HYDROCARBON RESOURCES ASSESSMENT IN THE NORTH SUMATRA BASIN

Mujito), Sasongko Hadipandoyo*), Tatut Hadiwiryono Sunarsono*)*

ABSTRACT

The assessment of undiscovered oil and gas potential is a critical aspect of oil exploration, especially in the unexplored basins, although it is also important as a basis for appraising the national's energy policies and can assist long term economic planning.

In the North Sumatra basin, the Tertiary sediments can be grouped into three stratigraphic sequences, based on which, the hydrocarbon play types can be classified. The play type is the basic unit that contains all elements for hydrocarbon generation and entrapment. The classification of the plays in the North Sumatra Basin, from bottom to top, are as follow :

- *stratigraphic sequence I,*
  - *clastic wedge base (Parapat Fm), as type I,*
- *stratigraphic sequence II,*
  - *carbonate wedge base (Arun/Malacca/Belumai Fm), as type II,*
- *stratigraphic sequence III,*
  - *clastic wedge middle (Middle Baong Sandstone Member of Baong Fm), as type III,*
  - *clastic wedge top (Keutapang and Seurula Fm), as type IV.*

The hydrocarbon potential of the play types is then evaluated by using the so-called IUGS method, to assess the total resources of the North Sumatra Basin. The result can be continuously updated in line with additional and development of the structural, stratigraphic and geochemical controls and concepts are available.

I. INTRODUCTION

The geological and geophysical data level in the North Sumatra Basin are varied from the point of view of exploration density activities and their quality. Nearly mature exploration activities have already done in the southern part of the basin, especially in the onshore area, which is the most producing hydrocarbon region of the basin. How ever, the value of the undiscovered hydrocarbon is still significant, since the deposit is accumulated in the clastic sedimentary and carbonate reservoir rocks, in the form of stratigraphic and structural traps. On the other hand, the data level in the northern part of the basin, towards the Andaman Sea, is scarse compared to the southern part, ie. regional data. In optimizing the achievement of the hydrocarbon resources on the basin, the effort of discovering new hydrocarbon accumulation has to be continued, regardless the condition of the data level.

There are several methods that can be applied for assessing the resources, which estimate and calculate :

*) PPPTMGB "LEMIGAS"

- the hydrocarbon potential in the basin on any data level,
- the probable size of the resources and the probability of their existence.

In using the method, the degree of uncertainty para meters used in the calculation should be identified and quantified. The method employed is able to guide the mana gement in making decision, developing exploration strategis and evaluating opportunities. One promising method is the so-called USGS resources assessment method.

The application of the USGS method in the North Sumatra Basin is expected to solve the problem on the probability of the hydrocarbon potential, which is approximately the real potential of the basin.

II. GEOLOGIC SETTING

II.1. General

The North Sumatra Basin is an asymmetric, NW-SE trending and steep block faulted basin. The SW flank is bounded by the Barisan Mountain that was uplifted since the Middle Miocene, while in the SE part the basin is bounded by the Asahan arc. The Malaysian Peninsula limits the basin in NE flank. In the northern part, the basin is opened towards the Andaman Sea. Two structural trends prevailed in the basin, i.e. the Pre-Tertiary N-S fault pattern and Plio-Pleistocene NW-SE and NE-SW strike-slip fault pattern, which were developed since the Middle Miocene (Fig. 1).

The Pre-Tertiary structural grain appears to controll the sedimentation during the Tertiary times (Fig. 2).

II.2. Tectonic and Sedimentation

The Pre-Tertiary rocks consist of volcanoclastic sedimentary rocks, that has been metamorphosed and folded, and batholitic intrusions (Fig. 3).

During the Late Oligocene, block faulting took place in the North Sumatra basin, and the coarse clastic sediments of the Parapat Formation was deposited in fluvial to paralic environments, unconformably overlain the basement. The basin was later on subsided gradually and an isolated marine environment was formed in which the black phyritic shale and calcareous nodule of the Bampo Formation were deposited in restricted and auxenic condition. The Bampo Formation conformably overlain the Parapat Formation.

In the Early Miocene, compressional stresses were reac tivated which had lasted until Middle Miocene time. The northern part of the basinwas uplifted , whereas in the southern part a shallow marine conditions prevailed. The subsidence of the basin occurred followed by the deposition of shale and reefal limestone of the Peutu Formation, unconformably upon the Bampo Formation. To the south, the Peutu Formation is dominated by glauconitic sandstone and calcarenite, which was deposited conformably on the Bampo Formation. After the Peutu Formation was deposited, the North Sumatra region was uplifted, due to the collision between the Asian and Australian Plate and this resulted the wrench sumatran fault system.

In the Middle Miocene, the Baong Formation was deposited unconformably on the Peutu Formation, except in the southern part where the Baong Formation conformably overlain the Peutu Formation. The Middle Baong Sand Member was deposited in the southern part of the basin and appears as the lower part of the Keutapang Formation towards the S-E.

Uplifting continued which resulting in the shallowing of the environment of deposition during the Late Miocene, followed by the deposition of the clastic sediments of the Keutapang, Seurula dan Julu Rayeu Formations.

II.3. Hydrocarbon Occurrences

II.3.1. The Source Rocks

The Bampo, Peutu, Belumai and Lower Baong Formations are considered to be the source rocks in the basin, with depth varied from 2000 to 4000 m. To the southwest, these formations are cropping out. The geothermal gradient ranges from 36.4^0 to 45.5^0C/km, and the Total Organic Contents of those formations are 0.5%. The thermal maturity zone is located approximately in the central part of the basin with average depth to the top of oil window 1500 m (Fig. 4).

II.3.2. The Reservoir Rocks

The reservoir rocks are clastic and carbonate sediments, ie. the Parapat Formations, Middle Baong Sand Member, Keutapang, Seurula Formations, and Belumai Formation, Arun Limestone of the Peutu Formation.

The porosities and permeabilities range from 13-25% and 50-100 md respectively.

II.3.3. Hydrocarbon Migration

The hydrocarbons that has been generated since Miocene time in the Bampo, Peutu and Lower Baong Formations migrated through the fault system and accumulated in the Arun LS, Belumai Formation, Middle Baong Sandstone Member and Keutapang Formation (Fig. 5). The over-pressure of the Baong shale also affected the migration of the hydrocarbon.

II.3.4. Cap Rocks

The Parapat Formation is sealed by the shale of the Bampo Formation, while the basal Miocene carbonates are capped by the Lower Baong Formation. The sandstones of the Keutapang Formation are sealed by the shaling out of the formation itself.

II.3.5. Traps

Several types of traps can be observed in the basin, ie. anticline faults, fault related structures, drape- overs, stratigraphic traps in the carbonate deposit (build up, pinacle) and clastic sediments (sand lenses, wedge out, unconformity).

III. RESOURCE ASSESSMENT METHOD

III.1. Definition

The equality of understanding about several terms used in the assessment method is very usefull, because these terms have been variously defined in the literature. The terms of ***prospect, pool, field*** and ***play*** are often used interchangable, without clear definition. Podruski et al. (1988) composed definition of that terms as follows :

- ***a pool*** is a discovered accumulation of hydrocarbon typically within a single stratigraphic interval that is hydraulically separated from any other oil accumulation. Any number of pools can exist within a field.
- ***a prospect*** is an untested exploration target, usually within a single stratigraphic interval.
- ***a field*** is used to designate an area that produces oil without stratigraphic interval restrictions.
- ***a play*** consist of a family of pools and/or prospects that share a common history of hydrocarbon generation and migration, reservoir development, and trap configuration.

III.2. The Play Concept

By practical definition, a ***play*** is ***a group of prospects with geologically similar source, reservoir and trap control of oil and gas occurence*** and this has geographic and stratigraphic limits.

Geologists try to recognize, within a certain interval of geological evolution, a condition of stratigraphical, sedimentological or structural model that are then to be translated into the play definition. Due to the geological change that usually occurs in the basin, the play definition is unconsistent that does not fit and can not be applied in the whole basin.

In reality, the play analysis method is more applicable in the restricted and interested area, such as a geological trend consisting of reef of specific age or turbidite sandstone along major fault. The increasing of the geological understanding as a result of the exploration activities, leads the plays to be subdivided into better predefined elements, in order to get a more reliable estimate.

III.3. Hydrocarbon Appraisal

In any assessment method, there are several parameters which usually cause the decisions to be subjective. The minimizing of this subjectivity depends on the sense of the geological knowledge of the area. The existing data must be comprehensive, such as type of maps, cross-section charts, and graphs of the geological, geophysical and geochemical analyses, in order to obtain an efficient and reliable assessment.

The application of the USGS resources assessment method requires data, ie. the existing discoveries within the play. All the available data are then quantified and recorded in the oil and gas appraisal data form (Fig. 6).

This form is organized by three main catagories :

- Play attributes,
- Prospect attributes,
- Hydrocarbon volume parameters.

The quantification recorded can be calculated manually or by computer simulation, and yields a probability of resource appraisal and pool size distribution of the play in the studied area.

III.3.1. Play attributes

The play attributes consist of hydrocarbon source, timing, migration and potential reservoir facies attribute. The hydrocarbon attribute determine whether the conditions of the play are favourable for occurrences of oil and gas.

The conditional deposit probability expresses the probability that any randomly selected prospect is an accumulation, given that the play parameters are favourable.

The marginal play probability expresses the probability that all of the first four play parameters are con curently favourable somewhere in the play.

III.3.2. Prospect attributes

The determination of the nature of the prospect needs three parameter, i.e. trapping mechanism, effective porosity and hydrocarbon accumulation. Evaluation of these parameters is accomplished by recording a single value between 0 (total certainty that the parameters is absent), and 1 (total certainty that the parameters is present) for the probability that the parameters is generally favourable in a randomly selected prospect within the play area.

III.3.3. Hydrocarbon volume parameters

The parameters are consist of reservoir lithology, hydrocarbon mixture and reservoir parameters. The reservoir parameters include area of closure, reservoir thickness, effective porosity, trap fill, and reservoir depth. The parameters describe the range of possibility value of the generic reservoir characteristics that determine the volume of the hydrocarbon present in an individual accumulation within the play. So, the hydrocarbon volume parameters quantifications are conditional on the play attributes and the prospect attributes of being favourable.

The number of drillable prospects is the play characteristic that describes the range of possible value for the number of valid targets that would be considered for drilling of the play where to be fully explored.

IV. RESOURCES ASSESSMENT IN THE NORTH SUMATRA BASIN

IV.1. Play Types

The stratigraphy of the North Sumatra Basin can be subdivided into three stratigraphic sequences, i.e the Oligocene, Early - Middle Miocene, and Late Miocene - Pleistocene stratigraphic sequences (Fig.7,8,9).

In the northern part of the basin, each of those sequences is clearly separated by an unconformity while in the southern part, unconformity can be detected only between the first and the second sequences.

The wedge base type of the play model is made up by clastic deposit of the Parapat Formation and carbonate sediments (the Arun LS of the Peutu Formation), which can be recognized in the first and second sequences. The third sequence contains the wedge middle (the Middle Baong Sand of the Baong Formation), and wedge top (the Keutapang and Seurula Formations).

IV.2.1. Parapat Wedge Base Play

The Parapat Formation is a very arenaceous clastic, usually occupied the irregular low topographic areas and thickened to the north (Fig. 10). So far, there has not been any evidence detected for hydrocarbon accumulation in the wedge base, either from outcrop or borehole data. However, in the northern part, especially in the vicinity of structural highs, the occurence of prospect in this play type need to be carefully investigated. Actually the depth of this play is deeper than the base of the oil generation level. This means that the play tend to contain gas instead of oil.

IV.2.2. Carbonate Wedge Base Play

The carbonate rocks of the Peutu and Belumai Formations can be found in three locations, which indicate that the content of the hydrocarbon is different (Fig. 11). In the southern part, it contains oil, while in the northern part it is dominated by gas.

The Arun Gas Field data shown in Table 1 is an example of used to predict the undiscovered gas potential of this play type.

IV.2.3. The MBS Wedge Middle Play

The MBS is producing zone in the southern part (Aru area) (Fig. 12, 13 & 14). The sandstones are interpreted as turbidite deposits, and appears as the lower part of the Keutapang Formation in the southeast. The potential sandstone layers of the MBS are Besitang River, Sembilan, Susu and Aru sandstones. The over-pressure caused by diapiric structure of the Baong shales occurred in the Aru area. The discovery wells show the reservoir data as follows :

- sand layer thickness (lenses) : 50 - 75 m
- porosities : 10 - 25 %
- oil (paraffinic) : 45-52 API

The undiscovered hydrocarbon in this play is less than that estimate for the Keutapang Wedge Top Play. This due to the influence of several factors as restricted area of deposition, predominant stratigraphic traps and the shaly reservoir rocks.

The evaluation shows that the maximum undiscovered oil of this play is estimated as 2.5 MMBBL and the minimum is 0.15 MMBBL.

IV.2.4. Keutapang Wedge Top Play

The Keutapang Formation was deposited in the deltaic environment. Potential reservoir are thin sandstones layers trending NW-SE, which are dominated by stratigraphic traps. The structural traps are faulted and dome-like. The reservoirs are usually vertically sealed by shale

The depth of this play type ranges from 800 m to 1100 m subsea. The sandstone porosities and permeabilities are approximately 15-20% and 50-100 mD respectively. The 43-51 API oil is paraffinic.

The play evaluation indicates that this is the most important oil play in the North Sumatra Basin. The maximum undiscovered oil is 504 MMBBL and the minimum is 0.37 MMBBL.

V. CONCLUSION

1. Stratigraphic wedge play concept of the North Sumatra Basin provides a logic geological processes and show a simple understanding in a choicing the play type.
2. The Keutapang Wedge Top Play should be explored in detail as undiscovered potential of this play is high.
3. The resources assessment method is a tool for management to control and develop the exploration activity. This method is also very useful in estimating hydrocarbon potential of unknown areas.

REFERENCES

Abrahamsen, K.A., 1988. *Application of the Reference Estimation Program FASPUM* ; Experiences From Offshore Norway, 6th Meeting of the WGRA-CCOP, Bangkok, 29 Aug. - 2 Sept. 1988

Baker,R.A., 1988. When is prospect or played out ? *Oil & Gas Journal*, 77. Jan 11.1988.

Burnaman, M.D. et al 1985. Discovery of the Canada Gas Field, Bee Block, North Sumatra, An Intergrated Geologic/Seismic Stratigraphic Case History. *Proc. I.P.A. Fourteenth Annual Convention*, Jakarta, Vol..1, pp. 453-498.

Dalton, L.G., Bird,T., Grovelli,R.A. 1987. Assessment of In Place Oil and Gas Resources, *Petroleum Geology of the Northern Part of Artic National Wildlife Refuge*. Chapter 22. pp. 277-298.

Davies, P.R. 1984. Tertiary Structural Evolution and Rela ted Hydrocarbon Occurence, North Sumatra Basin. *Proc. I.P.A. Thirteenth Annual Convention*, Jakarta, Vol.1, pp. 19-50.

Djunnudin, A. 1980. The Geological Evulotion of Northern Sumatra. *Proc. I.P.A. Ninth Annual Convention*, Jakarta, pp. 149-188.

Gravess, R.R. 1973. Geology of the Arun Gas Field North Sumatra. *Proc. I.P.A. Second Annual Convention*, Jakarta, pp. 23-52.

Hartoyo, Pramu et.al. 1974. Paleogeography of N.E. Suma tra. *Proc. I.P.A. Third Annual Convention*, Jakarta, pp. 45-62.

Helm, R.B. 1984. Stratigraphic Delineation of the Baong Sandstones by High Resolution Acustic Invertion in the North Sumatra Basin. *Proc. I.P.A. Thirteenth Annual Convention*, Jakarta, Vol.1, pp. 443-460.

Kamili,Z.A. et.al. 1976. Contribution to the Pre Baong Stratigraphy of North Sumatra. *Proc. I.P.A. Fifth Annual Convention*, Jakarta, Vol.2, pp. 99-108.

Kingstone,J. 1978. Oil and Gas Generation, Migration and Accumulation in the North Sumatra Basin. *Proc. I.P.A. Seventh Annual Convention*, Jakarta, pp. 75-104.

Lee, P.T., Eggen, Sven.S., Vain, Ian.R. *Use of Probabilistic Approach In Assessing Petroleum of The Northern North Sea*, Geological Survey of Canada Contribution, No 52187 pp. 1-21.

Mulhadiono et. al. 1976. Depositional Study of The Lower Keutapang Sandstone in the Aru Area North Sumatra. *Proc. I.P.A. Fifth Annual Convention*, Jakarta, Vol.1, pp. 115-132.

Mulhadiono et. al 1977. Notes on Hydrocarbon Trapping Mechanism in the Aru Area, North Sumatra. *Proc. I.P.A. Sixth Annual Convention*, Jakarta, Vol.1, pp. 95-116.

Mulhadiono et. al. 1978. The Middle Baong Sandstone Unit as one of theMost Prospective Unit in the Aru Area, North Sumatra. *Proc. I.P.A. Seventh Annual Convention*, Jakarta, pp. 107-132.

Mulhadiono et.al. 1982. Besitang Rivers Sand as the First Turbidite Reservoir in North Sumatra Indonesia. *Proc. I.P.A. Eleventh Annual Convention*, Jakarta, pp. 265-298.

Mulhadiono et. al. 1984. The Determination of Economic Basement of Rock Formation in Exploring the Langkat Medan Area, North Sumatra Basin. *Proc. I.P.A. Thirteenth Annual Convention*, Jakarta, Vol.1, pp. 75-108.

Naim, A.M., Kamili, Z.A., 1973. Stratigraphy of Lower and Middle Miocene Sediments North Sumatra Basin. *Proc. I.P.A. Second Annual Convention*, Jakarta, pp. 53-72.

Pegrum, R.M., Spencer, A.M. 1988. *Hydrocarbon Plays in The Northern North Sea*. Geological Society of London.

Petroconsultants, Inc., 1986. *Indonesia Oil Outlook, Petroconsultants Group Economics Division*, Houston.

Podruski, J.A., Barclay, J.E, Hamblin, A.P., Lee, P.J., Osadet Z, K.G., Procter, R.M., Taylor,C.G. 1988. *Con ventional Oil Resources of Western Canada (Light and Medium)*. Geological Survey of Canada Paper 87 - 26.

Helm, R.B. et. al. 1982. Miocene Carbonate Buildups, Off shore North Sumatra. *Proc. I.P.A. Eleventh Annual Convention*, Jakarta, Vol.1, pp. 127-146.

Situmeang, S. et. al. 1986. Geochemical Study of Asamera's Block 'A', Production Sharing Contract Area, North Sumatra Basin. *Proc. I.P.A. Fifteenth Annual Con vention*, Jakarta, Vol.1, pp. 321-340.

Situmorang, B. & Yulihanto, B. 1985. The Role of Strike Slip Faulting in Structural Development of the North Sumatra Basin. *Proc. I.P.A. Fourteenth Annual Convention*, Jakarta, pp. 21-38.

Sosromihardjo, S.P.C. 1988. Structural Analysis of The North Sumatra Basin with Emphasis on Synthetic Aperture Radar Data. *Proc. I.P.A. Seventeenth Annual Convention*, Jakarta, Vol.1, pp. 187-210.

Walker, P. et, al. 1986. Structural Interpretation Problem of a Lower Miocene Reef Associated a Shallow Velo city Anomaly, North Sumatra Basin. A Geophysical Case History, *Proc. I.P.A. Fifteenth Annual Convention*, Jakarta, Vol.1, pp. 279-304.

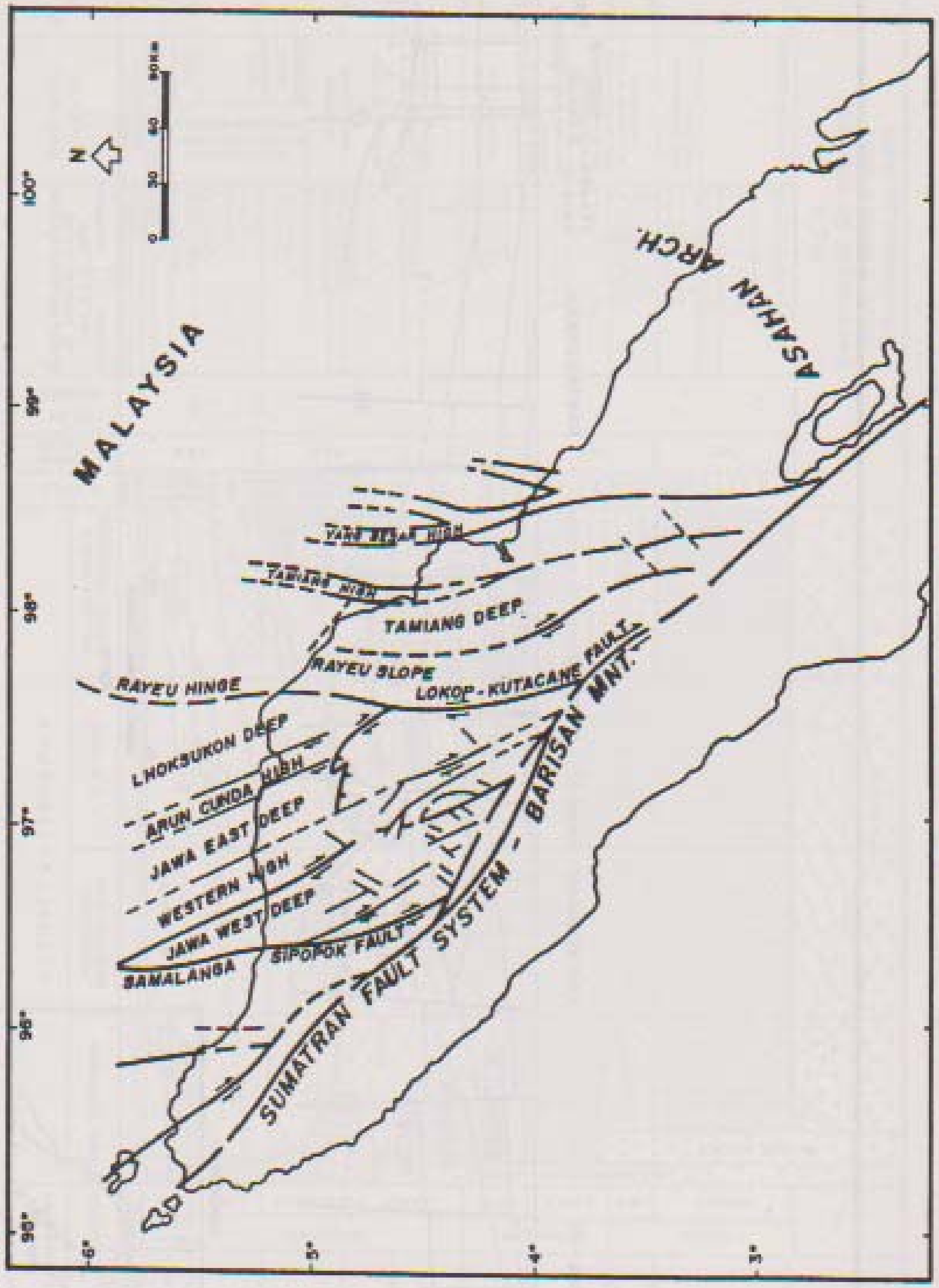


Figure 1. Tectonic Elements of the North Sumatra Basin

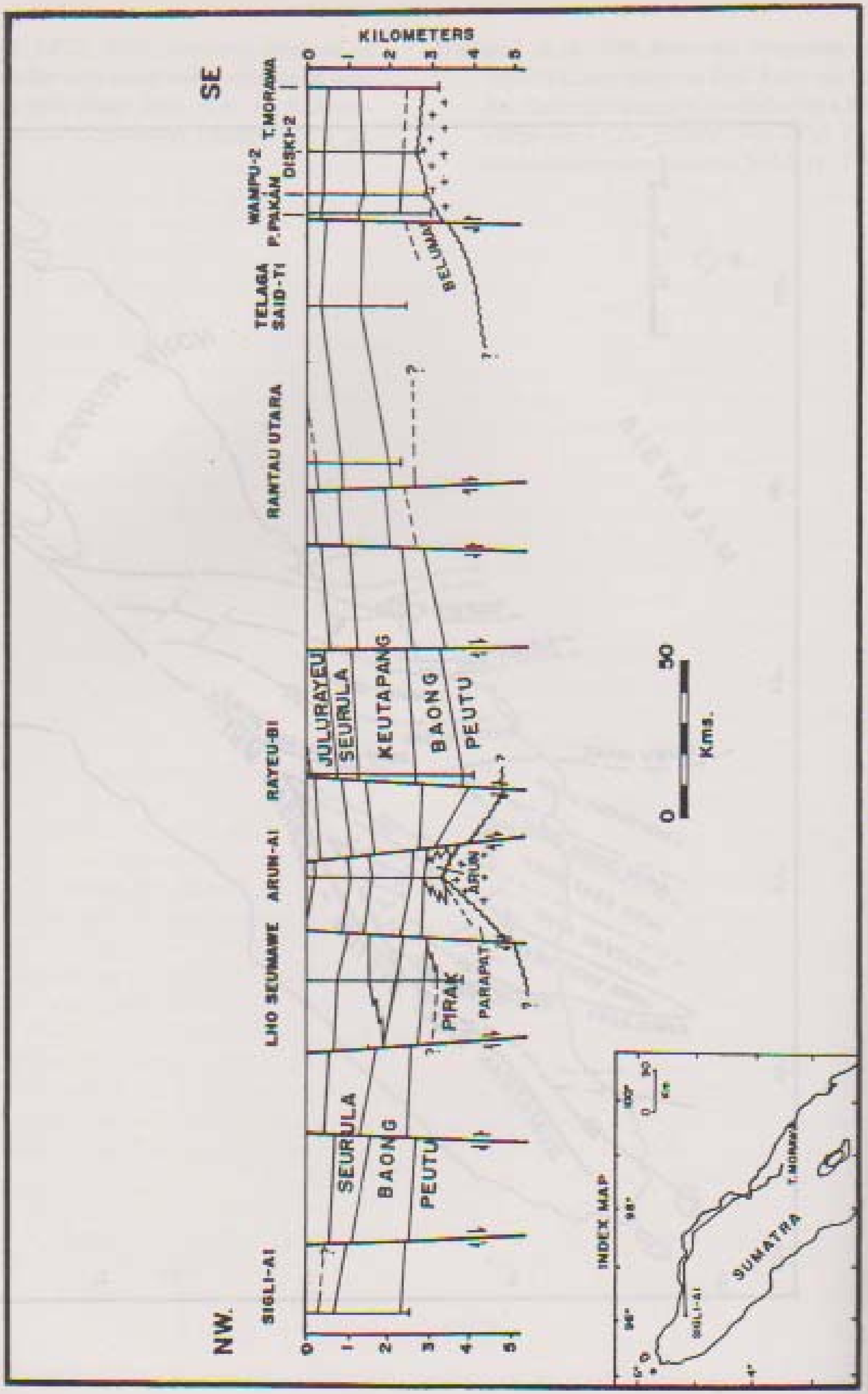


Figure 2. Structural cross section

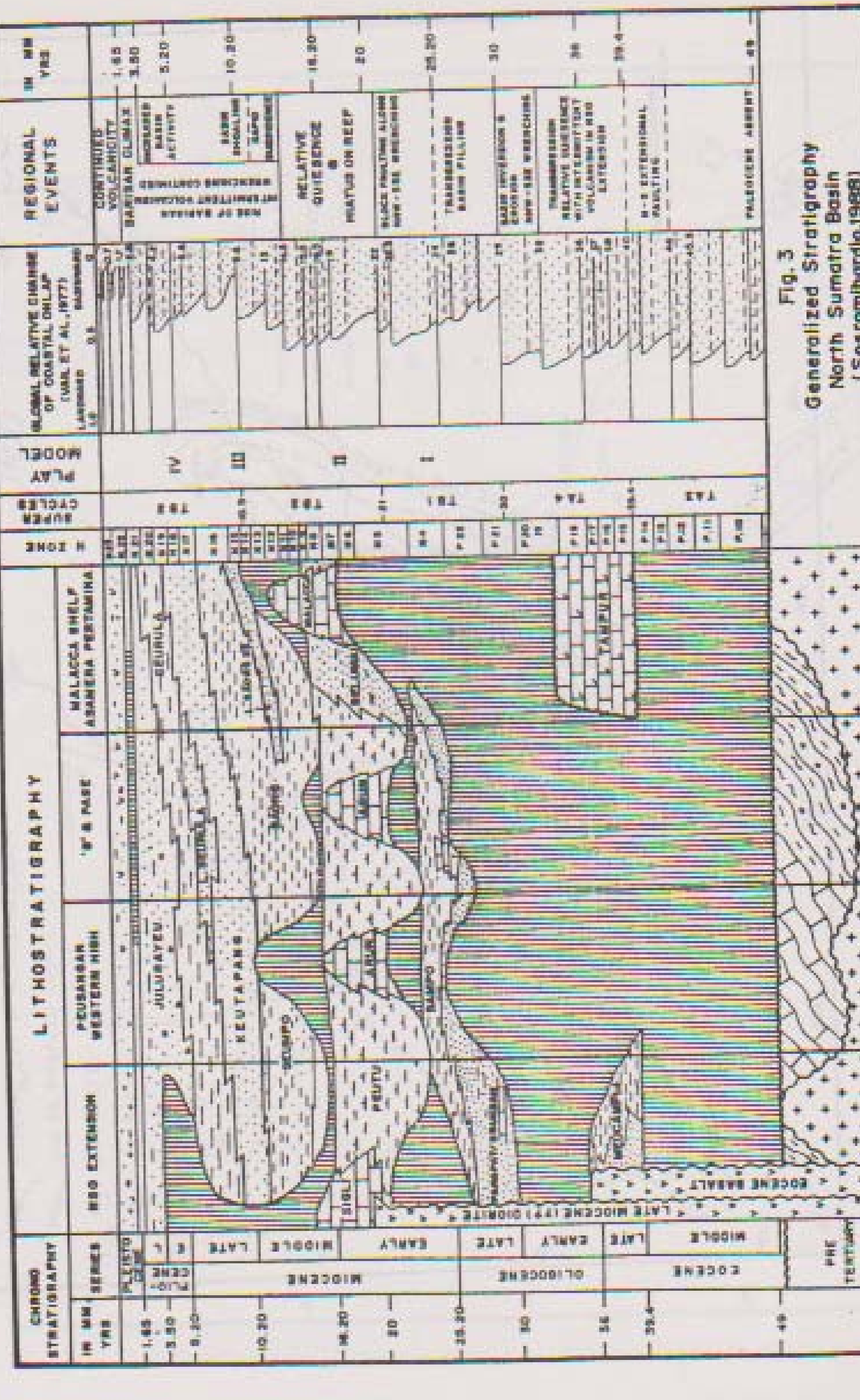
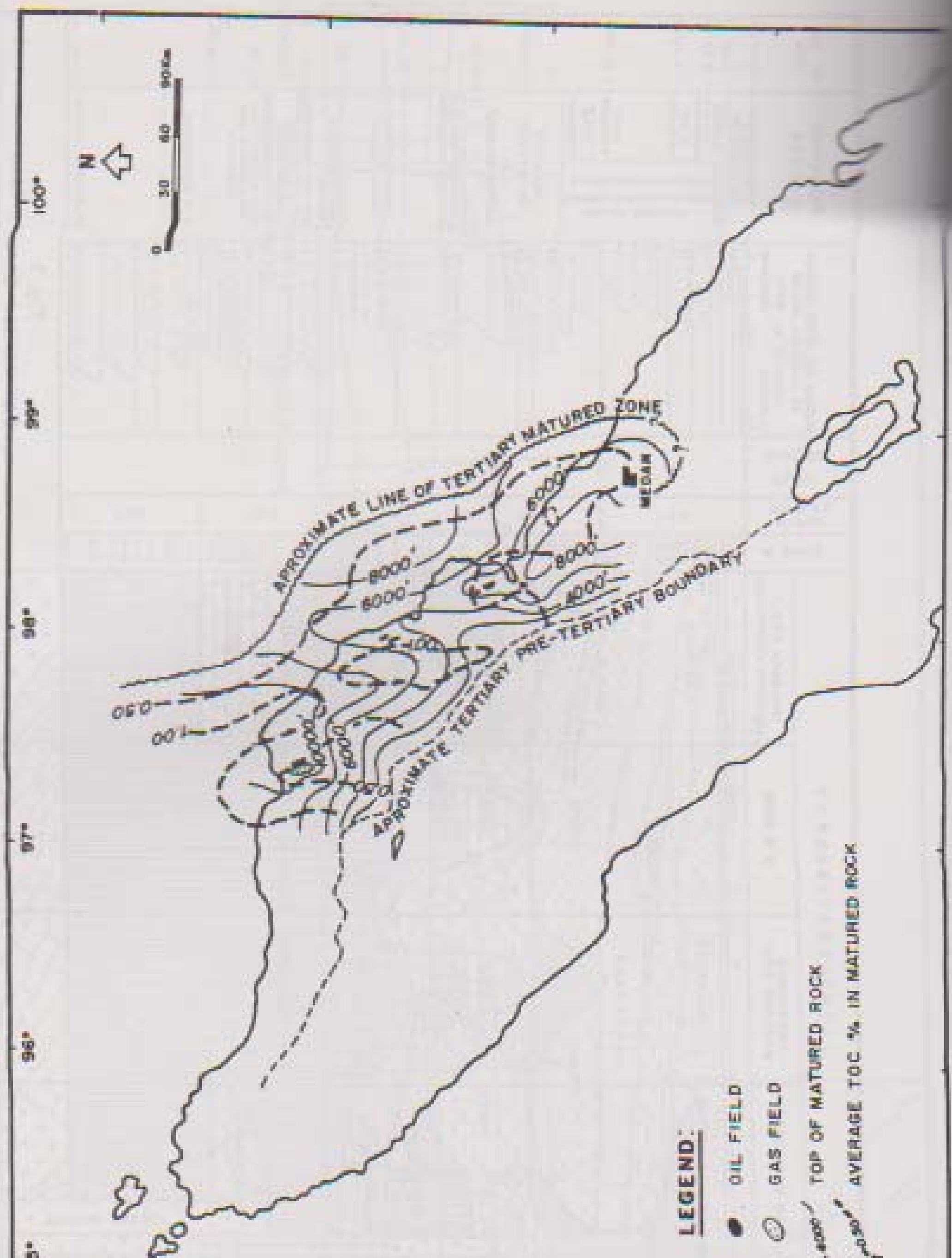


Figure 3. Generalized stratigraphy of North Sumatra Basin (Sosromihardjo, 1988)


LEGEND:
OIL FIELD
GAS FIELD
TOP OF MATURED ROCK
AVERAGE TOC % IN MATURED ROCK
APROXIMATE LINE OF TERTIARY MATURED ZONE
APROXIMATE TERTIARY PRE-TERTIARY BOUNDARY
MEDAN
N

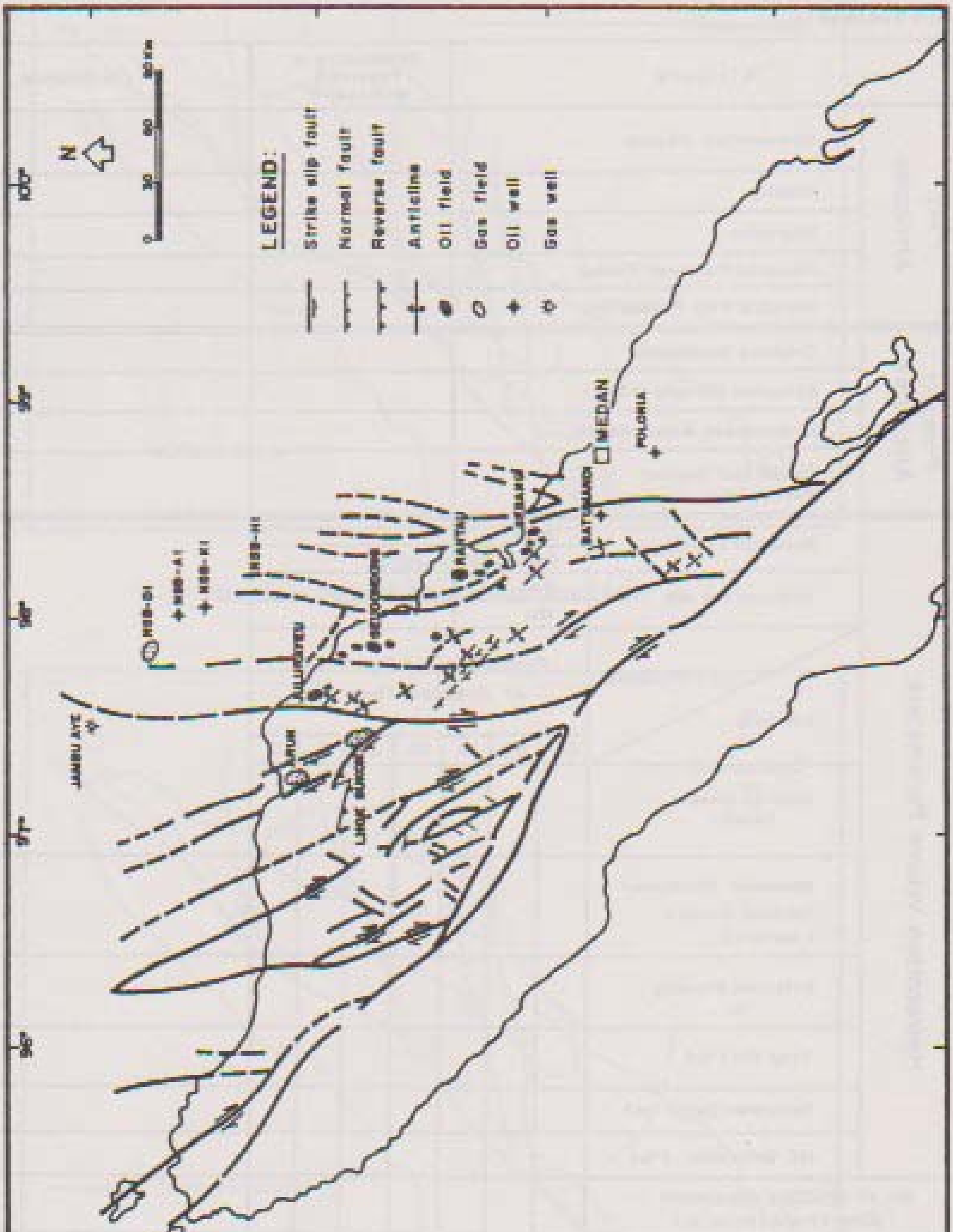


Figure 5. Structure and field locations map North Sumatra Basin

OIL AND GAS APPRAISAL DATA FORM

Evaluator : ______________________ Play Name : ______________________

Date Evaluated : ______________________

	Atribute		Probability of Favorable or Present	Comments
Play Attributes	Hydrocarbon Source			
	Timing			
	Migration			
	Potential Reservoir Facies			
	Marginal Play Probability			
Prospect Attributes	Trapping Mechanism			
	Effective Porosity (>3 %)			
	Hydrocarbon Accumulation			
	Conditional Deposit Probability			
Hydrocarbon Volume Parameters	Reservoir Lithology	Sand		
		Carbonate		
	Hydrocarbon Mix	Gas		
		Oil		

	Atribute \ Fractiles	Probability of Equal To or Greater Than							
		100	95	75	50	25	5	0	
Hydrocarbon Volume Parameters	Area of Closure (Km2)								
	Reservoir Thickness/ Vertical Closure (meters)								
	Effective Porosity %								
	Trap Fill (%)								
	Reservoir Depth (m)								
	HC Saturation (%)								
No. of drillable prospects (play characteristic)									

Figure 6

Oil and gas appraisal data form (Modified from US Department of Interior, 1979)

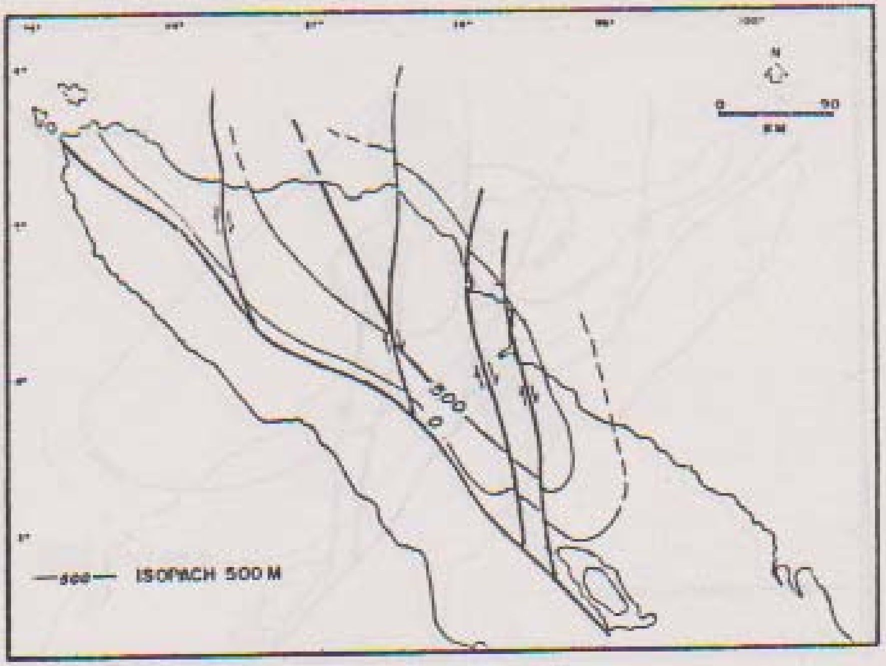


Figure 7
Time Slice Isopach Map (Oligocene Time)

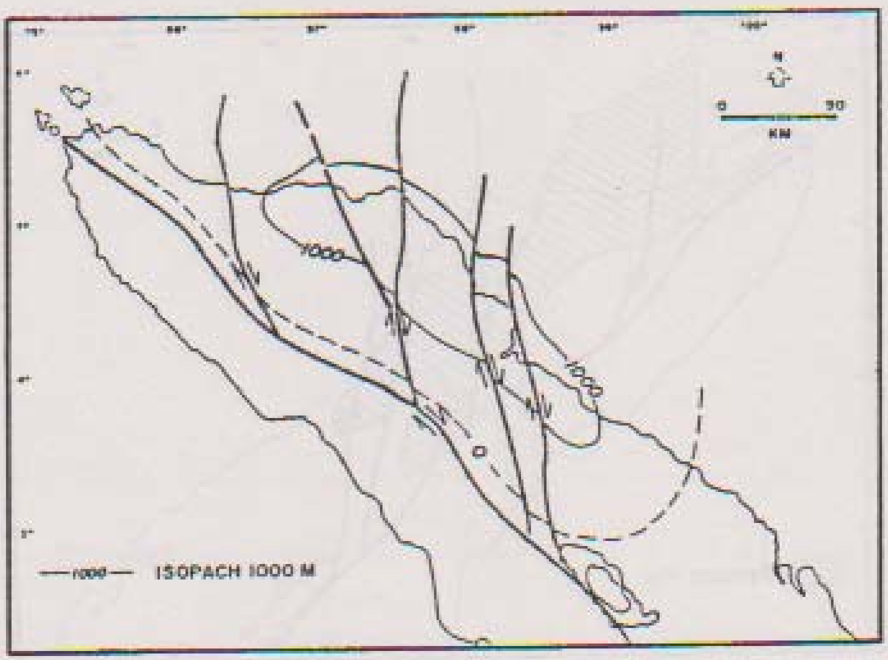


Figure 8
Time Slice Isopach Map (Early-Middle Miocene Time)

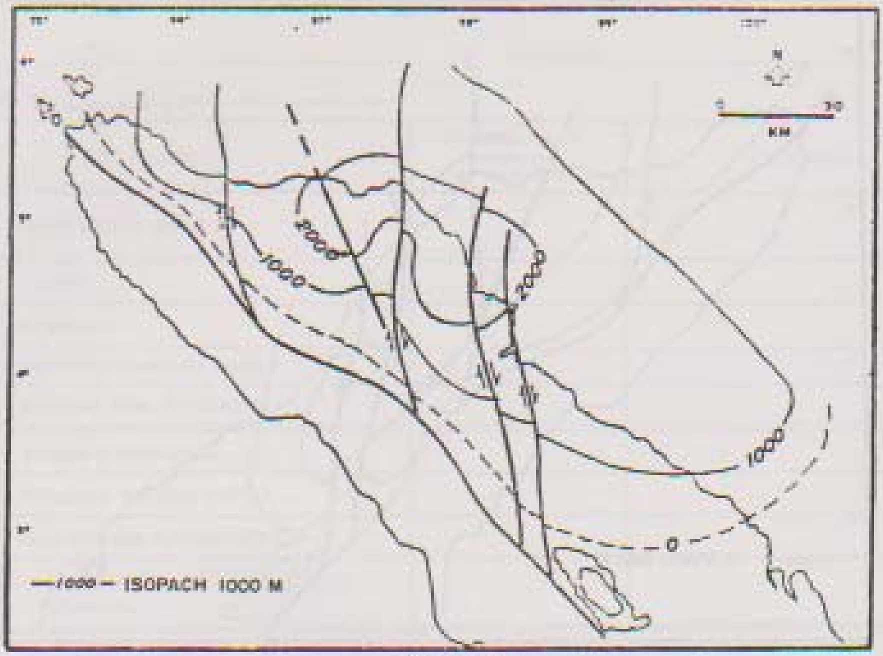


Figure 9
Time Slice Isopach Map (Late Miocene-Pliocene Time)

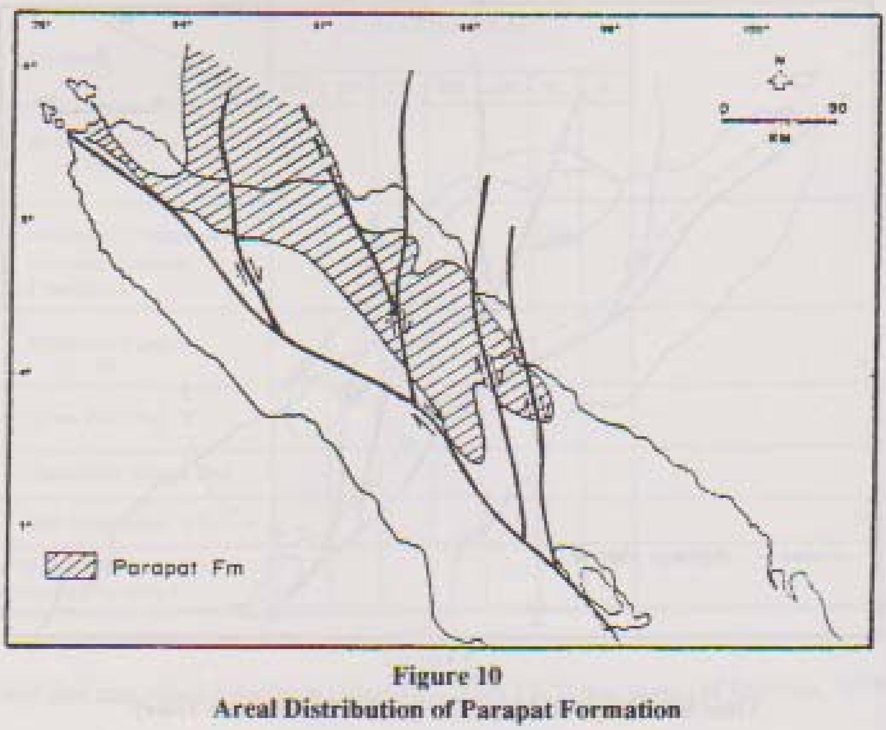


Figure 10
Areal Distribution of Parapat Formation

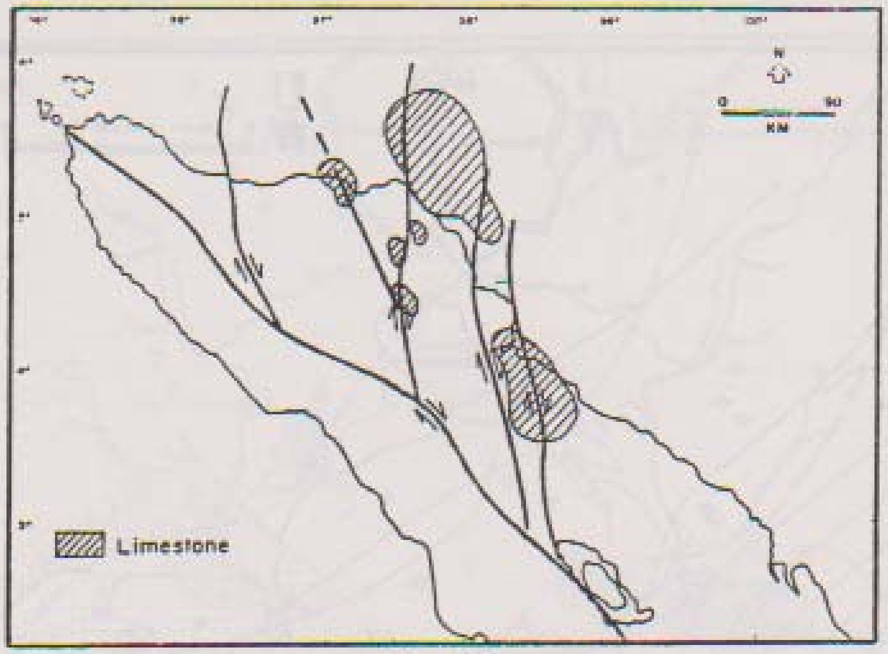


Figure 11
Areal Distribution of Limestone (Peutu, Belumai Formations)

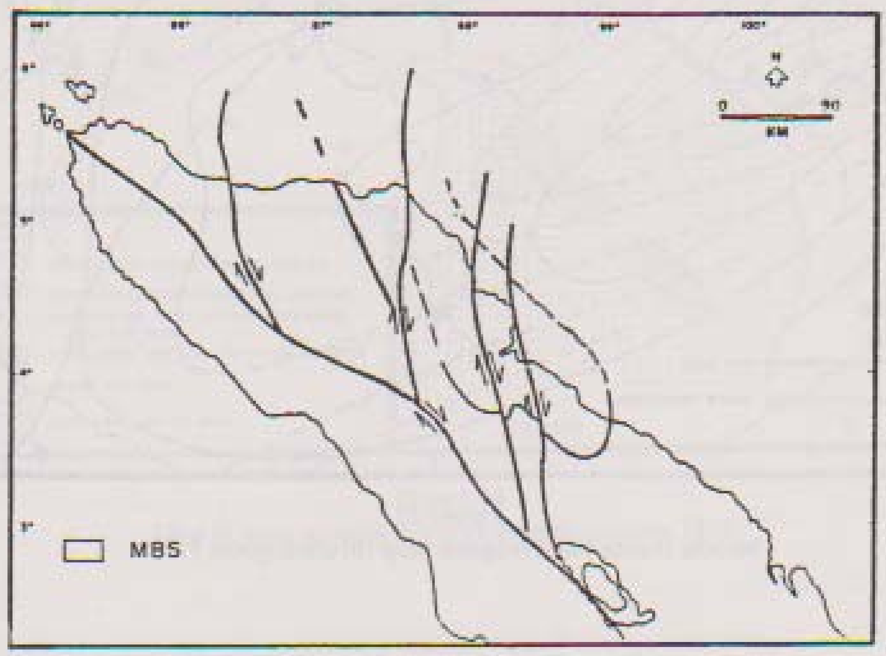


Figure 12
Areal Distribution of Middle Baong Sand (Baong Formation)

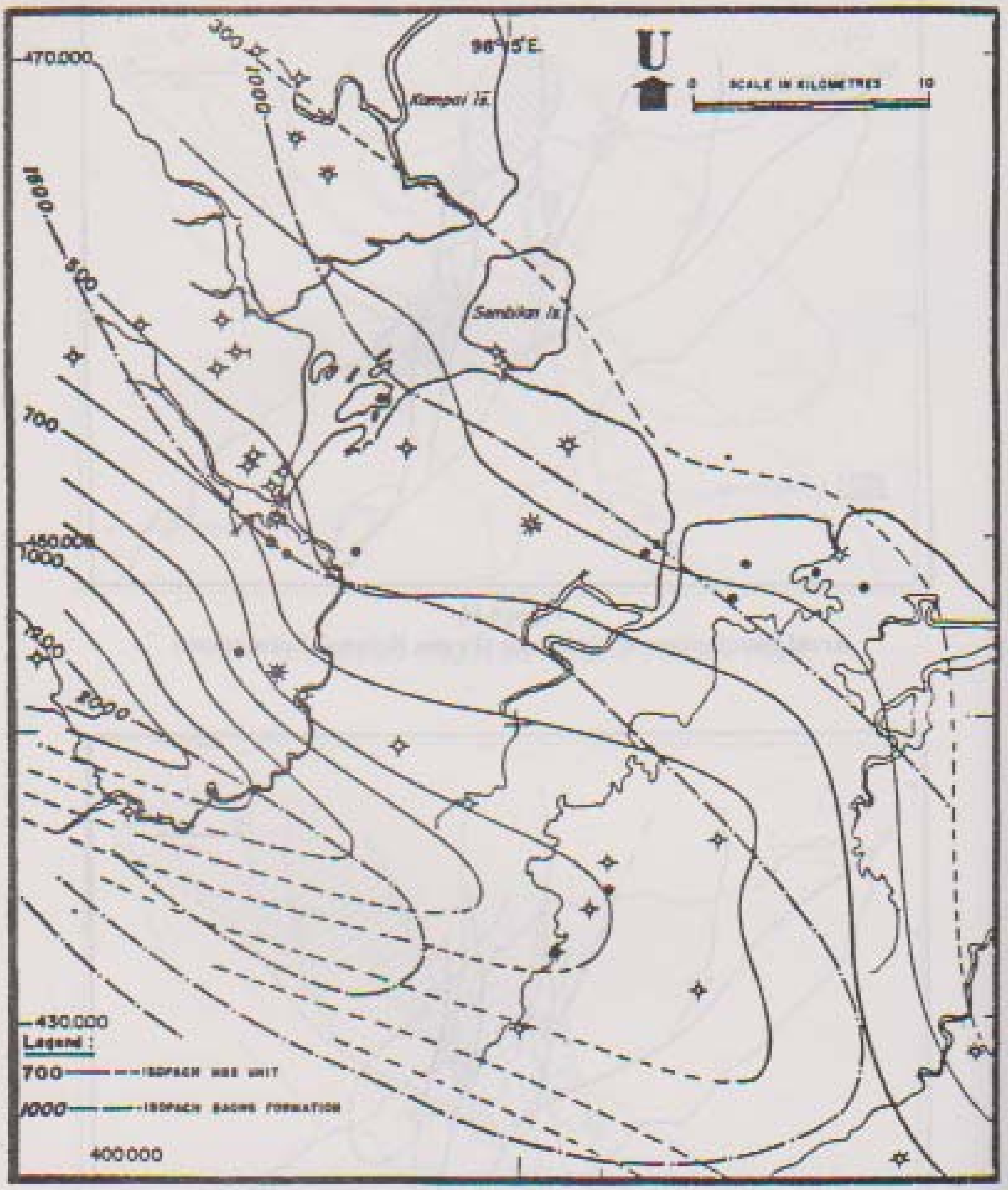


Figure 13
Middle Baong Sand Isopach Map (Mulhadijono, 1978)

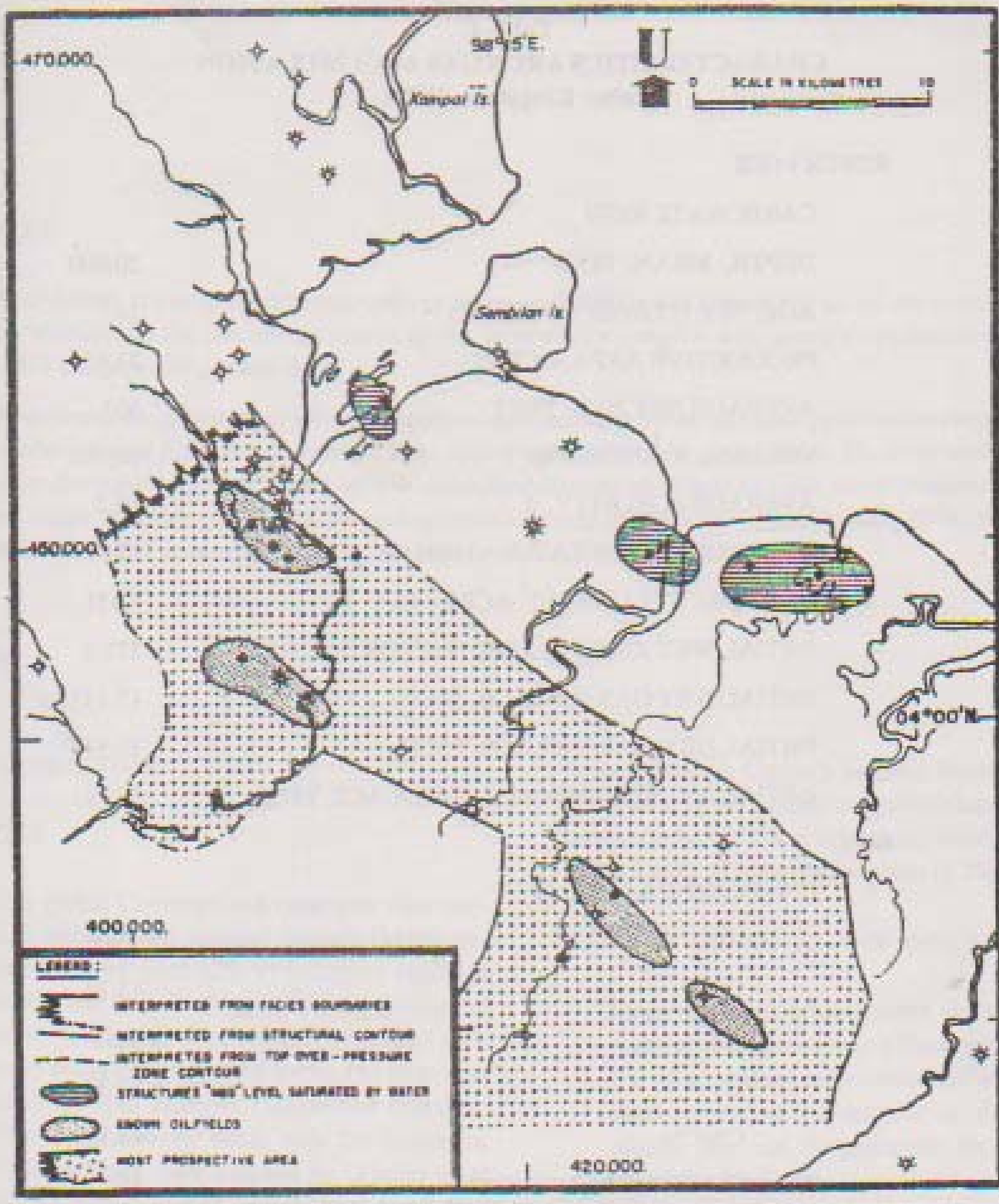


Figure 14
Map of most prospective area (Mulahadijono, 1978)

Table 1
CHARACTERISTICS ARUN GAS ACCUMULATION
(after Kingstone, 1978)

RESERVOIR	
CARBONATE REEF	
DEPTH, MEAN, FEET	10,000
AGE, MY. (LOWER MIOCENE)	14
PRODUCTIVE AREA, ACRES	21,450
AVERAGE NET PAY, FEET	503
VOLUME, 10^3 ACRE-FEET	10,789
AVERAGE POROSITY, %	16.2
AVERAGE WATER SATURATION, %	17.0
GAS PORE VOLUME, 10^3 ACRE-FEET	1,451
INITIAL WET GAS VOLUME FACTOR, SCF/RCF	271.3
INITIAL WET GAS-INPLACE, TSCF	17.147
INITIAL DRY GAS-INPLACE, TSCF	16.135
INITIAL HYDROCARBON GAS-INPLACE, TSCF	13.721
GAS	
COMPONENTS, MOL %	
H_2O	5.90
CO_2	13.76
N_2	O.32
C1	67.30
C_2-C_7+	12.70
TEMPERATURE, RESERVOIR	352^0
RESERVOIR PRESSURE	7100 psi
HYDROSTATIC PRESSURE	4350 psi
SALINITY OF WATER	10-20 ppm NaCL
ISOTOPIC COMPOSITION-C^{13} VALUE ppm ABOVE 10,000 FOR METHANE	659.1