Zone of Interest Gas Shale Potential For Deep Gas Exploration with Lacustrine Facies Model and Geochemistry Analyze From Nindy Deep Well#1 And Nindy Deep Well#2 Pematang Group-South Aman Trough-Central Sumatera Basin

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Shale gas is unconventional energy that is currently developed by Indonesia. Shale gas use as a source rock from shale as well as their reservoir. The rising price of gas is more economicist then Indonesia is now developing the potential of shale gas resources to increase the productivity of gas to meet gas demand in Indonesia so It's required for study and exploration of potential shale gas in Indonesia. The object of this shale gas potential research is come from Pematang Group, Aman South Trough, Central Sumatra Basin. This study is very interesting because it requires the analysis from deep wells sample because shale gas is become from source rock as a reservoir, so for exploration will be called deep gas exploration.The analysis data is come from log, seismic and geochemistry analysis from Nindy Deep Well. The depth of Nindy Deep Well#1 reaching 8175ft and Nindy Deep Well#2 reaching 9000ft. From the results of geochemical studies with analysis of rockeval pyrolysis zone interest of Nindy deep well # 1 is at a depth of 6280 ft -6610 ft with shale lithology, TOC values range from 3.49% -6.62%, Yield Potential (S1 + S2)11.7 to 27 mg / g, Hydrogen Index 262-384 mg HC / g org.C and Tmax (pyrolysis temperature) range values 439-4430 C. While the zone of interest Nindy Deep Well # 2 is at a depth of 7800-7920 ft with shale-sand lithology, TOC values from 2.41 to 4.39%,Potential Yield (S1 + S2) from 6.08 to 7.53 mg / g , Hydrogen Index 62-170 mg HC / g org.C and Tmax (pyrolysis temperature) range values 479-4830 C. The result of well correlation zone of interests in the Nindy Deep Well # 1 and Well# 2 from the log data and seismic data is acquired interest zone is located on Brown Shale Formation of the Pematang Group in the South Aman Trough, and from integrated data core and log will be known the depositional facies of zona interest is a lacustrine facies with sub facies nearshore lacustrine.

INTRODUCTION

Shale gas is natural gas produced from shale. Shale gas has become an increasingly important source of natural gas in the United States over the past decade, and interest has spread to potential gas shales in the rest of the world. One analyst expects shale gas to supply as much as half the natural gas production in North America by 2020.

In Indonesia, shale gas will be developed at Source Rock who have good organic material supply and high gas content. In this case, shale gas will be explored at Brown Pematang Shale at Pematang Group South Aman Through, Central Sumatera basin. In thats case study about geochemsitry analysis and facies model for helping shale gas exploration at pematang group.

Some analysts expect that shale gas will greatly expand worldwide energy supply. A study by the Baker Institute of Public Policy at Rice Universityconcluded that increased shale gas production in the US and Canada could help prevent Russia and Persian Gulf countries from dictating higher prices for the gas it exports to European countries.

Shale gas development will help reduce greenhouse gas emissions. Some studies have alleged that the extraction and use of shale gas may result in the release of more greenhouse gases than conventional natural gas, although other studies have criticized one of these for relying on implausibly high leakage rates and misstating the global warming potential of methane. Other recent studies point to high decline rates of some shale gas wells as an indication that shale gas production may ultimately be much lower than is currently projected.

Shale gas was first extracted as a resource in Fredonia, NY in 1825 in shallow, low-pressure fractures. Work on industrial-scale shale gas mining did not begin until the 1970s, when declining production potential from conventional gas deposits in the United States spurred the federal government to invest in R&D and demonstration projects that ultimately led to directional and horizontal drilling, microseismic imaging, and massive hydraulic fracturing. Mitchell Energy, a Texas gas company, utilized all these component technologies and techniques to achieve the first economical shale fracture in 1998 using an innovative process called slick-water fracturing. Since then, natural gas from shale has been the fastest growing contributor to total primary energy (TPE) in the United States, and has led many other countries to pursue shale deposits. According to the IEA, the economical extraction of shale gas more than doubles the projected production potential of natural gas, from 125 years to over 250 years

Because shales ordinarily have insufficient permeability to allow significant fluid flow to a well bore, most shales are not commercial sources of natural gas. Shale gas is one of a number of unconventional sources of natural gas; other unconventional sources of natural gas include coalbed methane, tight sandstones, and methane hydrates. Shale gas areas are often known as *resource plays* (as opposed to *exploration plays*). The geological risk of not finding gas is low in resource plays, but the potential profits per successful well are usually also lower.

Shale has low matrix permeability, so gas production in commercial quantities requires fractures to provide permeability. Shale gas has been produced for years from shales with natural fractures; the shale gas boom in recent years has been due to modern technology in hydraulic fracturing (fracking) to create extensive artificial fractures around well bores. Horizontal drilling is often used with shale gas wells, with lateral lengths up to 10,000 feet (3,000 m) within the shale, to create maximum borehole surface area in contact with the shale.

Shales that host economic quantities of gas have a number of common properties. They are rich in organic material (0.5% to 25%), and are usually mature petroleum source rocks in the thermogenic gas window, where high heat and pressure have converted petroleum to natural gas. They are sufficiently brittle and rigid enough to maintain open fractures. In some areas, shale intervals with high natural gamma radiation are the most productive, as high gamma radiation is often correlated with high organic carbon content. Some of the gas produced is held in natural fractures, some in pore spaces, and some is adsorbed onto the organic material. The gas in the fractures is produced immediately; the gas adsorbed onto organic material is released as the formation pressure is drawn down by the well.

STUDY AREA

Nindy Deep Well#1 prospect is a seismically defined structural closure with about 120 feet of vertical relief and approximately 225 acress of areal extent (when mapped at the urb fm). It is located in the northern section of the Southern Aman Trough (see index map, montage A). This part of the trough contains several giant oil fields, including duri (2662 MMBO), Bekasap (558 MMBO), and Pematang (246 MMBO). Many smaller fields exist in this area also. Nindy Deep Well#1 prospect lies about 1.5 km south aman fields. (see Map A, montage A). Although Aman Field is relatively small in size (about 500 acress of maximum areal closure when mapped at the upper red beds horizon). Its reserved are significant (47 MMBO of proven and probable ultimate recovery to depletion). This is due, in part to the presence of 11 individual reservoirs stacked within its closure (see Geologic Cross Section, Montage B and type log , montage A). A smiliaar number of reservoirs can be expected at the nearby filled near the spill point. Nindy Deep Well#1 lies directly in a postulated hydrocarbon migration route which drains a large portion of the southern Aman through (see Map E Montage B). Because of its lower structural position relative to Aman fields, the Nindy Deep Well#1 closure may have a filled with hydrocarbon first before spilling over into Aman field. Primary objectivities include reservoirs in the bekasap, bangko, menggala and upper red bed formation all pays at Aman field (see type log. Montage A) The amount of structural closure mapped at the different primary objectivities varies. Structure flattens up section so that the bekasap horizon has less closure and prospective area than does menggala or upper red bed (see map A, montage A and map B and map C, montage B). Structural growth and depositional thinning during post menggala sedimentation probably accounts for much of the differences in closure. Southward thinning between post menggala seismic events can be noted from Aman field to Nindy Deep Well#1 prospect and onward to the south (see seismic line 7056, montage D). Also, significant eastward thinning of the pematang group creates a difference in the crestal location between the top of the brown shale structure and the near top of the upper red beds structure (see maps c and d, montage b). At Nindy Deep Well#1 no 1 the well will penetrate the most prospective reservoirs, thoses of the menggala and upper red beds, at optimum structural location.

Secondary objectives at Nindy Deep Well#1 are sandstones below the lower most oil bearing sand in the Aman field (see forecast log and type log, montage A) oil shows were encountered in sandstones of the lower upper red bed and in the upper lower red bed of the aman no1 (see type log). However, near absence of structural closure at these levels may explain why hydrocarbons were not trapped (see map d, montage B, note : only very weak east dip at Aman fields at the brown shale level). At Nindy Deep Well#1 prospect these horizons have a structural closure making them viable exploration objectivties. Additionally seis-strat analysis (see line 7056, montage D) suggest an on lapping relationship of upper red bed strata to the underlaying brown shale. This condition sets up possible structurally-enhanced stratigraphic traps in sandstone bodies. Finally, the brown shale is a secondary objective as oil bearing sands have been encountered in this formation in the victinity of cebakan field (see map, montage A and geologic cross section, montage b). These sands maybe of deltaic or turbdite origin.

The Nindy Deep Well#2 prospect is geologically located in the southern part of Aman Through, the most prolific source area in the CSB. The prospect is a fault closure associated with tilted fault block, 12 km north east of the giant libo south east field. The aman through is a N-S graben covering over 1000 km2. Graben formation was probably initiated in Paleogen time and the feature began to be filled with lacustrine and fluvial deposits of the lower Pematang group. Sedimentation occured in subsiding, en-chelon grabens as a result of the early tensional phase of wrench fault tectonics which is ever present in the evolution of a wrench-basin. Graben development continued into late oligocene time when subsidence ceased and erosion dominated.

The lower red beds formation which floors the aman through probably represent fluvial deposits of the pre graben stage. During the graben fill stage the brown shale and upper red beds formation were deposited. The brown shale was deposit in a deep lacustrine environtment and its the main source rock in the area. The upper red bed, which consist of fine to coarese grained sandstone, red mottled claystone and siltstone of fluvial origin, is oil bearing in several oil fields with proved plus probable reserves over 140 MMBO (OOIP over 300 MMBO)

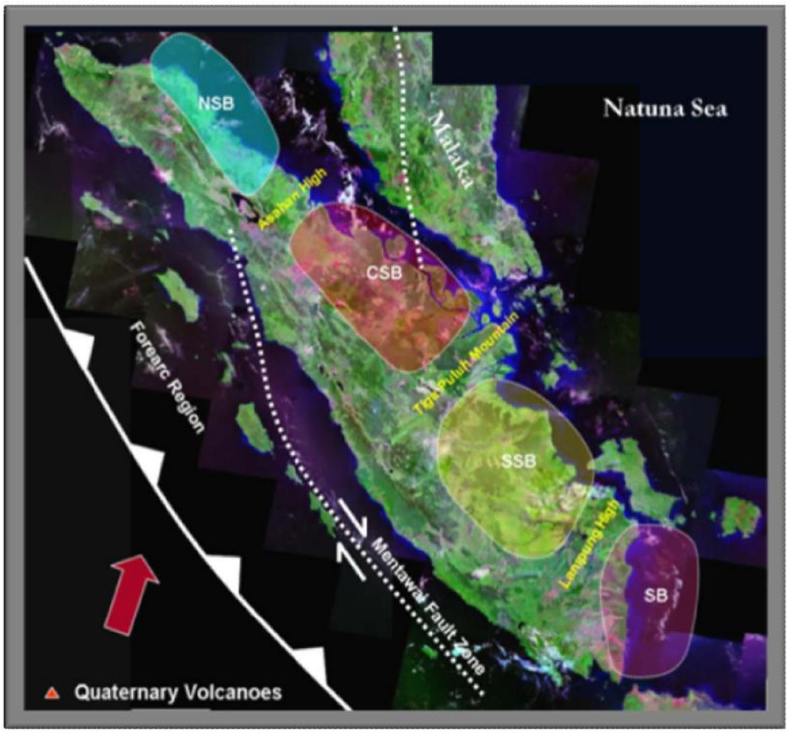
The pospect is controlled by high angle SE-NE trending normal faults, which appear to be the dominant pre-sihapas faults in the Aman Trough. Due to the composition of the pematang group which consist of sandstone, siltstone, claystone and shale most pematang aged faults are usually sealing faults. These have been demonstrated in the kelabu – jingga (kiri through, 35 km to the west) and sidingin fields where oil accumulation occurs in the down thrown fault block. Hence in the Nindy Deep Well#2 structure not only the upthrown faults block, but the down thrown faults block where the Pematang Upper Red Beds juxtaposed the Brown Shale is also prospective.

The primary is the pematang upper red bed sands, which productive in aman, ampuh, bekasap, cebakan, pematang, petani, pudu and recently discovered Mangga, Gulamo and Sidingin Fields. The well will evaluate 750 ft of pematang upper red beds, and over 1000ft of Pematang Brown Shale for probable occurence of fan delta sand wedges in situ due to proximity to the minas and libo highs. The secondary objective is the upthrown Lower Sihapas sands which are expected to be well developed at Nindy Deep Well#2 prospect (refer to type log). Reserves were not assigned to this interval due to uncertainty in the vertical extend of the Nindy Deep Well#2 faults. Either oil or gas, or both, may be encountered in Nindy Deep Well#2 since it is 6 km east of the Sangsam (Sihapas-Oil) and Talas (Sihapas-gas) fields and 12 km north east of the giants libo (sihapas oil and gas) fields. Nindy Deep Well#2 is high potential and high risk prospect. The structure covers 4000 acres of areal closure (2/3 fill-up) with vertical closure of 250 ft at the proposed location. The high risk factor (1:8) is basically due to the uncertainty of the pematang upper red beds sands, such as its distribution, porosity and productivity. No wells have been drilled to the Upper red bed in the southern part of Aman Trough and Nindy Deep Well#2 will be the first pematang test in this area. Hence although Nindy Deep Well#2 is a large prospect, we have deliberately assigned conservative figures for the economic evaluation, 50 ft average net pay and 160 BAF recovery factor.

REGIONAL SETTING

Central Sumatra Basin isa back arc basin bounded by Asahan High on the north and south of the Thirty Tinggian (Figure 2.1) and is formed bytunjaman oblique (oblique subduction) of about 50-60 between the plates of the Indian Ocean to the Continental Shelf Asia West Sumatra waters that occur. This systemresulted in the formation of mountains tunjaman row, the island -a small island as the island of Nias. Transpresional movement to the right (dextral wrenching transpessional)Sumatran fault and plutonic activity in Niogen (Simanjuntak and Barber, 1996).

Establishment of the Central Sumatra Basin is controlled by pre-Tertiary basement of Sumatra Basin (Pulunggono, 1984). Pre-Tertiary basement of Sumatra Basin consistsof several continental and oceanic microplate. Mergui Microplate, East Malaya Malaccaand joining each other on the Sundaland during the Late Triassic. Then the oceanicmicroplate of terrain Woyla join in the Mesozoic. Mergui Microplate plutonisme formed by Palaeozoic granites and volcanic rocks of Permian and Pebbly mudstonerock-Carbon UNTAET Information Bulletin Boards. Malacca Microplate dominated bylowgrade metamorphism, whereas the suture complex, known as Mutus assemblagescomposed of argillites, massive red-shales, basalt, and tuff.



Pict 1. Central Sumatera Basin Map and Boundaries

Cenozoic basin formation during the back-arc is also affected by the spatial and temporal changes in the subduction complex. During the Late Cretaceous to early Tertiary, there was a collision between the Indian subcontinent with Eurasia whichresulted in the extrusion to the east of the southeast Asian continent (Tappionier, 1982).The impact of this extrusion in Southeast Asia in the form of a horizontal section of thefault, such as the Red River Fault and the Great Sumatran Fault.

Another opinion stated that a large section to the right in Sumatra triggered by obliqueconvergence between the Indo-Australian plate with the Children's Sunda Continent(Fitch, 1972). This oblique convergence in addition to generating a horizontal sectionalso produces magmatisme path along the island of Sumatra. The results of radiometricanalysis on the path to the Barisan Mountains indicate that volcanism in this pathway iseffective since the Early Miocene (Ryacudu, 2005). Sapiie et al, 2005, demonstratedthat the pattern of Paleogene rift basins in Sumatra is essentially flat to the right is controlled by faults trending NW-SE Central Sumater Basin . formed in the earlyTertiary (Eocene Oligocene) and a series of half graben dar sruktur separated by ablock Horst.

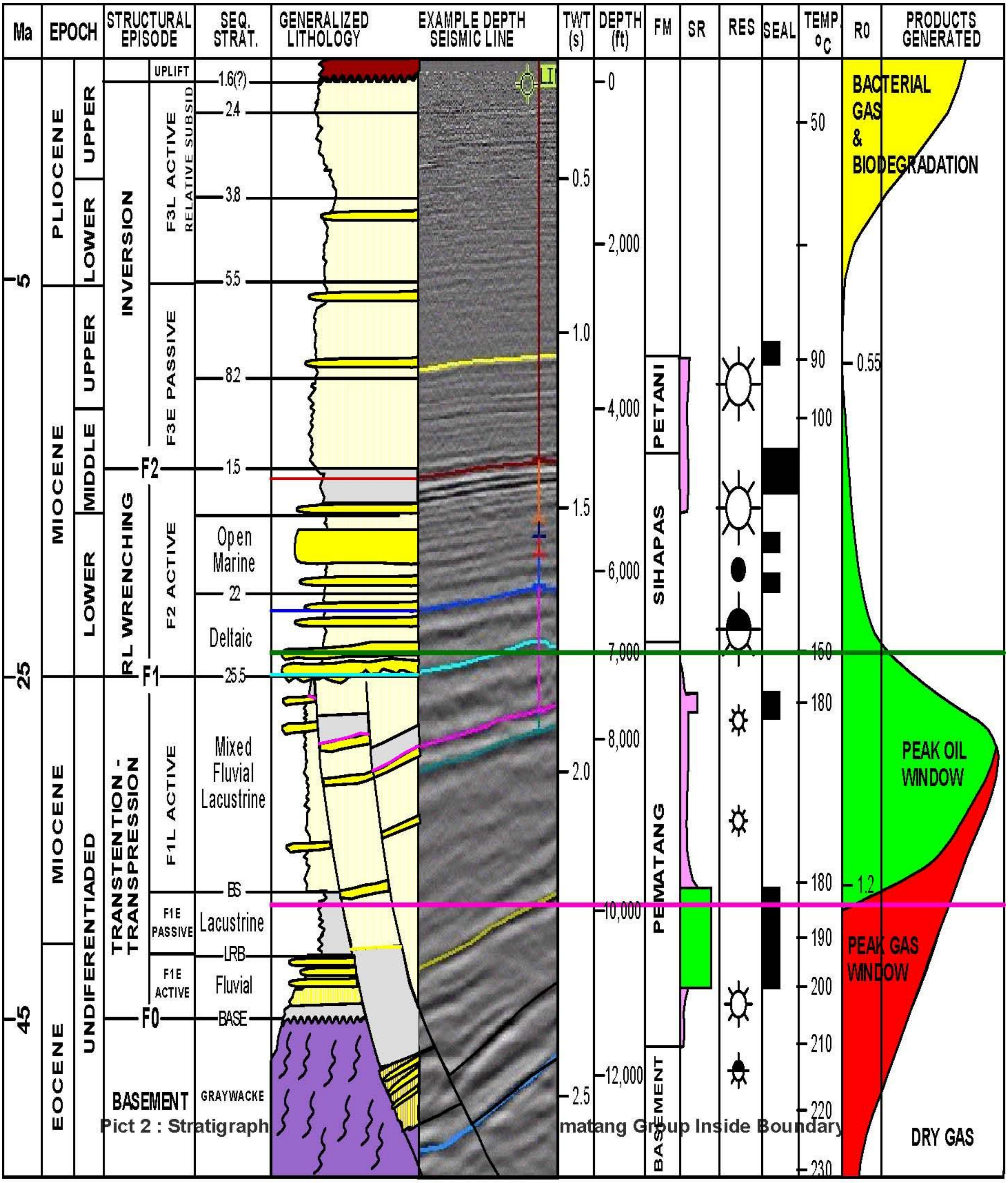
Stratigraphy Pematang Group

Pematang group is divided into three formations based on the facies associated with the stages of basin formation and filling, namely :

a) Lower Red Bed Formation consists of mudstone, siltstone, sandstone arkosik, conglomerates were deposited in alluvial environments and alluvial fan that turns laterally into fluvial environments, lacustrine and delta. The bottom of this formation in some deep basins may reach a thickness of 3000 meters. Sandstones in this formation have a poor quality of the reservoir because it is still very close to the source and poor sorting..

b) Brown Shale Formation as the name consists of shale is brown and is deposited in lacustrine environments / lacustrine to shallow lakes in the host rock and hydrocarbons.A good host rock formation on the formation is caused by several factors, namely the lack of significant heights along the fault that limits the basin, basin basis decreased faster than the deposition of lead in the environment of the lake, which serves as the boundary fault basin has a gentle to moderate dip and Brown Shale was deposited during the tectonic conditions are inactive. In addition to clay, in this formation there are also fan-delta deposits and turbidit. Turbidit precipitate formed by the mechanism of grain flow (grain flow) has been used as a target of exploration in general will have the type of stratigraphic trap.

c) Upper Red Bed Formation was deposited during the final stage in a minor inversion transition environments are changing rapidly into lacustrine environments in which interspersed by shallow lacustrine. Increased sedimentation rate and cause the basin to supply klastika full and turned into a fluvial environment and alluvial. Constituent lithology of this formation of sandstone, conglomerate and shale red-green color. Sandstones in this formation has been the target of exploration.



GEOCHEMISTRY ANALYZE

SOUTH AMAN TROUGH EXPLORATION SUMMARY CHART

Geochemical studies of rocks for the evaluation done by Rock-Eval analysis pyrolisisPematang Group Formation in Upper Red Bed, Brown Shale and the Lower Red Bed.Geochemical evaluation aims to determine the level of organic richness and maturity ofthe host rock and the type of kerogen is produced from rocks. The data used forevaluation of rock derived from the TOC data, Yield Potential, Hydrogen Index, Tmax, andReflekstensi vitrinite (Ro) from Nindy Deep Well#1 and Nindy Deep Well#2 (Table 1).

Total Organic Compound Nindy Deep Well #1

Quantity of organic material or property declared with the host rock of Total OrganicContent (TOC), while the quality of the host rock of the graph obtained from therelationship between TOC and TOC S1 + S2 with the hydrogen index (HI). TOC values are shown in Nindy Deep Well #1on Upper Red Bed Formation at a depth of 3370 feetto 5680 feet range from 0.5 to 2.372% rocks with TOC between 0.5% -1.0% have a limited ability to produce hydrocarbons. While that has the potential of more than 2%have excellent potential. (Waples, 1985). Then in Nindy Deep Well#1in Brown Shale Formation at a depth of 5800 feet to 6730 feet range from 0.7% to 6.21%. Rock that has more than 2%TOC considered as a rock that has potential as a host rock of hydrocarbons that have a very good value and can expulsed hydrocarbons. (Appendix Table 1.1.). The wells in Brown Shale Formation at a depth of 6750 feet to 8175 feet range from 0.2 to6.83%. Rock that has more than 2% TOC considered as a rock that has potential as ahost rock of hydrocarbons that have a very good value and can expulsed hydrocarbons. (Appendix Table 1.1.).

Total Organic Compound Nindy Deep Well #2

TOC values are shown in Nindy Deep Well#2 on Upper Red Bed Formation at a depth of 6610 feetto 7390 feet range from 0.04 to 1.3% rocks with TOC between 0.5% -1.0% have a limited ability to produce hydrocarbons . These rocks will not function as an effectivehost rock, but still can expulsed (remove) a small amount of hydrocarbons (Waples,1985). Then in Nindy Deep Well#2in Brown Shale Formation at a depth of 7420 feet to 8512feetberkisar between 1.09% to 5.97%. Rocks which had TOC less than 2% to be considered as a rock that has potential as a host rock of hydrocarbons that have a verygood value and can expulsed hydrocarbons. (Appendix Table 1.1.) In terms of the quality of the host rock is known based on the graph the relationshipbetween TOC in S1 + S2 and TOC with HI. Bedrock Formations in Nindy Deep Well#2 on UpperRed Bed memilliki indicated good quality hydrogen index values ranged from 23 mg /GC -59 mg / GC which showed that the host rock has a poor ability to producehydrocarbons and is classified in the TOC level IV (Law, 2009). Bedrock wells in Nindy Deep Well#2 atBrown Shale Formation memilliki indicated good quality hydrogen index values ranged from 41 mg / GC -197 mg / GC which showed that the host rock has a good ability to produce hydrocarbons and is classified in the TOC level II-III (Law, 2009). At the Nindy Deep Well#1 quality hydrogen index, showed a slightly different value of Nindy Deep Well#2, judgingfrom the index value higher hydrogen formation is the Upper Red Bed 119 mg / GC 227 mg / GC (Appendix Table 1.1.), Then at Brown Formation Shale 97 mg / GC -384mg / GC and the Lower Red Bed Formation 83 mg / GC -1559 mg / GC indicating that the quality of rock geochemistry to expulsed hidrokasrbon in Nindy Deep Well#1 is better than Nindy Deep Well#2. (Law, 2009).

Maturity Index Nindy Deep Well#1

Maturity of the host rock in the study area can be determined based on the value TmaksRock-Eval analysis and reflektanasi vitrinite (Ro). Level of maturity can also be known bybiomarker analysis. Maturity analysis performed after pengeplotan into the chartsTmaks of hydrogen index (HI) and Ro of depth. Tmaks graph of HI used to determine thetrend of maturity and type of kerogen is produced, whereas Ro to the depth chart is used to determine at what depth of host rock started to mature and begin to produce hydrocarbons (Law, 2009). Maturity of the host rock formations for Nindy Deep Well#1 on Upper Red Bed has been entered onthe immature stages ranged between 327-4350C and Nindy Deep Well#1in shale formations Brownhas entered the mature stage ranged between 317-4780C which shows the value ofmature. As for the wells in the Lower Red Bed Formation Tmax value which ranges from441-470 0C indicating a mature value. Then based on the value reflekstansi vitrinite (Ro) indicate that most of the samples inNindy Deep Well#1 on Upper Red Bed formations have been entered on the immature stagesranged between .32 to .47. Whereas for Nindy Deep Well#1in Brown Shale Formation has a greatervalue of Ro values ranged from 0.59 to 0.69 the value of early mature menunujukan. As for the Lower Red Bed Formation wells Ro Nindy Deep Well#1 has a value ranging between 0.68 and0.82 which indicate early mature (Geoservice, 2005). From the quantity analysis, qualitative and maturity of the rocks through geochemicalevaluation will be obtained then the zone of interest and potential for shale gasexploration in the dike with a correlation group using log data and seismic horizons.

Maturity Index Nindy Deep Well#2

Based on HI Tmaks graph shows that the majority of wells sampled in the formation of Lon Upper Red Bed has entered the mature stage ranging from 4410C to 4500C whichshows the value of mature. While for Nindy Deep Well#2in Brown Shale Formation has a greatervalue of Tmax which ranges from 441-483 0C indicating the value that is too ripe. Based on the value reflekstansi vitrinite (Ro) indicate that most of the samples in Nindy Deep Well#2on Upper Red Bed formations have been entered on the immature stages ranged between 0.4 to 0.5. While for Nindy Deep Well#2in Brown Shale Formation has a greater value ofRo ranged from 0.8 to 1.3 which indicates that the value is able to generate oil and gas(peak-oil generated late) (Geoservice, 2005).

Shale Gas Zone Potential Nindy Deep Well #1

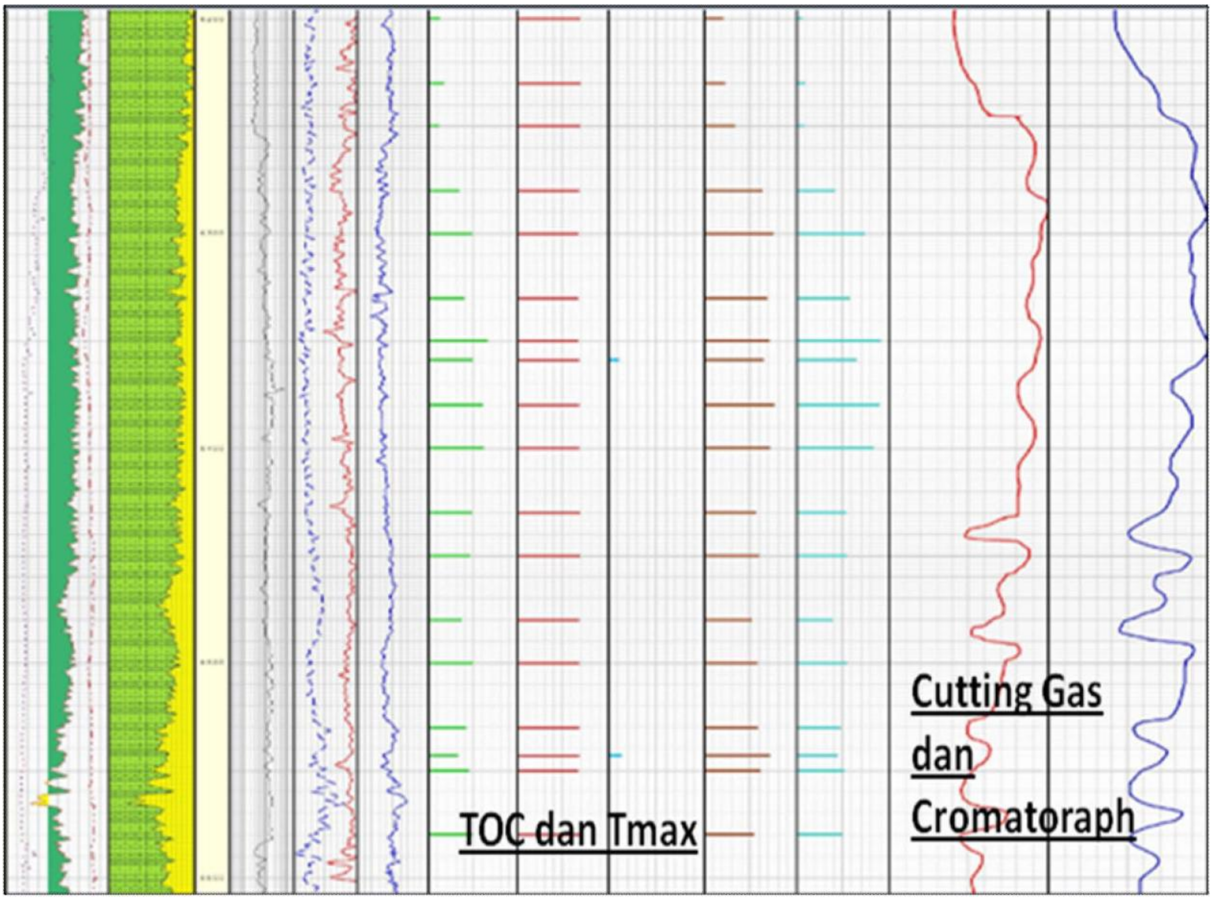
From the analysis of geochemical data from Wells Nindy Deep Well #1 has 3 zones, namely the Upper Red Bed Formation 3770-5620 feetwith a depth of TOC criteria had good but not yet mature, well T Brown Shale Formationat a depth of 5800-6730 feet with a TOC criterion is very nice and ripe, then the formationLower Red Bed at a depth of 6750-8175 feet with moderate to good TOC criterion, andmature. Whereas for Nindy Deep Well#1on Upper Red Bed formations have been entered on the immature stages ranged between 327-4350C and Nindy Deep Well#1in shale formations Brown hasentered the mature stage ranged between 317-4780C which shows the value of mature.As for the wells in the Lower Red Bed Formation Tmax value which ranges from 441-4700C indicating a mature value.

Shale Gas Zone Potential Nindy Deep Well #2

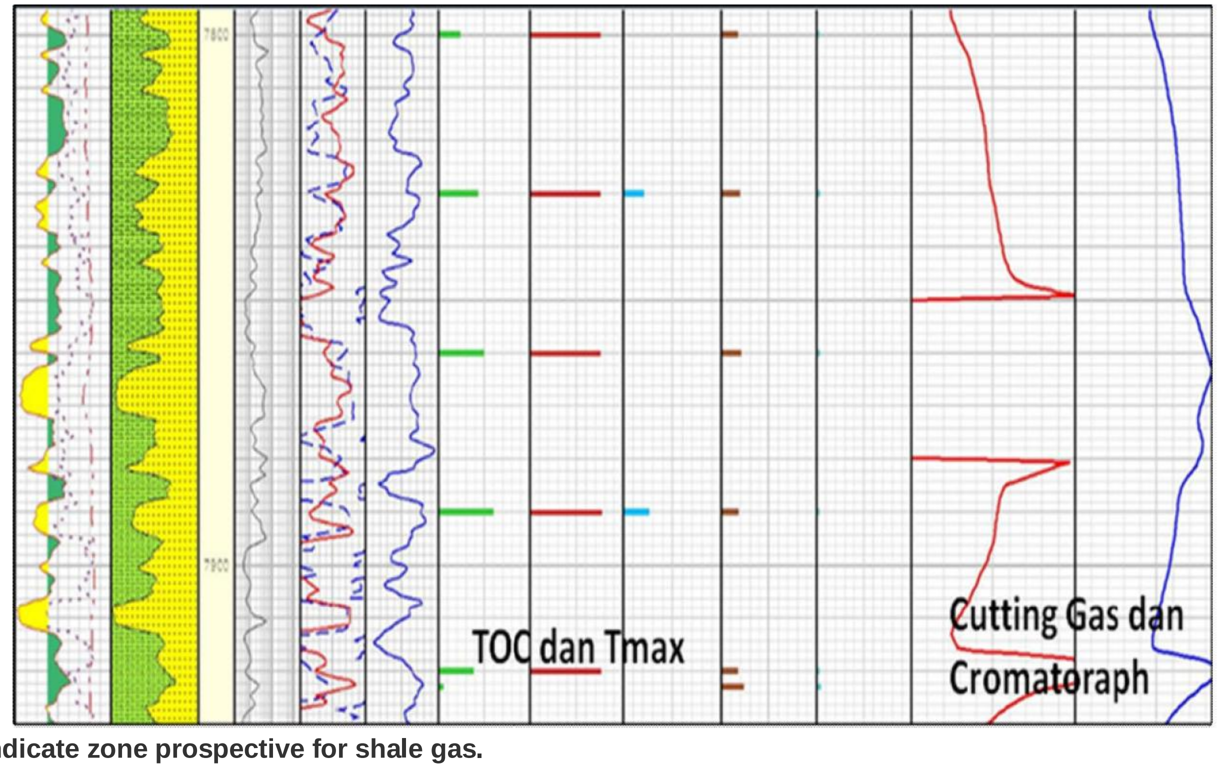
The Nindy Deep Well#2 known that there are two zones of interest is the well L on Upper Red Bed Formation depths of 6510 to 7390 feet with thecriteria TOC zone has a good potential but has a poor level of maturity and Nindy Deep Well#2inBrown Shale Formation at a depth of 7420 feet to 8512 feet with a very good TOCcriterion, and a mature level of maturity.

Corelation Zone Potential Nindy Deep Well #1 and Nindy Deep Well#2

Through the geochemical data, it can be assumed that the zone of interest and potentialfor development of shale with TOC values of criteria is the stem and mature of the two wells are in the zone of Brown Shale Formation at depths of 7420-8512 feet in Nindy Deep Well #2and 5800-6730 feet in the Nindy Deep Well #1. To see the shape of the correlation of the two wellsProspect Zone can be seen from seismic data and log data. From the well log data composite Nindy Deep Well #1 and Nindy Deep Well#2 are made with added geochemical data it can be seen from the curve of geochemical data in the form of rods TOC, HI, Potential Yield,Tmax and Ro. Nindy Deep Well #2 data it can be seen that the most interesting zones are at depths of 7700-8100 feet with bar graph indication of a large geochemical (TOC morethan 2, Tmax more than 435) and the value of cutting gas and gas kromatograp rose significantly.



Pict 3. Well Log, Geochemistry and Chromatograph Nindy Deep Well #1 Analyze at 6280 and 6610 ft

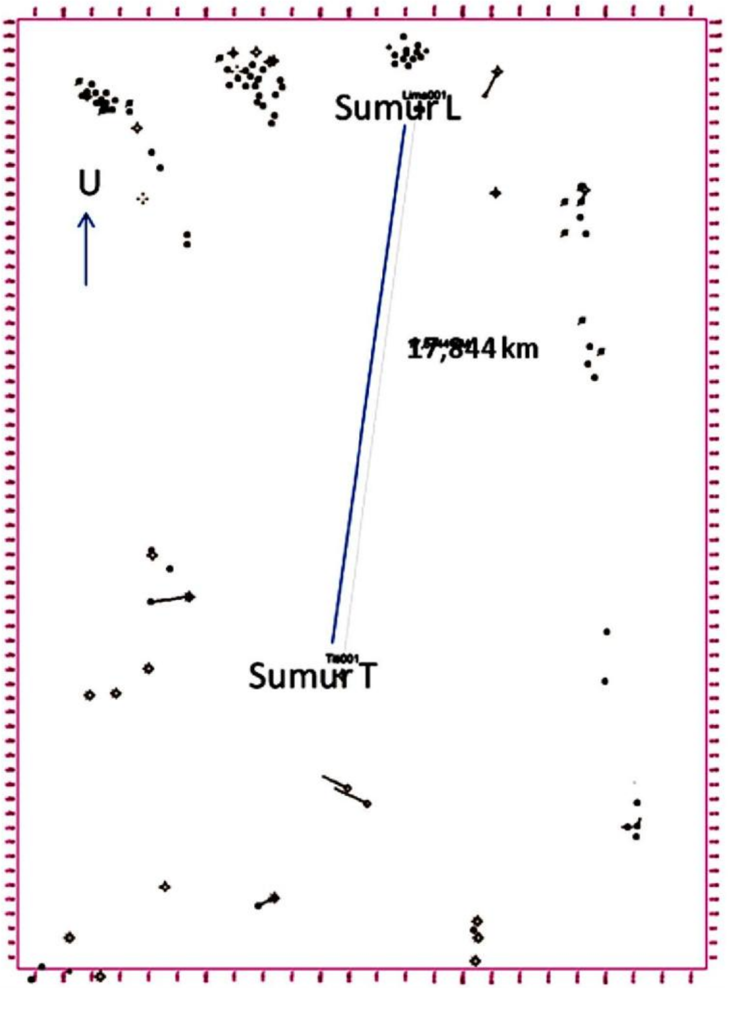


indicate zone prospective for shale gas.

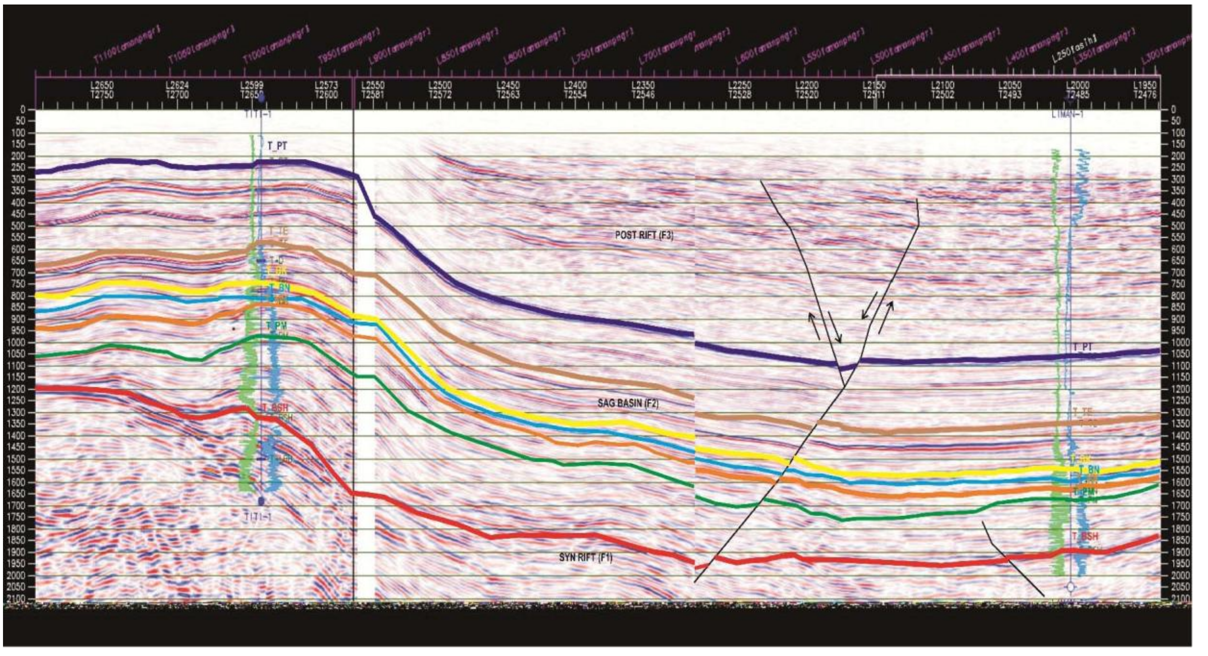
Pict 4. Well Log, Geochemistry and Chromatograph Nindy Deep Well #2 Analyze at 7700 and 8100 ft indicate zone prospective for shale gas.

While the composite data from well logs are made with added Nindy Deep Well #1 geochemical data it can be seen from the curve of geochemical data in the form of rods TOC, HI, Potential Yield,Tmax and Ro, it can be seen from the well composite log Nindy Well#1 has the most interesting zoneis at a depth of 6280 -6610 feet with bar graph indication of a large geochemical (TOCmore than 2, Tmax more than 435) and the value of cutting gas and gas kromatograprose significantly.

From seismic data can know the position of Nindy Deep Well #2and T which has a range of about1.78 Km and the depth interval of different horizons. Prospect zones, namely the Brown Shale Formation in the wells at a depth L is 7921 -9000 feet and thewells at a depth of 6100-7150 feet T. Top of the brown shale picking seismic horizonsshowed that the correlation between Top Brown Shale wells and Nindy Deep Well #2 shows aplateau formation in Nindy Deep Well #2and ride south to the formation of anticline in Nindy Deep Well #1. Then there is a fault structures that make up half graben down. This can be correlated with regional tectonics which shows Brown Shale Formation in the dike groupis formed on the regional tectonic phase of rifting and Intra-rift infill Cratonic (TectonicPhase F1) is the collision between the Indo-Australian Plate and the continent ofEurasia is the force resulting in transtensional series of half-graben structures that are interconnected electrical fault that begins with the alignment pattern of north and south.Down the fault of the results obtained show an indication of picking formed electrical fault which will form the half-graben on the regional structure.



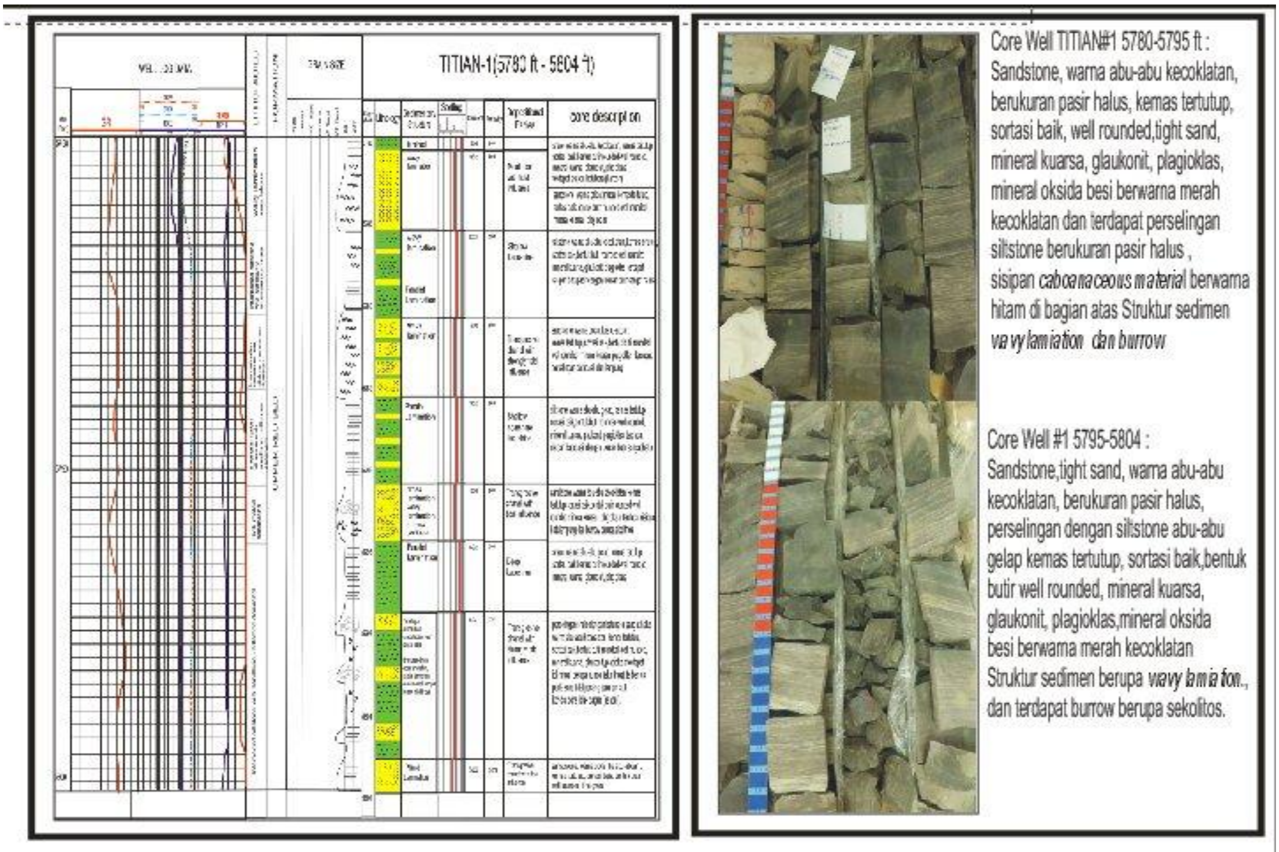
Pict 5. Basemap Nindy Deep Well31 and Nindy Deep Well#2

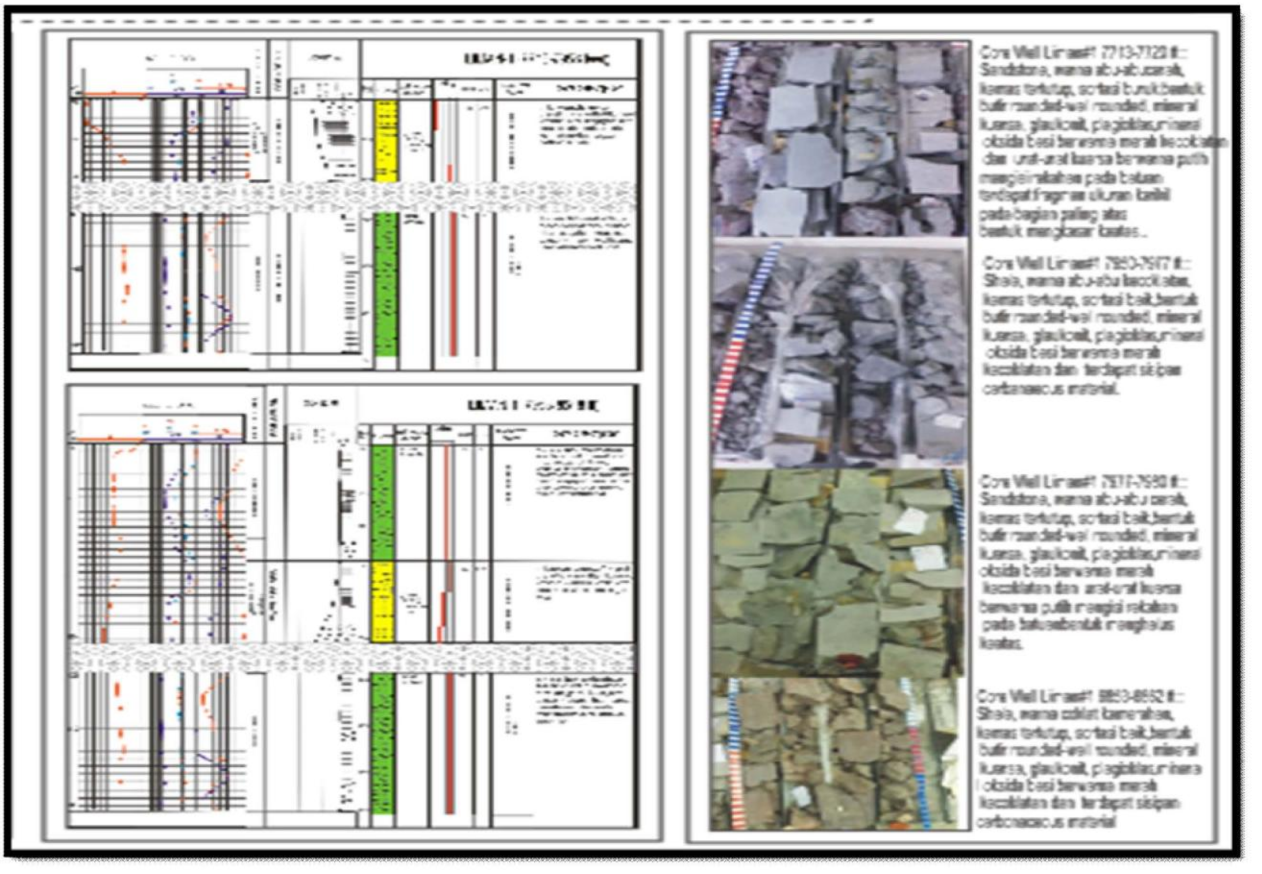


Pict 6. Seismic Well Correlation Nindy Deep Well#1 (left) and Nindy Deep Well#2 (right) From the results of the study zone of shale gas prospects that can be used in gasexploration in the recommendations based on data from two wells, ie wells and Nindy Deep Well #1 is found most prospective zone of interest to be developed in gas exploration wells inwhich the Nindy Deep Well#2 is at a depth of 7800-7920 is with the conclusion of a shale-sand lithologi,TOC ranged from 2.41 to 4.39% which shows a very good value. Potential Yield ranged from 6.08 to 7.53 indicating good value. Type III and IV the TOC. Hidrocarbon potential isgas. Maturity index is 479-483oC Tmax value that indicates the value mature. Whereas in the Nindy Deep Well#1 zone wells of interest is at a depth of 6280-6610 is the conclusion of lithologi shale, TOC ranged from 3.49 to 6.62% which shows a very good value.Potential Yield ranged from 11.7 to 27 which shows a very good value. TOC Type is II.Potential oil and gas hidrocarbonis. Maturity index is 439-443oC Tmax value that indicates the value mature.

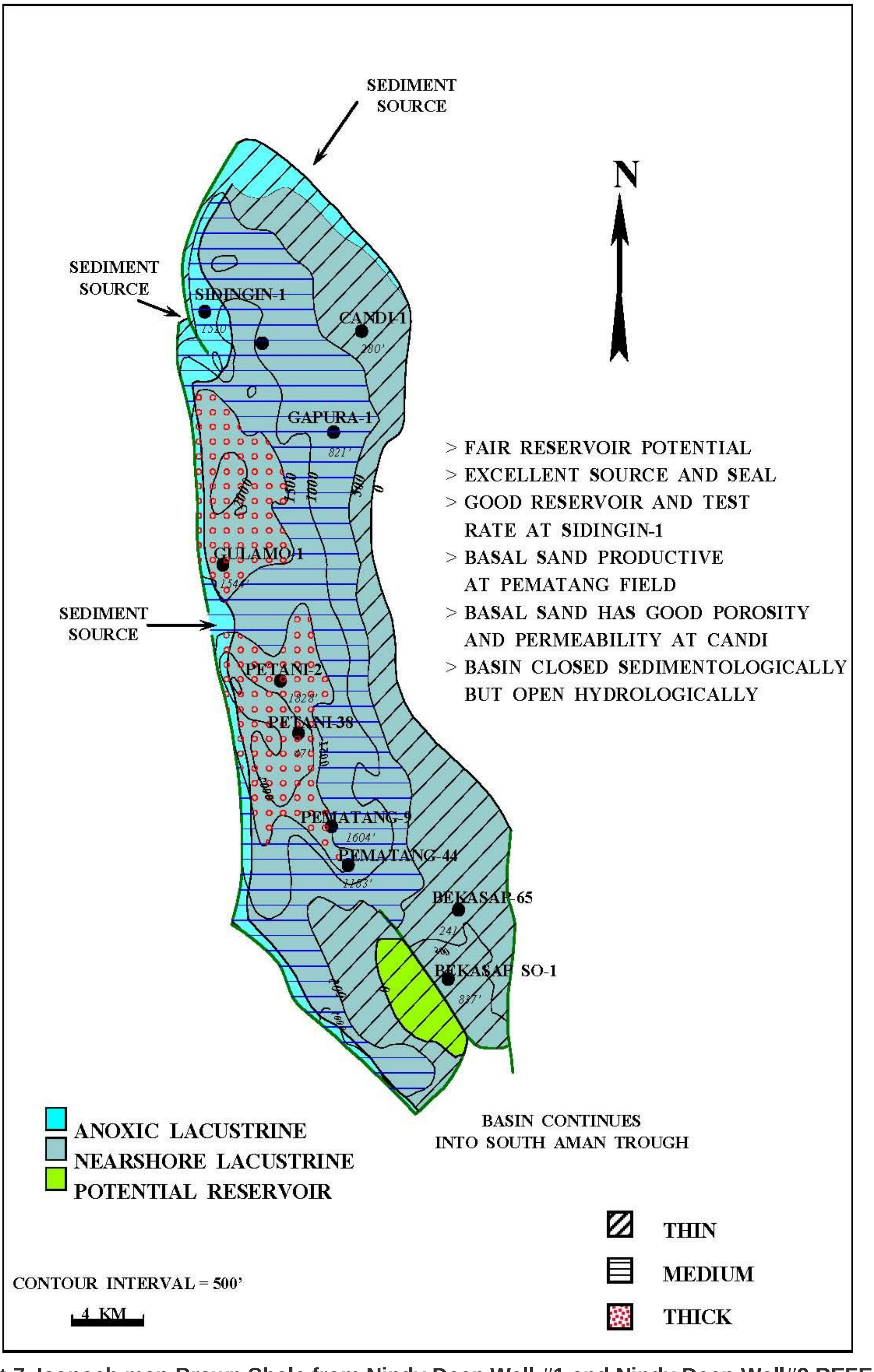
DEEP LACUSTRINE FACIES MODEL

Deep lacustrine deposite from Zone Shale Gas Potential of Nindy Deep Well#1 and Nindy Deep Well#2 are commonly present in the Pematang Group Brown Shale Formation and Lower Red Bed Formation. Its will be appear from deep lacutrine deposit indicate from dark Till red mudstone (an-oxidize effect from deep lacustrine), thin turbidite sandstone and slump breccias of coal (Pict 6). These lacustrine deposits are either massive or show horizontal laminations displayed by fine grained graded bedding, stripped side rites and so on. These features indicate that they were formed in deep lake environtment below wave base. Associated fossils include fish remains, small grastropoda, ostracodam but lacking any bivalve mollusces. The brown shale Formation, an extremely thick mud member ranging from 400 to 600 m in thickness is dominated by dark and massive mudstone with high organic carbon (2 – 4.3%), which have been considered as typical deep lacustrine deposits. This mud member is the major oil source rock in the basin. In its turn overlying Lower Red Bed Formation and the underlying Upper Red Bed Formation are respectively, the major coal bearing and oil producing units in the South Aman Through Central Sumatera basin. Relatively thick lacustrine mudstone can be identified by seismic facies analysis. They are often represented by weak reflections and low velocity zones with high continuity, weak or mid amplitude and low frequency. These Mudstone members with typical reflection characteristic, particulary the Brown Shale Formation are the major markers for the correction of time stratigraphic units throughout the whole basin.


TITIAN-1(5780 ft - 5804 ft)
core description
Core Well TITIAN#1 5780-5795 ft :
Sandstone, warna abu-abu kecoklatan, berukuran pasir halus, kemas tertutup, sortasi baik, well rounded,tight sand, mineral kuarsa, glaukonit, plagioklas, mineral oksida besi berwarna merah kecoklatan dan terdapat perselingan siltstone berukuran pasir halus , sisipan caboanaceous material berwarna hitam di bagian atas Struktur sedimen wavy lamiation dan burrow
Core Well #1 5795-5804 :
Sandstone,tight sand, warna abu-abu kecoklatan, berukuran pasir halus, perselingan dengan siltstone abu-abu gelap kemas tertutup, sortasi baik,bentuk butir well rounded, mineral kuarsa, glaukonit, plagioklas,mineral oksida besi berwarna merah kecoklatan Struktur sedimen berupa wavy lamia ton., dan terdapat burrow berupa sekolitos.



Pict 6.Core Analysis for Deep Lacustrine Facies Nindy Deep Well #1 (Top) and Nindy Deep Well#2



Pict 7. Isopach map Brown Shale from Nindy Deep Well #1 and Nindy Deep Well#2 REFERENCES

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