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Maturity Modeling of Gomin and South Gomin fields Southern Pattani Basin, Gulf of Thailand

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Abstract

Two explorations wells found oil in the South Gomin area. To understand where the oil came from, 3D seismic plus wireline logs from ten wells were used to model maturity based on the depth of each formation, the present formation thickness, the earliest age of deposition plus the lithologies and amount of erosion represented by unconformities. Some of the wells were not drilled deep enough to penetrate the source rock; in those cases, source rock burial depth was determined from seismic data. Oligocene and Lower Miocene source rocks are overmature across the study area except in the east where they are still in the main gas generation phase. Lower middle Miocene source rocks are in the main gas generation phase to the west and in the oil generation window (mid to late mature) to the east. The upper middle Miocene and upper Miocene to Pliocene source rocks are in the early to late mature oil generation phase. The maturity model closely matches the hydrocarbon discoveries for Oligocene, lower Miocene and upper Miocene source rocks except for two wells that found gas in upper Miocene source rocks where it is mature for oil generation, although both are close to the oil/gas generation boundary. Most wells found gas in upper middle Miocene and upper Miocene to Pliocene source rock but the maturity model predicts oil generation. The gas probably migrated from older, more deeply buried source rocks that have matured to the gas generation phase. The models indicate that maturity levels are suitable for hydrocarbon generation throughout the study area. This suggests that there is remaining exploration potential, especially in the southeast where few wells have been drilled.

Keywords : Gomin and South Gomin Fields, Maturity Modeling, Hydrocarbon Generation

1. Introduction

The Gomin and South Gomin Trend is located in the southeastern flank of the Pattani Basin (red box in Figure 1). The study area is in the east flank of Pattani Basin close to the Thai/Cambodia line boundary. Approximately 500 square kilometers. Ten exploration wells supplied by chevron have standard curves comprised of gamma ray, resistivity, neutron, density and sonic logs. As a result, Geochemistry data, total organic carbon (TOC) and rock eval pyrolysis data.

This research project focuses on the hydrocarbon generation by maturity modeling and the objectives of the study are :

1.) To study maturity level of the all fives source rock unit.
2.) Expulsion timing of all five units.
3.) Type of hydrocarbon oil, gas and condensate related to source rock maturity.

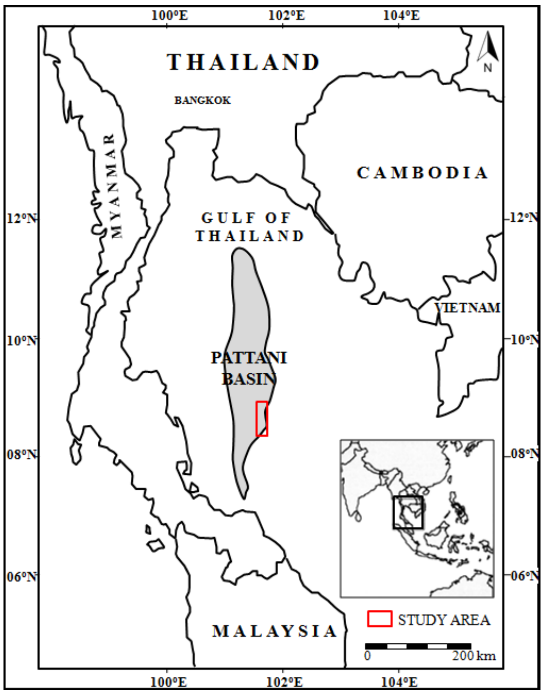

Figure 1. the location of the study area

2. Methodology

The Methodology, started with well log data. Sands, shales, coals were interpreted from well log data such as gamma ray, resistivity, neutron, density and sonic logs. Following by, the key markers were correlated from well to well. Then the percentage of lithology was calculated. All data were used to construct the maturity model.

Consisting of the top depth of each formation, the present thickness of formation, beginning age of deposition and unconformity, lithology and eroded thickness. The erosion thickness was the essential parameter because it could affect timing of hydrocarbon generation. For present thickness values, well log data from drilled wells were used. However, in case of some well that not drilled deep to the source rock, seismic data were used to obtain depth. The unit of seismic data was millisecond (in term of time) but the unit that basin modeling requires was meters. So, the time-depth function from the sonic logs and synthetic seismograms of the South-Gomin-06 was used to convert time to depth. Comprise of geothermal gradient from previous study and final well report and bottom hole temperature (BHT), which derived from the final well report. Bottom hole temperature was calculated to find out the heat flow value of this area. The bottom hole temperature and surface temperature were re-checked and changed to appropriate heat flow value result which was about 2.1 HFU. Then input all data into the BasinMod 1D (2009) Next Burial history was plotted and calibrated to maturity level (vitrinite reflectance or %Ro values) to show maturity level of source rock, which are either early mature, mid-mature, or late mature.

The present day surface temperatures were derived from the report of annual temperatures (www.worldclimate.com). The paleotemperature was calculated using the following equation;

$$T(^{\circ}C) = 27.6 - (0.0414L) - (0.00599L^2)$$

Where L was the Paleo-latitude of Gulf of Thailand that was derived from (www.scotese.com). The present day surface temperature was 28.1 ºC. After that, the paleoclimate change through time was taken for more accuracy. As an example of the process.

The rifting heat flow method was chosen in the geothermal calculation for this study. It was assumed that the rifting in the Pattani Basin started in late Eocene (39.5 my) and censed at late Oligocene (25.5 my) (Jardine,1997). The rifting beta factor (β) or the lithospheric factor was taken at about 2.1 (Bustin et. al., 2003), which was acquired from the nearest well that has data (Funan-1). The thickness of lithosphere was taken as about 120 kilometers. The rifting heat flow chart on this research was based on Waples (2000) model; it emphasized that radiogenic heat production (RHP). The RHP had a significant influence on surface heat flow; during the rifting period, the thinning of the crust resulted in a loss of radiogenic heat production, so the basin looses the heat very quickly. After that, the heat from crust caused slowly increasing heat flow. An example of the rifting heat flow chart which was used in this research.

The heat flow value was corrected by the measured bottom hole temperature (BHT) as shown in Figure 13. The corrected present heat flow in this study is 2.18 HFU.

In this study, mechanical compaction rate was chosen in the modeling process. In unit 1,3 and 5, the (Baldwin and Butler, 1985) porosity reduction method was used because they contain mostly shale that suitable to used this function. In Unit 2 and 4 that mainly contain sands, the exponential (Sclater and Christie, 1980) method, which was tested in the clastic rocks, was used to measure porosity values, which were used to calibrate the compaction rate model. The plot of porosity versus depth calibrated with measured porosity values. All these data were then input into the BasinMod 1D and 1D-maturity model for each well plotted.

From my study, most of the exploration and delineation wells were located to the flank eastern side of study area. There were no drilled well to confirm on the western side; therefore, five Pseudo wells were added as shown in the base map (Figure 2). These pseudo wells aided to confirm and add the data point for maturity map establishment. All pseudo wells were located to the western of the study area that step out from the graben area and next to the axis of Pattani Basin.

3. Results

Burial history and maturity level (%Ro) were plotted to show the 1D maturity models for the ten delineation wells and five analyzed Pseudo wells in the location map (Figure 2) and the example of maturity model of South Gomin 01 (Figure 3).

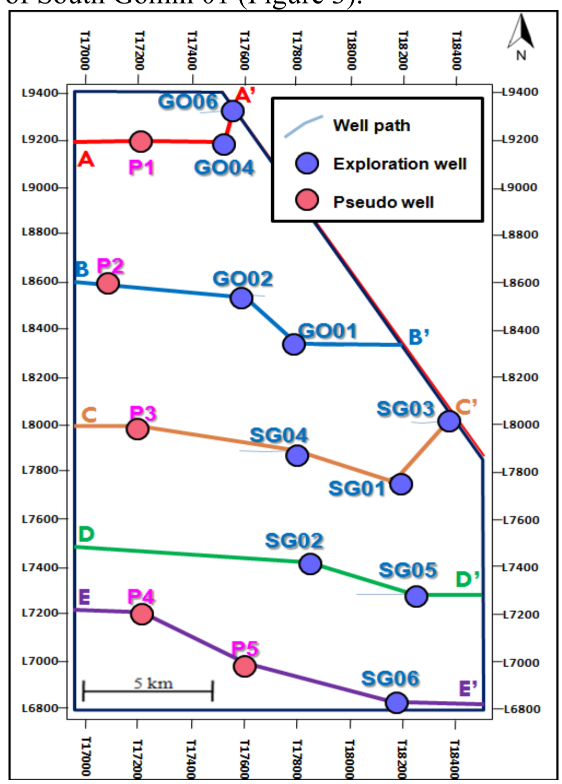

Figure 2. The base map of the study area, blue circle is exploration wells and pink circle is pseudo wells.

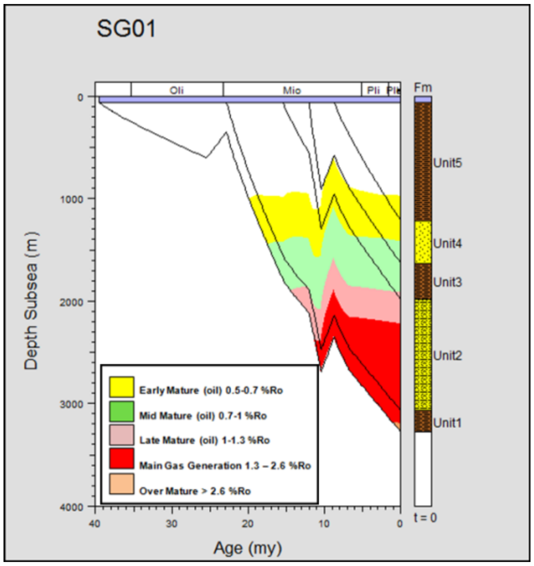

Figure 3. Example of maturity modeling of SG01.

From each maturity model section can interpret to the western part, there are overmature than to the eastern part of the study area.

Maturity Maps

All maturity level (%Ro) calculated at the base of each source rock (Unit 1-5) from 1D maturity models of ten delineation wells and 3 pseudo wells were plotted on the base map to see the trend of kitchen area (mature source rock zone).

Source rock maturity levels were influenced by the temperature, so the source rock deeper basin tends had higher maturity than the source rocks deposited in the flank of basin or shallower part.

Unit 1 Source rock (Oligocene)

The base of unit 1 maturity map at the present time (0 my) shown that source rock generally reached high maturity (over mature %R0>2.6) to the basin ward (west) and tended to be lower mature along the flank of the basin. In GO01 and SG04, they all were still generating hydrocarbon (main gas generate %Ro1.3-2.6) red color to the east and south east. The main source rock within Unit 1 or Oligocene source rock, located in the east and southeast of this area which had a high potential for gas generation.

Unit 2 Source rock (Lower Miocene)

The base of unit 2 maturity map at the present time (0 my) shown that source rock generally reached high maturity to the basin ward (west) and tended to me lower mature along the flank of the basin. In the west GO04, GO02 and all five pseudo wells to the west, there were already stopped generating hydrocarbon since about 2-15 my ago. The main source rock within Unit 2 or Lower Miocene source rock, located in the middle and west of the study area which had a high potential for hydrocarbon generation.

Unit 3 Source rock (Lower - Middle Miocene)

The base of unit 3 maturity map at the present time (0 my) shown that source rock generally reached higher maturity to the basin ward (west) and tended to be lower mature along the flank of the basin. The main source rock within Unit 3 or Lower - Middle Miocene source rock, located in the middle and west area which had a high potential for hydrocarbon generation. To the west of the study area, all five Pseudo wells shown that they were still generating in the Main gas generation (%Ro 1.3-2.6) red color. To the middle of study area GO05, GO01, SG04, SG01 and SG02, there were still generating late mature (oil) %Ro 1-1.3. Finally to the southeast of this area SG03, SG05 and SG06 shown that source rock unit 3, was still generating on the Phase of Mid Mature (oil) %Ro 0.7-1.

Unit 4 Source rock (Middle Miocene)

The base of the unit 4 maturity map at the present time (0 my) shows that source rock generally reached high maturity to the basin ward (west) and tended to be low mature along the flank of the basin. The main source rock within Unit4 or Middle Miocene source rock. To the west of this area, the result from pseudo-well 01, 02 and GO04, they were generating late mature (oil) %Ro 1-1.3. To the east and south east of this area, it was in the phase of Mid Mature (oil) %Ro 0.7-1.0 which was shown in green color. In this sequence, were still generating hydrocarbon which had good potential for hydrocarbon generation.

Unit 5 Source rock (Upper Miocene to present)

The base of unit 5 maturity map at the present time (0 my) shown that source rock generally reached high maturity to the basin ward (west) and tended to be low mature along the flank of the basin. The main source rock within Unit 5 or Upper Miocene source rock , located in the middle and west area. Unfortunately, this source rock of this unit was poor coals lignite stage that was not a good potential to be good source rock.

4. Discussion

Unit 1 or Oligocene source rock that is generating hydrocarbon at present day, produces mainly gas (red color) in the eastern part of the study area. In addition, there is overmature source on the eastern side. Wells SG01, SG02, SG03 and SG05 are in the overmature source rock zone (%Ro>2.6) and all four wells were dry, which matches the maturity modeling. The results of SG04 and SG06 also match the modeling because the models indicate that the source rock is in the main gas generation phase (1.3-2.6 %Ro) and gas/condensate was found in this interval (Figure 4)

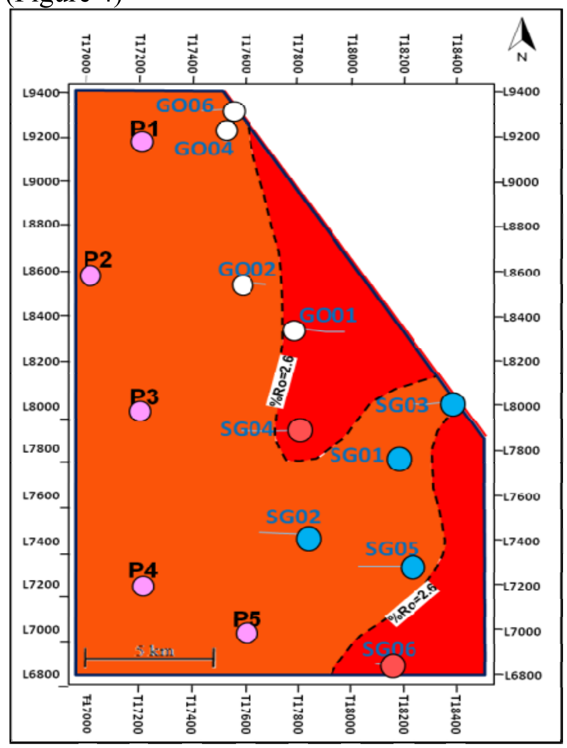

Figure 4.The Unit 1 (Oligocene) maturity map overlain with the Unit 1 hydrocarbon distribution. Pink circle is pseudo well, Blue circle is dry well, Red circle is gas/condensate well and white circle is no data due to not penetrated in this interval.

For the Unit 2 or Lower Miocene source rock, there is a close match between the proven hydrocarbons and the maturity model mature as nearly all the wells that discovered gas lie in the main gas generating area (Figure 5). GO02 and GO04 are the exceptions but both lie very close to the gas generation/overmature boundary and the presence of gas can be explained easily by short distance migration. Two wells in the south found both oil and gas/condensate in this interval. Gas matches the maturity modeling results but for oil does not. The oil probably migrated from underlying Unit 1 source rock or from the Ubon and/or Morakotfields that are located nearby (Figure 5).

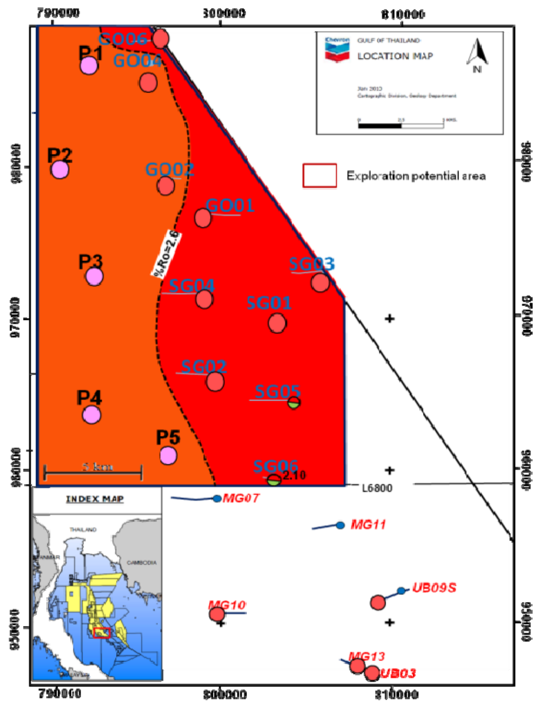

Figure 5. The Unit 2 (Lower Miocene) maturity map overlain with the Unit 2 hydrocarbon distribution. Pink circle is pseudo well, Red circle is gas/condensate well and half red and green circle is oil/gas/condensate well that found in this interval.

All the wells in the study found gas/condensate in the lower middle Miocene but only two, GO04 and GO02, are in the main gas generation phase according to the maturity modeling whilst the other wells are in less mature areas. Again, this almost certainly results from relatively short distance migration of gas into less thermally mature areas.

All the wells in the study area also found gas in Unit 4, but the maturity models indicate that the entire area is still in the oil generation phase. The gas probably was generated from deeper more mature source rocks and then migrated into Unit 4. Similarly, the gas/condensate that was found in Unit 5 in five wells probably came from a more deeply buried source rock, whilst the other five wells that were dry better reflect the maturity level of the Unit 5 source.

There is remaining exploration potential in the study area. The models show that the generation window and maturity level are suitable for hydrocarbon generation throughout the area. Most exploration potential appears to be in the southeastern part of the area where there are few exploration wells despite widespread mature source rock.

5. Conclusions

Source rock maturation was analyzed by 1D maturity modeling that indicates the area to the west (basinward) has a higher maturity level than the eastern side of the study area (basin flank). The maturity level ranges widely from overmature (%Ro >2.6) to early mature (%Ro 0.5-0.7). The hydrocarbons, both oil and gas/condensate, are derived from two sources which are the following;

1. The oil came from the Unit1 or Oligocene source rock that generated oil about 10-25 Ma according to the modeling. The oil migrated up-dip and was trapped in Unit 2 in wells SG05 and SG06.

2. Some oil may have come from the nearby Ubon and Morakot areas which are located close to the southern part of the study area

3. The gas/condensate came from an *in situ* land plant source rock that has been matured to the gas generation window in Units 1, 2 and 3 based on maturity modeling.

4. The gas/condensate migrated up-dip and was trapped in Unit 4 and Unit 5 reservoirs, which are less thermally mature.

5. There is remaining exploration potential in the study area, mostly in the southeastern part.

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