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GIANT FIELDS OF INDONESIA: PLAY TYPES, GEOLOGIC FACTORS, AND PROSPECTIVITIES OF FUTURE GIANT FIELDS

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ABSTRACT

Seventeen oil and gas fields of Indonesia are classified as giant fields (estimated ultimate recovery/ EUR/ reserve ≥ 500 MMBO or 3 TCFG) and two as supergiant fields (EUR ≥ 5000 MMBO or 30 TCFG) with total reserves 3P (proven+probable+possible) of 38.17 BBOE. The fields are located in eleven sedimentary basins with the Central Sumatra Basin being the richest basin volumetrically. The supergiant fields: Minas oil field (reserve 3P 5.45 BBO) and Natuna D-Alpha gas field (contingent recoverable resource 3P 46.30 TCF, undeveloped) are the largest oil and gas fields in Southeast Asia.

Globally, the number of giant fields is only 2% of the total fields of all sizes, but they contribute 60% of the production (Merrill and Sternbach –AAPG, 2017) and account for 67 % of the world's petroleum reserves (Mann et al., 2003). The situation is similar in Indonesia, where most of the oil and gas production has come from 16 producing giant fields. Most of these are very mature, and are presently in production decline. Therefore, the discovery of giant fields is very important for the national petroleum production and reserve.

To explore systematically the prospectivities of future giant fields of Indonesia, the play types, geologic factors, and tectonic settings of the existing giant fields are evaluated. The nineteen giant-supergiant fields of Indonesia can be simply grouped into six play types with each reserve 3P as follows:

1. Miocene reefal build-ups (four fields: 11,224 MMBOE),
2. Miocene inverted structures (five fields: 10,208 MMBOE),
3. Miocene deltaic structures (six fields: 8,895 MMBOE),
4. Jurassic rifted structures of Australian passive margin (four fields: 6351 MMBOE),
5. Pre-Cenozoic fractured basement (one field: 950 MMBOE), and
6. Miocene deep-water structures (two fields: 545 MMBOE).

The evaluation provides lessons for exploring the possibility of future giant fields in Indonesia: play type/s that can still account for new giant fields or new play type/s that should be developed. The play types of future giant fields, their locations and petroleum systems are determined by geologic settings, and some areas to focus on are proposed in this study.

INTRODUCTION

A giant field is generally considered to contain in excess of 500 MMBO/3TCFG estimated ultimate recovery (EUR) (called in this case the reserve 3P – proven+probable+possible). Supergiant oil fields are considered to contain a minimum reserve 3P of 5 BBO or 30 TCFG reserve 3P. Mega-giant fields have a minimum of 10 BBOE reserve 3P (Merrill and Sternbach –AAPG, 2017).

Until 2017, there have been 957 giant fields, 97 supergiant fields, and 7 mega-giant fields discovered globally (Merrill and Sternbach, 2017). Giant to mega-giant fields are very important for the world's supply of energy because these giants, although they compose only 2 % of the total fields of all sizes in the world (more than 65,000 fields - Li Guoyu, 2001), they hold 67% of global reserves (Mann et al., 2003), and contribute 60% of the global production (Merrill and Sternbach, 2017). Discoveries of giant fields are therefore, always important for the world.

In Indonesia, there are 19 giant-supergiant fields from a total of around 1,300 oil and gas fields of all sizes (1.5% as giant-supergiant fields from total fields), and they contribute most of oil and gas production (not included fields of Natuna D-Alpha - undeveloped, Abadi –under development, Gula-undeveloped) – see Table 1 and Figure 1. However, most of Indonesia's giant-supergiant fields are very mature, and are presently in production decline. Therefore, the need to discover new giant fields is

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very real, and vital for the security of Indonesia's national production and reserves.

This study reviews the play types of existing giant-supergiant fields of Indonesia to understand the various play types and geological factors controlling them. This provides lessons for examining future possibilities of finding other giant fields based on the giants' play types – either in new/underexplored areas, or in mature areas where new play types need to be considered.

DATA AND METHODS

Databases of oil and gas fields of Indonesia were examined during this study in order to determine how many giant fields have been discovered in Indonesia. Reserves data of the fields are based on formal data of Pertamina (2000) Oil and Gas Reserves Indonesia, IPA's Oil and Gas Field Atlas (Indonesian Petroleum Association, 1988, 1989a, 1989b, 1990, 1991a, 1991b), data from U.S. Energy Information Administration (2018) and Mann et al., 2003 (AAPG Memoir 78). Reserves of some fields are also based on internal data of operating companies (see Table 1 for source of data).

The volumetric data used is reserve of 3P. This is more or less similar with EUR (estimated ultimate recovery). Cumulative production of each field (until 2000) can be seen in Pertamina (2000). Some fields are not included in this list, as they are currently under-development or undeveloped.

Seventeen oil and gas fields of Indonesia are classified as giant fields and two as supergiant fields (Table 1). The fields are located in eleven sedimentary basins of Indonesia. Discussion of this was first presented by Sujanto and Satyana (2002), and updated by Satyana (2018a, b). To review other possibilities of play types associated with future giant fields in Indonesia, publications of Satyana (2014b, 2017) provided the main references. The giant fields database and related publications were reviewed to understand the various play types and their associated geological and tectonic settings. This results in reviews of possibilities to find future giant fields, their play types, and likely locations.

RESULTS AND DISCUSSIONS

Giant-Supergiant Fields of Indonesia

Seventeen oil and gas fields of Indonesia are classified as giant fields (from Sumatra to Timor Sea: Arun, Duri, Bangko, Bekasap, Suban, Banyu Urip, Attaka, Badak, Handil, Nilam, Tunu, NW Peciko, Gula, Senoro, Wiriagar Deep, Vorwata, Abadi), and two as supergiant fields (Minas, Natuna D-Alpha) (Table 1, Figure 1).

From around 1,300 oil and gas fields in Indonesia, 17 are categorized as giant fields (6 oil fields, 11 gas fields) and 2 supergiant fields (1 oil field, 1 gas field) (Satyana, 2018a, b – modified). These 19 fields make up just 1.46 % of all fields of all sizes in Indonesia. Of these 19 fields, 15 are located in western Indonesia and 4 are located in eastern Indonesia.

The 19 fields are located in 11 sedimentary basins (North Sumatra, Central Sumatra, South Sumatra, East Natuna, NW Java, NE Java, Kutai, North Makassar, Banggai, Bintuni, Malita-Calder Basins), with the Central Sumatra Basin being the richest basin accommodating more than a quarter of Indonesia's giants. Total estimated reserves (3P) of the fields are 38.17 BBOE (two third is gas; 12.47 BBO and 154.21 TCFG/ 25,70 BBOE). The supergiant fields are Minas oil field (Central Sumatra Basin, discovered in 1944 by Caltex) with reserve 3P of 5445 MMBO and Natural D-Alpha gas field (East Natuna Basin, discovered in 1973 by Esso) with contingent recoverable resource 3P of 46.3 TCFG (7717 MMBOE) (the contingent recoverable resource 3P of Natuna D-Alpha is actually 210 TCFG but 71% is CO_2 gas).

From the 19 fields, 16 are producing, but more than half of the fields are depleted (Arun, Minas, Duri, Bangko, Bekasap, Arjuna B, Attaka, Badak, Handil, Nilam, Tunu) due to the lifetime of the fields. Some fields are under development (Abadi), two fields are not yet developed (Natuna D-Alpha, Gula).

Play Types of the Giant-Supergiant Fields

Nineteen giant fields can be grouped into six play types as follows, ordered with decreasing volume of the fields' reserves 3P included into the play type (Table 1, Figures 2, 3):

1. Miocene reefal build-ups (four fields: 11,224 MMBOE),
2. Miocene inverted structures (five fields: 10,208 MMBOE),
3. Miocene deltaic structures (six fields: 8,895 MMBOE),
4. Jurassic rifted structures of Australian passive margin (four fields: 6351 MMBOE),
5. Pre-Cenozoic fractured basement (one field: 950 MMBOE), and

6. Miocene deep-water structures (two fields: 545 MMBOE).

The total amount of reserve 3P of the giant-supergiant fields of Indonesia is 38.17 BBOE. Miocene reefal build-ups are at the top of the reserves 3P list as a result of the supergiant gas field of Natuna D-Alpha (with contingent recoverable resource 3P of 46.3 TCFG or 7717 MMBOE). If the Natuna D-Alpha is excluded from the list, the Miocene inverted structure will be the most important play type volumetrically. The order of the play types of Indonesian giant fields may be important when trying to understand where new giants may be located.

It is understandable why most of the giant fields are within Miocene inverted structures as most of the basins of western Indonesia (i.e. Sumatra, Java, Kalimantan, Natuna) have histories characterized by Paleogene rifting, post-rifting/sagging, and Neogene inversion due the change of regional tectonics of Indonesia through the Cenozoic. In terms of exploration history, this play type was the first to be tested by oil companies since the broad and shallow inversion structures were easily seen by geological mapping and later seismic data, and were often characterized by oil seeps. Most of the early discoveries of giant fields were from this play type.

Deltaic deposits have multiple stacks of source, reservoir, and sealing rocks in one deltaic sequence that can contain multiple petroleum accumulations. Migration is often not a problem since sources and reservoirs are not separated in space and time. In addition, multiple stacks of the deltaic sequences typically provide a very effective burial mechanism to bring source rocks into the oil/gas maturity window. Traps are often numerous, and related to delta progradation and/or are typically stratigraphic.

Play types of Miocene deltaic stratigraphy and Miocene inverted structures, as well as Miocene reefal build-ups are mostly located in mature – very mature areas/basins. Many fields of these play types have been discovered and produced from, including giant fields. The likelihood of discovering new giant fields with these play types is therefore small. The possible play type for the next giants is most likely Jurassic rifted structures of the Australian passive margin.

Play Type: Miocene Reefal Build-Ups

This play type composes the giant Arun gas field (North Sumatra Basin, reserve 3P 13.08 TCFG, discovered in 1971 by Mobil Oil), Natuna D-Alpha supergiant gas field (East Natuna Basin, contingent recoverable resource 3P 46.30 TCFG, discovered in 1973 by Esso, not developed yet), Senoro gas field (Banggai Basin, eastern Sulawesi, reserve 3P 3.59 TCFG, discovered in 1999 by JOB Pertamina-Arco), and Banyu Urip oil field (NE Java Basin, reserve 3P 729 MMBO, discovered in 2001 by Exxon-Mobil) (Figures 2, 3).

Reefal build-ups of Arun (Early-Middle Miocene), Natuna D-Alpha (mid-Miocene to Pliocene), Banyu Urip (Early Miocene), and Senoro (Late Miocene) occur seaward of the carbonate platform bank edge, as isolated vertical features. Their development is in response to a rise in relative sea level over the reef body, frequently the result of active basinward subsidence and maximum transgression during the Miocene. Hydrocarbons have been found within cores from Lower to Upper Miocene pinnacle reefs, and associated bioclastic porosity. Pinnacle reefs have excellent reservoir quality, characterized by high production rates. Miocene Tomori and Matindok marls organic-rich marine shales in Senoro, and Oligocene Bampo and Middle Miocene Baong in Arun, and Ngimbang Eocene shales in Banyu Urip, and Oligocene Gabus and Pre-Gabus shales in Natuna D-Alpha, provide the main source rocks. Stratigraphically, regional shales of post-carbonate sedimentation trap the accumulations.

Graves and Weegar (1973) point out that "condensate rich-gas is reservoired in Arun reef and associated carbonates of Lower and Middle Miocene age which in places exceed 1000 feet in thickness". They continue to explain, "The reef carbonates occur on a large paleotopographic high trending in a general north-south direction. The gas accumulation is mainly stratigraphic, having been trapped in a porous reefal facies which is overlapped by upper Baong (Middle and Upper Miocene) shales" (Graves and Weegar, 1973, pg. 23). The upper part of the reservoir has excellent porosities (20-30%) and permeability, and provides deliverability 2-3 times than that of lower reservoirs.

The Natuna D-Alpha gas field in East Natuna Basin is well known as being the host for the largest gas field in Southeast Asia, with 210 TCFG in an isolated build-up in the upper part of the thick (almost 5,000 feet), Middle Miocene to Upper Pliocene Terumbu carbonates, which were deposited during progressive relative sea level rise. Episodic exposure has created and preserved average porosity of 15%. Unfortunately, 71% of the gas is carbon dioxide (Dunn et al., 1996) and as such, estimated contingent recoverable resource is 46.30 TCFG. The source of CO_2 is from thermal degradation of carbonate in an over-mature zone to the east of the field, in the Sarawak Deep (Satyana et al., 2007).

The Banyu Urip field is by far the largest carbonate oil field in Southeast Asia. The early wells penetrated an almost 1,000 feet thick oil column within high porosity Oligo-Miocene carbonate. Banyu Urip is an isolated carbonate buildup in the Cepu block, East Java Basin, containing a shallow-water carbonate succession locally named as the Kujung Carbonate of Oligo-Miocene Miocene age. The buildup formed by aggradation on a structural high, during basin subsidence, maintaining a shallow water depositional system, and back stepping up through the Early Miocene. This resulted in approximately 3,000 ft. of relief relative to the surrounding platform. Following the drowning, the reservoir build-up was sealed with a transgressive clastic and shale unit, deposited throughout the basin (Hakiki et al., 2012). Reservoir quality in this platform was controlled primarily by dissolution diagenesis that overwhelms the depositional fabric of the shallow water carbonate system. As a result, the porosity is 25% to 35%, The field is also the highest feature and was the locus of the oil that spilled from the adjacent fields as they filled with gas.

The Senoro gas field is different from other reef fields in Indonesia. While other reef fields developed in situ in each basin, the Senoro reef and other reefs in the Banggai Basin developed when Banggai micro-continent drifted during the Miocene before colliding with the East Sulawesi Ophiolite Belt in the Mio-Pliocene, forming the foreland basin of Banggai. Carbonate platforms and reefs developing at the frontal part of Banggai micro-continent as syn-drifting sequence by the collision, isostatically subsided and entered the window of hydrocarbons which migrated up dip, charging reefs like Senoro (Satyana et al., 2008). Senoro is the first giant gas field discovered in the frontier petroleum exploration province of Sulawesi Island of eastern Indonesia. Potential reservoirs are provided by Miocene carbonates of the Tomori Formation and the Minahaki Formation, including the Mantawa Member reefal facies limestones, which contain excellent porosity and permeability. In the Senoro-3 well, this platform carbonate sequence provides a good reservoir, with porosities ranging up to 26%. The lithology comprises mainly skeletal wackestones and lime mudstones (Hasanusi et al., 2004). The Mantawa Reef Member at the top of Minahaki Formation generally provides excellent reservoirs in the Senoro field. The lithologies predominantly comprise skeletal packstones and wackestones with a pelletal matrix, in addition to coralline algae and dissolved coral fragments. Karst zones are present and likely to have abundant grain moldic and vugular to cavernous porosities up to 30% with an average of 23%, and permeability up to 1350 mD. Bathyal shales of the Pliocene Kintom Formation, at the base of the post-tectonic sediments of the Sulawesi Group, provide an effective regional seal for the Miocene carbonate reservoirs. (Hasanusi et al., 2004). Charge for this system occurred in Pliocene time, derived from Miocene marine shales and coals within the Tomori and Matindok Formations (Hasanusi et al., 2004).

Play Type: Miocene Inverted structures

This play type composes the giant oil fields discovered in Central and NW Java Basins. They include: Minas supergiant oil field (reserve 3P 5445 MMBO, discovered in 1944 by Caltex, the largest oil field in SE Asia), Duri oil field (reserve 3P 3483 MMBO, discovered in 1941 by Caltex), Bekasap oil field (RR 3P 633 MMBO, discovered in 1955 by Caltex, and Bangko oil field (reserve 3P 647 MMBO, discovered in 1970 by Caltex) (Figure 2).

The reservoirs of these giant fields are the Paleogene sections, deposited as late syn-rift and mainly post-rift sequences, which were mostly inverted in the Late Neogene forming inverted, faulted anticlinal traps. The fields have late syn-rift transgressive deltaic to coastal-marine sandstones with oils derived from terrestrial lacustrine and deltaic source rocks, occupying the shallower Oligocene to Lower Miocene parts of the rift basins. The traps of the fields are anticlinal dip closures developed into foreland basins in the late post-rift stage (Doust & Noble, 2008), where they may affect the entire syn- and post-rift sequences. They form elongate drag folds, are frequently cross-faulted, and are often bounded by reverse faults or thrusts nucleated above syn-rift boundary faults (the so-called inverted structures or ‘‘Sunda folds’’ of Eubank & Makki (1981)). Many of these structures are related to wrench inversion of the syn-rift and are located adjacent to graben boundary faults (Doust and Noble, 2008).

Reservoirs of Minas, Duri, Bekasap, and Bangko fields are equivalent to much of the Sihapas Group, including several paralic facies that record a gradual transgression: The Menggala Formation is still fluvial, but is overlain by shallow marine sandy (Bekasap Formation) and slightly argillaceous (Bangko Formation) facies. The Menggala and

Bekasap formations contain the best reservoirs of the basin, with porosities of the order of 25% and permeabilities of up to four Darcies (Doust and Noble, 2008). The fields were formed as a result of Early–Middle Miocene inversion and gentle folding, accompanied by wrench faulting along a NW–SE (Barisan) trend. This period follows the early post-rift. Williams and Eubank (1995) noted that most of the oilfields are concentrated in drape structures over basement palaeo-highs and along the eastern flanks of the half graben rifts, up-dip of the basin center source rocks, while others are developed in drag and inversion folds (''Sunda folds'') adjacent to the basin boundary faults. The sources are organic brown shales of the Oligocene Pematang Formation, having average TOC of 3.7 wt. % (non-coaly facies range from 0.21-23.25 wt.%). The geothermal gradient is higher than normal (5-6 °F/100ft) and constituting one of the highest GG's in the world. Sufficient high temperature is reached at a shallow depth, and the hydrocarbons are enabled to migrate into sandstone reservoirs before greater depth of burial reduced their porosity by secondary quartz overgrowth. The brown shales of the Pematang Group in Central Sumatra Basin were estimated to generate 60 BBO of oils. Preferential migration is along fractures, faults, and carrier beds. Giant oil accumulations contained in the Sihapas reservoirs are sealed regionally by the overlying Telisa shales, which record the maximum transgression during the early-Middle Miocene. In total about 25 billion barrels STOIIP have been located in the basin, of which 8 and 4 billion barrels are located in the Minas and Duri fields, respectively.

Play Type: Miocene Deltaic Structures

This play type composes the giant oil and gas fields discovered in Miocene deltaic reservoirs of the on- and offshore Mahakam Delta in the Kutai Basin, East Kalimantan. They include the Attaka oil field (reserve 3P 668 MMBO, discovered in 1970 by Union Oil), the Badak gas field (reserve 3P 6.78 TCFG, discovered in 1972 by Huffco), the Handil oil field (reserve 3P 867 MMBO, discovered in 1974 by Total), the Nilam gas field (reserve 3P 5.30 TCFG, discovered in 1974 by Huffco), the Tunu gas field (reserve 3P 23.85 TCFG, discovered in 1982 by Total), and the NW Peciko gas field (reserve 3P 8.23 TCFG, discovered in 1991 by Total). See Figure 2). Duval et al. (1998) discussed the history of discoveries of these fields and development of the geological and petroleum system concepts, as well as exploration technologies involved in the discoveries. Their discussion is summarized as follows.

The Mahakam Delta is a very old petroleum province, where production started in the onshore area almost 125 years ago. The swampy coastal plain and the adjacent offshore area remained untouched until they opened to the industry by the PSC system in the late 1960's.

A new cycle of large to giant oil and gas discoveries, Attaka (1970), Badak (1972), Bekapai (1972), Nilam (1974), and Handil (1974), took place thereafter, utilizing seismic technology to locate structural closures. By the mid 1980's, when production started to decline, a global requisitioning was undertaken through a regional synthesis, based on the reinterpretation of existing seismic and well data. One of the tools of choice used during this study was sequence stratigraphy. A new petroleum system model was defined and allowed exploration to be revitalized. Targets linked to stratigraphic concepts within or near to the associated kitchens were identified. A second cycle of exploration starting in 1986 reversed the trend of production decline. Huge gas discoveries were made as a result of incorporating new stratigraphic concepts with other techniques.

Some of these targets were successfully drilled, and one of them, NW Peciko (1991), was quickly recognized as a new giant gas and condensate field. Understanding the trapping model, and particularly its hydrodynamic component, was a key factor for fast and successful delineation. Sedimentological studies (including field observations on similar sand bars of the modern delta) combined with systematic pressure measurements, greatly contributed to the field model. The thin sand reservoirs were more continuous than expected and thus, organized into more manageable, thicker flow-units. The NW Peciko model was in turn, applied to the previously discovered Tunu field (1982), leading to spectacular new reserve additions that uplifted the Tunu reserve to almost supergiant gas field status (RR 3P 23.85 TCFG). Improved exploration and appraisal efficiency has resulted in rapid increases in production.

Over 25 years of active exploration and production in the Mahakam area represents a balanced combination of on-going exploration, appraisal and development. A reasonable understanding of the petroleum system has been reached with a high degree of confidence. This offers a good opportunity to analyze in detail the chronology of operations and characterize past exploration efficiency as a function of time and applied efforts (Duval et al., 1998).

All of the giant fields of Mahakam Delta are included into the late post-rift regressive deltaic petroleum system type (Doust and Noble, 2008). This is typically gas and oil prone, derived from rich deltaic terrestrial source rocks that were deposited in deltas that prograded out over the basins in the Neogene. This progradation was in response to inversion and uplift of the Kuching High in the upper Kutai Basin, while gravity tectonics was responsible for the Samarinda Anticlinorium in the lower Kutai Basin (e.g. McClay et al., 2002).

The onshore to offshore Mahakam Delta, which includes the majority of prospective sequences, belongs to a thick, late post-rift continental margin stage of development. In this rich oil and gas province, almost all of the hydrocarbons are sourced from, and trapped in, post-rift deltaic reservoirs. Reservoir sands, belonging to a series of stacked regressive deltaic progradational sequences range in age from Middle Miocene to Pliocene, and most accumulations occur at several levels, separated by intraformational sealing shales representing maximum flooding surfaces. As in other Cenozoic deltas, a range of trap types is represented, including: hanging wall anticlinal rollovers associated with growth faults, elongated inverted anticlinal rollover structures related to thrusts and reverse faults, and stratigraphic traps related to deltaic sand bodies encased in shales.

Duval et al. (1998) summarized some of the most important parameters that impact hydrocarbon prospectivity. They indicated that the main charge for fields in the Tambora and Tunu trends is derived from thick deltaic coals and coaly shales in the intervening syncline, with minor contributions from a marine and leaner source rock in the offshore trend between the Tunu and Sisi fields. They noted that efficient short migration paths up to 15km in length lead from these charge kitchens into adjacent structures, and highlighted the gradual transition from oil, in more proximal anticlinal fields (Tambora, Handil) to gas/condensate rich fields in more distal trends, where source rocks are leaner, and thicker shale packages restrict migration of heavier hydrocarbons. These observations relate to the shallow progradational deltaic sequences.

Play Type: Jurassic Rifted Structures of Australian Passive Margin

This play type composes the giant gas fields discovered in the Jurassic reservoirs of Bintuni and Malita-Calder Basins, eastern Indonesia. They include the gas fields called Tangguh complex in the Bintuni Basin: Wiriagar Deep (reserve 3P 6.08 TCFG, discovered in 1994 by Arco), Vorwata (reserve 3P 14.03 TCFG, discovered in 1996 by Arco), and Abadi gas field in Malita-Calder/ Masela Basin (reserve 3P 18.00 TCFG, discovered in 2000 by Inpex) (Figure 3).

The Mesozoic (and Late Paleozoic) sedimentary rocks were initially considered by Nayoan et al. (1991) to be hydrocarbon prospective in Eastern Indonesia based on numerous fields in the NW shelf of Australia, and onshore West-Central Papua New Guinea. The reservoirs are Permian to Cretaceous sandstones. The Jurassic provides the most prolific reservoirs and sources from these sequences. Tectonically, these sediments record deposition in rift basins, formed along the Australian continental passive margin, which extends into Eastern Indonesia (Nayoan et al., 1991).

In Indonesia, the Jurassic source rocks and reservoirs are proven prospective and productive by discoveries of large to giant gas fields in offshore Berau Bay and Bintuni Basin (Bird's Head of Papua) presently known as the Tangguh field complex (Wiriagar Deep, Vorwata, Ubadari, Roabiba, Ofaweri, Wos) and Abadi field in offshore Masela area, Timor Sea. Marcou et al. (2004) and Casarta et al. (2004) provided the exploration history and analysis of the petroleum geology of the Tangguh field complex.

Middle Jurassic shallow marine to deltaic sandstones form the main reservoirs of the Tangguh field complex. The Late Jurassic and Cretaceous marine shales are described as being the primary sealing lithology for the Middle Jurassic reservoirs. Lower to Middle Jurassic and Permian coals/shales are described as the source rocks. The trapping structures formed during Miocene to present-day compressional tectonics. The hydrocarbons are modeled to have been generated at approximately 5 to 3 Ma, migrating up dip through Jurassic sandstone carrier beds, charging the available traps. Hydrocarbon generation continued from 3 Ma to the present day in optimum thermal maturity zones rimming the northern, western, and southern margins of the Bintuni Basin.

The Abadi field geologically, comprises rifted Australian continental margin that extends into Indonesian waters. It lies on the eastern extremity of the Sahul Platform and occupies a large tilted fault block bounded to the east and south by the Malita-Calder Grabens. The accumulation contains a significant gas column, reservoired within shallow marine, highly mature, quartzose sandstone of the

Middle Jurassic Plover Formation. Close analogues include the giant Greater Sunrise and Bayu-Undan fields. The source for the Abadi gas is postulated to be laterally equivalent marine shales deposited contemporaneous with the Plover Formation. Thermal maturity studies indicate such source rocks should be mature for gas in the Malita-Calder Grabens, Masela Deep, and directly down-dip from the Abadi field towards the Timor Trough. The Abadi structure is a paleo high that has been reactivated and modified by subsequent rifting, both in the latest Jurassic/earliest Cretaceous, and in the Neogene. Lower Cretaceous shales of the Echuca Shoals Formation, provide the primary side-seal and top seal (Nagura et al., 2003).

Play Type: Pre-Cenozoic Fractured Basement

Suban gas field (reserve 3P 5.70 TCFG, discovered in 1998 by Gulf) is the only giant field discovered from this play type (Figure 2).

In Indonesia, only a few fields produce oils from pre-Cenozoic basement reservoirs (such as the Teras field in South Sumatra and the Tanjung field in South Kalimantan), even though exploration into basement started in 1976, when Beruk Northeast-1 well targeted the pre-Cenozoic basement to explore for oil in the Central Sumatra Basin. The well tested oil. Intensive exploration into the basement only initiated in the 1990's when Gulf Resources explored South Sumatra's basement in the Jambi area. Gas was discovered in fractured granites of Dayung and Sumpal. The giant gas field of Suban was discovered in 1998 by drilling Suban-2, which encountered high deliverability gas in fractured pre-Cenozoic andesite and overlying sandstone of the lower Talang Akar Formation.

Naturally fractured basement rocks form an important portion of the reservoir in the Suban gas field. The field contains reserves in conventional reservoirs of reefal Miocene limestones overlying coarse-grained Oligocene clastics. These conventional reservoirs are believed to contain approximately half of the reserves in the field. The remaining reserves are contained within the underlying fractured pre-Cenozoic basement. The basement at Suban consists primarily of Jurassic-Cretaceous igneous granitoid rocks with subordinate amounts of Jurassic volcanic and Permo-Carboniferous metasedimentary rocks. Storage capacity to gas within the basement rocks is exclusively within fractures. All reservoirs are believed to be in pressure communication, primarily through an extensive network of natural fractures. Individual well deliverability is often above 100 MMCFD (Pujasmadi et al., 2002).

To be charged by petroleum, the basement objective should have a well-developed fracture network, and be positioned on the horst block bordering the graben, which hosts the kitchen. Generated hydrocarbons then migrate from the graben up dip into the fractured basement.

Fractures in the basement typically form by: (1) contraction joints within pre-Cenozoic igneous rocks during cooling of the rocks, (2) fractures and faults formed during multiple stages of tectonic readjustment, and (3) fractures formed during uplift (uploading) and surface weathering. The degree of fracturing varies with the age and lithology. Older, brittle rocks typically contain more faults and fractures than those of younger age and greater ductility.

To date in Indonesia, hydrocarbon production from basement rocks has been minimal but major gas discoveries in South Sumatra including the giant Suban gas field have triggered basement exploration in Indonesia during the period of 2000-2015. Some discoveries in the pre-Cenozoic basement following the success of Suban field include: Suban Barat, Karang Makmur, Kenanga (South Sumatra), Pondok Makmur (West Java), KE 29-1 (East Java) (Satyana, 2016b).

Play Type: Miocene Deep-Water Structures

This play type composes the giant field discovered in the Miocene deep-water reservoirs of the North Makassar Basin (Figure 2). This includes the Gula gas field only (3P 3.27 TCFG, discovered in 2000 by Unocal), which lies in excess of 56,000 feet of water on the continental slope of the Makassar Straits.

In the late 1980's the deep-water play was the concept of exploring deep-water areas worldwide in front of active prograding deltas, During the sea level low stand, deltaic deposits were eroded and redeposited on the slope and basin floor. Packages of deltaic reservoirs and source rocks were redeposited in deep-water areas and could generate and trap petroleum. These concepts were successful in many deep-water areas of the world such as the Gulf of Mexico, Niger Delta, and Campos Basin of Brazil. The concept was brought to Indonesia in the early 1990's and proved to be successful from the mid-1990's, with discoveriesat West Seno, Bangka-Aton, Merah Besar, Ranggas, Gendalo, Gandang, Gula, Gehem, Jangkrik, Merakes.

As has previously been reported, "the reservoirs were deposited in slope channel and basin floor systems", and "reservoir quality sands have been found widely distributed in the Middle Miocene to Pliocene sections" Doust and Noble (2008, pg 121). Sands are dominantly fine grained to very fine grained and moderately to poorly sorted. Reservoir quality of the sandstone units is invariably excellent with 12% to 35% porosities and hundreds of mD to Darcy permeabilities, proven by high flow rates achieved from DST's (Doust and Noble, 2008). In the West Seno field, reservoir characteristics are related to depositional facies and the massive sands have the best reservoir quality. Similar features were also observed on cores recovered from the Ganal PSC (including the Gula field). Despite the sands being thin to very thin bedded, the reservoir quality is generally excellent (Doust and Noble, 2008). The majority of the deep-water sands are quartzose. Excellent seals are from both intra-formational mudstones and hemipelagic mudstones. Individual sandstone units encased by intra-formational mudstones frequently exhibit their own independent pressure regimes.

The oil and gas accumulations are thought to have received charge from organic matter of land plant origin, transported into deep-water settings by turbidity flows. As noted by Doust & Noble (2008, pg 121), "compressional anticlines and toe thrusts form the primary structural traps in the Mahakam deep-water system. Reservoir sands occur in confined amalgamated channel–levee complexes (e.g. Merah Besar and West Seno discoveries), and as unconfined sheet-like submarine fans" (Gula). They also point out that "due to the nature of the sand bodies, opportunities clearly exist for stratigraphic trapping. There is still much to be learned about the geometry and productivity of these sand bodies as additional discoveries are made and appraised" (Doust and Noble, 2008, pg 121). The West Seno field was Indonesia's first deep-water development with the first barrel of oil produced in mid-2003. The Gula field is undeveloped. Other fields of Gendalo-Gehem-Gandang are under development of IDD (Indonesian Deep-Water Development) Project.

Geologic Factors for the Formationof the Giant Fields

The AAPG (American Association of Petroleum Geologists) discussed for the first time, the giant petroleum fields in the world, in a symposium held in Oklahoma City, April 23-25, 1968. This was followed by an AAPG Memoir (No. 14) focused on the Geology of Giant Petroleum Fields (edited by Halbouty, 1970). The Memoir listed at least 187 giant oil fields and 79 giant gas fields in the world known at that time (1970). The Minas giant oil field in Central Sumatra Basin was the only giant field listed from Indonesia. Since then, each decade the publication of the memoir on giant fields has continued, reporting on the giant fields discovered globally and discussing the geology of some important giant fields of the decade: 1970's (Memoir 30), 1980's (Memoir 54), 1990's (Memoir 78), and the last memoir between 2000-2010 (AAPG Memoir 113, published in 2017).

Since the first publication of the memoir, geologic factors affecting the formation of giant fields have been discussed in detail as lessons to be learned and to inspire exploration for new giant fields around the world. The geologic factors may include modes of occurrence of the accumulations, the types of trap, how each trap was formed and how it was discovered, in addition to the ages and qualities of the reservoirs and of the source rocks, the sealing capacity, the timing of generation, migration and accumulation, and the preservation of the accumulation. Factors that are usual and unusual about each of the accumulations should be discussed, and unusual factors should be understood, as it is typically the unusual factors that are key to giant accumulations (Halbouty et al., 1970).

Based on at least 266 giant fields in the world, Halbouty et al. (1970) listed the important geologic factors irresponsible for giant fields. These are given below, in addition to explanation of how each factor is fulfilled by giant fields of Indonesia.

1. There is a giant trap, formed more or less concurrently with generation of the hydrocarbons from the organic source materials,
   - *All giant fields of Indonesia have large trap, mainly: Vorwata, Abadi, Tunu, and Minas; formed earlier (from Jurassic as draping fold on horst block to Mio-Pliocene as prograding deltaic structure) than timing of hydrocarbon generation (mostly in Mio-Pliocene to Plio-Pleistocene).*

2. Abundant nonmarine and marine source rocks, rich in organic matter and mature, sourced the hydrocarbons to giant fields. There is no preferred age of source rocks, the important factor is the time when, during the sedimentation cycle of a basin, the largest amounts of organic matter were buried and preserved. Higher than normal geothermal gradients probably resulted in greater

efficiency of hydrocarbon generation in certain basins,

- *Sources charging hydrocarbons to giant fields of Indonesia vary from lacustrine (Minas, Duri, Bangko, Bekasap), fluvio-deltaic (Suban, Natuna D-Alpha, Banyu Urip. All giants fields in Kutai Basin and its deep-water field in the North Makassar Basin), to marginal marine (Arun, Senoro, Abadi, Tangguh field complex); the Oligocene Pematang brown shales sourcing Minas, Duri, Bangko, Bekasap giants fields are organic-rich brown shales having average TOC of 3.7 wt. % (non-coaly facies range from 0.21-23.25 wt.%). The age of sources range from Jurassic and Late Permian (Abadi and Tangguh field complex) to Mio-Pliocene (deltaic giant fields in Kutai Basin and deep-water North Makassar Basin); averagely large dimension of kitchen; gradient geothermal is mostly average (around 3.5°F /100 ft.), except Central Sumatra Basin which is very high (5 to 6°F /100 ft.) - one of the highest GGs in the world.*

3. The reservoir rocks are very porous and permeable, but there are notable exceptions; in the exceptions, total reservoir volume compensates for deficiency in reservoir quality. There is no preferred age of reservoir rocks,
   - *The reservoir rocks of Indonesia's giant fields are averagely high quality and thick, some are very thick because they developed as multi-stacked reservoirs, especially for giant fields in the deltaic setting of the Kutai Basin. High relief of build-up reef up to 5000 ft., and containing gas makes Natuna D-Alpha a supergiant field and the biggest in SE Asia (210 TCFG with 71% CO_2 or 46.3 TCF methane gas).*

4. Migration pathways, the reservoir rocks must be interconnected with channels of migration, or carrier beds, from the source beds.
   - *The reservoirs of giant fields of Vorwata, Wiriagar, Abadi, Attaka, Badak, Handil, Nilam, NE Peciko, Tunu, Senoro, West Seno, Gula were sourced by similar-aged source rocks.This makes migration is easier (lateral). There is contact between mature source rocks (kitchen) and carrier beds of similar age and migration continues into reservoir rocks with similar ages in the field. Hydrocarbon migration in deltaic and deep-water giant fields occurs over short distances because the sources and reservoirs are sedimentologically associated. The reservoirs of giant fields of Arun, Minas, Duri, Bangko, and Natuna D-Alpha are charged by sources older in age but the fields are located very close to, or within the graben kitchen areaand connected by faults. Basement reservoirs of Suban giant field are in charging contact with Talang Akar sources which onlap the basement.*

5. An effective seal must be present to prevent escape of hydrocarbons from the reservoir.
   - *The giant fields of Arun, Minas, Duri, Bangko, Bekasap, Banyu Urip are sealed by thick regional shales deposited during the maximum transgression in the Miocene, (Baong shale for Arun; Telisa shale for Minas, Duri, Bangko; Tuban shale for Banyu Urip). Giant fields in deltaic and deep-water setting of Kutai and North Makassar Basins are sealed by numerous shales associated as deltaic and deep-water sedimentation.*

Tectonic Setting of the Giant Fields

Halbouty et al. (1970) evaluated the types of basins having the largest number of giant fields globally. They are: (1) the basin which is, or was, a downwarp toward an oceanic area; (2) intermontane basins, developed either as geosynclinal-type basins between rising geanticlines or in a transverse downwarp setting which is generally smaller in size, but many such basins contain clusters of very large fields. (3) interior cratonic areas exposed to long periods of erosion and tectonic and/or epeirogenic activity contain numerous large fields, but a smaller percentage of giant fields. The terminologies used are in context of tectonic concepts developed up until 1970. In terms of present knowledge, these basins can be considered to occupy (1) continental passive margins, (2) collision zones, and (3) shelfal areas.

Mann et al. (2003) classified the tectonic setting of the giants in the world (877 fields up to 2003) into six simplified classes of the tectonic setting for basins, ordered from the most to the least number of giant fields. These include: "(1) continental passive margins fronting major ocean basins, (2) continental rifts and overlying sag or "steer's head" basins, (3) collisional margins produced by terminal collision between two continents, (4) collisional margins produced by continental collision related to terrane accretion, arc collision, and/or shallow subduction, (5) strike-slip margins, (6) subduction margins not affected by major arc or continental collisions" (Mann et al., 2003, page 15). Giant fields may have multiphase histories that can have the "most profound effect on hydrocarbon formation, migration, and trapping. The classification is based mainly on the basin style dominating at the most typical stratigraphic and structural level of giant accumulations" (Mann et al., 2003, page 15).

Mann et al. (2003) classified giant fields of Kutai Basin (Attaka, Badak, Handil, Nilam, Peciko, Tunu, West Seno Complex), as well as Natuna D-Alpha in East Natuna Basin as continental passive margins fronting a major ocean basin. This is because they are located along the margins of Kalimantan fronting the major seas (the Makassar Straits, the South China Sea). The Kutai Basin formed as a rifted area in the Middle Eocene as the result of opening of the Makassar Straits and Philippine Sea (e.g. Satyana et al., 1999). Since the Miocene, a period of eastward deltaic progradation (Mahakam Delta) has occurred. Inversion and uplift in the upper part of the basin started in the Early Miocene which contributed immense thicknesses of sediments into the basin as eastwards-prograding deltaic and deep-water complexes (e.g. Satyana et al., 1999). Giant fields now produce from reservoirs of Middle Miocene to Pliocene age. The East Natuna Basin is at the continental margin to the southwest of the South China Sea. The supergiant gas field of Natuna D-Alpha is reservoired within the Upper Miocene reef that developedon the continental margin. *The present author includes Gula, Arun and Abadi, Wiriagar Deep, Vorwata gas fields to this classification with the three last mentioned fields now in collisional setting between Australian passive margin and the Banda Arc.*

Mann et al. (2003) classified giant fields of North Sumatra, Central Sumatra, South Sumatra, and West Java Basin as subduction margins. These basins lie north of Sunda volcanic arc on the southwestern margin of the Sunda continent. Collision between Australia and the eastern Sunda in the late Miocene-Pliocene produced structural inversion of Paleogene rifts. The tectonic conditions for giants in this area include Paleogene rifts with thick, oil-prone lacustrine shales overlain by thick marine clastic reservoirs of Miocene age, high heat flow associated with the volcanic arc, and multiple phases of deformation that formed traps prior to the main phase of maturation and migration. Structural inversion of the rifts occurred in the Middle Miocene. Increased coupling between the subducting Indian Plate and overriding Sunda Block was responsible for inversion of rifts by reverse motion on bounding normal faults. Reservoir rocks include Paleogene and Miocene sandstones and carbonates. *The present author argues that these fields are better classified as continental rifts and overlying sag basins with rifts that were later inverted. Subduction margin is not the main control on these accumulations. Arun gas field is excluded from the classification. Suban gas field and Banyu Urip oil field are proposed to be included in this classification.*

Mann et al. (2003) classified giant gas fields of the Wiriagar Deep and Vorwata in the Bintuni Basin as continental rifts and overlying sag or "steer's head". They occur along the northern edge of the Bintuni Basin. Reservoirs occur in Late Paleozoic and Mesozoic clastic units derived from erosion of the northern edge of the basin (Kemum Block). Source rocks are from similar units. *As mentioned above, the present author includes these fields and also Abadi field to continental passive margins fronting major ocean basins which are now in a collisional setting.*

Recent Global Findings of the Giant Fields & Future Prospectivity

Giant field discoveries have been reported in the AAPG Memoirs for 30 years, and as stated by Merill & Sternbach (2017, publication overview) "It is exciting to know that giant fields are still being found today. The last decade (2000-2010) was characterized by the rise of unconventional plays of the giant fields. These are dominated by large regional accumulations in small microscopic pore throats. In addition to the unconventional accumulations, deep-water accumulations continue to have increased importance in the global hydrocarbon budget".

They go on to say "New technology has enabled us to revisit mature basins with dramatic success. Traditional roles in discovering giant fields over previous decades included the rockers (geologists focused on reservoirs), the trappers (geophysicists mapping geometry of accumulations), and the sealers and sourcers (explorers following source rocks and seals). More than ever, successful giant field discovery in the decade 2000 through 2010 was led by the integrators, who brought together all of the varied geosciences disciplines in their work in order to achieve this success" (Merill and Sternbach, 2017, publication overview).

They continue to note that "basin analysis, geochemistry, cutting-edge seismic imaging, and rock mechanics have become critical additions to the explorer's skill set and workflows" - "Looking at the discovery rate of giant fields since the late nineteenth century, at least four factors seem to control the frequency of discovery of giant oil and gas fields. These include concepts (e.g. geological models), technology, price, and access to drilling locations". They also suggest that "giant fields will continue to be found with renewed technology, new exploration and production concepts, enhanced imaging, and the boldness to explore in deeper water and more remote geography" (Merill and Sternbach, 2017, publication overview). Howes (2001) mapped possible future accumulations and conceptual volumes of all sizes, and it is hoped that some of these will become large to giant accumulation discoveries (Figure 4).

Prospectivities of Future Giant Fields of Indonesia

Evaluating the possibilities of future giant fields in Indonesia, we should first examine the working status of each play type of existing giant fields discussed above in terms of their maturity level, i.e. 'overmature', 'mature', 'immature'. 'Overmature' refers to the play type that is very common to giant fields and the areas where this play type has been explored extensively. As such, the possibility of finding future giant fields with this play type is low. 'Mature' refers to the play type that is very common to giant fields, and the areas where this play type has been explored sufficiently-extensively. As such, the possibility of finding future giant field with this play type low to medium, as long as geologic factors are supportive. 'Immature' refers to the play type that is successful, but has not been explored adequately and the areas where this play type remain underexplored. As such, the possibility of finding future giant fields with this play type is medium to high, as long as geologic factors are supportive.

From the six categories of play types of existing giant fields, and considering the intensity of exploration in the areas where the giant fields are located, the status of the play types based on criteria mentioned above are given below.

1. Miocene reefal build-ups (four fields: 11,224 MMBOE): overmature.
2. Miocene inverted structures (four fields: 10,208 MMBOE): overmature.
3. Miocene deltaic structures (six fields: 8,895 MMBOE): overmature.
4. Jurassic rifted structures of Australian passive margin (three fields: 6351 MMBOE): immature-mature.
5. Miocene deep-water structures (two fields: 545 MMBOE), immature-mature.
6. Pre-Cenozoic fractured basement (one field: 950 MMBOE): immature.

Based on these play types of existing giant fields, the highest possibility of finding future giant fields in Indonesia is within Jurassic rifted structures of the Australian passive margin, Miocene deep-water structures, and pre-Cenozoic fractured basement. This is assuming that the areas where these play types exist have not been extensively explored.

Satyana (2017) proposed future regional petroleum play types across Indonesia for exploration of hydrocarbon accumulations of all sizes. The proposed future play types can be grouped regionally into: (1) Paleogene syn-rift and pre-Cenozoic Basement of Sumatra-Java-Natuna-Barito, (2) Neogene delta and deep-water of eastern Kalimantan-Makassar Straits, (3) Paleogene syn-rift & post-rift of West Sulawesi, offshore-Bone-Gorontalo, (4) Gondwanan Mesozoic sections of Sumatra-Java-Makassar Straits, (5) Paleogene-Neogene sub- and intra-volcanic of Java-West Sulawesi, (6) collided Mesozoic Australian passive margin sediments in Gorontalo-Buton-Banggai-Sula-Outer Banda Arc and Lengguru-Central Ranges of Papua, (7) Paleozoic sections of Arafura Sea-South Papua, and (8) Neogene Pacific province of North Papua.

With regards to the play types of existing giant fields, in addition to geologic factors, tectonic settings (discussed in this paper), proposed future regional petroleum play types of Indonesia (Satyana, 2017), and level of exploration maturity/intensity of basin/area in Indonesia, the focus areas and play types of future giant fields of Indonesia can be considered as follows (with tectonic settings based on the classification of Mann et al. (2003)):

i. Pre-Cenozoic fractured basement horst blocks of Central Sumatra rifts.
   - continental rifts and overlying sag or "steer's head" basins.
   - subduction margins.

ii. Miocene-Pliocene deep-water structures of Tarakan Basin.
   - continental passive margins fronting major ocean basins.

iii. Jurassic rifted structures of Australian passive margins-collided since Neogene time of some areas of Outer Banda Arc, fold-thrust belt and foreland basin of the Central Ranges of Papua, Gorontalo Basin.
   - continental passive margins fronting major ocean basins, collided in Neogene time.

iv. Gondwanan Mesozoic sections of South Makassar Straits.
   - collisional margins produced by continental collision related to terrane accretion, arc collision, and/or shallow subduction.

Figure 5 shows the focus areas for exploring the possibilities of future large to giant accumulations in Indonesia.

Fractured basement (horst block) in Central Sumatra

This play involves a series of horsts and grabens where the grabens became the kitchen in which the organic-rich Pematang shales were deposited, matured, and generated hydrocarbons, charging fields on the horst blocks bordering the grabens (Marpaung et al., 2010) (Figure 6). Supergiant fields of Minas, Duri, Bangko, and Bekasap are located in the basement horst blocks bordering the Aman and Balam kitchen grabens (Figure 7). The basement horsts have been uplifted and deformed several times since the pre-Cenozioc, causing the horsts to become weathered and naturally fractured reservoirs. Most of the basement in these horst blocks is granitic (Williams and Eubank, 1995) (Figure 8) and borders the kitchen grabens that contain good quality and mature source rocks. Minas, Duri, Bangko, Bekasap drape the basement horsts and have been charged, and thus the likelihood of the fractured basements also being charged is real. Around 60 BBO were estimated to be generated in the grabens of Central Sumatra, 25 BBO of which were stored as OOIP of fields, this excludes the possibility of oils within fractured basement reservoirs. Accordingly, pre-Cenozoic fractured basement horst blocks of Central Sumatra provide interesting exploration potential, and could include future giant oil/gas fields like the giant Suban gas fields in Jambi and the giant oil field of White Tiger, offshore Vietnam. These two examples have geological similarities to the basement horsts of Central Sumatra.

Miocene-Pliocene deep-water structures of Tarakan Basin

This represents a continental passive margin fronting a major ocean basin (Figure 9). Here from west to east is a transition from Paleogene non-marine to marine sediments, Neogene deltaic to deep-water, to oceanic sea floor of the Celebes Sea. Most fields discovered in the Tarakan Basin relate to roll over anticlines from growth faulting, with some related to deep-water sedimentation, such as Aster and Tulip (Figure 9). However, the exploration in this basin has not been extensive, and thus discovering large to giant deep-water fields like those in outer Kutai-North Makassar Basin is theoretically possible. Recent discoveries in Tarakan onshore (Pidawan, Bajul Besar) and its offshore shelf area (Bedug-South Kecapi, Badik-West Badik) (Satyana, 2016b) show the potential of extending discoveries into deep-water Tarakan.

Jurassic rifted structures of Australian passive margins-collided since Neogene time

This play type typically occupies areas of the Outer Banda Arc (Timor and Arafura), the fold-thrust belt and foreland basins of the Central Ranges of Papua, and Gorontalo Basin. In some areas, the play type is producing, such as the gas and oil fields in Bintuni Basin, oil fields in Seram and asphalt field in Buton, or is under development, such as is the case for the Abadi gas field, Timor Sea.

Mesozoic sediments that were deposited along the passive margin of northern Gondwana/northern Australia continent, rifted in the Triassic/Jurassic, drifted, and collided with other terranes at various times throughout the Cretaceous through to the Neogene (Hall, 2002). This depositional and tectonic history was responsible for developing this platy type (Satyana, 2017). The parts of the rifted northern Australian continental margin which did not detach are now located on the NW Shelf of Australia, in the Timor Sea, to the east of Tanimbar and Kei islands, and in the Semai area to the SW of the Bird's Head, and to the south of Papua's Central Range. These areas collided with terrains of the outer Banda Arc (Timor, Tanimbar, Kei, and Seram) in the Neogene (Hall, 2002). The northern, rifted margin of the Australian continent to the south of Central Ranges of Papua collided with an island and formed the Central Ranges of Papua (Hall, 2002).

The resulting rift structures of Mesozoic passive margin sedimentary rocks of the Australian continent in NW Shelf of Australia, Timor Sea, and Bintuni Basin, have been prolific petroleum provinces. Large to giant gas fields and some oil fields have been discovered and are mostly producing. Flamingo, Sunrise-Troubadour, Evans Shoal, Bayu and Laminaria on the NW Shelf, Abadi in the Timor Sea, Vorwata, Wiriagar Deep, Ubadari, Roabiba, Ofaweri, Wos, Asap, and Merah in the Bintuni Basin are all examples of fields of the play type with main reservoirs and sources within Jurassic sandstones and carbonaceous shales. This play type is also proven in the collision zone of the Central Ranges of

Papua where the Mesozoic sequences were involved in the deformation. Exploration targets include Jurassic and Cretaceous clastics on the leading edge of the fold and thrust belt, and structural plays within Miocene carbonates. Prime examples of this play in Papua New Guinea (PNG) include the Elk/Antelope, Iagifu, Hedinia, Juha, Hides, and Kutubu which are reservoired in Jurassic-Cretaceous sandstones. Kau and Cross Catalina discoveries are the counterpart in the Indonesian Papua area. (Figure 10). The existence of large to giant fields in the fold-thrust belt of Indonesia's Papua Central Range and the foreland basins to the south (Akimeugah and Iwur Basins) is possible due to the fact that the basins are formed in the areas of pre-breakup Mesozoic Australian passive margin (Figure 11). Collision and deformation of this margin during the Neogene, developed the foredeep, formed hydrocarbon traps, and brought the Mesozoic sedimentary section into maturity.

In offshore areas, such as in the Timor Sea, rifted structures of the Mesozoic passive margin collided with the Banda Arc. The Abadi giant gas field is located in this area. Other large to giant fields may also be located on this trend, such as in the Semai area. However, several dry wells drilled in this area should provide lessons for further exploration (Satyana, 2016b, 2017). The wells indicated that deeply buried Jurassic reservoir rocks, and late-formed structures that post-date the main hydrocarbon charging periods were the key challenges. As such, the identification of shallower-buried Lower Jurassic sandstones and early-formed structures (in Late Miocene or Mio-Pliocene time) is vital to understanding the true prospectivity of the Semai area. Key to this process is successful reconstruction of many stratigraphic and structural sections and running seismic attribute analysis to predict reservoir quality after these reconstructions.

This Mesozoic play type is also considered to be prospective in the area of Gorontalo Basin, Sulawesi. Seismic data indicate a thick depositional basin with sediment thicknesses exceeding 6 seconds (TWT)/10 kilometers in the Gorontalo area, deformed forming multiple stacked rifts (Figure 12). Jablonski et al. (2007) interpreted some of the lower sequences as thick pre-break-up sedimentary sections of the Australian/Gondwanan passive margin. They report a "complex configuration of bedding—interpreted as remnants of older extensional rifts" and continue to explain that "thick, complicated bedding is common along the northern edge of the Gorontalo Basin" (Jablonski et al., 2007, page 3). They interpreted that "Mangkalihat in eastern Kalimantan and West Sulawesi, including Gorontalo were derived from Gondwana in the Late Triassic to Late Jurassic", and that "Separation of these blocks commenced 205 Ma, and subsequently, collided with Sunda sometime in the Late Cretaceous" (Jablonski et al., 2007, page 3). The new seismic data of Gorontalo area indicate the pre-Paleogene play includes the "older rift-fault blocks associated with the rifting of the Australian plate and subsequent collision with Borneo in the Cretaceous), some of which contain stacked reservoir–seal pairs sourced by multi-source rock intervals" (Jablonski et al., 2007, page 5), They continue to explain that the pre-Eocene collision elucidates the break-up history of Gondwana, drifting of terranes, and their collisions. Cenozoic sections of Gorontalo Basin also show the presence of Paleogene rifts (Figure 13) which are proven prolific in western Indonesia. They note that "Despite the complexity of the onshore geology, which displays mostly compressional features, the offshore region of the Gorontalo Basin predominantly displays extensional tectonics" (Jablonski et al., 2007, page 6). Large structures are observed at various stratigraphic levels (Figure 13), and they suggest "while still classified as a frontier region, the Gorontalo Basin offers an offshore opportunity that challenges the perception of the region." (Jablonski et al., 2007, pg 6).

Gondwanan Mesozoic sections of South Makassar Straits

The Cenozoic sections are the main economic stratigraphy of the sedimentary basins in western Indonesia (Sumatra, Java, Kalimantan, Natuna, and Makassar Straits). Historically, all petroleum exploration and production has focused on the Cenozoic sections. Pre-Cenozoic sections here are usually considered as economic basement of the basins. When the basement became the target of exploration in these basins, as discussed above, these pre-Cenozoic sections were evaluated but as fractured reservoirs only. The pre-Cenozoic sections in western Indonesia basins are typically thought to be metamorphosed, and thus have no more source capability to generate hydrocarbons. Oil or gas within fractured pre-Cenozoic reservoirs was derived from Paleogene sources, which has resulted in most explorationists to exclude these pre-Cenozoic sections in their petroleum system analyses, except in terms of fractured basement reservoirs.

However, deep seismic sections acquired in some areas of western Indonesia, such as the JavaSpan project by ION-GXT (Emmet et al., 2009), revealed very thick intervals of pre-Cenozoic sedimentary rocks, much thicker than had previously been thought to exist below the normally accepted acoustic basement (Figure 14). The survey imaged stratigraphic thicknesses of 5 to 10 km of pre-Middle Eocene strata locally preserved. Based on seismic characteristics, these pre-Cenozoic sections are thought to be unmetamorphosed, and so all the elements and processes of a petroleum system may be present in these deep sections. They also support the tectonic models that suggest the existence of Gondwanan/Australian microcontinents, which collided with SE Sundaland during the mid-Cretaceous (Satyana, 2014a, Figure 15).

The Sepanjang oil field, located at the southern margin of the Paternoster-Kangean micro-continent, shows that its oils were sourced by Mesozoic source rocks. Studies by Sutanto et al. (2015, 2016), and Satyana (2016a), based on various biomarkers, suggested that the source of oils are Lower Cretaceous marine shalesdeposited when the microcontinent drifted toward SE Sundaland. The Sepanjang oil field is located right on the Kemirian Terrace, which is considered the southern margin of the Paternoster-Kangean micro-continent. The margin is also the site of the later-developed major Sepanjang strike-slip fault, which may have provided a conduit to allow hydrocarbons derived from the Lower Cretaceous source beds to migrate vertically to fractured carbonate reservoirs of the Eocene Ngimbang Formation of the Sepanjang field. This shows that the Mesozoic section overlying the Gondwanan microcontinent has generated hydrocarbons, which have migrated to the available traps. Available deep seismic sections to the north of the area, in the South Makassar Straits, overlying the Paternoster-Kangean microcontinent, show the existence of thick Late Paleozoic and Mesozoic sections and large structures. Additional seismic data with better resolution and deeper coverage into the pre-Cenozoic objectives are required to better constrain this play type. Future large to giant discoveries may be located in the Mesozoic objectives in this area.

CONCLUSIONS

1. Seventeen oil and gas fields of Indonesia are classified as giant fields (Arun, Duri, Bangko, Bekasap, Suban, Banyu Urip, Attaka, Badak, Handil, Nilam, Tunu, NW Peciko, Gula, Senoro, Wiriagar Deep, Vorwata, Abadi), and two as supergiant fields (Minas, Natuna D-Alpha). They are distributed in eleven sedimentary basins, with total reserves 3P of 38.17 BBOE (12.47 BBO and 154.21 TCFG, two thirds are gas fields).

2. The number of giant-supergiant fields in Indonesia makes up less than 2% of all fields of all sizes, but most of the production of oil and gas comes from these giant-supergiant fields. They also hold most of the reserves (similar trend, globally), so are clearly very important. However, 86 % of the giant oil fields have been depleted and so the discovery of new giant fields is paramount. More than half producing giant gas fields are depleted, while other gas fields are under-development or undeveloped.

3. To explore systematically the possibilities of future giant fields in Indonesia, the play types, geologic factors, and tectonic settings of existing giant fields were evaluated. Nineteen giant-supergiant fields of Indonesia can be grouped into six play types with each total reserves 3P as follows:

   a. Miocene reefal build-ups (four fields: 11,224 MMBOE),
   b. Miocene inverted structures (five fields: 10,208 MMBOE),
   c. Miocene deltaic structures (six fields: 8,895 MMBOE),
   d. Jurassic rifted structures of Australian passive margin (four fields: 6351 MMBOE),
   e. Pre-Cenozoic fractured basement (one field: 950 MMBOE), and
   f. Miocene deep-water structures (two fields: 545 MMBOE).

4. Considering the geologic factors, tectonic settings, future regional petroleum play types of Indonesia (Satyana, 2017), and the level of exploration maturity/intensity of basins/areas in Indonesia, the focused areas and play types of future giant fields of Indonesia may be as follows:

   a. Pre-Cenozoic fractured basement of horst blocks of Central Sumatra rifted structures.
   b. Miocene-Pliocene deep-water structures of the Tarakan Basin.
   c. Jurassic rifted structures of Australian passive margins, colliding with other terranes since the Neogene: some areas of the outer Banda Arc, fold-thrust belt and foreland basin of the Central Ranges of Papua, and Gorontalo Basin.
   d. Gondwanan Mesozoic sections of the South Makassar Straits.

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TABLE 1

GIANT FIELDS (RESERVE OF EACH FIELD ≥ 500 MMBO OR ≥ 3 TCFG) AND SUPERGIANT FIELDS (RESERVE OF EACH FIELD ≥ 5000 MMBO OR ≥ 30 TCFG) OF INDONESIA. SOURCES AND STATUS OF DATA AND ARE EXPLAINED BELOW THE TABLE

GIANT - SUPERGIANT FIELDS OF INDONESIA

NO.	FIELD	BASIN	DISCOVERY YEAR	DISCOVERY COMPANY	RESERVE (MMBO)	RESERVE (TCFG)	RESERVE (MMBOE)	PLAY TYPE
1	ARUN	NORTH SUMATRA	1971	MOBIL OIL		13.08	2180	MIOCENE REEFAL BUILD UP
2	NATUNA D-ALPHA	EAST NATUNA	1973	ESSO		46.30	7717	MIOCENE REEFAL BUILD UP
3	SENORO	BANGGAI	1999	JOB PERTAMINA-ARCO		3.59	598	MIOCENE REEFAL BUILD UP
4	BANYU URIP	NORTHEAST JAVA	2001	EXXONMOBIL	729		729	MIOCENE REEFAL BUILD UP
5	DURI	CENTRAL SUMATRA	1941	CALTEX	3483		3483	MIOCENE INVERTED STRUCTURE
6	MINAS	CENTRAL SUMATRA	1944	CALTEX	5445		5445	MIOCENE INVERTED STRUCTURE
7	BEKASAP	CENTRAL SUMATRA	1955	CALTEX	633		633	MIOCENE INVERTED STRUCTURE
8	BANGKO	CENTRAL SUMATRA	1970	CALTEX	647		647	MIOCENE INVERTED STRUCTURE
9	ATTAKA	KUTAI	1970	UNION OIL	668		668	MIOCENE DELTAIC STRUCTURE
10	BADAK	KUTAI	1972	HUFFCO		6.78	1130	MIOCENE DELTAIC STRUCTURE
11	HANDIL	KUTAI	1974	TOTAL	867		867	MIOCENE DELTAIC STRUCTURE
12	NILAM	KUTAI	1974	HUFFCO		5.30	883	MIOCENE DELTAIC STRUCTURE
13	TUNU	KUTAI	1982	TOTAL		23.85	3975	MIOCENE DELTAIC STRUCTURE
14	NW PECIKO	KUTAI	1991	TOTAL		8.23	1372	MIOCENE DELTAIC STRUCTURE
15	WIRIAGAR DEEP	BINTUNI	1994	ARCO		6.08	1013	JURASSIC RIFTED STRUCTURE OF AUSTRALIAN PASSIVE MARGIN
16	VORWATA	BINTUNI	1996	ARCO		14.03	2338	JURASSIC RIFTED STRUCTURE OF AUSTRALIAN PASSIVE MARGIN
17	ABADI	MALITA-CALDER	2000	INPEX		18.00	3000	JURASSIC RIFTED STRUCTURE OF AUSTRALIAN PASSIVE MARGIN
18	SUBAN	SOUTH SUMATRA	1998	GULF		5.70	950	PRE-TERTIARY FRACTURED BASEMENT
19	GULA	NORTH MAKASSAR	2000	UNOCAL		3.27	545	MIOCENE DEEP WATER STRUCTURE

NOTE

1. All reserves are 3P (proven+probable+possible).
2. Reserves of Arun, Duri, Minas, Bekasap, Bangko, Attaka, Badak, Handil, Nilam, Tunu, NW Peciko are based on Pertamina (2000).
3. Natuna D-Alpha is undeveloped, the reserve here is contingent recoverable reserve (Pertamina, 2000).
4. Gula is undeveloped, the reserve here is contingent recoverable reserve (U.S. Energy Information Administration, 2018).
5. Reserve of Senoro is based on U.S. Energy Information Administration (2018).
6. Reserves of wiriagar Deep and Vorwata are based on Marcou et al. (2004 - IPA Proceedings).
7. Reserves of Banyu Urip, Abadi, Suban are based on current data as the fields are produced (Suban & Banyu Urip) or developed (Abadi).

GIANT - SUPERGIANT FIELDS OF INDONESIA

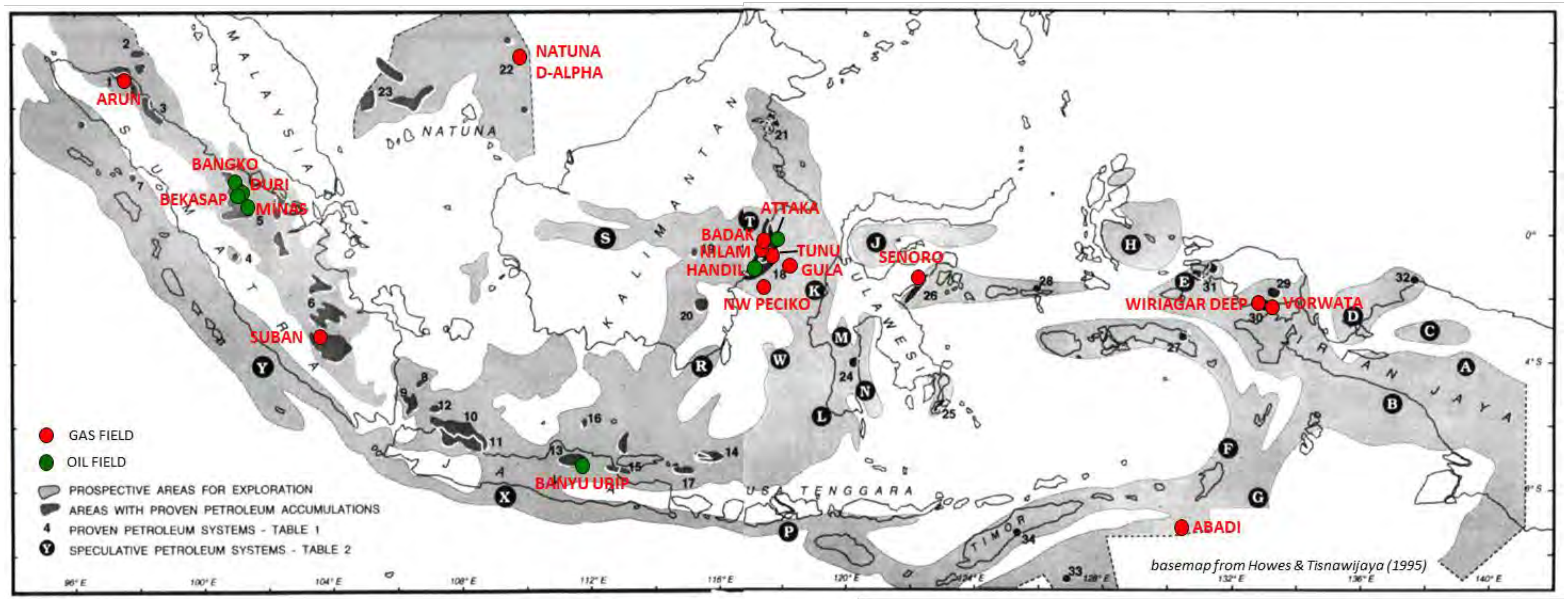


Figure 1 - Locations of giant and supergiant oil or gas fields of Indonesia. Supergiant fields are Minas oil field (producing, cumulative production between 4.5 to 5.0 billion barrels of oil) and Natuna D-Alpha (46.3 TCFG of methane gas, undeveloped). The two fields are the largest fields in Southeast Asia.

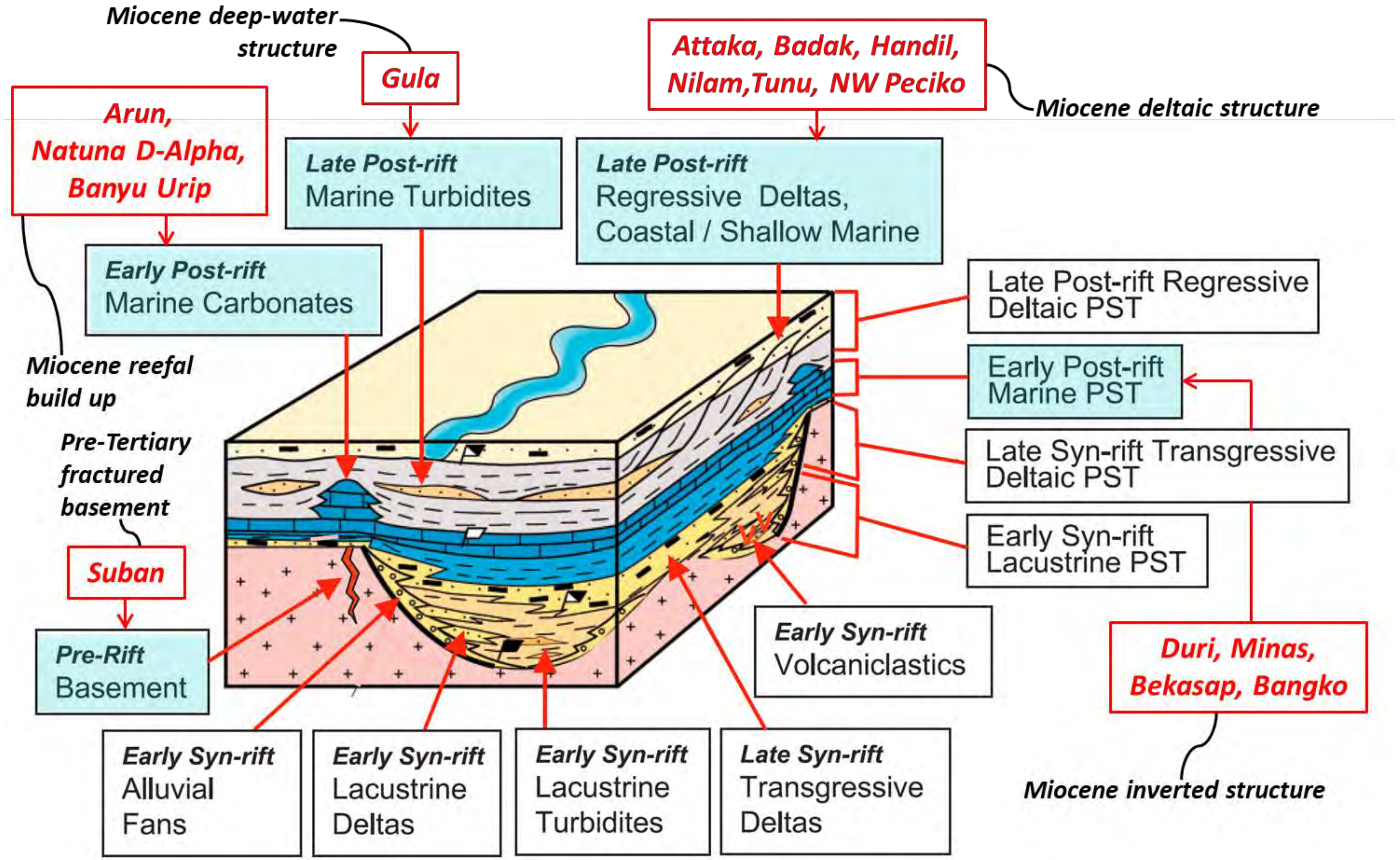


Figure 2 - Schematic diagram showing major lithofacies reservoir plays belonging to the four petroleum system types (PSTs) for SE Asian Cenozoic rift basins (Doust and Sumner, 2007; modified). Boxes filled with light blue color compose the giant fields of western Indonesia with the name of fields are indicated by red boxes, and the name of play types are added to the boxes. Example: pre-rift basement composes the giant field of Suban with the play type of pre-Cenozoic fractured basement.

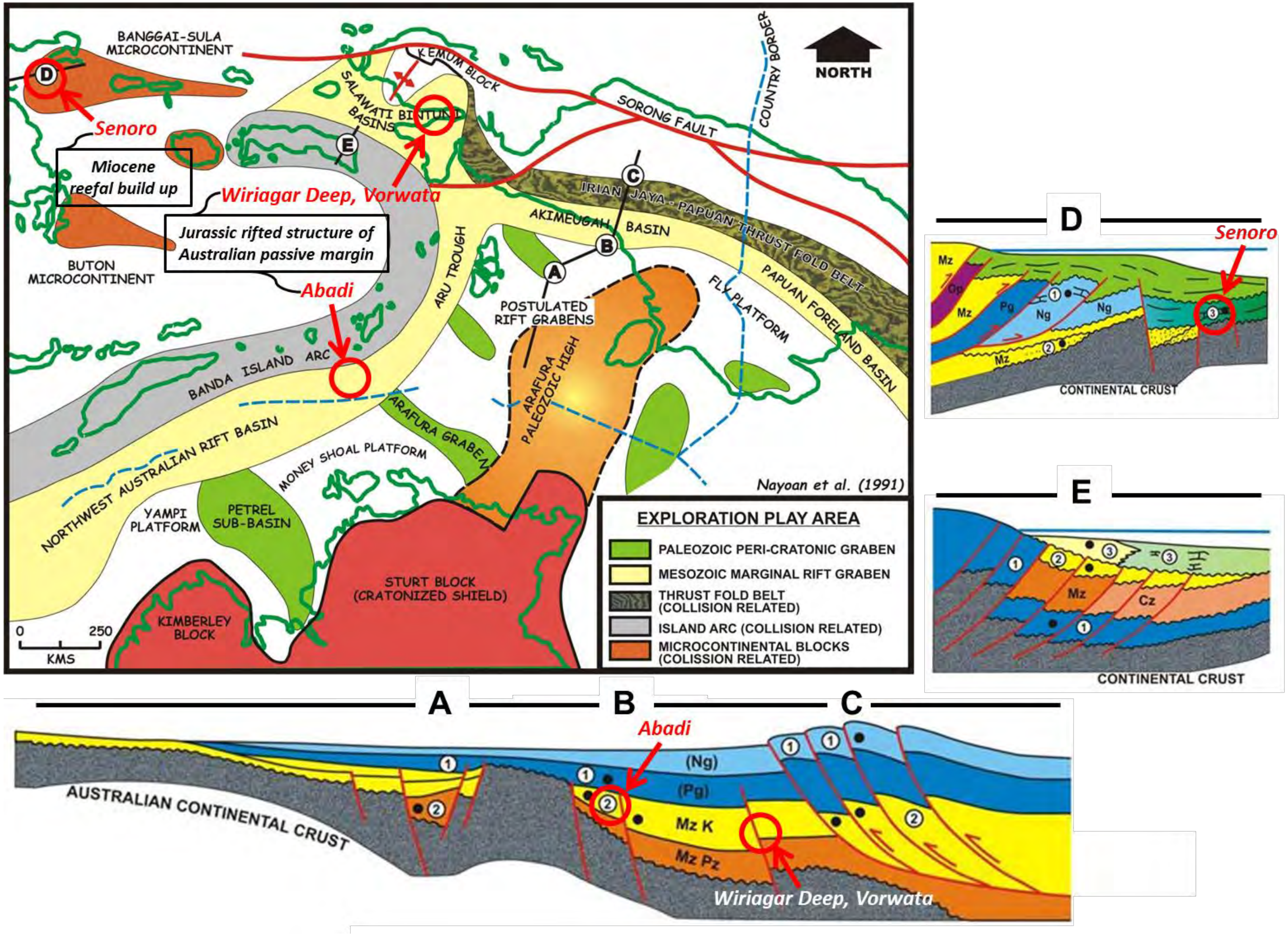


Figure 3 - Map and schematic cross sections of exploration play types of eastern Indonesia (modified after Nayoan et al., 1991). The locations of four giant gas fields of eastern Indonesia are indicated (Senoro, Wiriagar Deep, Vorwata, Abadi) on the map and the section with their play types written in the boxes.

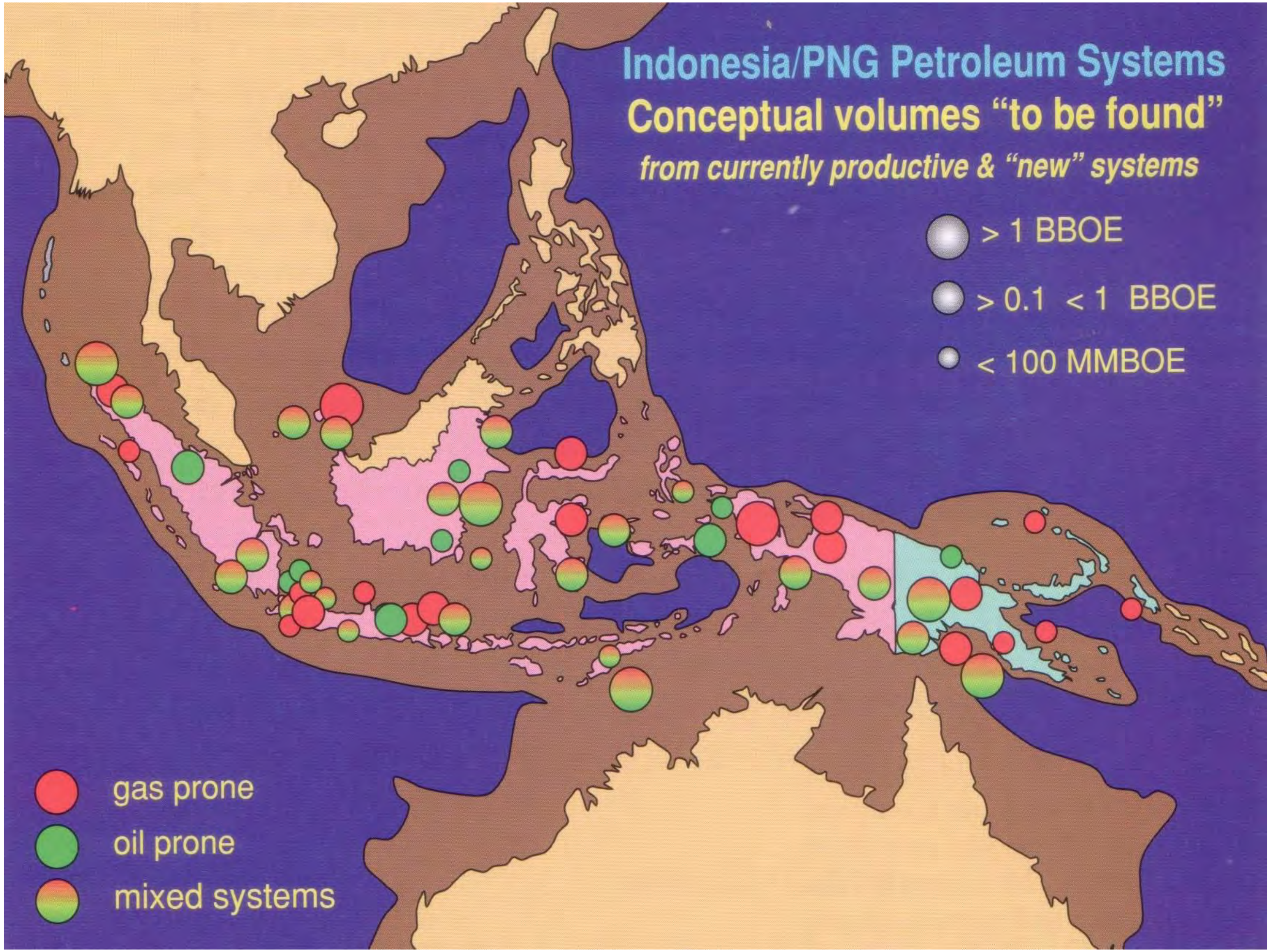
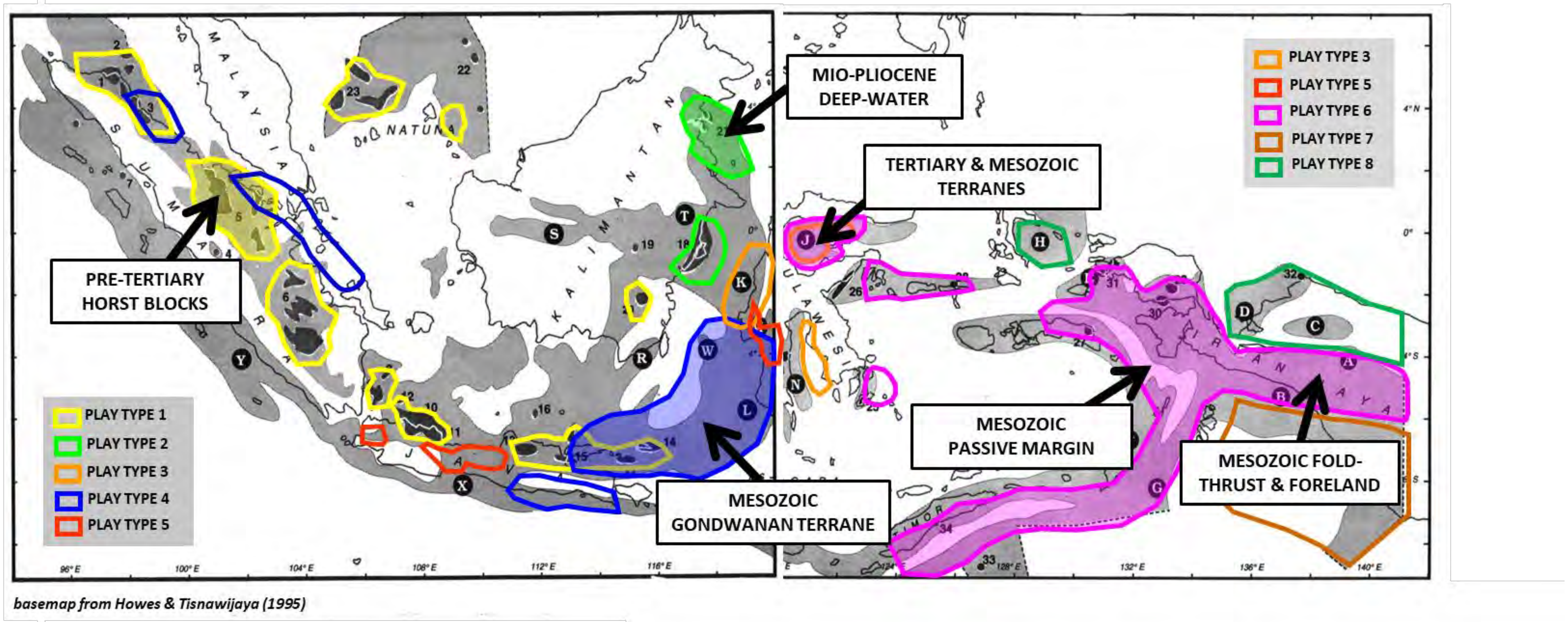


Figure 4 - Future conceptual volumes of hydrocarbons to be found in Indonesia and Papua New Guinea (Howes, 2001), prospective volumetric illustrated by sizes of circles shows that large to giant discoveries in the region are possible.

FUTURE REGIONAL PLAY TYPES OF INDONESIA & FOCUSED AREAS FOR POSSIBLE GIANT FIELDS



PLAY TYPES: (1) Paleogene synrift and pre-Tertiary Basement of Sumatra-Java-Natuna-Barito, (2) Neogene delta and deepwater of eastern Kalimantan-Makassar Straits, (3) Paleogene synrift & postrift of West Sulawesi offshore-Bone-Gorontalo, (4) Gondwanan Mesozoic sections of Sumatra-Java-Makassar Straits, (5) Paleogene-Neogene sub- and intra-volcanic of Java-West Sulawesi, (6) collided Mesozoic Australian passive margin sediments in Gorontalo-Buton-Banggai-Sula-Outer Banda Arc-Lengguru-Central Ranges of Papua, (7) Paleozoic sections of Arafura Sea-South Papua, (8) Neogene Pacific province of North Papua.

Figure 5 - Future regional play types of Indonesia (Satyana, 2017). Areas of play types with possible future discoveries of giant fields to focus based on existing data and geological concepts are indicated with large arrows and the areas are shaded, names of related play types are put in the boxes.

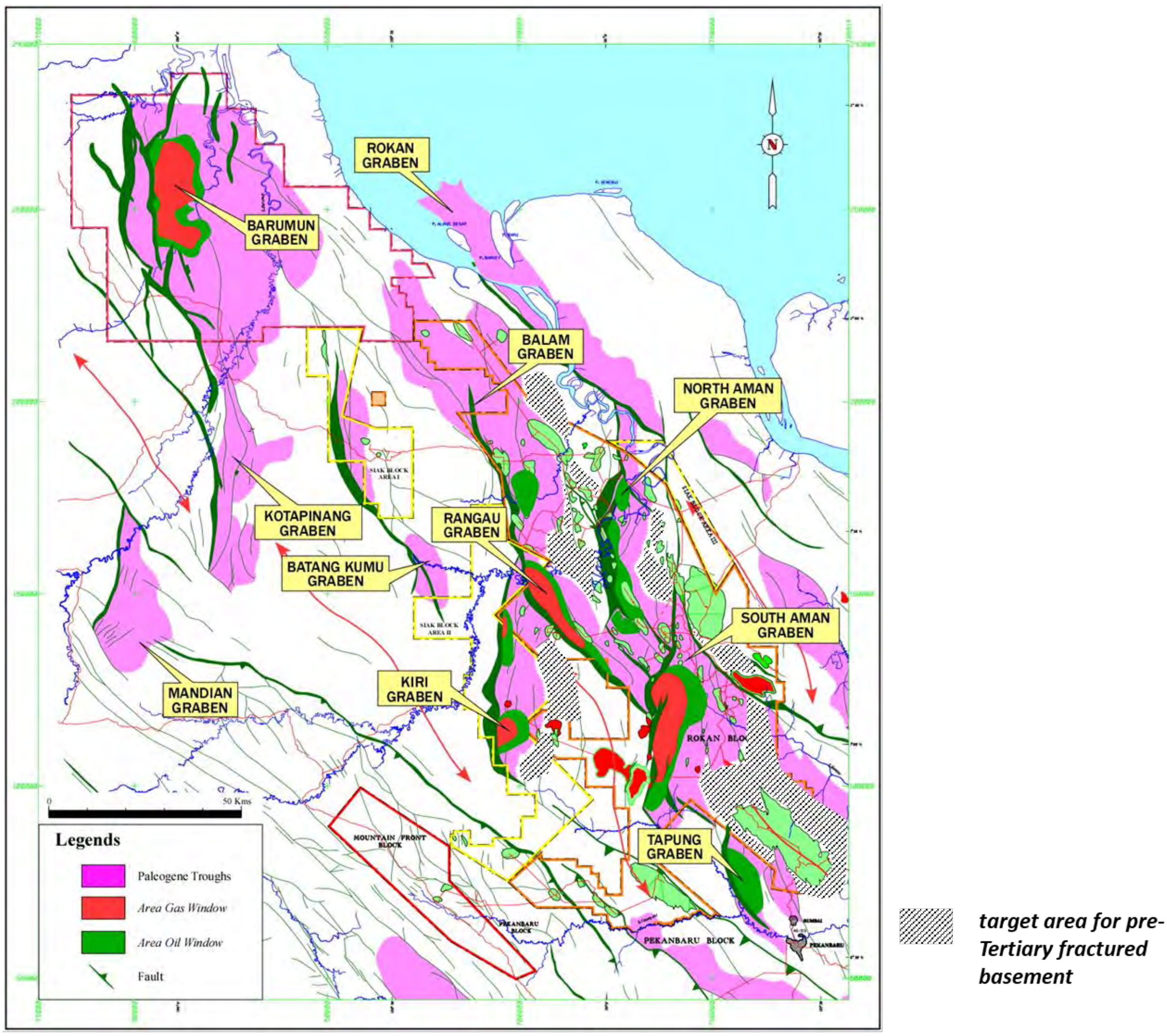


Figure 6 - Rifted basement of the Central Sumatra Basin resulted in a series of horsts (white area) and grabens (pink colored area) filled with Paleogene sediments. Paleogene grabens/troughs become the proven kitchens. A number of fields (light green) are indicated (Marpaung et al., 2010; modified). The area of horst blocks close to, and are encircled by, kitchen grabens (shaded by tilted lines) are possible objectives for giant field accumulation in pre-Cenozoic fractured basement.

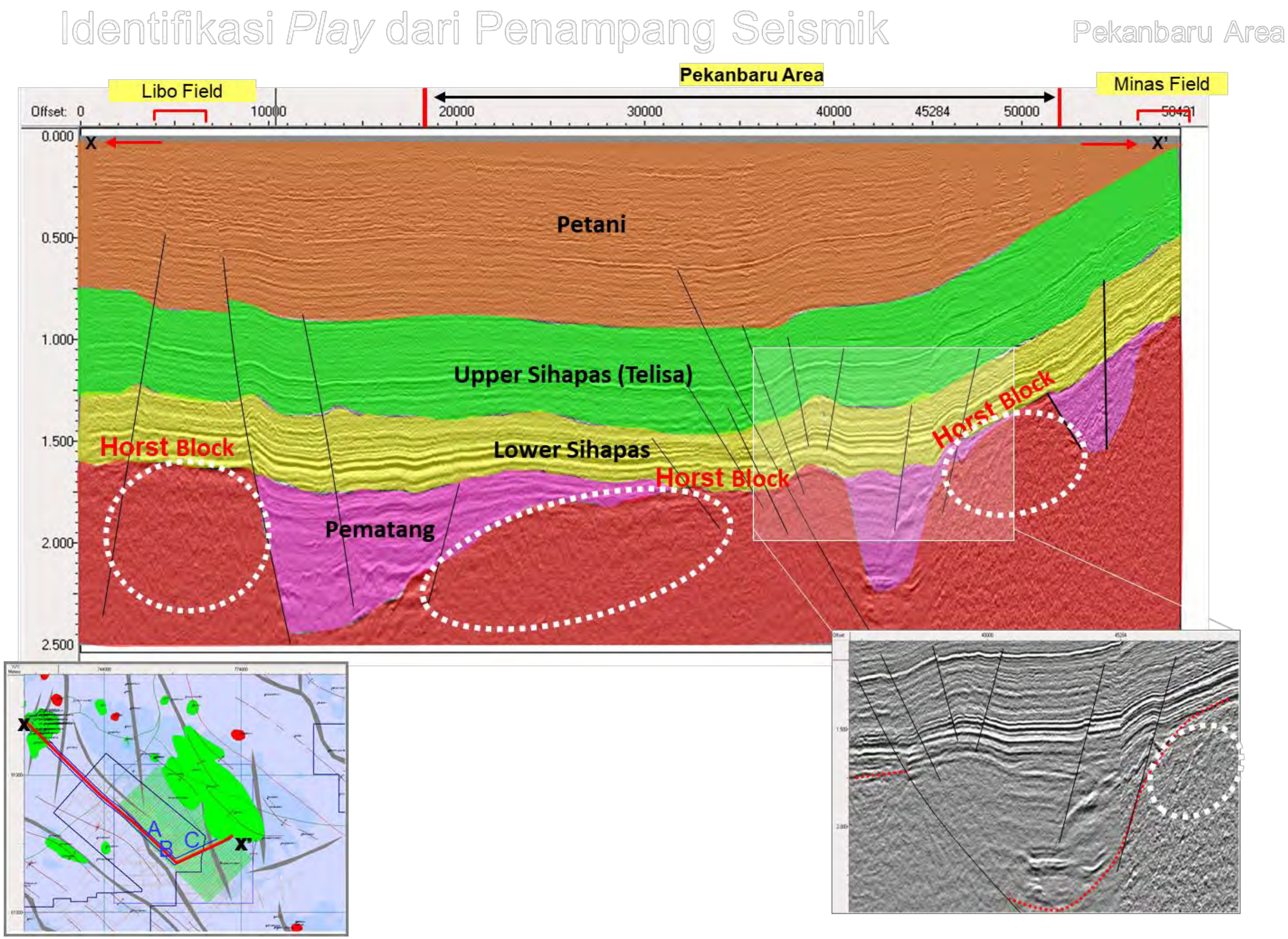
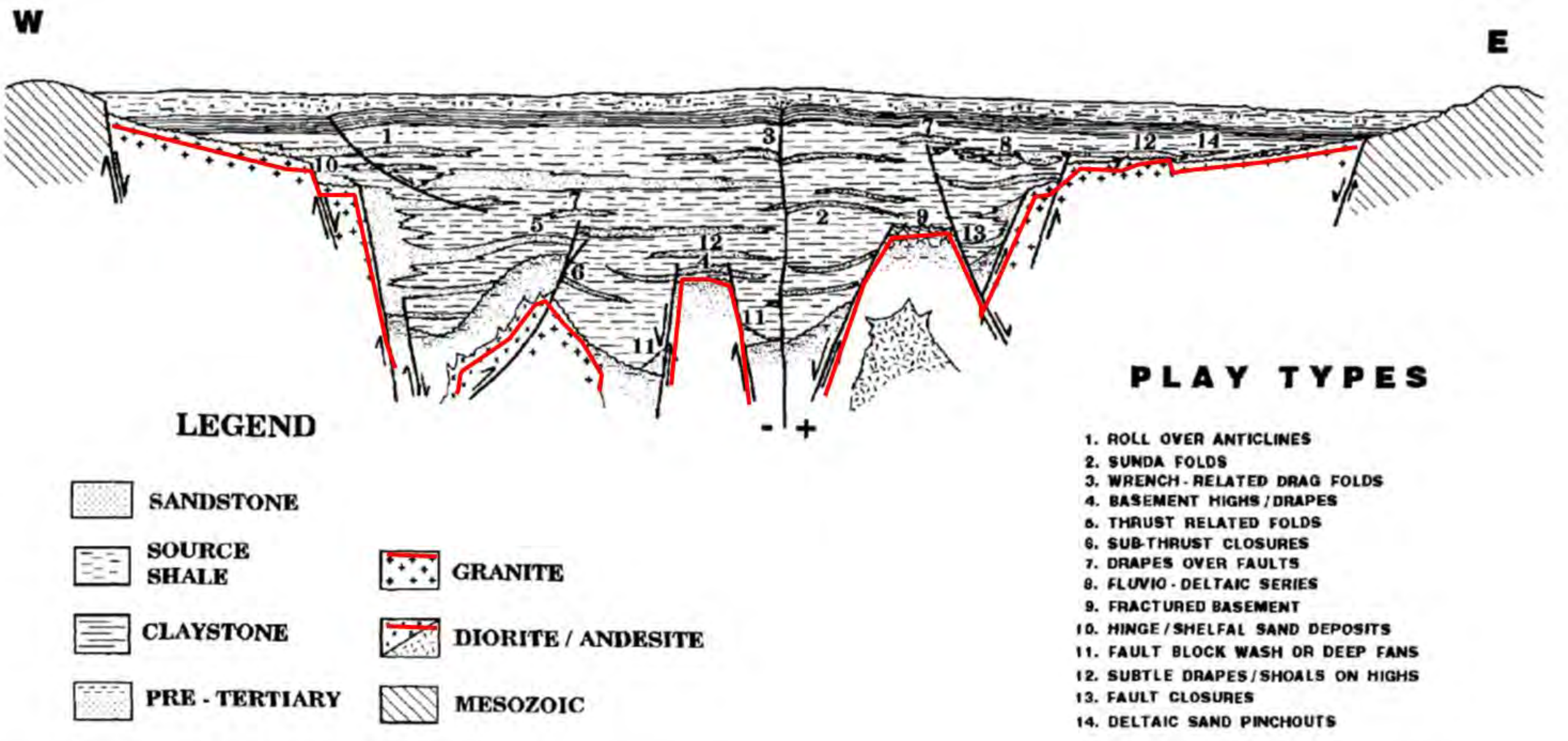


Figure 7 - A seismic section in Central Sumatra Basin traversing Libo Field to part of Minas Field through kitchen grabens of South Aman and Tapung and a number of horst blocks. Targets of pre-Cenozoic fractured basement are possible on the horst blocks (indicated by white ellipses), charged by oils generated from the adjacent kitchens. The kitchens are proven as oil generators.



The factors that have contributed to the prolific oil production of the Central Sumatra Basin include:

1. **Presence of graben and half-graben rifts with thick organic-rich lacustrine shales;**
2. **Presence of an overlying marine Miocene sandstones sequence with high porosity and permeability;**
3. **High heat flow since the mid-Miocene which has resulted in maturation of the organic-rich lacustrine shales;**
4. **Favorable timing of structures by wrench-related folding and faulting in the Late Oligocene to Middle Miocene;**
5. **Focused migration, short migration distances and presence of an excellent carrier system.**

Figure 8 - Diagrammatic cross section of producing & prospective plays in Central Sumatra syn-rift sequences (Williams and Eubank, 1995). Note the presence of basement horst blocks (indicated by red lines) composed mainly of granite. Granite is the best composition for basement to fracture as naturally fractured reservoirs as proved by fields in SE Asia. The horst blocks are adjacent to proven kitchen grabens. This is good condition for targeting horst blocks of Central Sumatra as exploration objective.

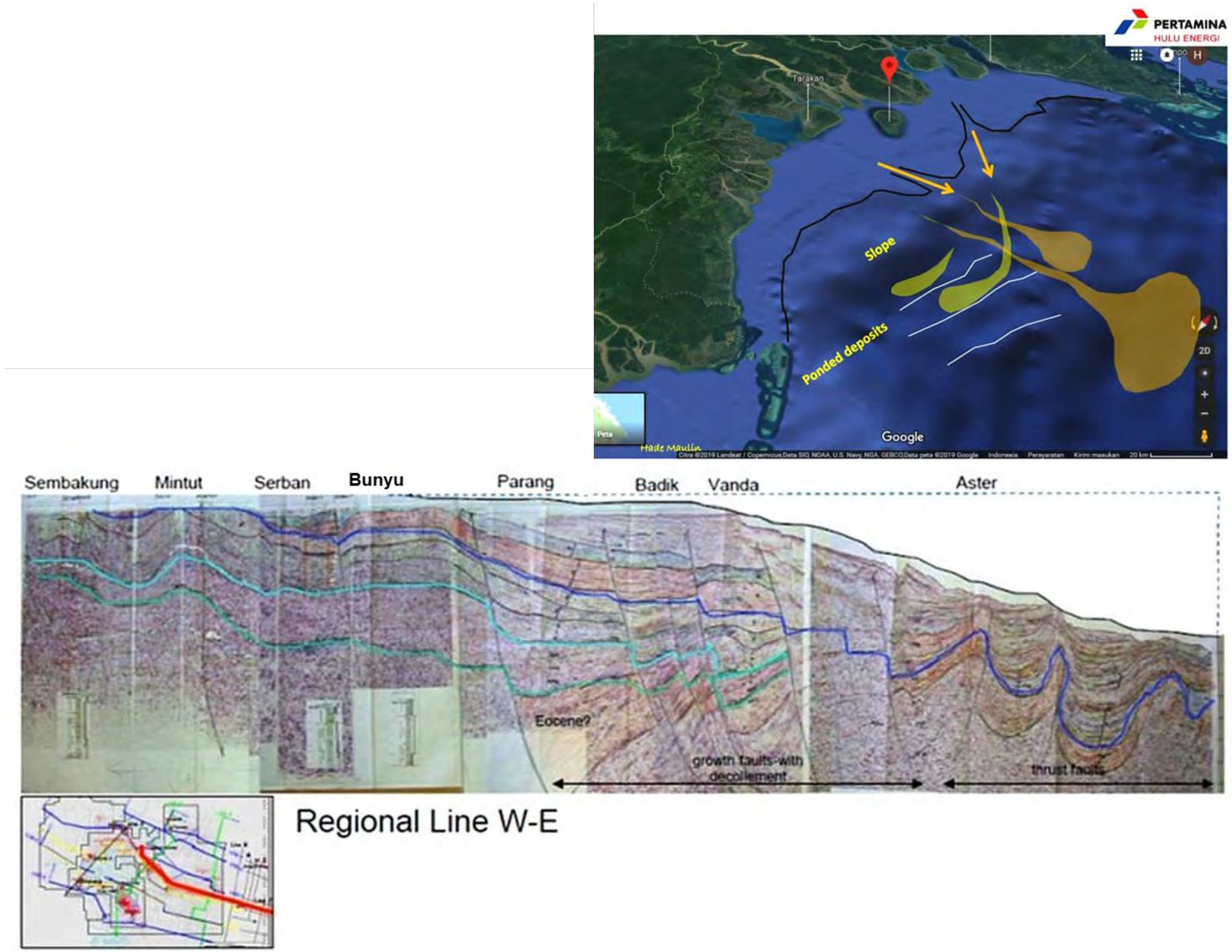
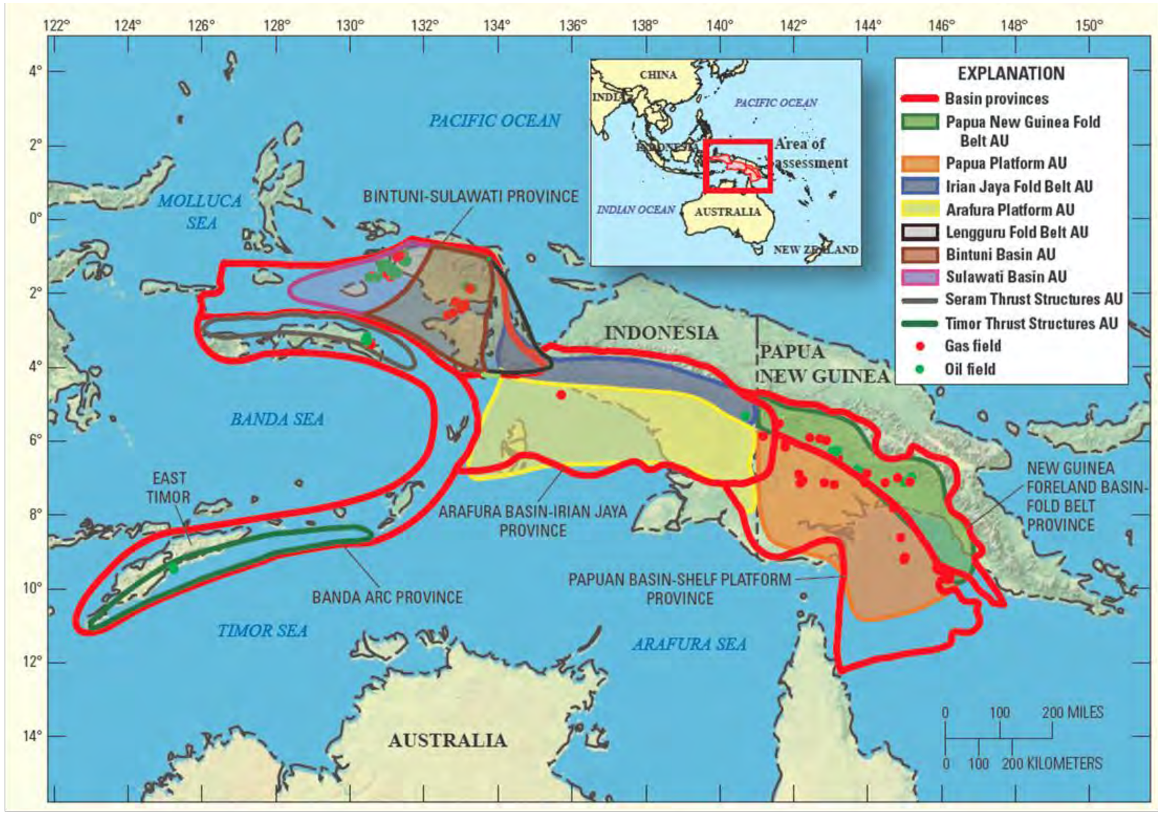


Figure 9 - Google map of Tarakan area (Bunyu Island is indicated by red bubble location). Physiographically, the map preserves attributes by sedimentary and tectonic processes like deposition of sediments prograding to open ocean-direction of arrows (delta, slope, feeder channel, submarine fan deposits), presence of toe thrusts (white line) which may divert and confine sediments to be ponded. Seismic section below the map shows the sedimentary and structural styles of the Tarakan Basin, from delta, shelf and slope, to deep-water. Attributes on map and section show potentials of exploring deep-water plays in Tarakan Basin which so far has been inadequate. Large to giant fields have been discovered in North Makassar Basin to the south of Tarakan Basin, this can provide success analogues. (map and section is interpreted by Hade Maulin – Pertamina Hulu Energi-Nunukan).



Total petroleum systems (TPS) and assessment units (AU)	Field type	Largest expected mean field size	Total undiscovered resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Irian Jaya Fold Belt AU	Oil	235	330	836	1,863	932	2,305	5,916	13,400	6,629	35	93	214	104
	Gas	1,411					1,955	4,995	11,288	5,601	32	83	190	93
Arafura Platform AU	Oil	95	241	496	957	534	1,478	3,103	6,054	3,352	23	49	97	53
	Gas	1,545					7,671	14,928	27,524	15,910	135	263	489	281

Figure 10 - Geologic provinces of Papua and other regions as undiscovered resources assessment by U.S. Geologic Survey (Schenk et al., 2011). Results of assessment is on the table below the map, put only for the areas of Papua fold belt (Irian Jaya Fold Belt AU –assessment unit) and Papua foreland (Arafura Platform AU). The results (note the mean volumetric) show the possibilities of finding giant resources for oil or gas fields.

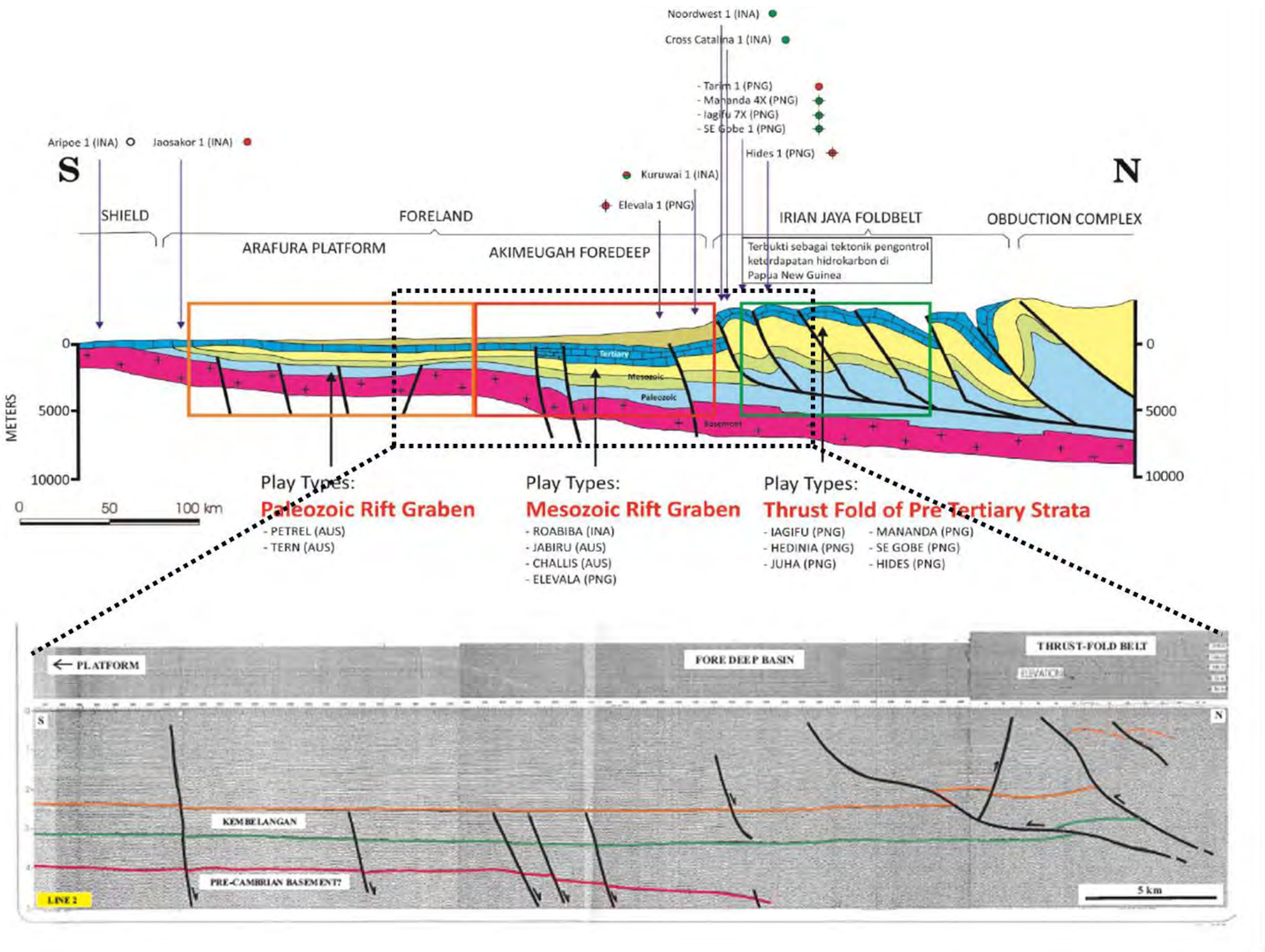


Figure 11 - Schematic cross section and seismic section from South Papua (Arafura Platform) to the Central Ranges of Papua (Pertamina and Beicip, 1992), showing regional play types of rifted Paleozoic and Mesozoic sections and thrust fold belt. Fields related to Paleozoic, Mesozoic, and thrust fold belt are indicated. These become the analogues for exploring Papua foreland and Papua fold-thrust belt for possibilities of future large to giant fields.

Gorontalo Basin: Stacks of Mesozoic & Tertiary Rifts

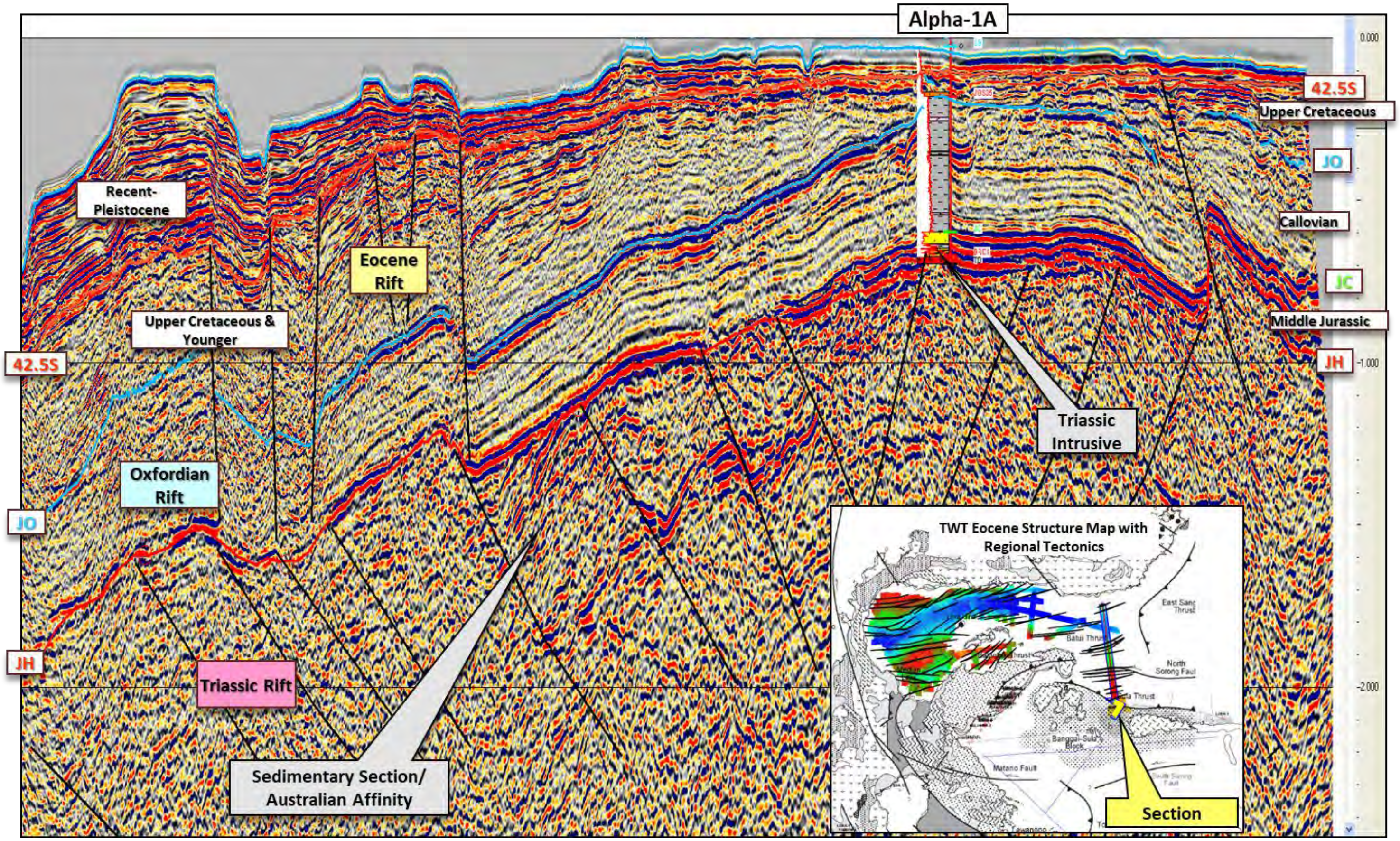


Figure 12 - A seismic section in Gorontalo area (Jablonski et al., 2007), showing thick sedimentary sequences interpreted as multiple stacks of rifts from Jurassic to Miocene. Well Alpha-1, TD in the Triassic was used as a basis for seismic horizon interpretation. The Oxfordian rifts of Lower to Middle Jurassic are typical of Australian passive margin sediments, interpreted to be drifted and collided with Sundaland in the Late Cretaceous. The Eocene rifts are typical of Paleogene rifts in Sundaland, and to be interpreted as extension of the Makassar Straits, forming the play type of Paleogene synrift & postrift of Gorontalo. Stacks of these rifted sequences provided Gorontalo Basin with many petroleum opportunities.

Gorontalo Basin Prospectivity

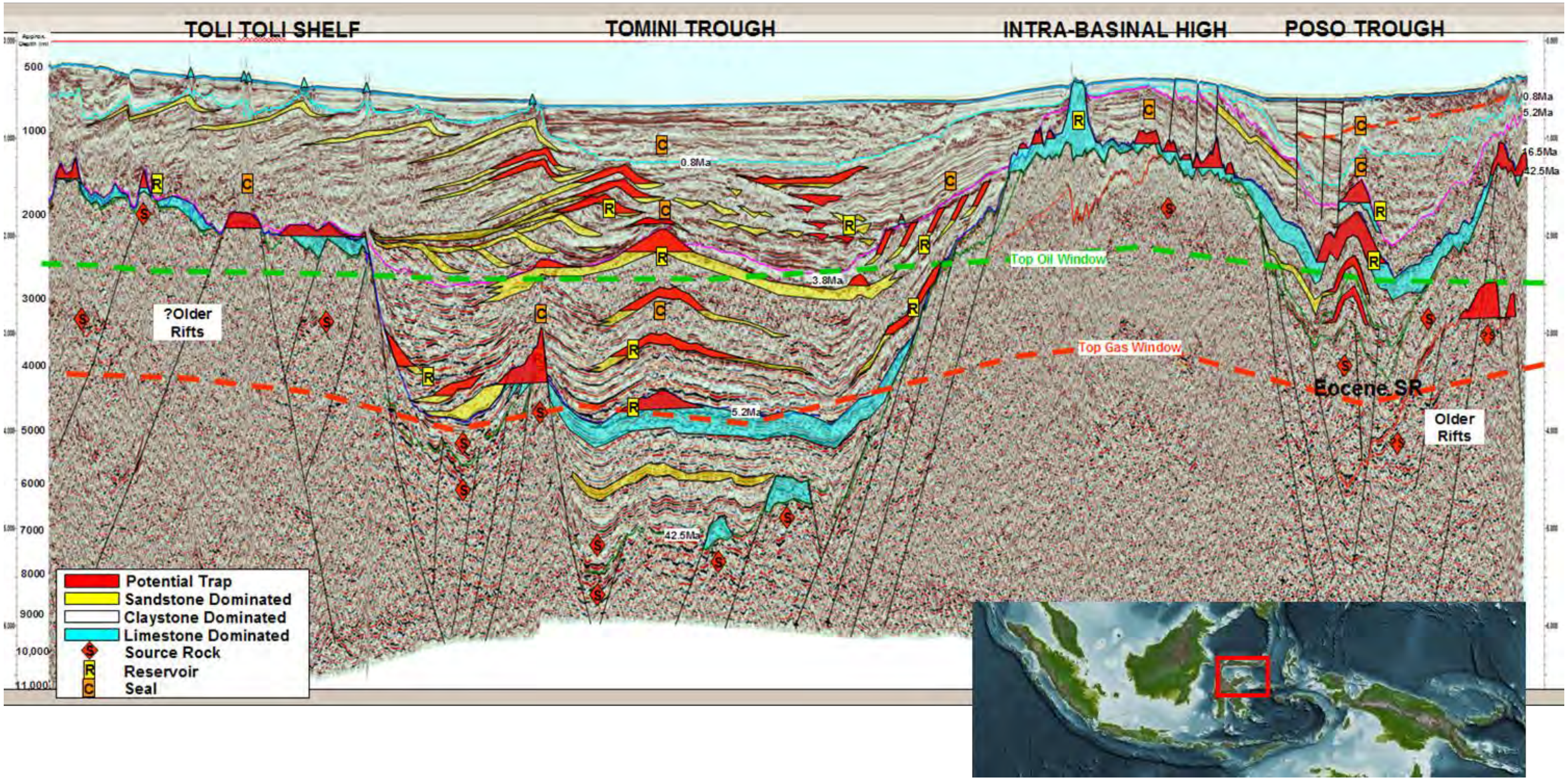


Figure 13 - A seismic section in Gorontalo area (Jablonski et al., 2007), showing prospectivity of the Cenozoic objectives with many potential traps development. Gorontalo area is the eastern margin of Sundaland, it preserves the presence of the Paleogene rifts which are typical to Sundaland basins.

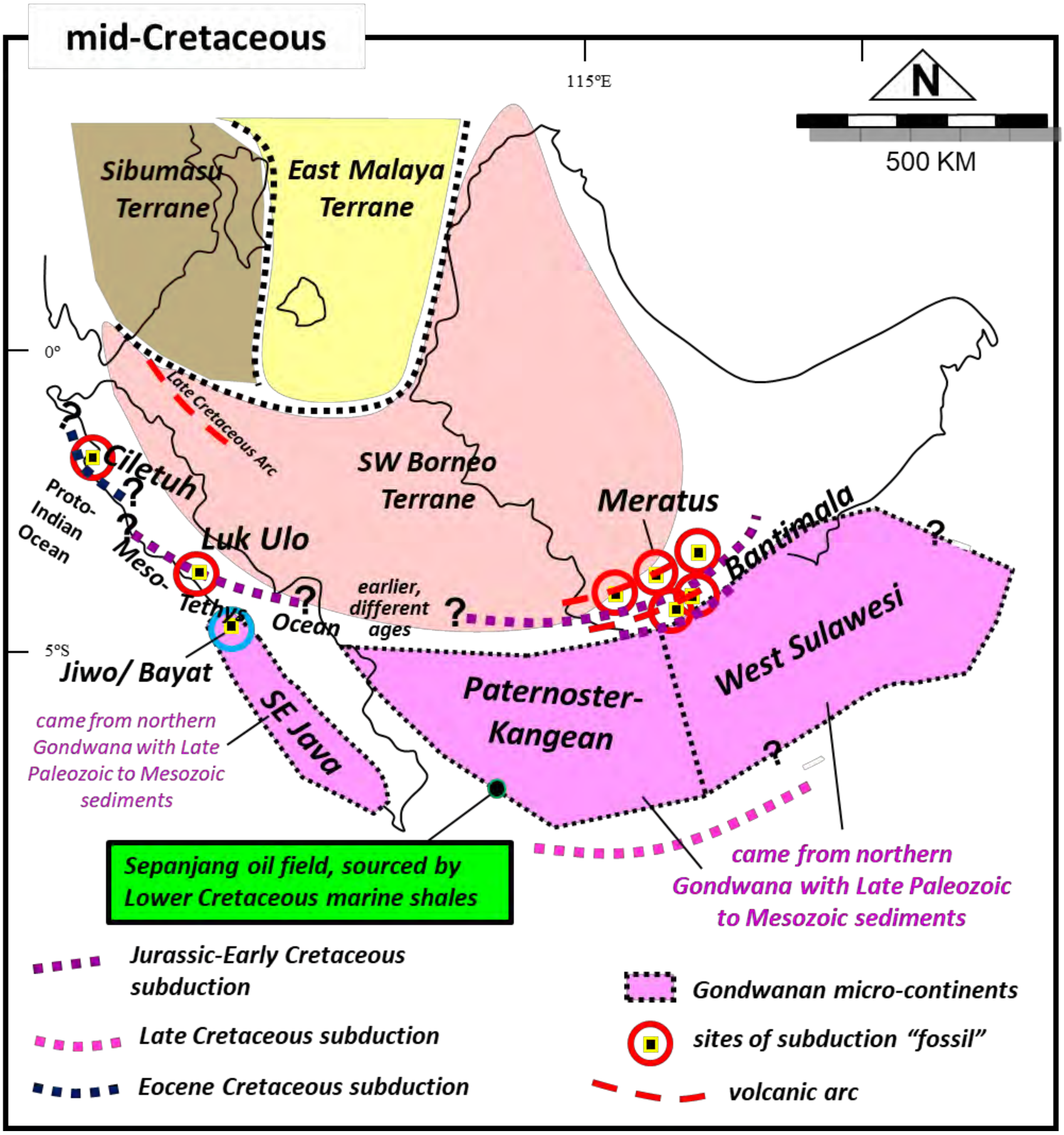


Figure 14 - New tectonic reconstruction of SE Sundaland (in mid-Cretaceous time - Satyana, 2014a, 2016a; modified) provides new regional framework of petroleum geology of SE Sundaland, mainly for pre-Cenozoic objectives. The presence of Gondwanan micro-continents colliding SE Sundaland is proven by drilling and field geology. Late Paleozoic and Mesozoic sediments of pre-drifting and syn-drifting sequences overly the micro-continents. The sediments have potentials for pre-Cenozoic petroleum system in these areas. Sepanjang oil field in Kangean area, reservoired by Eocene fractured carbonates, were sourced by Lower Cretaceous marine shales deposited when the microcontinent drifted to this area (geochemically proven – Sutanto et al., 2015, 2016; Satyana, 2016a). The presence of Mesozoic sediments overlying the microcontinent and the evidence of Lower Cretaceous sourced-oils in Sepanjang field show the prospectivity of Mesozoic in this area. Mesozoic targets have resulted in giant discoveries in eastern Indonesia, and these can be analogues for SE Sundaland.

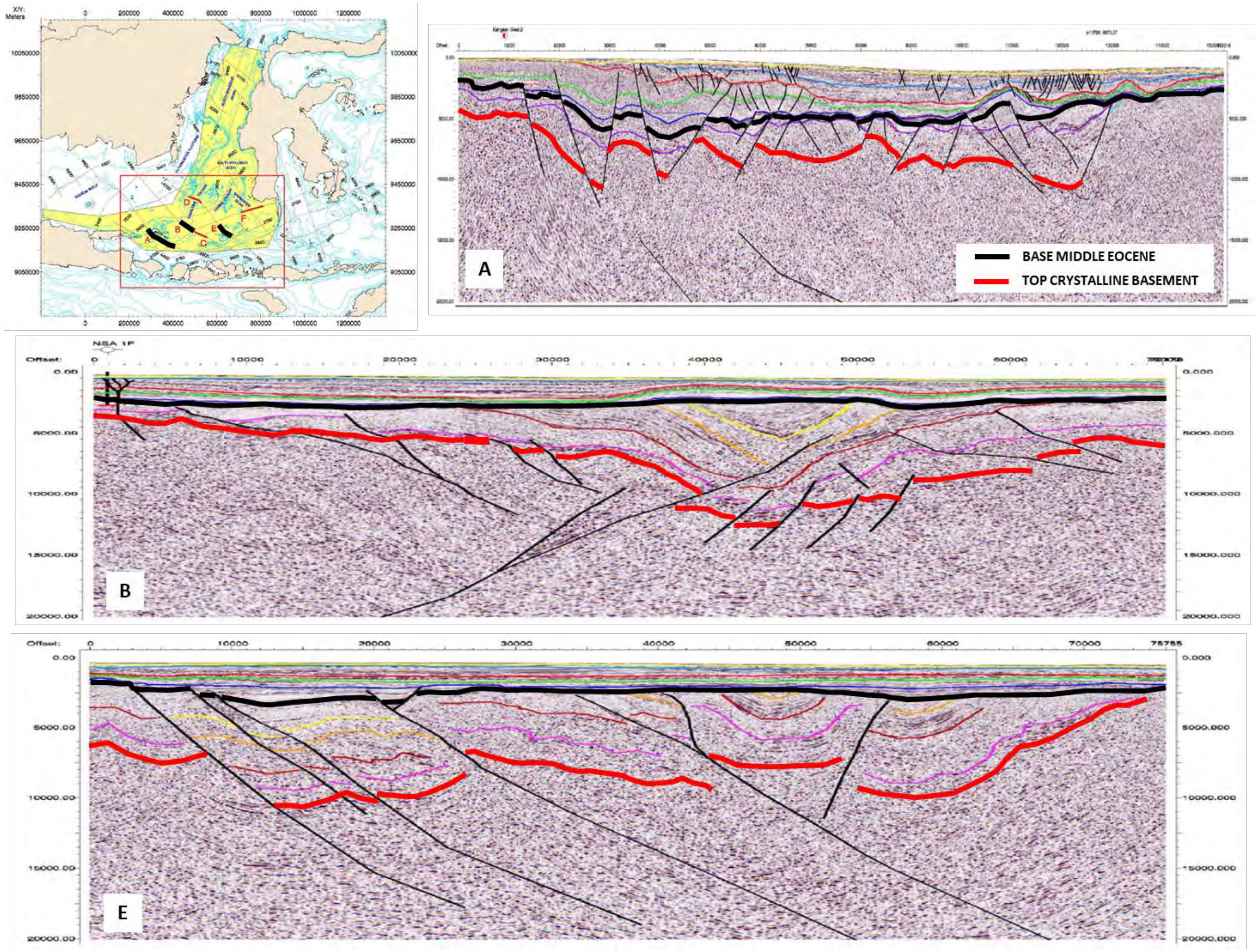


Figure 15 - Some deep seismic sections of JavaSPAN at Kangean area, East Java Sea (Emmet et al., 2009, modified). The bold black horizon is the base Middle Eocene, formerly interpreted as top of Basement on shallow seismic data. Bold red horizon is considered as top of the crystalline Basement. Based on these new deep seismic data, there are around five km of pre-Cenozoic sedimentary sections considered Mesozoic and Late Paleozoic in ages remain unexplored, this opens opportunities to explore Mesozoic sections in the South Makassar Straits, Mesozoic targets have resulted in giant discoveries in eastern Indonesia, and these can be analogues for their detached terrane in SE Sundaland.