UNIVERSITY OF INDONESIA

GEOSTATISTICAL APPROACH USING WELL LOG AND SEISMIC DATA TO DEFINE RESERVOIR POTENTIAL IN MATURE FIELD

Case Study : "E-Sand", Mutiara Field, Kutai Basin East Kalimantan, Indonesia

THESIS

A Thesis Report submitted as partial fulfillment for the Degree of
Master of Science in Geophysical Reservoir at University of Indonesia

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The Writer

ABSTRACT

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GEOSTATISTICAL APPROACH USING WELL LOG AND SEISMIC DATA TO DEFINE RESERVOIR POTENTIAL IN MATURE FIELD

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To define reservoir potential or to have a better understanding of reservoir characterization become the most important part to get many subsurface information. It will be very useful to analyze and prospect new candidates. Reservoir characterization combined with the formation evaluation data between vertical and horizontal dimensions will produce a geologic model, which is used as an input for reservoir simulation.

The objectives of this research is to develop a reservoir model within the producing interval of interest defined as horizons "E" where it plays as a main oil target. It is a part of the Salemba Field, Kutai Basin, East Kalimantan.

A geostatistical method used for the study was stochastic since the data set availability is good. But to have better self confidence, a glance of deterministic method was applied to see how the differences. There are three kind of stochastic method will try for facies modeling, there are: Object-base Modeling, Facies Transition and Sequential Indicator Simulation. Each method was varied using exponential types of variogram, which is considered as the best match use in Mutiara Field.

By using the existing software, it resulted more than 10 good scenarios and realizations of geological model generated for this study. Also the criterion of the main ranking will use the OOIP and OGIP. The result also was calibrated with current condition, cumulative production and recovery factor to see the remaining reserves.

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Chapter 1

Introduction

1.1 Background

The Salemba Field is an oil and gas producer which located in the Sanga Sanga PSC, Kutai Basin, East Kalimantan. The Salemba Field has several reservoir levels that have been tested and produced. The objectives of this research is to develop a reservoir model within the producing interval of interest defined as horizon "E" where it plays as a main target. It is a part of the SLB Field, Kutai Basin, East Kalimantan. The aim is to therefore understand reservoirs in terms of their distribution, geometry, connectivity, and quality.

Although considered as a development field, Salemba Field is still interesting to be evaluated for further development of the field, especially in the saddle and southern part. Many studies have been done in the Salemba Field, especially studied the facies and depositional setting of the reservoir. The studies mostly were based on the core data and other conventional well log interpretation. Basically, the results of the studies show that reservoir within Salemba Field have two depositional environments, fluvial and tide-river dominated delta

However, most of the previous studies in Salemba Field has limitation in only interpreting the facies distribution in 2D point of view. The present work did by The Reservoir Modelling Team tried to integrate the analysis of facies distribution through 3D visualization by using new software called "Petrel."

Reservoirs may be characterised using different types of data: outcrop/cores/cuttings, conventional log and FMI analysis, or seismic interpretation. In this research, wireline logs are integrated with 3D seismic data through seismic inverse modeling.

1.2 Goal and Objective

The goal of the thesis was partially to fulfill the requirements for the degree of Master of Science, Reservoir Geophysics Postgraduate Program, Faculty of Mathematics and Natural Sciences, Department of Physics, University of Indonesia.

The main objectives of this thesis was to establish the best practice and the most effective way of evaluating hydrocarbon fluid properties, build a 3D facies of Salemba Field and display into 3D visualization. The facies distribution was done through the 3D model. Also the study applied the geostatistical method to have the best practice of qualitative and quantitative predictions, and the model is expected to be applied and tested in other exploration and development fields in the East Kalimantan. It is expected that the study could provide better ranking of leads/prospects and better delineation efforts.

1.3 Scope of the study area

The scope of the thesis was focused in the investigation of hydrocarbon fluid properties using the integration of geology, seismic and geostatistic in the Salemba Field, East Kalimantan with hope to get a good clarification and identification of reservoir characterization of the research area.

The seismic analysis was mainly focused to see the horizon continuity effect over the CRS data and to see the sand pattern across the area.

Well log data information used were mainly from the proven hydrocarbon producing wells that consist of oil bearing sands and gas bearing sand. The well data consist of log data including data from wireline, petrophysical analysis and core data.

For integrating reservoir studies, the following tools were used will use some tools such as

1. **Syntool**, wass used for analyzing some information taken from the seismic data. Syntool was applied to avoid miss tie between the well and the seismic data.

2. **Seiswork,** was used for seismic interpretation. CRS data was used to pick the interesting zone then the output was used for RMS modeling (sand pattern based on data). Fault were taken from the existing fault picking zone since the fault are not covered in the study area. Seismic data were only used for preliminary work.

3. **Stratwork**, was used for preliminary working on the zone correlation between the wells. It was very useful to identifying the sand layering correlated to each other sand layers. While in the delta area, sands are most likely thin and have an evev distribution..

4. **Zmap**, was used for mapping the sand and structural distribution. The grid resulted from the zmap was used as an input data for "Petrel"

5. **Petrel,** was used for making some modeling especially for geostatistical algorithms to stimulate petrophysical and geological properties inter well location and integrate data at various scales. The structural modeling to integrate faults, horizon, seismic data was used to identify the current model then it was matched for ranking and history matching with the production data.

1.4 Location of The Study Area

Salemba Field is located in the Kutai Basin, part of onshore area of East Kalimantan. The field embraces part of the regional Sanga-Sanga, Samboja anticline, which extends a distance of some 80 kilometers. The study are is located in the southern part of Salemba Field (SLB Field) on the Northeast – Southwest trending regional anticline.

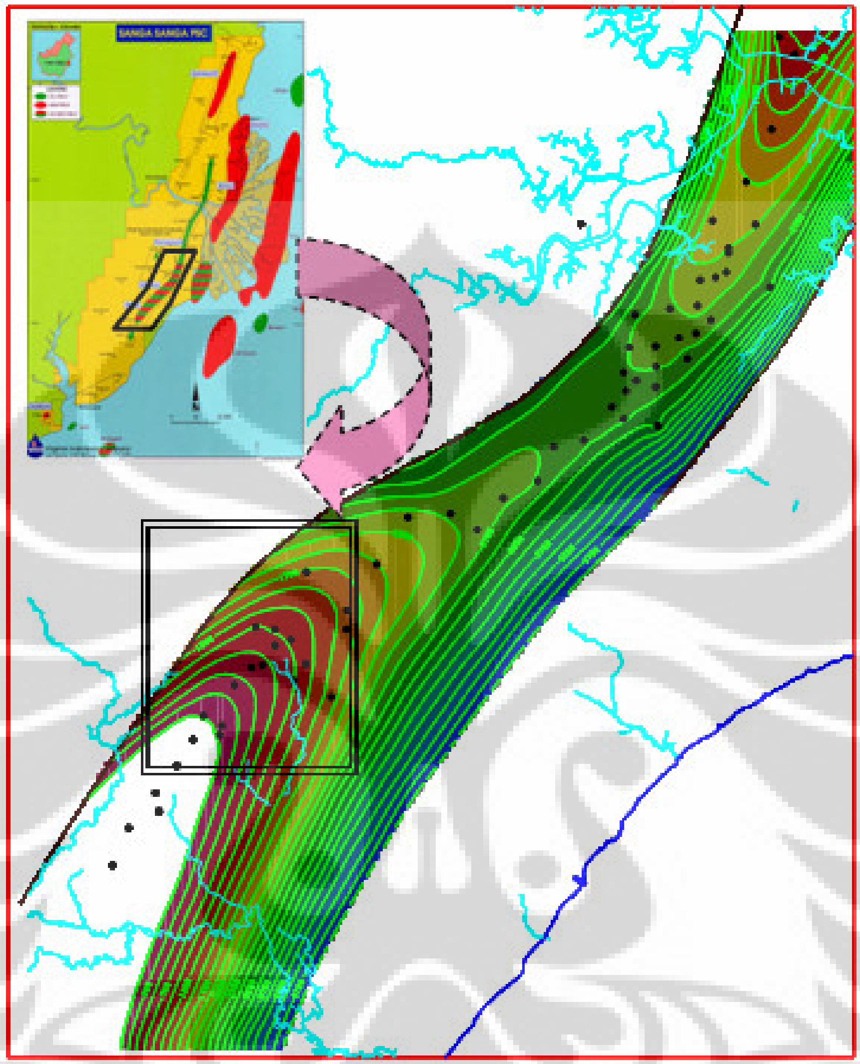

Figure 1.1 Salemba Field, Kutai Basin, Sanga-Sanga , East Kalimantan

1.5 Writing Sistematization

The thesis contains several chapters with explanation regarding this writing as below:

The first chapter explains about the background, goal and objective of the study, scope of study, also a brief summary of study area

The second chapter explains about regional setting including the tectonic, structural, and stratigraphy setting. Also the hydrocarbon play in the study area includes the reservoir characteristics, seal potential, hydrocarbon accumulation, generation and migration of hydrocabon in the study area

The third chapter explains about the definition, basic theory of geostatistical model as a basic for Facies modeling.

The chapter will explains the results of data prosessing, modeling and all related methods used for this writing.

The chapter summarizes the whole results of the writing and recommendation related to the future jobs.

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Chapter 2
REGIONAL GEOLOGICAL SETTING

2.1 Regional Settings

2.1.1 Tectonic Setting

The study area is situated on the coast of East Kalimantan. It is the easternmost extension of the Kutai Basin and connected to the West Kalimantan, Melawai Basin. The Kutai Basin lies on the Eastern margin of Sunda land, which represents the southern extension of the Eurasian continental mass. The Kutai Basin is bounded to the north by the Bengalon Lineament of the Sangkulirang Fault Zone and to the south by Adang Fault zone. These large regional faults appear to have acted as down-to-the basin hinge zones from the Late Oligocene to present. To the west the Kutai Basin is bounded by highly deformed and uplifted paleogene sediments and Cretaceous meta-sediments that make up the Central Kalimantan Ranges. The Kutai Basin is open to the east and continues with deep water North Makassar basin.

The Kutei Basin can be divided into an overall transgressive Paleogene deposits, and an overall regressive Neogene deposits (Allen and Chambers, 1998). The Paleogene deposits began with extensional tectonics and rift infill during the Eocene and culminated during the Late Oligocene. The Neogene deposits beginning during the Lower Miocene, and continuing to the present day, resulted in deltaic progradation across the Kutai Basin.

The Mahakam river system from the Middle Miocene to the present appears to have incised to Samarinda Anticlinorium and thus propagated from a single point source near the present day head of passes. This has been combined with the present day in Mahakam Delta areas has resulted in an aggraded series of deltas below present day delta

2.1.2 Structural Settings

The early Miocene was a time of significant tectonic subsidence, with a little uplift. The initiation of fold belt structuring progressed from west to the east in an overall subsiding regime. This structuring, thought to be due to contraction forces derived from the Kuching uplift, led to a recycling of older sediments and thus deposition of clean sandstone with little or non-lithic fragments in the depositional centers

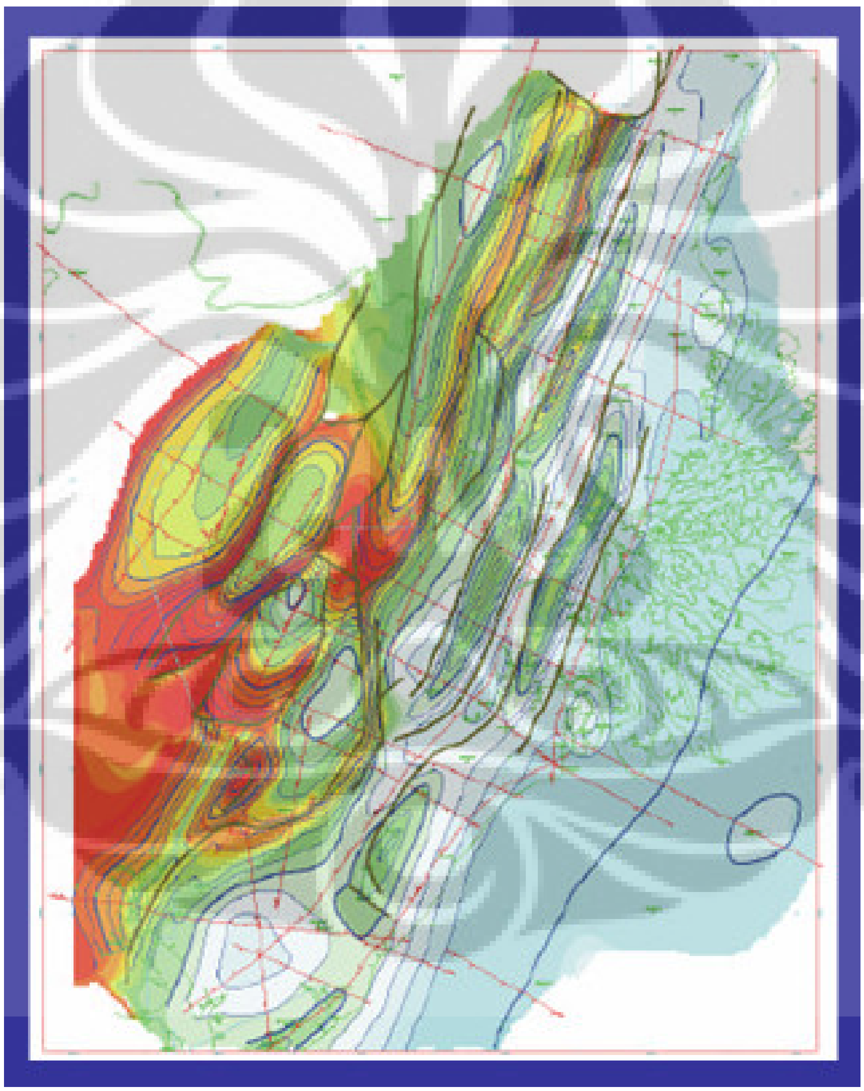


Figure 2.1. Regional structural pattern in the Kutai Basin.

In the surrounding area, it was believed that the structural growth of the Sanga-Sanga anticline initiated around N12 time (Blow zone) equivalent to the E sand interval, as a part of the basin inversion that initiated during the Lower Miocene. Associated with this uplift, is trapping of sediments on the west flank of the anticline, as evident in the revealed differences in reservoir properties across wet-northwest striking “barriers” which led to the assumption of syn-depositional structuring in the area. This kind of strike slip faulting can be observed in many middle Miocene reservoirs and may represents a reactivating of a pre-existing basements lineaments jointly between Vico Indonesia and Prof Mc Clay (Royal Holloway University of London, Geology department)

In the first phase, an extensional regime prevails. Growth faults, common in a deltaic settings are active and segment the sediment. From interpretational view, assume that the nature of the growth faults, the thickening of strata into the faults is not-yet properly established by isopach mapping in the study area.

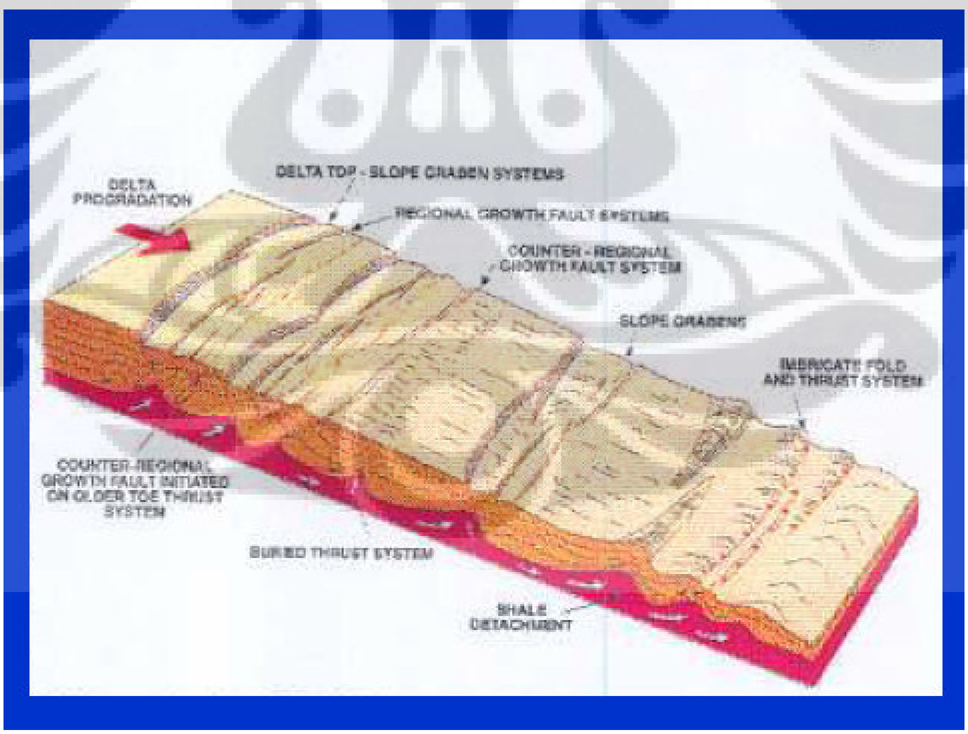


Figure 2.2 Concept of initial Extensional faulting with detached growth faults

The second phase is a compressional regime which leads to the rejuvenation and inversion of the pre-existing faults along. The main western bounding fault along the SLB-PAM anticlinorium is rejuvenated growth faults system. The degree of tectonic deformation in this series from East to West. The deformation is the strongest in the onshore parts west of Vico's Sanga-Sanga PSC area and decreases in strength eastward towards the offshore area.

The tectonic inversion and its timing is important because it defines the time when the reservoirs were put into structural position to receive and trap hydrocarbon.

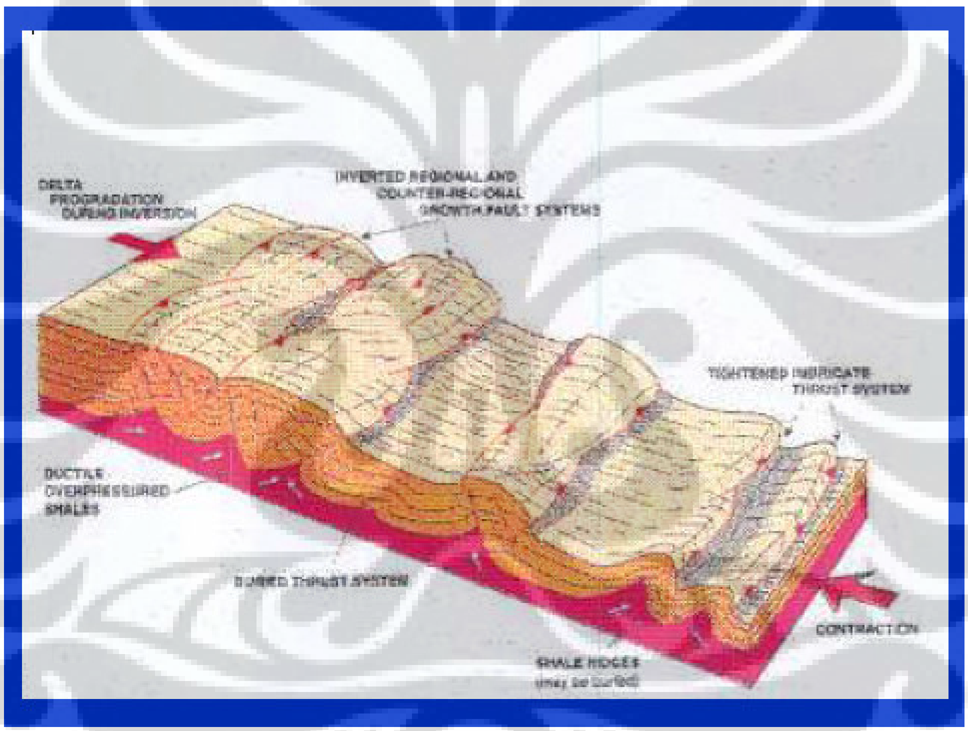


Figure 2.3 Second phase: compression (The pre-existing growth faulting is inverted)

2.1.3 Stratigraphic Settings

The earliest sediments in the Kutai Basin area Eocene age0and were result of the Makassar Strait opening at the time. The basin was widely transgressed during the Eocene and the early part of the Oligocene resulting in the depositional of predominantly marine politic sediment. From late Oligocene onward, the basin has an overall regressive setting, resulting in infill of the accommodation space with clastic sediments from the west. Average sedimentation rates were extremely high and the estimate total thickness from 8,000 – 14,000 meters of sediments.

Kutai Basin become a major fluvial deltaic depocentre since the Early Miocene. Sediment supply to the basin has been variable with time, with intervals of rapid sedimentation occurred during the Lower Miocene and Pliocene and temporarily changed the nature of the sediment supply

Sediments within the productive section are typical deltaic deposits with shales, sand and coal. Carbonate depositional is insignificant by volume and extent. The presence of coal within the sedimentary section distinguishes this delta from several other popular deltas that serve as study objects, such as Mississippi Delta.

The morphology and hydrographic pattern of the delta directly reflects the type and intensity of the predominant sediment transport mechanism the coast. Three basic processes can be active: fluvial influx, tidal influx and waves. Within this framework, Mahakam delta is considered as tide and river dominated delta.

The characteristics of such a tide-river dominated delta area :

- the absence of alluvial levees and crevasse splay deposits
- channels are flanked by supra-tidal marsh and tidal flats
- distributaries are about rectilinear with side bars

In the tide-river dominated deltas, the effect of river floods will usually be dampened out by tides. Therefore, fluvial deposits would be lacking and features such as graded beds, climbing ripples, parallel laminae, water escape structure, would generally be absent in these delta

As Mahakam delta was tide and river dominated like the modern delta, there are no levee channels and therefore no crevasse splays deposits. The inter channel realm is occupied by marsh and peat. These organic rich deposits are believed to have relatively high resistance against erosion. Therefore amalgamated channels have the tendency to accumulate (stack) vertically rather that eroding into the river bank.

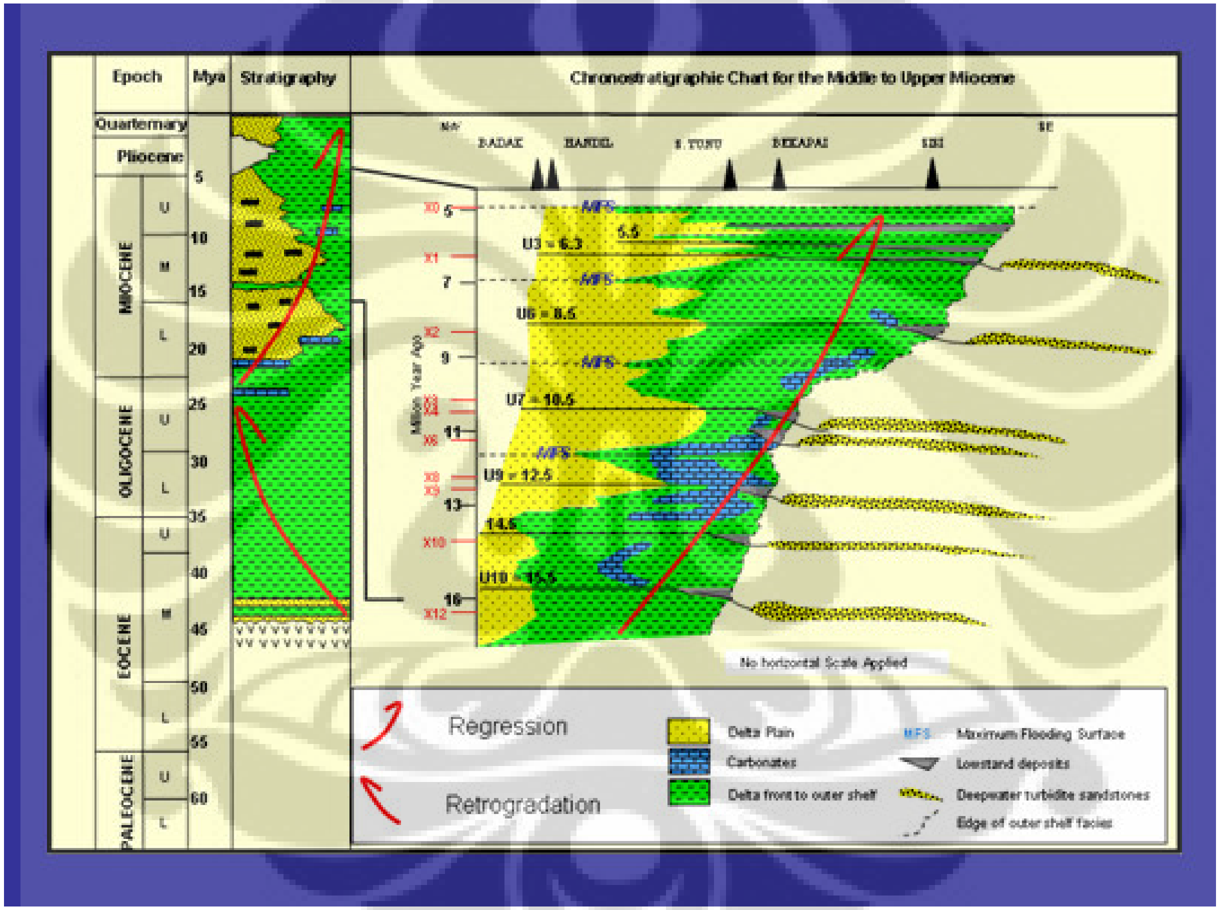


Figure 2.4 Overall Retrogradation and Progradation Pattern during Paleogene and Neogene

2.2 Hydrocarbon Play

2.2.1 Reservoir

As a part of the western margin of the Kutai basin. The study area has undergone the sedimentation with two distinct types of petrologic composition. The Lower Mioce (N4 – N9 Blow zone) is mainly volcanogenic composition, whereas the Middle and Upper Miocene (younger than N10) sediments are highly quatzitic with mostly less that 30 percent ductile or chemically unstable grains. These latter sediment due to their relative homogeneity have suffered diagenetically less complex fluid rock interaction. Because they still retain substantial reservoir quality. These rock have become an important site for hydrocarbon accumulation.

There is no producing carbonate reservoir in the study area. Experienced in east Kalimantan has shown that carbonates are disappointing exploration targets.

2.2.2 Seal and Seal Potential

An important aspect of hydrocarbon trapping is the capacity of overlying shale retain the hydrocarbon charge. There are two possible mechanism that lead to leakage of an hydrocarbon accumulation: fracturing and leakage through the undisturbed top seal.

The quality of seal would determined by the minimum pressure required to displace connate water from pores or fractures in the seal, thereby a leakage.

2.2.3 Hydrocarbon Generation and Migration

According to Surdam (1993), the source rock of the Mahakam delta can be divided into three categories : black coal, brown coal and organic rich shales. Generally, the contribution from coals is much higher that from organic shales.

The black coal are huminite-rich lignites and vitrinit-rich bituminous coals; brown coals are liptinite-rich coals that at high maturation levels are transformed into vitrinite–rich coals and the shales contain phytoclasts (vitrinite and inertinite) dispersed amorphous organic matter in a clay –mineral matrix.

2.3 SALEMBA GEOLOGICAL SETTING

The geological structure of the study area The Salemba Field is a long, linear, asymmetric thrust-fault-bounded anticline striking north-northeast – south-southwest. The anticline was formed by contractional reactivation of early delta-top extensional growth faults at approximately 10 Ma and 6.5 Ma (Ken McClay *et al.* (2000). Hydrocarbons in this field are trapped in middle to upper Miocene deltaic sandstone reservoirs that occur mainly in two-way structural/stratigraphic traps that result from delta-plain, reservoir-channel sandstones crossing a later structural high at an oblique angle.

The deltaic facies of Salemba Field was deposited in the shallow marine environment to delta-plain setting. Depositional environment in the modern Mahakam delta is an ideal analog for Miocene delta deposits in the Kutei basin. Four major depositional environments could be identified; Fluvial Delta Plain, Tidal Delta Plain, Delta Front and Prodelta.

Fluvial Delta Plain

Fluvial delta plain is the main framework in this depositional environment. It is characterized by a fining upward pattern, cross bedded medium-grained sandstone with carbonaceous laminae which grades upward into rippled sand lamination and finally into organic clay and coal.

Tidal Delta Plain

Sandstone in this environment is deposited as tidal sand ib distributary channels. It is characterized by a fining upward pattern, cross bedded and rippled fine to medium sandstone with thin mudstone laminae which grades upward into rippled sandstone-mudstone lamination with scattered burrows.

Delta Front

Distributary mouth bar is the main framework in this depositional environment. It is characterized by coarsening upward pattern, bioturbated mudstone with fine grained sandstone which grades upward into fine to medium bioturbated sandstone.

Prodelta

Sediments in this depositional environment are dominated by massive mudstone.

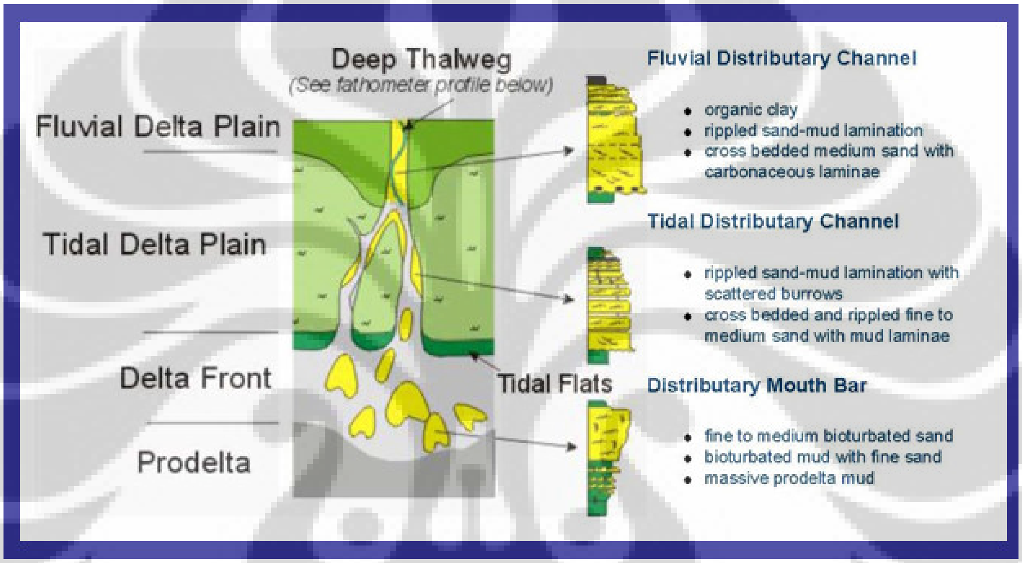


Figure 2.5 Typical Mahakam Delta Facies (Allen And Chamber, 1996)

Chapter 3

DATA PREPARATION AND METHODOLOGY

The data preparation consisted of identification of the well and seismic 3D data. The data provided by Vico Indonesia for this study consist of well data, seismic data, check shot data, core analysis etc.

3.1 DATA PREPARATION

3.1.1 Seismic Data

The seismic data are CRS 3D seismic data which cover an area of approximately 55 km^2. The area is limited by inline 2400 - 2750 and cross line 4300 - 4700. Spacing for inline is 30 meters and cross line is 20 meters.

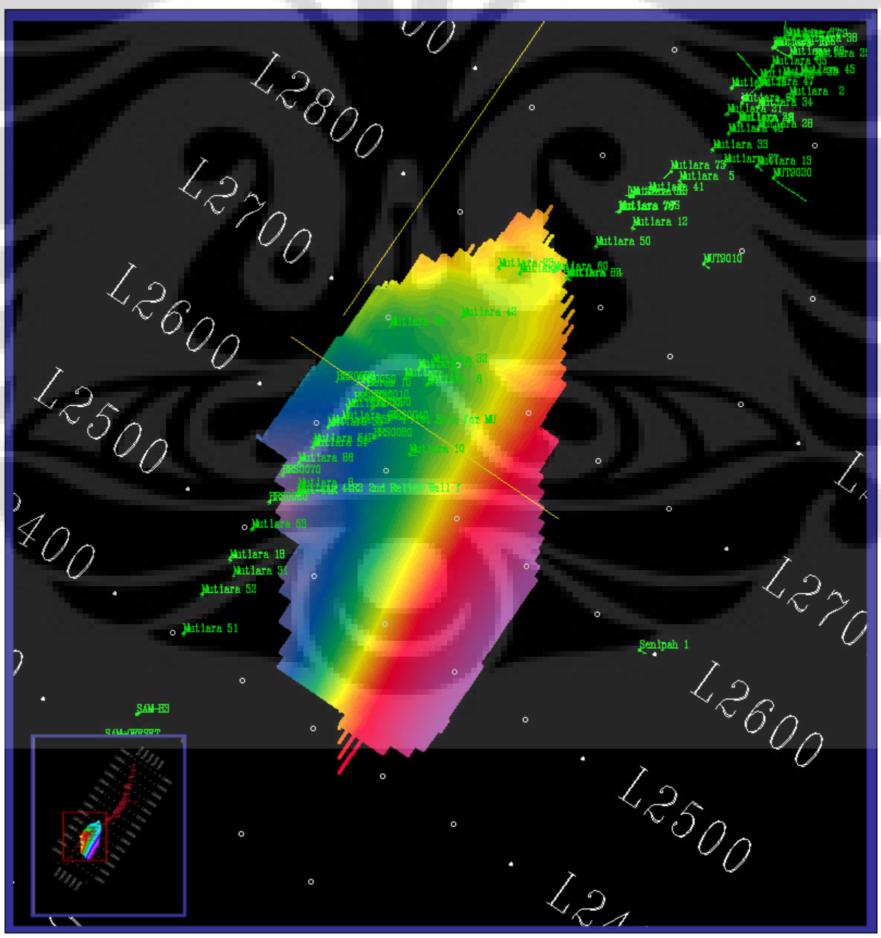


Figure 3.1 Seismic trace and line of Salemba Field

The interval of interest ranges from 0 to 1200 ms (TWT). Vertical seismic resolution within the interval of interest is calculated to be 25 ms, by assuming 2500 m/s as the velocity value and a dominant frequency of 25 Hz.

3.1.2 Well Data

There are 10 deviated wells that used in this study, which are SLB-1, SLB-3, SLB-4, SLB-5, SLB-6, SLB-8, SLB-9, SLB-10, M55, and SLB-72 (*Table 3.1*). All wells have density, sonic, and Gamma Ray logs but not all have neutron log data and check shot data. All of well information was summarized in Table 3.1.

Table 3.1 Well data availabilities of SLB Field

Nama Sumur	Jenis Sumur	Jenis Log Sumur										
		GR	SP	CAL	RXO	RT	LLD	LLS	NPHI	RHOB	DT	CS
B1	Deviated	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓
B3	Deviated	✓	✓	✓		✓			✓	✓	✓	
B4	Deviated	✓	✓	✓		✓			✓	✓	✓	✓
B5	Deviated	✓	✓	✓		✓			✓	✓	✓	
B6	Deviated	✓	✓	✓		✓			✓	✓	✓	
B8	Deviated	✓	✓			✓			✓	✓	✓	
B9	Deviated	✓	✓	✓		✓			✓	✓	✓	✓
B10	Deviated	✓	✓	✓		✓	✓		✓	✓	✓	✓
M55	Deviated	✓	✓	✓					✓	✓		
M72	Deviated	✓	✓	✓		✓			✓	✓		

3.1.3 Additional data

a. Core Data

The sedimentological description and facies interpretation was done by Chuck Siemers (PT.Geoservice, 1993) for SLB-3 and SLB-4 cores; and by CBP.Cook & I Nengah Sadiarta (PT.Corelab, 1999).The E reservoir has been cored at SLB-3, SLB-4 and SLB-8. All the E sand facies indicate a fluvial deltaic channel with crevasse splay environment.

Table-3.2 :" E" core facies interpretation(C.Siemers, 1993 ; I.Nengah S., 1999)

Well	Core Depth	E-log Depth	Facies	Remarks
SLB-3	1563–1667	1572–1676	Fluvial / Deltaic Channel sand	All core interval is E sand
SLB-4	1777–1872	1789–1884	Fluvial / Deltaic Channel sand	All core interval is E sand
SLB-8	1605–1635	1610–1640	Crevasse splay	Only recovered 1.5' of E botsand at top core

b. Elan Plus Log

To support the An ELANPlus interpretation model has four parts : formation components and response equations, parameter and constraint.

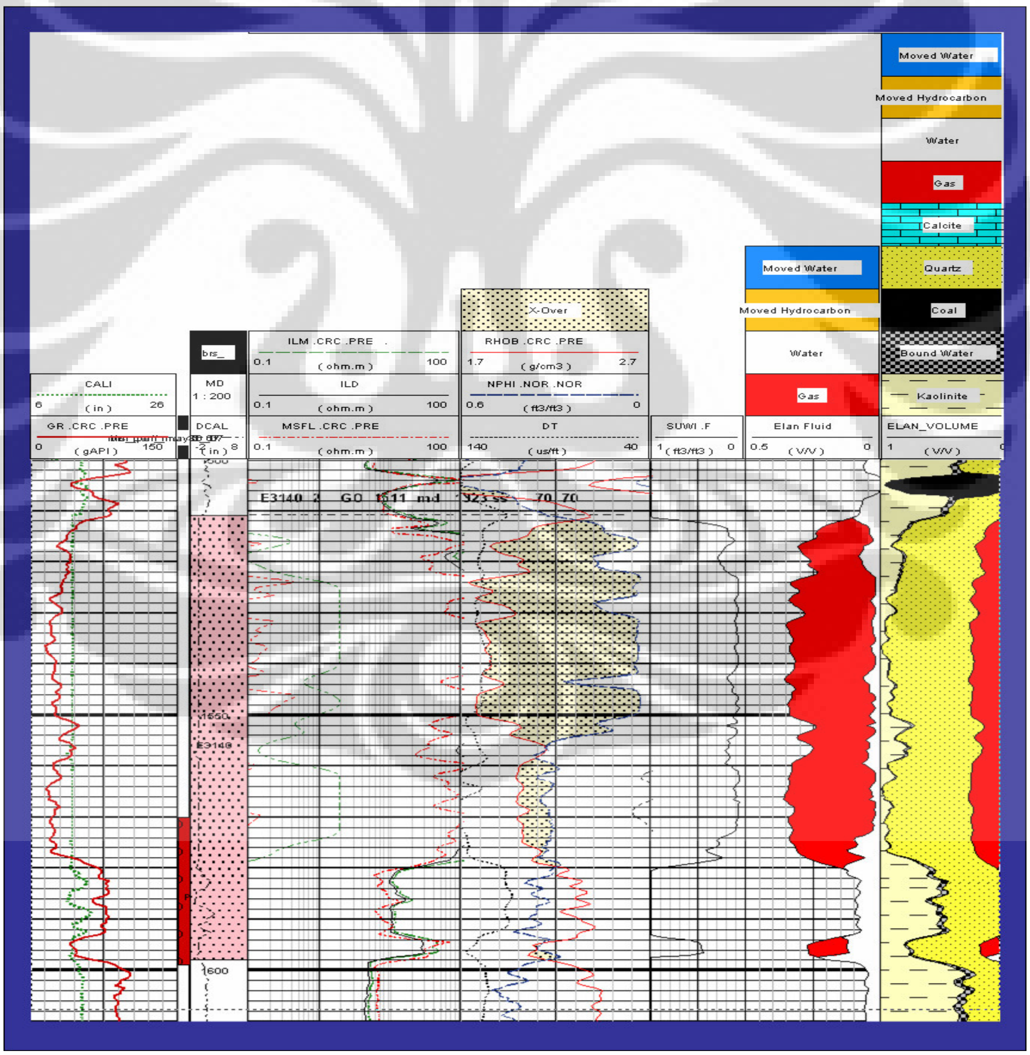


Figure 3.2 Elan plus log describes the petrophysical properties

For example, E-sand in SLB-6 show very thick sand about 100- 110 feet of net sand (interval depth 1511 -1600 feet) consist of quartz, kaolinite as a clay plug. It show high resistivity and very good cross over.

3.2 METHODOLOGY

The study methodology consists of three major steps. The first was seismic interpretation, including horizons and faults interpretation. The second was building the structural model, and the last was building the facies model.

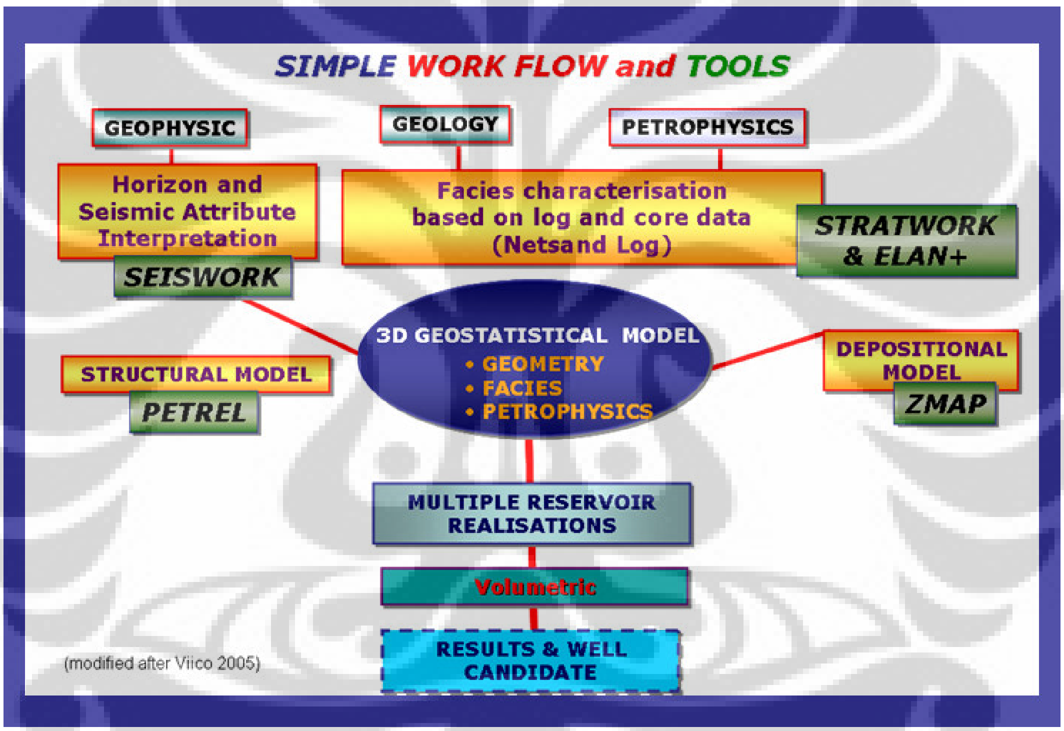


Figure 3.3. Simple Work Flow and Tools using in the Project
(Modified after Vico Report, 2005)

The seismic interpretation process was based on seismic data and well data. Synthetic seismograms were built to tie seismic data and well data using Syntool (Landmark software). Horizons were interpreted using Seiswork from Landmark.

The structural model was built using Petrel software. The structural model was built based on horizons and faults interpretation. Firstly, the interpreted horizons and faults were exported from Landmark to Petrel in the depth domain. Time to depth conversion was done using TDQ application of Landmark

The structural model was then used as an input for facies model. Other data used in the facies modeling process were well log data and seismic attributes. The detailed processes undertaken in this study will be explained as the workflow in

3.2.1 Geostatistic definition

Geostatistics is a statistical technique that accounts for spatial relationship of variables in estimating values of the variables at unsampled locations. The reservoir properties are spatially related, as the distance between the measured value increases, the similarity between the two measurements decreases. Then geostatistic uses correlation function (variogram) to quantify the spatial relationship.

Even the geostatistics offered a good solution especially for dense and rare data but it also has advantages and disadvantages using the geostatistical method.

Advantages :

1. The spatial relationship are customized for a particular data set rather than using a generalized relationship for all data sets.
2. Geostatistics provides an estimation of errors, account volume support, honored samples,
3. Some techniques allow qualitative information
4. It also allows uses of extensively sampled variables to estimate the values of other sparsely sampled variable.

Geostatistics also has some disadvantages which need some additional data, subjective decision making and need to do some details work.

3.2.2 Variogram modeling

A sample variogram is a plot of separation distance against semivariance for the data. The variogram model is an idealized version of this mathematically described variogram settings. It is generated by finding pairs of data of similar separation distances and then calculating the degree of dissimilarity between these pairs. Below is a typical variogram (Petrel manual , 2004) :

a. ***Sample Variogram***, variogram calculated for a sample data using a direction and separation distance
b. ***Variogram Model***, a continous mathematical expression used to describe the sample variogram. The variogram model in Petrel also contains information of anisotropy
c. ***Range**,* describes where the variogram reaches its plateau (i.e the separation distances where there is no longer any change in the degree of correlation between pairs of data values).
d. ***Sill**,* the semi variance where the separation distance is greater than the range (on the plateau). Describes the variation between unrelated samples. Transformed data should have a value of 1 and values much higher or lower than this (e.g +/- 0.3) may indicate a spatial trend
e. ***Nugget,*** the semi variance where the separation distance is zero. Describes the short scale variation in the data. This is often accurately identified from vertical data where the sampling interval is usually much lower.
f. ***Plateau,*** the part of variogram model where an increase in separation distance no longer increases the variogram value.
g. ***Transition,*** Variogram models that reach plateau are refer to as transition models. Different types of variogram are used to describe the transition.

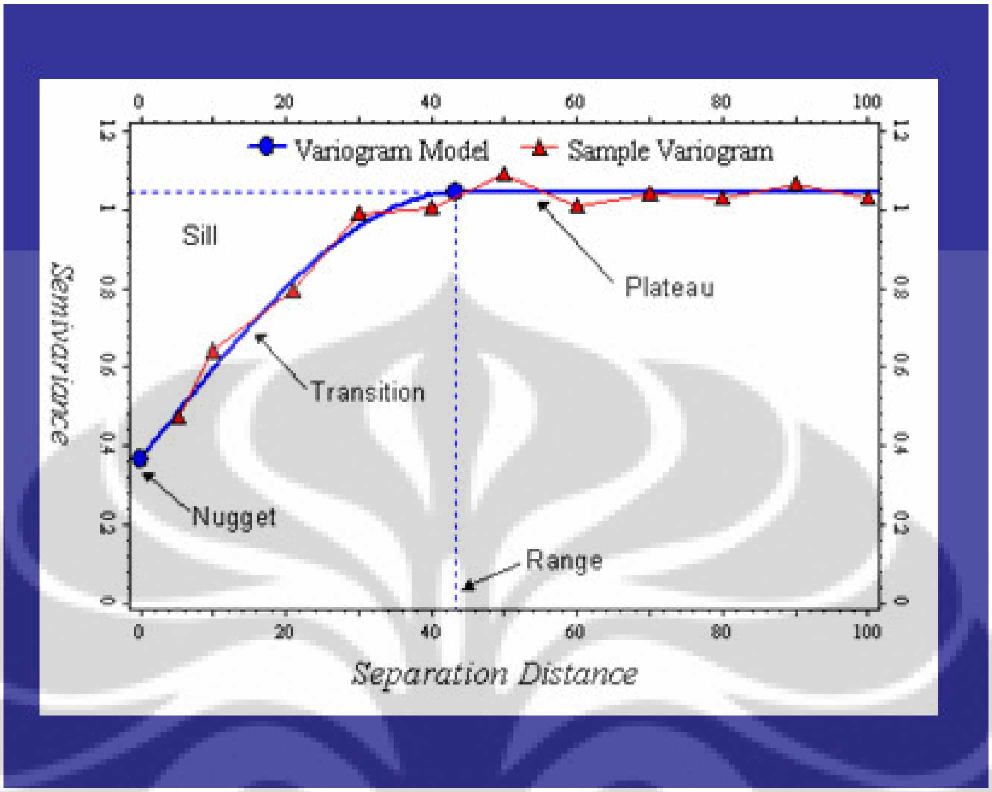


Figure 3.4. Typical variogram (Petrel, 2004)

The procedures for data sampling in different directions are approximately the same, except that the vertical sample variogram always are calculated isotropically (i.e orientation is not used). Nugget, sill and variogram type values will be the same in all three direction whilst the range will vary.

The data sampling method for horizontal sample variogram and the terminology used in Petrel is described as figures below.

Three types of models can be used when constructing a variogram model in Petrel. All these are " transition' models:

a. **Exponential** : This model reaches its sill (c) asymptotically and the effective range (a) is defined as the distance at which (h) = 0.95c

   C = sill – nugget

$$\gamma\ (h) = \text{nugget} + c\ [1 - \exp\ (-h/a)] \quad (3.1)$$

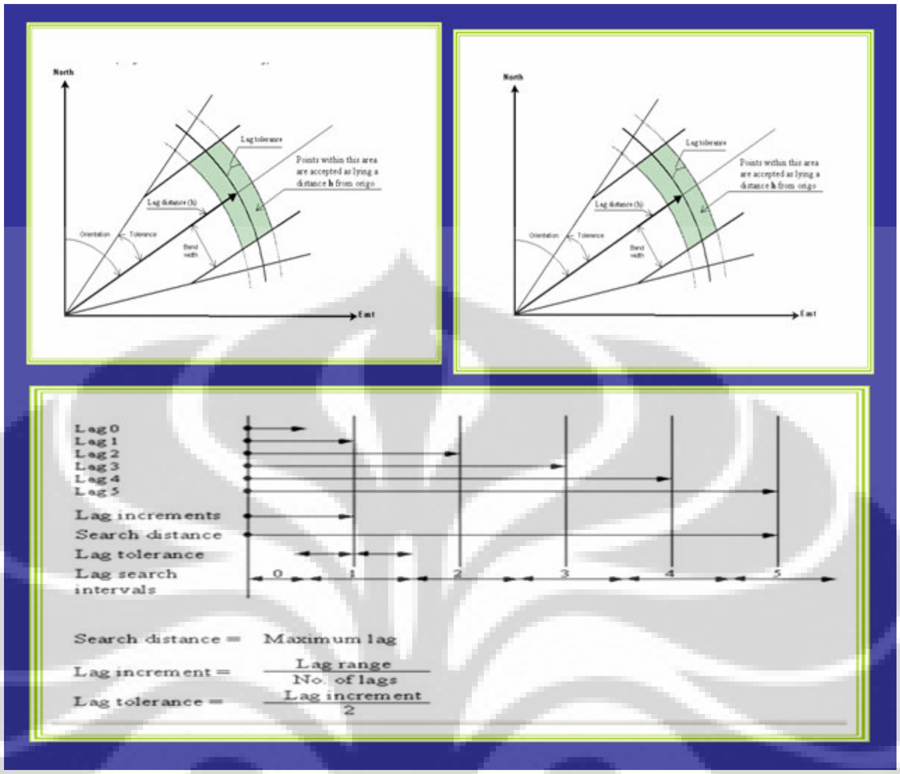


Figure 3.5 A group of horizontal sample variogram (Petrel, 2004)

b. **Spherical** : This model producer linear behavior at small separation distances (h) and reaches the sill at the effective range (a). The effective range equals theactual range

C = sill – Nugget , if h≤ a

$$\gamma\ (h) = \text{nugget} + c\ [1.5\ h/a - 0.5\ (h/a)^3] \qquad (3.2)$$

c. **Gaussian** : This model reaches its sill (c) asymptotically and the effective range (a) is defined as the distance at which (h) = 0.95c. this model has a parabolic behavior near the origin and is the only model that has an inflection point.

C = sill – nugget ,

$$\gamma\ (h) = \text{nugget} + c\ [1\text{-}\exp\ (-h^2/a^2)] \qquad (3.3)$$

Gaussian variogram model should not be used for categorical variables without using a nugget.

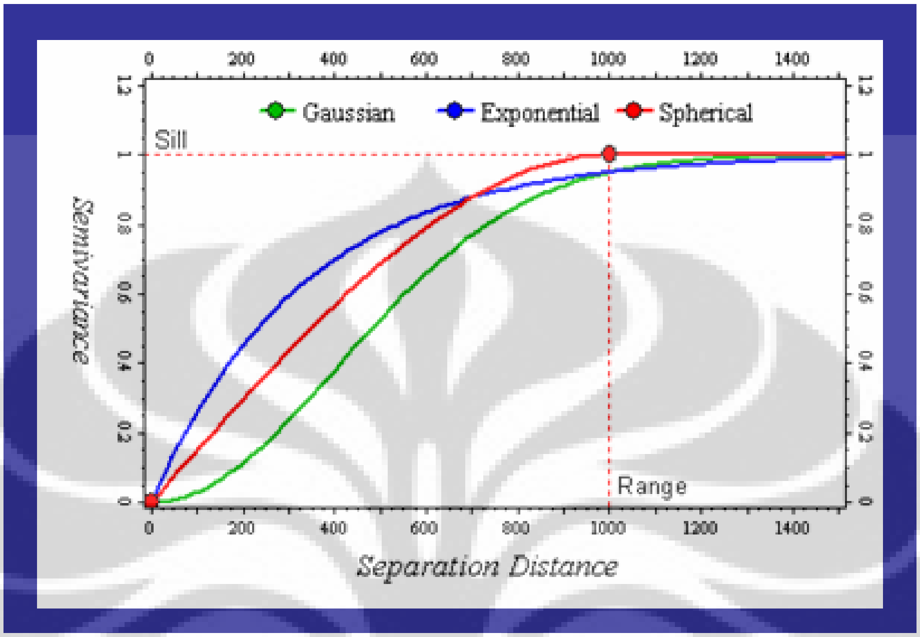


Figure 3.6. Types of variogram models (Gaussian, Spherical, Exponential)

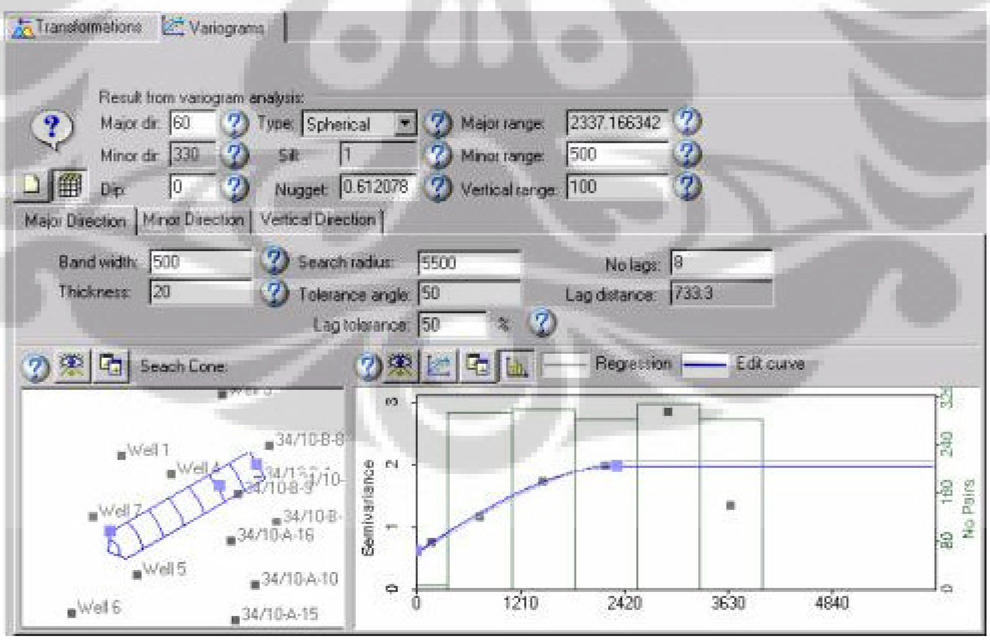


Figure 3.7. Example of variogram model for E sand using spherical type

3.3 Geostatistical Method as a Basic for Facies Modeling

Two geostatistical algorithms in property modeling are provided by Petrel. These are the deterministic algorithm and the stochastic algorithm. Deterministic technique is typically used when dense data is available and the method will always give the same result with the same input data. The stochastic technique is often used in conditions where sparse data is present. This method can give several similar results from the same input data (Schlumberger, 2004).

Well data used in this study is restricted to the southern part of the area, which means there is little well control for the remaining area. The most appropriate geostatistic method in facies modeling is the stochastic method.

Petrel provides three different kinds of stochastic methods for facies modeling, there are:

1. Object-Based Modelling
2. Facies Transition Simulation
3. Sequential Indicator Simulation

3.3.1 Object-based model

It is one of the most popular methods used in facies modelling. In creating the model, object-based method needs information about the shape, size, and relative position of the sand bodies as parameter.

3.3.2 Facies Transition Simulation Model

The second method is the facies transition simulation model, which was designed to be used in a large scale ordered facies progradation and retrogradation such as in shoreface or delta front environment. The method needs a conceptual sedimentological model to define facies transitional pattern including source type, depositional direction and progradation angle (Schlumberger, 2004).

3.3.3 Sequential Indicator Simulation Method

The last method is the Sequential Indicator Simulation (SIS) method. The SIS method is a pixel-based facies-modelling algorithm used to model facies without clear shape and boundary. This method is similar to Indicator Kriging, which calculates the probability of a facies at specific location instead of calculating the facies itself, and is usually used to generate the preliminary facies model.

The Object based method became the choice to be used for creating the facies model in the current project for facies modeling.In creating the model, object base methods needs information about the shape, size, and relative position of the sand bodies as parameter

3.4 Structural Modeling

The structural model is very important because the structural model gives basic framework for the further modeling process in this study. Basically there are three steps in creating the structural model; 1) creating fault model, 2) pillar gridding process, and 3) making horizon, zone, and layer.

The structural model was created in the depth domain using Petrel software. Hence, the interpreted horizons and faults as the main input in structural modeling process were exported from Landmark to Petrel in the depth domain.

3.5 MODELING PROCESS

3.5.1 Up-scaled Log

When modeling petrophysical properties, the modeled area is divided by generating a 3D grid. Each grid cell has a single value for each property (Schlumberger, 2004). Reservoir modeling, facies distributions, and petrophysical parameters modeling performed within 3D grid cell structure normally has larger cell thickness than the well data sample density so that the facies logs need to be scaled up before they can be entered into the grid.

The average method used for up scaling the facies log in this study is called the “most of” average method. This method selects the discrete value which is most representative in the log for each particular cell.

3.5.2 Variogram Analysis

A variogram is a plot of variability in terms of semi-variance against separation distance. It is generated by finding pairs of data with similar separation distances and then calculating the degree of dissimilarity between these pairs (Schlumberger, 2004). A semivariogram is modeled by fitting certain mathematical functions, such as spherical, exponential, or Gaussian, through experimental data. Parameters used for the variogram analysis were the same for all zones.

3.5.3 Probability Analysis

Probability for each lithofacies was approximately based on well data observations.

3.5.4 Multiple Realizations

Realizations are several possibilities of model results that can be generated from one input data. Without enough reference, it is difficult to define which realization is the most representative for the input data. To manage this problem, some tests were applied to the model. After the models were finished create the cell along the well bore test from the realizations were compared to the original upscaled log. The best match between the realizations and the original upscaled log was considered as best model to be interpreted.

After doing multi-realization, we continue to build an overlaid model with each parameter. It will give the best figure of which is the most potential area, even still rough because we have to use other possibility to rank the potential area.

To have any additional support for identifying the best location, calculating the volumetric IGIP and OOIP was done for each multi realization. It will help us to define how much the reserves in place then compared to current production. Data also also from the engineering side will be useful to calculate the remaining reserves. They will be put in the field history match.

Chapter 4
Interpretation and Discussion

4.1 Seismic Interpretation

The structural model was built using Petrel software. The structural model was built based on horizons and faults interpretation. Firstly, the interpreted horizons and faults were exported from Landmark to Petrel in the depth domain.

4.1.1 Creating Synthetic Seismogram

A synthetic seismogram was used for tying the well data and seismic data. The synthetic was obtained by convolving the reflection coefficients, which were calculated from the well, with a wavelet. Other important data in creating the synthetic seismogram was the checkshot data. Considering the importance of checkshot data, only wells that have checkshot data were used to create the synthetic seismogram. The wells are: SLB-1, SLB-4, SLB-9 and SLB-10. Check shot was used to correct the sonic log before calculating the reflection coefficient.

4.1.2 Horizon Interpretation

Two horizons were interpreted based on provided well data tops. The well tops are E.TSD pick which is the shallowest well top, followed by E.BSD. Basically the well markers were picked on flooding surfaces. Whereas in the log correlation E sand has been divided into five sections which are A, B, C, D and E. But in the seismic line , only top and bottom of E-sand were picked.

By using the synthetic seismogram created previously, the E-TSD and E-BSD pick from well data were traced through the whole seismic section. Based on their coefficient reflection value, the TSD horizon was picked on trough because it has a negative reflection coefficient, while BSD was picked on peak because it has a positive reflection coefficient. The horizons were traced every 25 lines and 25 traces and then interpolated to get the interpretation of the whole seismic area.

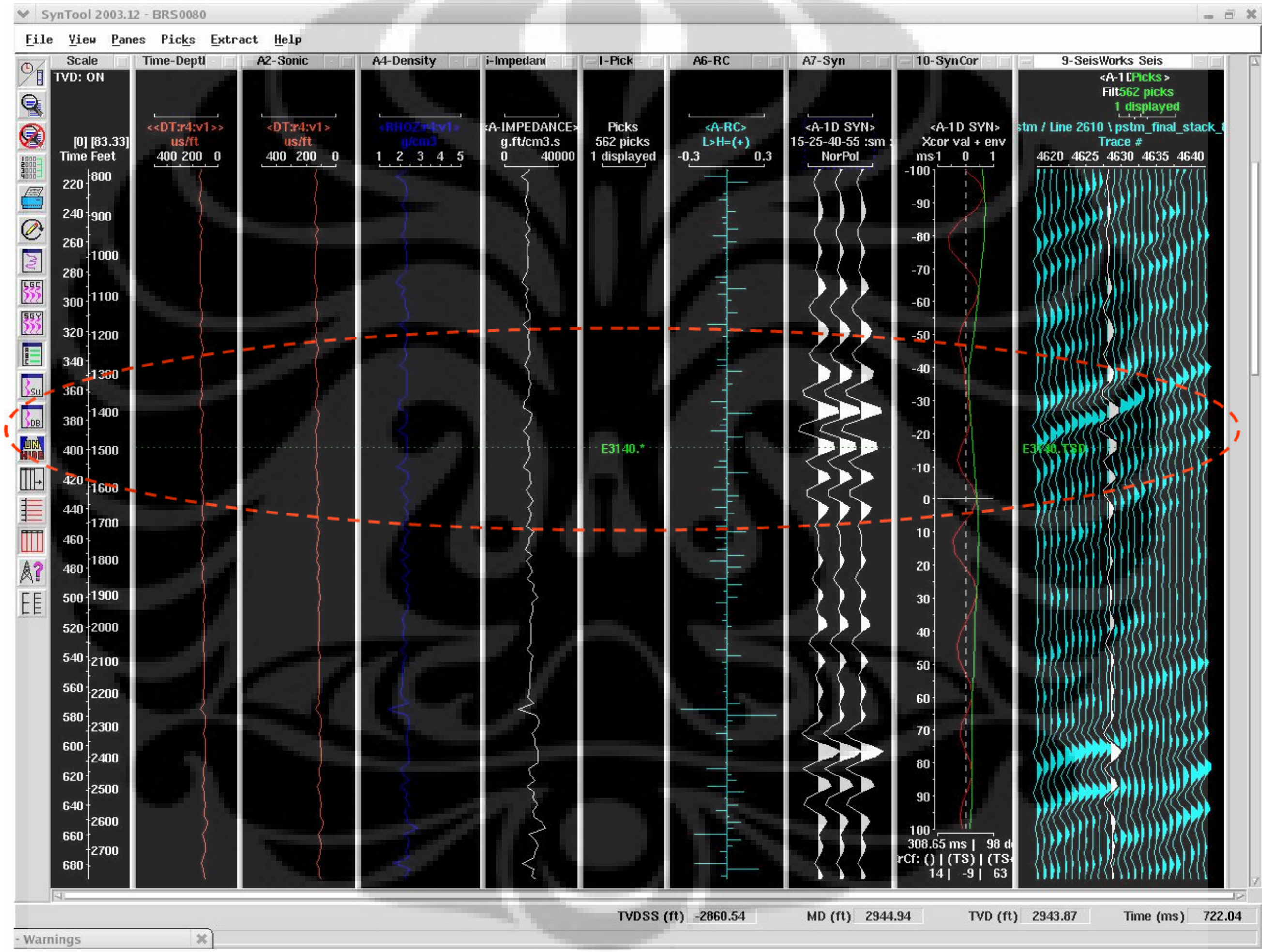


Figure 4.1 Synthetic seismogram from SLB-8

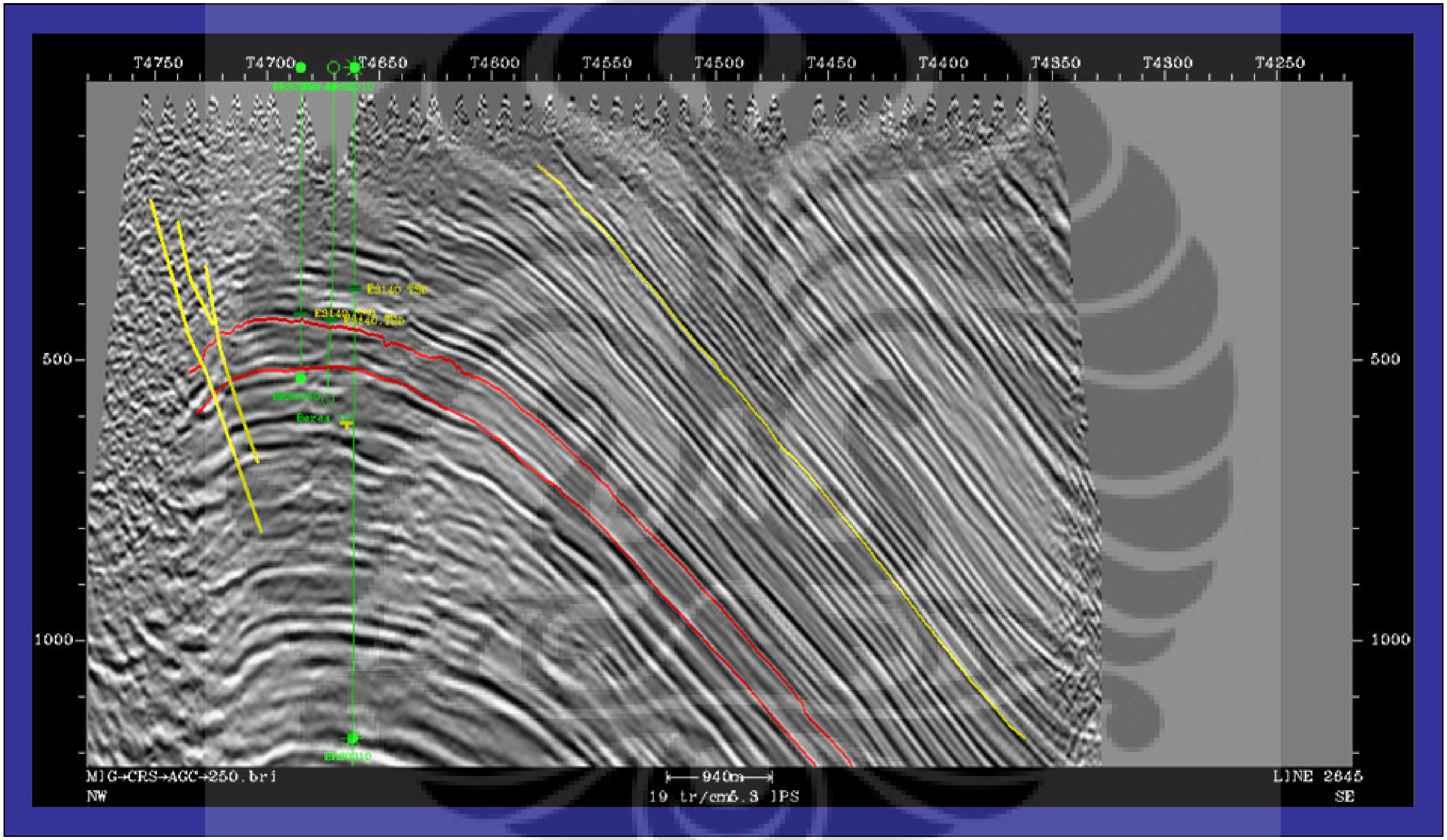


Figure 4.2. Seismic line 2645

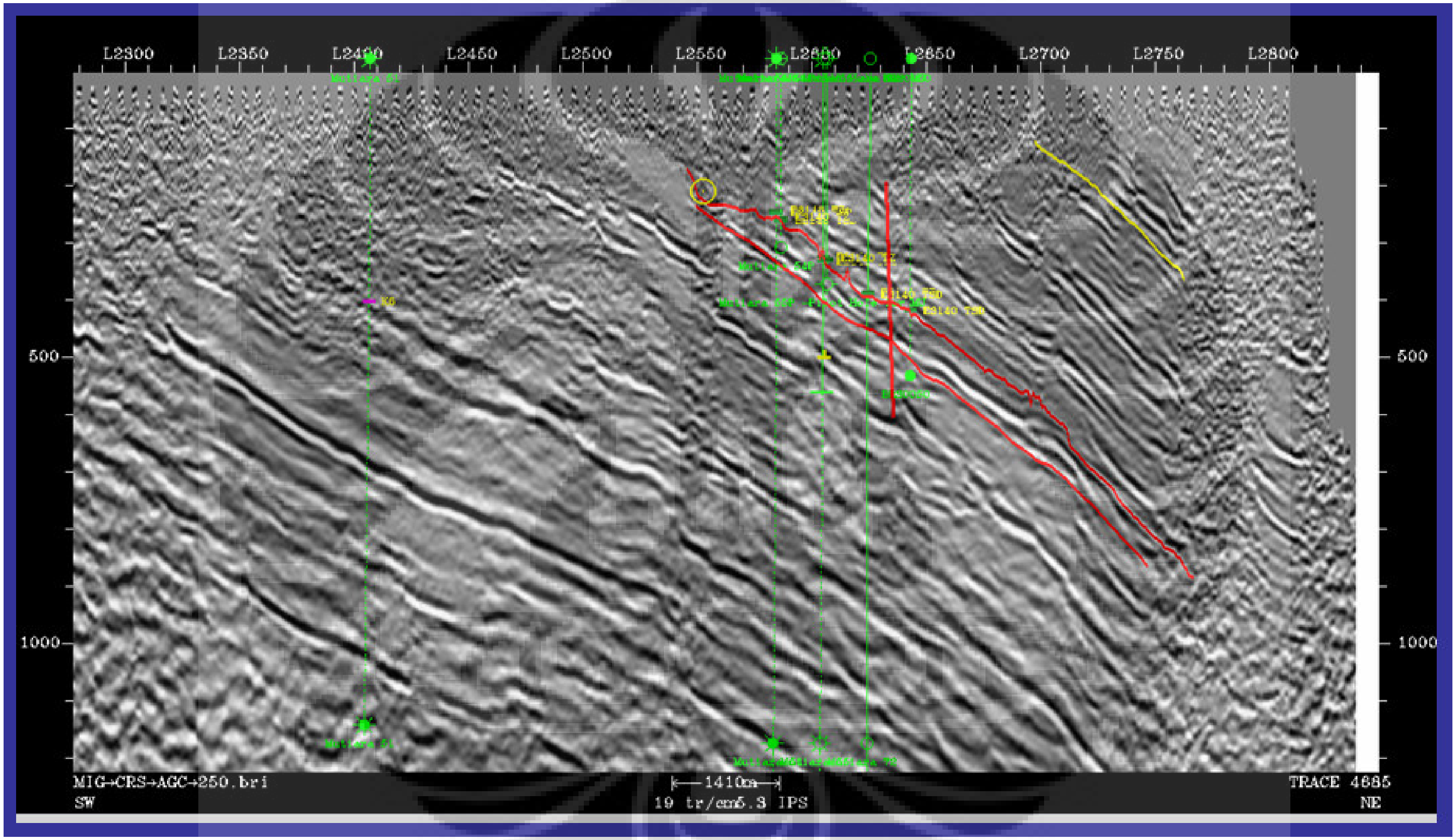


Figure 4.3 Seismic trace 4685

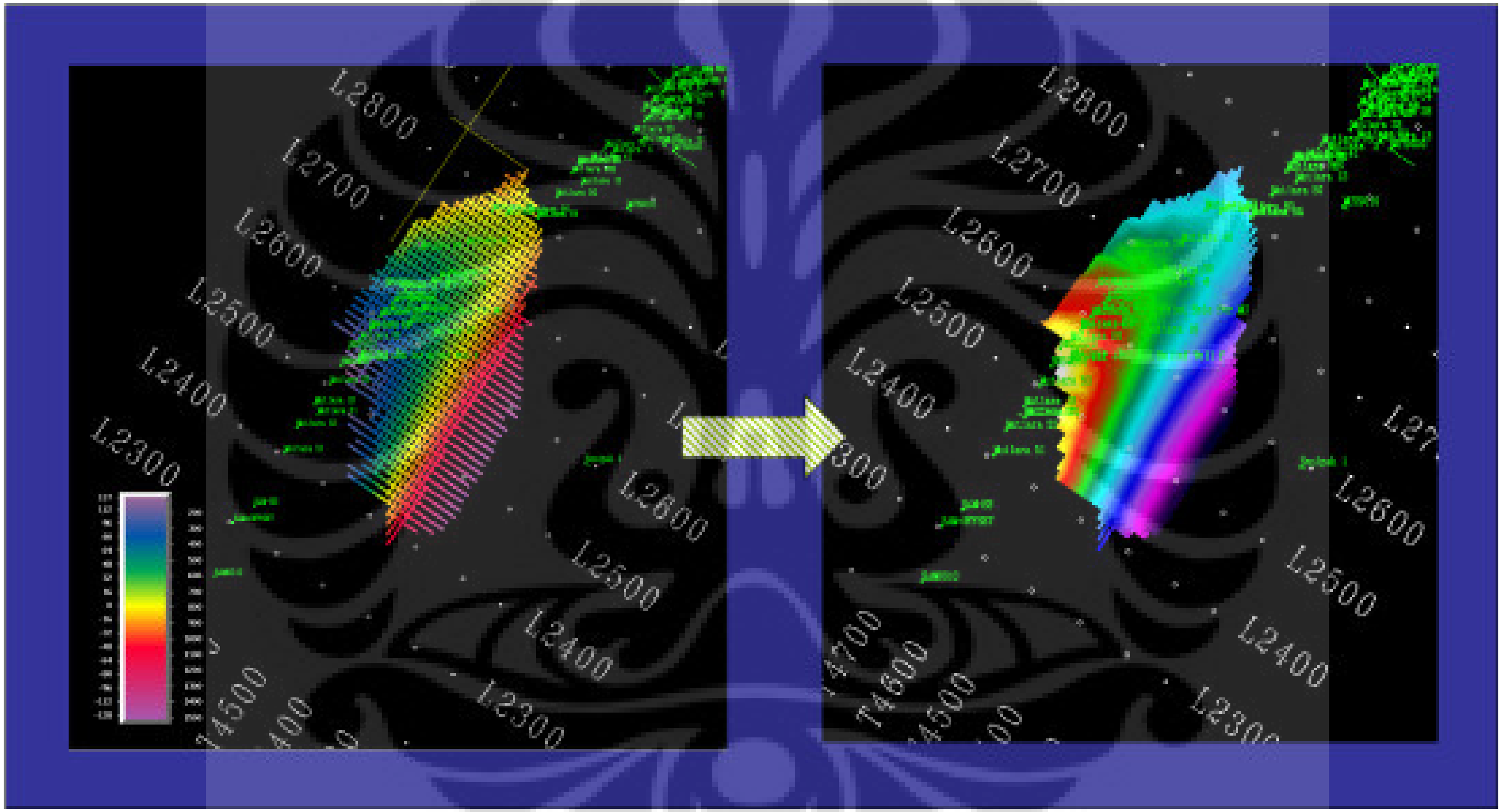


Figure 4.4 Structural map of E sand interpretation

4.1.3 Fault Interpretation

Faults were recognized from seismic section by distinct discontinuity or abrupt jump of seismic reflection. Since the current data not really enough to have a good fault interpretation, then the existing fault data will be used as a guidance for fault modeling in petrel.

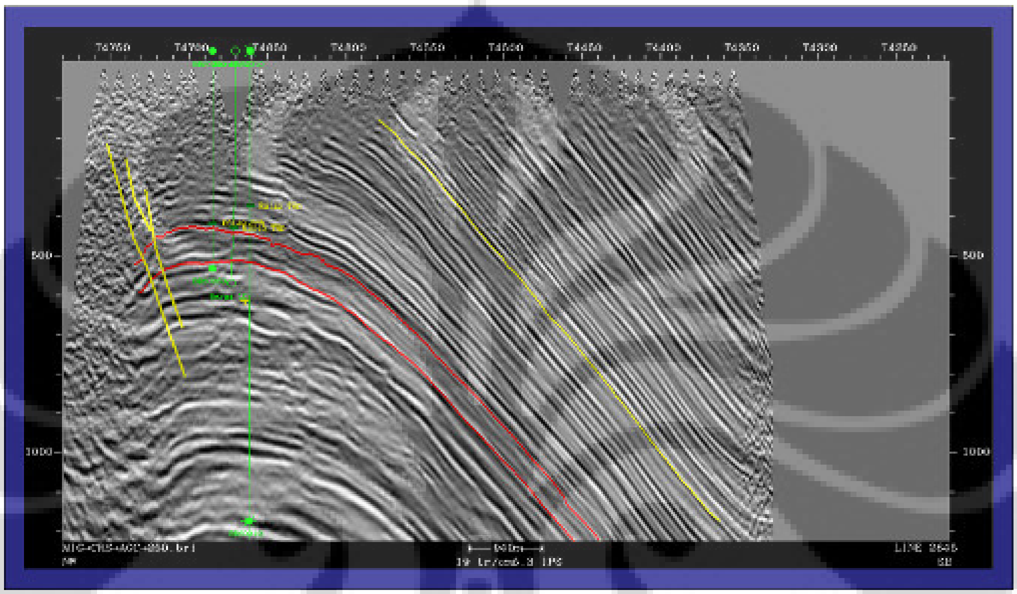


Figure 4.5. Fault interpretation develop in the southern area (Angus, 2006)

Fault system has been interpreted as a minor fault develop in the southern Salemba area. The fault indication could not be clearly identified in the project area since it has a limited data.

4.1.4 SEISMIC ATTRIBUTES GENERATION

RMS amplitude will be used as a guidance for facies modeling in the Petrel. Several RMS amplitude maps with different window size were created for each horizon. The initial purposes in creating the amplitude map was for knowing the distribution of high and low amplitude distribution around each horizon and try to find any special features in the study area, such as channel, that can be used as an additional information in the further facies modeling process.

The RMS amplitude extraction process was done by using StratAmp application of Landmark. Input used for this process was the interpreted seismic horizon that was already been interpolated. Window used for this process were 0 ms and 5 ms above and below each horizon.

The RMS amplitude of the E sand has an ambiguity for the interpretation since the existing seismic data has a low quality for interpretation and make the interpretation ambiguous. Amplitude only shows contrast, cannot be related to the lithology (sand) distribution due to high influences of coal.

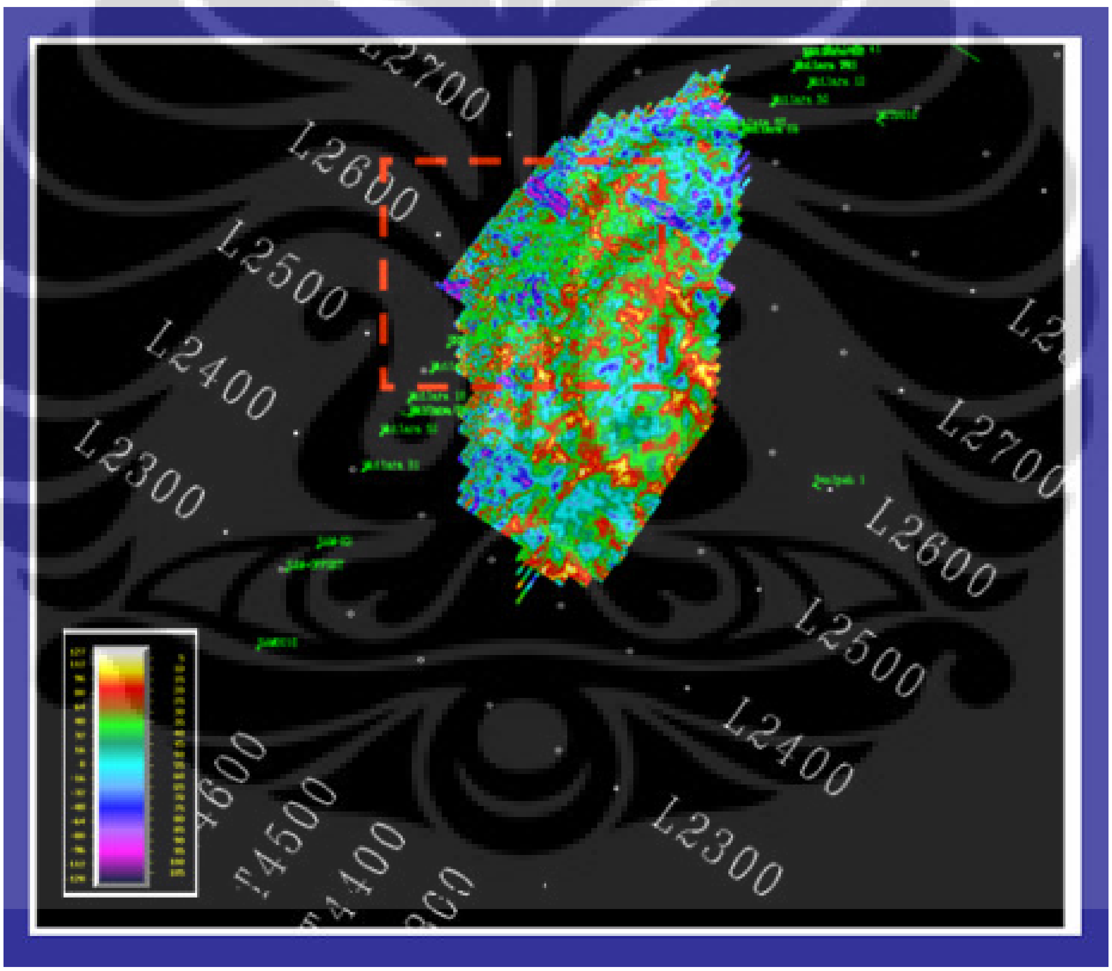


Figure 4.6. RMS amplitude map of E sand

From the picture above, it can be seen that sand can not be identified clearly as it is influenced by the high amplitude from the coal. In the delta area, most likely sand are deposited as a laminated sand, with variable thickness ranging from 5 to 55 feet. And sometimes coal developed thicker than the sand. Amplitude reading in this area needs a tuning thickness of more than 60 feet to be read in the seismic line. As the sand is usually bounded by the thicker coal, then seismic reading will be dominated rather than the sand itself. Absolutely it will make a confusion while interpreted the attribute seismic generation. It becomes one of the reasons, in this area sand resulted as a high amplitude reading.

Seismic attributes used to guide the facies modeling also can cause errors. It is possible that the wrong attribute was used, which does not relate to the geology. Therefore, the probability analysis that generated based on relation of seismic attribute and well data will lead to incorrect facies model.

.2 Geological Interpretation

4.2.1 Core Analysis

Based on the core data taken in SLB-3, SLB-4 and SLB-8 wells as previously mentioned that most of the E sand facies indicate a fluvial deltaic channel with crevasse splay environment.

The sandstone at the base of core includes a mix assemblage of sedimentary structures including evidence of both non-marine and marine environments. The coal overlying argillaceous unit appears to be in situ (a probable rootlet is identified in the argillaceous horizon underneath) indicating a period of exposure in a non marine or marginal marine.

From the core in SLB-3 wells, it was interpreted that the sand as Fluvial/Deltaic Channel Sand : multi story, well stratified (cross-bedded and ripple-bedded) to locally massive-appearing; traction-current deposition, with extensive syn-sedimentary fluidization. Sand has a good thickness with stratified sand and shale break in between.

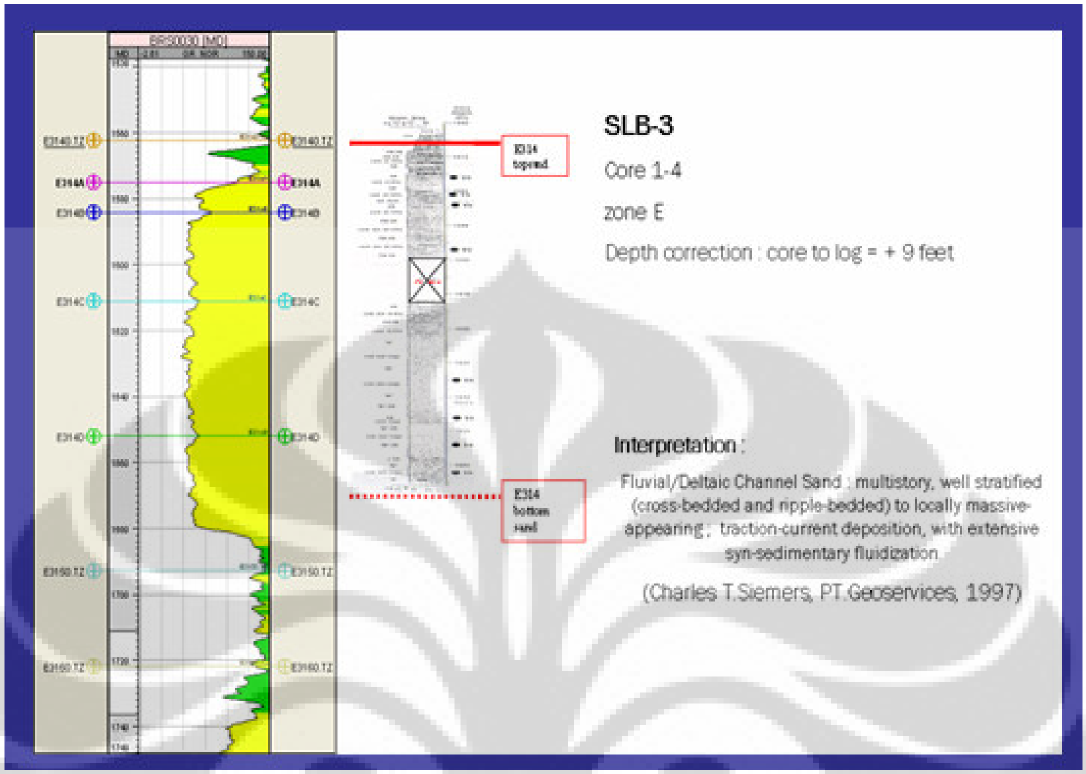


Figure 4.7. E sand core analysis from SLB-3 well

4.2.2 Well Logs data correlation

Some items should be highlighted in the processes of converting 2D map into 3D geological model to obtain the best estimate for IOIP and to run dynamic modeling. The basic reservoir shape and orientation did not change appreciably from the previous interpretation. It depicted a 2-1/2 km wide sand body crossing the structure at a slightly oblique angle to plunge, then bifurcating with one axis paralleling the structural plunge to the northeast and a second axis continuing due east. The reservoir thickness follows a slightly curved northwest-southeast trend through SLB-3, SLB-5, SLB-10, SLB-1, SLB-9 & SLB-4 well respectively.

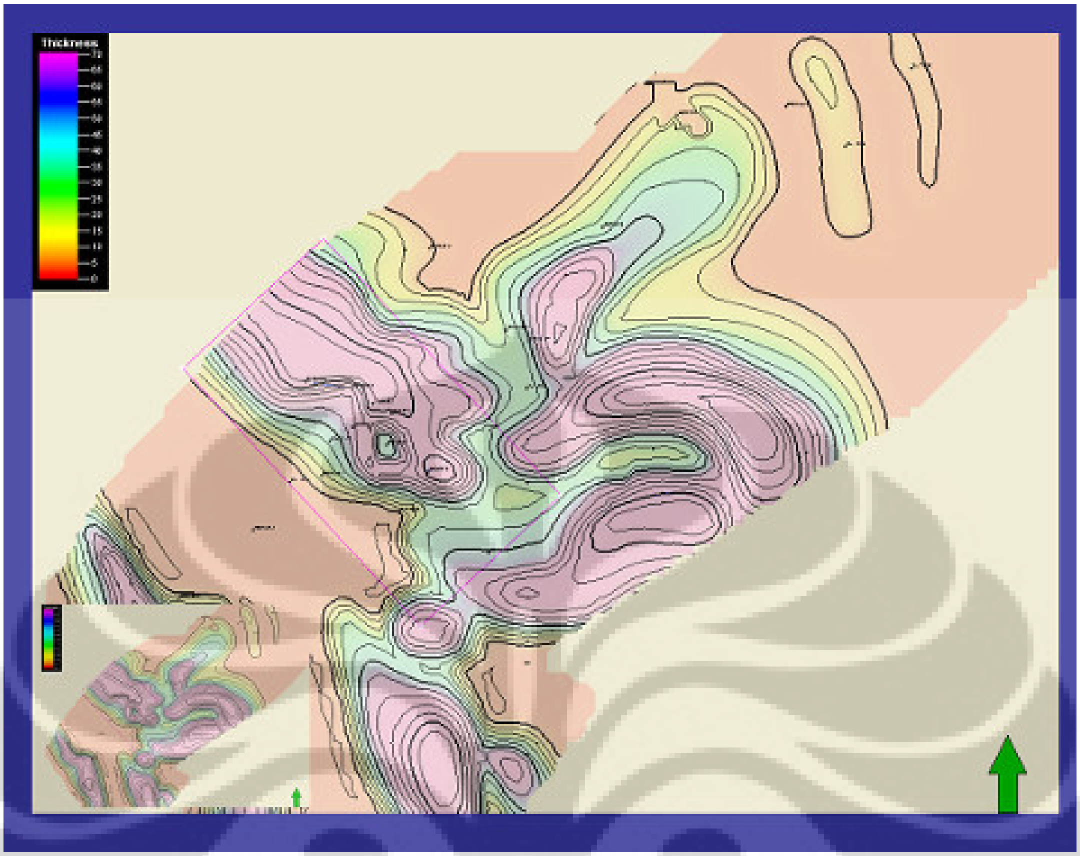


Figure 4.8. Exis ting E-sand map (netsand map)

Detailed correlation splits E-sand into four zones A, B , C, and D from top to bottom and left E sand as only one single zone. Vico has developed top structure and gross thickness maps for each zones. In sme areas/wells, one or more zones were missing (pinching out)

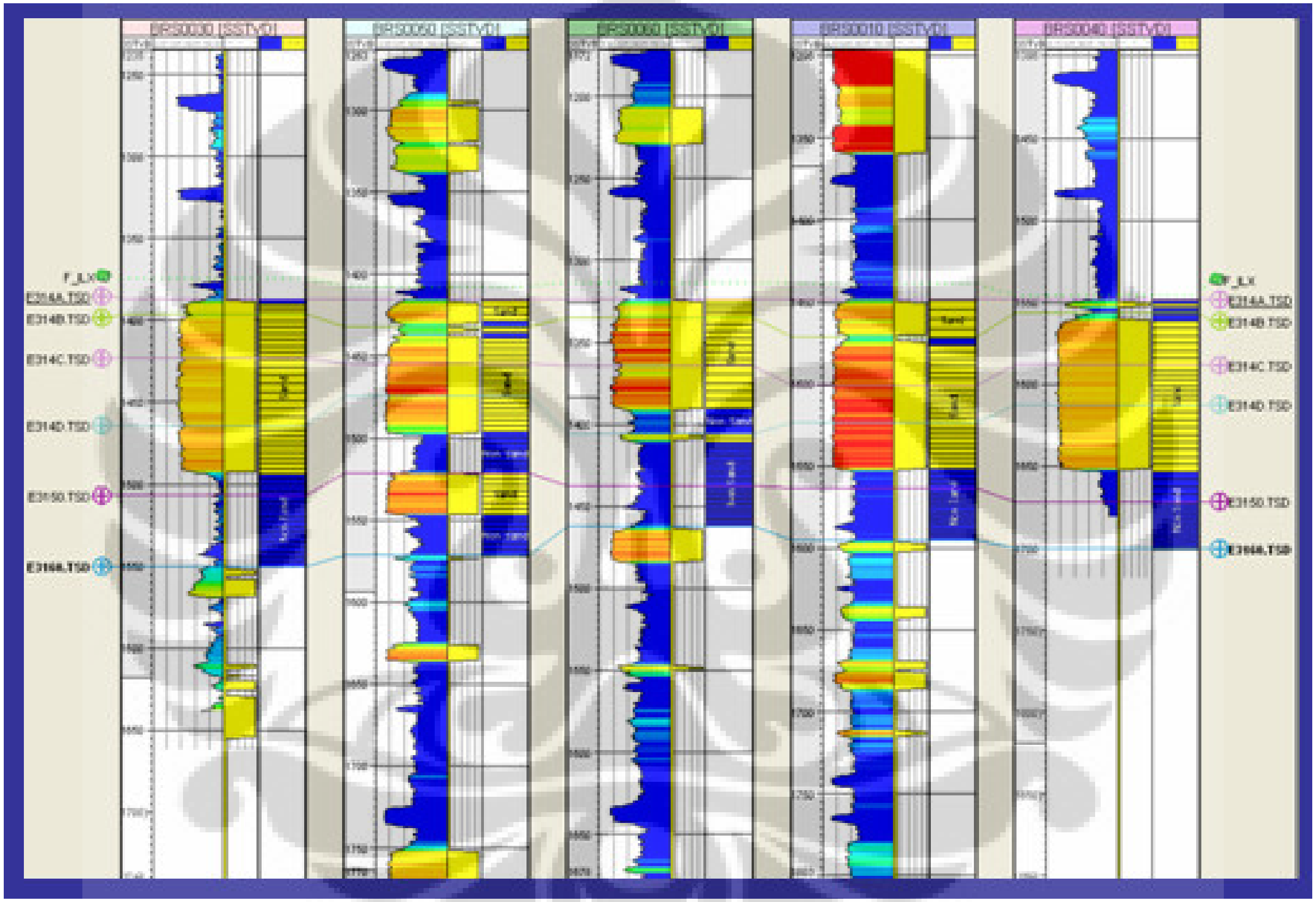


Figure 4.9. E-sand Correlation

The existing 3D grid produced by Schlumberger in 2002 was used as reference to build a new 3D grid with same grid size and amount and simplified structures. For comparison with reloaded Schlumberger's grid. The reservoir boundary was based on the zero net pay isopach of the total net sand thickness map (all zones lumped together).

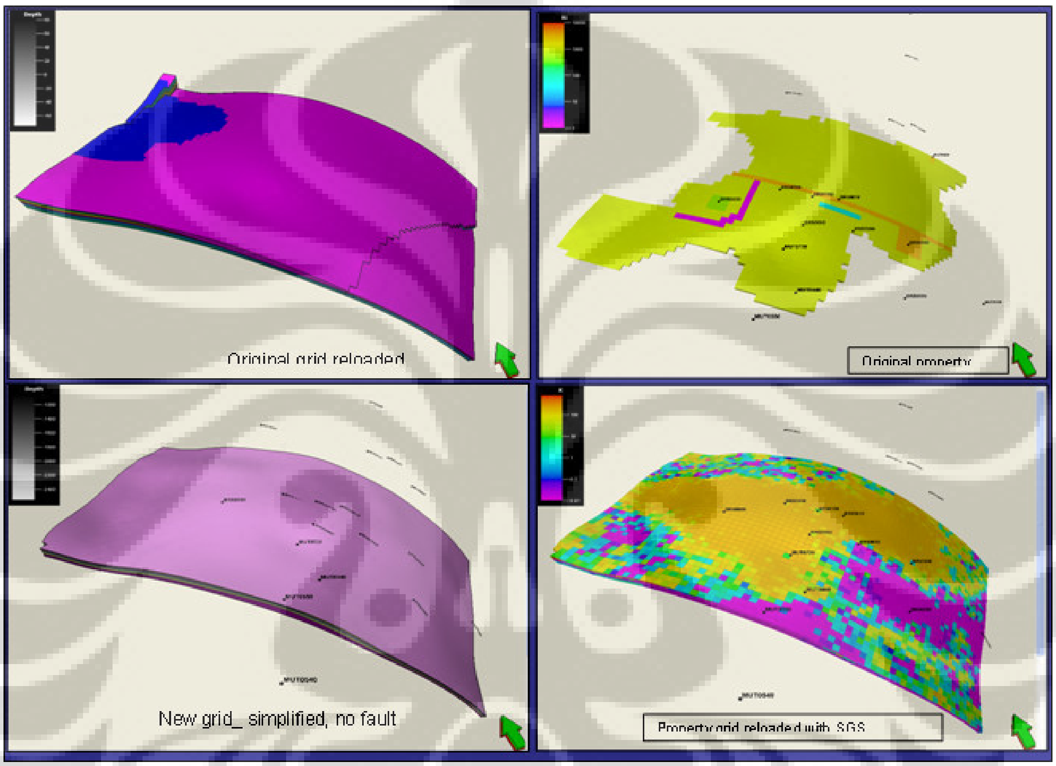


Figure 4.10. Comparison with reloaded Schlumberger's and Vico grid

Original gas-oil contact (GOC) and oil water contact (OWC) were estimated at -1340 TVDSS and -1575 TVDSS. These data were taken from the previous simulation study because the earliest GOC and OWC interpreted by Vico geologist were obtained from the wells that were drilled after two years of production.

4.3 Petrophysical Interpretation

Most properties such as PIGN, KINT and Netsand log were ready to import to Petrel. E-sand used a Sequential Gaussian Simulation where the distribution method of petrophysical model with normal distribution using mean around 0.26, standar deviation 0.0 - 3. Petrophysical method would include the porosity, permeability and saturation model

4.3.1 V-Shale Analysis

Fundamental understanding ELANPlus response equations is the knowledge and the concept of wet versus dry clay. ElanPlus logic makes uses of the Dual Water Model formulation for clay where wet clays are composed of dry clay and associated (bound water)

For a sand-shale sequence, a commonly used equation for volume of clay from GR log is :

$$\text{Volume of Clay} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}}$$

Where GRmin and GR max are picked from the logs in a clean sand a good shale, respectively. From this analysis it can be define that E sand contains mostly of quart 60%, Ilite 18%, smectite 15%. For Salemba field we used v-clay cut off about 27 %.

4.3.2 Porosity Analysis

Total porosity can be defined from density log and neutron log, calibrated with the total porosity form each core data. For Salemba Field use some cut off to define the effective porosity (ø_e) cut off as below :

a. If $TVDSS \leq 1000$, then $f\ (TVDSS) = 0.165$

b. If $1000 < TVDSS < 5000$, then $f\ (TVDSS) = 0.19 - 2.5*10^{-5} * TVDSS$

c. If $TVDSS \geq 5000$, then $f\ (TVDSS) = 0.065$

4.3.3 Permeability Derivation

A lot of permeability calculations were used to define the permeability value using the formula as below

PermExp

= $4.4+ +3.0 \log_{10}(\mathrm{PHIT})-2.0 \log_{10}(1.0-\mathrm{PHIT})$

Where,

WghtPerm : Weight permeability

PHIT : Total porosity.

4.3.4 SW Calculation

Water saturation calculation used in the petrophysical analysis is Dual Water model, because the E sand reservoir contain shale (V-shale) which can absorb the bound water and the remain as free water. Correction need to be applied to have an initial water saturation for each well before drained.

For Salemba field, water saturation cut off value are :

a. If $ø \leq 0.10$ then $f(ø_e) = 0.75$

b. If $ø < ø_e < 0.25$ then $f(ø_e) = 0.85$

c. If $ø \geq 0.25$ then $f(ø_e) = 0.60$

Table 4.1. Petrophysical result of E sand from ELAN Plus , Salemba Field

Well	Type	TSD	BSD	VCLNet	NetSnd	NetPay	PorPay	SWPay	KPay	KHPay	GOCMD	OWCMD	GOCSS	OWCSS
SLB1	G	1683	1788	0.04	99	94	0.33	0.17	2192	204971				
SLB3	G	1575	1681	0.03	105	102	0.30	0.23	1356	137650				
SLB4	OW	1780	1884	0.07	96	21	0.31	0.29	919	19308.4		1815		1583
SLB5	G	1598	1681	0.07	76	73	0.30	0.18	1161	84155.4				
SLB6	GO	1511	1598	0.10	70	70	0.31	0.14	769	53436.6	1555		1366	
SLB9	G	1564	1595	0.11	23	23	0.29	0.19	500	11620.3				
SLB10	GOW	1600	1750	0.09	108	107	0.29	0.11	524	56104.6	1616	1742	1427	1531
MTM72	G	1424	1499	0.07	69	64	0.28	0.15	607	38848.5				

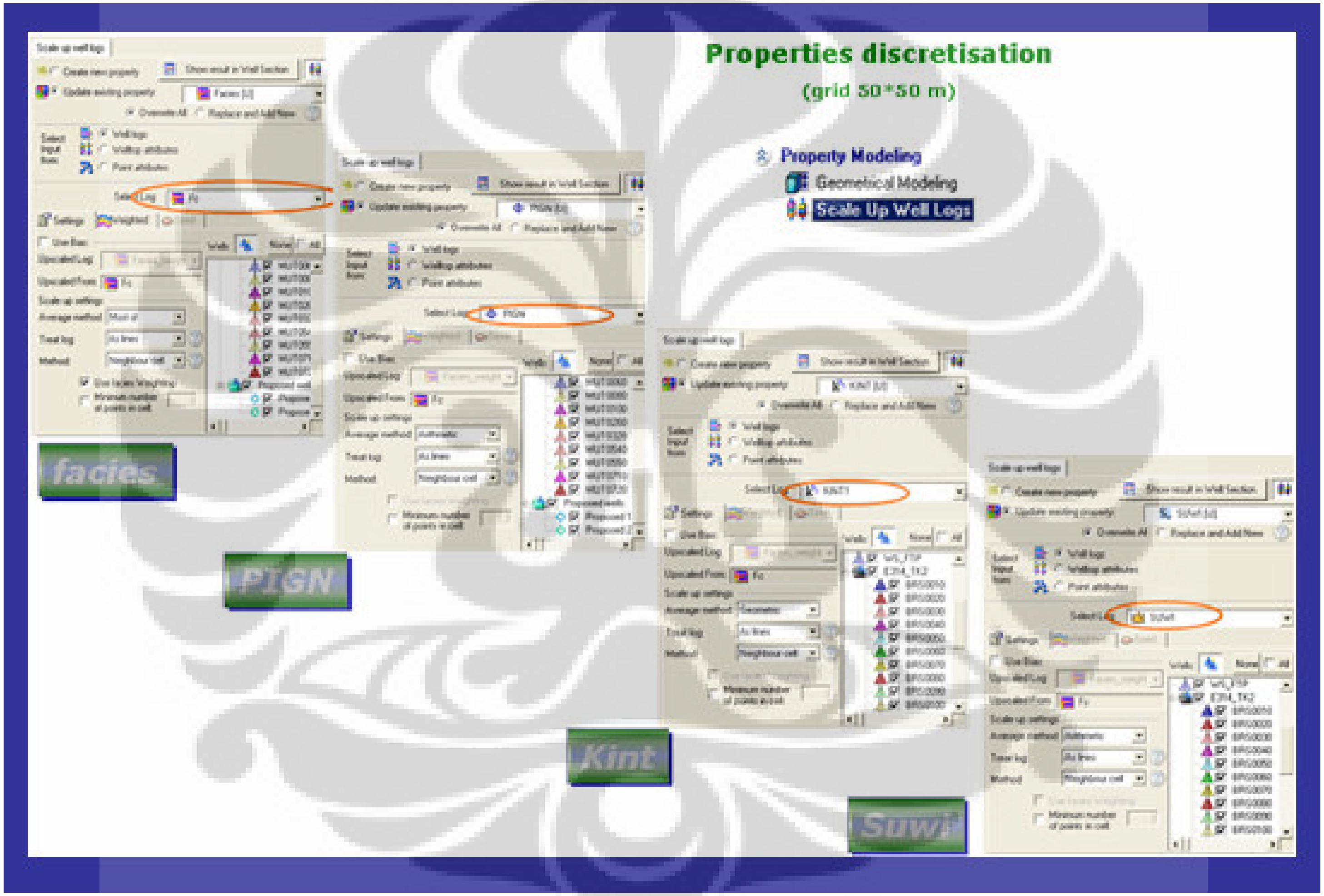


Figure 4.11 Reservoir properties discretisation

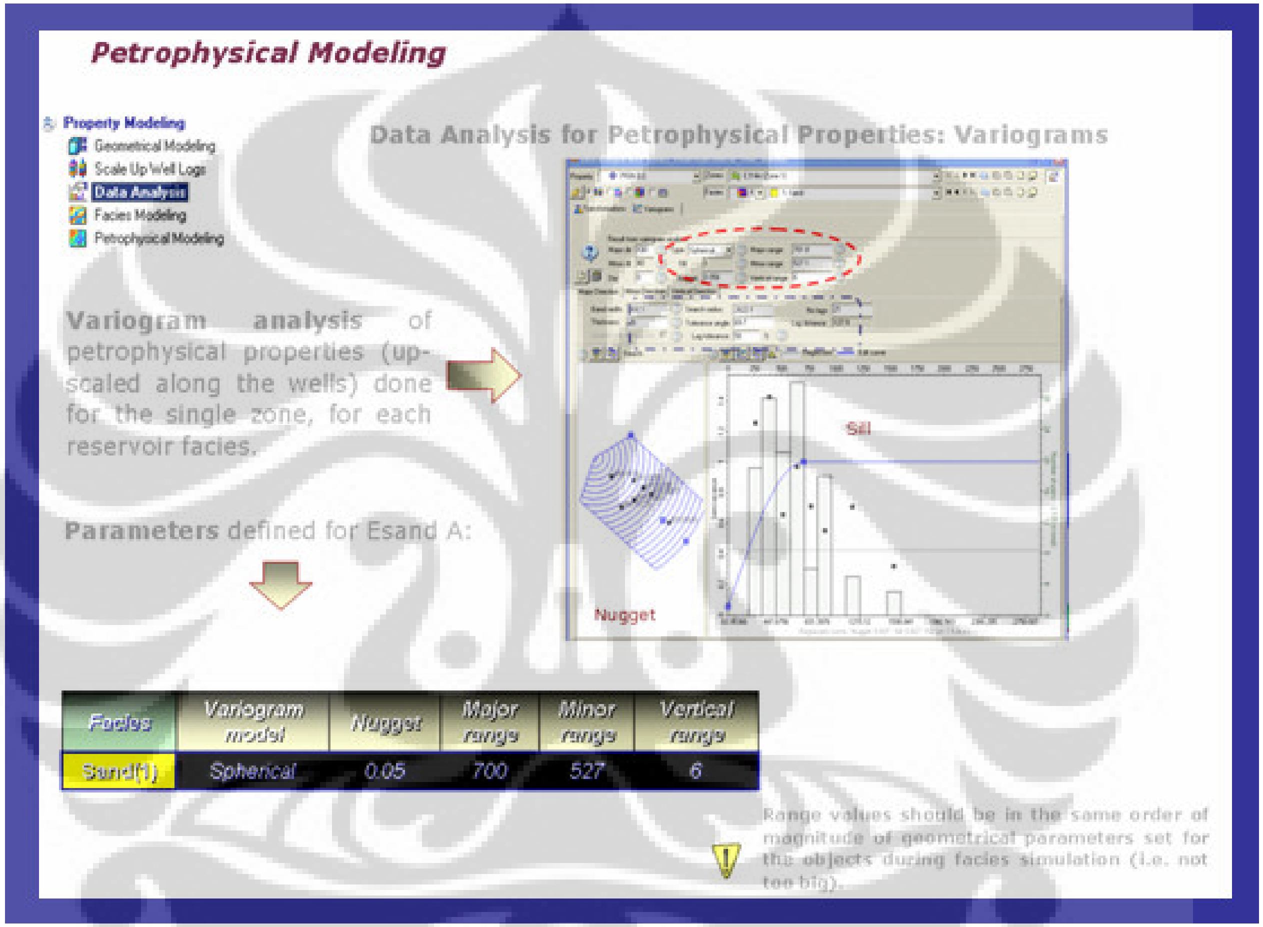


Figure 4.12 Petrophysic modeling of E-sand

Variogram analysis of petrophysical properties was (after up-scaled along the wells) done for single zone for each reservoir then can most likely reservoir facies can be defined using the same parameter of spherical variogram model with nugget about 0.05, major range 700, minor range 527 and vertical range 6.

All parameter then were applied to all the petrophysical properties which include facies type, porosity, permeability, and water saturation. After trial and error process was done to get the best result, then it can be mapped with map distribution for each property on its layer.

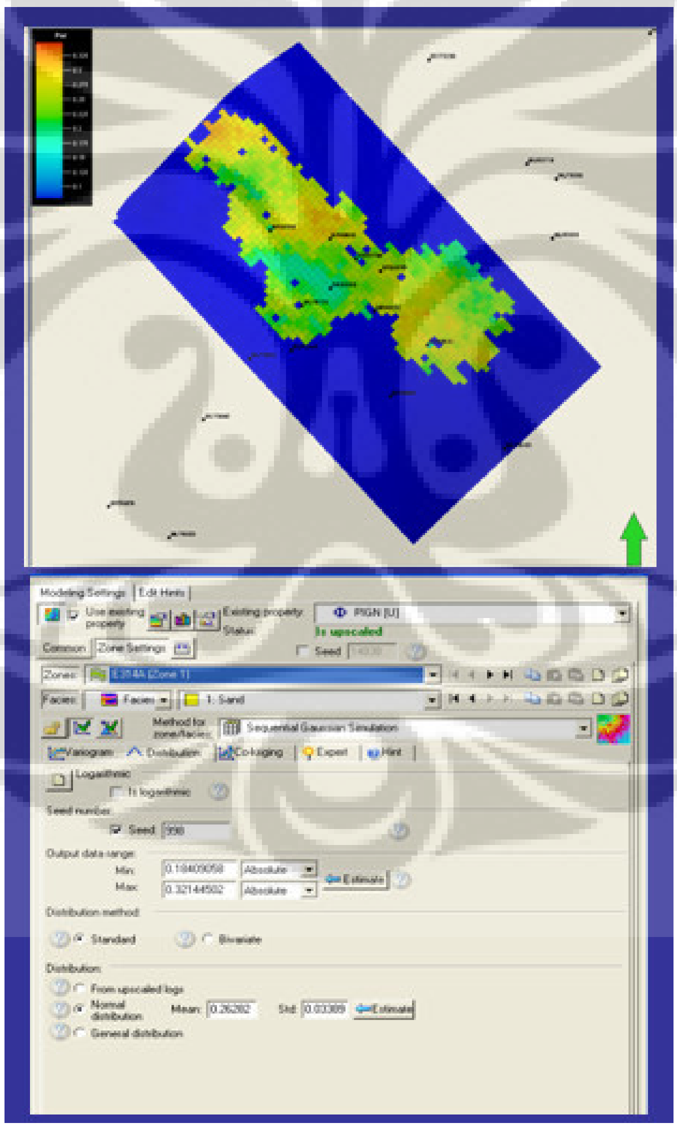
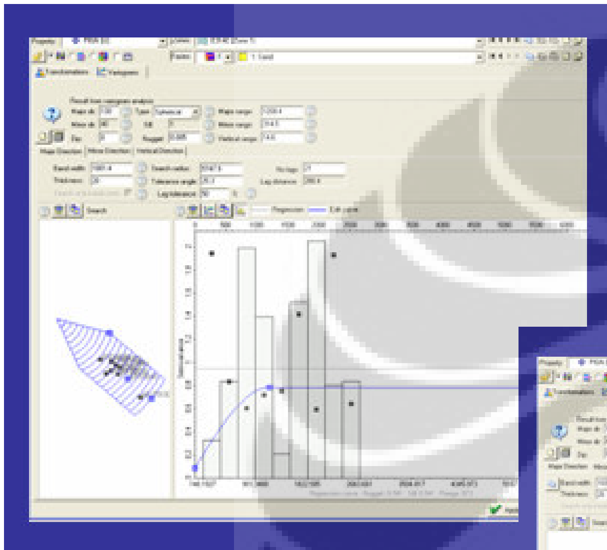
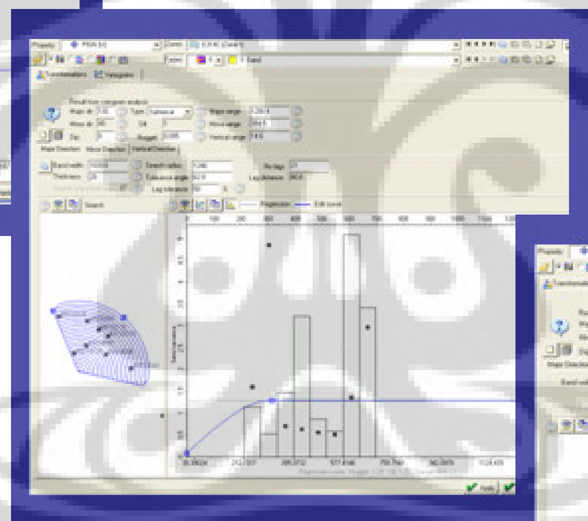


Figure 4.13 Simulation of Porosity layer distribution on Petrel





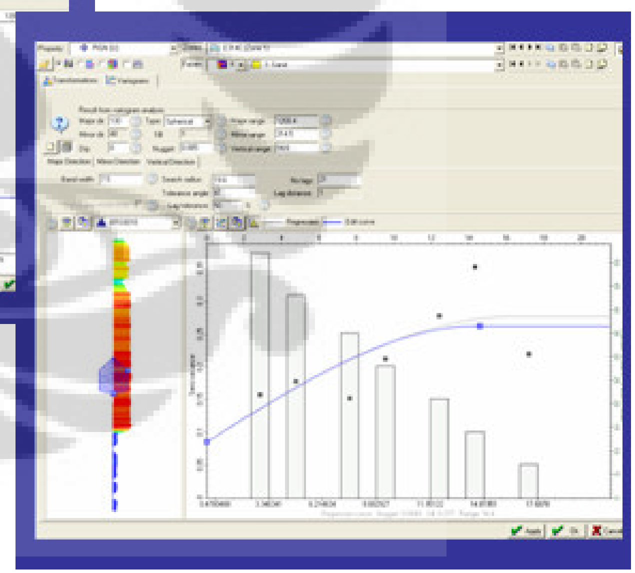


Figure 4.14 Variogram model for porosity simulation on Petrel

4.4 Structural Modeling

The structural modeling has been done directly on Petrel, by importing existing VICO Top Sand structural maps, calibrated picks, especially in SLB-8 well. This modeling process has been performed on the entire study interval for a total of 5 zones. Zone simulations (petrophysical properties areal distribution) have been carried out through geo-statistical algorithms on 5 zones. The fine 3D grid (50x50m grid-sized) has been populated by the geological properties (netsand, porosity, permeability and Sw) using some geostatistical algorithms available in Petrel.

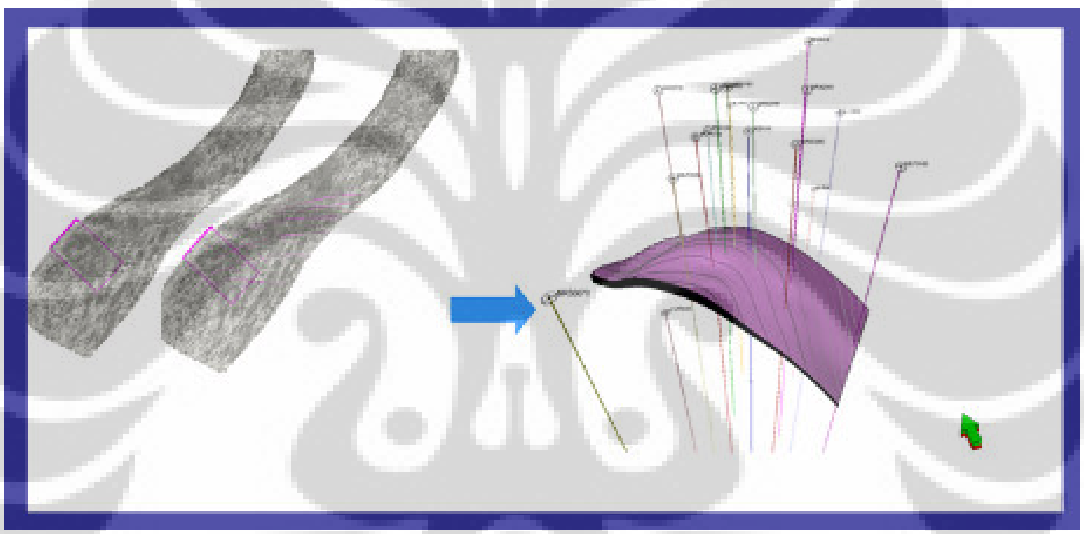


Figure 4.15 Structural map of E sand on Petrel (2006)

From the structural map defined in Petrel, it can clearly be seen the most of the wells are located in the anticline. The field is having a long and big anticline bounded by the fault in the western area and also fault in the eastern area.

4.5 FACIES MODELING

The facies models basically show some cyclic pattern of increasing and decreasing of sands content. The E sand has been divided into five sections which are zone A, B, C, D and E as can be seen in the previous detail correlation above.Each layer will be identified for its own multi realization then overlaid each other to get the best figure that reflected the original condition

4.5.1 Netsand (Net/Gross Distribution)

VICO has established a netsand log curves to define reservoir and non-reservoir lithologies. The cutoff is derived as function of Vclay, Vshale and Por. The netsand 3D distribution which also reflects the N/G ratio has been defined using a Sequential Gaussian Simulation and been constrained with the trend map. Trend maps are defined for each zones and reflects the probability of reservoir sand existence in the area.

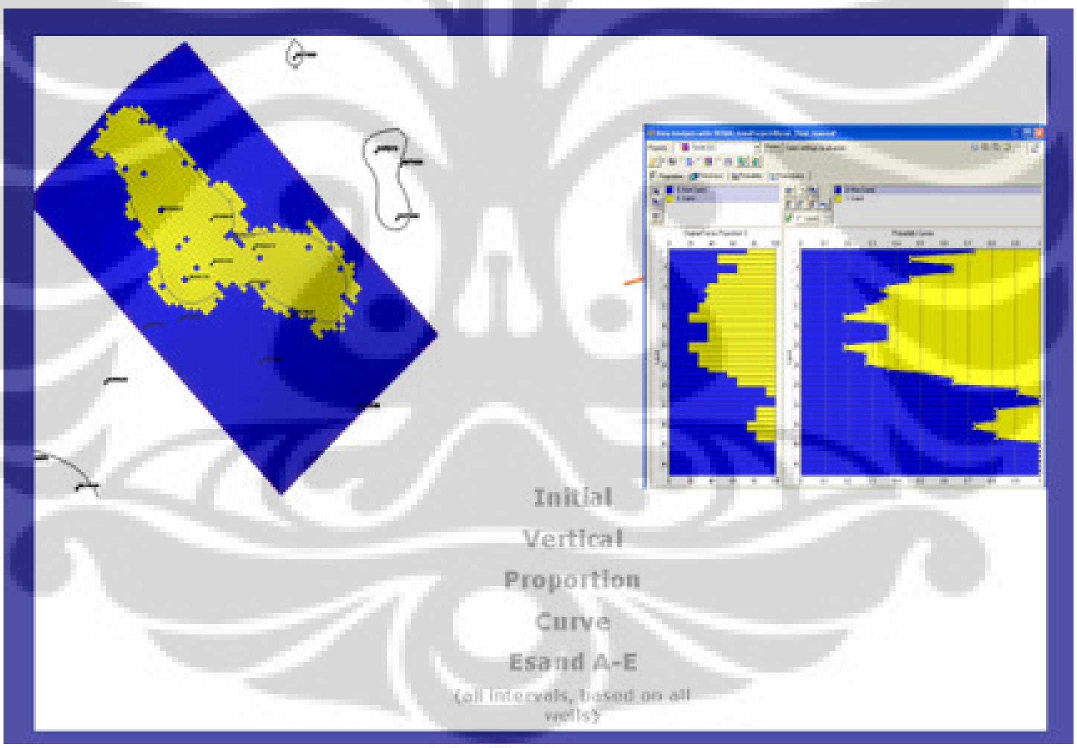


Figure 4.16 Initial vertical proportion curve of Esand form A-E

Each layer of E sand has been identified to find the comparison between the real netsand and gross sand. It has been done using all the existing data. It is very important step to have a good sand distribution developed in the area. From the result most likely sand distribution developed from the northwest to the southeast of area with variable netsand thickness.

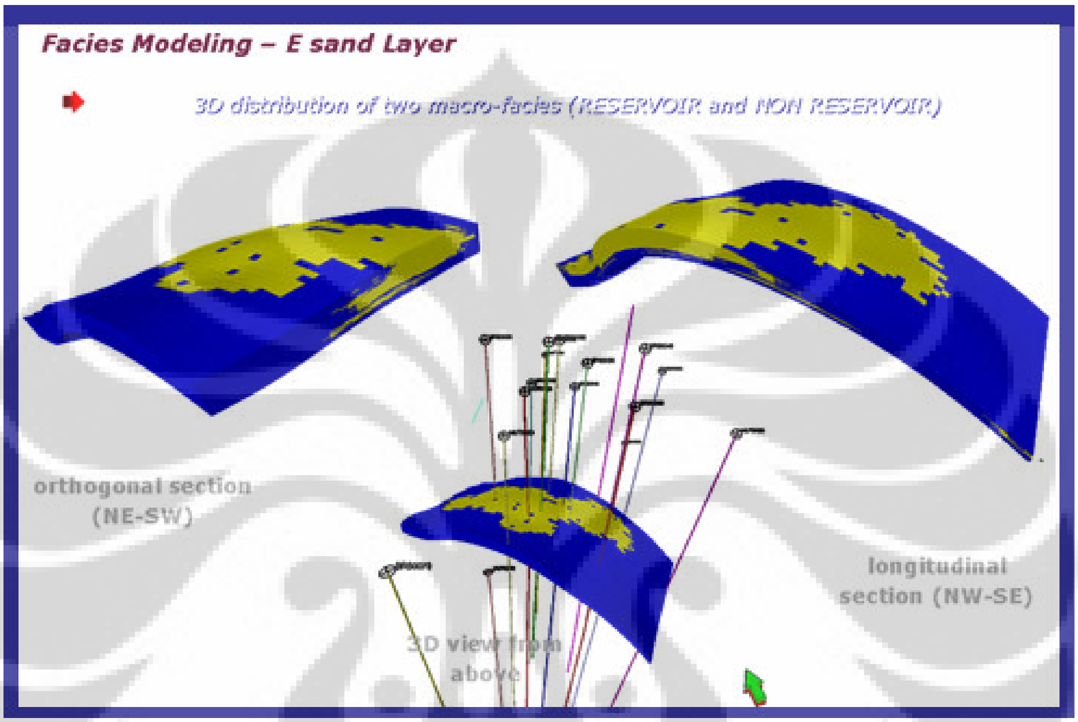


Figure 4.17 Facies Modeling of E-sand for all the layers

The E sand wich has 5 layers then can be defined into two macro facies, reservoir and non reservoir. In this case reservoir define as sand, and non reservoir as shale. From the figure above, wells are located most likely in the middle of sand reservoir which has thicker sand thickness. The variability of sand thickness has been calculated automatically by the Petrel using the same parameters.

Facies distribution after overlaid between each layer resulted the sand pattern with a good reservoir distribution.

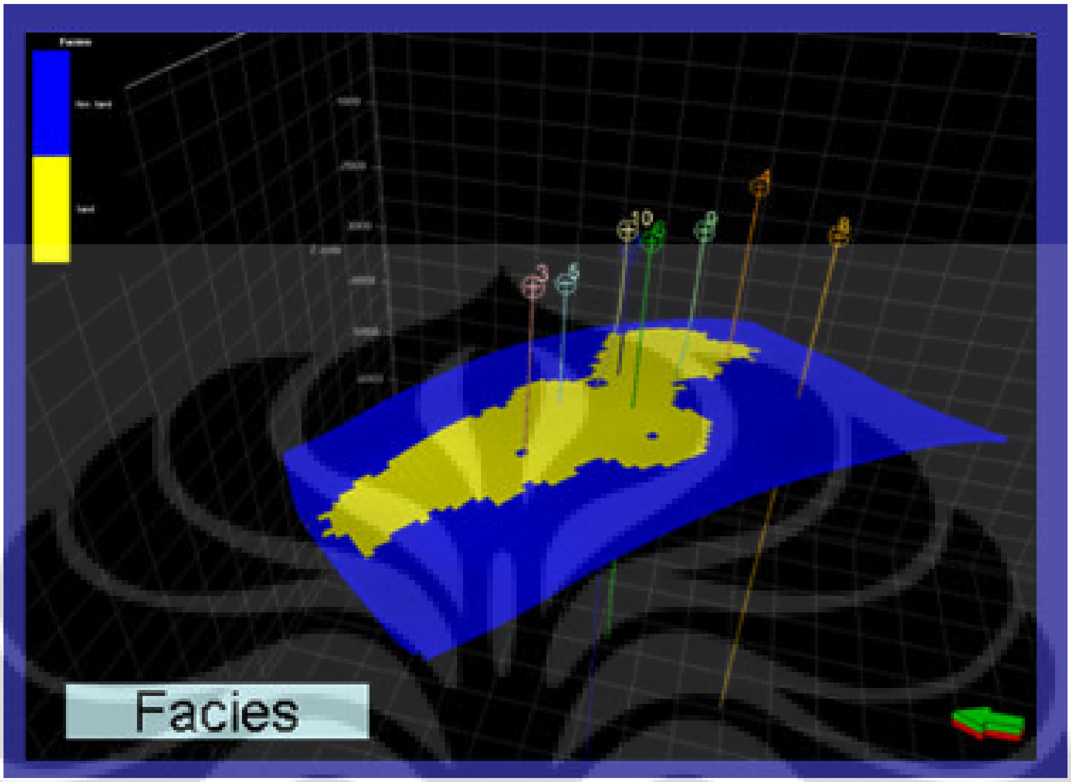


Figure 4.18 Facies model E-sand

4.5.2 Porosity & Permeability Model

Porosity distribution has been defined using a Sequential Gaussian Simulation. In order to perform the simulation, porosity continuity ranges referred to the main spatial directions (major, minor, vertical direction) should be defined.

After setting these parameters, we can perform the porosity simulation. The result will be a 3D porosity property constrained to the Netsand or Net to Gross (N/G) distribution previously defined. The 3D porosity distribution is constrained to the N/G using a Collocated Co-Kriging technique.

Porosity map has been defined after some modeling using the same parameter as told before. After overlaid between each layer of E sand, the porosity distribution has variation distribution with interval range between 25% and 45 % porosity. The highest porosity value (red color) can be found in the western part of the area, the average number (green color) will be found in the middle of the sand. But even having the average number, the reservoir has shown good productivity

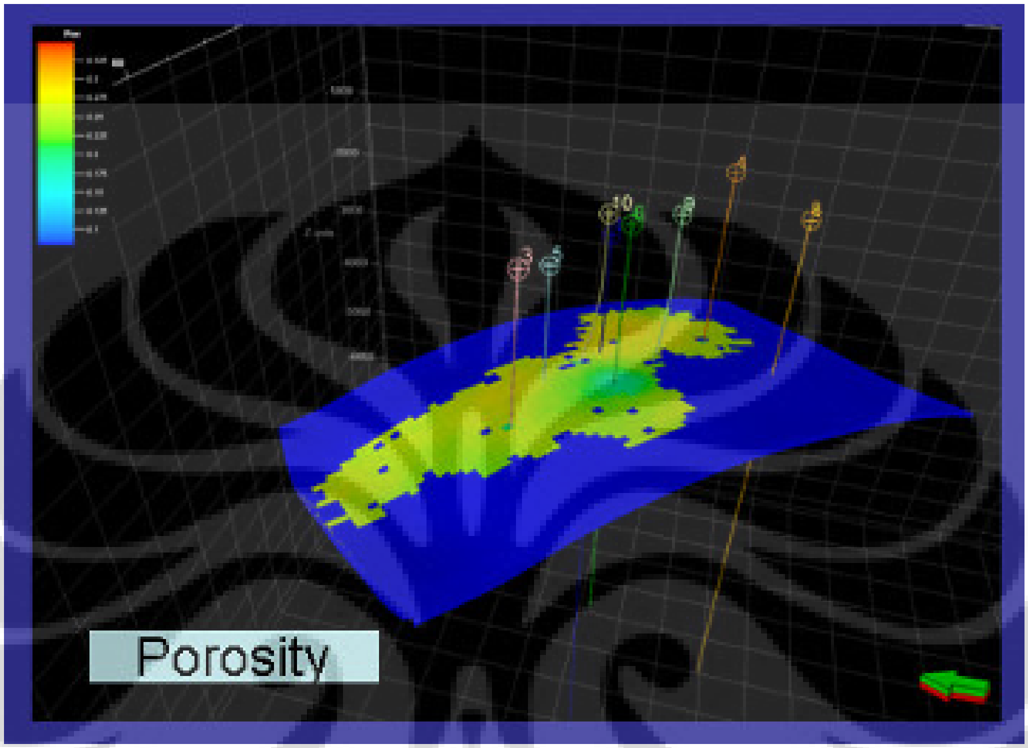


Figure 4.19 Porosity distribution for E-sand

The same simulation can be applied also for permeability calculation. Since the permeability will involve other parameters, the result of permeability will be more variable rather than the porosity.

After overlaid all the permeability distribution has variation ranges between 179 mD and 2192 mD. The highest permeability value (red color) can be found in the northwest and southeast where to the east direction average number permeability (green color) can be found in the middle of the sand. The permeability distribution will help us to define the sand which has good reservoir properties.

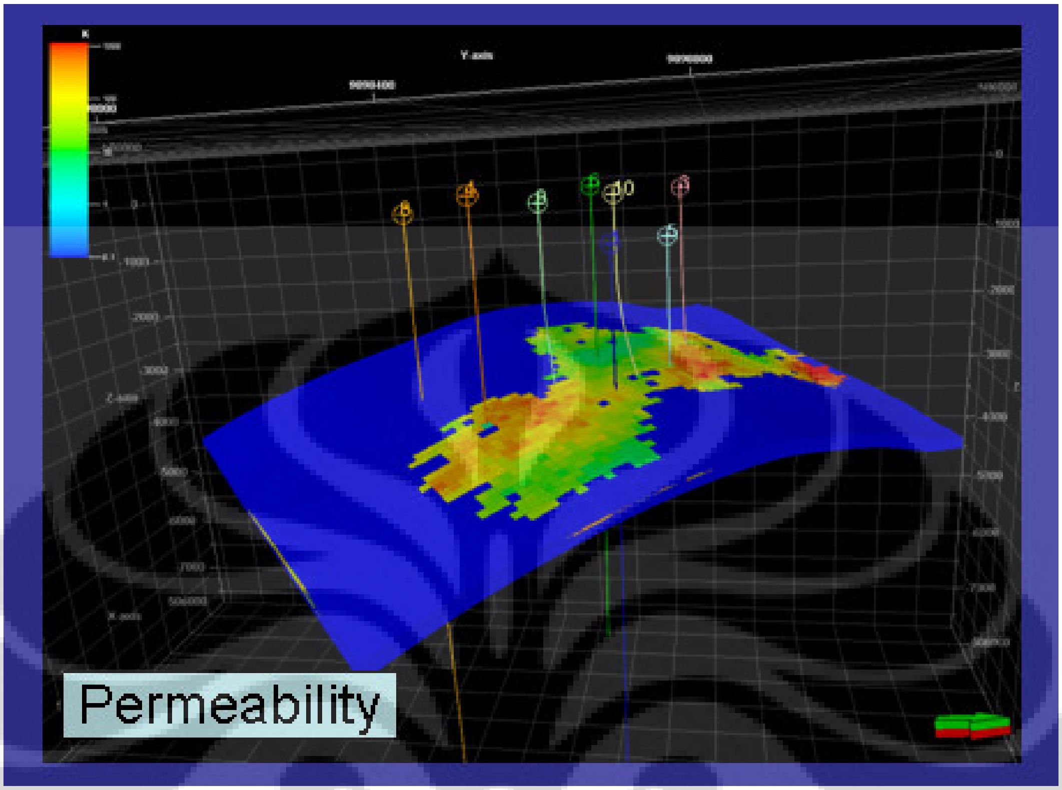


Figure 4.20 Permeability distribution for E-sand

4.3 Saturation Model

Even though saturation does not played as important as porosity and permeability, saturation distribution model will help to identify potential high water area. The most potential high water will be found in the eastern part shown by green color where the interval ranges between 42% and 50 % and the lowest saturation water is located in western.

After some properties modeling is done, all the results were overlaid for facies distribution, porosity, permeability and water saturation. There is some anomaly with red color where the best of facies and petrophysics properties will be located. The good area is in the middle of the reservoir zone.

But to have a better view between all the facies (all E layers: A, B, C, D and E) also the reservoir properties will be described in the multi-realizations.

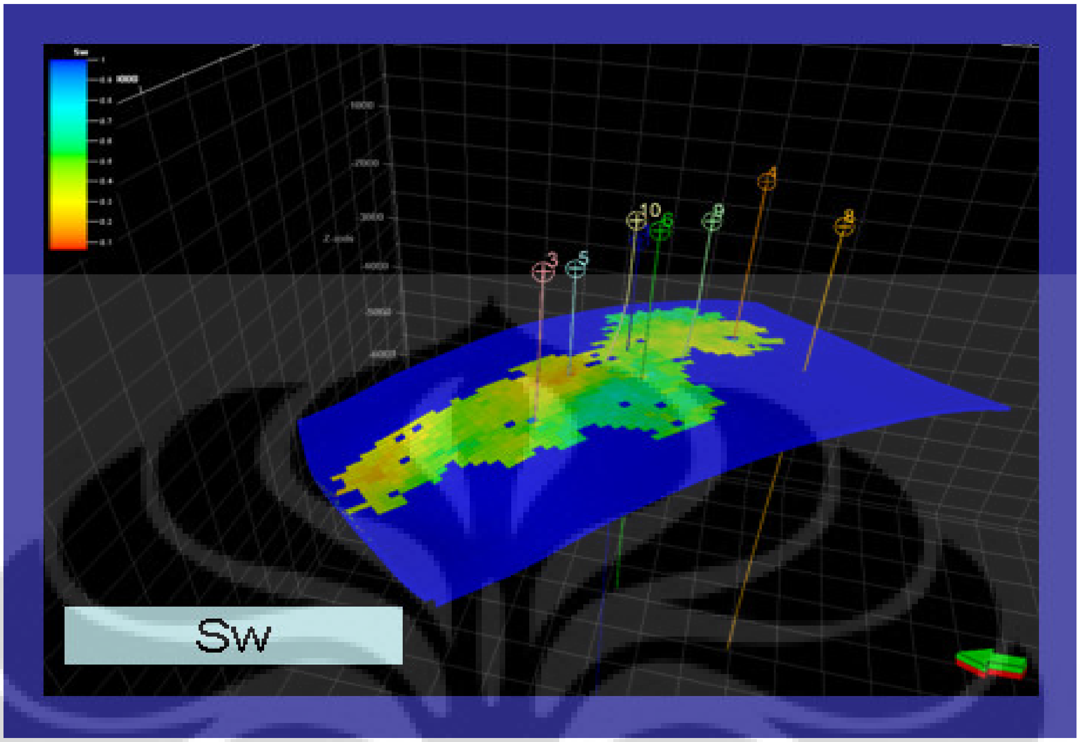


Figure 4.21 Water saturation distribution for E-and

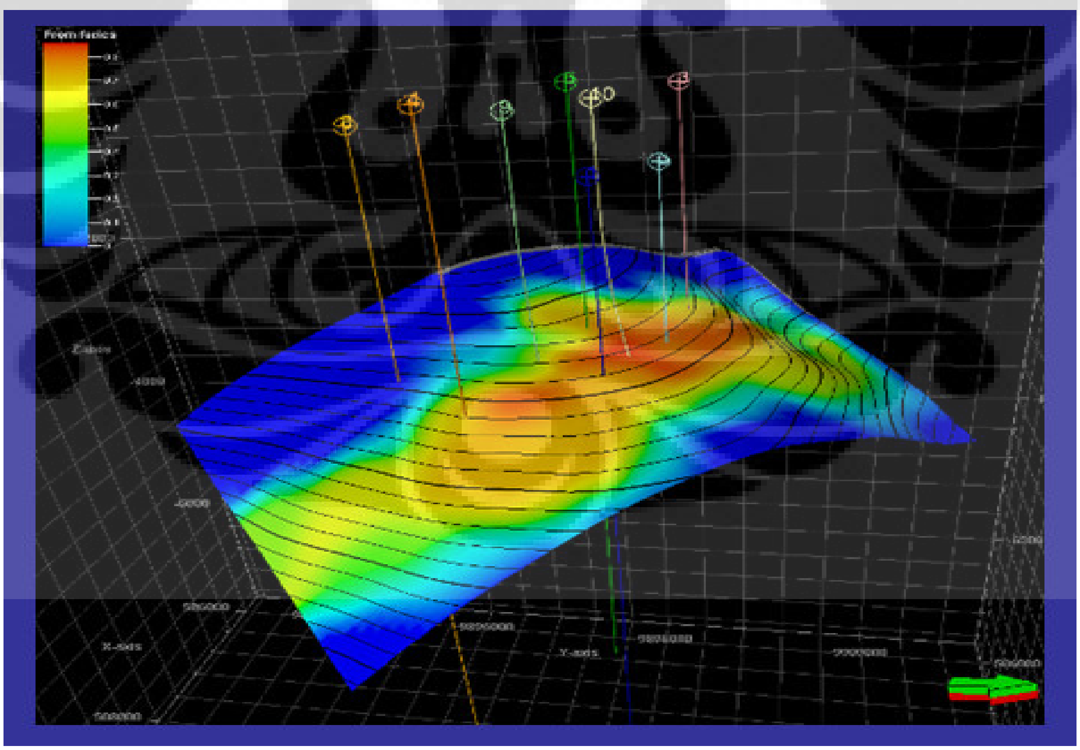


Figure 4.22 Overlaid map between porosity and all reservoir properties distribution for E-sand

4.6 Multi Realisation

Once the complete geostatistical workflow has been performed, the Petrel project is based on one complete set of 3D properties, from facies to petrophysical ones.

The great advantage of geostatistics is that a huge number of statistically equiprobable realisations can be gathered out just changing what is commonly called the random seed number. This number is just a random number requested by the mathematical algorithms to perform the geostatistical simulation. By changing this number, the stochastic realisation we get will be different in terms of spatial distribution of the properties, but will honor in the same way all the well data, the trends and the statistical parameters previously defined. Accordingly to this basic concept, the number of the simulation sets can be multiplied very easily.

As a support to this operation of generating multiple realisations, an automatic workflow can be defined in Petrel in order to perform this operation automatically. Basically, once the parameters have been defined, this phase is automatic and does not require too much subjective contribution by the user, apart from an accurate QC at the end of the process. This means that this step can be easily reproduced anytime using the automatic workflow set in Petrel. After the computation of several equiprobable realisations (for Salemba the number of realisations is fixed to 10) for the N/G property, the related 3D petrophysical properties can be simulated in the same way.

Finally, after the workflow run, the project will have 10 N/G realisations and the respective 10 realisations for porosity, permeability and water saturation. Exploring these different simulation sets gives information about the uncertainties related to the model. For instance, the computation of volumetrics for all the 10 realisations gives an indication of the range of oil and gas in place in the reservoir. In the case of Salemba the equivalent with some realisations differ just for the stochastic simulations related to different random seeds. In other words, all the simulation sets are based on a single sedimentological scenario (one trend map) and any parameter related either to facies and petrophysics have been modified.

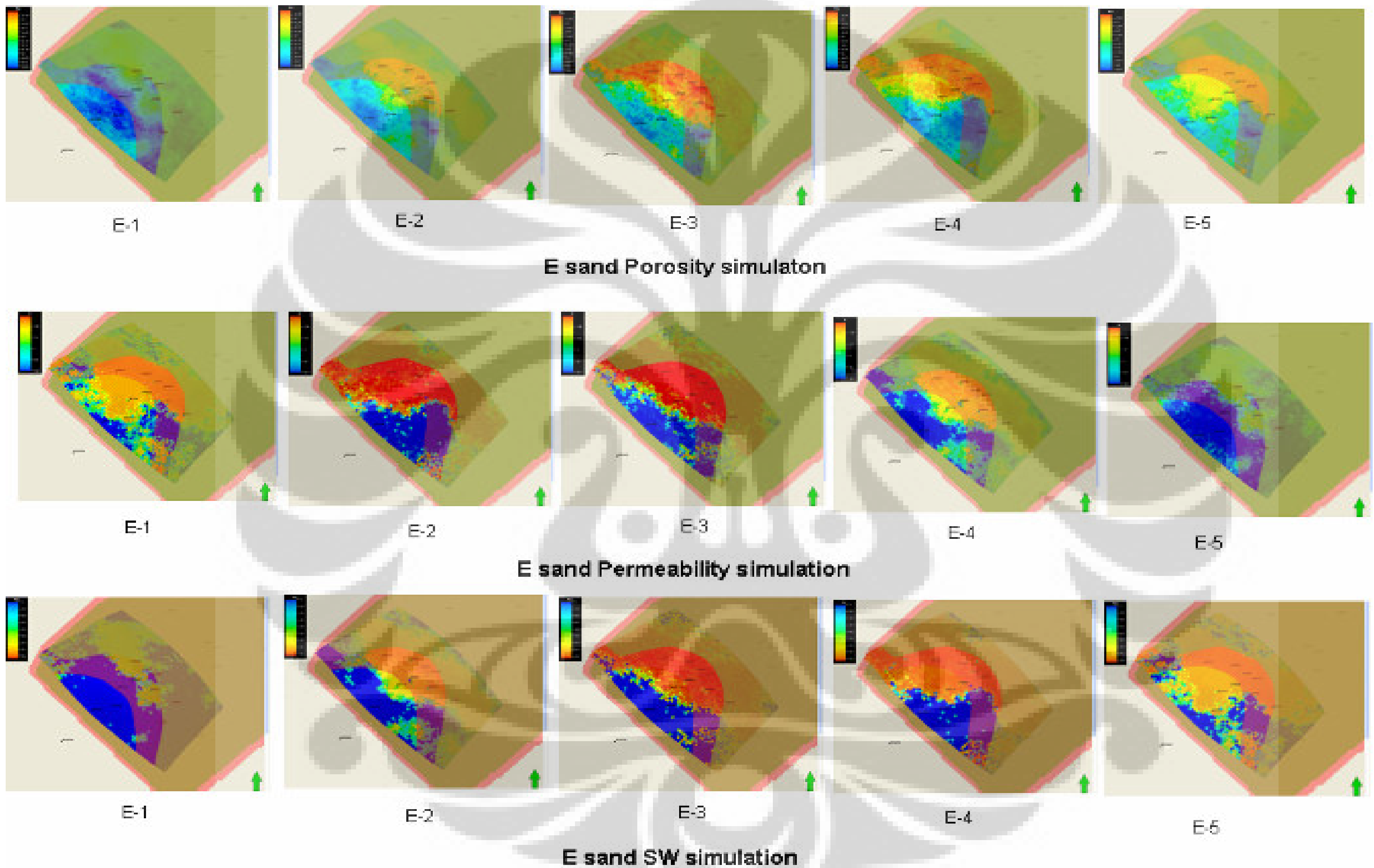


Figure 4.23 Reservoir properties multi realization

4.7 Volumetric

Volumetric calculation has been also derived from these 10 realisations and resulted in 10 volumetric sets as shown below:

Table 4.2 . Volumetric of 10 realizations

Case	Bulk volume [*10^6 ft3]	Net volume [*10^6 bbl]	Pore volume [*10^6 RB]	HCPV oil [*10^6 RB]	HCPV gas [*10^6 RB]	STOIIP [*10^6 STB]	GIIP [*10^6 MSCF]
1	4063	724	84	74	13	66.079	3.143
2	4063	724	84	74	15	66.455	3.201
3	4063	724	83	74	11	65.959	2.903
4	4063	724	84	73	13	66.064	3.097
5	4063	724	84	74	12	66.406	2.954
6	4063	724	83	73	13	65.977	3.097
7	4063	724	84	74	14	66.466	3.335
8	4063	724	84	74	13	66.031	2.88
9	4063	724	83	73	12	66.385	2.961
10	4063	724	83	72	13	65.998	2.933

Note : (HCPV : *Hydrocarbon Pore Volume*; STOIIP : *Stock Tank Oil Initial In Place*; GIIP : *Gas Initial In Place)*

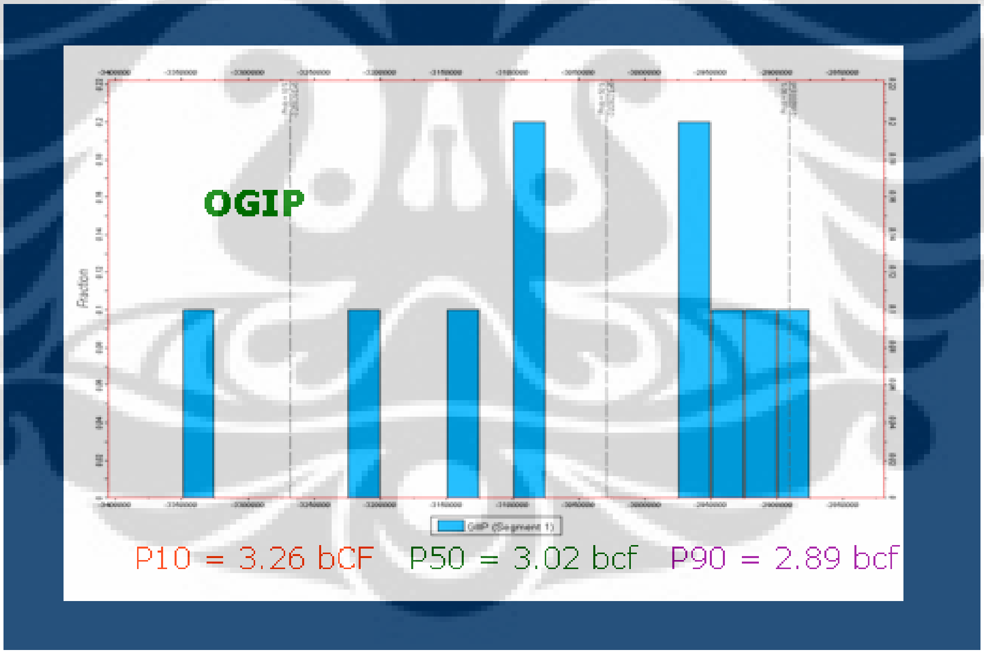


Figure 4.24 OGIP Volumetric Histogram Distribution (Irma, 2007)

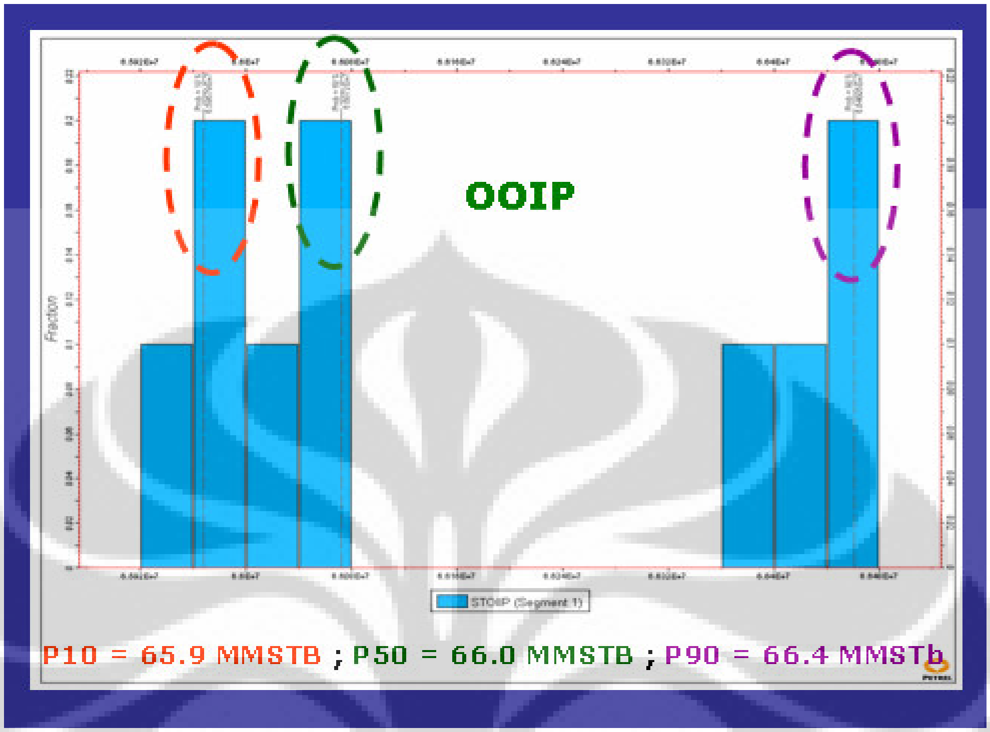


Figure 4.25 OOIP Volumetric Histogram Distribution

4.4 Field History Match

To make a validity check of the model, a field history matching was conducted after getting the geostatistical model which model resulted OOIP 66 MMSTB and OGIP 3.02 BCF.

From the pressure trend analysis it can be defined that cumulative production until February 2008. The pressure trend give a good trend where the sand has been producing with such amount of oil and gas. As the pressure show bit higher due to water.

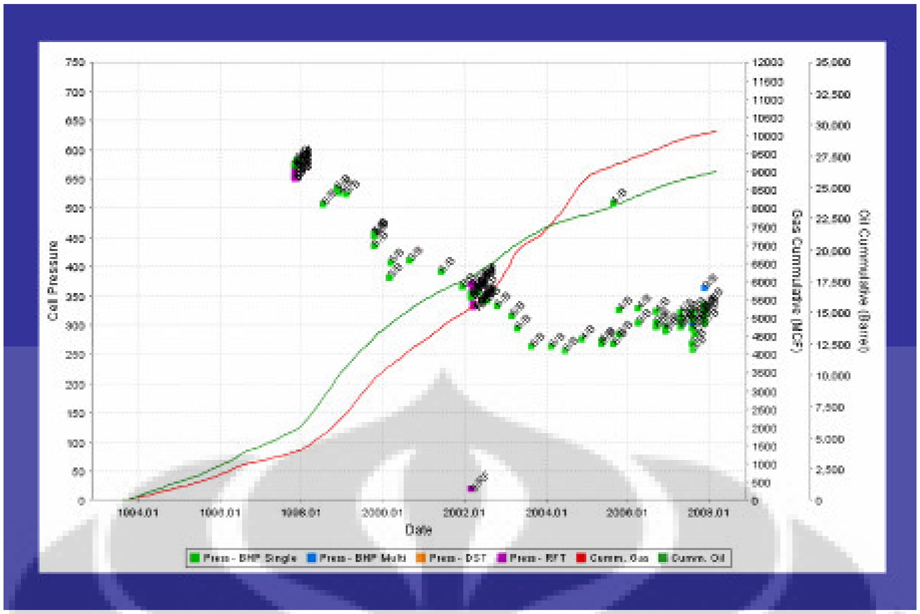
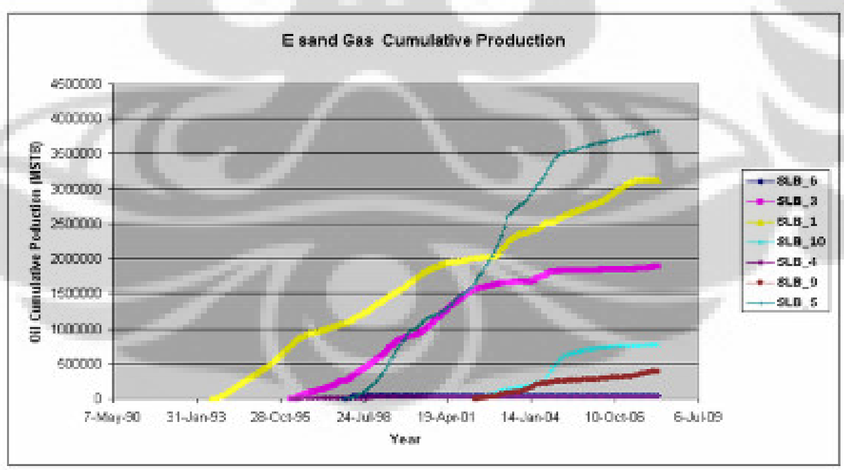


Figure 4.26 E-sand pressure trend analysis

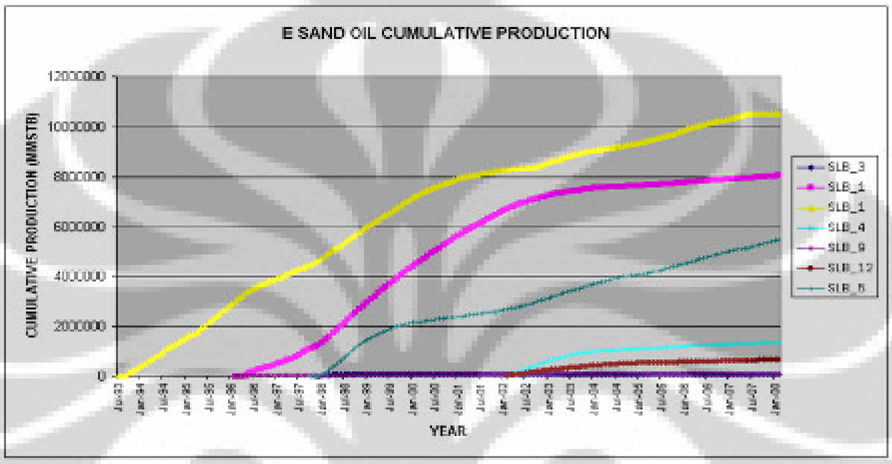
The figure show that most of the wells have good oil contribution for the E sand cumulative production. SLB-5 well is the biggest contributor than the SLB-6 well. Current gas cumulative production is about 10.1 MCF. Compared to the OGIP model , we will potentially to have another gas cap.



SLB_6	SLB_3	SLB_1	SLB_10	SLB_4	SLB_9	SLB_5	Cum (MCF)
47436	1891259	3136131	779782	31892	392894	3823546	10.1

Figure 4.27 E sand Gas cumulative production

The figure show that most of the wells have a good oil contribution for the E sand cumulative production. SLB-1 well is the biggest contributor than the SLB-3 well. Current gas cumulative production is about 10.1 MCF. Compared to the OOIP model, we will potentially to have another potential oil



SLB_3	SLB_1	SLB_1	SLB_4	SLB_9	SLB_12	SLB_5	Cumulative (MMSTB)
65784	8052505	10540281	1360409	74449	862527	5470243	28.23

Figure 4.28 E sand pressure trend analysis (Vico, 2007)

From the model and history matching, it can be concluded that the field area still have potential for oil and gas. Since it has a good water driven, potential oil and gas can be recoverable if we drill updip from the existing wells

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

Based on the data used, descriptions and some analyses within the previous chapters, the thesis investigation can be concluded as follow :

- The reservoir thickness follows a slightly curved northwest-southeast trend through SLB-3, SLB-5, SLB-10, SL B-1, SLB-9 and SLB-4 wells respectively.
- Seismic interpretation could not imagine perfectly to differentiate sand and non sand due the high influence of the coal and poor data acquisition.
- According to the log characteristics and supported by other data such as core, mudlog and log the depositional environment of study area is a Fluial/Deltaic Channel Sand.
- The E-sand at Mutiara Field has various reservoir properties with average porosity 28 – 33 %, permeability KPay 500 – 2191 mD. Water saturation (Sw) between 11% - 29%, and net pay thickness 21 – 107 feet.
- The Object Based modeling is the appropriate model to be applied for the study area
- The distribution of facies might be influenced by relative sea level changes and sediment supply amount since the study area is located in the deltaic position. Area with abundance sand was interpreted to have high sand supply compared to area with less sand.
- Reserves calculation of P50 are OOIP 6.60 STB and OGIP 3.02 Bcf.
- From the field history matching look, the E-sand in the study area still has significant remaining reserves to access by new wells. As it is also driven by the water, the most up dip well be opportunities to drain the remaining reserves.

- From the current models which are facies, porosity and permeability model, we still have a possibility to study furthermore in the western flank updip from SLB-3, SLB-5 well (need further detailed study)

5.2 RECOMMENDATION

As the conclusion has done, follow up work for further study which will be useful for future developing area, are shown below :

- It is recommended the next investigation using the combination of detail seismic interpretation analysis with more extended area and also suggested to use all the existing data where the seismic attributes used to guide the facies modeling which also can cause errors. It is possible that the wrong attribute was used, which does not relate to the geology. Therefore, the probability analysis that generated based on relation of seismic attribute and well data could lead to incorrect facies model.
- A more advanced investigation to estimate the hydrocarbon fluid properties and distribution is recommended, especially using Lambda Mur ho (LMR) inversion method.
- In order to have a valid and solid result of the investigation of exploration or development project, an integrated work of petrophysical with any seismic inversion method is highly recommended. This is because detailed study of seismic amplitude always require accurate calibration of the rock properties with the seismic response derived from existing data.

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