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Decision-Making Process for Development of Oil Fields Based on Static and Production Data Analysis from Exploration Wells

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Abstract

Kokoh Field and Kelok Northeast (NE) Field are two recent discovery fields in the Central Sumatra Basin, Indonesia. Due to limited exploration well data and remote field locations which preclude additional exploration due to high capital expense, the decision to drill development wells requires management of key subsurface uncertainties that could result in marginally or uneconomic development investment in the case of low-side uncertainty outcomes. To manage this risk, the information from available exploration wells and surveillance data are identified to resolve subsurface uncertainties that have the greatest impact on development outcomes. Of particular value are production surveillance data from exploration wells including single-completion versus commingled production streams per well, reservoir pressure, fluid analysis, wellbore integrity and facilities flow assurance that enable characterization of development well performance forecasts and their uncertainty.

This paper describes the approach to, as well as the challenges encountered during, production surveillance from exploration wells in Kokoh and Kelok NE fields. Surveillance and analyses performed include extended single-well production tests, downhole pressure and temperature monitoring, fluid analysis and fit-for-purpose reservoir simulation modeling for dynamic reservoir characterization. During production surveillance, several challenges required management including early water breakthrough, high wellhead pressure, high ESP motor temperature, intermittent pipeline flow and oil congealing, all of which jeopardized the collection of surveillance data. Analysis of the surveillance data set, together with investment efficiency analysis, resulted in the decision to drill a single development well in Kelok NE Field. The production outcome to date is within the forecast reliability range and, therefore, within the expected range of economic outcomes.

Introduction

Capital investment decisions are required in oil field development, particularly when moving from discovery to a development phase. These decisions involve a broad range of issues, e.g., development well production performance forecasts, surveillance activities, artificial lift type (if any) and flow assurance. Kokoh and Kelok NE Fields are two recent discovery fields in Central Sumatra Basin (CSB), Sumatra, Indonesia. There is 1 exploration well each in Kokoh Field and Kelok NE Field. The development objective of Kokoh and Kelok NE wells is to produce oil from the Pematang formations. A well test program was conducted at these wells during exploration drilling with an opportunity identified to Put on Production (POP) both wells.

In this paper we present a general decision-making process, as well as the challenges encountered, for development of Kokoh and Kelok NE Fields based on static and production data measured at the two exploration wells.

Data and Method

Static and production data from the exploration wells were processed to plan and optimize short-term development production from both fields, and also to provide input data for long-term reservoir management. Three major processes were systematically performed for both Kokoh Field and Kelok NE Field to identify development opportunities and support associated capital investment decisions.

1. Review historical well production performance and surveillance data
2. Evaluate subsurface data including dynamic reservoir characterization and reserves estimation
3. Evaluate surface facilities data including fluid flow assurance

Result and Discussion

Kokoh Field Development

There are two productive reservoir zones penetrated by KO-01 (Zone A and Zone B). Initial WC of commingled production was 57% WC, then WC increased rapidly in 1 month to 83% WC. The possibility of a sub-optimal completion strategy was investigated with subsequent surveillance jobs.

A swab test program was conducted for each individual reservoir zone (Zone A and Zone B) to identify wet (high WC) intervals. Results from the swab tests showed both zones to have low WC, with Zone A at 25% WC and Zone B at 5% WC. However, the swab results appeared optimistic when compared against commingled production data with a WC at 83%. Therefore, it was decided to produce from single zones, from bottom to top, to more accurately characterize production behavior.

Initial production of single-zone production Zone B was 61% WC. Then, similar to the commingled production history, WC increased rapidly from 61% to 91% after 2 months of production, whereas The WC ranges between 95-97% from the single-zone production of Zone A.

It was concluded that during commingled production, oil from Zone B contributed more than from Zone A. However, the single-zone well test data remained in contradiction with the single-zone swab test data, indicating that additional surveillance activity was required to confirm the more plausible interpretation from the well test.

A Cement Bond Log (CBL) job was conducted after exploratory drilling. Both reservoir zones showed a good cement bond with amplitude less than 10 mV and with no free pipe indication from the Variable Density Log (VDL). Therefore, the CBL reading indicated there was no issue from cement which might have impacted the production performance of KO-01.

That said, a more comprehensive ultrasonic cement evaluation tool was additionally run to validate the CBL result and to identify potential channeling not captured by the CBL. Although ultrasonic log interpretation for Zone A (Figure 1) did identify a channel at a reservoir sand depth below the perforation interval (perforation bottom at depth 6658 ft MD), petrophysical evaluation suggests that no oil-water contact was identified in this zone; therefore, any channeling in this interval would not have contributed to the high water cut production from Zone A.

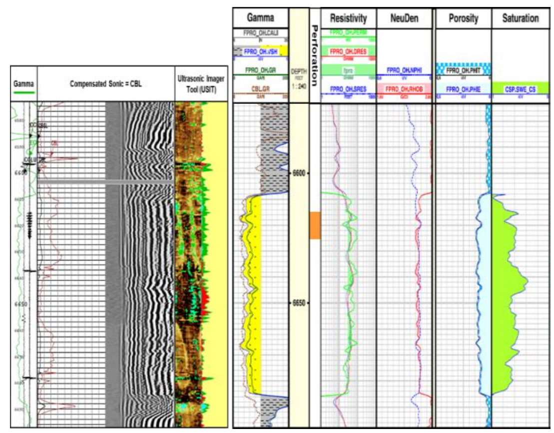

Figure 1: Zone A Cement Evaluation.

Based on ultrasonic log interpretation of Zone B, a substantial interval of channeling was identified at the shale above the producing interval. However, the shale interval directly above the reservoir sand has 10 ft of good cement bond. Severe bonding issues were also identified at the shale below the producing interval (Figure 2) indicative of air within the annulus. Although it is possible that fluid flows into the annulus and upwards into the reservoir from the formation below, it is unlikely because the shale has low total porosity and only clay-bound water within the porosity. In the end, it was concluded that the production interval of Zone B has a good cement bond for the entire producing interval.

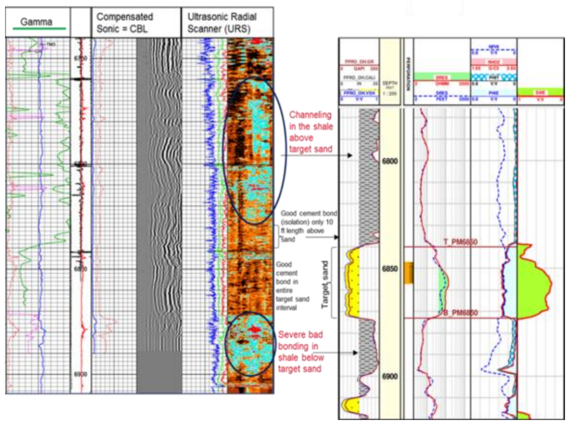

Figure 2: Zone B Cement Evaluation.

A fit-for-purpose reservoir simulation model was developed for dynamic reservoir characterization. The commingled and single-zone KO-01 flow test histories were integrated into the simulation model by reproducing the bottom hole pressure data from the downhole memory gauge and history matching to the observed oil and water production rates. Relative permeability and oil/water saturation end-points were applied as the reservoir uncertainties calibrated to achieve the history match. Figure 8 shows measured production data and the history matched simulation of oil rate and water cut for the commingled and single-zone KO-01 flow test histories. Learnings from dynamic reservoir characterization of Zone A and Zone B are listed in Table 1.

Table 1: Learnings from History Matching

Zone A	Zone B
Lower quality reservoir (100 md horizontal absolute permeability)	Higher quality reservoir (290 mD horizontal absolute permeability)
High initial Sw	Low initial Sw
High initial mobile Sw contributes to high initial WC in commingled test and is confirmed by single-zone flow test	High initial mobile Sw contributes to high initial WC compared against swab test data
Insufficient data to characterize OOWC given high mobile Sw and oil to base of Zone A well penetration from log interpretation (OOWC at 6230 ft TVDSS)	OOWC at approximate depth of LKO (6385 ft TVDSS) and not to base of well. Strong water coning from OOWC to perforation to interval is interpreted

Based on these learnings it is confirmed that both zones have high initial mobile Sw which contributes to the high initial WC, in contrast to the swab test data. However, Zone B has an appreciably lower initial Sw and produces at higher oil rates than Zone A.

Using the OOWC inferred from history matching, recoverable reserves were estimated using a deterministic assumption of a well drainage volume limited by the OOWC. A number of permutations were computed that span the uncertainty range of input reservoir properties including porosity, water saturation and recovery factor, resulting in marginal field recoverable reserves. Figure 3 shows a depth structure map of Zone B for perspective on the recoverable volume relative to well spacing.

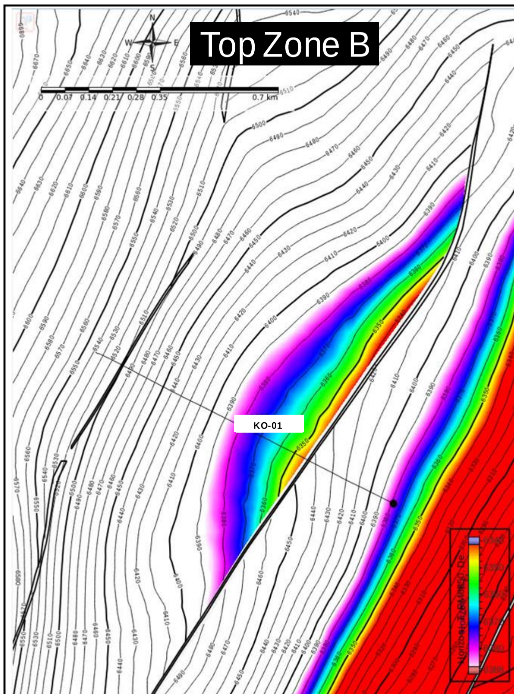

Figure 3: Depth Structure Map of Zone B.

Oil production from Kokoh Field flows through a 4” 10 km pipeline from the wellhead prior to being tied in to the main production line of Libo Gathering Station (GS). Selection of the pipeline size is based on fluid capacity and back pressure. A 4” pipeline is sufficient to support production from existing and additional infill wells~~.~~

During KO-01 production, an abnormal wellhead pressure and pressure drop were detected. Wellhead pressure at ~400 psi was higher than predicted, normally ~240 psi, and the pressure drops across the 4” pipeline was also higher than predicted at 20 psi/km. A standard pressure drop across new 4” pipeline is ~6 psi/km. A thermographic camera was run to identify any anomalies along the 10 km flow line. Because the thermographic report indicated normal progressive temperature drop along the 10 km pipeline from 235°F to 108°F, it was suggested that the high pressure drop resulted from clogging by materials such as sediment or scale. A laboratory analysis was also conducted to understand the fluid characteristics of Kokoh Zone B. Oil and water samples were taken at the wellhead during single-zone production from Zone B and a Fann Viscosity test was performed to assess the impact of water that emulsifies in crude oil. Emulsion viscosity can be substantially greater than the viscosity of either the single-phase oil or water because emulsions can show non-Newtonian behavior associated with droplet crowding or structural viscosity. Figure 4 shows the effect of water cut on viscosity at 150 °F.

At approximately 85% WC, an interesting phenomenon is observed. At 600 rpm, high viscosities of up to 80 cp are achieved in comparison to single-phase viscosities of oil at 4.6 cp and water at 1 cp. Therefore, it is posited that the increase in fluid viscosity results in the high flowline pressure loss and is associated with increased friction at the wall of the pipe. Under the existing flowline conditions where wellhead pressure and pressure drop are higher than expected, the maximum flowline capacity is reduced to 50% from the expected capacity, limited by the pipeline rating with maximum pressure of 550 psi.

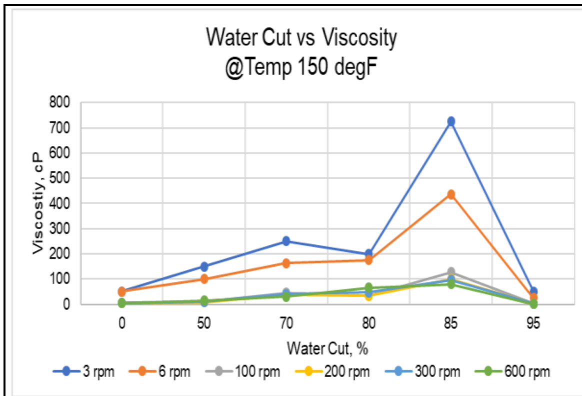

Figure 4: Fann Viscosity Test Result of Kokoh Fluid.

Kelok NE Field Development

There are three productive reservoir zones penetrated by the KE-01 well (Zone A, Zone B and Zone C). A swab test program was conducted during the initial completion job to re-validate 2013 exploration test results. The current swab tests were consistent with prior results, with a WC of less than 10% for each individual zone. Initial production was 57% WC. The WC subsequently increased rapidly in the first month to 71% and then increased more gradually over the next 2 months. Figure 11 shows the commingled production history of KE-01.

A cement evaluation tool was run after exploratory drilling to confirm the wellbore integrity. Results from the CBL confirmed a good cement bond with amplitude less than 10 mV and no free pipe indication from the VDL reading over all productive zones.

Recoverable reserves were estimated using a deterministic approach over a well drainage volume limited by the OOWC. Two approaches of OOWC estimation were used, one assuming that all reservoirs share a common contact and the other based on the assumption that each reservoir has an independent contact. The multiple OOWC approach used Repeat Formation Tester (RFT) data which suggested different pressure gradients in Zones A, B and C, as shown in Figure 5.

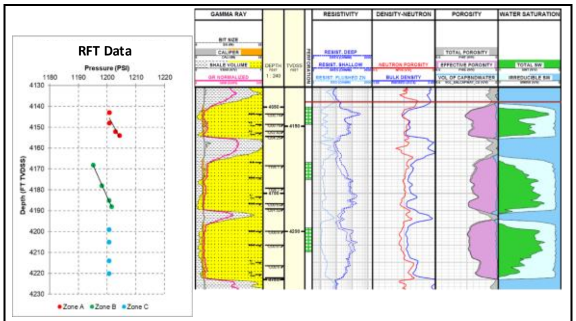

Figure 5: RFT Data of KE-01

The RFT formation pressures have a conspicuously narrow pressure range between 1,195 – 1,205 psi over a depth interval of 400 ft. A review of the pre-test data indicated that a steady-state drawdown period was not achieved during testing. It is possible that insufficient drawdown into the formation was induced, flowing only air into the piston, resulting in a false buildup and interpretation of excessively high fluid mobility. Considering the likelihood of RFT measurement error, the alternative approach to OOWC estimation assumed that all sands share the same OOWC. This is geologically plausible as all sands are within the same environment of deposition and are classified as a fluvial braided channel system which typically has medium to high connectivity.

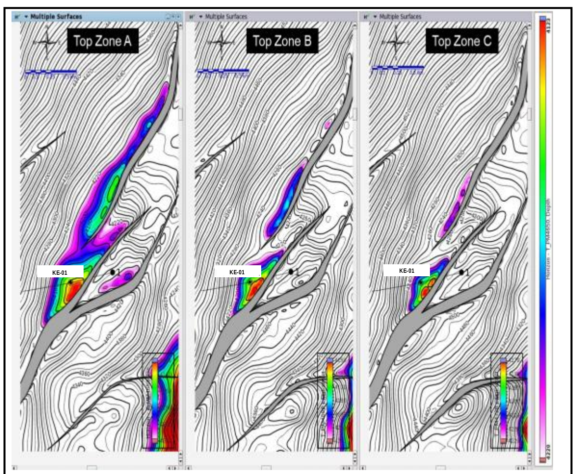

Figure 6: Depth Structure Map of Single OOWC

Using the two OOWC estimation methods, field recoverable reserves was estimated to decide further development decision. Figure 6 shows a depth structure map of all zones for perspective on the recoverable volume relative to well spacing using the single OOWC assumption.

Result

Encouraged by the exploration well information acquired during early production period of KO-01 and KE-01, it decided to drill a single development well in Kelok NE Field. The expected reserve and historical production performance of the exploration wells were key parameters to decide further development decision for both fields. A single development well in Kelok NE Field was drilled with a good initial oil production and low WC. The production was contributed from single zone A only which confirms that common OOWC interpretation is more valid than multiple OOWC interpretation. The production outcome is within the forecast reliability range and within the expected range of economic outcomes.

Conclusions

Lessons learned from the decision-making process of Kokoh Field and Kelok NE Field development are:

1. Single-zone production at exploration wells is essential to accurately understand individual zone / reservoir deliverability, particularly when the decline rate during commingled production is different (namely higher) than expected. Data from single-zone production also enables a significant uncertainty reduction in dynamic reservoir characterization which, in turn, results in more accurate reserves estimation to support development decisions.
2. A more comprehensive cement evaluation tool, an ultrasonic tool in this application, enabled successful identification of behind-pipe fluid channeling that was not captured by a standard cement evaluation tool.
3. Installation of a downhole memory gauge permitted frequent monitoring of both pump and reservoir performance which

improved dynamic reservoir characterization due to high quality surveillance data.
4. Fit-for-purpose reservoir simulation, in addition to volumetric analysis, improved dynamic reservoir characterization.
5. Single and multiple OOWC scenarios for reserves estimation were verified to correctly capture subsurface uncertainty risks.
6. Viscosity of emulsion can be substantially greater than the viscosity of either single-phase oil or water and can result in a higher wellhead pressure and flowline pressure drop.

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