

## Optimum Pattern and Rate Injection Determination of Waterflooding Project (Case Study in Block “A” on “DS” Field)

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### Abstract

“DS” field is one of the mature field located in Block “A” which has been produced since 1975. The remaining reserves of this field is 14,285 MSTB with remaining recovery factor 25.04%. The Water Oil Contact is up-leveling during the production phase where in current condition, this field has high water cut which means high water production. While the remaining reserves is still big enough to produce and the field produces a lot of water, field development with waterflooding method may be applied. Analysis of development scenarios using ECLIPSE 2010.1 reservoir simulation software. The parameter considered is the pattern and rate of injection. Base case is a scenario that simulates the field from history matching condition until August 2032. Scenario 2 with peripheral injection pattern and the 9 scenarios of injection rate. Scenario 3 with regular injection patterns 5 and 6 spots injection rate scenario. Scenario 4 with regular injection patterns 4 spot and 6 injection rate scenario. From engineering analysis, the best scenario is Scenario 2 with 10 peripheral injection wells but from economic analysis, the best fit scenario is Scenario 3 with 8 5-spot injection wells.

**Keywords:** Reservoir simulation; Waterflooding; Pattern; Injection rate; Development scenario

### Introduction

“DS” field is located in the Central Sumatra Basin, Sumatra, Indonesia. The number of wells currently active (until December 2011) is 27 wells. Until December 2011, there are 36 wells on the “DS” field with 27 production wells that still produce with primary recovery method, 4 abandoned wells, and 5 suspended wells. “DS” field is one of the mature fields that has been produced since 1975. There was a decrease in the field rate of production measured in 2009-2013 from 1,000 BOPD to 600 BOPD. The remaining reserves at this field is 14,285 MSTB which is big enough to be produce trough seconderay recovery method.

Since “DS” field has a high water production (high water cut), large remaining reserves and able to utilize a large water production, then this field is considered to be developed with waterflooding methods.

The purpose of this paper is to develop Field “DS” to waterflooding methods to improve oil recovery in the field “DS”. Meanwhile, the objective is to determine the pattern of injection and optimum injection rate that can be applied to the field “DS” [1].

### Material and Methods

Here are the steps being taken to solve the problems in the paper are: Collecting and processing the necessary data, specifying drainage radius wells are then made bubble map, Determining candidates injection wells, injection wells Determining patterns. Determining the injection rate, doing scenario development to determine the pattern and the optimum injection rate; and evaluate the scenario by incremental RF, RF parameters, and economic analysis [2]. The methodology of this paper is shown in Figure 1.

According to Thakur, Ganesh. in the development of waterflooding, there are some things that need to be considered in planning the development of the flood pattern waterflooding among other things, performance prediction, and determination of reserves [2].

Water injection is a water injection rate per unit pressure difference between the production and injection wells. A drastic decline in water

injection occurs at the beginning of the injection until the reservoir is filled solution gas drive. After the fill-up, variations of water injection rate is also affected by the mobility ratio. If  $M=0$  then it will be a constant injection rate, increased if  $M>1$  (which is not expected), and decreased

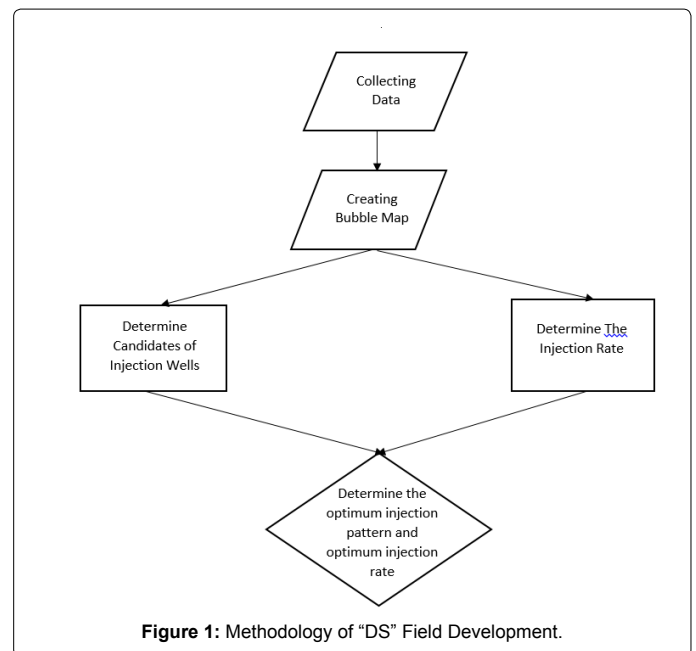


Figure 1: Methodology of “DS” Field Development.

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if  $M < 1$  (which is expected). Criteria for a court to say the prospect of doing waterflooding is a field that has a high water cut and the field have an adequate water supply injection [3]. Stages in the development field "DS" using waterflooding as follows:

### Specifying drainage radius and plotted on the bubble map

The radius of the absorption is the radial distance from a borehole in the reservoir where there is fluid flow (oil and water) into the well and outside the boundary where the pressure *reservoir* fixed and no fluid flow occurs. The radius of the intended absorption is effective draining radius ( $r_e$ ) to each well which has not changed and is the maximum value of the radius of dewatering wells ( $r_d$ ) at steady state conditions [4].

$$r_e = r_w EXP \frac{0,00708kh(P_e - P_{wf})}{\mu_o B_o q_o} \quad (1)$$

where;  $r_e$ : boundary radius, ft;  $P_{wf}$ : bottom-hole flowing pressure, psi;  $r_w$ : well radius, ft;  $\mu_o$ : oil viscosity, cp;  $k$ : permeability, mD;  $B_o$ : oil formation volume factor, bbl/STB;  $h$ : thick of layer, ft;  $q_o$ : rate of oil production, bbl.day;  $P_e$ : external boundary pressure, psi.

After getting the calculation of drainage radius of each well, then be plotted on the bubble map.

### Determining candidates injection wells

In the Field development "DS" to waterflooding methods, candidate wells - injection wells are used to suspend the conversion wells and production wells are analyzed using the scatter plot by watching the water parameters and cumulative high cut low production and small production rate [5].

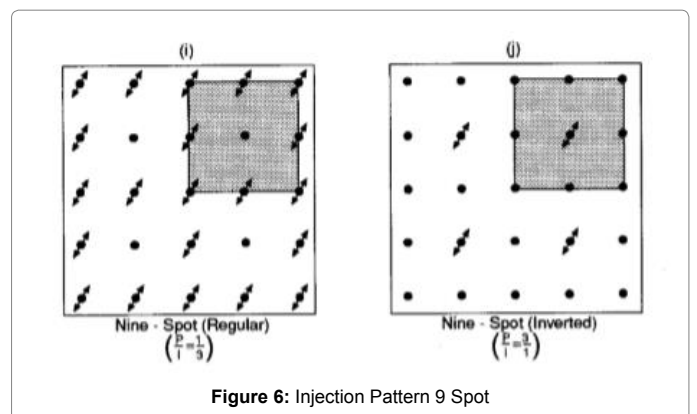
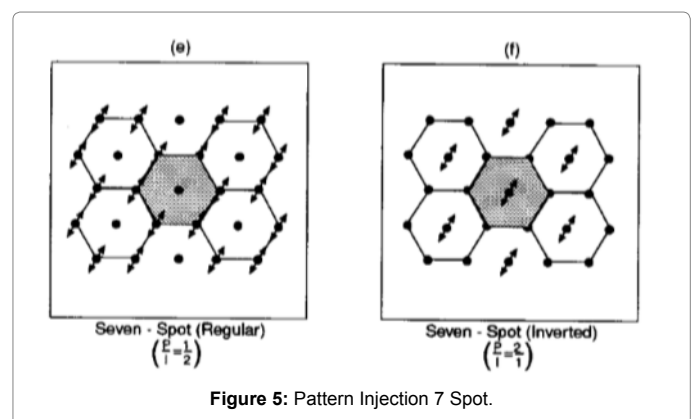
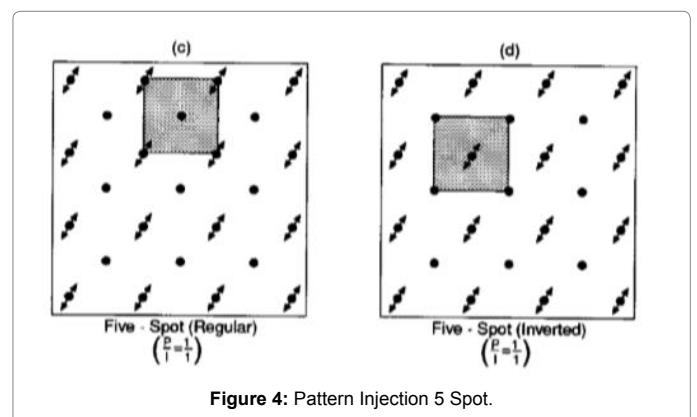
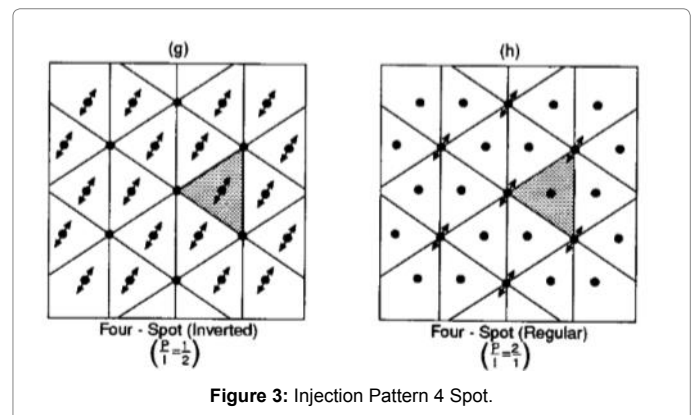
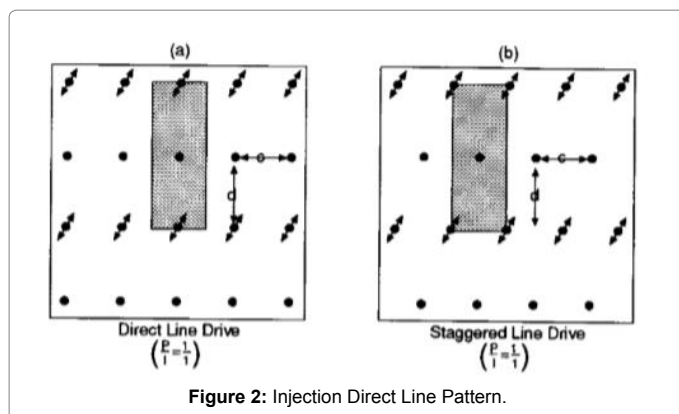
### Determining the injection pattern

Injection pattern is one important parameter in planning waterflooding. Pattern - a pattern that can be applied include direct line, regular and inverted 4 spots, 5 spots, 7 spots, 9 spots, peripherals.

These are the images of injection pattern according to Ganesh Thakur and Wilhite (Figures 2-7) [1].

### Injection rate determination

The Injection rate is determined by the method of voidage replacement ratio. Voidage Replacement Ratio (VRR) is the ratio of the volume of fluid injection with a fluid volume of production (Aldousary, 2015). Mathematically expressed in eqns. (2) and (3).



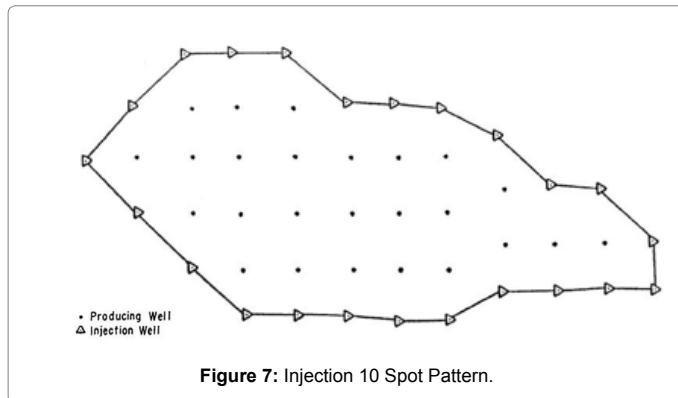


Figure 7: Injection 10 Spot Pattern.

$$VRR = \frac{\text{injected volume}}{\text{produced volume}}$$

$$VRR = \frac{\text{injected volume}}{W_p + N_p} \quad (2)$$

$$IR = \frac{\text{injected volume}}{(365 \times n)} \quad (3)$$

where;

Wp: cumulative water production (MBBL); Np: cumulative oil production (MBBL); IR: the rate of water injection (bbl/day); N: time of injection (days).

### Scenario analysis results against rf

The parameters that determine the effectiveness of development scenarios performed on Field “DS” to calculate the increase and incremental oil recovery factor from each scenario against basecase. Eqn. (4) shows the RF equation and eqn. (5) shows the determination of incremental oil equation [6].

$$RF = \frac{N_p}{OOIP} \times 100\% \quad (4)$$

$$Inc. oil = \frac{N_{p \text{ scenario}} - N_{p \text{ basecase}}}{N_{p \text{ basecase}}} \times 100\% \quad (5)$$

where; RF: Recovery Factor, %; Inc. oil: Incremental Oil to the Basecase, %.

## Case Study

### Data

The reservoir on “DS” Field located on two formation: Layer A with 50 ft of thickness and Layer B with 150 ft of thickness. Productive formation of “DS” field is shown in Figure 8 and Table 1.

### Determination drainage radius depletion

The drainage radius draining manually calculated by eqn. (1). Example calculation of the drainage radius of DS\_1 wells. Field drainage radius “DS” on the Layer A is shown in Figure 9. Radius dewatering and Field “DS” on the Layer B is shown in Figure 10.

### Determination of injection wells

Prospects of production wells used injection wells are wells that have had high water cut and low Np. Figure 11 shows the results of the analysis of the scatter plot of water cut Cumulative (%) with cumulative oil production (bbl) in the Field “DS” [7]. The classifications are shown in Table 2.

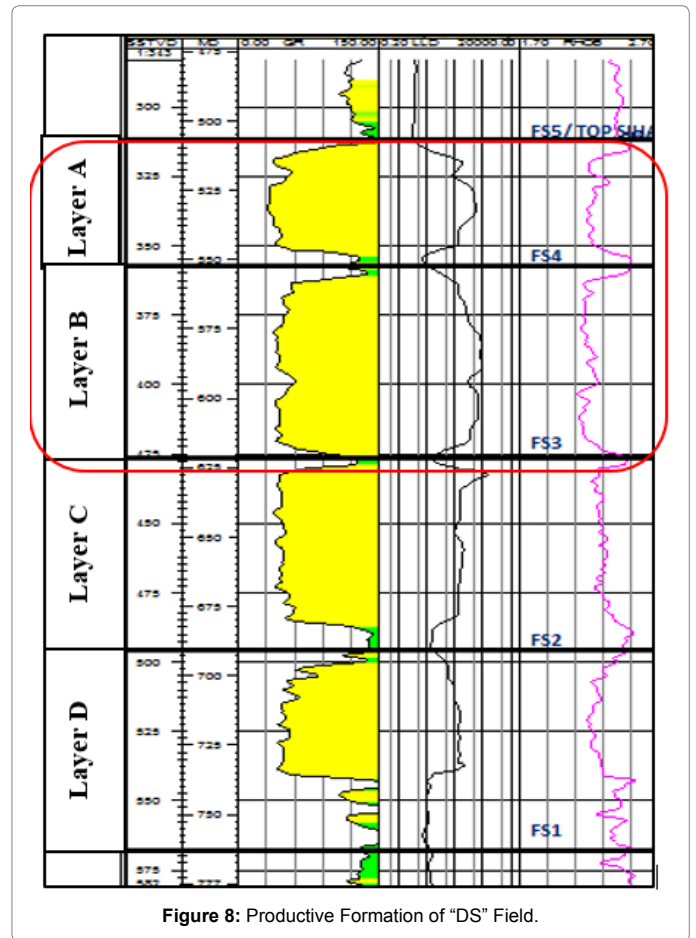


Figure 8: Productive Formation of “DS” Field.

Parameter	Information
OOIP	49,488 MSTB
Backup Time	14,285 MSTB
Drive Mechanism	Water Drive
RF	25.04%
API Gravity Oil	31.7
Initial Pressure	2,860 psi

Table 1: Data Reservoir and Simulation.

Class	Water Cut (%)	Np (Mbbbl)	Oil Rate (bbl/day)
High	>95.4	>816	>26
Medium	89.6-95.4	235.5-816	11.0-26
Low	<89.6	<235.4	<11

Table 2: Classification of Injection Well Based on Water Cut, Np, and Oil Rate.

In addition to notice water cut and cumulative production parameters, determining candidate also noticed parameter injection wells oil production rate. based on analysis of the ability of the reservoir, obtained the following classifications. Table 3 shows the results of the analysis of the injection wells candidate determination based oil rate

### Injection pattern determination

Based on the analysis of the determination of the injection wells, there are 17 wells that are candidates injection wells. The number of production wells, there were 15 wells. In consideration of injection wells more of the production wells injection patterns that can be applied is peripheral, regular 5 spot, and regular 4 spot. Third injection

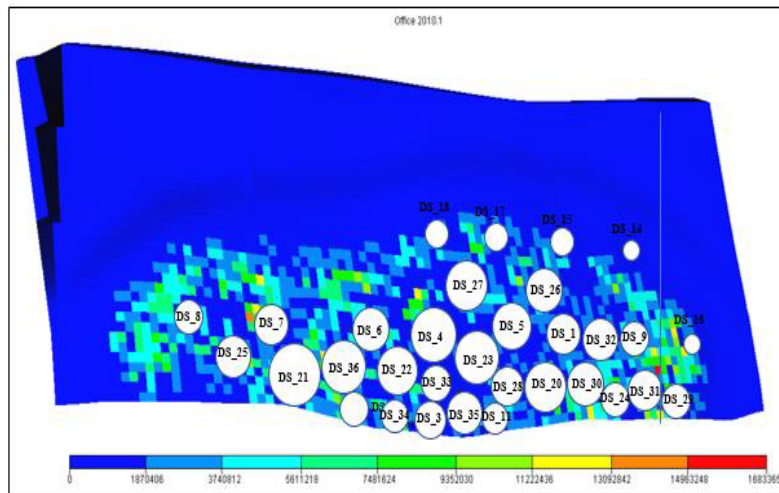


Figure 9: Re Field "DS" Layer A.

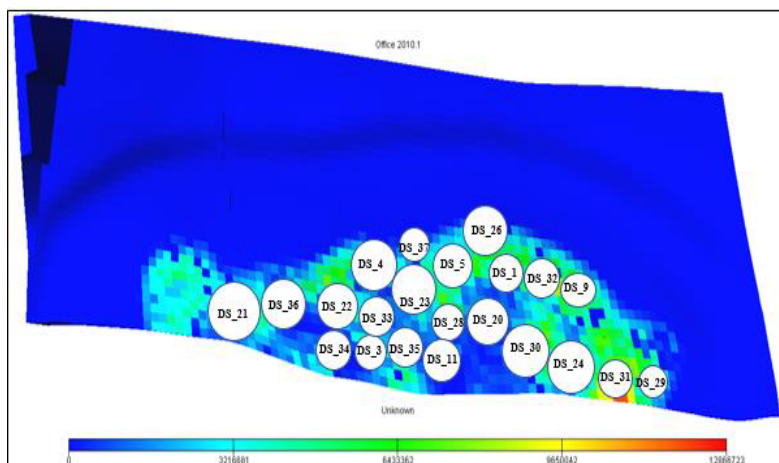


Figure 10: Field Re "DS" Layer B.

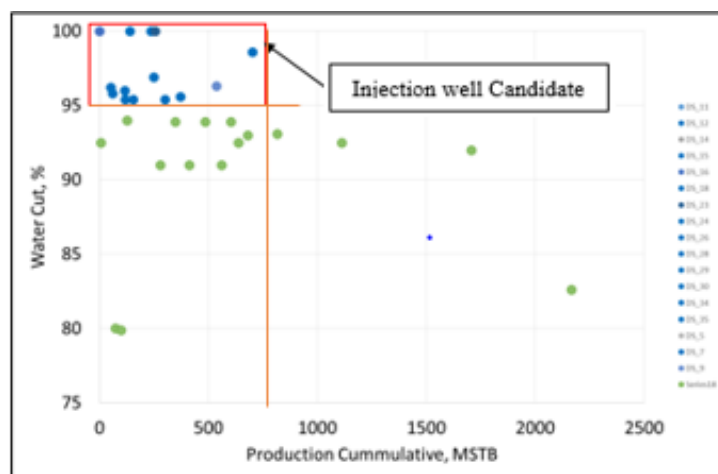


Figure 11: Scatter Plot Candidates Injection Wells.

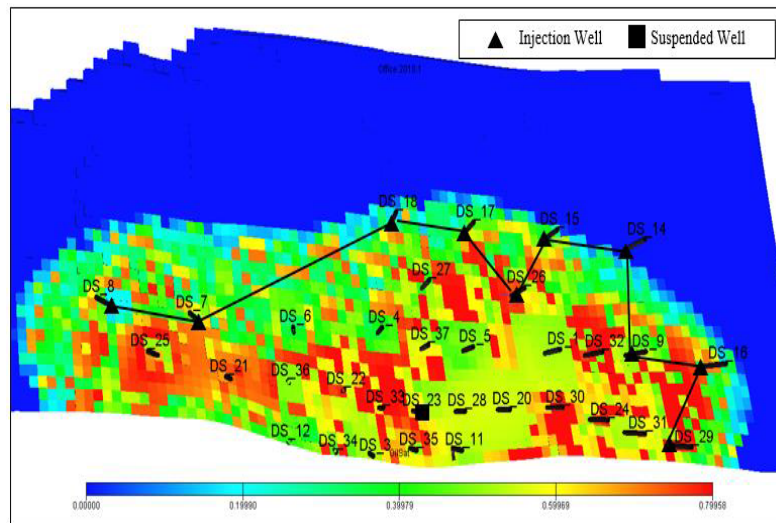


Figure 12: Pattern of Peripheral Injection Scenario 2.

Well	Oil Rate (bbl/day)	Information
DS_11	8	LOW
DS_12	10	LOW
DS_14	0	LOW
DS_15	0	LOW
DS_16	0	LOW
DS_18	0	LOW
DS_23	0	LOW
DS_24	8	LOW
DS_11	8	LOW
DS_12	10	LOW
DS_5	8	LOW
DS_26	4	LOW
DS_28	3	LOW
DS_29	8	LOW
DS_30	8	LOW
DS_34	8	LOW
DS_35	5	LOW

Table 3: Determination of Wells Injection Candidate Analysis.

pattern will be divided into three development scenarios. In scenario 1 with peripheral injection patterns, there are 10 injection wells. Producing wells in the Field "DS" as many as 22 wells. Figure 12 shows the injection patterns in scenario 2. Table 4 shows the tabulation of the injection wells and production wells scenario 2..

Table 5 shows the tabulation of injection and production wells in Scenario 3 with regular injection patterns 5 spot. Injection pattern in Scenario 3 is shown in Figure 13.

Table 6 shows the tabulation of injection and production wells in scenario 4 with a regular injection patterns 4 spot. Patterns injection in scenario 4 is shown in Figure 14.

### Injection rate determination

Field "DS" has never been the development of the field with waterflooding methods, then there is no data prior injection rate. The injection rate is determined by the method of voidage replacement ratio [8]. The amount of injection rate calculated by eqns. (2) and (3).

Injection wells	Location Grid
DS_8	B1
DS_7	C2
DS_18	A4
DS_17	A5
DS_15	A6
DS_16	C8
DS_29	E8
DS_14	A7
DS_9	C7
DS_26	B6

Table 4: Well Injection - Production Scenario.

Production	Injection
DS_20	DS_11, DS_26, DS_15, DS_30
DS_31	DS_24, DS_9, DS_16, DS_29

Table 5: Injection wells - Production Scenario 3.

Production wells	Injection wells
DS_3	DS_34, DS_35, DS_23
DS_27	DS_5, DS_18, DS_17
DS_31	DS_24, DS_9, DS_29
DS_32	DS_30, DS_9, DS_15

Table 6: Well Injection - Production Scenario 4.

$$VRR = \frac{\text{injected volume}}{W_p + N_p}$$

$$0.7 = \frac{\text{injected volume}}{23114687}$$

$$\text{Injected Volume} = 16,180,281 \text{ Mbbbl/year}$$

$$N \text{ (days)} = 1/02/2018 - 7/31/2032 \text{ (5294 days)}$$

$$\text{Injected Rate} = \frac{\text{injected volume}}{(n)} \frac{16180281}{(5294)}$$

$$\text{Injected Rate} = 3,300 \text{ bbl/day}$$



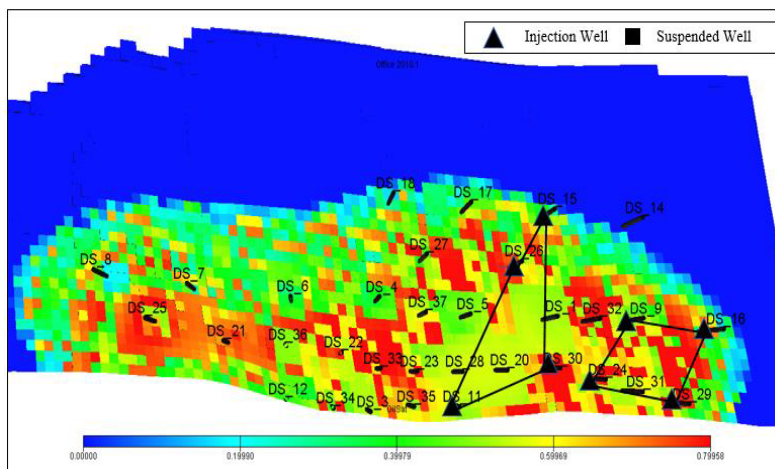


Figure 13: Pattern of Peripheral Injection Scenario 3.

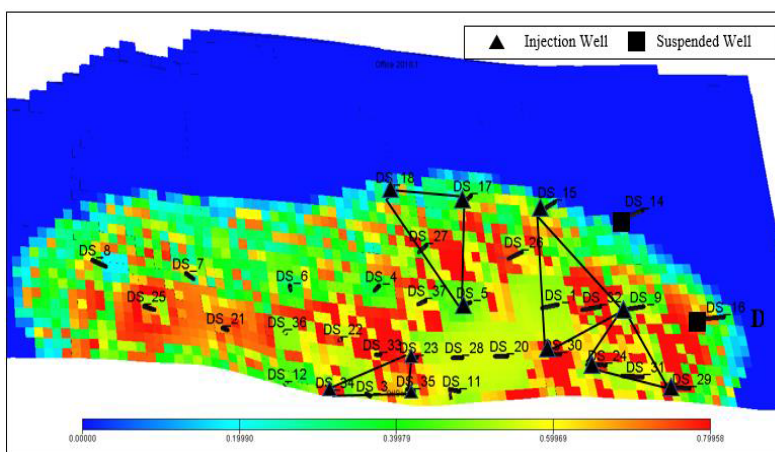


Figure 14: Pattern of Peripheral Injection Scenario 4.

## Scenario development

There are several scenarios performed on Field "DS", among others:

**Scenario 1 (Base case):** In basecase, the predictions made by forwarding the production wells that are still in production (27 wells) at the end of history matching up to August 2032.

**Scenario 2 (Basecase+conversion of 10 wells):** In this scenario made the development of the basecase+conversion of 10 production wells into injection wells, which means there are 17 production wells. In this scenario conducted some sensitivity rate of up to optimum such as 330 bbl/day, 500 bbl/day, 800 bbl/day, 1000 barrels/day, 2000 barrels/day, 2500 barrels/day, 10000 bbl/day, 15000 bbl/day, and 20000 bbl/day. This scenario made on February 1, 2018 until July 2032. The pattern of injection wells is peripheral (Table 7).

**Scenario 3 (Basecase+Conversion of 8 wells):** In this scenario do development basecase+conversion of 8 wells into the injection wells, which means there are 19 production wells. In this scenario conducted some sensitivity rate of up to optimum such as 412 bbl/day, 500 bbl/day, 800 bbl/day, 1000 barrels/day, 2000 barrels/day, and 2500 bbl/day. Skenario was conducted on February 1, 2018 to July 2032. The pattern of injection wells is a regular 5 spot.

**Scenario 4 (Basecase+conversion of 11 wells):** In this scenario made the development of the basecase+conversion of 11 production wells into injection wells, which means there are 16 production wells. In this scenario conducted some sensitivity rate of up to optimum such as 253 bbl/day, 500 bbl/day, 800 bbl/day, 1000 barrels/day, 2000 barrels/day, and 2500 bbl/day. This scenario made on February 1, 2018 until July 2032. The pattern of injection wells is a regular 4 spot.

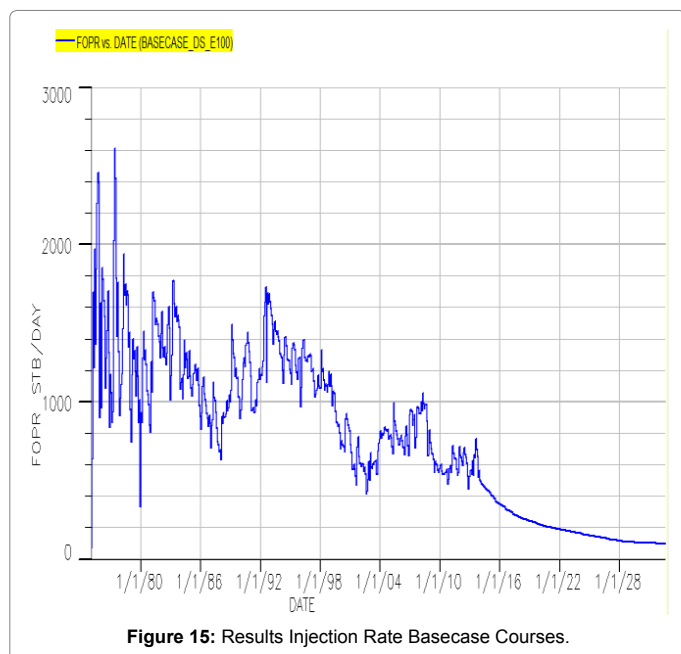
## Result

### Scenario 1 (Basecase, 27 production wells)

Basecase is to maintain the last state scenario Field "DS" which consists of 27 production wells were simulated by the end of 2032. The results of prediction basecase used as a basis of comparison in the next scenario planning so they will know the amount of the increase in oil recovery and recovery factor. At the end of 2032 with the existing wells, 27 production wells are obtained cumulative oil production amounted to 13,764,277 STB and RF 27.81%. The recovery factor in the Field "DS" decrease from the original 38.92% to 27.81% due to more wells were dead because of pitch-cut off by constraints on basecase. With this scenario, field able to produce until August 2032. RF calculations were done using eqn. (4) (Figure 15).

Case	Objectives	Notes
Scenario 1 (BC)	Do nothing	Production from 27 existing wells
Scenario 2	Basecase + Conversion of 10 Wells – Peripheral (17 Production Wells)	Rate Sensitivity:
		2A. 330 bbl/day
		2B. 500 bbl/day
		2C. 800 bbl/day
		2D. 1,000 bbl/day
		2E. 2,000 bbl/day
		2F. 2,500 bbl/day
		2G. 10,000 bbl/day
Scenario 3	Basecase + Conversion of 8 Wells - Regular 5 Spot (19 Production Wells)	Rate Sensitivity:
		3A. 412 bbl/day
		3B. 500 bbl/day
		3C. 800 bbl/day
		3D. 1,000 bbl/day
		3E. 2,000 bbl/day
Scenario 4	Basecase + Conversion of 11 Wells - Regular 4 Spot (16 Production Wells)	Rate Sensitivity:
		4A. 253 bbl/day
		4B. 500 bbl/day
		4C. 800 bbl/day
		4D. 1,000 bbl/day
		4E. 2,000 bbl/day
		4F. 2,500 bbl/day

Table 7: Scenarios for Field Development.



Sken.	Rate (bbl/day)	NP (STB)	RF (%)	Incr. (%)
2A	330	1,44,03,380	29.1	1.291
2B	500	1,44,16,182	29.13	1.317
2C	800	1,44,37,587	29.17	1.361
2D	1,000	1,44,51,079	29.2	1.388
2E	2,000	1,45,09,753	29.32	1.506
2F	2,500	1,45,34,246	29.36	1.556
2G	10,000	1,47,45,824	29.79	1.983
2H	15,000	1,47,81,505	29.86	2.056
2I	20,000	1,47,38,987	29.78	1.97

Table 8: RF Tabulation and Incremental Oil on Skenario 2.

are assumed to cost USD 600,000/well/year. The cost of installation of the water injection pump, for example, an Elmar water/grease. The cost of installing a gathering system for the water gathering and maintenance is USD 100,000. The cost of installing water lines for transporting the water from the oil well where the water well is, execution of associated civil works and maintenance of water facility for two years is less than USD 950,000. So, the total cost for injection plant is USD 85,050,000. Table 8 shows the results of the injection rate scenario in scenario 2.

Determining the optimum rate is not indicated by the acquisition of the largest cumulative oil production but by determining the intersections between it and injection rate [10]. This well able to produce until August 2032. The result of the analysis of the optimum injection rate shown in Figure 16.

In scenario 2 with the peripheral injection pattern optimum injection rate of 6,600 bbl/day with 14,640 Mbbl of oil cumulative production. With this scenario, field able to produce until August 2032 with 2,865 bbl/day of oil production rate. By assuming that production cost is 5 USD/bbl, then total production cost is 73,200,000 USD .

$$RF = \frac{N_p}{OOIP} \times 100\% \quad (6)$$

$$RF = \frac{13764277}{49488000} \times 100\% = 27.81\%$$

### Scenario 2 (Basecase+conversion of 10 wells)

In scenario 2 with peripheral injection patterns performed 9 injection rate scenarios [9]. All injection wells whether new or existing,

### Scenario 3 (Basecase+conversion of 8 wells)

In scenario 3 with regular injection patterns performed 5 spot injection rate scenario [9].

All injection wells whether new or existing, are assumed to cost USD 600,000/well. The cost of installation of the water injection pump, for example, an Elmar water/grease. The cost of installing a gathering system for the water gathering and maintenance is USD 100,000. The cost of installing water lines for transporting the water from the oil well where the water well is, execution of associated civil works and maintenance of water facility for two years is less than USD 950,000. So, the total cost for injection plant is USD 68,250,000. Table 9 shows the results of injection rate scenarios in Scenario 3.

Determining the optimum rate is not indicated by the acquisition of the largest cumulative oil production but by determining the intersections between injection rate and Np [9]. Results of analysis of optimum injection rate shown in Figure 17.

In scenario 3 with the peripheral injection pattern optimum injection rate of 1,270 bbl/day with 14,420 Mbbl of oil cumulative production. With this scenario, field able to produce until August 2032 with 2,822 bbl/day of oil production rate. By assuming that production cost is 5 USD/bbl, then total production cost is 72,100,000 USD.

### Scenario 4 (Basecase+conversion of 11 wells)

In scenario 4 with regular injection patterns performed 4 spot injection rate scenario (Ahmad Tarek, 2012).

All injection wells whether new or existing, are assumed to cost USD 600,000/well. The cost of installation of the water injection pump, for example, an Elmar water/grease. The cost of installing a gathering system for the water gathering and maintenance is USD 100,000. The cost of installing water lines for transporting the water from the oil well where the water well is, execution of associated civil works and

maintenance of water facility for two years is less than USD 950,000. So, the total cost for injection plant is USD 93,450,000. Table 10 shows the results of injection rate scenarios in Scenario 4 with the acquisition of Np.

Determining the optimum rate is not indicated by the acquisition of the largest cumulative oil production but by determining the intersections between injection rate and Np [11]. Results of analysis of the optimum injection rate shown in Figure 18.

Table 11 showed the analysis of optimum injection rate for the whole scenario. In scenario 4, with the peripheral injection pattern optimum injection rate of 1,150 bbl/day with 14,240 Mbbl of oil cumulative production. With this scenario, field able to produce until August 2032 with 2,822 bbl/day of oil production rate. By assuming that production cost is 5 USD/bbl, then total production cost is 71,200,000 USD (Figure 18).

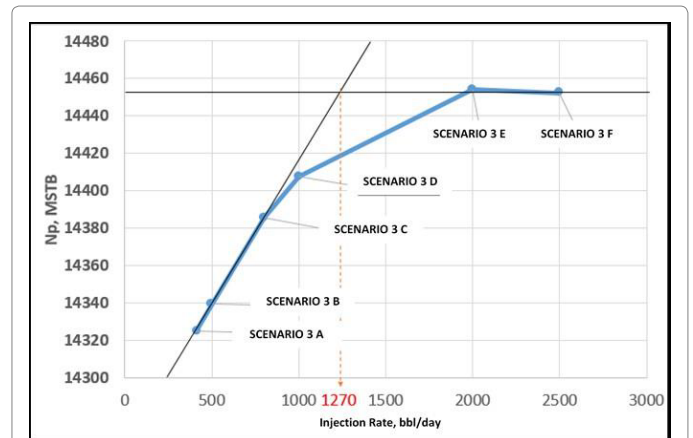


Figure 17: Rate Analysis Optimum Scenario 3.

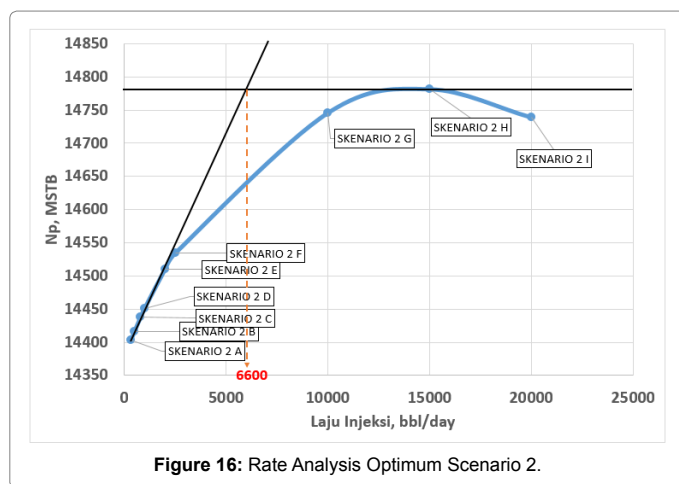


Figure 16: Rate Analysis Optimum Scenario 2.

Sken.	Rate (bbl/day)	Np (STB)	RF (%)	Incr. (%)
3A	412	1,43,24,782	28.946	1.133
3B	500	1,43,39,391	28.975	1.162
3C	800	1,43,85,445	29.069	1.255
3D	1,000	1,44,07,337	29.113	1.299
3E	2,000	1,44,54,031	29.207	1.394
3F	2,500	1,44,52,390	29.204	1.39

Table 9: RF Tabulation and Incremental Oil on Skenario 3.

Sken.	Rate (bbl/day)	Np (STB)	RF (%)	Incremental (%)
4A	253	1,41,24,848	28.54	0.729
4B	500	1,41,69,838	28.63	0.82
4C	800	1,42,15,517	28.72	0.912
4D	1,000	1,42,35,542	28.76	0.952
4E	2,000	1,42,69,069	28.83	1.02
4F	2,500	1,42,42,892	28.78	0.967

Table 10: RF Tabulation and Incremental Oil on Skenario 4.

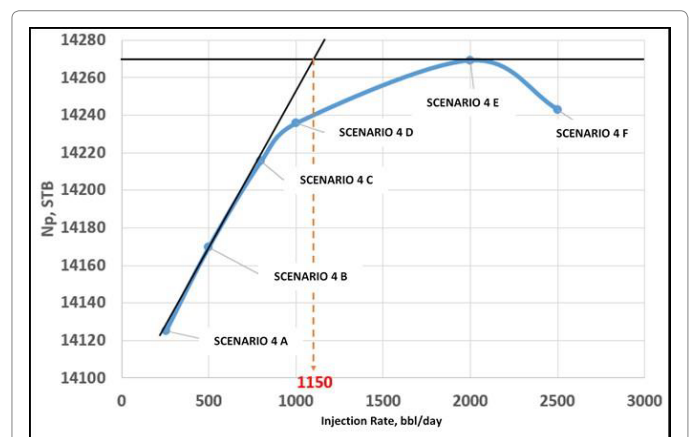


Figure 18: Rate Analysis Optimum Scenario 4.



### Economic analysis

The selection of the best scenario wasn't only analyzed based on the increase of cumulative oil production and recovery factor obtained from each scenario [12]. However, it is important to consider the economics of each scenario. Table 12 shows production cost estimation; Table 13 shows injection plant cost estimation; and Table 14 shows cost analysis of "DS" field.

Based on the economic analysis above, each scenario produces different profits according to the treatment in each scenario.

### Discussion

Field "DS" is an old oil field located in Block A, Central Sumatra Basin, Indonesia. The decline of the rate production at Field "DS" occur at the year 2009-2013 is from 1,000 BOPD to 600 BOPD. The productive zone of "DS" field is located at Bekasap Sihapas Group Formation. The condition of the reservoir consists of 120°F reservoir temperature and 438 ft of datum depth reservoir. From the laboratory result, the API of the oil is 31.29, the viscosity is 23.9686 cp, and the dominant composition of hydrocarbon is C7+ (87.6%).

Based on the analysis of the scatter plot, there are 16 production wells into injection wells among other candidates DS<sub>14</sub>, DS<sub>15</sub>, DS<sub>16</sub>, DS<sub>18</sub>, DS<sub>23</sub>, DS<sub>28</sub>, DS<sub>26</sub>, DS<sub>35</sub>, DS<sub>29</sub>, DS<sub>24</sub>, DS<sub>32</sub>, DS<sub>34</sub>, DS<sub>12</sub>, DS<sub>30</sub>, DS<sub>37</sub>, and DS<sub>17</sub>. Moreover, PI matching done at the key well and some of the production wells that still alive such as DS<sub>31</sub>, DS<sub>32</sub>, DS<sub>33</sub>, DS<sub>36</sub>.

Injection patterns which can be applied to the field "DS" is peripheral, regular 5 spot, and regular 4 spot with more consideration

Scenario	Inj. Rate (bbl/day)	Np (Mbbl)	% RF	% Inc RF
2 (peripheral)	6,600	14,640	29.58	1.77
3 (regular 5 spots)	1,270	14,420	29.13	0.96
4 (regular 4 spots)	1,150	14,240	28.77	1.32

Table 11: Tabulation Injection Rate Optimum Whole Scenario.

Scen	Prod. Wells	Q, (bbl/day)	Production Cost (USD/bbl)	Total Production Cost (USD)
2	17	2,865	5	7,32,00,000
3	19	2,822	5	7,21,00,000
4	16	2,787	5	7,12,00,000

Table 12: Total Production Cost of "DS" Field.

Scen.	Injc. Wells	Inj. Cost (USD/well)	Maint. & Gath. System (USD)
2	10	6,00,000	1,00,000
3	8	6,00,000	1,00,000
4	11	6,00,000	1,00,000
Scen.	Water Plant (USD)		Total Injection Cost (USD)
2	9,50,000		8,50,50,000
3	9,50,000		6,82,50,000
4	9,50,000		9,34,50,000

Table 13: Total Injection Cost of "DS" Field.

Scen.	Total Production Cost (USD)	Total Injection Cost (USD)	Gross Income (Np x 50 USD/bbl, USD)	Net Income (USD)
2	7,32,00,000	8,50,50,000	87,84,00,000	72,01,50,000
3	7,21,00,000	6,82,50,000	86,52,00,000	72,48,50,000
4	7,12,00,000	9,34,50,000	85,44,00,000	68,97,50,000

Table 14: Cost Analysis of "DS" Field.

of wells into injection wells compared to a production well. This is based on the total injection wells which are 17 wells and total production wells which is 15 wells.

Voidage Replacement Ratio Based on the analysis, the optimum injection rate of Field "DS" is based on an analysis of 3300 bbl/day. This method is the comparison between the injected volume fluids with the total fluids being produced [13-15].

There are 22 development scenarios performed on Field "DS". Based on the engineering analysis of reservoir simulation conducted obtained Np (cumulative production) and RF (recovery factor), scenario optimum that can be applied to the field "DS" is the injection pattern of peripherals of 10 injection wells with the injection rate of 6,600 bbl/day which resulted in the acquisition of Np at 14,640 MSTB, RF 29.58%. But economically speaking, the best scenario for this field is Scenario 3 with 8 5-spot injection wells since it has the highest net income on 72,850,000 USD. This is because the operational cost for 8 injection wells is cheaper than operation cost for 10 injection wells compare to income achieved from the oil cumulative production from both scenarios [16-18].

### Conclusion

- Based on the analysis of the scatter plot, there are 16 production wells into injection wells among other candidates DS<sub>14</sub>, DS<sub>15</sub>, DS<sub>16</sub>, DS<sub>18</sub>, DS<sub>23</sub>, DS<sub>28</sub>, DS<sub>26</sub>, DS<sub>35</sub>, DS<sub>29</sub>, DS<sub>24</sub>, DS<sub>32</sub>, DS<sub>34</sub>, DS<sub>12</sub>, DS<sub>30</sub>, DS<sub>37</sub>, and DS<sub>17</sub>.
- Injection patterns which can be applied to the field "DS" is peripheral, regular 5 spot, and regular 4 spot with more consideration of wells into injection wells compared to a production well.
- Voidage Replacement Ratio Based on the analysis, the optimum injection rate of Field "DS" is based on an analysis of 3,300 bbl/day.
- From engineering analysis, the best scenario is Scenario 2 with 10 peripheral injection wells but from economic analysis, the best fit scenario is Scenario 3.

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