection rate in the gas cap zone for Sub-layer A-1 is 2570 MSCFD.

TABLE 2. The Sensitivity of CO2 Injection Rate in Gas Cap "Jupiter" Field with One Injection Well at BHP 2307 psi

Scenario	Rate Injection	Cumulative Oil Production
	MSCFD	MMSTB
II-A	2000	8.20
II-B	2250	8.24
II-C	2500	8.25
II-D	2570	8.26
II-E	2750	8.22
II-F	3000	8.22

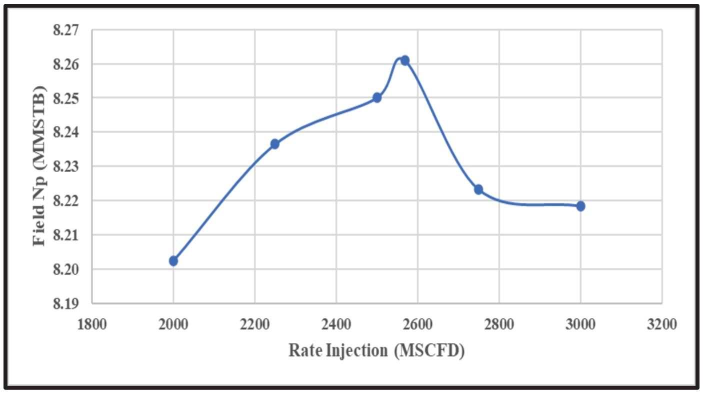

FIGURE 8. The sensitivity of CO_2 Injection Rate in Gas Cap

Scenario II-D is the optimum scenario than the other Scenario II. The cumulative oil obtained from Scenario II-D is 8.26 MMSTB, and the recovery factor 27.27%. If the injection rate increases again, it will cause the production well to off earlier because the GOR in the well has exceeded the maximum GOR constraint.

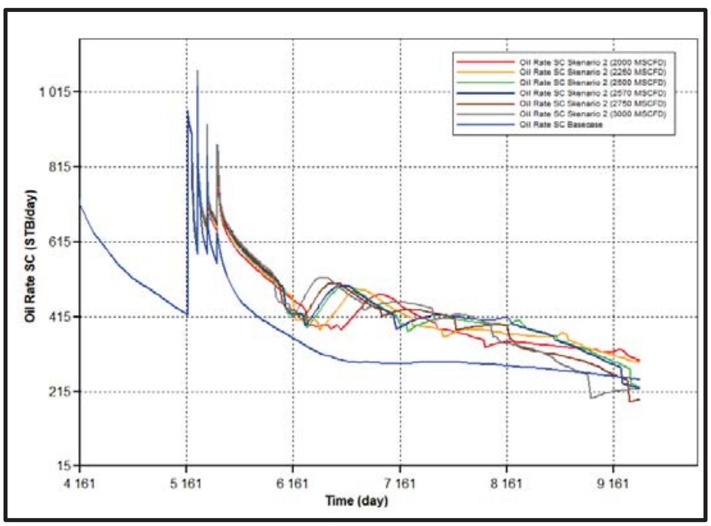

FIGURE 9. Oil Production Rate Prediction of Sub-layer A-1 "Jupiter" Field (Scenario II)

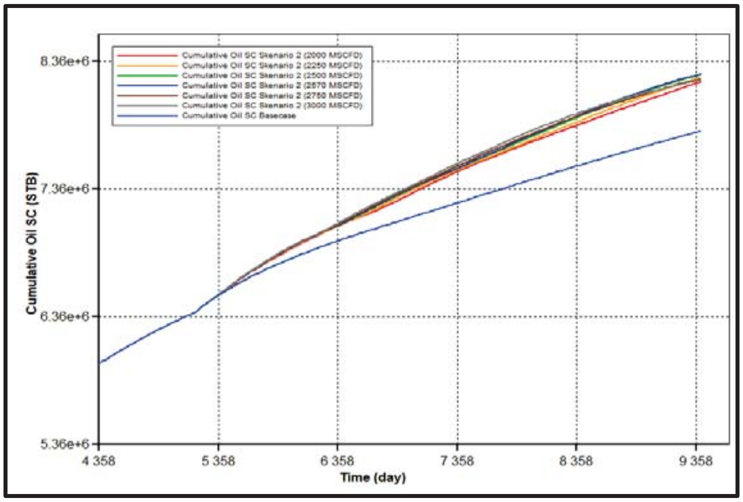

FIGURE 10. Cumulative Oil Production Prediction of Sub-layer A-1 "Jupiter" Field (Scenario II)

Scenario III: Scenario II-D + Injection Pressure Turn into 679 PSI

The Scenario III was simulated by different injection pressure than the previous scenarios to obtain the optimum injection pressure. The cumulative oil until day 9404 due to pressure sensitivity is shown in **TABLE 3**. The results of the injection pressure sensitivity in **FIGURE 11** indicate that the optimum injection pressure in the gas cap zone for sub-layer A-1 is 679 psi

TABLE 3. CO_2 Injection Pressure Sensitivity in Gas Cap "Jupiter" Field with One Injection Well and Injection Rate 2570 MSCFD

Scenario	Pressure Injection	BHP	Cumulative Oil Production
	psi	psi	MMSTB
III-A	621	1000	7.99460
III-B	679	2000	8.26121
III-C	686	2100	8.26083
III-D	694	2200	8.26083
III-E	702	2300	8.26083

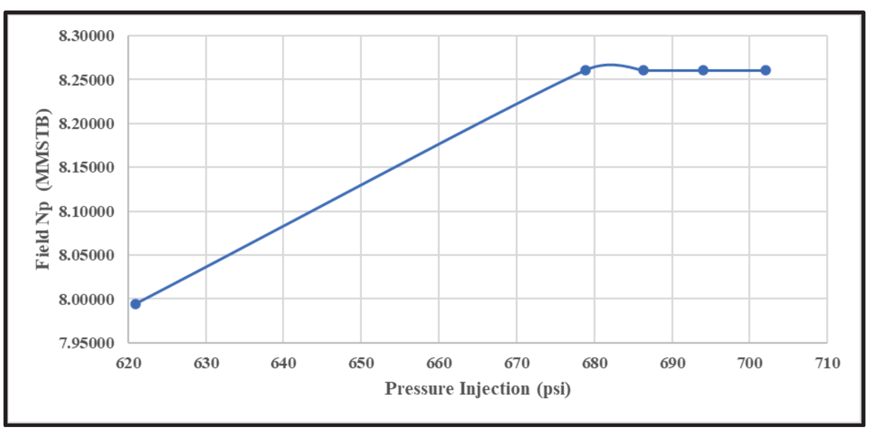

FIGURE 11 Injection Pressure Sensitivity

Scenario III-B is more optimum than the other Scenarios III. The cumulative oil obtained from Scenario III-B is 8.26 MMSTB, and the recovery factor is 27.27%. If the pressure is increased again, there will be a loss because the injection point is close to the fault, so it does not make changes to the cumulative oil and reservoir pressure.

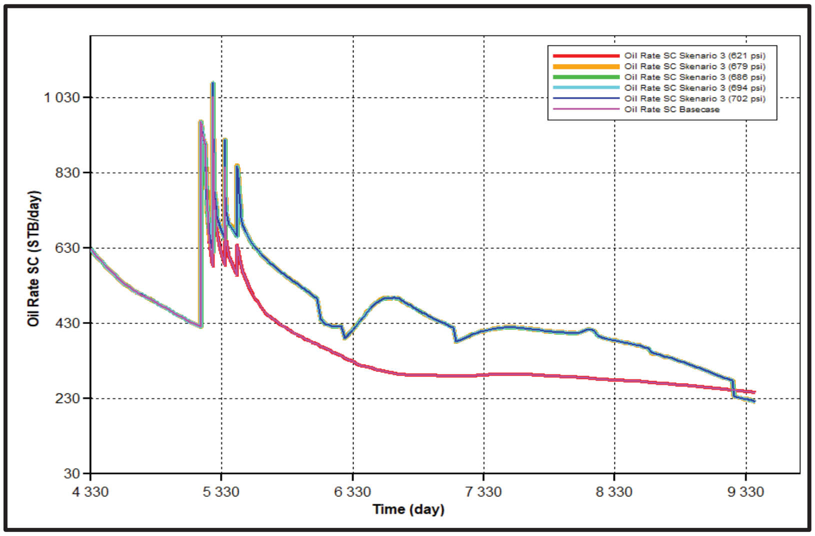

FIGURE 12. Oil Production Rate Prediction of Sub-layer A-1 "Jupiter" Field with Injection Pressure Variation (Scenario III)

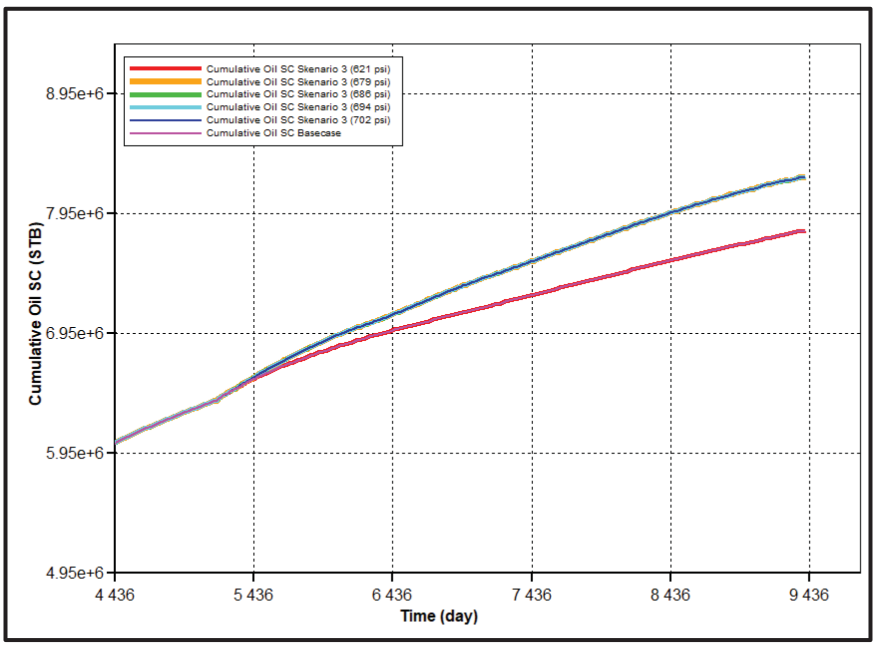

FIGURE 13. Cumulative Oil Production Prediction of Sub-layer A-1 "Jupiter" Field with Injection Pressure Variations (Scenario III)

Sub-layer A-1 "Jupiter" Field has OOIP 30.32 MMSTB, then at **TABLE 4**. Scenarios I, II, and III provide an additional RF of more than 1% until day 9404. Scenario III-B provides the largest additional RF, reaches 1.47% with cumulative production of 8.26 MMSTB.

TABLE 4. Summary of "Jupiter" Field Development Best Scenario Prediction Results until Day 9404

Scenario	The Details	Number of Well			Np
		Production	Water Inj.	CO2 Inj.	MMSTB
Base case	12 Production Wells + 6 Water Injection Wells	12	6	0	7.831
Scenario I	A. Base case + 1 CO_2 Injection Well in Gas Cap (Patternless)	12	6	1	8.22
	B. Base case + 2 CO_2 Injection Wells in Gas Cap (Patternless)	12	6	2	8.22
	C. Base case + 3 CO_2 Injection Wells in Gas Cap (Line Drive)	12	6	3	8.21
	D. Base case + 4 CO_2 Injection Wells in Gas Cap (Inverted Five Spot)	12	6	4	8.19
Scenario II	A. Scenario I-A + Rate Injection Turn into 2000 MSCFD	12	6	1	8.20
	B. Scenario I-A + Rate Injection Turn into 2250 MSCFD	12	6	1	8.24
	C. Scenario I-A + Rate Injection Turn into 2500 MSCFD	12	6	1	8.25
	D. Scenario I-A + Rate Injection Turn into 2570 MSCFD	12	6	1	8.26
	E. Scenario I-A + Rate Injection Turn into 2750 MSCFD	12	6	1	8.22
	F. Scenario I-A + Rate Injection Turn into 3000 MSCFD	12	6	1	8.22
Scenario III	A. Scenario II-D + Pressure Injection Turn into 621 psi	12	6	1	7.99
	B. Scenario II-D + Pressure Injection Turn into 679 psi	12	6	1	8.26
	C. Scenario II-D + Pressure Injection Turn into 686 psi	12	6	1	8.26
	D. Scenario II-D + Pressure Injection Turn into 694 psi	12	6	1	8.26
	E. Scenario II-D + Pressure Injection Turn into 702 psi	12	6	1	8.26

Based on the table above, it can be concluded that Scenario III-B is the most optimum scenario. This can be seen from the most massive increase in RF compared to other scenarios, which is 1.42% of the RF Base case scenario.

Comparison with CO_2 Injection in Oil Zone

Previously, a simulation of CO_2 immiscible and miscible injection in the oil zone was carried out by Ma'roefi [2]. The best immiscible scenario is Base case with 4 CO_2 injection wells with an injection rate of 1600 MSCFD resulting in cumulative production of 8.26 MMSTB, which is the same value as Scenario III-B. When compared, scenario III-B will be more optimal because with the addition of the same RF (i.e., 1.42%), Scenario III-B only requires 1 CO_2 injection well. Based on the low viscosity of CO_2, any free CO_2 gas at low reservoir pressure will cause an earlier penetration of the production well, thereby reducing sweeping efficiency. Unlike the case with CO_2 injection above GOC, heavy CO_2 will tend to migrate downward and prevent oil seepage into the hood zone so that oil can be swept optimally [9].

Then the best miscible scenario by Ma'roefi is Base case plus 4 CO_2 injection wells. The injection rate is 2300 MSCFD and the RF increase 9.23% from base case, which is much greater than Scenario III-B [2]. This is because miscible CO_2 injection can increase the recovery factor. After all, the mixing of CO_2 gas can reduce the oil itself's viscosity, swelling the oil, and can also reduce the interfacial tension between rocks and oil in the reservoir [9].

Gas Cap Expansions

The production process caused an increase in GOR Scenario I from 2764.66 cuft / STB to 3478.36 cuft / STB and Scenario II from 2764.66 cuft / STB to 3513.88 cuft / STB due to the decrease in pressure in the oil zone, so the value of Bg went up and there was an expansion of the gas cap which triggered gas coning. Production wells with a GOR that have exceeded the constraint, namely 25,000 cuft / bbl, will turn off first.

CONCLUSION

From this study is concluded that:

1. Variation of injection patterns in Scenario I shows that the pattern is not so influential in determining the success of CO_2 injection in the gas cap. This is because CO_2 injection in the gas cap with a pattern is not at the optimum injection point, and each addition of injection wells will cause GOR to increase GOR from 2764.66 cuft/bbl to 3478.36 cuft/bbl, which affects the age of a production well.
2. The optimum injection rate is 2570 MSCFD (Scenario II-D). If the injection rate increases again, it will cause the production well to off earlier because the GOR in the well has exceeded the maximum GOR constraint. The addition of GOR from Scenario II is from 2764.66 cuft/bbl to 3513.88 cuft/bbl.
3. The variation in pressure at the injection rate of 2570 MSCFD will be optimum with injection pressure 679 psi. If the pressure is increased again, there will be a loss because the injection point is close to the fault, so it does not make changes to the cumulative oil and reservoir pressure. This study will simulate with gas cap CO_2 injection to compare with CO_2 injection in the oil zone and only focuses on the A-1 sub-layer.
4. Scenario III-B—Base case with 1 CO_2 injection well in the gas cap zone with injection rate 2570 MSCFD and injection pressure 679 psi—is more optimal than the best immiscible scenario from Ma'roefi —Base case with 4 CO2 injection wells in the oil zone with an injection rate of 1600 MSCFD [2]—because with the same RF addition (i.e., 1.42%), it only requires one CO_2 injection well.

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