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Field Development with Scenario Reactivation of Non-Active Zones Through Reservoir Simulation: A Case Study of The Kappa Offshore Field, West Natuna

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Abstract

This research provides the scenario of a field development plant with the primary goal of acknowledging the reservoir model of Kappa Field in determining the optimum field development scenario to increase the recovery factor. In this research, field development will be carried out by creating scenarios that differentiate certain parameters to see the differences from these scenarios. The main problem in this field is to find out the feasibility of a field that has a history of production from 1986 to 2022 or for 33 years. In addition, the main objective of this research is to determine the reservoir driving mechanism of the Pasir RH-7 layer and determine the best field development scenario to optimize production in the Kappa field. The method used in this study is the reservoir modeling method using production data and reservoir data that has been obtained from the company and then managed using the Petrel Software assisted by Eclipse and MatBal. Before developing field development scenarios, an analysis is carried out using several different methods, including analysis with the decline curve analysis method in determining the remaining recoverable reserves as the validation of Kappa Field's feasibility, identify the driving mechanism of the reservoir, and history matching between history production data with simulation results. Sensitivity analysis of the field development is also conducted through various scenarios, including adding or adjusting well perforation interval, infill well adding, five water injection wells, and four gas injection wells. Other than that, injection gas and water rates in injection wells are also being exercised during the sensitivity analysis. Simulation results show the best scenario of Kappa Field is ten infill wells and four injection wells with a water injection rate of 1000 BWPD and gas injection rate of 1 MMSCF/d, giving the optimum recovery factor result of 39.33% from oil reserves. The results of this research will have a positive impact on the development of the Kappa field in order to increase production from fields that have been producing since 1986 and stopped production in 2019.

Keywords: Declined Curve Analysis, Driving Mechanism Reservoir, Field Development, Gas Injection, History Matching, Infill Wells, Reservoir Simulation, Water Injection

1. Introduction

fields spread across various regions, generally these fields are categorized as old fields or brown fields. So that over time, oil production in each field will decrease and not even a few wells will become unproductive. This is in line with the statement made by the minister of finance Sri Mulyani, namely "The current state of the Indonesian oil and gas industry is a challenging situation". The decline in oil and gas production, especially petroleum, has narrowed the gap between energy demand and supply, compared to the energy needs of Indonesia's population of 260 million, this situation will certainly not meet this energy demand (Afifa, 2021).

In June 2020, based on data from the Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas), total oil production in Indonesia reached 720,000 BOPD. When compared to oil production in 2018 which reached 768,000, oil production has recorded a significant decline from year to year. In addition, referring to data released by the Directorate General of Oil and Gas of the Ministry of Energy and Mineral Resources, stated that the volume of oil lifting in 2020 was 707 MBOPD, exceeding the production target of 705 MBOPD which had been lowered from the initial target of 755 MBOPD. Meanwhile, the volume of natural gas lifting was 975 MBOEPD, which was still below the initial target of 992 MBOEPD.

The deficit between oil production and consumption is getting bigger every year, this is a challenge for Indonesia in meeting domestic oil and gas needs. Therefore, certain field development schemes are needed to increase production from fields where production has decreased (Pratama, 2022).

Field development plans can be carried out by analyzing several aspects of the field, one of which is the reservoir aspect. In this study, analysis with reservoir simulation was used, by modeling the real condition of the reservoir through software so that it could test different production scenarios to find the most optimal scenario before the reservoir was actually produced. Reservoir modeling using software is usually based on the integration of various data such as seismic, well log, geology, and so on. Reservoir simulation is one of the parameters that is the main consideration in making decisions when planning for field development is carried out, because it can show reservoir flows and areas that require further review so that risks from production scenarios can be seen.

This research was conducted with the main objective of reservoir simulation studies in determining the best field development plan for the Kappa field in the West Natuna region of Indonesia, an oil and gas field that has been actively producing from 1986 until now. The Kappa Field is about 250 miles Northeast of Singapore. Even though it has been producing for a long time, this field still has large hydrocarbon reserves and consists of 16 reservoir layers. For this reason, researchers will conduct research in field development planning with the theme "Field Development with Scenarios of Inactive Zone Reactivation Through Reservoir Simulation: Case Study of the Kappa Offshore Field, West Natuna".

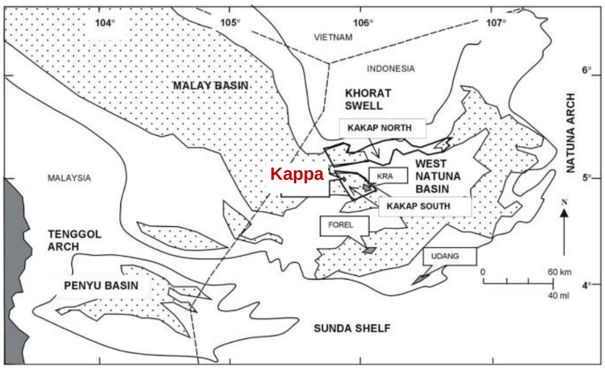

Fig. 1. Location of the Kappa Field in the West Natuna Basin

The Kappa field is located in the Northwest corner of the South Kakap production sharing contract (PSC) area in the West Natuna Basin (Fig. 1.), Indonesia, approximately 200 km Northwest of Natuna Island and more than 1000 km North of Jakarta, Indonesia. The total area of the Kakap PSC is 2006 km2 and water depths range from about 290 ft in the South Block to 190 ft in parts of the North Block. The West Natuna Basin is located in the South China Sea which is bounded into two distinct parts, the South and the West by the Indo-Australian plate. As previously mentioned, the depositional history of the West Natuna Basin consists of four parts with the following explanations:

- Early syn rift: The Lower Gabus was deposited in a fluvio-deltaic environment into the developing grabens.
- Late synrift: The Keras Shale and the Upper Gabus Formation were deposited in lacustrine and fluvial-deltaic environment. The Keras Shales are gradually replaced by the interbedded sandstones of the Upper Gabus Formation.
- Early postrift: This phase includes the Barat Shale and The Arang Formation. The Barat Shale was deposited in a lacustrine setting (in some parts of the basin it has been influenced by open marine). In the west of the basin, the Barat tends to be non-marine with coals whilst the east of the basin it is generally more open marine. The Pasir Formation overlays the Barat shales and is represented by fluvial to wave dominated delta. The Arang Formation is generally dominated by fluvio-deltaic sediments, though in parts of the basin is can be lacustrine
- Late postrift: Shallow marine conditions prevailed resulting in the deposition of the restricted claystones of the Muda Formation. The Base Muda Unconformity is a generally recognized feature of the West Natuna Basin. Minor deltaic sands are noted in some areas (Meirita, 2003).

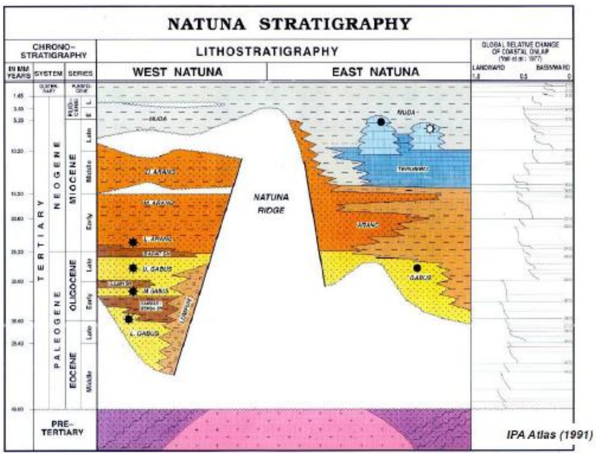

Fig. 2. General Stratigraphy of the Natuna Basin

The depositional model for the Pasir Formation have been based on the paleo-environment maps. The paleo-environment map indicates a large distributary channel system that has a wave influenced delta front. We have based our facies dimensions and orientations on these environment maps. With further stratigraphic work these can be locally refined for the Kappa field.

Over the Kappa Field, the interpreted thickness of the distributary channels is up to 100 feet thick. The channels show a general north to south direction over the Kappa Field and the channel complex has a width of ~10km and a shown length of ~4km

2. Material and Methods

2.1 Existing Well Data

The data used in this study is original data from a field in the Natuna Sea which has been producing from 1986 to 2019. This field consists of several layers of Pasir RH-1 to Pasir RH-10 which are distinguished into the Non-Associated Gas zone and Associated Gas zone. The Kappa field, especially in the Pasir RH-7 layer, consists of 15 existing wells consisting of 9 production wells: WH-1S, WH-2S, WH-3S, WH-5A, WH-6A, WH-7A, WH-8L, WH -9S, WH-10B, with the conditions WH-2S, WH-3S, WH-6A, WH-7A, and WH-8L were no longer accessible, so it was decided not to carry out any reactivation or processing of the five wells and 6 wells exploration: WH-1X, WH -2X, WH-3X, WH-4, WH-5X, and WH-6X. The research focused on 4 production wells located in the Pasir RH-7 reservoir: WH-1S, WH-5A, WH-9S, and WH-10B. Fig. 3. shows the locations of production and exploration wells, while the perforation intervals of production wells can be seen in Table 1.

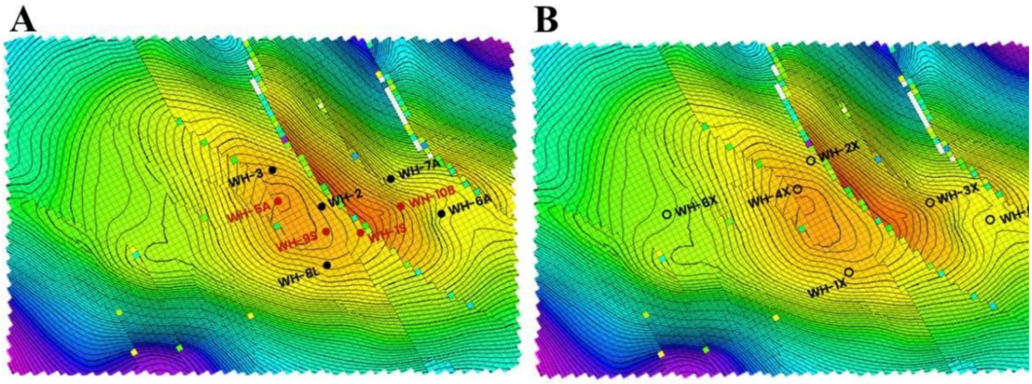

Fig. 3. Location of Wells on the HCPV Map: a) Production; b) Exploration

Table 1. Production Well Perforation Interval

Sumur	Interval Perforasi (ft)
WH-1S	6695 – 6700
	6725 – 6730
	6734 – 6739
WH-5A	7384 – 7392
	7413 – 7418
	7422 – 7432
WH-9S	6666 – 6678
	6702 – 6744
WH-10B	6606 – 6614
	6620 – 6626
	6844 – 6858

2.2 Pasir RH-7 Reservoir Data

The Pasir RH-7 layer was developed as an oil reservoir which initially had a gas cap, oil column and water column. Classified as an oil reservoir that has achieved an oil recovery factor of up to ± 24.7% as of January 2022. Pasir RH-7 consists of clean sand with an average permeability of 342 mD, an average porosity of 0.18, and a reservoir thickness of ±180 ft. The resulting oil is light oil with an approximate API of 43-47° and a saturation pressure of around 2601 psi.

Pasir RH-7 has good sand connectivity where sand can be seen almost everywhere. However, rock quality decreases towards the east side because the rock type becomes shale dominant. The Pasir RH-7 Reservoir is divided by a large fault and the zone is divided into two blocks, West and East, where there is a juxtaposition of sand along the fault in the South. Based on the information provided by the company, that there is a close relationship for the pressure parameters between the two blocks after the start of production.

Pasir RH-7 started oil production in March-October 1986 with six wells in the West block: WH-1S, WH-2S, WH-3S, WH-5A, WH-9S, WH-8L; two wells in the East block: wells WH-6A and WH-7A; and then in December 1992, the WH-10B well in the East block started production. In the completion process, an operation is carried out by punching a hole in the oil column first and after 4-5 years of new production, a perforation is opened in the gas cap zone to help lift it in the production process. As of January 2018, there are 4 active wells: wells WH-1S, WH-5A, WH-9S which have been producing with the help of gas lift injection since 1990 until now; and the WH-10B well which has been producing by gas lift injection from 2000 until now. In order to know the fluid behavior in the reservoir, it is necessary to know the initial condition data of the reservoir. This data is obtained from the model available in the Petrel software used.

Table 2. Reservoir Initial Conditions

Data	Value	Unit
Reservoir Temperature	224	°F
Reservoir Pressure	2740	Psia
Gas Oil Contact Blok Barat	6278	Ft
Oil Water Contact Blok Barat	6450	Ft
Gas Oil Contact Blok Timur	6285	Ft
Oil Water Contact Blok Timur	6500	Ft
Solution Gas Oil Ratio	1.2095	SCF/STB
Oil Formation Volume Factor	1.6	Rb/STB
Gas Formation Volume Factor	0.79	Rb/MSCF
Net Pay Thickness	176	Ft
Bubble Point Pressure	2601	Psi/ft

2.3 Rock Characteristics

The rock characteristics in the field that will be used are facies, effective porosity (PHIE), net-to-gross (NTG), water saturation (S_w), and rock compressibility. This data is obtained from the model available in the Petrel software used.

2.3.1 Facies

Based on the interpretation of the depositional environment of the Pasir RH-7 reservoir, facies modeling for this layer can be made. From the facies distribution data, there are 2 types of facies, shale and sandstone. The facies model and distribution can be seen in Fig. 4. and Table 3.

Table 3. Facies Distribution

Layer	Shale (%)	Sandstone (%)
RH-7	10.69	89.31

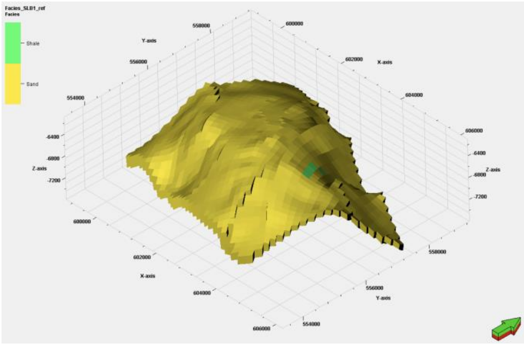

Fig. 4. Pasir RH-7 Facies Distribution

2.3.2 Effective Porosity (PHIE)

Porosity modeling is the next step after the lithofacies model is made. The input data value for modeling porosity in sand lithofacies is derived from the effective porosity log, calculated by the petrophysicist which is upscaled to the vertical resolution of the grid with the average arithmetic method, while the porosity in the shale lithofacies is set at a value of 0. The range of effective porosity values on Pasir RH-7 ranges from 0.04 to 0.2710, the average value of effective porosity on Pasir RH-7 is 0.1841. The effective porosity model can be seen in Fig. 5.

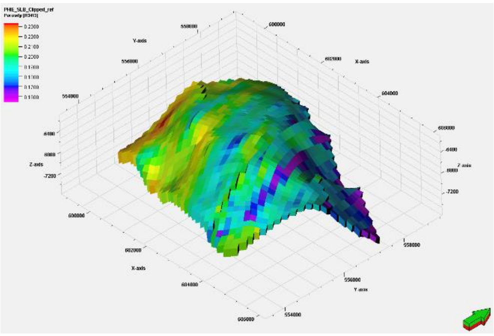

Fig. 5. Effective Porosity of Pasir RH-7

2.3.3 Permeability

The permeability log is calculated by a petrophysicist and calibrated with available core data in the field. The permeability log is upscaled to grid resolution and used as a data input value in permeability modeling for lithofacies sand while the permeability model for lithofacies shale is set at a value of 0. Based on the information received, the cross-plot between permeability vs porosity in log wells shows that there is a good correlation between the two properties, in this case the modeling for permeability in Pasir RH-7 is available in the reservoir model. Based on the results of the analysis the permeability values ranged from 0 mD to 2833 mD, and the average permeability value on Pasir RH-7 was 342.7643 mD.

In addition, the saturation function plays an important role in the three-phase mobility in Pasir RH-7. It is evident that the balance between aquifer strength and gas cap expansion combined with appropriate three-phase mobility will greatly influence the behavior of Pasir RH-7. But due to data limitations, the saturation function parameters such as residual oil saturation relative to water (S_{orw}), residual oil saturation relative to gas (S_{org}), core oil coefficient to water (Corey O/W), core oil coefficient to gas (Corey O/ G) and relative permeability in Sorw (Krw*) were made using templates from the Petrel software. This is done to optimize the suitability of oil, gas and water production

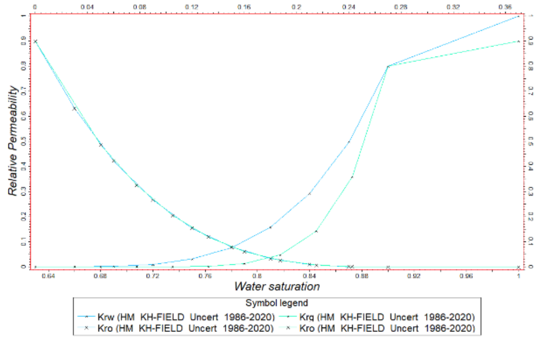

Fig. 6. Effective Permeability Chart

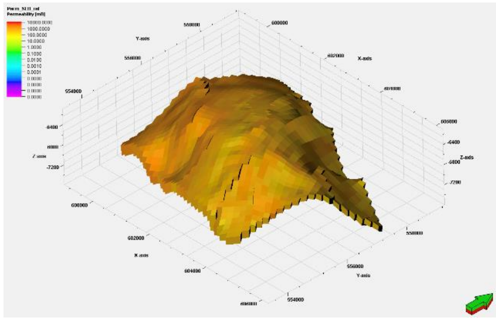

Fig. 7. Pasir RH-7 Permeability Distribution

2.3.4 Net-to-gross (NTG)

The Net-to-Gross property is the depth ratio between the thickness of all layers/reservoar and clean sand, the distribution of NTG values in the Pasir RH-7 layer ranges from 0 to 1. The average NTG value in the Pasir RH-7 layer is 0.7592 or 75.92 %. The NTG distribution can be seen in Fig. 8.

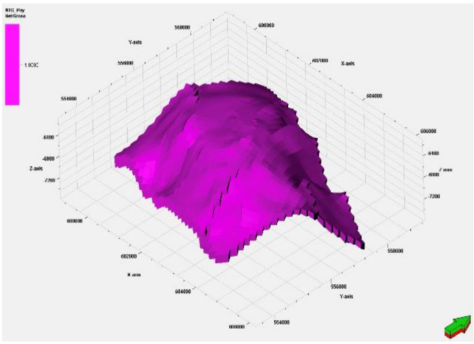

Fig. 8. Pasir RH-7 NTG Model

2.3.5 Water Saturation (S_w)

Water saturation (S_w) is modeled in the grid as one of the requirements for calculating the volume of hydrocarbons in the reservoir. Based on the available data, there are several types of oil and gas accumulation in Pasir RH-7, so there is a transition zone in the model. The higher the water saturation value, the lower the hydrocarbon saturation value in the reservoir, while the lower the water saturation value in the reservoir, the higher the oil and gas saturation value. The results of the analysis on the model show that Pasir RH-7 has a water saturation value that ranges from 0.1 to 1 with an average water saturation value of 0.48.

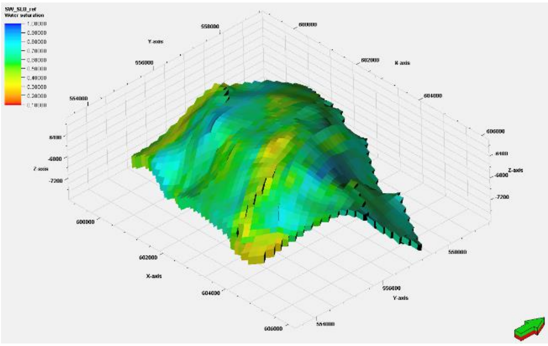

Fig. 9. Pasir RH-7 Water Saturation (Sw) Model.

2.3.6 Rock Compressibility

The rock compressibility value used in the reservoir model uses the Newman 1973 correlation derived from the value template in the Petrel software. It is known that the type of rock in Pasir RH-7 is consolidated sandstones with a reference pressure used of 5801.5 psi, so the compressibility of the rock (Cf) is 9.8 x 10-7 1/psi.

2.4 Reservoir Fluid Data

Based on information from the company, initial Gas-Water Contact (GWC) or Oil-Water Contacts (OWC), when observed in several wells, the median contact depth is given. Gas-Oil Contacts obtained from RFT when available in each layer, production data from existing perforations and observations of the neutron-density log as an anti-correlation between the two logs can be used as gas indicators. Several things need to be watched out for shale formation because the effect of gas on the neutron density will be covered by the effect of shale on the log. When no fluid contact is observed, an estimate of the contact depth is obtained from Gas-Down To (GDT) or Oil Down To (ODT).

In the Pasir RH-7 Layer, in the West Block GOC was found at a depth of 6278' TVDSS from open hole data in several wells WH-1, WH-2, WH-3, WH-5, and WH-9S. The shallowest gas up to (GUT) was found in well WH-2 at a depth of 6187' TVDSS and the deepest ODT was found in well WH-3 at 6450' TVDSS. In the East Block, GOC is derived from GDT in well WH-3X found at 6285' TVDSS and glimpsed RFT pressure data in the same well. GDT was found at WH-3X above a thin shale break (5' – 10' thick) separating several other layers. OWC found in well WH-5X at 6448' TVDSS. The shallowest GUT was found in well WH-3X at 6146' TVDSS and the deepest water down to (WDT) was found in well WH-7 at 6495' TVDSS. The location of the GOD and OWC used in the reservoir simulation can be seen in Fig. 10.

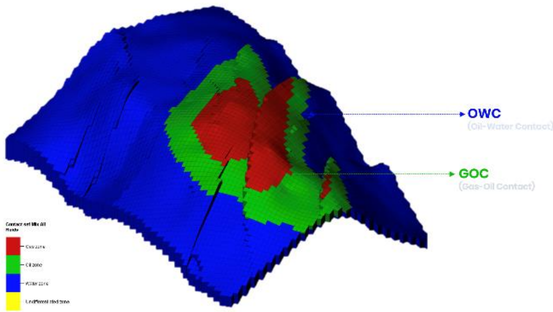

Fig. 10. Pasir RH-7 GOC and OWC models

The type of fluid in the Kappa Field is known from the data provided by the company. The Pasir RH-7 layer was developed as a layer with the main production being oil fluids, the oil produced is of the light oil type with an approximate API of 43-47° and a saturation pressure of around 2740 - 2741 psi. The fluid property model used in the reservoir simulation uses a combination of the data provided by the company and the data template from Petrel for unavailable data, Fig. 11. shows a graph of the fluid model used.

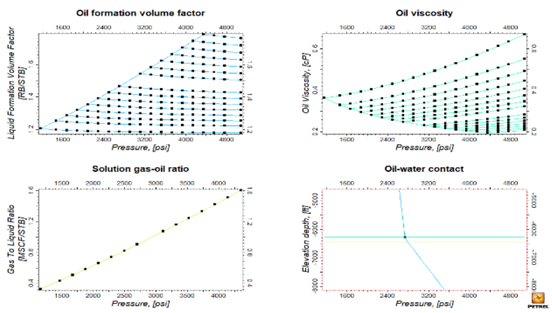

Fig. 11. Fluid Properties of Pasir RH-7

2.5 Initial Hydrocarbon Reserves

Determination of the initial volume of hydrocarbon reserves in 1986 which was above the water contact was carried out at Petrel. Volumetric calculations using a grid structure that has been filled with various properties in the static model, the results of calculating the initial volume of hydrocarbon reserves can be seen in Table 4.

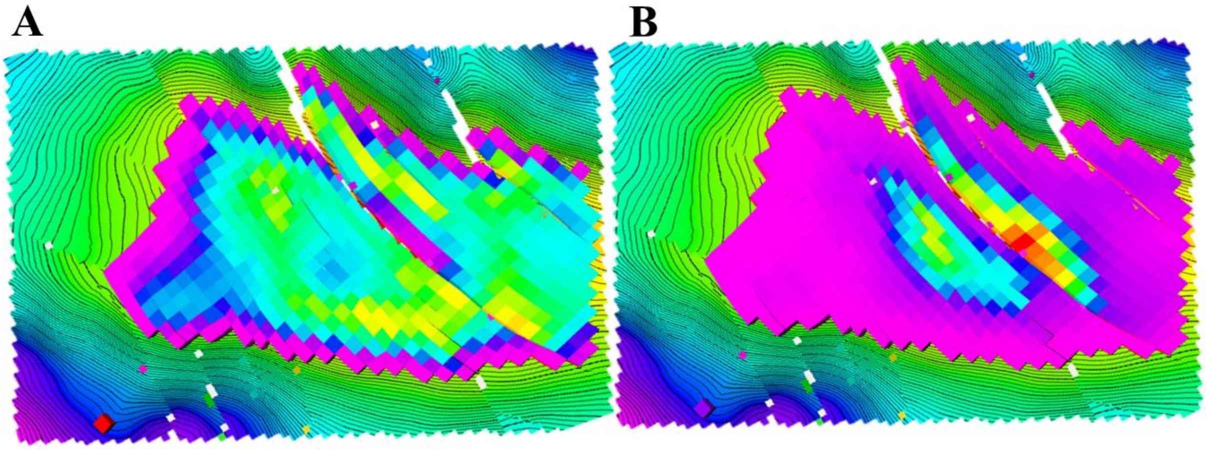

Fig. 12. HCPV Map on Pasir RH-7: a) Oil; b) Gases

Table 4. Determination of Inplace Volumetric Pasir RH-7 Year 1986

Parameter	Value	Unit
Bulk Volume	280.11	*10^3 acre.ft
Net Volume	280.11	*10^3 acre.ft
Pore Volume	53000	acre.ft
HCPV Oil	17000	acre.ft
HCPV Gas	7000	acre.ft
STOIIP	88.106	MMSTB
GIIP	115.335	BSCF

2.6 Production History

Production history data is presented in the form of an excel spreadsheet with the Petrel (*.vol) column format. The observation data provided is on a monthly basis as a cumulative total at the end of each month. The cumulative production per month is checked and the results are consistent with the cumulative production. Fig. 13. shows field production data provided by company for oil and gas reservoirs.

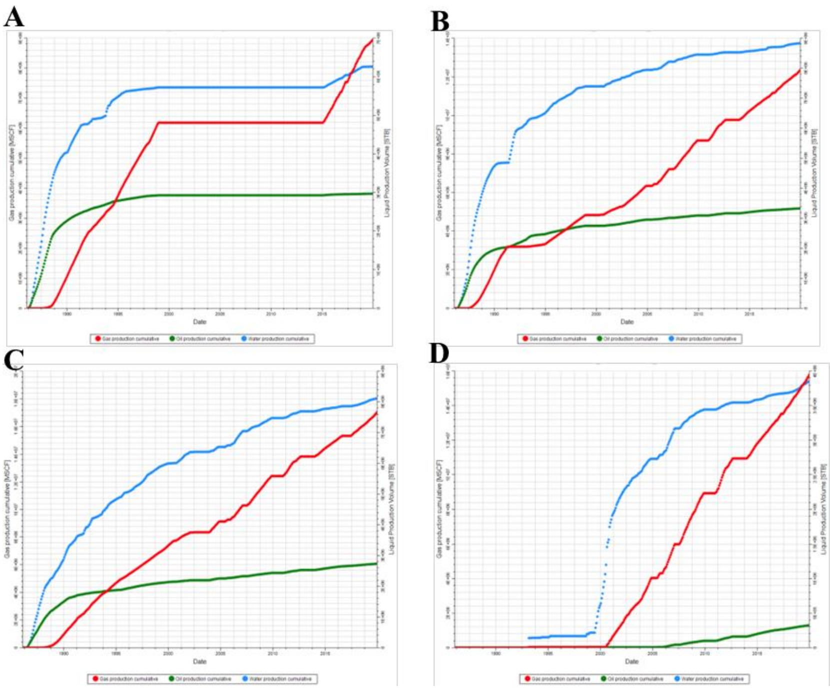

Fig. 13. History Production of Pasir RH-7: a) WH-1S; b) WH-5A; c) WH-9S; d) WH-10B

Production history data on Pasir RH-7 is available from March 1986 to December 2019 and is used as observational data for history matching. The available data are oil, water, and gas in each well. Fig. 13. shows the timeframe from which production was carried out until the well ceased production, all wells except Well WH-10B were initially produced in 1986 while well WH-10B began production in 1992. Only 4 wells remain active until 2019: Wells WH-1S, WH- 5A, WH-9S, and WH-10B. Of the four wells, WH-5A and WH-10B use a single string in the production process, and wells that use a double string are WH-1S and WH-9S. For wells with double strings, each string has its own production rate data to match its history (oil, gas, water). In Pasir RH-7 oil production, WH-1S Well is only produced from short strings. During the period of operation at Pasir RH-7, Well WH-9S was mostly produced from short strings, but in certain periods Well WH-9S produced from short strings and long strings. Well WH-9S produced from both strings in April 1991-May 1995 and April 1991-August 2003 respectively. However, all strings in each well produced from the same perforation interval. To simplify the analysis process during history matching, for the WH-9S Well, production rate data from short strings and long strings are totaled over a certain period.

3. Results and Discussion

3.1 Decline curve analysis (DCA)

Of the several reservoir layers available in the Kakap Field, the researchers chose to conduct research only on the Pasir RH-7 layer. This layer is the largest oil reservoir in the Kakap Field with a total of 4 active production wells until 2019. Therefore, the decline curve analysis (DCA) method was carried out to determine the feasibility value of the field which will be used for developing scenarios for field development. DCA is made based on the decrease in production rate over time for each well in the Kakap Field based on production data from 1986. The desired output from this step is to model the production decline curve for each well, and obtain the value of the total remaining recoverable reserves for determine the economics of the project from the oil and gas reserves produced. The first step in implementing DCA is to make a plot on a graph using well production data, then make a production forecast from 2022 to 2028 based on the decline rate of previous production data. DCA results can be seen in Fig. 14.

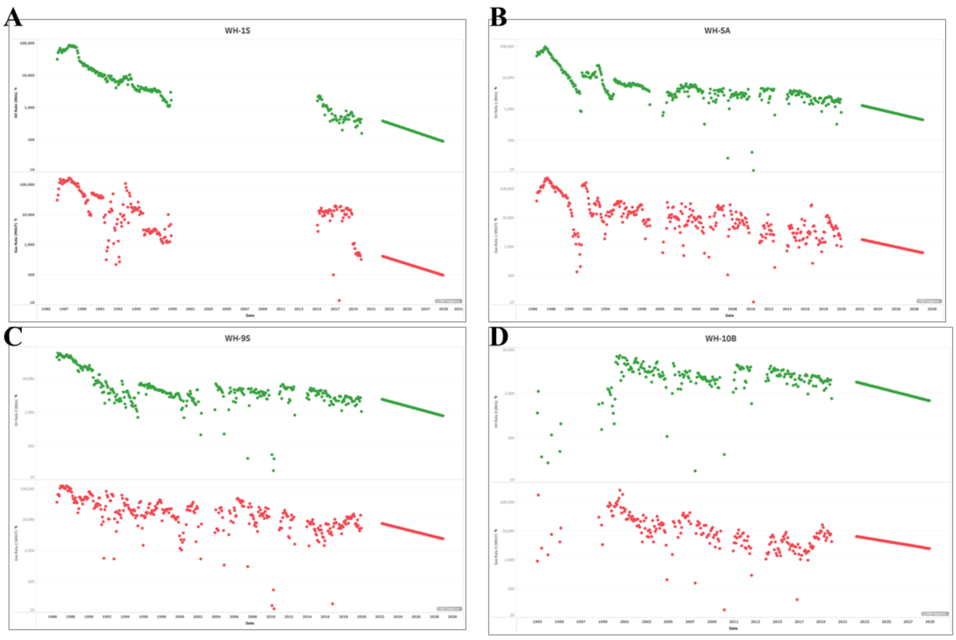

Fig. 14. Decline Curve Analysis of Wells: a) WH-1S; b) WH-5A; c) WH-9S; d) WH-10B.

Based on production forecasting using the DCA method above, the results obtained from remaining recoverable reserves are total production based on the well decline rate per year which ranges from 14-22%. Based on Table 5., the value of remaining recoverable reserves for the Kappa Field touched 0.29 MMBbls and 0.79 BSCF respectively for oil and gas. So it can be concluded that the hydrocarbons accumulated in the four existing wells are still abundant and the Kappa Field is feasible to continue the production process.

Table 5. Remaining Recoverable Reserves Pasir RH-7

Well	Dyear (%)	Oil (MMBbls)	Gas (BSCF)
WH-1S	22	0.016230	0.017361
WH-5A	17	0.063351	0.088629
WH-9S	16	0.118	0.360786
WH-10B	14	0.093258	0.331964
Total		0.2908	0.79901

3.2 Reservoir Drive Mechanism Analysis

Three types of propulsion mechanisms are found in the West and East Pasir RH-7 blocks, namely gas cap expansion, aquifer support, and rock and fluid expansion. According to the structural model of the static modeling, the West and East Pasir RH-7 blocks have adjoining positions. Based on the available information, pressure data from the West and East blocks also show the same trend, Fig. 15. shows plots of pressure data for the West and East Pasir RH-7 blocks.

To validate the relationship between the West and East blocks, two tank models were analyzed using material balance (MBAL). The West and East Pasir RH-7 Blocks show a good fit of the Pressure vs. Np plots.

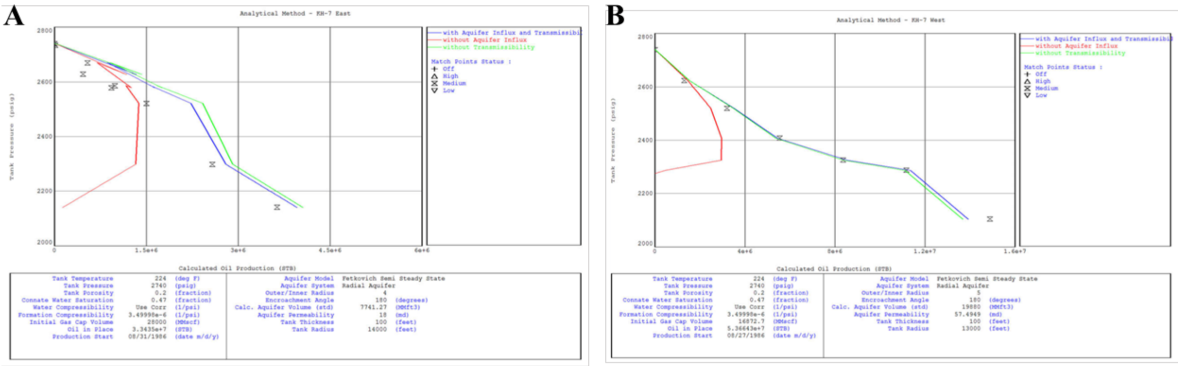

Fig. 15. Analytical Method Pasir RH-7: a) East Block; b) West Block.

Initial reservoir reserves for Pasir RH-7 based on MBAL touch 54 and 33.5 MMSTB respectively for the West and East blocks with a dominant driving mechanism for water influx. Large aquifers are needed to calibrate the reservoir energy of the two blocks with a volume of around 20,000 MMft3/8,000 MMft3 for the West and East blocks with a dimensionless radius (RD) of around 4 - 5. From the results of the analysis carried out, it was found that the reservoir driving mechanism is Pasir RH-7 there is a dominant water drive mechanism with aquifer support reaching 60% of the total energy system in Pasir RH-7.

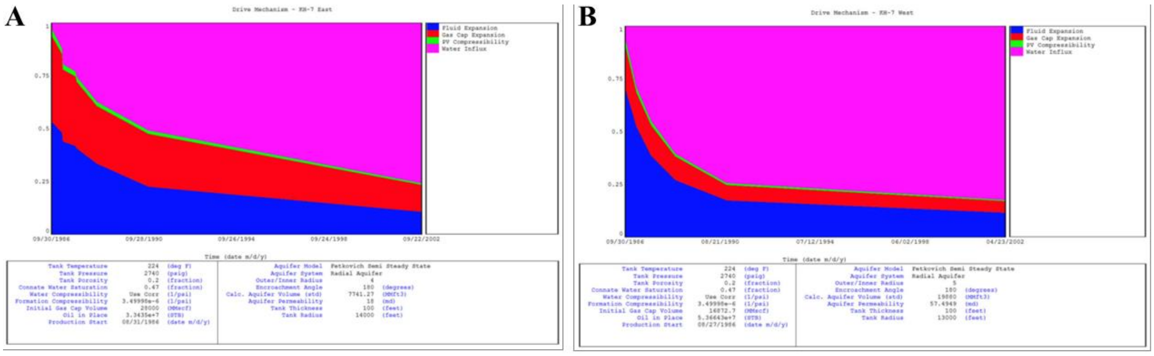

Fig. 16. Pasir RH-7 Driving Mechanism: a)East Block; b) West Block.

3.3 Initialization Reservoir Model

Initialization or matching in place is carried out on the static model which aims to see the coherence between the static model and the dynamic model with respect to the value of hydrocarbon reserves in the reservoir, original oil in-place (OOIP) and original gas-in place (OGIP). The OOIP and OGIP values in the dynamic model are generated from a simulation run using the Petrel software assisted by the Eclipse simulator, while the values from the static model are obtained from volumetric calculations.

Determination of hydrocarbon reserves by volumetric calculations uses some data in the form of Rs, Bo and Sw derived from dynamically generated model results to obtain more accurate results when compared to using a single value. Table 6., shows the results of the initialization in 1986 before the field was produced for the dynamic model of 88.5 MMSTB for OOIP and 115.3 BSCF for OGIP while the static model was 88.1 MMSTB for OOIP and 114.18 BSCF for OGIP.

The comparison of OOIP and OGIP values for static models and dynamic models is less than 5% so that it can be said that dynamic models can be used in field development scenarios, these results can be seen in Table 6.

Table 6. Results and Comparison of Hydrocarbon Reserves for 1986 Pasir RH-7

Parameter	**Value**	**Unit**
OOIP Volumetric	88.1	MMSTB
OGIP Volumetric	114.18	BSCF
OOIP Initialization	88.5	MMSTB
OGIP Initialization	115	BSCF
Difference OOIP	0.45	%
Difference OGIP	0.98	%

In order to get the best results in forecasting production with the scenarios that will be made, OOIP and OGIP will use hydrocarbon reserves in 2022. Based on the data received, the Pasir RH-7 Bed has produced up to 20.9 MMSTB of oil with an oil recovery factor of 24.7% in January 2022. So in 2022, the remaining OOIP is 67.6 MMSTB, while gas production has reached 71.87 BSCF (39.71 BSCF from the West Block and 32.03 BSCF from the East Block) so that OGIP in 2022 is 43.13 BSCF.

3.4 Field Production Production History Analysis and History Matching

Field production history data is very important to be analyzed together with simulation results to determine the suitability of the model with actual production data (Schlumberger, 2022). In this model, history matching is carried out from data on the four existing wells, namely WH-1S, WH-5A, WH-9S, and WH-10B which have produced from 1986 to 2019, so that analysis is carried out for cumulative production data of oil, gas and also water provided by the internal company.

During the history matching process, it is known that the well completion history data is one of the main sources of uncertainty in the history matching of Pasir RH-7, especially when a perforation hole in the gas cap is added to assist the well lifting process. There is uncertainty in the completion data where some wells can be described using the available complement data sources and some wells cannot. Rock property data is also a major challenge for aligning actual field production data, because rock data is not available, so only data templates from the Petrel software are used. Pasir RH-7 has a three-phase fluid system (oil, gas and water). The volume and movement of the gas cap is a significant challenge given the historical production of most of the gas at Pasir RH-7 has been through well production. Further analysis shows that Pasir RH-7 has a very limited gas cap volume where gas production has reached a very high figure of 71.87 BSCF (39.71 BSCF from the West Block, and 32.03 BSCF from the East Block) per 2017, so several efforts have been made to align the gas cap yield in the most reasonable way to achieve the observed gas production. In addition, it is also known that in the Pasir RH-7 static model, the permeability distribution is much lower around the WH-8L Well and WH-6A Well. Modifications around Well WH-8L and Well WH-6A are required to improve oil flow matching by increasing permeability locally. However, these changes are within the average permeability range around the wells.

From the analysis results in Fig. 17., it is found that the actual data and production simulations from 1986 to 2019 have matched for oil and water but for gas there is still a difference which is less than <10% for the total cumulative production.

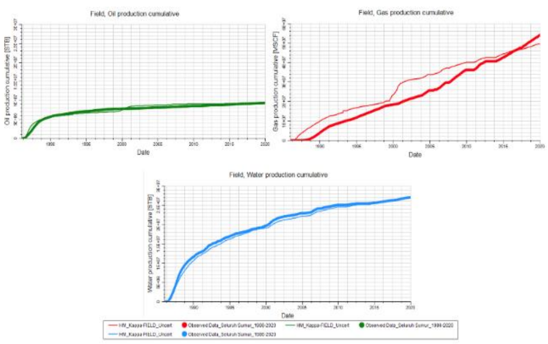

Fig. 17. History Matching Existing Wells.

3.5 Field Development Scenario Analysis

The Kappa field is planned for field development for 6 years (2022-2028) until the field contract with the company ends. There are 9 existing production wells in this field, WH-1S, WH-2S, WH-3S, WH-5A, WH-6A, WH-7A, WH-8L, WH-9S, WH-10B. Almost all of these production wells are no longer operating due to various problems, therefore the researchers only limited field development to wells WH-1S, WH-5A, WH-9S, and WH-10B. Based on the results of the analysis, that the four wells could be reactivated because the existing problems were considered to be overcome, therefore it was decided that the reactivation of the four production wells would be the base case of the field development scenario. Field development scenarios planned in this study include adding and changing the depth of perforation intervals, adding infill wells, gas injection, and water injection. This is done to determine the most profitable scenario in producing hydrocarbons in the reservoir.

3.5.1 Scenario 1: Production of 4 Existing Wells (Base Case)

In the first scenario, field development is carried out by producing hydrocarbons from existing wells, WH-1S, WH5A, WH-9S, and WH-10B wells. The four wells are located in locations with high oil saturation. Field development is planned for 6 years, starting from 2022 to 2028 with a production rate control constraint that is set based on the latest historical production data for each well. Based on the simulation of Scenario 1, it was found that the reservoir pressure decreased due to continuous production until 2028 which touched 2704.9 psi, then the oil recovery factor for 2022 to 2028 was 0.34%, with a cumulative total oil production of 0.30 MMSTB, cumulative gas production of 0.75 BSCF, and a water cut of 9.8%. The distribution of oil saturation after and before scenario 1 is carried out can be seen in Fig. 18.

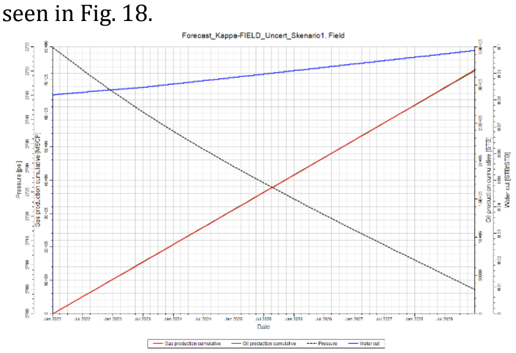

Fig. 18. Cumulative Production of Oil, Gas, Water Cut, and Reservoir Pressure Scenario 1

3.5.2 Scenario 2: Base Case + Increasing Well Perforation Interval

This scenario is based on scenario 1 and changes and additions to the perforation intervals for wells WH-1S and WH-5A are made. The perforation on WH-1 initially only had 3 perforation intervals so that 1 perforation interval was added between the existing perforation intervals, namely at a depth of 6708 – 6719.69 ft-MD. The new perforation interval is operated in 2022 to get maximum recovery factor results.

On WH-5A, the perforation interval was changed which was initially at a depth of 7422 – 7430 ft-MD, changed to a depth of 7400 – 7410 ft-MD. Perforation interval changes are made based on depth with high porosity and permeability parameters, as well as low water saturation. The depth of the long perforation interval was identified as having high water saturation, so it was decided to move it. Squeeze cementing is carried out at long perforation intervals to limit production at long perforation intervals. The application of Scenario 2 to this reservoir model results in an oil recovery factor for 2022 to 2028 of 0.41% with a cumulative oil production of 0.35 MMSTB, cumulative gas production of 0.85 BSCF, a decrease in reservoir pressure to 2698.25 psi, and a water cut of 10.1 % (Fig. 21.). The new perforation intervals are shown in Fig. 19. and Fig. 20.

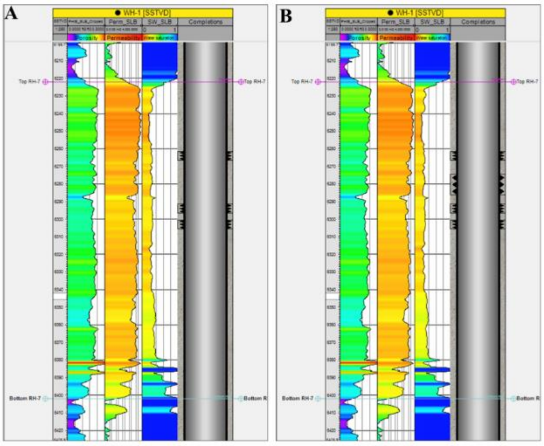

Fig. 19. WH-1 Well Perforation: a) Initial Interval, b) Added Interval

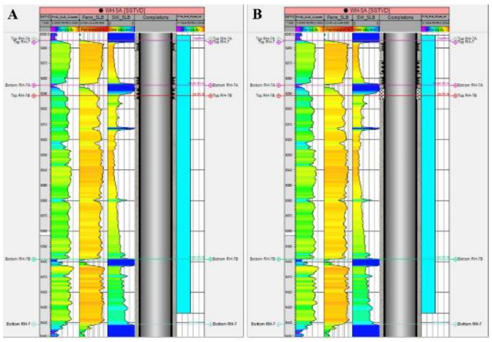

Fig. 20. WH-5A Well Perforation: a) Initial Interval, b) Altered Perforation Interval

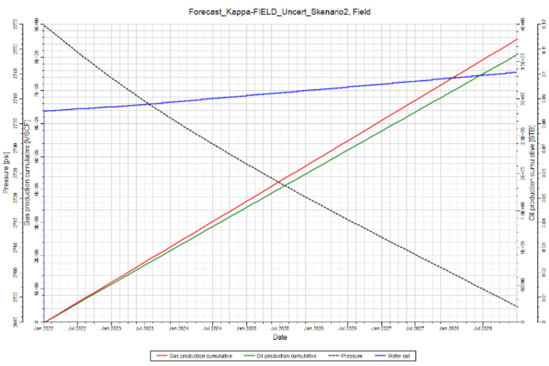

Fig. 21. Graph of Cumulative Production of Oil, Gas, Water Cut, and Reservoir Pressure in Scenario 2

3.5.3 Scenario 3: Scenario 2 + Infill Well

Scenario 3 is an advanced scenario from scenario 2 where additional infill wells are carried out in 2022. The addition of wells is carried out with the main objective of increasing the amount of hydrocarbon production in the field, because based on volumetric calculations there are still large reserves of hydrocarbons in the reservoir. In this scenario, the sensitivity of the number of infill wells used is carried out, so as to determine the number of wells with the most optimal production results. The results of the sensitivity of the number of infill wells can be seen in Table 7.

Table 7. Comparison of Sensitivity Results for Number of Infill Wells

Total Infill Well	**Cumulative Production**		**Oil Recovery Factor 2022 - 2028 (%)**	**Water Cut (%)**	**Reservoir Pressure (psi)**
	Oil (MMSTB)	**Gas (BSCF)**			
6 Infill Well	8.35	18.05	9.43	78	1682.33
7 Infill Well	9.47	20.49	10.70	80	1559.63
8 Infill Well	9.95	21.88	11.24	83	1470.78
9 Infill Well	10.79	25.04	12.20	86	1331.66
10 Infill Well	11.30	27.54	12.77	89	1217.53
11 Infill Well	11.35	21.42	12.82	91	1065.47
12 Infill Well	11.35	28.11	12.83	94	866.45
13 Infill Well	11.41	29.14	12.89	95	729.70
14 Infill Well	11.45	30.72	12.94	95	613.48
15 Infill Well	11.46	32.14	12.95	96	506.98
17 Infill Well	11.62	35.20	13.14	97	331.21
20 Infill Well	11.83	37.82	13.37	98	177.98

Based on the sensitivity results above, the addition of 20 infill wells produces the largest oil recovery factor value compared to the others, because it can produce up to 11.83 MMSTB of oil over a period of 6 years. From the above results it can be concluded that the more infill wells used, the more the field oil recovery factor will increase but the reservoir pressure will decrease. Sensitivity is only limited to 20 infill wells due to considering the value of the reservoir pressure which has decreased to 177.98 psi, so it is considered very low and other scenarios are needed to increase the pressure and production of hydrocarbons in the Kappa Field. Determining the location of infill wells was decided based on a trial-and-error process carried out by researchers, this was done to determine the most efficient location to produce high production rates and maximize the yield of hydrocarbons from the reservoir. Location of wells is based on zones or areas that have never been drilled and have high oil saturation, porosity and permeability, and low water saturation, in addition to considering the distance from each well which is based on the radius of drainage from each production well. The results of determining the drain radius can be seen in Table 8. below this.

Table 8. Existing Well Drain Radius

Well	Drain Radius	
	Ft	Meter
WH-1S	171.77	52.35
WH-5A	182.34	55.57
WH-9S	164.99	50.29
WH-10B	74.66	22.75

The value of the depletion area in Table 8. determined based on data from existing wells (WH-1S, WH-5A, WH-9S, and WH-10B), assuming that the starting point of the drainage area is in the wellbore and is in the form of a tube, then the calculation of the radius of drainage is carried out using the cylinder volume formula and the maximum drainage radius for each well is 60 meters or equivalent to 197 ft. In conducting simulations using infill wells, limiting parameters are used for each well, namely rate production control with a maximum of 1000 STB/day. Fig. 22. indicates the location of the infill well used.

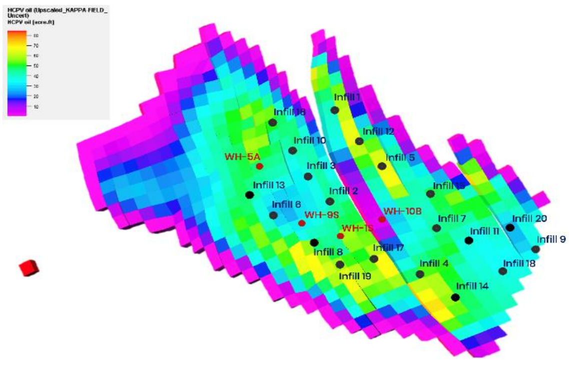

Fig. 22. Location of Infill Wells on the HCPV Oil Map

To validate the number of infill wells that will be used as the main scenario in Scenario 3, a comparison graph of the oil recovery factor is made for each number of infill wells used. The red area in Fig. 23. shows that the increase in oil recovery factor has reached an optimum point, namely the value with 10 infill wells is considered more efficient than 11 wells, because the value of the increase in oil recovery factor for 11 wells and so on has been close to a constant number. Fig. 24. shows the results of the cumulative sensitivity of oil production.

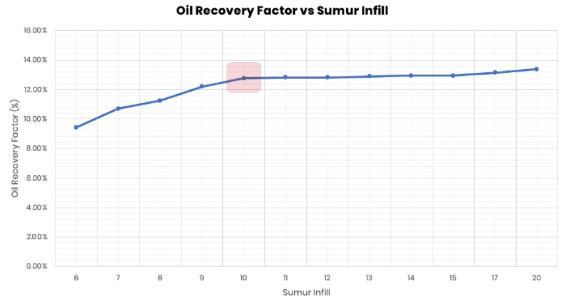

Fig. 23. Graph of Oil Recovery Factor vs Number of Infill Wells

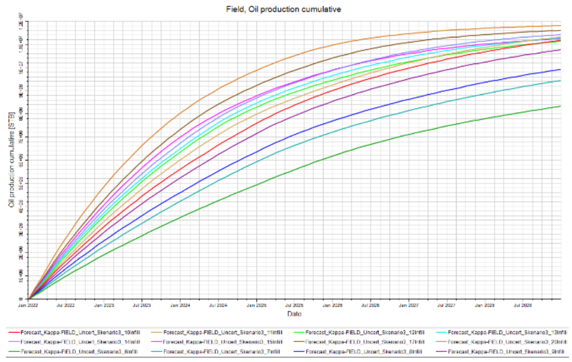

Fig. 24. Oil Production Cumulative Sensitivity Chart Scenario 3

3.5.4 Scenario 4: Scenario 3 + 5 Water Injection Well (Water flooding)

The purpose of making Scenario 4 is to increase production in reservoirs that still have hydrocarbon potential and maintain reservoir pressure, considering that reservoir pressure from Scenario 3 begins to decrease continuously. This scenario uses 4 existing wells, 10 infill wells, and 5 injection wells which will inject water fluid (waterflooding) starting from 2025. Water flooding is carried out to maintain reservoir pressure in the oil reservoir, therefore by doing waterflooding it is hoped that the pressure in the reservoir will can be maintained and the production process can still be carried out within a certain period of time.

Determination of the location of the injection well is determined from the zone that has good water saturation and the results of the sensitivity carried out on the oil recovery factor. Flood patterns and distance between wells affect the efficiency of the flooding process in the reservoir. In this scenario the researchers used peripheral patterns, namely injection wells positioned along the side of the reservoir with high water saturation. Injection wells are used to inject water fluids and use an injection flow rate that is determined based on the sensitivity test. Location of water injection wells as shown below.

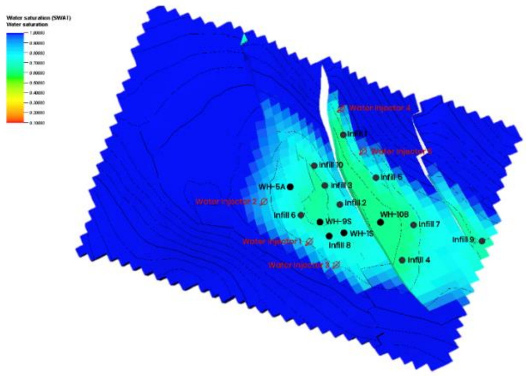

Fig. 25. Location of Infill Wells and Injection Wells on the Water Saturation (S_w) Map

The addition of 5 water injection wells was carried out with the injection flow rate determined using a sensitivity test to see the best results obtained from several injection rate values. The results of injection flow rate sensitivity can be seen in the table below.

Table 9. Comparison of Water Well Injection Rate Sensitivity Results

Rate Injection (BWPD)	Cumulative Production Forecast		Oil Recovery Factor 2022-2028 (%)	Water Cut (%)	Reservoir Pressure (psi)
	Oil (MMSTB)	Gas (BSCF)			
500	11.26	23.54	12.73	89.02	1403.27
1000	11.30	20.52	12.77	91.1	1570.22
1500	11.20	19.11	12.66	92.78	1694.74
2000	11.11	18.17	12.56	93.9	1814.17
3000	10.93	16.71	12.35	95.6	2076.64
4000	10.83	15.82	12.23	97.2	2384.89
5000	10.78	15.37	12.19	98.34	2773.17

Based on the sensitivity results (Table 9.), it is decided that Scenario 4 will use an injection rate of 1000 BWPD for each injection well because it has the best results compared to other sensitivities. The cumulative oil and gas production obtained was 11.3 MMSTB and 20.52 BSCF respectively, the water cut reached 91.1%, the reservoir pressure was 1570.22.48 psi, and the oil recovery factor increased to 12.77%. From these results, when compared to Scenario 3, there is no increase in oil production but only an increase in the water cut and reservoir pressure. This is because the water does not succeed in pushing the oil to get to the production wells and only water reaches the production wells when the injection is carried out.

The simulation results of Scenario 4 show that the parameters of oil recovery factor, cumulative oil and gas production, production flow rate, water cut and pressure will change over time. The flow rate in several wells has increased due to pressure from the injection fluid. Water injection affects the state of water saturation in the reservoir because it has increased and oil production has not increased because the injected water does not optimally act as a driving fluid in the reservoir or it can be said that the effectiveness of sweep efficiency has decreased. Fig. 26. shows a graph of cumulative oil production based on changes in water injection rate.

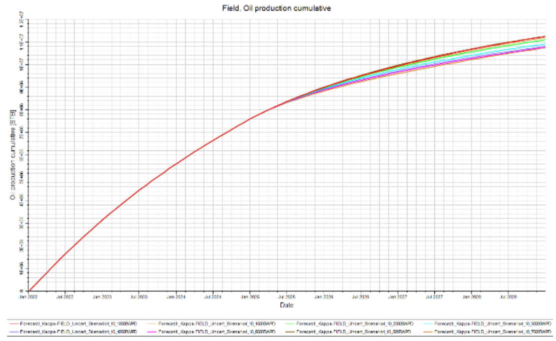

Fig. 26. Graph of Cumulative Oil Production Based on Sensitivity of Water Injection Rate

3.5.5 Scenario 5: Scenario 3 + 4 Gas Injection Well (Crestal Gas Injection)

Scenario 5 is a continuation of scenario 3 which includes additional gas injection wells or Crestal Gas Injection. The total number of operating wells in Scenario 5 is 18 wells, with 4 existing wells, 10 infill wells operating from 2022 and 4 injection wells which start injecting gas fluid from 2025. The injected fluid is gas obtained from the production process in the Kappa Field or in other words reinject Natural Gas into the reservoir to increase hydrocarbon production.

The determination of the location of the well is based on the spread of gas saturation and other parameters in the Kappa field, where the injection well is placed in the gas cap area, namely at the top of the anticline. The volume of the gas cap increases because the free gas comes out of the oil fluid when it passes through the bubble point pressure. Based on the results of the analysis, when oil is produced quickly within a period of 6 times, gas bubbles in the oil will form and spread to the rock pores, which might hinder the flow of oil or water in the reservoir. Accumulation of gas cap in the reservoir is an important point to know because it is needed for crestal gas injection, Fig. 27. shows the location of the gas cap on the gas saturation distribution in the reservoir model. Location of gas injection wells can be seen in Fig. 28.

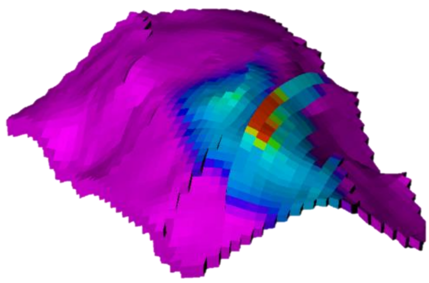

Fig. 27. Gas Saturation (S_g) in 2025

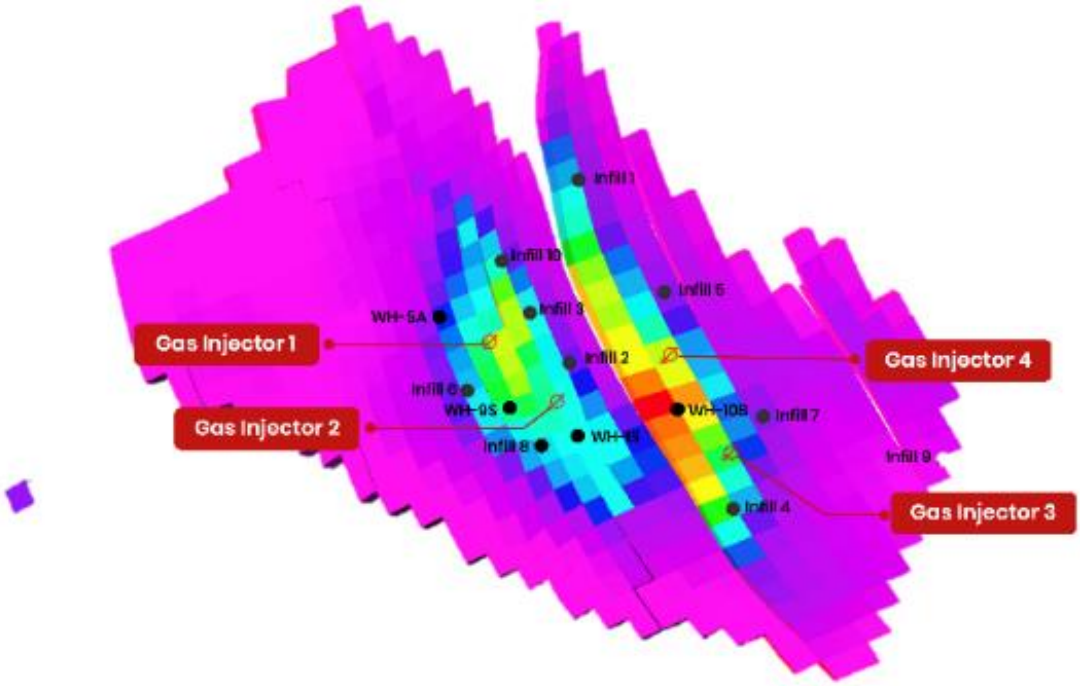

Fig. 28. Location of Gas Injection Wells on the HCPV Gas Map

The addition of 4 gas injection wells was carried out with the injection flow rate determined using a sensitivity test to see the most appropriate injection rate value for each well. The results of injection flow rate sensitivity can be seen in the table below.

Table 10. Comparison of Gas Well Injection Rate Sensitivity Results

Rate Injection (BWPD)	Cumulative Production Forecast		Oil Recovery Factor 2022-2028 (%)	Water Cut (%)	Reservoir Pressure (psi)
	Oil (MMSTB)	Gas (BSCF)			
1000	12.02	30.37	13.58	97.08	392.89
2000	12.07	33.83	13.63	97.12	412.19
3000	12.11	35.04	13.68	98.03	428.86
4000	12.14	36.35	13.72	98.03	442.94
5000	12.18	38.71	13.76	98.89	455.52

From the simulation results of the sensitivity of the gas injection rate in Scenario 5, it was decided that an injection rate of 1000 MSCF/d would be used for each gas injection well because based on the analysis results the increase in oil production was not proportional to the increase in the injection rate for each well because it would be too large for the total injected gas. Fig. 4.17. shows the results of the sensitivity for gas injection wells. There was a continuous decrease in pressure until 2028 which touched 392.89 psi, and a water cut of 97.08%, then an oil recovery factor of 13.58% was obtained, with a total predicted cumulative oil production of 12.02 MMSTB and a predicted cumulative gas production of 30.73 BSCF.

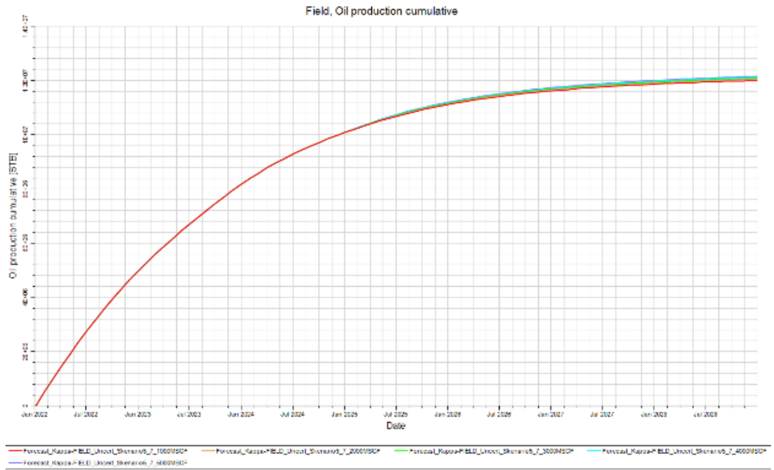

Fig. 29. Graph of Cumulative Oil Production Based on Gas Injection Rate Sensitivity

3.5.6 Field Development Scenario Comparison

After obtaining the results and sensitivity tests for each scenario of field development, a comparison of production values, especially the value of the oil recovery factor for each scenario, can be identified, as shown in Table 11.

Table 11. Comparison of Field Development Scenario Results

Scenarios	**Cumulative Forecast** **Oil (MMSTB)**	**Production** **Gas (BSCF)**	**Oil Recovery Factor 2022-2028 (%)**
Scenario 1: Production of 4 Existing Wells (Base Case)	0.30	0.75	0.34
Scenario 2: Base Case + Increasing Well Perforation Interval	0.35	0.85	0.41
Scenario 3: Scenario 2 + Infill Well	11.30	27.54	12.77
Scenario 4: Scenario 3 + 5 Water Injection Well (Water flooding) Air	11.30	20.52	12.77
Scenario 5: Scenario 3 + 4 Gas Injection Well (Crestal Gas Injection)	12.02	30.73	13.58

Based on the results in Table 11., Scenario 4 which uses water injection has the same oil recovery factor value as the scenario without using injection wells. So it can be concluded that water injection or water flooding is not effective to be applied as a development scenario in the Kappa Field. In scenario 5, the use of gas injection results in an increase in the oil recovery factor which reaches 13.58%. When compared to the scenario without using injection wells, Scenario 5 produces the highest oil recovery factor for the Kappa Field. This is because the gas is injected using the crestal gas injection method on the gas cap which is formed due to a decrease in reservoir pressure from the production process, the injected gas has a lighter density so that it will move the gas towards the upper position of the reservoir and fill the void. This process causes oil pressure to occur, so the oil recovery factor obtained is better than other scenarios. Therefore, it can be concluded that Scenario 5 using 4 existing wells, 10 infill wells, and 4 gas injection wells is the best scenario to be applied to the Kappa Field as an effort to increase oil production which had stopped in 2019.

4. Conclusion

This study yielded two values of remaining recoverable reserves using different methods, with a difference of 6% for oil and gas. The use of the DCA method for wells WH-1S, WH-5A, WH-9S, and WH-10B produces oil reserves of 0.2908 MMBbls and gas reserves of 0.7990 BSCF, while forecasting using the reservoir simulation method produces oil reserves of 0.30 MMSTB and gas reserves of 0.75 BSCF (Scenario 1).

Furthermore, based on the simulation results using the MBAL software, the driving mechanism on the Pasir RH-7 Layer is a water drive mechanism, and after making a comparison of the existing scenarios, the best field development scenario for the Kappa Field is Scenario 5 which uses 4 existing wells, 7 infill wells from 2022 and 4 gas injection wells with an injection flow rate of 1 MMSCF/d which began operating in 2025. Scenario 5 produces RF oil of 13.58%, with cumulative oil production of 12.02 MMSTB, cumulative gas production of 30.73 BSCF, water cut of 97.08%, and reservoir pressure of 392.89 psi.

Acknowledgment

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