BRIEF UNDERSTANDING OF CHARACTERISTICS DEPLETED RESERVOIR (INTERVAL-I) USING PORE PRESSURE AND FRACTURE GRADIENT ANALYSIS IN "X" FIELD, SANGA-SANGA AXIS, KUTAI BASIN

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ABSTRACT

Field X, as this study area's focus, boasts over 200 wells proven to be hydrocarbon producers. Two pore pressure regimes exist: normal hydrostatic and overpressure. The primary hydrocarbon reservoir in the Balikpapan Formation within the Sanga- sanga axis at Field X consists of sandstone. Drilling disturbances, particularly in the lower intervals of this reservoir, often occur due to overpressure. The main challenge encountered in this reservoir is mud losses. The objective of this study is to develop the Pore Pressure and Fracture Gradient characteristics and its relation to the geological environment. Furthermore, the distribution of Sand (Interval-I) is determined, which is the primary cause of losses due to production. Besides that, the parameters used to create optimal fracture gradient is also defined. Thirteen wells in this field were examined to identify the controlling factors of pore pressure. This study integrates wireline logging, velocity, mud logs, pressure tests, drilling parameters and event which are subsequently processed for determining shale points, Normal Compaction Trend (NCT), calculating overburden gradient, and estimating pore pressure using the Eaton method. From the analysis result, the distribution of overpressure and the generating mechanism of overpressure are determined. This study also carried out analysis to determine overpressure and depleted Sandstone (Interval-I) distribution. Subsequently, facies and depositional environment analysis are conducted, followed by modelling Sandstone (Interval-I) and determining Sandstone's poisson ratio from loss data and shale's from leak of test data for fracture gradient estimation. Overpressure is found in Interval-I with magnitude of 4000-4700 psi, which corresponds to delta plain to delta front depositional environment. Peak of overpressure is observed shorten in the southern than the northern due to geological structure conditions. The generating mechanism of the excess pressure is controlled by loading and fluid expansion. The experienced loss in overpressure zone, caused by reservoir production from the initial pressure of 4475 psi and has depleted to 373 psi. From the sandstone distribution model, the loss sandstones are a connected fluvial channel in southern ward. It is also observed several unconnected channel sandstones that did not experience loss. Poisson ratio parameter for sandstone is 0.35, which is calibrated from the loss event with minimum fracture gradient in Interval-I is approximately 4772 psi. It is expected that the understanding of pore pressure and Sandstone (Interval-I) distribution could be used to increase the success ratio for optimal drilling planning, including to choose effective casing design, mud weight, and appropriate total depth.

Keywords: *Eaton Method, Overpressure, Pore pressure, Fracture Gradient, Mud Loss*

INTRODUCTION

Oil and natural gas are vital energy sources that meet human needs. Exploration and exploitation of oil and gas fields become imperative in this context. The X Field, which has more than 200 wells, has been proven to be a significant source of hydrocarbons. However, this activity is not free from risks, especially those related to overpressure, which can cause problems such as loss, kick, or blow out. Studying the characteristics and distribution of overpressure zones is essential to reduce work safety risks, especially in planning drilling at Field X, where overpressure is an obstacle. The research focuses on losses in the overpressure zone due to Sandstone Distribution (Interval-I) production activities. Understanding the overpressure phenomenon depends on identifying the causal mechanism and knowledge regarding its distribution horizontally and vertically. Detection of

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overpressure and understanding distribution sandstone Interval-I is critical in preventing loss during drilling and determining optimal fracture gradient parameters. This study aims to minimize subsurface hazards, especially in X Field. It is hoped that this research can help in planning drilling safety and security by designing an optimal well, recommendations for mud drilling, and determining the exact casing point depth when approaching or penetrating the overpressure zone, as well as providing a reference for the area surroundings.

REGIONAL GEOLOGY

Physiography

Based on regional physiography, the Kutai Basin is the research area (modification of Nuay et al., 1985), the area covers ±60,000 km2 and consisting of Tertiary deposits with a thickness of up to 14 km (Rose & Hartono, 1971 in Mora et al., 2001). Extensional processes in the southern section of the Eurasian Plate producted Kutai Basin. Located on the eastern edge of the Sunda Shelf, this basin is bounded by the Bengalon and Sangkulirang Fault Zones to the north and the Adang Fault Zone to the south, which has been established as the basin's axis since the end of the Paleogene. To the west, the Kutai Basin is bounded by the Central Kalimantan Ranges, which consist of uplifted and deformed Cretaceous metasediments, while to the east, the basin is open and continues into the Makasar Strait. The Kutai Basin is divided into two parts: the upper part, which consists of Paleogene deposits, and the lower part, which consists of Neogene deposits (McClay, 2000).

Tectonics

Several tectonic phases developed in the Kutai Basin starting from its formation in the Middle Eocene until now, consisting of:

a. Pre Rift Phase (Basement)
b. Syn Rift Phase (Middle Eocene – Late Eocene)
c. Sagging Phase (Late Eocene – Late Oligocene)
d. Uplift Phase (Late Oligocene – Miocene)
e. Inversion Phase (Miocene – Recent)

In the early Miocene, marine regression and basin filling were characterized by the initiation of the progradation of the proto-Mahakam River, along with the deposition of deltaic sediments. During the early Miocene, tectonic inversion occurred within the basin, causing shallowing and eastward progradation of the delta. This inversion process continues today. This inversion was caused by subduction in the eastern part of Sulawesi, which resulted in a collision between Banggai-Sula and caused the acceleration of inversion, which formed the Samarinda anticlinorium and the Mahakam fold belt. It is assumed that overpressure occurred in the Miocene starting from the formation of delta deposits. The compressional regime in a northwest-southeast direction is ongoing today, with the Indo-Australian plate moving north towards the Banda arc (Moss & Chambers, 1999).

Stratigraphy

The stratigraphy of the Kutai Basin consists of layers that include certain formations and geological units that show the basin's complex evolution (**Figure 1**). The formation that makes up the research area is the Balikpapan Formation. These formations and units are essential in exploiting oil and natural gas resources, which can influence the region's distribution, accumulation, and characteristics of hydrocarbon reservoirs.

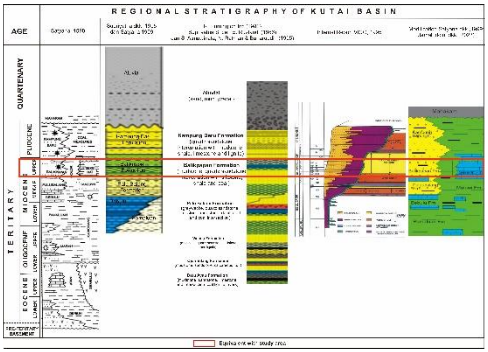

Figure 1. Regional Stratigraphy of Kutai Basin

Petroleum System of Kutai Basin

Petroleum systems in the Basin Kutai are divided into three different systems, wich are, the aged petroleum system Paleogene, the old fluvial-delta system Neogene, and the deep sea age Neogene system. Only the aged fluvial-delta petroleum system Neogene has

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reached stage production from the petroleum system. A study about petroleum systems in the Basin Kutai was conducted by Duval et al. (1992). Petroleum systems in the Basin Kutai are composed by:

a. Source Rock

Studies of source rocks carried out by Oudin and Picard (1982) and Burrus et al. (1992) in the Mahakam region concluded that the source rock, which is the source of hydrocarbons in the area, is of the humic type, namely shale-associated with coal. The Balikpapan Formation is recognized as the primary source rock within the Kutai Basin because it contains high organic material with an HI more significant than 400 and is mature. This formation is more than 3000 m thick and is estimated to produce relatively large hydrocarbons.

b. Reservoir Rock

The primary reservoir rocks in the Kutai basin generally consist of sandstone originating from the delta, delta front, delta/marine deposits, and prograding low-stand facies of the Middle Miocene-Pliocene age. This reservoir is located in the Balikpapan Formation (Late Miocene-Pliocene). The sandstone is found in multilayer layers, with a thickness ranging from 0.5 - 30 meters, a mean porosity of 14-10%, a mean permeability of 1 - 3,000 md, and a cumulative net pay thickness of around 200-300 meters. Hydrocarbon accumulation is primarily concentrated in Neogene rocks, especially within the Middle Miocene Balikpapan Formation and the Middle to Late Miocene, particularly within the Kampung Baru Formation.

c. Seal Rocks

In the Kutai Basin area, the insulating rocks are formed from shale deposits. High potential for shale as sealing rocks is shown by the Balikpapan Group and Kampung Baru Formation. This shale is distributed alternately with sandstone, a zone of hydrocarbon accumulation. The maximum flooding surface in the sequence stratigraphic framework is an effective sealing layer because it contains much shale.

d. Trap

The traps found in the Kutai Basin are structural traps with four-way and three-way closure-type characteristics, as seen in the Sanga-Sanga, Badak, Handil, Bekapai, and Attaka fields. Stratigraphic traps also play an essential role in the hydrocarbon trap process, although identifying their presence is more complex than structural traps. A combination of both types of traps, structural and stratigraphic, is often found in fields in the Kutai Basin.

e. Migration

Hydrocarbon migration in the Kutai Basin tends to dominate laterally in a direction parallel to the up-dip layer along the flank structure and vertically through a fault system (Paterson et al., 1997). This ongoing migration process is believed to have occurred in the Late Miocene to Pliocene time range and may continue.

RESEARCH METHODS

Overpressure Prediction

a. Data Quality Control

In this research, data quality control was carried out using the Equation, namely:

$$\text{Rugose} = \text{Caliper} > (5\%\ \text{x BS}) + \text{BS} \quad (\mathbf{1})$$
$$\text{Mudcake} = \text{Caliper} < \text{BS} - (5\%\ \text{x BS}) \quad (\mathbf{2})$$

With:

BS = Bitsize (inches)

When the reading from the caliper log shows a difference of approximately ±5% greater than the bit size used, this indicates an unevenness in the wellbore, which is called a rugose hole. Conversely, if the caliper log reading shows a difference of approximately ±5% less than the bit size, this indicates the presence of a mud cake (Tingay, 2003). These two conditions suggest that the data obtained from the log may be affected by the environmental conditions of the well, and data filtering is necessary.

b. RHOB Conditioning

Density data conversion was carried out using the Gardner (1974) equation. Gardner's Equation (1974), namely:

$$\rho = A(V)^B \quad \mathbf{(3)}$$
$$\rho = A\left(\frac{10^6}{DT}\right)^B \quad \mathbf{(4)}$$

With:

ρ = Rock density (gr/cc)
V = Interval Velocity (ft/s)
DT = Sonic (μ s/ft)
A = coefficient
B = exponential

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This conversion stage consists of converting interval velocity data into sonic data. Then, this sonic data is converted into density data with Equations (3 and 4). The converted density data is overlaid with density data from the wireline log to obtain the coefficient and exponent parameters for the Gardner (1974) method.

c. RHOB Extrapolation and Interpolation

Overburden calculations require density data from the surface to the bottom of the well. However, log data often does not start at the surface, so data extrapolation is necessary. Data extrapolation was carried out from surface depth to the first depth of density data using the RHOB Miller method. Additionally, some depths have no density data because there are no log readings at those depths. Interpolation was carried out using the Gardner (1974) formula to convert velocity intervals to Density. The following Equation is used in Miller's RHOB method to extrapolate density data:

$$\Phi = \Phi a + \Phi b \exp\left(-K(\mathrm{depth})^{\frac{1}{n}}\right) \quad \textbf{(5)}$$

Where

$$\rho = \rho\mathrm{matrix}\,(1 - \Phi) + \rho w\,\Phi \quad \textbf{(6)}$$

With :

ρ = Rock density (gr/cc)

ρ matrix = Matrix Density (generally 2.68 gr/cc for shale)

ρw = Density of water (generally 1.03 gr/cc)

Φ a = Sediment porosity at depth (fraction)

Φ b = Sediment porosity of fittings the same parameters as mudline porosity (fraction)

n = fitting parameter (default = 1.09 for Gulf of Mexico)

K = fittings parameters (default = 0.0035 for Gulf of Mexico)

Depth = depth below the mud line (ft)

After extrapolating and interpolating the density data, the overburden value was calculated using Equation (7). Overburden calculation or Vertical stress is calculated using the Equation according to Mouchet and Mitchell (1989), namely:

$$\sigma v = \rho b.g.z \quad \textbf{(7)}$$

With:

σv= Vertical tension ($ML^{-1}T^{-2}$)

ρb= Sedimentary rock density (ML^{-3})

g= Gravity acceleration (9.81m/s2) (LT^{-2})

z = Thickness of the rock layer sediment (L)

d. Shale Points Sorting

The lithology analyzed for overpressure analysis is a low porosity and permeability rock because it can store pressure efficiently. Based on shale volume data previously processed by the PT Pertamina Hulu Indonesia Regional 3 Zone 9 petrophysics team, Drillworks Predict 2016 software identified shale points in each well.

e. Averaging Data

To streamline the data analysis and help observers easily identify trends in the varying data involving averaging the data, combining median values, and grouping data based on these filtered results. This research applies filter values to sonic and Resistivity log data. The use of filter values between 199 and 399 is considered representative enough to even out the data distribution and make it easier for observers to see data trends. The data averaging process was carried out using Drillworks Predict 2016 software.

f. Determination of Normal Compaction Trend (NCT)

In this study, the average compaction trend for DT data was obtained using Miller's Equation:

$$\mathrm{DTnorm} : \frac{\mathrm{DTml}}{\frac{\mathrm{DTml}}{\mathrm{DTmatrix}} + \left(1 - \frac{\mathrm{DTml}}{\mathrm{DTmatrix}}\right)\exp(-\lambda\sigma\mathrm{norm})}$$

(8)

With:

λ = lambda

DT = sonic travel time (ft/sec)

DTml = sonic travel time on mudline (200 ft/sec)

DTmatrix = sonic travel time for matrix material (14000 ft/sec – 17000 ft/sec for shale)

σ norm = effective stress, assumed to be normal pressure, is the appropriate empirical value for the relationship between speed and effective stress in an area.

For wells that do not have complete sonic log data, resistivity log data is used, with the formula:

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$$\frac{1}{\mathrm{Rn}} = \frac{(\mathrm{Rm} - \mathrm{Ro})}{\mathrm{RoRm}} e^{-\mathrm{bz}} + \frac{1}{\mathrm{Rm}} \qquad \textbf{(9)}$$

With:
Rn = NCT Resistivity (Ohmm)
Rm = Matrix resistivity (Ohmm)
Ro = Resistivity on the surface (Ohmm)
b = Empirical constant fitting the transit time vs depth

g. Pore Pressure Calculation

Eaton (1975) used empirical statistical analysis of data from several wells in the Gulf of Mexico. The Eaton method is among the most widely used techniques for estimating pore pressure. In principle, this method estimates overpressure by calculating deviation log data against the normal compaction trend, which is formulated as follows:

$$\mathrm{P} = \sigma\mathrm{v} - (\sigma\mathrm{v} - \mathrm{Ph})\left(\frac{\Delta\mathrm{tn}}{\Delta\mathrm{t}}\right)^{\mathrm{E}}$$

for sonic log data **(10)**

$$\mathrm{P} = \sigma\mathrm{v} - (\sigma\mathrm{v} - \mathrm{Ph})\left(\frac{\mathrm{R}}{\mathrm{Rn}}\right)^{\mathrm{E}}$$

for resistivity log data **(11)**

With:
P = Pore pressure ($ML^{-1}T^{-1}$)
σv = Vertical stress ($ML^{-1}T^{-1}$)
P h = Hydrostatic pressure ($ML_{-1}T^{-1}$)
Δt = Sonic transit time value from log reading ($L^{-1}T$)
Δtn = Sonic transit time value for hydrostatic conditions ($L^{-1}T$)
R = Resistivity value from log reading ($M^2L^2T^{-3}I^{-2}$)
Rn = Resistivity value for hydrostatic conditions ($M^2L^2T^{-3}I^{-2}$)
E = Exponent / Eaton's

The exponent values in the Eaton equation above are empirical values that correspond to local geological conditions. The Eaton exponent in the Equation above is not absolute and can be changed according to the formation pressure conditions in the research area.

h. Fracture Gradient Calculation

To calculate the fracture gradient, the Eaton (1975) method is used, with the Equation:

$$\mathrm{FG} = \mathrm{P} + (\sigma\mathrm{v} - \mathrm{P})\left(\frac{\mathrm{v}}{1-\mathrm{v}}\right) \qquad \textbf{(12)}$$

With:
FG = Fracture gradient ($ML^{-1}T^{-1}$)
P = Pore pressure ($ML^{-1}T^{-1}$)
σv = Vertical stress ($ML^{-1}T^{-1}$)
V = Poisson's ratio

The data used involves sonic logs and resistivity logs, with exponents or Eaton exponents adjusted to direct pore pressure data from pressure test measurements in each well in the study area as validation. Apart from pressure test data, pore pressure validation is also carried out with other data from drilling, such as loss events, well flowing, gain, and kick, and drilling gases such as connection and pump-off gas. The fracture gradient is verified using the Leak-Off Test (LOT) or Formation Integrity Test (FIT) data—calculation of pore pressure and fracture gradient using Drillworks Predict 2016 software. Eaton's rank three is used with wireline log data and velocity intervals for pore pressure analysis. Meanwhile, the Poisson's ratio used for fracture gradient analysis is 0.35 for sand lithology and 0.49 for shale lithology, calculated from Poisson's ratio calculations.

Identify Overpressure

a. Burial History

Loading mechanism due to compaction disequilibrium was identified by looking at the sediment deposition velocity in the study area. This identification is done by looking at the sedimentation speed using burial history, which is compiled based on layer thickness and age data. The Thickness of the sediment is recorded by the time sequence for each formation, followed by calculating the sedimentation rate in meters per million years. The results of this calculation are depicted in the form of a diagram.

b. Sonic-Density Cross-plot

A cross-plot is conducted after the creation of pore pressure estimates, utilizing shale point density and sonic data. This cross-plot was carried out on 13 wells due to limited data on wells penetrating the hard overpressure zone. The ideal cross plot to represent the mechanism for the formation of top overpressure to hard overpressure is Well FEB-039. Trend smectite-rich mudrock and illite-rich mudrock are created based on graphical a cross-plot of sonic-density (Dutta, 2002)

c. %Ro and Temperature

Based on research (Ramdhan, 2010), mature source rock in the Kutai Basin espetialy in lower regionally has %Ro of

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0.6 and a temperature of around 130 $^{0.}$ It is associated to the source rock of the top of overpressure zone, which has %Ro of 0.6.

RESULTS AND DISCUSSION

Pore Pressure and Fracture Gradient Profile

The total depth data for 13 wells showed that the final depth range was 8212-13995 ftTVD. Regionally, this well penetrates the Balikpapan Formation. The sedimentation rate in the Balikpapan Formation reaches ±500 m/million years. It is related to a study by Swarbrick, which found that the loading mechanism that causes overpressure occurs when the sedimentation speed in a basin is >100m/million years.

The analysis of 13 wells using wireline logging on sonic logs, density logs, and neutron logs shows that pore pressure anomalies can be indicated as overpressure (**Figure 2**). Based on wireline logging data, it was found that standard compaction patterns varied in 13 wells at depths ranging from ±600-7986 ft. Standard conditions in the sonic log are shown by the relationship of sonic values, which decrease with increasing depth. The abnormal compaction pattern occurs at a depth of ±7986 – 9214ft. The emergence of this pattern is characterized by a constant value on the sonic log with no decrease or increase in value compared to the regular compaction pattern. Also, abnormal compaction patterns were found at a depth of ±10830 – 13995ft. The emergence of this pattern is marked by a reversal pattern in the form of an increase in sonic value compared to the normal compaction pattern.

The emergence of anomalies can also be observed through the pore pressure profile, which is indicated by the effective stress pattern. Normal conditions are shown by the relationship between the effective stress value, which increases with increasing depth. An abnormal compaction pattern showed a constant value of effective stress compared to the normal compaction pattern. This condition occurred at varying depths in 13 wells at a depth of ±7986 - 9820. Moreover, at different depths in 13 wells at a depth of ±10800-14000ft, which showed An anomaly characterized by a reversal pattern in the form of a decreasing effective stress value compared to the normal compaction pattern.

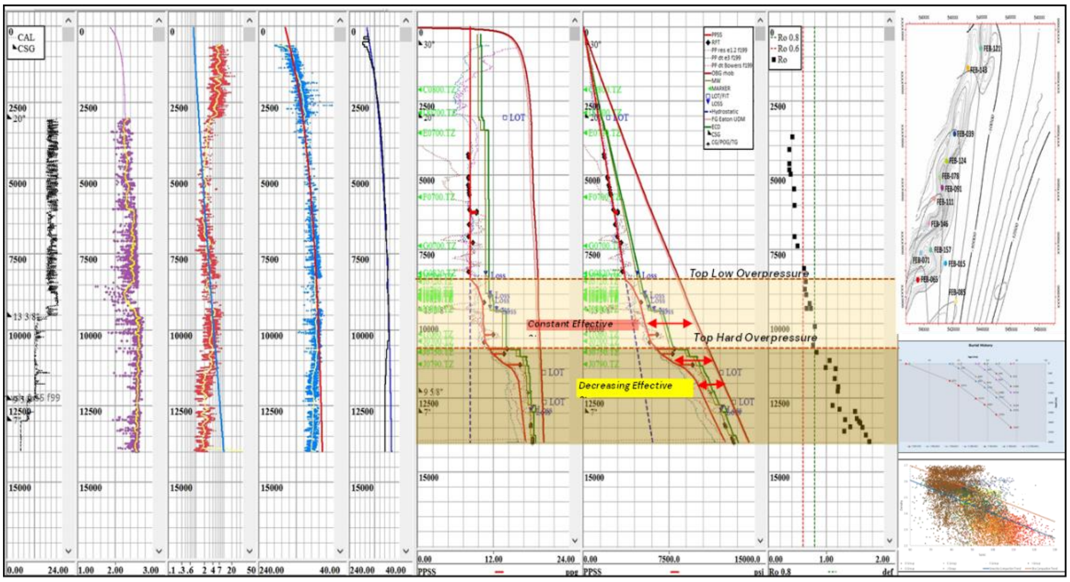

Figure 2. Pore Pressure Anomaly Pattern Based on Wireline Logging and Effective Stress

Overpressure Zone Analysis

Determination of the overpressure zone in this research area uses hydrostatic pressure parameters of 0.433 psi/ft = 8.345 ppg and lithostatic, 1 psi/ft. Lithostatic pressure is calculated based on log sonic values using the Eaton method. Estimation results in pressure pore use Eaton's method shows a correlation with the value of the mud weight used and pressure test data as validation. Wireline logging shows the

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presence of overpressure with low overpressure and hard overpressure zones, where enhancement pressure pore exceeds pressure hydrostatic detected (peak low overpressure) at a depth around ± 7752-9214 ftTVD, with a magnitude ranging from 8.5-8.9 ppg. Meanwhile, the hard overpressure zone is found at a depth of ±10830, obtained in the FEB-039 well. Analysis based on velocity interval data shows low overpressure and hard overpressure zones, with an increased pressure pore starting at a depth around ± 8229 ftTVD (low overpressure zone) and reaching a maximum of 12.66 ppg, as well as at a depth of approximately ± 10824 ftTVD in the hard overpressure zone with pressure pore maximum 16 ppg. Research on overpressure zones in the area triggers wellbore disruption, a significant challenge in oil and gas drilling activities. The drilling report shows that problem drilling form loss at depth varies on nine observed wells in Interval-I at a depth of 8764-8971ft and gas events at various depths, namely 9657-10588 ft.

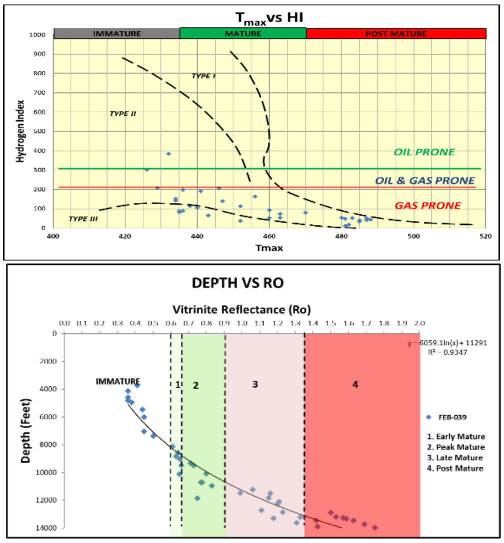

Figure 3. Types of Kerogen and Hydrocarbon Maturity *that Support the Unloading Generating Mechanism of Overpressure*

Generating Mechanism of Overpressure

The overpressure formation mechanism shows a smectite and illite compaction trend in the mudrock at a depth of ± 5000 – 8000 ftTVD. The shale is still in the smectite compaction trend. Then it experiences a reversal at a depth of ±8000 – ±10000 ftTVD, and at a depth of ±10000 – >13000 ftTVD, it is in the illite compaction trend with an unloading mechanism. This reversal indicates a decrease in rock density and an increase in sonic readings. The decreasing rock density is caused by the opening/increasing pores in the rock due to the expansion of H2O fluid from the change in the clay mineral smectite to illite. Meanwhile, growing sonic readings indicate increased rock deceleration due to increased rock pores. These changes in clay minerals affect the pore pressure in the rock, caused by decreasing effective stress, which is influenced by temperature. Areas with hard overpressure have temperatures between 140 – 175ºC, indicating that mineral diagenesis from smectite to illite has occurred at this temperature.

The dominance of Type III kerogen, which is gas-prone, and Type II/III kerogen, which is oil and gas-prone, is indicated in the source rock of the FEB-039 well by the Van Krevelen diagram results (**Figure 3**). Rocks with type III kerogen tend to significantly increase fluid volume during maturation, relative to type II kerogen, which only adds about 25% of the kerogen volume. The plot of %Ro against depth shows that the top low overpressure has a %Ro of 0.6 at a temperature of 130ºC, while the top hard overpressure has a %Ro of 0.8 at 140ºC. The formation indicated hydrocarbons with a %Ro 0.6 – 0.8 control top overpressure in the study area. Based on the burial history analysis, deposition with a thick sediment rate in Interval-I can cause compaction failure, contributing to the loading mechanism. The Balikpapan Formation in the "X" field, analyzed via Well FEB-039, shows a sedimentation speed of 791-1100 meters per million years, by initial estimates of overpressure occurring when the sedimentation speed reaches 100 meters per million years (Swarbrick, 2002). The overpressure mechanism due to loading is supported by pore pressure analysis, showing a transition zone from low overpressure to hard overpressure with constant relative adequate pressure at a depth of around 8597 - 10830 ftTVD. The Dutta plot shows a predominance of smectite minerals at this depth, indicating that the overpressure is controlled by a loading mechanism known as mechanical compaction. Thus, it can be

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concluded that the initiation of overpressure results from two mechanisms: loading (disequilibrium compaction) and unloading (clay diagenesis), whereas the development of hard overpressure is governed by an unloading mechanism, specifically hydrocarbon generation.

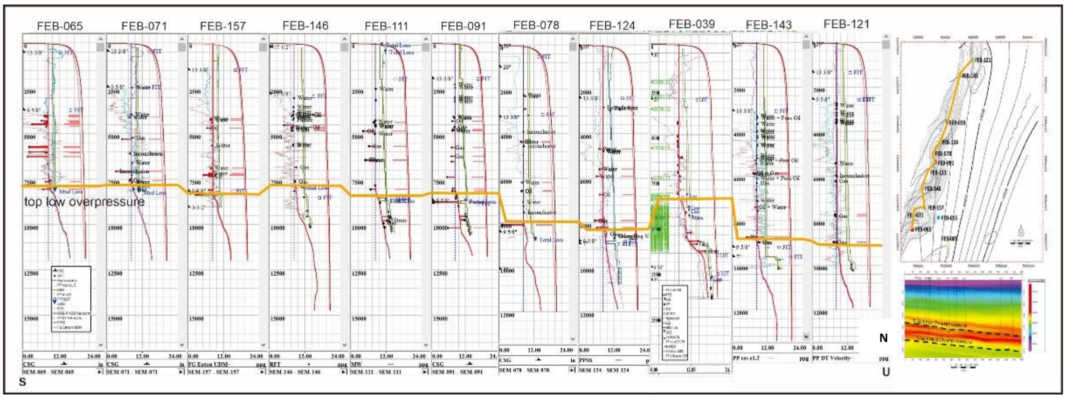

Figure 4. Pore Pressure Profile and Fracture Gradient on "X" Field

Overpressure Distribution

Two overpressure zones, a low overpressure zone due to the loading mechanism and a hard overpressure zone due to the unloading mechanism, were analyzed using wireline log data and velocity intervals. The overpressure distribution is divided into two parts: top overpressure and top hard overpressure. Based on stratigraphic correlation, the distribution of top low overpressure in Field "X" shows consistency with stratigraphic markers. Top low overpressure has a temperature of around 130ºC and %Ro 0.6, indicating smectite to illite mineral transition. Meanwhile, the mineral illite dominates the top hard overpressure, with a temperature of around 140ºC and %Ro 0.7. The distribution of overpressure shows differences in the North-South cross-section (**Figure 4**), with shallower depths in the southern part, thought to be due to the lifting of the overpressure layer, which is correlated with geological structural conditions and variations in the shale and sand ratio. The depth distribution in the West-East section is relatively uniform, with the top hard overpressure in the J interval. In the North-South section, the width of the transitional overpressure increases to the north, possibly due to a different geothermal gradient and uplift to the south. Top overpressure is determined by a decrease in the velocity interval, indicating compaction failure, while top hard overpressure is determined by a velocity interval value >10,000 ft/s.

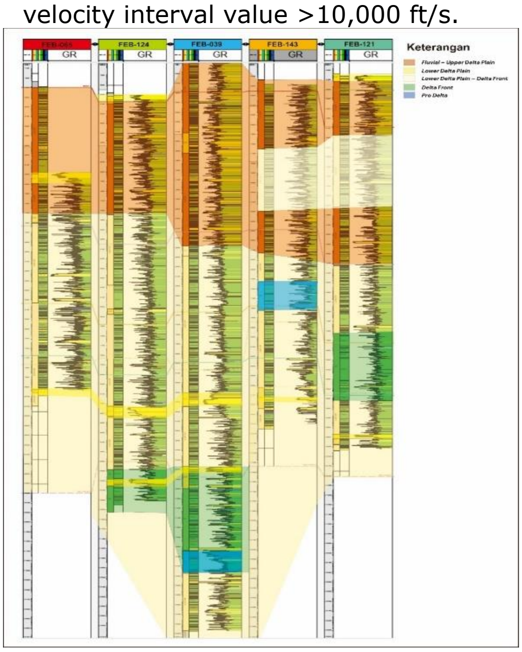

Figure 5. Depositional Environtment of the Research Area

Facies and Depositional Environments

Facies and depositional settings were analyzed using a Gamma Ray log curve pattern on the wireline logs integrated with mud data logs (**Figure 5**). Interpretation is carried out qualitatively by observing the curve of the wireline log, mainly the log Gamma curve. Rays are integrated with the results of lithological interpretation from the description of cuttings in the mud log and quantitatively by considering shale volume data. The lithologies found

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in this field are shale, sandstone, limestone, mudstone, and coal. Based on the analysis results, the research area is a prograding delta area with sand: shale ratio that is getting younger and bigger. The depositional environment is old to young, namely delta front, lower delta plain, upper delta plain, and fluvial. Overpressure in Field "X" is located in the lower delta plain to delta front facies, within the upper boundary of the low overpressure zone and hard overpressure in the facies delta front. In the southern part of the area, the study found that developing facies were dominated by the delta plain form channel; meanwhile, in the north, they were dominated by facies delta front correlated with bar deposits. According to (Nursasono, 2014), based on the results of studies of the modern Mahakam Delta analogy, the north section area study shows the character of unique reservoir rock, limited exposure , but excellent Thickness. In contrast, the study has extensive coverage in the southern region but only limited Thickness. Things that influence quality The reservoir rocks in both areas are facies. Accumulation Hydrocarbons in Field "X" are controlled by the sedimentation environment, forming deposition reservoir rock. Productive zone producer hydrocarbons in parts of the north area research were obtained in bar deposits trapped by the clay plug, while in the southern part of the area, potential zone research hydrocarbons were dominated by channels. Not just a bar section, data area research also found thin channel deposits that filled it between the bars.

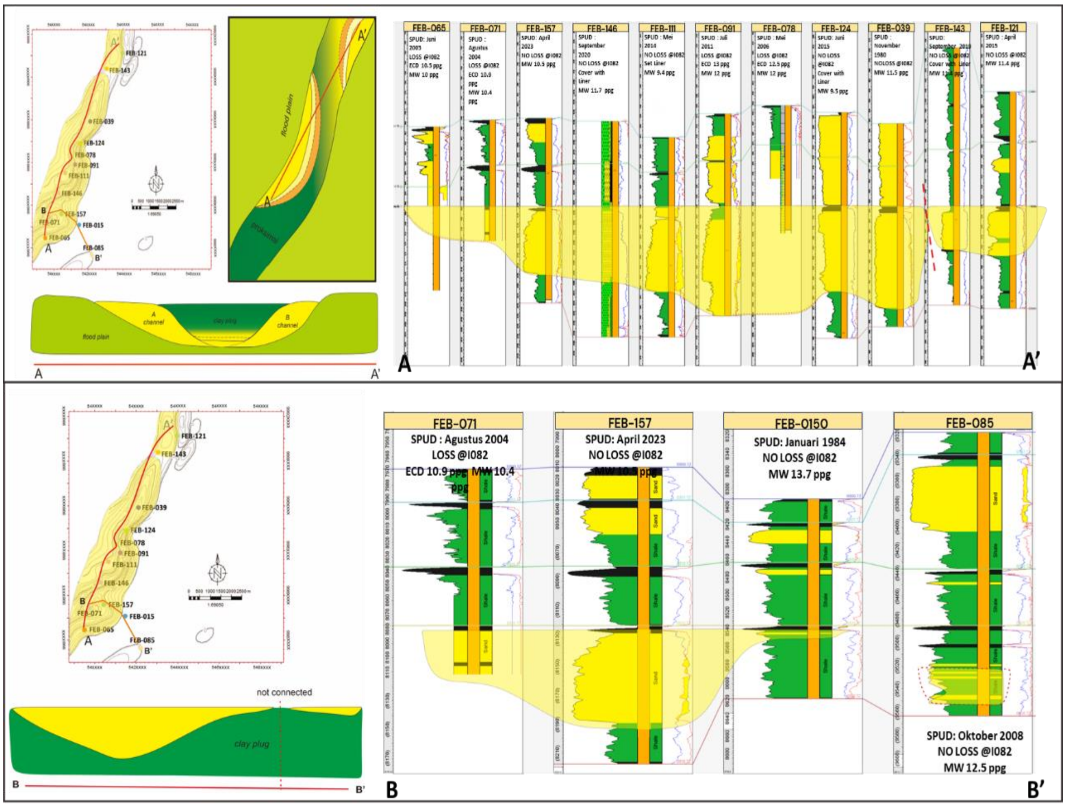

Figure 6. Reservoir Interval-I Distribution Model

Sandstone Distribution (Interval-I)

From observations of the pore pressure profile in the research area, an overpressure anomaly was detected in Interval I, which triggered wellbore disturbances during drilling operations. Nine of the 13 wells observed experienced losses in Interval I, which was dominated by sandstone lithology. This loss was caused by reservoir production, which reduced the initial pressure from 9.6 ppg to 0.8 ppg. The north-south and west-east correlation in "X" Field (**Figure 6**) this indicates that the sandstone experiencing loss was the connected channel in the southern region, while other channels in the north did not experience loss. The west-east correlation (**Figure 6**) in the study area shows that the sandstone that experienced loss, especially in the west, is not connected to the sandstone in the east. In the wells in the eastern part, the sandstone tends to be thin and layered in Interval I, while in the western part, the sandstone that experiences loss tends to be thick and blocky. Based on loss events and pressure test data, the poison ratio parameter in sandstone is calculated at 0.35, with a minimum fracture gradient in Interval I of around 11.1 ppg. Understanding pore pressure and sandstone distribution (Interval-I) is essential to reduce subsurface risks, streamline drilling operations, and reduce downtime. The Interval I sandstone distribution model identifies three clusters (**Figure 7**) based on loss events: the no-loss cluster, the partial loss cluster, which has an ECD value of around 12.5-13 ppg with an applied mud weight value of 12 ppg, and the massive loss cluster which has an ECD value of around 10. 5-12.5 ppg with an applied mudweight value of 10-12 ppg.

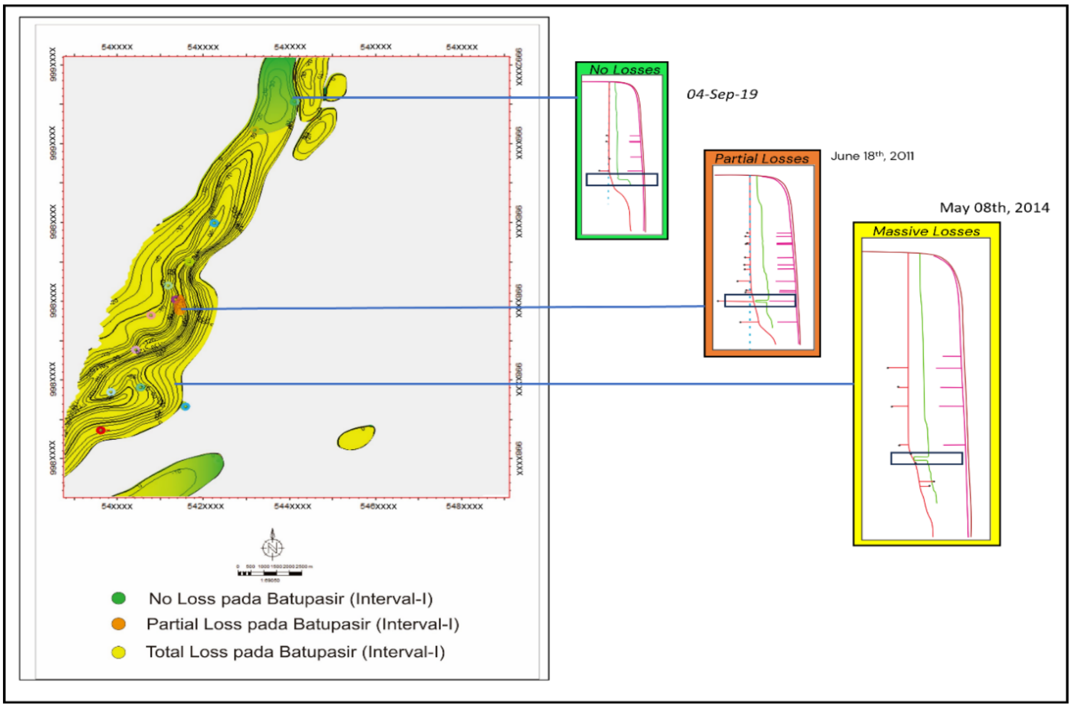

Figure 7. Loss Zone Distribution Map

CONCLUSION

Based on the results of studies in the field "X," the conclusion is that there are three pore pressure conditions: hydrostatic, low overpressure, and hard overpressure. The overpressure zone distribution shows top low overpressure at a depth of 7974 - 10877 ftTVD, with a temperature of 130 - 140ºC and %Ro 0.6, and a magnitude of 8.6 - 10.6 ppg. Top hard overpressure at a depth of 9820 - 11234 ftTVD, with a temperature of 140 - 175ºC, %Ro 0.8, and magnitude 10.4 - 13.3 ppg. The mechanism for forming overpressure involves loading in the low overpressure zone and unloading in the hard overpressure zone. Loading is caused by rapid sedimentation, with a speed of 791 - 1100 meters/million years. Unloading occurs due to the diagenesis of clay minerals and the formation of hydrocarbons. The dominant type III kerogen or prone gas indicates the change of kerogen to hydrocarbons, which produce significant fluids. The sandstone distribution model (Interval-I) shows a connected fluvial channel in the southern part and unconnected sandstone, with a Poisson ratio value of 0.35 and a minimum fracture gradient in the sandstone (Interval-I) of 11.1 ppg. Geological factors that influence overpressure include lithology, geological structure, facies, depositional environment, and hydrocarbon formation, supported by changes in minerals and temperature. Field "X" overpressure occurs in delta plain to delta front facies, with dominant

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mudstone lithology. Field "X" is part of the Balikpapan Formation, which consists of prograding delta deposits with geological structures in anticlines.

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