Available Online : https://proceeding.researchsynergypress.com/index.php/cset/index
RSF Conference Series: Engineering and Technology
ISSN 2809-6843 (Online) | 2809-6878 (Print)
Volume 1 Number 1 (2021): 43-53

Developing Scenario on "FDS" Volcanic Sandstone Formation for Gas Supply Demand in "TGA" Gas Field

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Abstract

Gas companies in developing the field are strongly influenced by the demand for gas supply from buyers. In this case, the gas supply demand from the buyer of 5 MMSCF/day for 5 years must be met. In order to fulfill the commitments of the Gas Sale and Purchase Agreement and to get the maximum Recovery Factor, simulations are done with various scenarios. The magnitude of the OGIP of the TGA Field in the Sandstone formation is 18.06 BSCF, the cumulative production is 3.21 BSCF and the Recovery Factor (RF) at the time of the study is 17.79%. The Sandstone FDS reservoir is a dry gas reservoir, which generally has an RF range of 80-90%. Based on the results of scenario 1, is optimizing choke 3 existing wells and installing compressors at the beginning of the first year, capable of producing for 3.5 years, a plateau of 5 MMscfd with incremental reserves of 7.06 BSCF with RF reaching 56.87%. Scenario 2, is scenario 1 with the addition of 1 infill drilling at the end of the third year provides incremental reserves of 12.39 BSCF with RF reaching 86.38%. Scenario 3, is scenario 1 with the addition of 2 infill drilling at the end of the third year provides incremental reserves of 12.46 BSCF with RF reaching 86.77%. Scenarios 2 and 3 meet the requirements of the Gas Sale and Purchase Agreement because they are capable of producing 5 MMscfd for 5 years. In terms of the number of wells, scenario 2 provides reserves of 0.7 BSCF less than scenario 3 which has 1 more well.

Keywords: scenario, volcanic sandstone, maximum Recovery Factor

INTRODUCTION

The "TGA" Gas Field is located in East Java Province and has been in production since 2009 which is managed by Minarak Brantas Gas, Inc. There are 5 wells that have been drilled (2014) consisting of 3 wells that are still in production and 2 wells of shut-in production. The FDS Sandstone Formation consists of layers C, D, E, and F with a recovery factor of 17.79%. This reservoir is a dry gas reservoir, with Recovery Factors generally ranging from 80-90%. (Craft, B.C. and M. Hawkins).

The company plans to develop the FDS field by offering a gas sale and purchase contract with details of 5 MMscfd for 5 years. Reservoir simulation method is used to determine EUR (Estimated Ultimate Recovery), because all existing data allows to use reservoir simulation. Reservoir simulation is done through initialization, history matching and production predictions up to the economic limit. From the reservoir simulation results, it can be seen whether the FDS Sandstone formation can be developed to meet buyer demands.

RESEARCH METHOD

The methodology in this study uses reservoir simulation which the first stage is covering data processing and analysis in the form of geological and geophysical (G&G) models, reservoir rock and fluid data, production data, total reserves volumetric, well test data, pressure and temperature data. The second stage is done by the model of initialization process, history matching, and predict of production using development scenarios, and proposing the best one.

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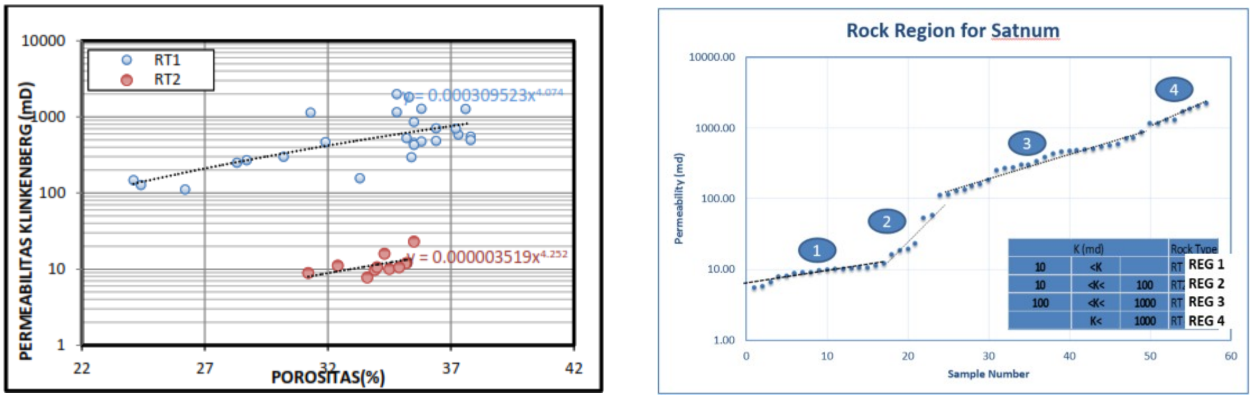
DOI: 10.31098/cset.v1i1.335

FINDING AND DISCUSSION

Porosity and permeability obtained from routine core analysis are used to determine the potential of hydrocarbons as well as a source of study for other data. Core samples came from wells TGA 1, TGA 2, TGA 3 and TGA 4 while Special Core Analysis data is available on TGA 4 only and is available for gas-oil-water systems and gas-water systems. Each data core is classified based on the depth per layer. The porosity ranged from 24.1% to 37.8% and permeability ranged from 7.71 md to 1980 md.

Data Preparation and Processing

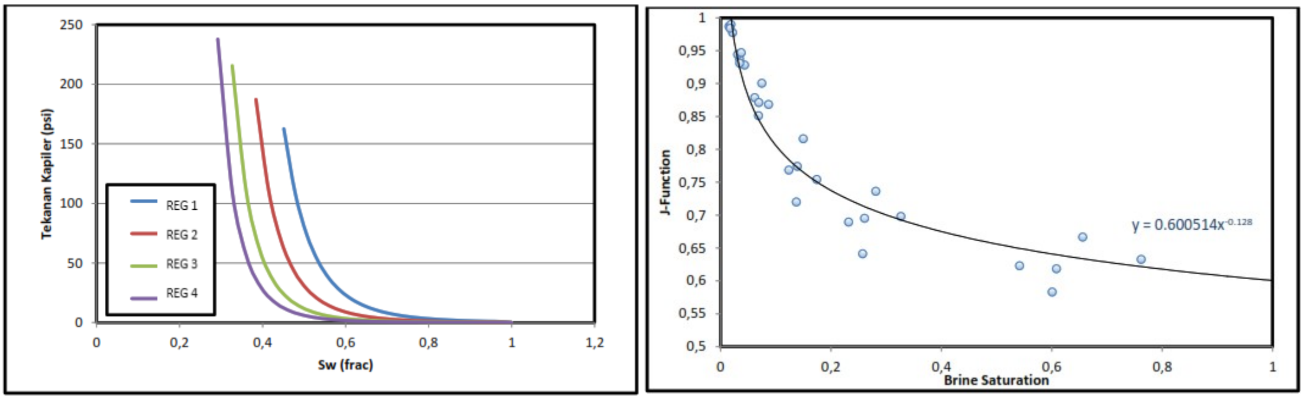
The Simulation stage is done by first collecting data, either geological, geophysical, reservoir, and production data. In the preparation of reservoir data, porosity and permeability obtained from routine core analysis are used to determine the potential of hydrocarbons and become a source of study for other data. Core samples for Routine Core Analysis come from wells TGA 1, TGA 2, TGA 3 and TGA 4 while Special Core Analysis data is available only on TGA 4 and also available for gas-oil-water systems and gas-water systems.



(a) (b)

Figure 1. (a) Porosity versus Permeability for TGA Field, (b) Rock region Based on Core Data

Besides the Data's stated above, there is also capillary pressure data. The capillary pressure of each sample which represents the reservoir quality is denormalized using the Leverret J-Function method to get a general reservoir pattern.



(a) (b)

Figure 2. (a) Result of Denormalization Capilary Pressure vs Sw, (b) J-function vs Sw for Water Saturation Distribution

Relative permeability is obtained from special core analysis (SCAL), and it is used to estimate field production performance, estimate oil recovery, water injection analysis, gas injection analysis, etc. Core samples were from well TGA-4 at depth intervals of 2960 ft to 2970 ft. The measured relative permeability consists the relative permeability of the water-oil system and the gas-water system.

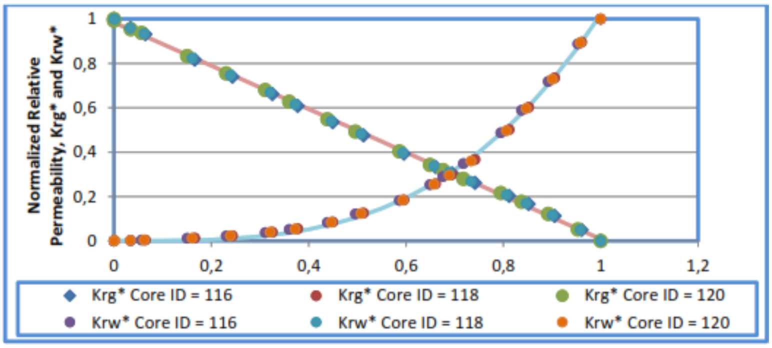


Figure 3. Relative Permeability Normalization vs Water Saturation for Gas-Water System

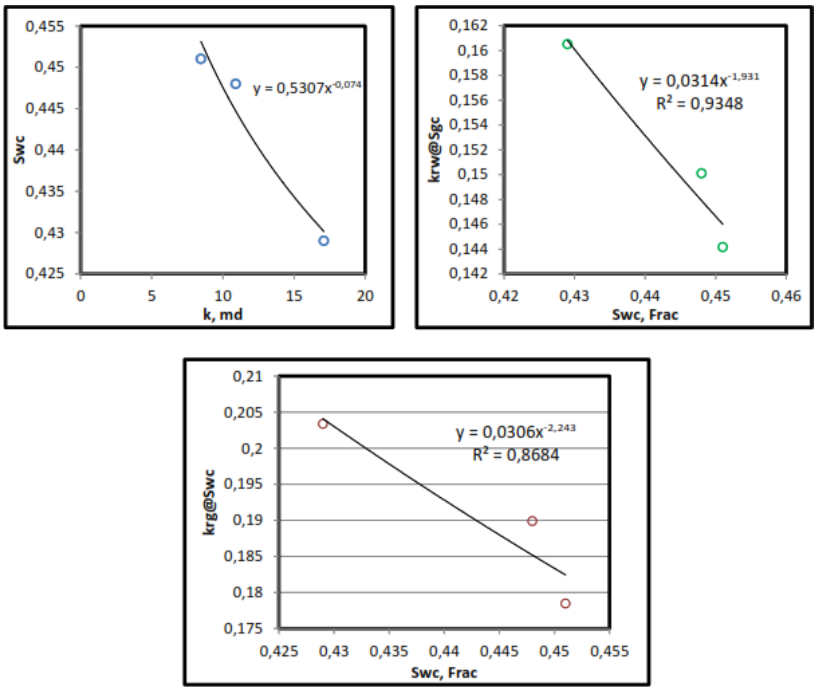
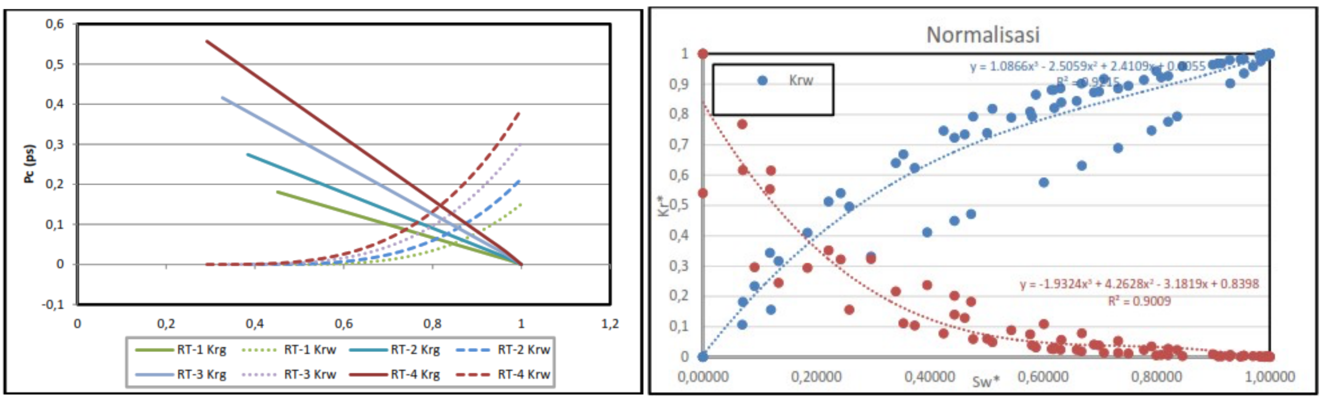


Figure 4. Plot End Point for Each Parameter



(a) (b)

Figure 5. (a) Result of Denormalization Relative Permeability for Well TGA 4, (b) Relative Permeability Normalization vs Water Saturation

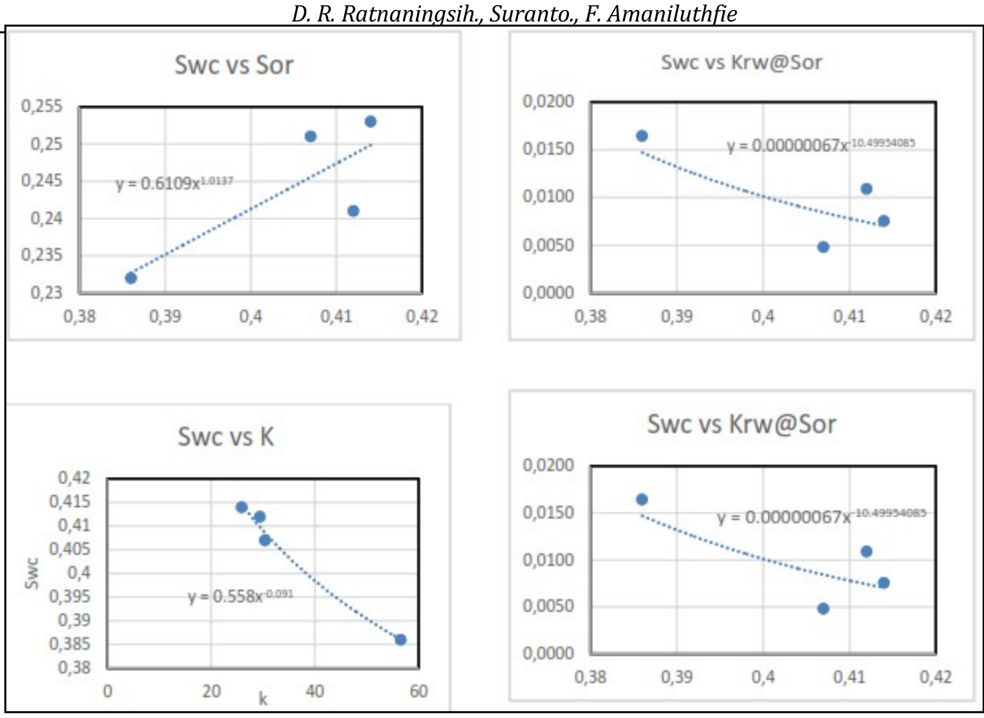


Figure 6. End Point for Each Parameter of Well TGA 4

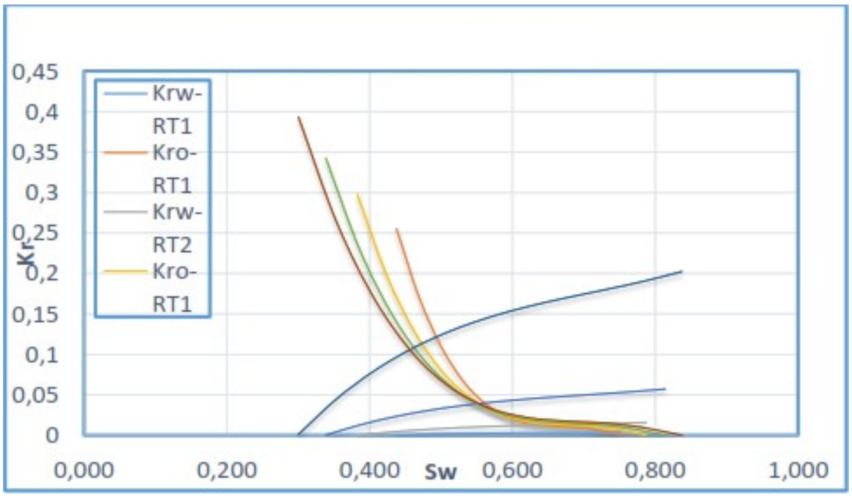


Figure 7. Result of Denormalization for Relative Permeability

Physical properties of reservoir fluids is obtained from laboratory analysis, it is used to calculate oil reserves, recovery rates, reservoir fluid classifications, and production operation strategies. The type of reservoir in the TGA field from the results of previous studies is a gas reservoir, the production target is a shallow interval volcanic sandstone rock type in the Pucangan-Wunut formation.

Table 1. Gas Composition Data

GAS COMPOSITION ANALYSIS					
Component	Component	Composition			
		(Mol %)	(Mol %)	(Mol %)	(Mol %)
		TGA-2 SS (C)	TGA-5 {E)	TA-5 (F20 L}	TA-5 (F20 U)
Hydrogen Sulfide	H2S	0.000	0.000	0.000	0.000
Nitrogen	N2	2.371	1.070	0.789	6.748
Carbon Dioxide	C02	0.000	0.040	4.090	1.191
Methane	CH4	97.534	98.15	91.156	93.942
Ethane	C2H6	0.058	0.490	2.964	3.008
Propane	C3H8	0.021	0.110	0.652	0.732
iso-Butane	1-C4H10	0.014	0.090	0.169	6:193
n-Butane	n-C4H10	0.002	0.020	0.055	0081
iso-Pentane	i-C5H12	0.000	0.030	0.044	0.054
n-Pentane	n-C5H12	0.000	0	0.011	0616
Hexanes plus	C6+	0.000	0	0.070	0,035
Heptanes pius	C7+	0.000	0.000	0.000	0.000
Total		100.0	100.0	100.0	100.0
GHV, BTU/Real CF		989	1010	1005	1037
SG real		0.564	0.565	0.624	0.596

Pressure and temperature data were obtained from well tests (Welltest) at TGA 01, TGA 03 and TGA 05. These data were plotted based on the depth so that the slope trend was obtained from the graph.

Table 2. Pressure and Temperature Test Results

Zone	Depth (ft)	Pres (psia)	Temp (F)
C10	1208.29	642.03	113.77
C20	1347.49	697.00	115.90
C50	1623.97	806.19	120.13
D10	1633.36	809.89	120.27
D20	1826.71	886.25	123.23
D30	1878	906.50	124.02
E10	2289.35	1068.94	130.31
E20A	2400.53	1112.85	132.01
F20	2698.53	1230.53	136.57
G20	2880	1302.19	139.35

Initialization

Initialization has to be done in order to equalize the OGIP of the reservoir model with the OGIP of the volumetric calculation results. If the difference between the OGIP of the reservoir model and the OGIP of volumetric results is more than 5%, then a review towards the static parameters of the model needs to be done. Table 3 shows that the initial gas content of the simulation model has a small difference (less than 5%) compared to the geological-volumetric model so that the reservoir-simulation model can be used for historical matching.

Table 3. Initial Gas In Place for Simulation

INITIAL GAS IN PLACE FOR SIMULATION (2P)			
Zone	Dynamic	Volumetric	% Error
	MMSCF	MMSCF	%
C50	3672	3643.77	0.10
D10	1830	1834	0.22
D20	173	176.81	0.39
E10	6734	6697.79	0.24
E20	373	371.51	0.20
F20	5290	4998.43	0.11
Total	18072	18048.946	0.13

From the table above, the initial dynamic model reserve is not much different from the volumetric reserve. Therefore, this model can be simulated for the next process, namely history matching.

History Matching

The purpose of history matching is to validate the reservoir simulation model with the actual reservoir conditions. The adjustment of production parameters are gas flow rate (Qg), water (Qw), cumulative gas (GP), and cumulative water (WP) between the model and the actual. If the results of the alignment between the simulated production data and the actual production data are the same (difference < 1% for gas flow rate, and < 10% for water flow rate). Figure 8. shows the final alignment result in the field scope.

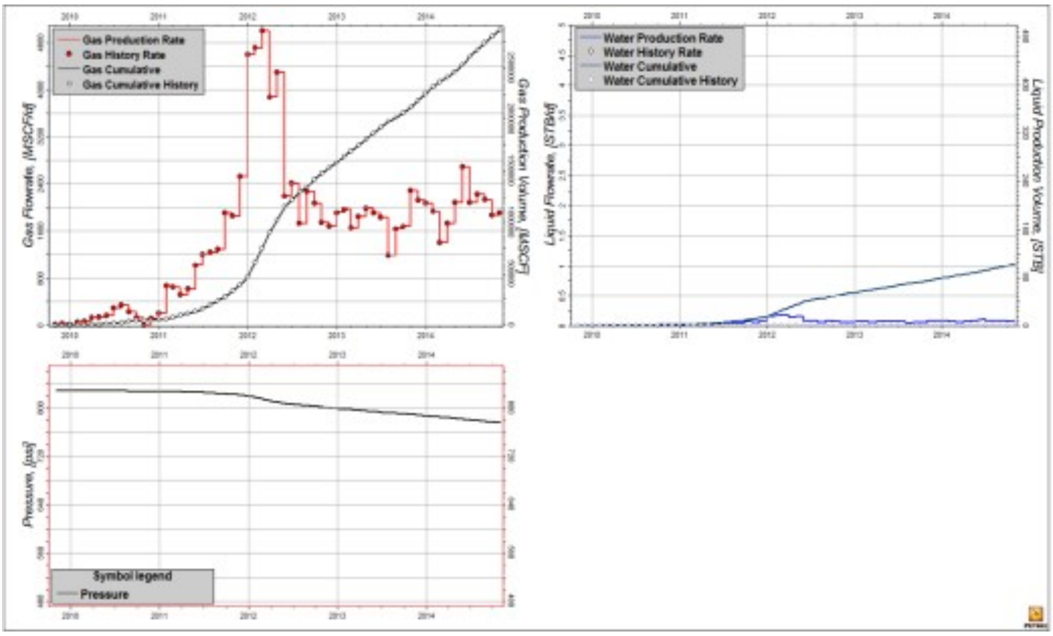


Figure 8. History Matching results for the TGA field (black: cumulative; red: gas; blue: water)

Production forecasting and developing scenario

After the previous history matching process has been successfully achieved, it is considered that the reservoir grid models represent actual characteristics and valid to be used as models for forecasting reservoir performance, including future production. The main objective this reservoir performance forecasting is to estimate the recovery and production of fluid, by applying several scenarios of this field development both technically and economically feasible. In this matter several development scenarios has been made including in terms of the number of production wells and water injection. Based on several scenarios studied above, the technically selected ones which might be developed are:

Basecase, 3 existing wells and plateau production rate of 2.5 MMSCFD

1. Scenario 1: Optimizing choke 3 existing wells + 1 Compressor 680 HP plateau production of 5 MMscfd

2. Scenario 2: Scenario 1 + Infill Drilling 1 plateau well production 5 MMscfd
3. Scenario 3: Scenario 1 + Infill Drilling 2 plateau wells producing 5 MMscfd.

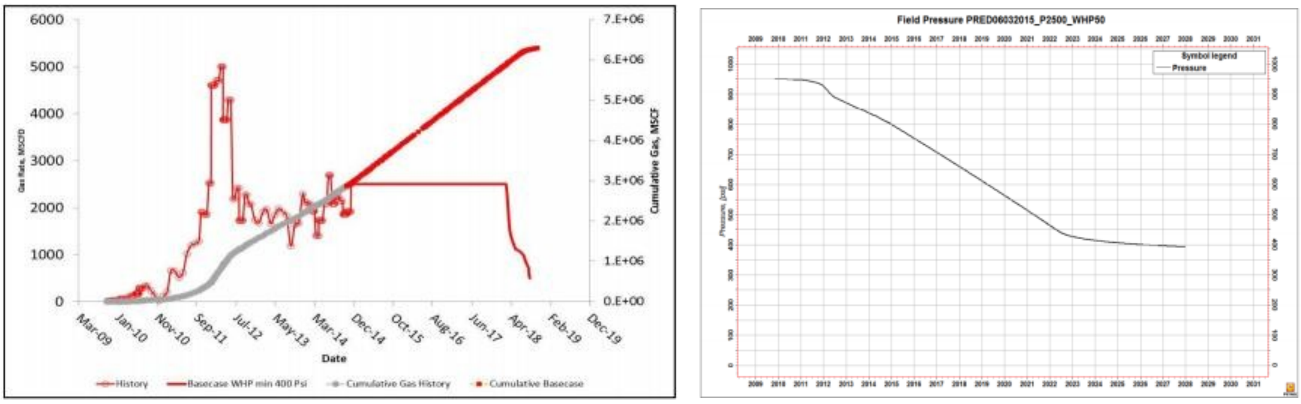
From the several scenarios above, there are scenarios with the installation of a compressor. The compressor installation time was in the first year, because the average pressure from each well was less than 450 psi during that year. The following scenario of development will be summarized in the Table 4.

Table 4. Choke opening schedule for each well

Scenario	Existing Well	Compressor 680 HP, Suction 50 psig, Discharge 600 psi	Infill Drilling	Production Plateau
Basecase	3			2.5 MMSCFD
Scenario 1	3	1	0	5 MMSCFD
Scenario 2	3	1	1	5 MMSCFD
Scenario 3	3	1	2	5 MMSCFD

Basecase : number of wells and plateau production rate 2.5 MMSCFD

Basecase scenario, producing 3 existing production wells with a plateau production rate of 2.5 MMSCFD. The cumulative gas production at the end of history matching was 3.21 BCF with an RF of 17.79%. Basecase prediction gives a cumulative total production of 6.53 BCF with a recovery factor (RF) of 36.14%. The prediction results of the basecase scenario are shown in Figure 9 (a) and Figure 9 (b).

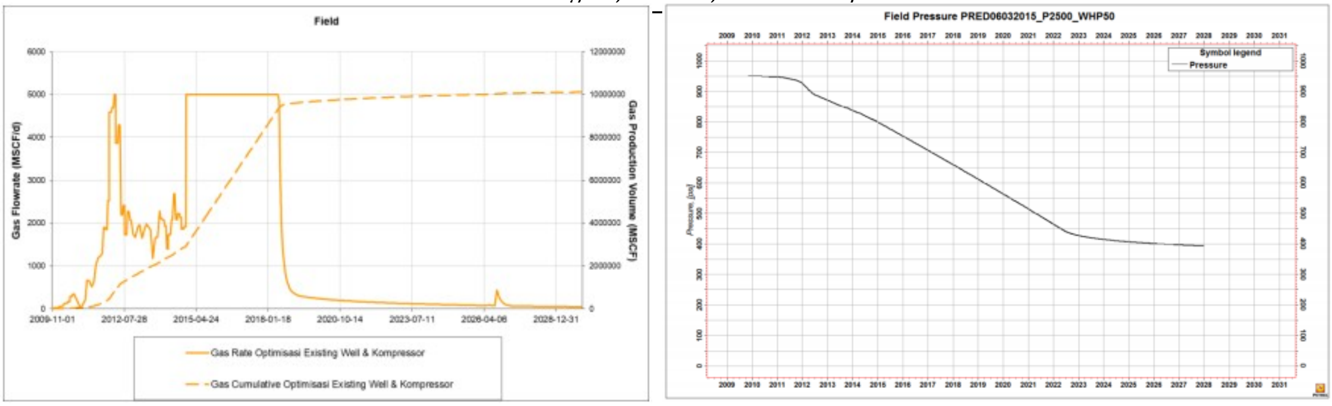


(a) (b)

Figure 9. (a) Basecase Production Prediction, (b) Basecase Pressure Prediction

Scenario 1: Optimization of 3 Existing wells & Compressor Installation of 680 HP Plateau Production of 5 MMSCFD

Scenario 1 is optimizing 3 existing production wells by calculating the optimal choke openings from each well. At this point the choke opening is 16/64 inch. By analyzing the Inflow Performance Relationship (IPR) from the well test results and making a VLP analysis for each well, the optimal choke is obtained according to 30% AOF contained in the choke opening 24/64 inch. After optimizing the choke, a compressor is needed to optimize the decrease in well head pressure that occurs after increasing the choke opening. The compressor installation schedule is beginning of the first year of scenario 1. Predicted production of this scenario can result in cumulative gas production of 10.27 BCF with RF 56.87%, cumulative gas increasing by 7.06 BCF from cumulative gas and RF increasing by 39.07% . The prediction results for scenario 2 are shown in Figure 10 (a) and Figure 10 (b).



(a) (b)

Figure 10. (a) Scenario 1 Production Prediction, (b) Scenario 1 Pressure Prediction

Scenario 2: Scenario 1 + Infill Drilling 1 Plateau Well Production 5 MMSCFD

Scenario 2 is Scenario 1 and 1 Infill Drilling with a production plateau of 5 MMscfd. When scenario 1 only reaches a production plateau for 3.5 years, it is necessary to add additional wells to drain the remaining reserves that are not produced by existing wells. The zones to be targeted are the E-10 and F-20 zones. The drilling schedule is done at the end of the third year in order to be able to produce at the beginning of the first year. The location of the infill drilling is shown in Figure 11.

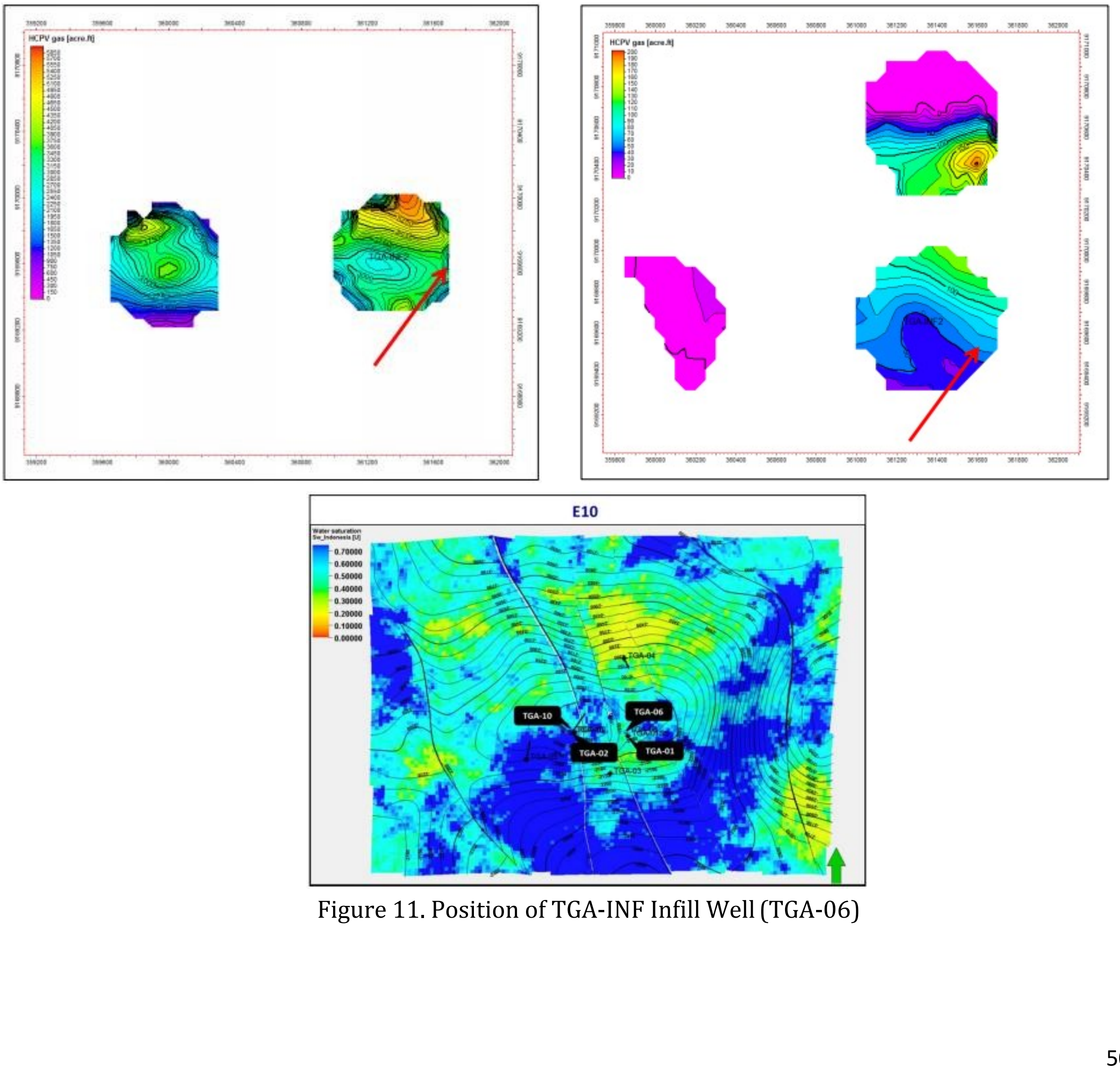
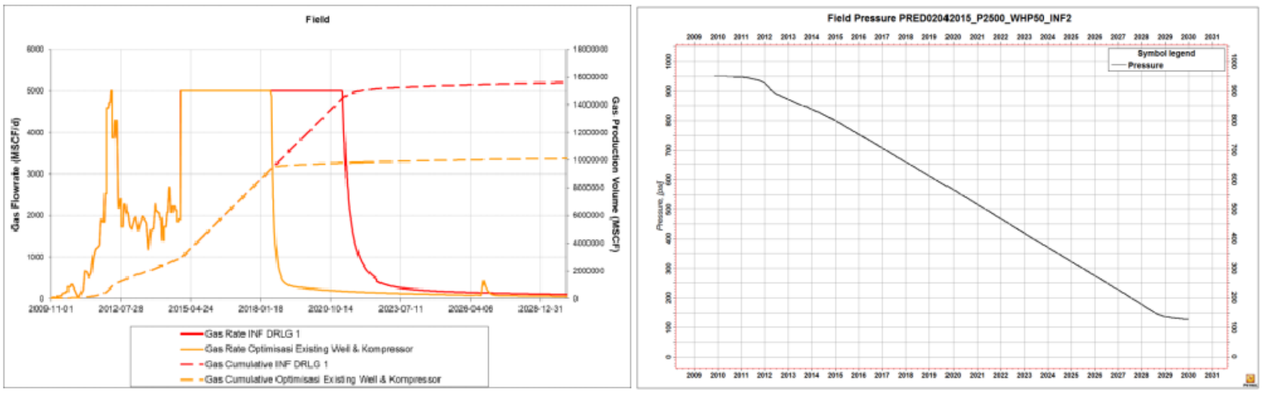


Figure 11. Position of TGA-INF Infill Well (TGA-06)

Scenario 2 can result in cumulative gas production of 15.60 BCF with RF 86.38%, cumulative gas increasing by 12.39 BCF from cumulative and RF increasing by 68.59%. The prediction results for scenario 2 are shown in Figure 12 (a) and Figure 12 (b).



(a) (b)

Figure 12. (a) Prediction of the Production Scenario 2, (b) Pressure Prediction Scenario 2

Scenario 3: Scenario 1 + Infill Drilling 2 Plateau Wells Production 5 MMSCFD

Scenario 3 is Scenario 1 and 2 of Infill Drilling with a production plateau of 5 MMscfd. Scenario 3 is another option from scenario 2 by adding 1 additional well from scenario 2, so the total infill well is 2 wells. The targeted zone is the C-50 zone. The drilling schedule is done at the end of the third year in order to be able to produce at the beginning of the first year. The location of the infill drilling is shown in Figure 5.62 to Figure 13.

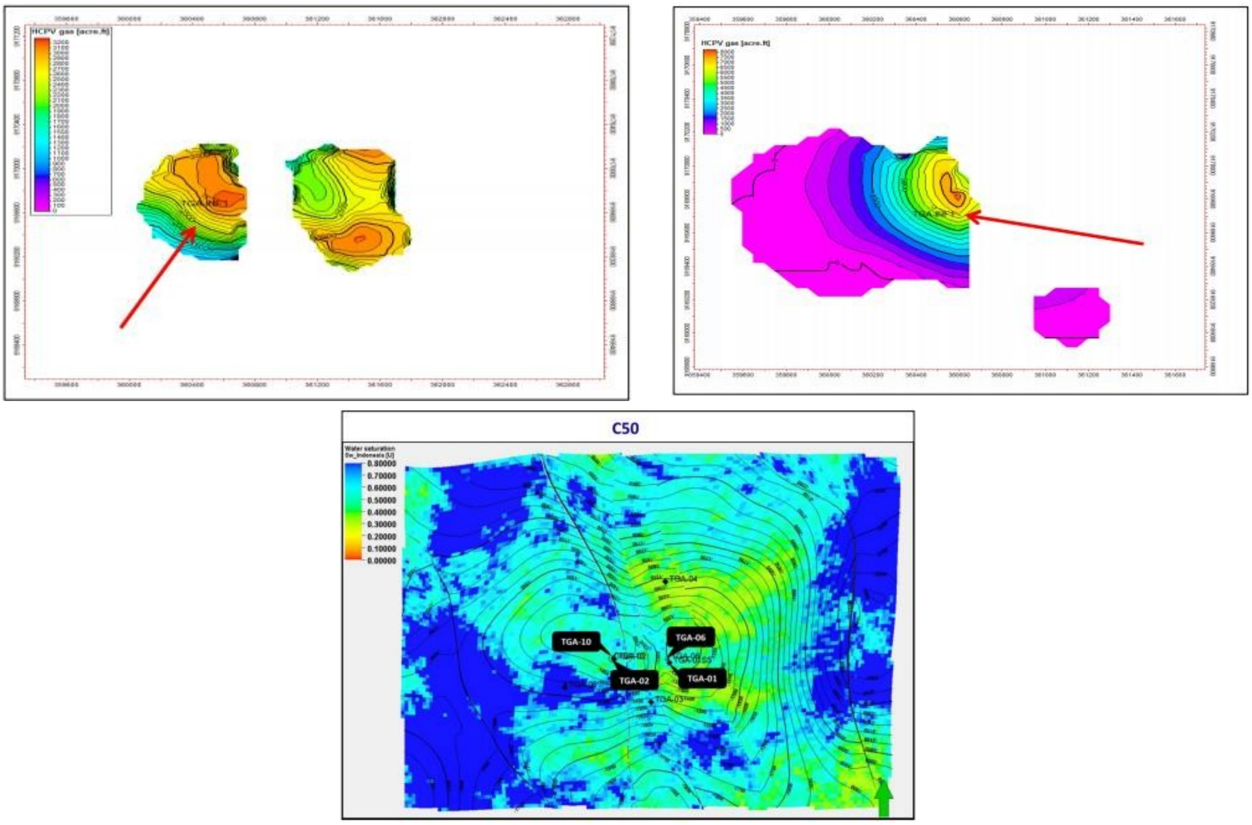
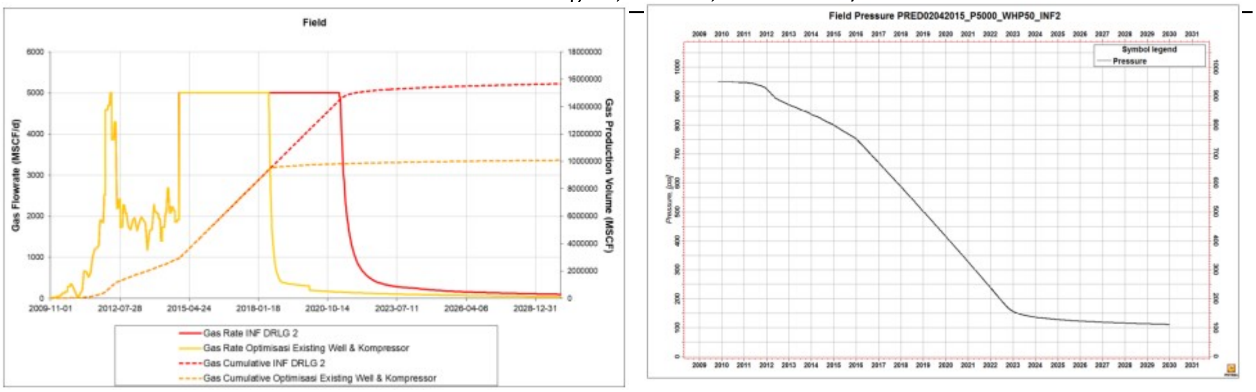


Figure 13. Position of TGA-INF Infill Well (TGA-10)

The scenario can result in cumulative gas production of 15.67 BCF with RF 86.77%, cumulative gas increasing by 12.46 BCF from cumulative gas and increasing RF by 68.97%. The prediction results for scenario 3 are shown in Figure 14 (a) and Figure 14 (b).



(a) (b)

Figure 14. (a) Prediction of the Production Scenario 3, (b) Pressure Prediction Scenario 3

Those prediction results which stated above could be explained on Table 5. The next step is to choose the best scenario that will be proposed for the developing of TGA Field in order to fulfill the agreement. Scenarios 1, 2 and 3 both produce significant incremental reserves and incremental RF. For scenario 1, the plateau age is 3.5 years. Scenarios 2 and 3 have a plateau of 5 MMSCFD for 6 years.

Table 5. Gas Recovery Summary

SKENARIO PENGEMBANGAN	OGIP (2P)			Forecast @		Incremental		Periode Plateau, Tahun
		GP	RF	EUR	RF	GP	RF	
	BCF	BCF	%	BCF	%	BCF	%	
Basecase, 3 existing well, Plateau 2.5MMscfd	18,06	3,21	17,79	6,53	36,14	3,31	18,34	
SK 1 (Optimisasi 3 Existing well & Kompresor)				10,27	56,87	7,06	39,07	3,5
SK 2 (SK 2 + 1 Infill Drilling)				15,60	86,38	12,39	68,59	6
SK 3 (SK 2 + 2 Infill Drilling)				15,67	86,77	12,46	68,97	6

For scenarios 2 and 3, it is necessary to optimize the number of wells to be drilled, considering the effectiveness of the number of wells will affect the company's investment. It is necessary to plot the number of wells with the amount of reserves to be obtained, as shown in Figure 15. For scenario 1 (for one infill well), it produces incremental reserves of 12.39 BSCF and the RF increases 68.59%. Meanwhile, for scenario 2 (for 2 infill wells), it produces 12.46 BSCF and RF increases 68.97%.

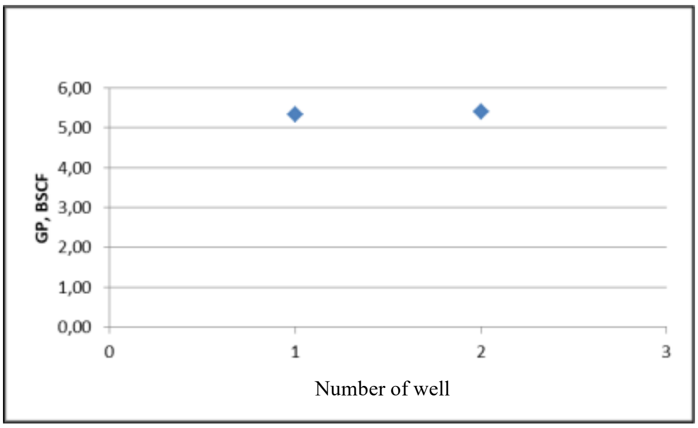


Figure 15. Number of Wells vs Incremental Reserves

From the plot results between the number of wells and the addition of reserves, it shows that scenario 2 is the best development scenario to develop the TGA Gas Field in order to maximize the recovery factor and fulfill the GSA plan.

CONCLUSION AND FURTHER RESEARCH

1. Prediction of gas production based on several scenarios, which are:
   a. Basecase, 3 existing wells and plateau production rate of 2.5 MMSCFD
   b. Scenario 1: Optimizing choke 3 existing wells + 1 Compressor 680 HP plateau production of 5 MMscfd.
   c. Scenario 2: Scenario 1 + Infill Drilling 1 plateau well production 5 MMscfd.
   d. Scenario 3: Scenario 1 + Infill Drilling 2 plateau wells producing 5 MMscfd.

   From the above scenarios, the first scenario is done by the installation of a compressor. The compressor installation time was in the first year, because the average pressure from each well was less than 450 psi.
2. The basecase scenario is the cumulative gas obtained 6.53 BSCF, the total predicted RF is 36.14%.
3. Scenario 1 is optimizing the existing choke wells (3 wells) with the addition of a compressor. The choke opening of each well is optimized up to 30% AOF. The cumulative gas obtained is 10.27 BCF and the total RF prediction is 56.87%
4. Scenario 2 is Scenario 1 + Infill Drilling 1 Plateau Well Production 5 MMSCFD, cumulative gas obtained is 15.60 BCF and total RF prediction is 86.38%
5. Scenario 3: Scenario 1 + Infill Drilling 2 Plateau wells Production of 5 MMSCFD, the cumulative gas obtained is 15.67 BCF and the predicted RF total is 86.77 %.
6. For Scenario 2 and 3, it is necessary to optimize the number of wells to be drilled, and also to plot the number of wells with the amount of reserves to be obtained, as shown in Figure 15. For scenario 1 with the number of infill wells 1, it generates incremental reserves of 12.39 BSCF and its RF increases by 68.59%. Meanwhile, for scenario 2 with 2 infill wells, it produces 12.46 BSCF and an increase in RF of 68.97%.

Acknowledgement

The authors would like to express the gratitude to Minarak Brantas Gas, Inc. for the willingness support and provide all the data in this research.

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