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Reactivation and Functional Shift of Suspended Wells for Injection to Increase Oil Recovery in Waterflooding Project Plans

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ABSTRACT: The "BDS" oil field volumetrically has Original Oil in Place (OOIP) of 56.84 MMSTB. This field has produced 20.45 MMSTB with a current recovery factor (RF) value of 35.89%. Because the remaining reserves are still large, this field is still suitable for development. The type of driving force is a water drive with very high water production, where the water cut is more than 95% so that it has the potential to carry out secondary recovery projects using the waterflooding method using reservoir simulation. Optimization is carried out by changing the reactivated suspended well into a production well and changing it into an injection well. This effort is intended to obtain an optimum scenario for the water injection project. Specifically, the aim of this research is to utilize suspended wells to become production wells and injection wells as well as to overcome the problem of surface formation water waste with limited water treatment facilities.

KEYWORDS: original oil in place, recovery factor, waterflood, reservoir simulation, sensitivity

I. INTRODUCTION

The reservoir's ability to produce oil to the surface continuously will decrease, so a way is needed to increase oil recovery by implementing a second stage method or secondary recovery.

The "BDS" field has thirty production wells, however many wells have experienced a water cut of more than 95% so that in existing conditions there are only 4 production wells. The "BDS" field has a total Original Oil In Place (OOIP) of 56.84 MMSTB, with cumulative production of 20.45 MMSTB and a current recovery factor of 35.89%. The “BDS” field has a water drive reservoir as a driving force. The decrease in pressure and oil production rate continues to occur and field water production continues to increase.

As the field production rate decreases, the field potential is still high enough to optimize production, so it is a consideration to develop the field using the waterflooding method. The "BDS" Field development planning uses the waterflooding method which injects water into the oil zo The waterflooding method was chosen with the aim of helping the efficiency of oil drainage, so that it can help increase oil recovery in production wells. Based on previous research, this method has been proven effective in increasing the Recovery Factor by injecting water into oil wells to push oil into production wells and reduce oil saturation in reservoir rocks (Agarwal & Singhal, 2016) [1]. Apart from that, reservoir simulators can also be used to predict and estimate the effectiveness of the waterflooding method in increasing RF (Gui et al., 2021)[2].

In the waterflooding method, there are several things that need to be considered when planning development, including: flood pattern, performance prediction, and determining reserves (Thakur G. 2020) [3].

The injection patterns that can be applied to the waterflooding method are based on (Thakur G, 2020)[3] as follows: Line drive pattern, 4-spot pattern, 5-spot pattern, 7-spot pattern, 9-spot pattern, Peripheral pattern.

An experiment conducted by Yang G. et al. (2022) [4], to determine the recovery factor after waterflooding. Reservoir simulation experiments were carried out on foam produced by carbon dioxide ($CO2$) and nitrogen ($N2$), cyclic C02 injection, water alternating gas (WAG) injection, active carbonated water injection (combining the effects of surfactants and carbonated water (CW) and introduced impact of alternating gas injection of activated carbonated water (combination of WAG and CW injection) after waterflooding. C02 is more viable than nitrogen, can be mobilized more in rock pores and provides a higher recovery factor. The foam produced with C02 has increased about 32% meanwhile it is around 28% for foam produced by N2. In addition, the maximum recovery factors for active carbonate water alternating gas injection, water alternating gas injection are 74%, 65%, and 48% respectively. In general, what is commonly done is water injection due to considerations of cost and ease of operating facilities.

In their study, Grema & Cao (2016) [5] , conducted research on a new approach to determining CVs for dynamic systems. The proposed approach is then applied to the waterflooding process to produce optimal operation. This method involves using measurement data to design the function of CVs offline and implementing these CVs in a closed manner. The results show that the feedback control method is close to optimal without any uncertainty. The loss recorded in the performance index value, net present value was only 0.26%.

In a study conducted by A. S. Grema, Yi Cao 2016 [6] which discussed optimal feedback control in the oil reservoir waterfloding process. When water is injected into the reservoir, more oil is expected to be produced. However, there are times when the water that was injected will be produced along with the oil. The worst case occurs when the water injected into the reservoir is in the opposite direction from the desired production well. Therefore, all efforts are directed towards finding optimal settings that can be maximized to increase oil production.

The use of water injection is very beneficial for the oil and gas industry, especially in increasing oil recovery. For example, a case study was carried out in the Lanea oil field located in the Chad area, which was carried out by Mahamat Tahir AMZ a.all. in 2021[9] proved that by carrying out water injection in wells that are currently producing, the recovery factor can be increased by 14.5–15%

In reservoir conditions that have a fairly high water cut, water injection can provide quite significant benefits. By using the water injection method it can be further developed to determine the final result of the recovery factor and can increase the effectiveness of the sweeping [10].

Another benefit is that the use of waste formation water from the surface production process will be more efficient if it is injected into the reservoir [11] .

Sometimes in implementing well injection, water is not only used as the injection fluid medium. The use of carbon dioxide (CO_2), nitrogen (N2), cyclic CO, a combination of water and gas (WAG), and active carbonated water injection are also often used. Guilin Yang at.all[12] has conducted research on the use of a combination of water and gas (WAG) as an injection fluid which has succeeded in increasing recovery up to 74% in an oil field. However, in this research, an attempt was made to simulate the use of suspended wells for production wells and injection wells, so that project costs can be reduced more cheaply and more efficiently.

II. METHODOLOGY

The methodology in this research follows several steps, as follows: namely recalculating reserves using simulation, comparing simulation results with reserves calculated initially (from actual data), and initialization. Then scenario 1, scenario 2, scenario 3, and conclusions were designed. The problem limits in this research are: maximum water production of approximately 3000 bbl and water treatment capacity of approximately 1000 bbl.

Increasing the recovery factor can be done by reservoir simulation which starts with data preparation that will be used to solve problems that occur in the "BDS" Field. Then proceed with initialization and history matching. After the data has been matched, predictions are made using a baseline and 3 scenarios using pattern parameters and injection rates. This is used to determine the cumulative production and remaining reserves of the "BDS" field. The flowchart for this research can be seen in Figure 1 below.

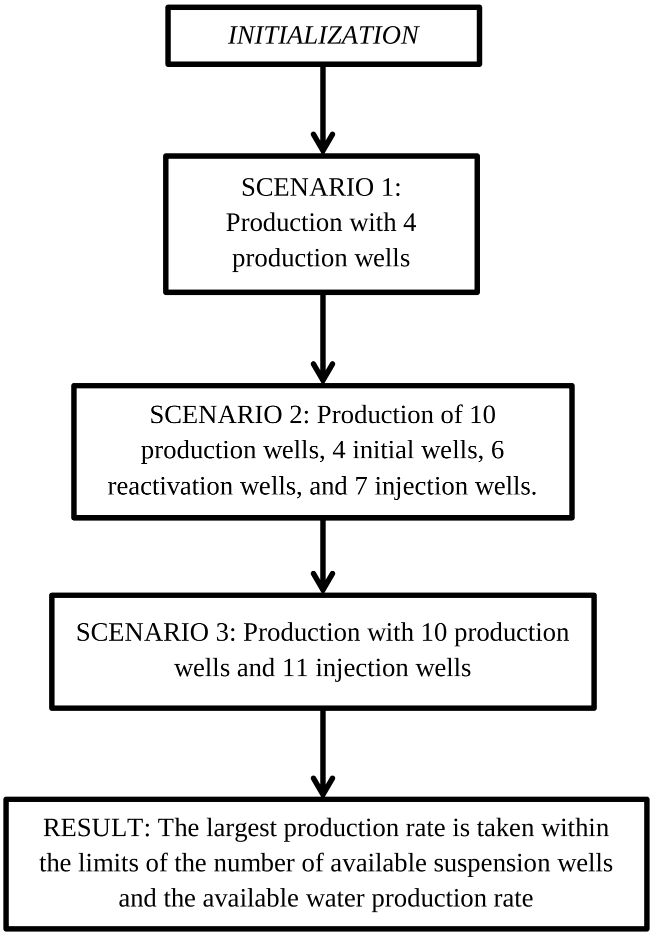

Figure 1
Flowchart Research

The prediction stage (forecast) is carried out with the aim of estimating the behavior of the reservoir in the future based on a predetermined time. Predictions for the “BDS” Field are made with the aim of trying various alternative development scenarios that will be carried out.

The base case scenario is a scenario carried out by continuing production of wells that are still producing (4 wells) at the end of history matching until the predicted time of December 2040. The "BDS" Field development scenario is as follows:

Table 1. BDS Field Simulation Scenario

Skenario	Information
Basecase	Continuing production of 4 production wells

Scenario 1	4 production wells + 6 reactivation wells
Scenario 2	4 production wells + 6 reactivation wells + 7 injection wells
Scenario 3	10 production wells above + 11 injection wells

III. RESULT AND DISCUSSION

The data needed in processing rock areas is permeability data from routine core analysis with a number of samples. Permeability and sample number are plotted on the graph. After plotting, a trend line is drawn for each point which shows the trend for each region as shown in Table 2 bellow:

Table 2. Distribution Results of Each Rock Region

Rock Type	Range (KmD)	Poravrg (Fraction)	Kav (mD)
1	75 - 115	0.130507258	102.7198
2	116 - 176	0.157420375	122.9346

Normalization is carried out to determine the shape of the curve that represents the entire field data. However, for this study, ready-made permeability data has been obtained and can be directly entered into the reservoir model. The following permeability data can be seen in Table 3.

Table 3. Permeabilitas Relative Reservoir

Rock Region 1			**Rock Region 2**		
Sw	**Krw**	**Kro**	**Sw**	**Krw**	**Kro**
0.2	0	0.403	0.2	0	0.526609
0.25	0.00304	0.287751	0.25	0.003981	0.350349
0.3	0.0066079	0.203655	0.3	0.006635	0.225604
0.35	0.013172	0.133743	0.35	0.010617	0.05441
0.4	0.020264	0.088149	0.4	0.018579	0.141998
0.45	0.033436	0.055726	0.45	0.033177	0.088914
0.5	0.054713	0.034449	0.5	0.050429	0.030523
0.55	0.086123	0.018238	0.55	0.090241	0.018579
0.6	0.013273	0.010132	0.6	0.136689	0.00929
0.65	0.183391	0.006079	0.65	0.200389	0.007962
0.7	0.24317	0.004053	0.7	0.290631	0.006635
0.8	0.417442	0	0.8	0.546757	0

PVT data is obtained using correlations which are mathematically processed by the CMG simulator. A summary of the physical properties of the reservoir fluid can be seen in Table 4.

Tabel 4. PVT BDS Field Data

Pressure psi	Bo bbl/stb	Rs Scf/stb	Viso cp
14.7	6.667274	1.993514	0.574627
292.4778	7.024407	24.09663	0.434981
570.2555	7.495288	51.34393	0.358176
848.0333	8.495288	81.42303	0.309979
1125.811	8.044641	113.5592	0.276336
1403.589	9.328805	147.338	0.251195
1681.367	9.939085	177.7882	0.234646

The data above is then used as input data in the simulation for the characteristics of the reservoir being simulated.

IV. DETERMINATION OF RESERVOIR AND RESERVE MODELS

The reservoir simulation modeling method was carried out using the Black Oil method with the characteristics of the field being studied. Characteristic data of the reservoir simulation model can be seen in Table 5.

Tabel 5. Characteristic of Reservoir Simulation Model Data

Parameter	Information
Simulator	Orthogonal
Grid Type	International Units
Amount of Grid (i x j k)	71 x 66 x 3
Grid Total	18318

Calculating the initial reserve value or original oil in place (OOIP) using the volumetric method requires several important parameters which are shown in Table III-6.

Tabel 6. Tabulation of Calculation Reserve Volumetric Data

Parameter	Value
Φ, fractiopn	0.188
Swi, frakction	0.2
Boi, bbl/STB	1.349
Volume Bulk, acre-ft	65739.85

Then the size of the "BDS" field reserves can be calculated using the volumetric method with the following equation:

$$OOIP = 7758\ x\ \frac{Vb\ x\ \emptyset\ x\ (1 - Swi)}{Boi} \quad (1)$$

OOIP = $7758\ x\ \frac{65739{,}85\ x\ 0{,}188\ x\ (1-0{,}2)}{1{,}349}$

OOIP = 56845600 STB

4.1. INITIALIZATION

The initialization stage aims to align the initial conditions of the model that has been created with the initial conditions of the actual reservoir. The parameter that must be conditioned as the initial condition of a reservoir is Original Oil in Place (OOIP). Determination of the initial reserve size in the "BDS" Field is obtained from geological modeling which is the result of geological and geophysical data processing. Based on the data, the initial reserve results (OOIP) were 56.8456 MMSTB. The maximum percent error from initialization is 5% between the geological volumetric reserve data and the initialization results from the simulation model. From the results of the initialization alignment carried out, with a % error of less than 5%, namely 0.1%, it can be said that the actual initial model and the simulation model are aligned. Table 7 is a summary of the results of the initialization of the "BDS" field that has been carried out.

Tabel 7. Tabulation Initialization

OOIP (MMSTB)			difference (%)
Field Data	Simulation	Modification	
56.84556	55.4667		2.49
56.8456		56.9045	0.10

4.2. Key Well Determination

Determining the key well to represent the history matching stage of the wells in the field. The determination is based on several parameters, namely wells that have a long production life and wells that are still producing at the end of their history. Based on these provisions, there are 4 wells in the "BDS" Field that meet the criteria for key wells, namely: well B11, well B14, well B19, and well B23.

4.3. History Matching

The history matching stage is carried out on the "BDS" Field by comparing the simulation results with historical field production data. The following are the results of harmonizing oil, water and gas production data for the "BDS" Field which are tabulated in Table 8.

Table 8. Tabulation of History Matching Result

Parameter	Field Production	Modified Simulation Model	Different (%)
Minyak, MMSTB	20.4434	20.4434	0.0
Air, MMSTB	1.8109	1.8016	0.5
Gas, MMSCF	19304.1540	19439.9974	0.7

4.4. Determination of Remaining Reserves

Carrying out drive mechanism analysis using the method used to identify the driving force of the reservoir or drive mechanism in the "BDS" field is by determining the drive mechanism diagnostic curve proposed by Ganesh Thakur and calculating the drive index using the material balance method. The Ganesh Thakur method uses a plot between the percent reduction in reservoir pressure and the percentage of oil production against the oil in place (OOIP) value which is tabulated in Table 9.

Recovery Efficency $= \frac{Np}{OOIP}\ x\ 100\%$ (2)

Recovery Efficency $= \frac{0}{56{,}9838}\ x\ 100\%$

Recovery Pressure $= \frac{P}{Pi}\ x\ 100\%$ (3)

Recovery Pressure $= \frac{1903.47}{1903.47}\ x\ 100\%$

Table 9. Tabulation Recovery Efficiency and Recovery Pressure

Pressure		Cumulative Production	
P Reservoir	% P Factor	Np (MMSTB)	% Rec Factor
1872.675903	98.38	0	0
1868.379761	98.16	34050.85938	0.06
1859.520508	97.69	113147.2656	0.20
1791.933228	93.61	720384.3125	1.27
1625.046875	85.37	1888282	3.32
1471.50647	76.10	3497697	6.15
1448.626953	73.47	4152842.75	7.31
1398.51294	71.59	5744075	10.10
1362.68689	70.70	703817.5	12.38
1345.808716	70.38	7722518.5	13.59
1339.684201	70.20	7841201	13.79
1336.202637	69.94	7937153.5	13.96
1331.286133	69.94	8098319	14.25
1292.059692	67.88	9659971	16.99
1245.59	65.44	11669254	14.25
1190.0494	62.52	14334178	16.99
1160.79	60.98	15723884	25.22
1153.45	60.60	16010529	28.16
1133.75	59.56	16895962	29.72
1115.19	58.59	17740698	31.21
1103.60	57.98	18337184	32.26
1098.63	57.72	18585644	32.69
1094.58	57.50	18817214	33.10
1074.18	56.43	19160356	33.71
1023.41	53.77	1941314	34.22
989.52	51.99	19691406	34.64
964.85	50.69	19864344	34.94
950.92	49.49	19992356	35.17
942.02	49.49	20056266	35.28
934.21	49.08	20096930	35.35
925.75	48.64	20131818	35.41
917.20	48.19	20157232	35.46
910.49	47.96	20176754	35.49
908.94	47.85	20197034	35.53

907.88	47.75	20211778	35.56
907.41	47.70	20229672	35.59
907.40	47.67	20249102	35.62
907.51	47.67	20258004	35.64
907.57	47.67	20262830	35.65
907.59	47.68	20265000	35.65
907.62	47.68	20266692	35.65
907.64	47.68	20269680	35.66
907.66	47.68	20276618	35.66
907.71	47.68	20276618	35.67
907.77	47.68	20276618	35.67
907.82	47.69	20276618	35.67
907.86	47.69	20276618	35.67
907.90	47.69	20276618	35.67
907.95	47.69	20276618	35.67
908.00	47.70	20276618	35.67
908.90	47.70	20276618	35.67
908.95	47.70	20276618	35.67
908.002	47.70	20276618	35.67
908.033	47.70	20276618	35.67
908.04	47.70	20278814	35.67
908.04	47.70	20282302	35.68
907.97	47.70	20289544	35.69
906.02	47.60	20334102	35.77

Determining Ultimate Recovery After knowing that the current reserve data is 56.9838 and the drive mechanism in the BDS oil field is water drive, we can determine the optimum reserve size that can be produced from the reservoir (ultimate recovery reserve). The recovery factor in the BDS oil field is 55%. then the size of the ultimate recovery reserve can be determined as follows:

UR = OOIP x RF (4)
= 56,9838 MMSTB x 55%
= 31.3411 MMSTB

Based on cumulative oil production (Np) data for the last year (2020) of 20,4556 MMSTB, calculations can be made:

$$RF = \frac{Np}{OOIP} \times 100\% \quad (5)$$
$$= \frac{20.4556}{56.9838} \times 100\%$$
$$= 35.89\%$$

Determination of remaining reserves in the “BDS” field is as follows:

Cadangan sisa = UR – Np (6)
= 31.3411 MMSTB – 20.4556 MMSTB
= 10.8854 MMST

V. DEVELOPMENT SCENARIO ANALYSIS

5.1. Basecase

The basecase well consists of 4 production wells which are simulated until the end of 2040. The results from the basecase will be used as a basis for comparison in planning the next scenario, so that the increase in the amount of oil (incremental oil) and the recovery factor value will be known. The results of the basecase scenario are shown in Figure 4.24. At the end of the predicted year, the cumulative oil production was 21.556 MMSTB and the RF value was 37.828%. The RF value is calculated as follows:

$$RF = \frac{Np}{OOIP} \times 100\% \quad (7)$$
$$= \frac{21{,}556}{56{,}9838} \times 100\%$$
$$= 37.828\%$$

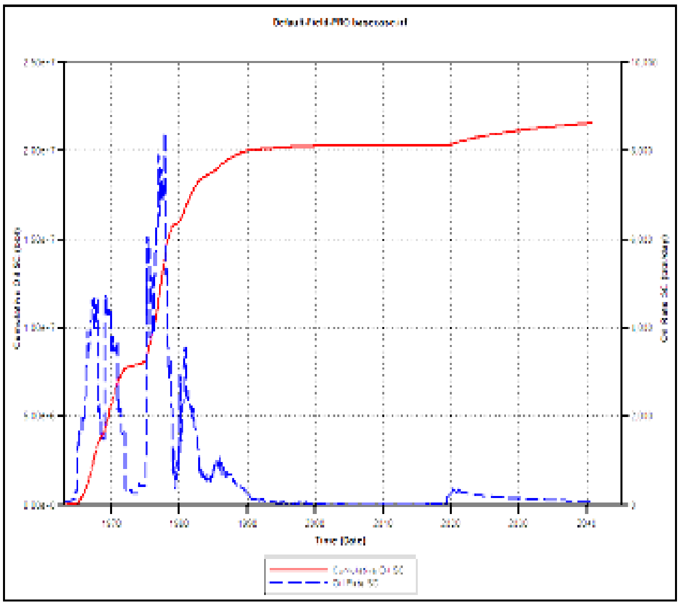

Figure 1.

BDS Basecase Field Oil Production Rate and Cumulative Results

Based on simulation results from 4 production wells, without additional injection wells or re-opening, the recovery factor was found to be 37.828% with cumulative oil production of 21.556 MMSTB.

5.2. Scenario 1

This is a scenario of re-opening 6 production wells which have been suspended so that the production wells become 10 wells without any injection wells. selected based on analysis of the feasibility parameters of each well. The suspended production well is planned to be reopened during the ongoing development of the "BDS" Field. All wells are analyzed to determine which wells are suitable for reopening. According to Tutuka Ariadji (2010) there are three parameters used to evaluate and determine field development techniques, including Oil Per Unit Area, permeability and pressure. These parameters are then analyzed using the Venn diagram concept and overlaying these parameters on each layer. It can be seen in Figure 2 below:

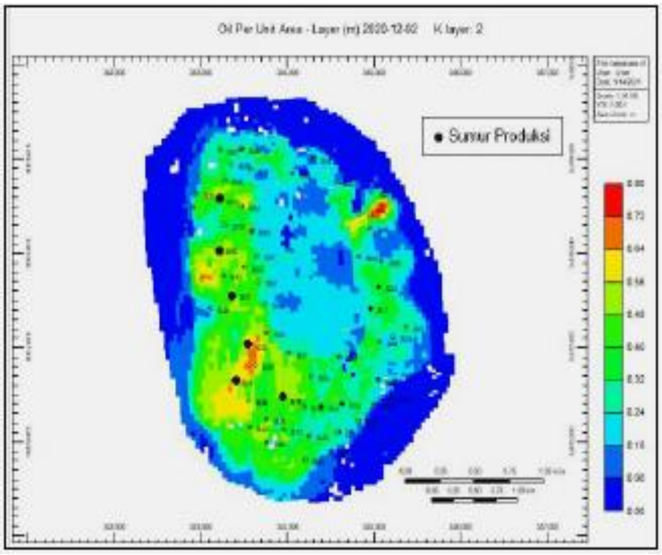

Figure 2

Results of Re-opening Well Candidate Analysis

The recovery factor value from the simulation results of this scenario is calculated using Equation 7.

$$\textit{Recovery Factor} = \frac{Np}{OOIP}\ x\ 100\%$$
$$= \frac{23{,}812}{56{,}9838}\ x\ 100\%$$
$$= 41.787\%$$

The simulation results in this scenario, namely with 4 production wells added to 6 re-opening wells, show a cumulative oil production of 23,812 MMSTB and a recovery factor value of 41.787%.

5.3. Scenario 2

In this scenario, field development uses the waterflooding method which is carried out with a line drive injection pattern. Determination of injection patterns that are possible to apply the waterflooding method is based on the reservoir conditions of the "BDS" Field. The selection of injection wells is a conversion well from a production well that has a high water cut and has been suspended. The injection well is selected based on the location of the production well and the results of analysis of permeability and oil parameters per unit area, so that the injection well is feasible and effective for use as an injection well. The addition of production wells and injection wells are conversion wells from production wells that have been selected from the candidate wells that have been analyzed. This scenario is scenario 1 with 10 production wells plus a number of injection wells.

The tabulation of production wells and injection wells in scenario 2 can be seen in Table 10 and the injection pattern for each scenario can be seen in Figure 3.

Table 10.Tabulation of Injection Wells and Production Wells Scenario 2

Scenario 2		
No	Injection Well	Production Well
1	B12	B01
2	B22	B11
3	B29	B14
4	B35	B18
5	B38	B19
6	B39	B23
7	B43	B31
8		B32
9		B37
10		B48

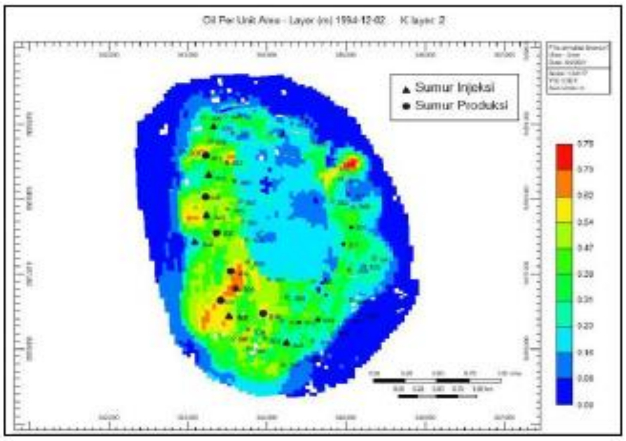

Figure 3

Scenario 2 Injection Pattern

The simulation is carried out with injection rate sensitivity to obtain the optimum injection rate value based on the recovery factor value obtained. Injection rate sensitivity analysis is shown in Table 11.

Table 11. Tabulation of Scenario 2 Sensitivity Analysis Results

Injection Rate Sensitivity	Np (MMSTB)	Recovery Factor (%)	Incremental Oil (%)
112	26.5620	46.613	8.79
150	27.5082	48.274	10.45
200	28.5181	50.046	12.22
250	29.3040	51.425	13.60
300	29.7707	52.244	14.42
350	30.0105	52.665	14.84
400	30.1243	52.865	15.04
450	30.1592	52.926	15.10
500	30.1107	52.641	15.01
550	30.0899	52.803	14.97
600	30.0155	52.674	14.85

The calculation values for the recovery factor and incremental oil values in scenario 2 use Equation 7 and Equation 8.

Recovery Factor $= \frac{Np}{OOIP}\ x\ 100\%$

$= \frac{29{,}3040}{56{,}9838}\ x\ 100\%$

= 51.425 %

Incremental Oil = RF scenario – RF basecase

= 51,425% – 37,828%

= 13.60%

The simulation results in this scenario are 10 production wells plus 7 injection wells with a line drive injection pattern and injection rate for a maximum RF value of 450 bwpd. The results obtained cumulative oil production of 30.1592 MMSTB and a recovery factor value of 52.926%. The optimum rate value is obtained with an injection rate of 250 bwpd which produces 29.303 MMSTB and a recovery factor of 51.425%.

5.4. Scenario 3

Scenario 3 is carried out by developing the field using the waterflooding method with a 4-spot irregular injection pattern. The addition of production wells and injection wells are conversion wells from production wells that have been selected from the candidate wells that have been analyzed. This scenario is scenario 1 with 10 production wells plus 11 injection wells.

The tabulation of production wells and injection wells in scenario 3 can be seen in Table 12 and the injection pattern for each scenario can be seen in Figure 4.

Table 12. Tabulation of Injection Wells and Production Wells Scenario 3

Scenario 2		
No	Injection Well	Production Well
1	B04	B01
2	B12	B11
3	B22	B14
4	B29	B18
5	B35	B19
6	B38	B23
7	B39	B31
8	B43	B32
9	B 52	B37
10	B53	B48
11	B54	

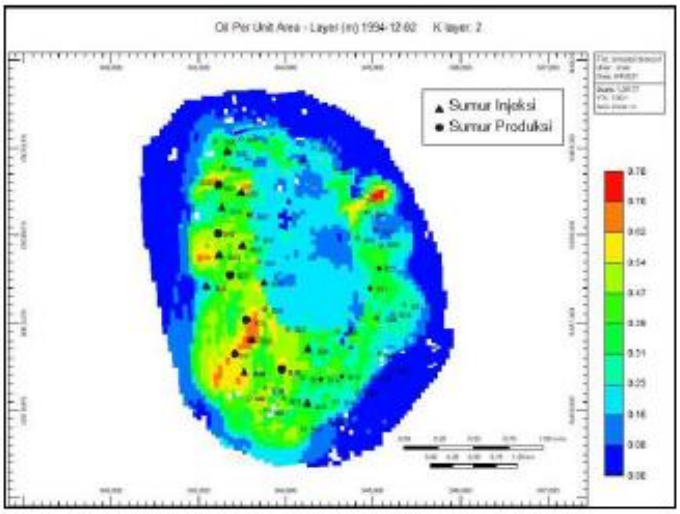

Figure 4

Injection Pattern Scenario 3

Injection rate sensitivity is carried out to obtain the optimum injection rate value based on the recovery factor value obtained. Injection rate sensitivity analysis is shown in Table 13.

Table 13. Tabulation of Scenario 3 Sensitivity Analysis Results

Injection Rate Sensitivity	Np (MMSTB)	Recovery Factor (%)	Incremental Oil (%)
112	27.6600	48.540	10.71
150	28.8077	50.554	12.73
200	29.8723	52.422	14.59
250	30.3199	53.208	15.38
300	30.4922	53.510	15.68
350	30.5304	53.577	15.75
400	30.5773	53.660	15.83
450	30.6049	53.708	15.88
500	30.6675	53.818	15.99
550	30.5916	53.685	15.86
600	30.5051	53.533	15.71

The calculation values for the recovery factor and incremental oil values in scenario 3 use Equation 3 - 7 and Equation 3 -8.

Recovery Factor $= \frac{Np}{OOIP}\ x\ 100\%$

$= \frac{29{,}8723}{56{,}9838}\ x\ 100\%$

= 50.554 %

Incremental Oil = RF scenario – RF basecase

= 50.554% – 37.828%

= 14.59%

The simulation results in this scenario are 10 production wells added with 11 injection wells with an irregular 4-spot injection pattern and an injection rate for a maximum RF value of 500 bwpd. The results obtained cumulative oil production of 30.6675 MMSTB and a recovery factor value of 53.818%. The optimum rate value is obtained with an injection rate of 200 bwpd which produces 14.59 MMSTB and a recovery factor of 50.554%.

VI. SUMMARY AND DISCUSSION

Based on the analysis of waterflooding method field development scenarios that have been carried out with the sensitivity of injection patterns and injection rates, optimum and maximum results for each scenario were obtained. Tabulation of recovery factor and incremental oil scenario results is shown in Table 14.

Table 14. Recovery Factor and Incremental Oil for Each Scenario

Scenario	Information	Injection Rate	Recovery Factor	Incremental Oil
		Bpd	%	
Basecase		-	37,828	-
Scenario 1			41.787	5.9
Scenario 2	Maximum	250	51.425	13.6
	Optimum	450	52.926	15.1
Scenario 3	Optimum	200	52.422	14.6
	Maximum	500	53.818	15.9

Based on the tabulation of scenario results carried out on the "BDS" field above, it can be seen that scenario 3 uses an injection rate of 200 bwpd with 10 production wells and 11 waterflood injection wells with an irregular 4-spot injection pattern, obtaining a cumulative oil production of 53,818 MMSTB and a recovery factor of 52.422%.

The prediction results from the various scenarios that have been carried out are as follows:

In the Basecase, predictions for the development of the "BDS" Field are carried out by continuing the production of wells that are still producing (4 wells) at the end of history matching until the prediction time of December 2040. The results from the basecase will be used as a basis for comparison in planning the next scenario, so that the increase in recovery will be known. the amount of oil (incremental oil) and the recovery factor value. In the base case scenario, the cumulative oil production is 21,556 MMSTB and the RF value is 37,828%.

In Scenario 1, this is a base case plus opening a production well that has been suspended (re-opening) based on the results of the analysis that has been carried out. There are 6 production wells that have been reopened. In scenario 1, the cumulative oil production is 23,812 MMSTB and the RF value is 41,787%. There are not many changes in scenario 1 from the base case predictions, this is because the pressure in each well is no longer able to lift oil to the surface and the reservoir is no longer able to push oil efficiently towards the wellbore.

Furthermore, for Scenario 2, scenario 1 is added with a waterflooding method with sensitivity in the form of a line drive injection pattern and injection rate. There are 7 injection wells. The sensitivity of the injection rate is analyzed in Table 9. The optimum injection rate is 250 bwpd with a cumulative oil yield of 29,304 MMSTB and a recovery factor value of 51.425% and an incremental oil value of 13.6%. The maximum injection rate is 450 bwpd with a cumulative oil yield of 30,159 MMSTB and a recovery factor value of 52,926% and an incremental oil value of 15.1%. The significant increase in the recovery factor value is due to water injection being efficient enough to push oil towards the drain radius of the production well and increasing the pressure in the production well so that oil can be produced to the surface.

In Scenario 3, which is scenario 1, the waterflooding method is added which is carried out with an irregular 4-spot injection pattern, there are 11 injection wells. The addition of injection wells is no longer possible because the injection water supply obtained from production wells is no longer sufficient. This scenario uses the sensitivity of the injection rate which is analyzed in Table 10. The optimum and maximum injection rate is 200 bwpd with a cumulative oil yield of 29,872 MMSTB and a recovery factor value of 52.422% and an incremental oil value of 14.59%. Like scenario 2, the significant increase in the recovery factor value is due to successful water injection and high efficiency in pushing oil towards the drain radius of the production well and increasing the pressure in the production well so that oil can be produced to the surface.

Based on the results of the analysis that has been carried out, it can be concluded that the development of the "BDS" Field using the waterflooding method in scenario 3 with a water injection rate of 200 bwpd is considered the most optimal scenario. This can be seen in the graphic analysis of scenario 3 of the cumulative value of oil production which is still high in line with production time. Based on oil depletion predictions, the injection pattern in scenario 3 has a high level of efficiency in pushing oil towards the depletion radius of the production well and increasing the pressure in the production well so that oil can be produced to the surface.

Utilizing suspended wells into production wells (reactivation) and into injection wells means that the cost of this project is cheaper because you don't have to make a new well. By reactivating 6 suspended wells, water production will increase and by re-injecting 250 bbl per injection well from 11 injection wells, it is hoped that waste water treatment will be more efficient and save costs.

VII. CONCLUTION

1. The reservoir simulation results in the basecase scenario have a cumulative oil production of 21,556 MMSTB and a recovery factor value of 37,828%.
2. Scenario 1 is a basecase scenario added by reopening 6 production wells (re-opening) and obtained from the simulation results to produce a cumulative oil production of 23,812 MMSTB and a recovery factor value of 41,787%.
3. Scenario 2 is scenario 1 with 10 production wells added with 7 injection wells with a line drive pattern and from the results of injection rate sensitivity, the optimum injection rate of 250 bwpd produces a recovery factor value of 51.425% with cumulative oil production of 29.304 MMSTB.
4. Scenario 3 is scenario 1 with 10 production wells and 11 injection wells added with an irregular 4-spot injection pattern and the optimum injection rate sensitivity results are 200 bwpd resulting in a recovery factor value of 52.422% with cumulative oil production of 29.8723 MMSTB.
5. So in waterflood planning, scenario 3 was chosen which has the largest recovery factor with an increase of 14.614% from the base case.

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