PROGRESS REPORT

EMAS PUTIH JOINT STUDY
NATUNA SEA BASIN, INDONESIA
PETROLEUM GEOLOGY & EXPLORATION POTENTIAL

PREPARED BY:
EDY SUNARDI
NISA NURUL ILMI

FAKULTAS TEKNIK GEOLOGI
UNIVERSITAS PADJADJARAN

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1. INTRODUCTION

1.1. GENERAL PETROLEUM INTEREST OF THE EMAS PUTIH AREA

The proposed Emas Putih Area Natuna Sea Basin (acreage 844.07 sqKm) is located at East Natuna Basin forms part of the basins of Northwest Kalimantan (Figure 1), bounded to the west to the positive Natuna Arch this represents the western extension of the Sarawak Basin.

The East Natuna basin can be divided into a number of discrete structural elements defined by depressions and highs in the basement of Cretaceous granites and metasediments (Figure 2). The Sokang trough in the southwest of the basin and immediately to the east of Natuna Island contains over 6,000 m of Tertiary sediments and is separated from the main basin by a structural high, the Paus ridge. To the north of the Paus ridge the narrow north–south oriented Komodo graben contains over 5,000 m of Miocene clastics. The Terumbu shelf in the north has developed between 2,500 and 4,000 m of Neogene cover that includes up to 1,500 m of Miocene to Pliocene Terumbu formation carbonates. The outer basin (Bunguran trough) dips east towards Sarawak and contains over 10,000 m of sediments.

The East Natuna basin is well known as being the host for the largest gas field in Southeast Asia, the Natuna Alpha gas field, with 210Tcf in an isolated buildup in the upper part of the thick, middle Miocene to late Pliocene Terumbu carbonates.

Figure 1. Location of Emas Putih Area Natuna Sea Basin (acreage 844.07 sqKm) within East Natuna Basin
Encouraging factors for exploration potential in the proposed Emas Putih Area is related to the no economic oil discovery has been made in the East Natuna Basin but a major gas discovery was made by Agip in 1973. This has since been appraised by Esso between 1981 and 1983. This giant "L" field, with net pay of more than 1,300 m, contains reserves of some 130 TCF, making one of the largest gas accumulations in the world. However, 70% of the total gas volume is carbon dioxide. With the exception of the "L" gas accumulation and gas discoveries in Bursa and AP-1X in reefal carbonates all the discoveries made in East Natuna Basins, have been made in sands of the Gabus, Barat and Arang Formations. Oil discoveries are concentrated in deltaic sands of the Gabus and to a lesser degree, the Barat Formation, while the Arang sandstones contain dry gas, frequently with a high CO2 content.

An integrated approach is proposed to carry out to understanding the petroleum system in the area and specifically assessing the potential objectives of reservoir at Oligocene Gabus sandstone, Lower Miocene Arang sandstone, and Mid-Upper Miocene Terumbu carbonates, and possible fractured Basement. The north-south normal fault trend could provide a good fault-dependent play of both Miocene and Oligocene clastics. Meanwhile the proven build-ups of Terumbu carbonates could also developed over the Emas Putih JSA study. To date, hydrocarbon source rock identification has been problematic for most areas of the Natuna Basin. Sample analyses from well data indicate that coals and coaly shales of the Arang Formation in general are the richest source rock in the area. However they are commonly thermally immature, except in deeper basinal areas where it may become marginally mature, therefore mature source rock expected in the axis of the sub-basin should be done using well results, depositional modeling and seismic data.

In order to address the critical petroleum systems element, a full block geologic review might be proposed which not only addressed structural aspects but also to unravel crucial stratigraphic keys. UNPAD is requested to lead this consortium amongst Migas – Talisman Sumatra B.V – Unpad and conducted this study within very short period.
1.2. SUMMARIZED OF PREVIOUS EXPLORATION ACTIVITY

The Natuna area is one of the youngest hydrocarbon provinces in Indonesia. The first exploration in this offshore area around the Natuna Islands commenced in 1968 after the award of four blocks covering 485,264 km$^2$. These were the South China Sea "A" (awarded to Agip in 1968), "B" (awarded to Conoco in 1968), "C" (awarded to Frontier Oil in 1968) and "D" (awarded to Gulf in 1968), which extended northward from 2°S to the international boundaries with Malaysia and Vietnam and were bounded to the east by the coast of Kalimantan and to the west by the coast of Sumatra.

After extensive seismic campaigns, drilling commenced in the "B", "C" and "D" Blocks in late 1970. These early wells, and those in the "A" Block in 1971 confirmed what had been suspected from seismic, namely that most of Blocks "C" and "D" were situated over the core of Sundaland which only had a thin veneer of sediments, and that the remainder of Block "C" and Blocks "A" and "B" were in fact separated into two basins, East and West Natuna, which were separated by the Natuna Arch (the surface expression of this arch being the Natuna Islands).

The first significant test of hydrocarbons occurred in February 1973 when Conoco flowed 4,320 BOPD and 24 MMCFGPD, from their Terubuk-1 exploration well. This was
Conoco's ninth well in the area and the twenty fourth well of all operators. However it was not until Conoco's sixteenth well, Udang-1, in 1974, that the first commercial oil field was discovered. This field, which has produced over 59 million barrels of oil, is the largest field in the West Natuna basin.

The other original operators were less successful: Gulf relinquished the "D" Block after three unsuccessful wells; Frontier Oil farmed out their "C" Block to Agip, who drilled four wells before relinquishing the block; Agip drilled thirty-two exploration and three delineation wells before their block expired in 1978. Agip made several discoveries (AL-1X, AQ-1X and Bursa-1X) which though uneconomical for Agip, provided encouragement for a later tender round in the Natuna area.

One block, Kakap, was awarded during this exploration phase in 1975 to Phillips and Teneco, who as partners with Agip had relinquished the area earlier. Marathon farmed into this block in 1977, took over operatorship, and discovered the KG field in 1978.

The Ikan Pari, Kepiting and "KH" fields have been developed, the Anoa and "KF" fields are in the process of development and the ultimate development of such gas fields as the "L" and Terubuk fields is dependent on the construction of a national gas grid in Indonesia.

Belut North-1 drilled in 1974, on the northern flank of an anticline oriented northeast found gas in Gabus sandstones. Belut North-2 drilled on the crest, found three gas bearing intervals yielding 9.84 MMCFGPD and 340 BPD of condensate on test.

Hiu-2 drilled in 1975, found several gas and condensate bearing sands in the uppermost Gabus and Barat Formations. 5 DSTs yielded a combined 44.2 MMCFGPD and 762 BPD of condensate.

Sepat-1, drilled in 1980, midway between wells Gabus-4 and Gabus-6, found oil and gas in the three uppermost Gabus sandstones. 3 DSTs yielded a total of 1725 BOPD and 1 MMCFGPD. Well Sepat-2 (1984) flowed oil with water only.

NB2-1X (Marathon, 1982) was drilled on a large anticline and tested a total of 15.5 MMCFGPD and 48 BPD condensate from a 2.4 m thick sand within the Gabus Formation. Well Forel-IA, drilled in December 1984, is reported as a new oil discovery by Conoco.
In 2007, Tuna Block (a part of the former Natuna Block “C”) was awarded to Premier Oil and MOECO through a direct tender process. The operator acquired 2D & 3D seismic data in north-western part of the block.

In 2011, Premier drilled 2 wells (Gajah Laut Utara-1 and Belut Laut-1) with result as dry hole with oil and gas shows.

In 2014, Premier drilled (Kuda Laut-1 and Singa Laut-1) as discovery wells and proved that petroleum system of western part of East Natuna is works.

2. REGIONAL GEOLOGICAL SETTING OF EMAS PUTIH AREA
The Natuna arch was created by Jurassic-Cretaceous subduction along the northeast margin of Sundaland, and metamorphism of the resulting accretionary prism. During the Tertiary, the East and West Natuna basins developed in a foreland setting above this pre-Tertiary basement complex.

Basin development was commenced in the middle Eocene with the initiation of graben systems in both basins. Continental sediments ranging from coarse clastics to lacustrine shales (Benua-Lama, Lumpur and lower Gabus Formations) were deposited from the middle Eocene to the early Oligocene.

A major event at around 30 Ma caused the tectonic regime to become compressional and major left lateral wrench movements occurred. During the late Oligocene braided fluvial systems which were draining northwesterly towards a large inland sea located in the Malay basin became established in the West Natuna basin.

The sands (upper Gabus Formation) deposited at this time form the main reservoirs in the West Natuna basin. Similar deposition also occurred in the East Natuna basin, but the drainage direction was east towards the open sea. The upper Gabus Formation is overlain by the Barat Formation lacustrine shales and silts in the West Natuna basin.

Following a minor compressive event at around 21 Ma the relatively fine grained clastics with interbedded coals and shales of the Arang Formation were deposited. This formation is fluvial at the base, and passes upwards into fluvio-deltaic sediments which are in turn overlain by marginal marine sediments. The upper part of this formation is time equivalent to the lower Terumbu Formation platform carbonates in the eastern part of the East Natuna basin.

Major uplift occurred in the West Natuna basin during the middle Miocene whereas gentle subsidence and marine transgression continued in the East Natuna basin. During the late Miocene rapid subsidence occurred in the East Natuna basin, which enabled large reef growth (eg. "L" field) whereas restricted marine sediments were deposited and preserved in local lows in the West Natuna basin.

The Muda Formation which comprises muds and sands of mainly shallow marine origin, was deposited in both basins during the Plio Pleistocene. Several regional
unconformities as well as many sea-level fluctuations are represented in this formation by extensive erosion by river systems developed during periods of sub-aerial exposure. The remaining potential in these basins would appear to lie in the deeper Tertiary sequences.

The East Natuna Basin shows the same succession of depositional cycles as the West Natuna Basin. Marine influences, however, are stronger and the cycles can more easily be distinguished and dated. On seismic records each cycle can be observed onlapping older deposits and basement.

The area was affected by rifting, the intensity of which was strongest during the Late Oligocene – earlymost Miocene cycle of deposition. This late rifting phase created the Komodo Trough, a narrow half graben that opens southward into the broad Sokang Trough. In the East Natuna Basin there are no Miocene compressional phases such as occurred in the West Natuna Basin. Both phases, caused regional uplift of the East Natuna basinal area instead. The Late Miocene uplift was accompanied by an increase in slope towards the east, where a thick Late Miocene to Pliocene sequence was deposited. This deep basinal area is known as the "Outer Basinal Area".

Pre-rift marine deposits of Paleogene age that occur locally in Western Indonesia have not been encountered in the East Natuna Basin.

The basin can be divided into a northern and southern segment by the nature of the sediments. In the northern half (former Agip Block A), carbonates form an important part of the sedimentary column. In the south, (former Conoco Block B) clastics predominate.

3. PETROLEUM SYSTEM

3.1 Reservoirs
Reservoir rocks abound in both the West and East Natuna Basins. As well as the Terumbu and Muda carbonates, present only in the east, sandstones with fair to excellent reservoir properties are abundant. They belong to various delta complexes and are difficult to correlate in the absence of reliable stratigraphical data, even within a single structure or field (e.g. Udang field).

**Pre-Tertiary reservoirs**

The Cretaceous marine sandstones encountered in wells Cipta A-1, Rusa 1 and AC-1 are tight with porosities of less than 10%.

**Pre-Gabus reservoirs**

They are poorly known as few wells have reached these horizons. They generally consist of medium to coarse grained clastics ("clastic sequence", "undifferentiated complex") of alluvial fan and alluvial plain type. Most well files record poor reservoir qualities.

**Gabus reservoirs/sandstones of the Barat Formation**

These form the main hydrocarbon bearing horizons in the West Natuna Basin. In the Udang field, the Gabus sandstones are thickly bedded, slightly kaolinitic, clean, fine to medium grained sandstones. Streaks of conglomerate are interbedded. Porosities range from 22 to 25%.

In the Bawal structure, the sands of the Gabus Formation are fine to very fine grained with poor to fair porosities. In Belut, they are fine to medium grained, occasionally showing carbonate cement. Porosities values of 27 - 34% are reported. In Belanak, the sands, including individual beds 17 -38 m thick, are fine to medium grained with some coarse grained interstratifications. Average porosities are 19% with poor permeabilities of only 10 to 100 mD.

In the Kakap KH field, the sands of the Gabus Formation are very fine to fine grained, slightly calcareous and locally argillaceous. Average porosity is 20%. In general, the sand/shale ratio decreases northeastward, and the best reservoirs are to be found in the upper part the Udang Member of the Gabus Formation, and sands of the Barat Formation.
Porosities decrease with depth. In well AQ4X, in the Anoa field, porosity decreases from 25% in the Barat Formation (1271-1325 m) to 15.6% in the Gabus Formation (1756 -1777 m). In well Kuda-1, the porosity is drastically reduced to less than 5% below 2103 m in the lower part of the Gabus Formation.

Clean sandstones of the shore/bar type usually show the best characteristics with permeabilities of 200-300 mD in the Tapis field. There, they rapidly pass laterally into muds (1012 mD). In the Udang field such isolated sandstone bodies show individual gas caps and oil-water contacts.

In the East Natuna Basin, the Gabus Formation has not yielded any significant hydrocarbon shows and petrophysical data are rare. From well AN-1X, porosities of up to 18% and permeabilities of 33 mD were reported from sandstones within the uppermost part of the unit.

Sandstones of the Arang Formation

As with the sands of the Gabus Formation, the sand/shale ratio of the Arang Formation decreases northeastward. The best reservoir horizons are found in the lower Arang sandstones, where they are fine to medium grained with rare coarse grained stringers. Porosity and permeability values are 20 - 24% and 50 - 200 mD in Terubuk, Alu-Alu and Lumba-Lumba wells with individual sandstone beds up to 21 m thick. They reach 30% and 1600 mD, in Tembang-1 with individual beds attaining a thickness of 12 - 15 m.

In the East Natuna Basin, petrophysical characteristics of the lower Arang sandstones are reported to be good. They are poor in the east and north (AS-1X: porosity 13%. permeability less than 10 mD), generally tight with low permeabilities, but occasionally porous (AP-1X, maximum porosity 17%). No shows of any importance are reported from those sandstones. In well Paus-S1, porosity values up to 25% are reported, but permeability is less than 50 mD due to a high kaolinitic content.

Sokang sandstones

Well Sokang-1 penetrated a gas bearing Middle Miocene sequence, 152 m thick, containing 40% fine to medium grained sandstones with an average porosity and permeability of 25% and 260 mD, respectively.
Individual sandstone beds were 7 to 24 m thick. The same sandstones were also encountered in the wells drilled on the Paus - Ranai Ridge, and by the southernmost wells CC and CB.

**Terumbu and Muda carbonates**

These carbonates are usually lumped together. Several depositional facies can be distinguish derived from higher land plants at a middle to late maturity for oil generation. With no source potential in the Arang Formation, the source of this oil has to be found in deeper series, the Oligocene, Gabus Formation equivalent or older rocks.

The origin of the high percentage of CO2 found in most of the gas wells is disputable. According to Esso, the coal rich facies of the Arang Formation is a likely source of CO2 and dry gas. An alternative argument relates the presence of CO2 to the existence of a calcareous basement (CA- 1X) and/or igneous basement. Yet another proposal, is the relationship of CO2 to volcanic activity.

3.2 SOURCE ROCKS

To date, hydrocarbon source rock identification has been problematic for most areas of the Natuna Basin. Sample analyses from well data indicate that coals and coaly shales of the Arang Formation in general are the richest source rock in the area. However they are commonly thermally immature, except in deeper basinal areas where it may become marginally mature.

Biomarkers from the Rhu oil indicate a significant terrigenous input in the source rocks from which it was derived. The penetrated Oligocene synrift sequence contains the right type but low quantity of organic matter: less than 1% Total Organic Carbon (TOC) and mainly Type III kerogen. Coals within the Penyu Formation have moderate to excellent generating potential (TOC = 10-26 wt%). Average Hydrogen Index (HI) values exceeding 200 in the east (at Soi-1, Rhu-1, Rhu-2, and Cherating-1) indicate that these rocks are capable of generating gas and, possibly, some oil when thermally mature.

The shales in the Miocene postrift sequence (Pari Formation) are lean in organic matter (TOC 4 wt%) and, like the synrift deposits, contain predominantly vitrinitic (Type III) kerogen. The Pari Formation is generally immature.
If it is accepted Ro=0.5% (about 2.1 km) as the top of the oil-generation window, the data suggest that only the synrift deposits in the deep half-grabens, i.e. the Oligocene are mature. The Miocene section is generally too shallow to have generated hydrocarbons. Estimated Ro of the basal Penyu Formation in four of the wells indicate that the synrift sediments are generally still within the oil and gas generation window. At the Penyu-1 well, where the basin is deepest, the basal sediments have attained Ro=1.9% and may have passed the gas generation stage.

Maturity modelling using BasinMod 1D and geochemical inversion suggest that oil generation from deep lacustrine synrift source rocks in the Bawal-1 Anambas Graben started early, between 30-24 Mya. The deep lacustrine facies was interpreted to be present at depth of between 9000ft and 12,000ft at the Ikan Emas-1 well, or deeper in areas of deeper basement. The interpretation suggests that early structural and stratigraphic traps with potential for bed lateral migration are more prospective for oil generated from the oil-prone lacustrine facies.

3.3 PLAY TYPES

Both structural and stratigraphic traps exist in the West and East Natuna Basins. Traps are mainly structural in the West Natuna Basin where the sand distribution was controlled by a deltaic environment. In the East Natuna Basin, stratigraphic traps are present in the form of reefal buildups along with structural traps created by draping over basement highs or structures related to growth-faults for sandy reservoirs.

At least four proven hydrocarbon play types pertaining to reservoir unit in the Natuna Basin are found to date, it could be classified based on the field size distribution these are:

- Oligocene Gabus-Lower Gabus Formation (59.47%, reserve by play),
- Early Miocene Udang-Barat Formation (4.9%),
- Lower-Mid Miocene Arang Formation (34.1%),
- Mid-Late Miocene Terumbu Formation (4.9%).

Potential new plays include fluvial deposits of the lower synrift graben-fill that onlap onto basement highs. Both hangingwall and footwall fan deposits, sealed by impervious basement and intraformational shales, have the potential to trap large amounts
of hydrocarbons that are generated by shales in the centre of the grabens. Alluvial fans along border faults may consist of coarse-grained sandstones and conglomerates which can have excellent reservoir quality. At Rhu, secondary porosity from fractures in the sandstones has upgraded the prospectivity of the play. Careful mapping of the seismic facies will help identify drilling targets.

The inversion or Sunda fold play has been the most obvious exploration target in the past. The failure of this play type seems to be due to inefficient vertical migration because of poor communication between source and reservoir rocks. The source rocks are likely to be synrift lacustrine shales in the half-grabens, but few faults connect the source facies to the postrift reservoirs.

The basement drape play is a proven play in the late synrift sequence that either onlaps or drapes over prerift basement highs e.g. Rhu structure. The Rhu oil is probably sourced from mid-synrift shales, migrated updip along carrier beds. Bed-parallel migration rather than vertical migration via fault conduits is the key element of this play.

**Stratigraphic traps**

Reefal buildups are only present in the northern part of the East Natuna Basin, where they are developed over the Terumbu carbonate platform. Two classes of reef are found at two different stratigraphic levels. Overlying the Terumbu Platform, the reefs are generally symmetrical with exaggerated vertical closure over 1500 m in "L" though rather small in areal extent. Above the base post-Muda unconformity reefal buildups have a smaller vertical development but a wider areal extent.

Sand bodies distributed within sand/shale facies are common traps in the Natuna Basin. Stacked sandstone reservoirs with individual gas caps and oil/water contacts, are typical of the type of deltaic deposition which results in frequent lateral and vertical facies changes and permeability barriers. Bar sands, tidal channels, shoals are all stratigraphically influenced traps commonly associated with the structural traps.

**Structural traps**
Draping of sediments over basement highs and subsequent differential compaction is common in both basins. Terubuk, Paus and Ranai are structures corresponding to this category of traps.

Faults are generally curvilinear and synsedimentary are very common in the East Natuna Basin, but are comparatively rare in the West Natuna Basin, where they have been overprinted by subsequent wrench tectonism.

The most common structural features in the West Natuna Basin are anticlines generally superimposed on earlier half-grabens or structural depressions filled by Oligocene sediments. Structural inversion is obvious with compressional stresses first occurring in the late Early Miocene, then periodically until Late Miocene (N17) prior to the Pliocene unconformity. The anticlines are frequently "en echelon" and definitely correspond to drag folds.

Very frequently, the compressional structures are cut by tensional faults perpendicular to their axes. These faults can control the petroleum accumulations e.g. the Tapis field in Malaysia. Structures formed in Plio-Pleistocene times i.e. subsequent to the nearly flat, Pliocene unconformity are rare.

4. PROGRESS EMAS PUTIH JOINT STUDY
The joint study activity covered regional geology analysis which consists of structural analysis, paleogeographic analysis, sediment facies model, biostratigraphy analysis, petroleum geology study from each developed paleogeographic system.

The Geological and Geophysical data provided for this joint study of proposed Emas Putih Area consists of 196 lines of 2D data seismic with length approximately of 2,855 km with basemap and 5 (five) exploratory wells with completed data: Arca-1X, AD-1X, Drupa-1X, Bursa-1X and Durian Besar-1 (uncompleted data) Wells. The analysis of gravity anomalies in this study comprised of spatial analysis and depth analysis.

New seismic lines of 1599 km acquired by spec survey in the process to get form PND, which will be integrated in order to have better geological and geophysical evaluation. These lines are covering regional context, therefore an extensive work is necessary to complete the interpretation and integrate the results within the regional vision: that is why more time is requested to finalize the Joint Study.

The seismic horizons markers were derived from the available geological and biostratigraphic interpretation found in the wells final reports. This study adopted a stratigraphic nomenclature constructed using lithostratigraphic. Seismic interpretation was refer to the following seismic markers with designated names, there are: Basement, Gabus, Arang and Muda Formations. Based on seismic interpretation, several play type can be identified in Emas Putih Area which consist of Four-way dip closure/Fault independent-Downthrown and Carbonate Build Up play.

4.1. SEISMIC CROSS SECTION AND INTERPRETATION

4.1.1. Seismic Data

Emas Putih Area is located in East Natuna Basin. The Block has 196 lines of 2D seismic with length approximately 2,855 km. Seismic data mainly has been acquired from PND which coverage study area with spacing between 2.16 up to 4.88 km. As general, seismic data of Emas Putih is vectorized with lower in quality than conventional seismic processing. Basemap of seismic data in Emas Putih area is shown in figure 3.
4.1.2. Data Quality

Seismic data quality is very poor – good. Some lines could not be used because continuous reflections were absent. Some seismic lines show good data at shallow horizons but the deeper horizons still cannot be clearly seen and need some enhancement to reduce the uncertainty related to seismic interpretation. Some horizons are discontinuous due to complex structure and carbonate.
4.1.3. Seismic Well Tie

Emas Putih has 5 (five) wells which has been purchased by PND, but only Drupa-1x, and Arca-1x wells that can been used in this step. The well has complete data such as DT, rhob, and "check shot" that are required to seismic well tie. Drupa-1x is shallow drilling, the well only reach on top of Terumbu fm and Arca-1x well is good to be key line because the well reach to Gabus fm. Generally speaking, well-seismic tie consists of three stages, i.e.:

- Loading well, seismic, and "check shot" data.
- Wavelet extraction
- Check shot correction and correlation

Wavelet extraction was using well and seismic data around the well location. Wavelet is an operator, which was convoluted to the reflectivity series generated by the well log to approximate the seismic trace. Correlation of well data and seismic conducted by stretch/ squeeze operation to increase the correlation coefficient between the synthetic and seismic data. The Figure 5 and 6, demonstrates a result of well-seismic tying exercise, comparing synthetic seismogram reflector of well data against seismic reflectors.
Figure 5. Well seismic tie Drupa-1x (Corr : 0.850 calculation window : 1150ms – 1254ms)

Figure 6. Well seismic tie of Arca-1x (Corr : 0.665 calculation window : 1050ms – 2300 ms)

4.1.4 Seismic Interpretation
As generally, Emas Putih block has 4 (four major) horizon. Each horizon has a different seismic character. As long as doing seismic interpretation, many phenomena of geological was founded such as faults, folds, erosion, and carbonat built up. The following is a list of seismic horizons with designated names and color key (oldest - younger horizons).

- Blue or Top of Terumbu fm.
- Pink or Top of Arang fm.
- Light green or Top of Gabus fm.
- Blue violet or Top of Basement Metamorf

Interpretation of Seismic data 2D is done by picking the horizon or the determination of the horizontal boundaries of a deposition phase that occurs at a certain time. This process is primarily done with the basic interpretation of seismic structures by looking at the response which is a reflection of the areas below the surface of the horizontal boundary.

A series of representative seismic section lines and maps of which illustrate the seismic character and seismic interpretation of the Joint Study area (Figure 7).
4.1.5. Time Surface Map

In this study, we concern to map several major horizons. They are Bsement (Metamorphic), Gabus fm, Arang fm, and Terumbu fm. Regional data is used as a secondary data to help to interpretation seismic data of Emas Putih area.
Figure 8. Time surface of Terumbu fm.
Figure 9. Time surface of Arang fm.
Additionally, gravity modelling have also been carried out as part of the Joint Study (Figure 11).

Figure 10. Time surface of Basement Metamorf.

Figure 11. Residual anomaly Map Emas Purtih Area
4.2. PETROPHYSICAL ANALYSIS

4.2.1. WELLS SUMMARY

1. ARCA-1X WELL

ARCA-1X well was drilled by AGIP Ltd in East Natuna Basin with 11200 feet total depth. The Terumbu Formation was occupied by limestone consisting of predominantly Calcite and Dolomite. No traces hydrocarbon were observed while DST through this interval. However, gas shows were obtained in Terumbu Formation, Arang Formation and Gabus Formation. The log data acquisition started from 750 – 11620 feet. Available logs data were CALI, GR, ILD, LLD, SFLU, MSFL, NPHI, RHOB, DRHO, SP and DT. Log evaluation was done using Geolog (Deterim Analysis) and inputs from the well technical data.

The formation tops in ARCA-1X was divided on 4 intervals and 15 sequences boundary (SB). Muda Formation was started at 573 feet, and mainly consists of shale. Terumbu Fm was encountered at 3170 feet, the section composed of limestone with 3 intervals. Arang Fm was encountered at 6943 feet mainly consist of sand with interbeds of shale which it has had 6 SB. Gabus at 8844 feet mainly consists of clastic sediment shale and sand with 5 SB.

Table 1.1 Top Formation of ARCA_1X Well

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<th>ARCA_1X DEPTH (FEET)</th>
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2. AD-1X WELL

AD-1X well was drilled by AGIP Ltd in East Natuna Basin with 9009 feet total depth. Generally, it consists of Muda Formation, Terumbu Formation and Arang Formation. DST was tested on 4655 to 4773 ft (Terumbu Formation) with salt water slightly. However, gas shows were obtained in DST Zone with C1 80, C2 2.8, C3 1.1, C4 0.4, Nc4 0.19. The log data acquisition started from 694 – 9009 feet. Available logs data were CALI, GR, LLD, MLL, SN, NPHI, RHOB, DRHO, SP and DT. Log evaluation was done using Geolog (Determin Analysis) and inputs from the well technical data.

The formation tops in AD-1X was divided on 3 intervals and 9 sequences boundary (SB) on the target formation. Muda Formation was started at 720 feet, and generally consists of shale. Terumbu Fm was determined at 4674 feet, the section composed of limestone with 3 intervals which is most of this unit is composed medium grained mud to grain supported biomicrites, calcite and dolomite. Arang Fm was encountered at 8060 feet mainly consist of sandstone with small amounts of shale and conglomerates which it has divided into 6 SB.

Table 1.2 Top Formation of AD-1X Well

<table>
<thead>
<tr>
<th>AD-1X DEPTH (FEET)</th>
<th>SB</th>
</tr>
</thead>
<tbody>
<tr>
<td>720</td>
<td>Muda Fm</td>
</tr>
<tr>
<td>4674</td>
<td>TMB-2</td>
</tr>
<tr>
<td>5837.48</td>
<td>TMB-1</td>
</tr>
<tr>
<td>6400</td>
<td>TMP-1</td>
</tr>
<tr>
<td>8060</td>
<td>Arang Fm</td>
</tr>
<tr>
<td>8096.458</td>
<td>SB6 Arang</td>
</tr>
<tr>
<td>8320.417</td>
<td>SB5 Arang</td>
</tr>
<tr>
<td>8396.806</td>
<td>SB4 Arang</td>
</tr>
<tr>
<td>8448.021</td>
<td>SB3 Arang</td>
</tr>
<tr>
<td>8700.625</td>
<td>SB2 Arang</td>
</tr>
<tr>
<td>8925.729</td>
<td>SB1 Arang</td>
</tr>
<tr>
<td>9009</td>
<td>TD</td>
</tr>
</tbody>
</table>
3. DRUPA-1X WELL

DRUPA-1X well was drilled by AGIP Ltd in East Natuna Basin with 4140 feet total depth. Generally, It only consists Muda and Terumbu Formation. DST was tested on 3721 to 4035 ft (Terumbu Formation) with salt water slightly with 16500 ppm. The log data acquisition started from 1546 – 4123 feet. Available logs data were CALI, GR, ILD, SFL, NPHI, RHOB, DRHO, SP and DT. Log evaluation was done using Geolog (Determination Analysis) and inputs from the well technical data. The formation tops in Drupa-1X was divided on 2 intervals, Muda Formation was started at 497 feet and generally consists of shale. Terumbu Fm was found at 4140 feet, the section composed of limestone Terumbu Fm. Indeterminate wackestone / packestone whitish to light grey, fossiliferous (algae, corals, foraminifers, fossil fragment). Slightly dolomite, medium hard. Presence of thin intercalations of mudstone/wackestone, fossiliferous

Table 1.3 Top Formation of Drupa-1X

<table>
<thead>
<tr>
<th>DRUPA-1X DEPTH (FEET)</th>
<th>SB</th>
</tr>
</thead>
<tbody>
<tr>
<td>497</td>
<td>Muda Fm</td>
</tr>
<tr>
<td>3989</td>
<td>TMB-2</td>
</tr>
<tr>
<td>4140</td>
<td>TD</td>
</tr>
</tbody>
</table>

4. BURSA-1X WELL

BURSA-1X well was drilled by AGIP Ltd in East Natuna Basin with 11000 feet total depth. Generally, It only consists Muda, Terumbu and Arang Formation. The log data acquisition started from 1498 – 11861 feet. Available logs data were CALI, GR, ILD, SFLU, MSFL LLD, LLS, NPHI, RHOB, DRHO, SP and DT. The formation tops in BURSA-1X was divided on 3 intervals and 10 sequences boundary (SB) on the target formation. Muda Formation was started at 547 feet, and generally consists of shale. Terumbu Fm was determined at 4961 feet, the section composed of limestone with 3 intervals which is most of this unit is composed calcite and dolomite. Arang Fm was encountered at 9854 feet mainly consist of sandstone with shale which it has divided into 6 SB.
4.2.2. PETROPHYSICAL EVALUATION

Determine analysis consists of environment correction of log and petrophysical analysis (determin method). It consists of pre-calc, environmental correction, bad hole, volume shale, porosity, formation water resistivity, hydrocarbon saturation, permeability, and net pay evaluations. Petrophysical calculation was divided by SB interval.

4.2.2.1. Pre-Calculation

Pre-calculation has been calculated by using top log temperature, bottom log temperature, resistivity and temperature of mud sample, mud cake sample, mud filtrate sample which has been used for porosity and water saturation input.

4.2.2.2 Environment Correction

GR log was corrected to drilling fluid density. Density log was corrected to drilling bit size. Neutron Porosity logs was corrected to salinity of mud, drilling fluid density, salinity of mud filtrate, etc. Unfortunately RT (true resistivity) log could not been performed, because resistivity logs are not complete with TD. The effect of these corrections is very small in the zone of interest. The environmentally corrected curves have been used for quantitative petrophysic interpretation.
4.2.2.3 Badhole Evaluation

Bad hole conditions was tested by using the indicators of excessive hole collapse and the rugosity indication contained within the density correction curve. If bad hole was found to be present, the flag curve BADHOLE would set to false (1), otherwise it maintains its initial value of true (0). Either of the collapse or rugosity indicators would cause the frame to be flagged as bad hole. For the rugosity check, the absolute value of DRHO and Caliper Log was checked against the cutoff.

4.2.2.4. Shale Volume Evaluation (VSH)

Shale volume value was calculated from GR max and GR min with linear method on sequences boundary interval. The general form of linear method equation is:

\[ V_{SH} = \frac{(GR_{log} - GR_{min})}{(GR_{max} - GR_{min})} \]

The example value of GR max and GR min from each unit can be seen at SB figure below.

![Figure 12. Values of Grmax and Grmin from each unit](image)

4.2.2.5 Porosity Evaluation

The porosity was calculated by Sonic equation. It assumed a DT shale and DT matrix (SH) for DT porosity calculation. DT matrix was assumed at 55 us/f for sandstone and 47 us/f
for calcite, density matrix 2.65 for sandstone and 2.71 for limestone because there is no data about this. DT shale was plotted at 100.2 us/f, density shale of 2.26 gr/cc from DT-RHOB crossplot, total porosity from density-neutron crossplot was 0.26 with nphi wet shale of 0.31 for SB 6 Arang Formation.

Figure 13. Crossplot DT-RHOB, RHOB-NPHI of SB 6 Arang Formation (ARCA-1X).

4.2.2.6 Water Saturation (Sw) and Water Resistivity Evaluation (Rw)

The Indonesia Equation was used to compute effective water saturation (Swe) for Terumbu Formation, Arang Formation and Gabus Formation (figure 6). Water resistivity (Rw) for Terumbu Formation was obtained from water analysis laboratory data. Furthermore, Arang and Gabus Formation was determined by picket-plot Porosity-Resistivity log because there is no data from water analysis. Rw value from water analysis on Terumbu Formation was 0.19 ohmm at 125 °F. Meanwhile, picket-plot porosity-resistivity Arang Formation was 0.05 ohmm at 177.8°F and 0.07 ohmm at 192°F for Gabus Formation.
4.2.2.7. Permeability Evaluation

The permeability method that was used Whyilie-Rose method. The general form of Whyllie-rose equation is:

\[ k = C_1 \times \text{PHIE}^{D_1} / (\text{SWE}_{\text{IRR}}^{E_1}) \]

The various versions of this equation have been implemented in the familiar format of page 10-3 of the 1989 Schlumberger Log Interpretation Principles/Applications.

\[ k = ((C \times \text{PHIE}^{D} / (\text{SWE}_{\text{IRR}}^{E}))^{2} \]

Required inputs are effective porosity, irreducible water saturation both in V/V. Morris-Biggs: Per paper X from the 1967 SPWLA Using Log-Derived Values of Water Saturation and Porosity by R.L.Morris and W.P.Biggs. For medium gravity oil, \( C = 250 \); and for gas \( C = 79 \); \( D = 3 \) and \( E = 1 \). This is the basis for Chart K2 of the Schlumberger Chart Book.
4.2.3. NETPAY EVALUATION

Netpay evaluation was resulted by cutting off porosity, permeability, and hydrocarbon saturation. Besides, Cut off East Natuna Basin was determined from secondary data.

<table>
<thead>
<tr>
<th>FORMATION</th>
<th>VSH</th>
<th>PHIE</th>
<th>SW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Terumbu Formation</td>
<td>0.3</td>
<td>0.13</td>
<td>0.68</td>
</tr>
<tr>
<td>Arang Formation</td>
<td>0.32</td>
<td>0.11</td>
<td>0.7</td>
</tr>
<tr>
<td>Gabus Formation</td>
<td>0.33</td>
<td>0.11</td>
<td>0.7</td>
</tr>
</tbody>
</table>

Table 1.5 Cutoff East Natuna Basin

4.3. GEOCHEMISTRY ANALYSIS (ARCA-IX)

4.3.1. ROCK EVAL and GC-MS ANALYSIS
TOC, Rock eval and GC-MS data from ARCA-1 well covering Arang and Gabus formation. Based on TOC, Gabus formation has better quantity of organic richness compare to Arang Formation. Average organic richness of Gabus formation is 0.95%wt while Arang formation average organic richness is 0.5%wt. Both Arang and Gabus formation have coal layers with very high organic content (>90%). Nerveless, very thin coal layers in Arang and Gabus formation didn’t have much impact to the quality of source rock richness. From TOC quantity, Gabus Formation have better source quality compared to Arang Formation.

![Figure 15. ARCA-1 Rock evaluation data summary](image)

Kerogen type based on Hydrogen Index (kerogen type III) and GC-MS indicate that organic matter origin of Arang Formation is high plant terrestrial with aquatic non-marine algae influence while at Gabus Formation more pure from high plant terrestrial. Even though there is no direct correlation, origin of organic matter can provide more confident level for interpretation of geological depositional environment process.
Figure 16. Van Krevelen diagram for kerogen type classification

Figure 17. Pristane/Phytane plot for organic matter origin analysis

Figure 18. Ternary plot C27-C28-C29 for organic matter origin analysis

Virinite reflectance data have a smooth trend corresponding to the depth indicated that sedimentation history continued from Gabus to Arang Formation with relatively no
interference from compressional tectonic activity. Since the vitrinite reflectance data doesn’t cover all the ARCA-1X interval (only from 7000-11200ft), conclusion of relatively stable tectonic cannot directly applied for the whole section. Vitrinite reflectance can be used as an indicator for maturity in hydrocarbon source rock. Based on vitrinite reflectance values in ARCA-1X maturation start from 11200ft.

![Vitrinite Reflectance vs Depth](image)

Figure 19. Crossplot Ro-Depth to analyze sedimentation history and maturation

4.3.2. BURIAL HISTORY

Burial history is one of method to reconstruct sedimentation history, with burial history profile we can predict sedimentation, tectonic and maturation processes through time, this is very important processes to reconstruct hydrocarbon maturation, migration and accumulation.

Burial history of ARCA-1X will complete with two different scenario’s. First scenario is just to rely on Ro trend which in ARCA-1X show no interference from compressional tectonic, second scenario will adapt regional tectonic event at the interval where no vitrinite reflectance data is. In this progress report only first scenario that have been done while second scenario still in progress.
Burial history with first scenario suggest that whole section of ARCA-1X still immature expect at the base of Gabus Formation (Well TD) that already in early mature state. This condition indicate that deep interval of ARCA-1X still cannot generate hydrocarbon. ARCA-1X located at high contour give us opportunity to find better maturation range at the deeper part.

**Figure 20. 1D maturity profile of ARCA-1X well**

**Figure 21. Burial History of ARCA-1X well**
4.4. PETROLEUM SYSTEM OF EMAS PUTIH AREA

Reservoir Characteristic of the Emas Putih Area are developed at several stratigraphic horizons and equivalent reservoir unit (Figure 22).

**Source:**

Source is expected from coals of the Oligocene Gabus fm, and Lower Miocene Arang Fm.

**Reservoir:**

Oligocene Gabus sands, the formation consists of shale grey, silty with interbeds of argillaceous sandstones and siltstones. The Sandstone contains quartz and porosities are ranging from 20 – 10 %. Gabus fm developed in littoral – supralittoral (Arca-1x).

Lower - Middle Miocene Arang fm. Sand/Sandstone of the formation has thick 607” and contain of quartz and lithic, medium to coarse grained. This reservoir developed in sublittoral – supralittoral (Arca-1x, AD-1x).

Middle – Upper Terumbu fm, reef facies in Emas Putih block is good as reservoir. Terumbu fm comprised Packstone – Wackestone and below 5300” contain of dolomite. Porosities are ranging 19-27 %, and permeabilities ranging from 12 – 390 md. Dolomite, Porosities range from 3 -30 % with permeabilities is 140 Md (Arca-1x).

**Seal:**

Muda formation developed in sublittoral. Base on regional data, Muda shale is good for seal for Arang and Terumbu fm that been in Bathyal.

**Traps:**

Most of carbonate build up, four way dip closure, rotated faults block, and faults dependent that can be as traps of hydrocarbon in Emas Putih Area.
Figure 22. Play Concept in Emas Putih Area
5. CONCLUSION AND RECOMMENDATION

Although on-going study encourages significantly, the prospectivity of the Emas Putih Joint Study area still remain concern. These may be mitigated by the result of planned future work:

- Seismic and geological model integration and play analysis for detail analysis of source rocks and reservoirs continuity.
- Conduct basin modeling
- The timing between hydrocarbon expulsion, migration and basin structuration
- Prospectivity, risk analysis and conclusions