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An Accurate Simulation Model in a New Virgin Production Layer in Sungai Gelam-C Field: Challenges, Data Analogue, and Further Improvement

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Abstract

Defining forecast oil production of new layer N1 sand is challenging. In initial stage of field development, data availability in static to dynamic is limited, especially Special Core Analysis (SCAL). Production test data used to validate model was inadequate in history matching phase. Therefore, new method is needed and conducted to deliver accurate model in proposing new drilling wells.

Regional geological concept and lithology log data indicating that existing N sand and new N1 sand was deposited in same environment so they could be analogized alike. Correlation between static pressure, flowing pressure, and production rate of existing N sand used as an approach to construct the relative permeability curve of new N1 sand. Production rate is predicated on the amount of saturation within the reservoir rock. Increasing water saturation causes in decrease of effective permeability. J-function reconstruction and contact determination are conducted from water saturation versus depth in existing wells' log analysis.

In 2020, two wells were drilled based on latest simulation model, located in outer existing wells with radius around 400-500 meters. In updated static model, there is no major difference to the previous one. The last two wells drilled encountered similar sand facies of marine deposit with thickness of 11.5 meters (15% thicker than estimated), and porosity near 22% (8% bigger than estimated). Like static model, the dynamic model is also had a good accuracy. Static formation pressure, dynamic formation pressure, and multi rate test were being used to validate reservoir simulation by comparing to actual data in the last one year (December 2019-December 2020) which resulting a good relation to the actual production data (oil production cumulative 230.2 MSTB forecast vs 220.7 MSTB actual).

By applying this validation method of data limited-reservoir model will help us to minimize subsurface risk and deliver accurate deliverability of model and production's well performance. This method could be implemented and as a standard of new sand reservoir development.

Keywords: Analogue Method, SCAL, Dynamic Model, Field Development, Minimum Data

Introduction

The Sungai Gelam C field is an oil field in Jambi, Indonesia that produces from two main sands, namely an existing N sand productive zone and newly discovery N1 sand, which located below N sand. In developing the N1 sand, it is necessary to carry out a proper dynamic reservoir simulation, which generally requires complete data in order to obtain accurate forecast results. However, it is common that new sand having limited data such as relative permeability and capillary pressure data. N and N1 sand are belong to Air Benakat Formation, which in deposited in shore environment. Both sands are typically a blocky and thick reservoir.

In this paper, we will describe the process of data validation used in building a dynamic reservoir model, especially for field with the same case. These validation methods generate good result of actual to production forecast. Eventually, it is expected that these methods could be taken into consideration in conducting data analogue in order to reduce the subsurface risk/uncertainty.

Data and Method

Relative Permeability Reconstruction and Fluid Mobility

Relative permeability data is needed in making a representative and accurate reservoir dynamic model. In the absence of these data, relative permeability can be generated using the power-law model. Power-law models have been widely used to represent relative permeability curves because of their simplicity (Lee et al., 1987). The empirical equation as shown below:

$$k_{rw} = a_w \left(\frac{S_w - S_{wc}}{1 - S_{orw} - S_{wc}}\right)^{b_w} \quad (1)$$

$$k_{ro} = a_o \left(\frac{1 - S_{orw} - S_w}{1 - S_{orw} - S_{wc}}\right)^{b_o} \quad (2)$$

From the above equation, From the above equation, several variables are involved in defining the relative permeability. If relative permeability is defined as normalization of the effective permeability of each phase with absolute oil permeability at unreduced water saturation, then a_o= 1. The connate saturation (S_{wc}), which plays an important role in this procedure, can be established from log evaluations, with the lowest water saturation encountered normally assumed to represent residual oil saturation (S_{orw}) (Larsen, 1990). Lastly for b_w and b_o, this we can do fine adjustments to get a good match with the production data but for reservoirs with few production data, some validations are needed so that unsuitable exponent factors are not entered into the simulation.

For this validation, it is necessary to understand the relationship between exponential factors and fluid mobility which can be seen in the equation below (Larsen, 1990):

$$\lambda_{total} = \frac{k_{rw}}{\mu_w} + \frac{k_{ro}}{\mu_o} \quad (3)$$

$$\lambda_{water} = \frac{k_{rw}}{\mu_w} \quad (3a)$$

$$\lambda_{oil} = \frac{k_{ro}}{\mu_o} \quad (3b)$$

With relative permeability which is a function of saturation, it is possible to plot a graph of mobility vs saturation (see **Table 1** & **Fig. 2**). Based on the relationship from these data, it is possible to perform an exponential factor sensitivity to obtain a suitable relative permeability curve

J-function reconstruction

Capillary pressure is used as the basis for the saturation distribution when running dynamic reservoir simulations, where saturation in the dynamic model is a function of the height above the Water-Oil Contact. The relationship between the two can be seen in (Holmes, 1977):

$$P_c = \frac{h}{144}(\rho_w - \rho_o) \quad (4)$$

From log analysis, saturation gradient above the Water-Oil Contact (WOC) can be derived as the basis for capillary pressure. First, the saturation log data is plotted against the height above the Water-Oil Contact then an equation will be obtained to determine the relationship between h vs S_w (see **Fig. 5**).

By using the saturation gradient trend, it can then be used to find the correlation graph of Pc vs Sw. From these results, a capillary pressure curve is obtained which can be included in the reservoir dynamic model (see **Table 2** & **Fig. 6**).

Result and Discussion

Three different kinds of relative permeability data are entered into the reservoir dynamic simulation for history matching. Because the production data for the N1 sand is still limited, the history match is carried out on the top layer, namely the N sand. In the history match, it is carried out for the liquid rate, oil rate, water rate, and flowing bottom hole pressure. The results of history matching can be seen in **Fig. 3**. Based on the figure, the effect of the difference between b_o and b_w, where the relative permeability data is the most suitable is in Example 3. The table data in Example 3 is used to forecast the N1 sand which incidentally is still virgin but has rock properties like the N sand.

In reservoir dynamic simulation, the use of capillary pressure data also has a very important role, especially for the spread of saturation in the model. If the capillary pressure data is not known, the correlation between the petrophysical log and the height above the Water-Oil Contact can be used as shown in the **Fig. 6**. The result of using this method is a saturation distribution which is then compared with the value of the petrophysical log (see **Fig. 7**).

After all data is entered completely, a forecast is made for the virgin N1 sand by proposing two infill wells and two work over wells. The proposal was successful and then the production realization was monitored for one year, which showed accurate results with cumulative 230.2 MSTB forecast vs 220.7 MSTB actual (see **Fig. 4**).

Conclusions

The results of the exercise show that the use of "b_w" and "b_o" values in the construction of the relative permeability curve have big effect on the wells performance, both in history match and forecast stage. In addition, the saturation distribution in dynamic model of the P_c vs S_w curve could be reconstructed using petrophysical log data. By applying this validation method of limited data-reservoir model will help us to minimize subsurface risk and deliver accurate deliverability of dynamic model. This method could be implemented and as a standard of new sand reservoir development

Nomenclature

k_{rw}	: relative permeability of water, fraction
k_{ro}	: relative permeability of oil, fraction
a_w	: relative permeability of water @ S_{orw}
a_o	: relative permeability of oil @ S_{wc}
b_w	: water exponential or shape factor
b_o	: oil exponential or shape factor
S_w	: water saturation, fraction
S_{wc}	: connate water saturation, fraction
S_{orw}	: residual oil saturation, fraction
λ	: mobility, mD/cp
μ_w	: water viscosity, cp
μ_o	: oil viscosity, cp
ρ_w	: water density, lb/cuft
ρ_o	: oil density, lb/cuft
h	: height above contact, ft
P_c	: capillary pressure, psi

References

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Larsen, L., Kviljo, K., and Litlehamar, T., 1990, SPE Formation Evaluation: 360-368.

Lee, T.-Y., and Seinfeld, J.H. 1987, Inverse Prob. Eng.: 711-728.

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Table 1-Relative Permeability and Mobility Tabulation

1

μ_o	0.273 cp	b_{Oil}	2
μ_w	0.2664 cp	b_{Water}	2
S_{wi}	0.35	a_{Oil}	1
S_{orw}	0.21	a_{Water}	0.4

Example 1

S_w, Fraction	K_{rw}, Fraction	K_{ro}, Fraction	Mobility Tot. Relative cp^{-1}	Fractional Flow Fraction
0.35	0.00	1.00	3.66	0.00
0.37	0.00	0.90	3.31	0.00
0.39	0.00	0.81	2.98	0.01
0.42	0.01	0.72	2.68	0.01
0.44	0.02	0.64	2.40	0.02
0.46	0.03	0.56	2.15	0.04
0.48	0.04	0.49	1.93	0.07
0.50	0.05	0.42	1.73	0.11
0.53	0.06	0.36	1.56	0.15
0.55	0.08	0.30	1.41	0.22
0.57	0.10	0.25	1.29	0.29
0.59	0.12	0.20	1.20	0.38
0.61	0.14	0.16	1.13	0.48
0.64	0.17	0.12	1.08	0.59
0.66	0.20	0.09	1.07	0.69
0.68	0.23	0.06	1.07	0.79
0.70	0.26	0.04	1.11	0.87
0.72	0.29	0.02	1.17	0.93
0.75	0.32	0.01	1.25	0.97
0.77	0.36	0.00	1.36	0.99
0.79	0.40	0.00	1.50	1.00

2

μ_o	0.273 cp	b_{Oil}	4
μ_w	0.2664 cp	b_{Water}	4
S_{wi}	0.35	a_{Oil}	1
S_{orw}	0.21	a_{Water}	0.4

Example 2

S_w, Fraction	K_{rw}, Fraction	K_{ro}, Fraction	Mobility Tot. Relative cp^{-1}	Fractional Flow Fraction
0.35	0.00	1.00	3.66	0.00
0.37	0.00	0.81	2.98	0.00
0.39	0.00	0.66	2.40	0.00
0.42	0.00	0.52	1.91	0.00
0.44	0.00	0.41	1.50	0.00
0.46	0.00	0.32	1.16	0.01
0.48	0.00	0.24	0.89	0.01
0.50	0.01	0.18	0.68	0.03
0.53	0.01	0.13	0.51	0.07
0.55	0.02	0.09	0.40	0.16
0.57	0.03	0.06	0.32	0.29
0.59	0.04	0.04	0.29	0.48
0.61	0.05	0.03	0.29	0.67
0.64	0.07	0.02	0.32	0.83
0.66	0.10	0.01	0.39	0.92
0.68	0.13	0.00	0.49	0.97
0.70	0.16	0.00	0.62	0.99
0.72	0.21	0.00	0.79	1.00
0.75	0.26	0.00	0.99	1.00
0.77	0.33	0.00	1.22	1.00
0.79	0.40	0.00	1.50	1.00

3

μ_o	0.273 cp	b_{Oil}	2.6
μ_w	0.2664 cp	b_{Water}	2.2
S_{wi}	0.35	a_{Oil}	1
S_{orw}	0.21	a_{Water}	0.4

Example 3

S_w, Fraction	K_{rw}, Fraction	K_{ro}, Fraction	Mobility Tot. Relative cp^{-1}	Fractional Flow Fraction
0.35	0.00	1.00	3.66	0.00
0.37	0.00	0.88	3.21	0.00
0.39	0.00	0.76	2.79	0.00
0.42	0.01	0.66	2.42	0.01
0.44	0.01	0.56	2.09	0.02
0.46	0.02	0.47	1.80	0.04
0.48	0.03	0.40	1.56	0.07
0.50	0.04	0.33	1.34	0.11
0.53	0.05	0.26	1.17	0.17
0.55	0.07	0.21	1.03	0.25
0.57	0.09	0.16	0.93	0.35
0.59	0.11	0.13	0.86	0.47
0.61	0.13	0.09	0.83	0.59
0.64	0.16	0.07	0.82	0.71
0.66	0.18	0.04	0.85	0.81
0.68	0.21	0.03	0.90	0.89
0.70	0.24	0.02	0.97	0.94
0.72	0.28	0.01	1.08	0.98
0.75	0.32	0.00	1.20	0.99
0.77	0.36	0.00	1.34	1.00
0.79	0.40	0.00	1.50	1.00

Table 2-Capillary Pressure

ρ_o	42.56 lb/cuft
ρ_w	62.40 lb/cuft
S_{wi}	0.35
S_{orw}	0.21

S_w Fraction	Elevation Fraction	Pc Fraction
0.35	118.41	16.32
0.37	97.56	13.44
0.39	81.28	11.20
0.42	68.40	9.42
0.44	58.07	8.00
0.46	49.69	6.85
0.48	42.84	5.90
0.50	37.18	5.12
0.53	32.46	4.47
0.55	28.50	3.93
0.57	25.15	3.47
0.59	22.30	3.07
0.61	19.86	2.74
0.64	17.75	2.45
0.66	15.94	2.20
0.68	14.36	1.98
0.70	12.97	1.79
0.72	11.76	1.62
0.75	10.70	1.47
0.77	9.75	1.34
0.79	8.92	1.23

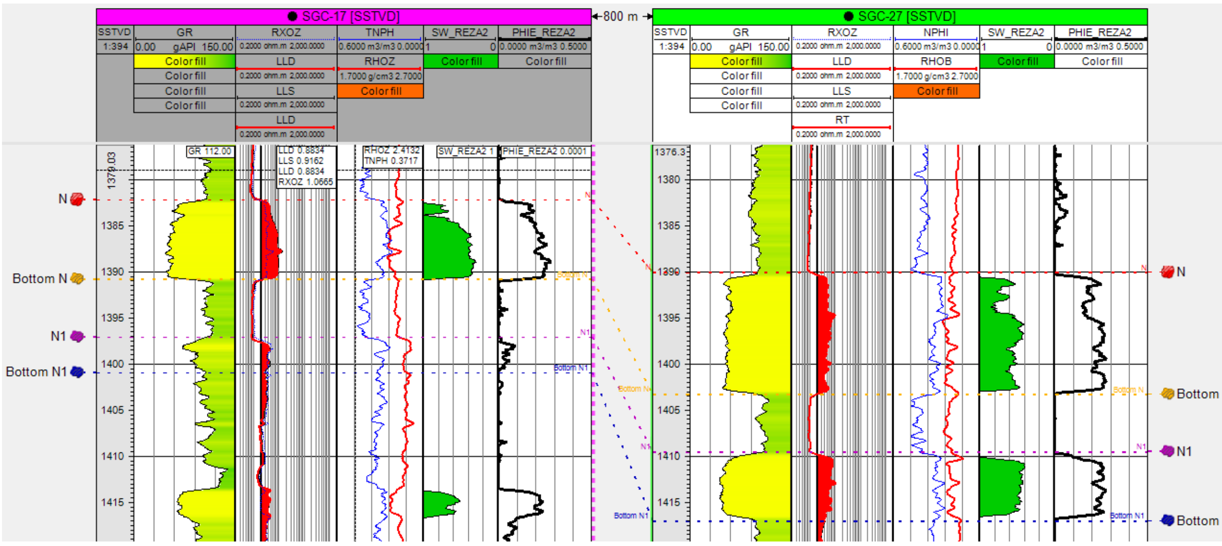

Fig. 1-Well Corelation

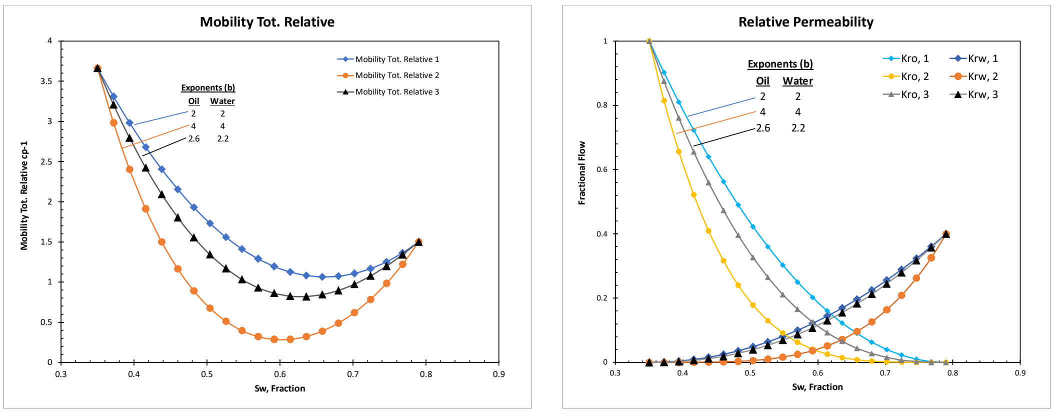

Fig. 2-The Effect of Exponent Factor on Total Mobility

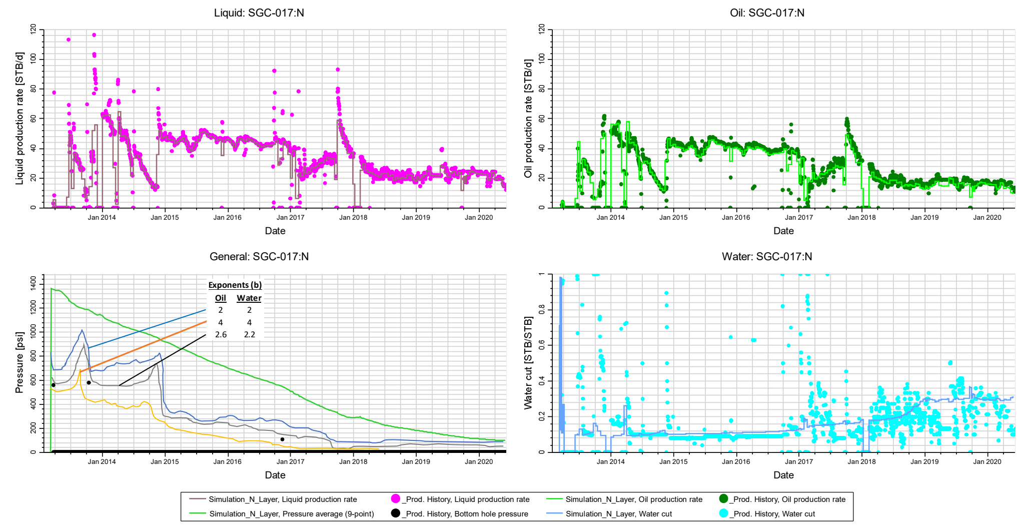

Fig. 3- Relative Permeability Validation using FBHP Data and Production Match of N sand

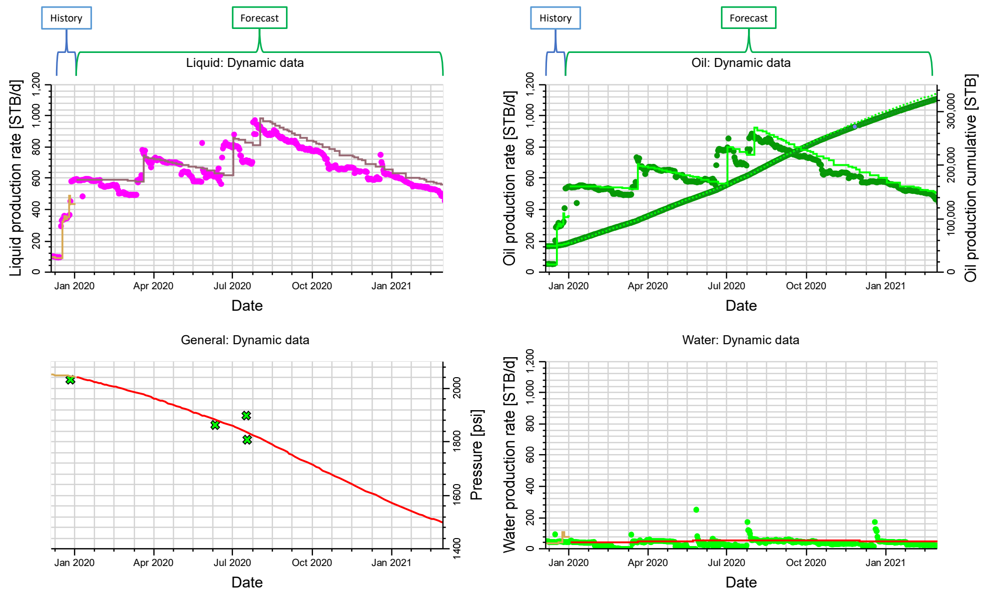

Fig. 4- Sungai Gelam Field Forecast Result in N1 sand

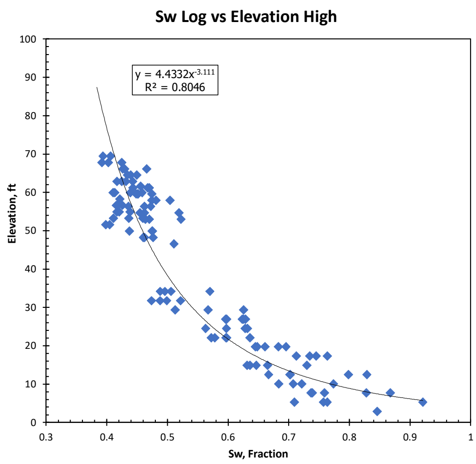

Fig. 5- Sw Loq vs Elevation Height

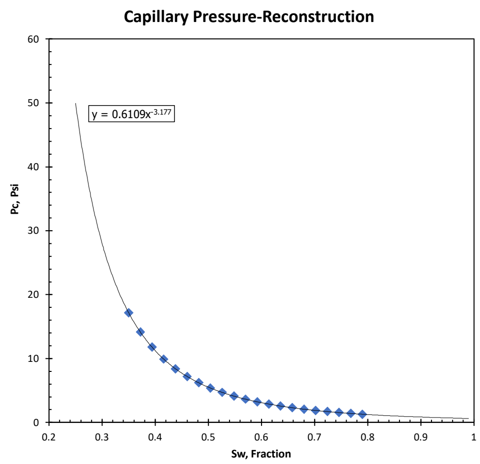

Fig. 6- Capillary Pressure

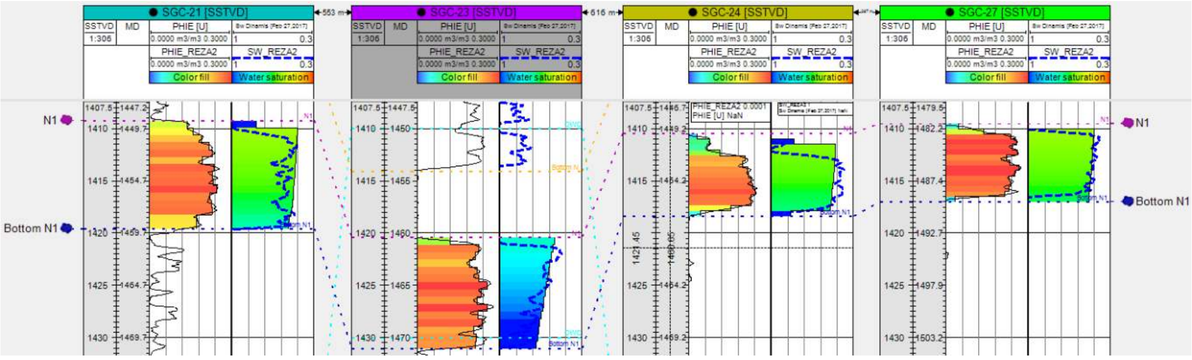

Fig. 7- Sw Model Validation of Capillary Pressure Reconstruction from Petrophysical Log