Proceeding International Conference on Religion, Science and Education (2022) **1**, 703-714

Determination of Location and Number of Optimum Development Wells in "Nero" Field Using Reservoir Simulation

Haykal Kurniawan*, Aldi Priambodo, Cahyadi Julianto, Hidayat Tulloh
Petroleum Engineering Department, Faculty Mineral Technology, Universitas Pembangunan Nasional "Veteran" Yogyakarta, Jl. SWK Sleman Yogyakarta.

Corresponding author*
kal.kurniawan18@gmail.com

Abstract: The "Nero" field is an oil field located in the Central Sumatra Basin. The productive zone located on Lakat Formation at depth 1241 ft to 1830 ft with water drive mechamism. This field has been produced from November 1970 to December 2019 with cumulative oil production of 6,202 MMSTB or 31.03% of OOIP with only 5 production wells and 2 injection wells. The average porosity of the "Nero" field is 0.21, with average permeability of 888.4 mD and reservoir pressure of 601.7 psi. To optimize the recovery factor, determination of location and number of infill well must be done. This become the purpose of this study. This study contain with reservoir simulation Computer Modelling Group (CMG) IMEX 2015.10 with grid dimention 64x50x60 and projected to 2070. The process began with initialization, history matching, and projecting scenario. Development of this field depend on the amount of Oil per Unit Area (OPU) by considering the drainage radius and the distance between wells. From the scenario 1 the cumulative production obtained is 6.46 MMSTB with a current recovery factor value of 32.30%. Scenario 2 done with cumulative production of 7.17 MMSTB with current recovery factor of 35.89%. Scenario 3 done with cumulative production of 8.094 MMSTB and current recovery factor of 40.50%. Also from the scenario 4 cumulative production gain with 8.066 MMSTB with recovery factor of 40.36%. From this case, it can be seen scenario 3 is the best option with the addition of 1 reopening well and 6 infill wells.

Keywords: OOIP, OPU, recovery factor, reservoir simulation, infill well.

Introduction

The Nero Field is an oil field located in District 1 of the Kampar Block in the Central Sumatra Basin. Layer K in Nero Field has Original Oil in Place (OOIP) of 19,987 MMSTB. This field was produced from November 1970 to December 2019 with oil production of 6,202 MMSTB or a current recovery factor of 31.03% of OOIP. Based on the calculations, the estimated ultimate recovery (EUR) in this field was obtained at 10.86 MMSTB. Layer K of the Nero Field has a residual reserve of 4.65 MMSTB, so it is necessary to plan for field development to maximize drainage in this field.

In the development of oil planning, one way to use the drainage field in the reservoir is to add infill wells. Infill wells or insertion wells are wells that are located between existing wells, with the aim of producing projections in areas that are not taken up by existing wells. The function of this infill well is as a project to accelerate or accelerate the anticipated drain in the reservoir.

The position of the new infill well optimizes to optimize the function of the new well so that with a minimum number of wells it is expected to drain the maximum reserves, or at least if you have to add new wells it must be proportional to the results to be obtained. (OPU). The OPU map is a map of the overlay of isoporosity, isosaturation and fold folds to obtain a map of the potential representation of the oil contained.

Method

In this study, the method used for the analysis of the Nero field is reservoir simulation method.

ISSN 2829-3355 | EISSN 2828-8467

Reservoir simulation studies are used to describe reservoir behavior in the future, such as production, pressure, and the age of the reservoir itself so that reservoir management can run well and maximize hydrocarbon recovery in a field. The use of reservoir simulation is expected to be used as a decision-making tool on how to develop the most optimal and most economical field. The following are the steps taken in completing this research.

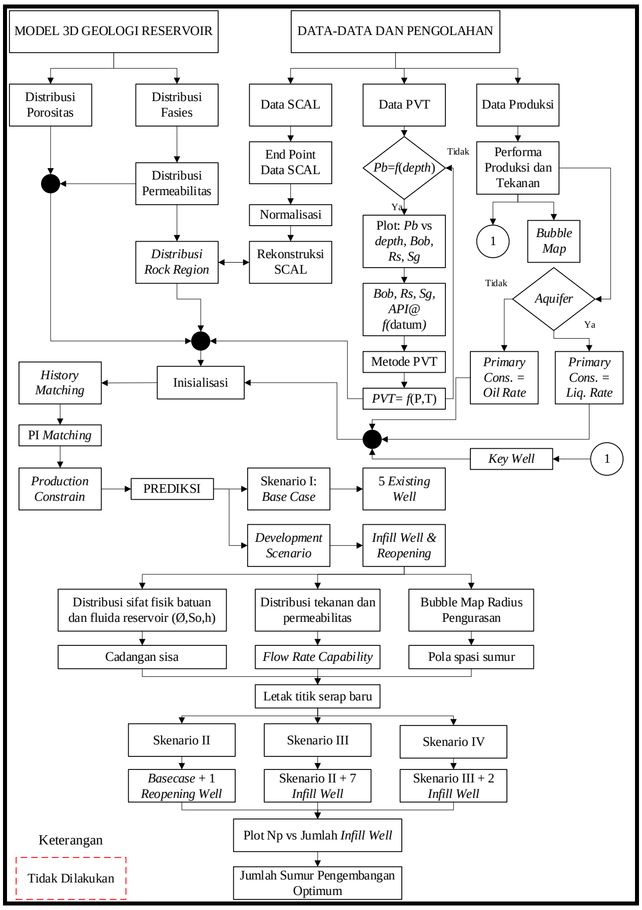

Figure 1. Flowchart

Result

Nero field development planning is carried out by adding infill wells. The parameter that affects this scenario is the amount of Oil per Unit Area (OPU) by considering the drain radius and the distance between wells. The expected result of this scenario is to increase the incremental oil and recovery factor (RF) of the Nero field.

Volumetric OOIP calculation

The OOIP (Original Oil in Place) calculation aims to determine the amount of reserves in the K layer of the Nero field which will later be compared with the amount of reserves in the simulation results. The parameters needed in the OOIP calculation are rock volume data, porosity, initial water saturation, and oil formation volume factor. The reserve calculation will be based on.

$$\boldsymbol{OOIP} = \mathbf{7758} \times \frac{\boldsymbol{Vb} \times \emptyset \times (\mathbf{1} - \boldsymbol{Sw_i})}{\boldsymbol{Bo_i}}$$

$$\boldsymbol{OOIP} = \mathbf{7758} \times \frac{\mathbf{20716 \times 0.1896 \times (1-0.325)}}{\mathbf{1.029}} = 19987 \text{ MSTB}$$

Driver mechanism analysis

In this study to determine the driving mechanism using the Ganesh Takur method because this method uses a plot between recovery efficiency (%) which is the ratio of cumulative production at a certain time to the amount of OOIP, and recovery pressure (%) which is the ratio of pressure at a certain time to the amount of pressure. Initial

$$\textit{Recovery Efficiency} = \frac{\boldsymbol{Np}}{\boldsymbol{OOIP}} x \ 100\ \%$$

$$\textit{Recovery Efficiency} = \frac{\mathbf{1190.55}}{\mathbf{19987}} x \ 100\ \% = 5.96\%$$

$$\textit{Recovery Pressure} = \frac{\boldsymbol{P}}{\boldsymbol{Pi}} x \ 100\ \%$$

$$\textit{Recovery Pressure} = \frac{\mathbf{489.56}}{\mathbf{600.43}} x \ 100\ \% = 82\%$$

Table 1. Determination of Drive Mechanism of Nero Field

Date	Pressure (Psia)	Np (MSTB)	P/Pi (%)	N/OOIP (%)
3-Feb-1970	600.43	0	100	0.00
11-Mar-1973	489.56	1190.549	82	5.96
11-Apr-1973	459.83	1269.453	77	6.35
31-Jan-1977	343.02	3204.634	57	16.03
10-Mar-1979	410.78	3816.992	68	19.10
25-Mar-1980	364.70	4062.669	61	20.33
18-Jun-1982	362.13	4467.29	60	22.35
3-Feb-1984	329.14	4735.033	55	23.69

Based on this, the Nero field has a water drive driving force because the plot results from the Nero field resemble the shape of the water drive curve in the Ganesh Takur method.

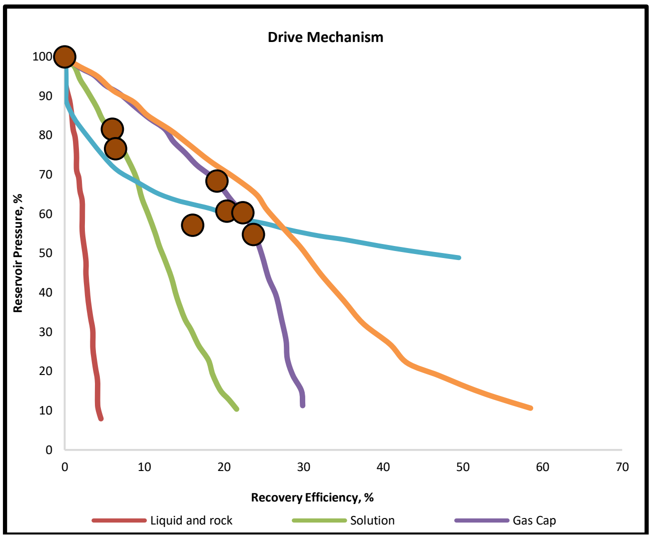

Figure 2. Drive Mechanism

Recovery factor and remaining reserve calculations

Ultimate recovery (UR) is the maximum number of reserves that can be produced according to technology at the primary production stage until it reaches its economic limit. Based on the calculation, ultimate recovery is the product of the initial reserve (OOIP) against the recovery factor of a layer or field. The amount of the recovery factor can be calculated using the volumetric equation contained in the equation below.

$$RF = \frac{1-Swi-(1-Sw_{max})}{1-Swi} x\ 100\ \%$$

$$RF = \frac{1-0.325-0.308}{1-0.325} x\ 100\ \% = 54.3\%$$

After knowing the value of the recovery factor in the K layer of the Nero Field, then the ultimate recovery can be calculated using the following equation.

UR = OOIP x RF

UR = 19987 x 54.3% = 10856.64 MSTB

Prior to the development of the K layer of the Nero Field, it is necessary to analyze the number of residual reserves. Based on the data, Nero Field has been produced from November 1970 to December 2018 with a cumulative production of 6202.8 MSTB. To find out the number of residual reserves contained in layer K, calculations can be made using the following equation.

RR = EUR - Np

RR = 10856.64 - 6202.28 = 4654.35 MSTB

Based on the calculation results above, it can be seen that the maximum reserves that can be produced in the primary stage are 10856.64 MSTB or 54.3% of OOIP, and the remaining reserves that can be produced in this study are 4654.35 MSTB.

Dynamic model validation

After preparing and processing all input data, then making a dynamic reservoir model from layer K in Nero Field using reservoir simulation, namely Computer Modeling Group (CMG) IMEX 2015.10. The CMG simulator is used during the initialization process until the end of the prediction and scenario process. The characteristics of the reservoir model made with the CMG software can be seen in Table 2.

Table 2. Summary of Nero Field Static Model

Parameters	Value
Simulator	*CMGIMEX* 2015.10
Grid Type	*Cartesian, Corner Point*
Grid Dimention	64 x 50 x 60
Active Grid	192.000
Porosity System	Single
Total Layer	60

Processed data that has been inputted into the model is then validated. The validations carried out here are initial reserve (OOIP) and pressure, history matching, and PI matching.

OOIP initialization and pressure

The initialization stage aims to align the initial conditions of the model that has been built with the initial conditions of the actual reservoir. There are two parameters that must be harmonized, namely the initial reservoir pressure (Pi) and Original Oil in Place (OOIP).

Figure 3. shows the initial oil saturation condition of the K layer in the Nero Field after initialization.

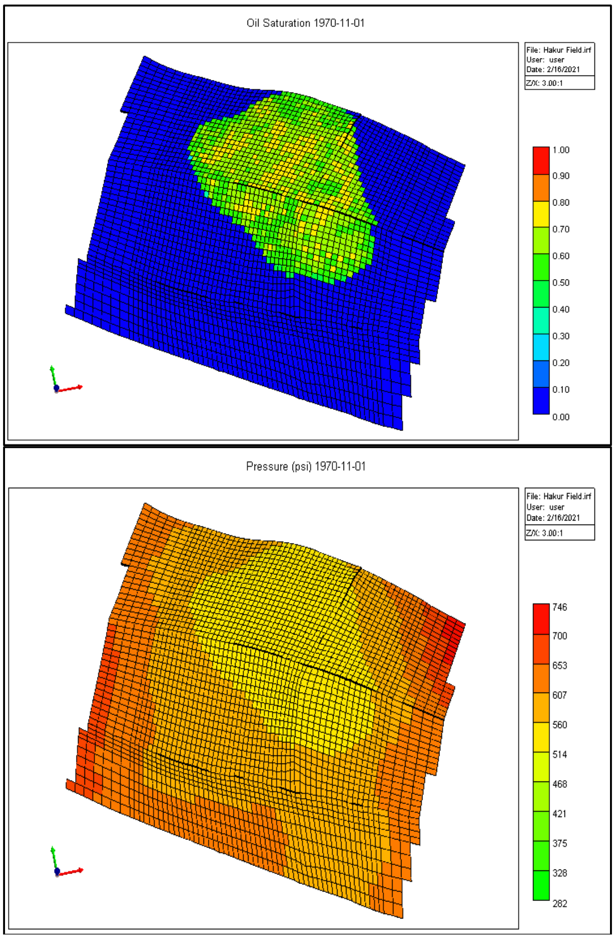

Figure 3. Initialization

History matching

History matching is a process of validating production performance and dynamic model pressure in order to achieve alignment with the historical production performance of field data. The history matching process started from the beginning of production, namely November 1970 to December 2018 with a total of 21 production wells. History matching on Nero Field Layer K using liquid constraint as a control in the simulator.

Table 3. Nero Field K Layer History Matching Results

Parameter	Calculation	Cumulative Production	%Error	Max Error
Np (MSTB)	Actual	6202.286	-3.41%	5%
	Simulation	6413.8		
Wp (MSTB)	Actual	31855.78	1.76%	5%
	Simulation	31294		
Lp (MSTB)	Actual	38058.07	0.92%	1%

Productivity Index alignment (PI Matching)

Before making predictions based on simulation results, it is necessary to do PI Matching for 1 year before the end of production. The goal is to align oil and water production rates so that the model does not give too optimistic or too pessimistic predictions. PI Matching is carried out on wells that are still producing. In the Nero Field Layer K, PI Matching was carried out on wells HK-01, HK-15, HK-24, HK-28, and HK-35. The parameters that are changed are well parameters such as skin and PI modification.

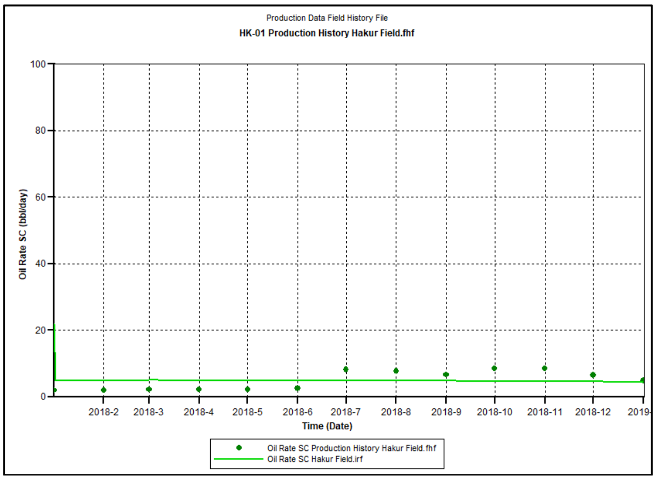

Figure 4. Oil Flow Rate Last 1 Year HK-01 Well

Development scenario of "Nero" field

Prediction or forecasting is the final step of simulation reservoir project. The objective of this stage is to analyze the behavior of the reservoir in the future based on the scenario. Primary target from this study are to determine the location and number of development well to optimize the production of "Nero" field, which can be detailed into:

a. Scenario I (Base Case) = Production with 5 existing well
b. Scenario II = Base Case + 1 reopening well
c. Scenario III = Scenario II + 6 infill well
d. Scenario IV = Scenario III + 3 infill well

a. Scenario I (*Base case*)

In the base case, predictions are made by producing wells that are still in production phase until the end of history matching (December 2018). The K layer on the Nero Field can produce until October 2033 and obtained a cumulative production of 6.46 MMSTB with a current recovery factor value of 32.30%.

Figure 5 show the location of existing well used as base case. Then, Figure 6. show the cumulative prediction results and the rate production of the K layer of the Nero Field in the basecase. And figure 7. shows the change in pressure of the K layer in the Nero Field on basecase.

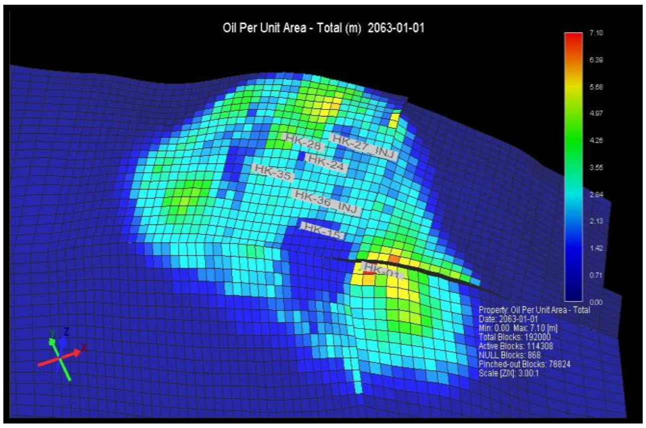

Figure 5. Location of Well based on Scenario I

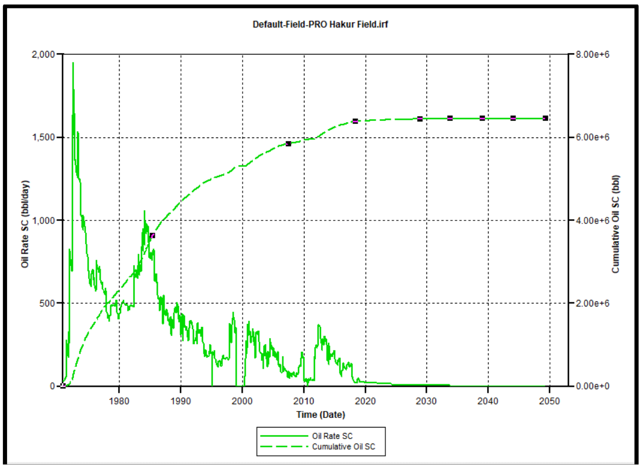

Figure 6. Prediction of Rate and Cumulative Production of Layer K "Nero" Field

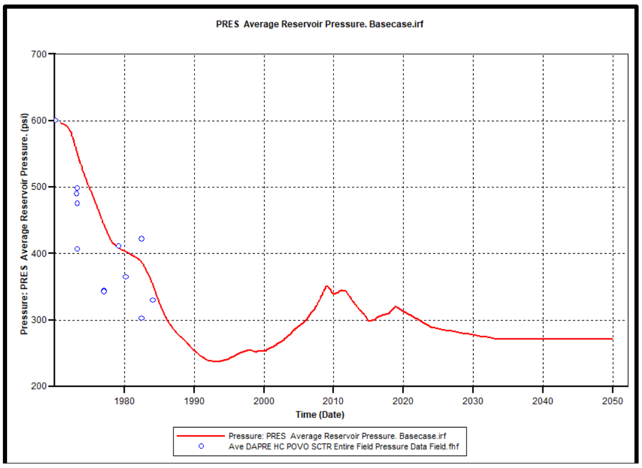

Figure 7. The Pressure Change of Base Case

b. Scenario II

In scenario II, predictions are made by producing existing wells, plus 1 reopening well, namely well HK-22. Determination of reopening well because the residual oil content in the HK-22 well is still quite high (it can be seen on figure 8) so that it is still quite economical to do a reopening and workover on this well.

From this scenario, layer K in Nero Field can produce until January 2068 and the cumulative production is 7.17 MMSTB and the recovery factor value is 35.89%. The result of this scenario show at figure 9.

It show the prediction result of cumulative production and rate production of layer K "Nero" field, with at figure 10 also show the change of pressure at layer K using scenario II.

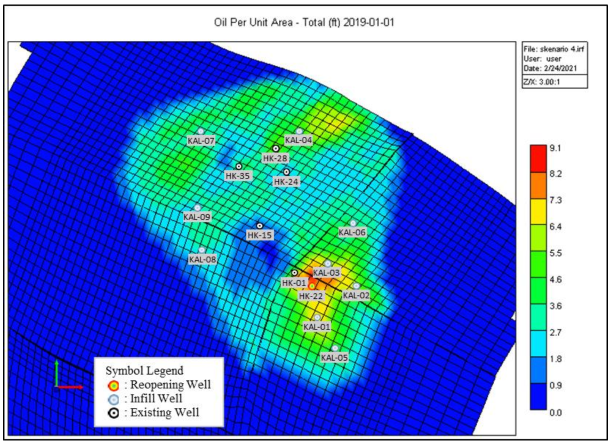

Figure 8. Distribution of Remaining Oil Reserves on the OPU Map

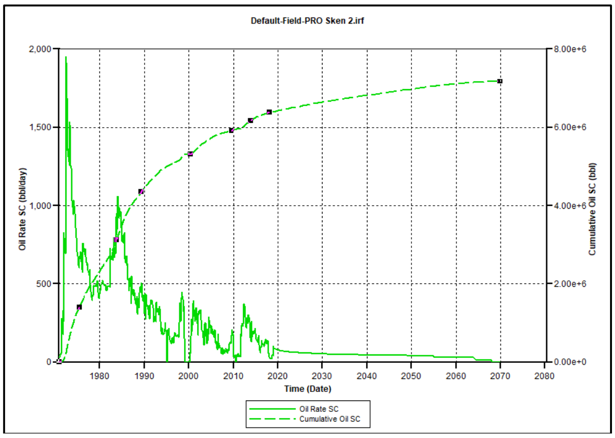

Figure 9. Prediction of Cumulative and Rate Production of Layer K using Scenario II

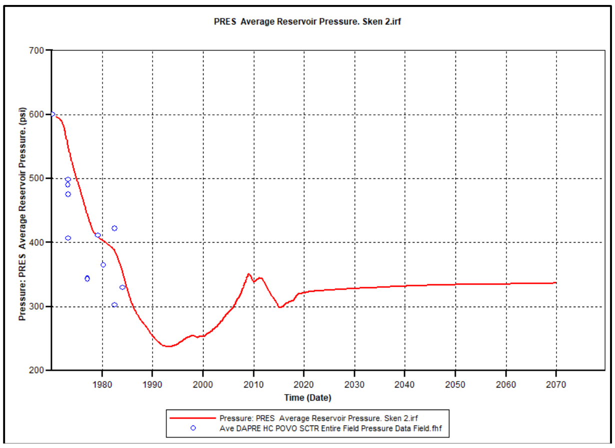

Figure 10. The Pressure Change of Layer K using Scenario II

c. Scenario III

In scenario III, predictions are made by producing existing wells, plus 1 reopening well (HK-22) and 6 infill wells namely KAL-01 to KAL-06. Based on scenario III the K layer in the "Nero" field can produce until January 2070 and the cumulative production is 8,094 with recovery factor value of 40.50%. Location of wells used in scenario III can be seen in figure 11 below.

The result of scenario III show by figure 12 and figure 13. Figure 12. show the result of cumulative and rate production of layer K at "Nero" field, beside at figure 13 show the pressure change. This change also influenced by the amount of production, rate, and the production time.

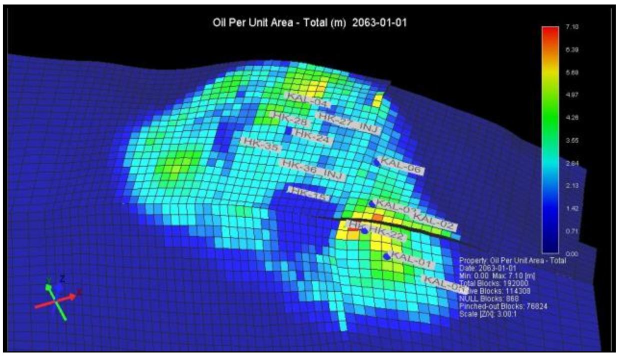

Figure 11. Location of Production, Reopening, and Infill Well Scenario III

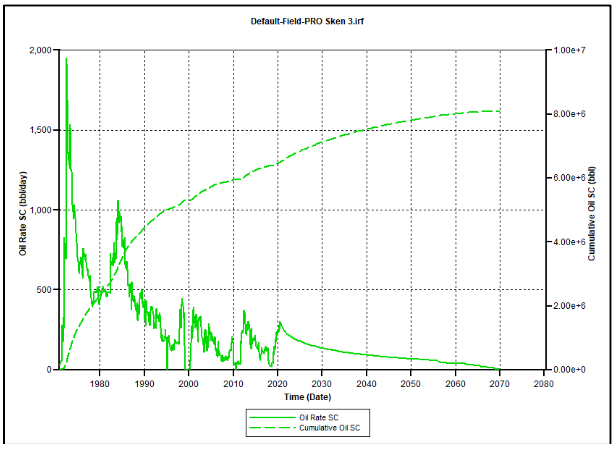

Figure 12. Prediction of Oil Production Rate and Cumulative Production of Scenario III

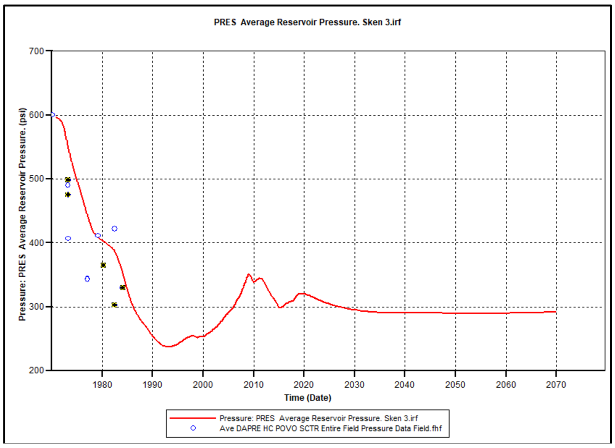

Figure 13. Changes in Pressure in Scenario III

In scenario IV, predictions are made by producing existing wells with 3 reopening well and 9 infill well (KAL-01, to KAL-09). Based on scenario IV, layer K in Nero field can produce until July 2065 and the cumulative production is 8,066 MMSTB with recovery factor value of 40.36%.

Figure 14 describe the location and number of development (infill and re-opening well) used in scenario IV. The result of this scenario show at figure 15. describe the cumulative prediction results and the rate of layer K in the Nero Field in scenario IV.

d. Scenario IV

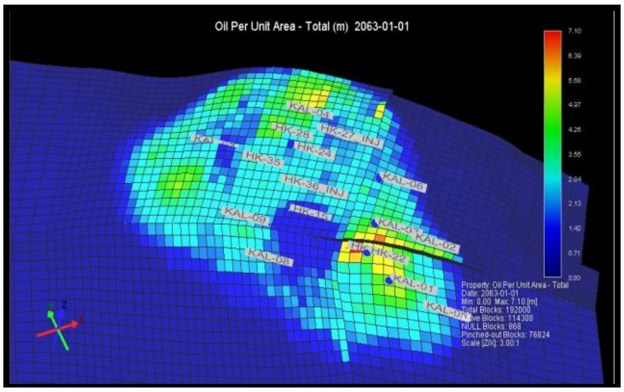

Figure 14. Location of Production, Infill and Reopening Well used in Scenario IV

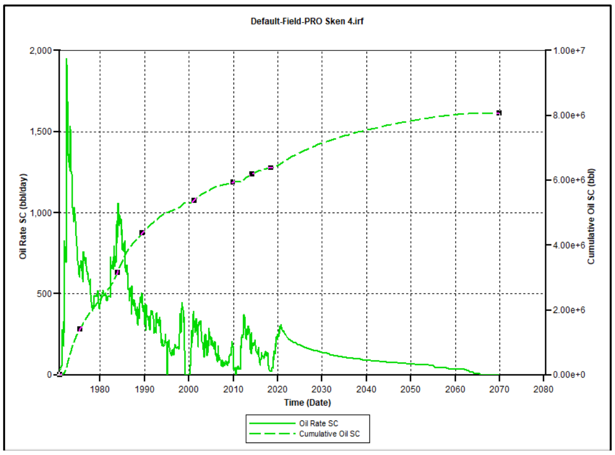

Figure 15. Prediction Results of Oil Production Rate and Cumulative Scenario IV

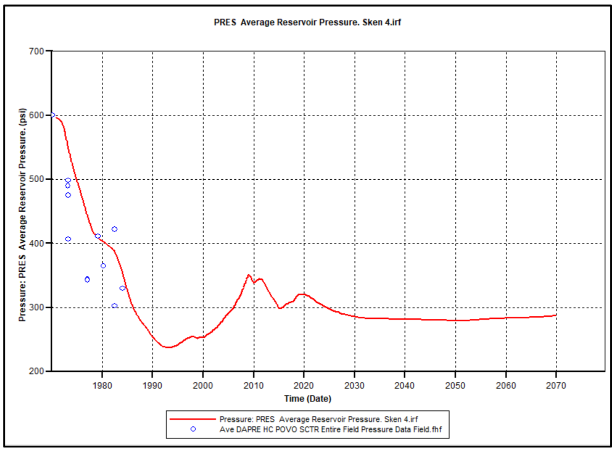

Figure 16. Changes in Pressure in Scenario IV

The simulation results from Scenario I to Scenario IV are summarized in Table 4.

Tabel 4. Summary of Prediction Results of "Nero" Field K Layer"

Scenario		Np Hist, MSTB	RR, MSTB	End of Prediction	Prediction		*Incremental*	
					Np, MSTB	RF	Np, MSTB	ΔRF
Scenario I (*Base Case)*	5 *Existing Well*	6389.7	4654.35	14/10/2033	6455.98	32.30%	-	-
Scenario II	*Base Case* + 1 *Re-opening well*			1/1/2068	7173.26	35.89%	717.28	3.59%
Scenario III	Scenario II + 7 *Infill well*			1/1/2070	8094.83	40.50%	1638.85	8.20%
Scenario IV	Scenario III + 2 Infill *well*			2/7/2065	8066.65	40.36%	1610.67	8.06%

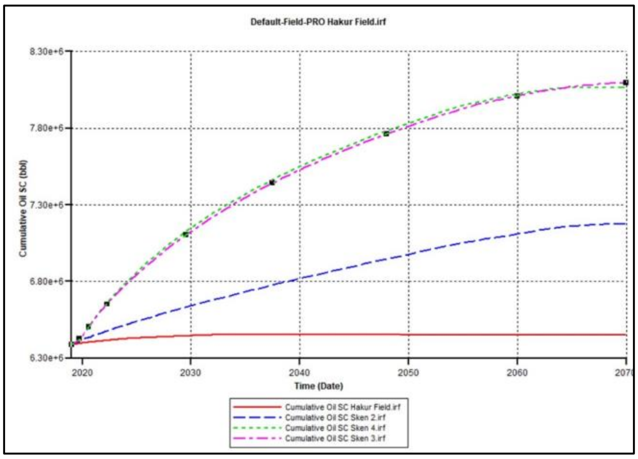

Figure 17. Comparison of Cumulative Oil Production for Each Scenario

Discussion

The "Nero" field is an oil field located in the Central Sumatra basin, which is included in District 1 Blok Kampar, Riau. Based on the geographical location, this field is 140 km from the southeast of Pekanbaru City and 200 km to the northwest of Jambi. Layer K of the "Nero" field has an initial reserve (Original oil in place) of 19,987 MMSTB and began production in November 1970 with cumulative oil production (until December 2018) reaching 6202.29 MSTB and a current recovery factor of 31.03%. The operating wells in layer K of the "Nero" Field consist of 18 production wells (5 active wells as of December 2018, 7 plug & abandon wells, and 6 shut-in wells), 4 injection wells, and 3 convert to injection wells (2 wells) active until December 2018 as an injector well and 1 shut-in well).

This reservoir simulation study was carried out using the flow diagram shown in Figure 1. where the simulation phase begins with data collection and processing, both geological model data, reservoir data, and production data which are then processed using a reservoir simulator. The reservoir simulator used in this thesis is CMG IMEX 2015.10 with a coarse grid model that has dimensions of 64 x 50 x 60 (I x J x K). The first stage is the preparation and data processing stage, which begins with determining the rock region. From the results of testing the physical properties of rocks, we can determine the characteristics of reservoir rocks and can divide the rock region. The main function of the division of rock regions is to group areas in the reservoir based on the properties they have in order to separate areas with good properties from bad properties. In addition, the division of rock regions also aims to facilitate the initialization process and history matching, where if the wells have different rock regions, the process of modifying the rock physical properties data will not affect one well to another. In theory, the rock region of a reservoir can be divided based on facies, based on the value of Swi, based on the value of permeability or based on the value of FZI (for carbonate reservoirs). For Layer K in the "Nero" Field, the rock region division is based on the distribution of the permeability values from the static model. The permeability value is obtained from the porosity permeability cross plot correlation where the porosity is distributed in a static model based on the distribution of facies. From the results of the analysis, Layer K has 2 regions based on the distribution of the permeability of the reservoir simulation model. Region 1 has a permeability value of more than 100 mD, and for areas with a permeability value less than 100 mD enter Region 2.

After obtaining the rock regions in the reservoir simulation model, the values for Swi, Sor, Kro@Swi, and Krw@Sor, were determined for each region using correlation. From the results of end-point data processing, the relative permeability and capillary pressure curves for each region are determined. For water-oil systems, the range for Swi values is 0.260 (Region 1) - 0.296 (Region 2); the range for Sor values is 0.3 (Region 1) - 0.33 (Region 2); for Kro@Swi value is 1 (for all regions); the range for the value of Krw@Sor is 0.247 (Region 1) - 0.268 (Region 2).

After processing rock region data and end-point SCAL data, data processing was continued by normalizing de-normalization of relative permeability and capillary pressure data. Furthermore, the relative permeability and capillary pressure curves for each region were determined using the SCAL end-point data. For Region 1, water saturation ranges from 0.297 to 0.67 with relative oil permeability ranging from 1 to 0 and water relative permeability ranging from 0 to 0.268. For Region 2, water saturation ranges from 0.254 to 0.705 with relative oil permeability ranging from 1 to 0 and water relative permeability ranging from 0 to 0.243.

For Region 1, water saturation starts from 0.260 to 0.678 with capillary pressure starting from 10.53 psia. For Region 2, water saturation starts from 0.296 to 0.652 with capillary pressure starting from 27.08 psia. After the SCAL data has been analyzed, the next step is to process the PVP data which will be entered into the simulator. PVP data obtained from laboratory analysis. The data on the physical properties of the fluid in this thesis are inputted into the simulator using a black oil model by including the physical properties of the fluid and reservoir conditions such as reservoir temperature (Tres), oil and gas density, bubble point pressure (Pb), oil formation volume factor (Bo), and solubility of gas in oil (Rs).

The next stage of data processing is the determination of key wells. The determination of the key well is done to simplify the history matching process. The criteria for key wells are wells that have been in production for a long time and represent the K layer area of the "Nero" Field with a total cumulative production of wells (Np and Wp) of more than 75% of the cumulative layer production (Np and Wp). From the analysis of the contribution of Np and Wp of the wells to the Np and Wp of the layer, 11 key wells were obtained, namely HK-01, HK-03, HK-14, HK-15, HK-18, HK-22, HK-24, HK-27, HK-28, HK-35, and HK-36.

The drain radius of existing wells is determined by using the Estimated Ultimate Recovery (EUR) value as the hydrocarbon volume of the wells obtained from the decline analysis of each well. After all the data is processed, the next step is the calculation of reserves using the volumetric method, which begins with the calculation of Original Oil in Place. The calculation of Original Oil in Place (OOIP) begins with the preparation of data in the form of an isopach map, the average porosity value, the initial average water saturation value, and the initial oil formation volume factor value. The calculation results show the OOIP Layer K value of 19,987 MMSTB.

Calculation of Recovery Factor (RF) for Layer K using volumetric equations. RF calculations with this method use the values of Swi and Swmax. From the calculation results, it is found that the amount of reserves that can be produced is 54.3% of OOIP or 10.86 MMSTB and the amount of remaining reserves that can be produced in the primary stage (remaining reserves) in layer K of the "Nero" field is 4.65 MMSTB.

After data processing and data input is complete, it is continued with the initialization stage, namely aligning the initial conditions (OOIP and pressure) of the simulation results with field data. In the initialization of OOIP, modifications were made to the capillary pressure values of each rock region. The initialization results show that the simulation OOIP is 19,987 MMSTB while the OOIP calculated using the volumetric method is 19,987 MMSTB. OOIP simulation results show that the model is in accordance with the difference of 0% (less than 5%). Furthermore, it is continued by equating the initial pressure of the simulation with the initial pressure of the well testing results. The pressure initialization process is carried out by changing the depth of the pressure datum. The results of the initialization of pressure which show that the initial simulated pressure and the measured initial pressure are almost the same with a difference of 0.91%.

The next stage is history matching, which is aligning the flow rate and cumulative production and pressure from the simulation results with the rate and cumulative production and actual pressure. By aligning the production data, it can be seen whether the reservoir model created represents the actual reservoir conditions by testing the suitability of the simulation production performance with the actual field production data. History matching in the field "Nero" layer K uses liquid constraint as a control on the simulator because the driving force acting on layer K is the water drive mechanism. The history matching results for the rate and cumulative liquid production are less than 0.92%, the history matching results for the rate and cumulative oil production are more than 3.41%, history match results for rate & cumulative water production less than 1.76%.

Especially for the oil field, the last step in the dynamic model validation stage is the PI Matching stage, namely by aligning the oil and water production rates in key wells and wells that are still producing. The goal is that the model does not give predictions that are too optimistic or too pessimistic. In the “Nero” Field Layer K, PI Matching was carried out on wells HK-01, HK-15, HK-24, HK-28, and HK-35. The parameters that are changed are well parameters such as skin, transmissibility, and modified productivity index (PI) of the well.

After validating the model through initialization, history matching, and PI matching; then the Layer K reservoir simulation can proceed to the prediction stage (forecast). In this stage, the scenario is focused on planning the development well points and reopening shut-in wells to determine the optimum number of development wells at Layer K. The scenario starts with the base case, then continues with scenario II in the form of base case plus 1 reopening well. III in the form of Scenario II plus 6 development wells, and Scenario IV in the form of Scenario III plus 3 reopening wells. Forecasting reservoir performance is carried out starting from January 2019 up to the economic limit.

The primary constraint parameter used in the prediction of the K layer of the “Nero” Field is the liquid rate in existing wells. Meanwhile, the economic limit for development wells is to use a bottom hole pressure of 200 psi, a minimum well oil rate of 5 STB/day, a minimum field oil rate of 25 STB/day, and a max water cut of 98%. In the Base Case, predictions are made by producing existing wells that are still alive, namely HK-01, HK-15, HK-24, HK-28, and HK-35 wells up to the economic limit. In this scenario, Layer K can produce until July 2029. Wells HK-01, HK-15, and HK-24 shut in at the beginning of the prediction period because they have reached the rate economic limit. The HK-28 and HK-35 wells are still in production until October 2033 (HK-28) and March 2024 (HK-35). This is because the K-layer area is still quite large and the pressure contribution to the HK-28 and HK-35 wells by the simulator is still large enough so that the wells can produce for a long period of time. From this scenario, the cumulative production is 6.46 MMSTB with the recovery factor price of 32.30%.

In Scenario II, predictions are made by producing existing wells (HK-01, HK-15, HK-24, HK-28, and HK-35), plus reopening shut-in wells, namely HK-22. With this scenario, Layer K can produce until January 2068 and get a cumulative production of 7.17 MMSTB with an incremental cumulative oil production of 717.28 MSTB against the Base Case. The recovery factor price is 35.89%.

In Scenario III, the prediction is made by producing 5 existing wells (HK-01, HK-15, HK-24, HK-28, and HK-35), 1 reopening well (HK-22), plus production from 6 development wells namely KAL-01, KAL-02, KAL-03, KAL-04, KAL-05, and KAL-06. With this scenario, Layer K can produce until January 2070 and the cumulative production is 8.09 MMSTB with an incremental cumulative oil production of 1.64 MMSTB against the base case. The recovery factor price is 40.50%.

In Scenario IV, predictions are made by producing 5 existing wells (HK-01, HK-15, HK-24, HK-28, and HK-35), 1 reopening well (HK-22), 9 development wells (KAL-01, KAL-02, KAL-03, KAL-04, KAL-05, KAL-06, KAL-07, KAL-08, and KAL-09). With this scenario, Layer K can produce until July 2065 and the cumulative production is 8.07 MMSTB with an incremental cumulative oil production of 1.61 MMSTB against the Base Case. The recovery factor price is 40.36%.

Based on the simulation results, it can be seen that if it is predicted to reach the economic limit, the scenario that is able to provide the largest cumulative production is Scenario III with 6 development wells and 1 reopening well. Cumulative scenario III is greater than scenario IV. This can be caused by the situation in scenario IV which has more wells than scenario III, so it can cause the pressure in the "K" layer to decrease more quickly (large pressure drop). Based on the comparison between the cumulative oil production of each scenario vs the number of wells, it is found that the most optimum scenario is Scenario III because the addition of 3 wells from scenario III to scenario IV does not result in a significant increase in cumulative production, Scenario III (1 reopening well and 6 infill wells) is the best scenario and the optimum number of wells in layer K of the “Nero” Field.

Conclusion

Based on the calculation of reserves using the volumetric method on the K layer of the "Nero" Field with a water drive, the Original Oil in Place (OOIP) value is 19,987 MMSTB.

Based on the calculation of the Recovery Factor (RF) of 54.3%, the Ultimate Recovery (UR) value of 10.86 MMSTB was obtained, so that in the initial conditions before the prediction (January 2019) the number of Remaining Reserves (RR) in layer K "Nero" Field amounted to 4.65 MMSTB. This value indicates that the reserves in layer K are feasible for field development.

Planning for field development in layer K of the "Nero" field by using the addition of infill wells and reopening of shut-in wells. The selection of development well locations in this study was based on the Oil Potential Unit (OPU) map and the drain radius of existing wells.

Based on the simulation results of the development scenario in layer K of the “Nero” Field, the optimum number of development wells to reach the economic limit is 6 development wells (Scenario III). The predicted time for this development well will start from January 2019 to January 2070. With the addition of 6 development wells, the cumulative production of layer K up to the economic limit reaches 8.09 MMSTB with an incremental cumulative oil production of 1.64MMSTB against Base Case. The recovery factor price is 40.50%.

References

Ahmed, Tarek H., 1989. Hydrocarbon Phase Behavior. Houston, Texas: Gulf Publishing Company.

Ahmed Tarek, McKinney Paul D., 2001. Reservoir Engineering Handbook 2nd Edition Texas: Gulf Publishing Company.

De Coster, G. L., 1974, The geology of the Central and South Sumatra Basins, Indonesian Petroleum Association, Proceedings of the Third Annual Convention, Jakarta.

Ghadami, Nader et.al, 2017. Enhanced History Matching and Prediction Using Integrated Analytical and Numerical Modeling Approach, SPE-186384-MS, dipresentasikan di SPE/IATMI Asia Pacific Oil & Gas Conference, Jakarta.

Laboratory of Plan Development Archive., 2020. Laboratory of Plan Development. Universitas Pembangunan Nasional "Veteran" Yogyakarta. Yogyakarta.

Pamungkas Joko. Ir. MT., 2011. Pemodelan dan Aplikasi Simulasi Reservoir, Yogyakarta: UPN "Veteran", Yogyakarta.

Rukmana, Dadang, 2009. Pedoman Simulasi Reservoir. Presented at Lemigas and K3S.

Rukmana D, Kristanto D, and Aji V. D. Cahyoko., 2011. Teknik Reservoir: Teori dan Aplikasi, Yogyakarta: Pohon Cahaya.

Thakur, Ganesh C. 1994. Integrated Petroleum Reservoir Management. Chapter 6. page 103 - 105, Chapter 8 page 155 – 158.