# Maturity Modeling of the Nakhon Basin, Gulf of Thailand

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**ABSTRACT**

The maturity of Oligocene potential source rocks in the Nakhon Basin was evaluated with a 1D maturity model that was calibrated with vitrinite reflectance data. Burial and thermal histories during basin development were modeled assuming a subduction rollback tectonic and paleo-heat flow was calculated with a transient model. The maturity model suggests that most potential source rocks are currently in the early oil window; although approximately 40% of those in the northern sub-basin have reached the main oil window, as have approximately 10% of the source rocks in the southern sub-basin. These results suggest that there may not have been a significant amount of oil generated in the Nakhon Basin.

**Keywords**: Maturity Modeling, Nakhon Basin, Gulf of Thailand

## 1. Introduction

The Nakhon Basin is located in the western Gulf of Thailand. The basin formed as a result of subduction rollback combined to rifting extension by the collision of the India Plate with the Eurasian Plate. The Nakhon Basin has 2 sub-basins separated by a structural high in Figure 2. The basin is approximately 2,400 $km^2$ in area and around 80 km in length and 40 km in width and the maximum thickness of the stratigraphic succession is around 3,200 m. There are 3 exploration wells in the basin. Well-1 was drilled to test the southern sub-basin while Well-2 and Well-3 tested the northern sub-basin in Figure 1. However, all three wells were unsuccessful. One uncertainty in the well results is whether there are mature source rocks in the basin, especially in late Oligocene lacustrine shales.

1D maturity modeling was used to evaluate the source rock potential in the Nakhon Basin by modeling source rock maturity in the late Oligocene sedimentary rocks. The 3 existing wells were used in the study, plus 1 pseudo-well, which was located in the depocenter of the northern sub-basin and labeled Well-4. Burial histories generated from the well data were compared with the measured vitrinite reflectance on sidewall cores and cutting samples from Well-1 in order to construct the thermal history of the basin. Based on this data set and basin models, isomaturity for the late Oligocene potential source rocks was mapped across the basin.

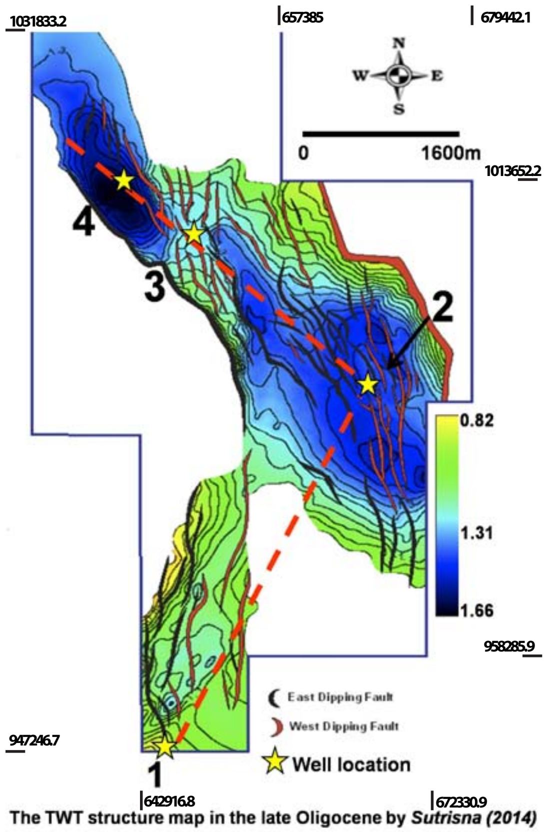


**Figure 1.** The time structural map of the late Oligocene section in the Nakhon Basin and the well locations in the study

## 2. Methods

### Database

Well data comprised neutron, density, sonic, gamma ray, mud logs and biostratigraphic data from Well-1, Well-2 and Well-3 supplied by Coastal Energy. These data provided the formation tops, lithology and bottom-hole temperature in each well. Two wells, Well-1 and Well-3, were drilled to basement; the lithologies in the deep section to basement were constructed using these two wells. Ages of events and formations were taken from Hall and Morley (2004), Morley and Westaway (2006), Morley and Racey (2011), Petersen and Mathiesen (2007) and Pradidítan and Dook (1992). Horizons interpretations from 2D seismic by Sutrisna (2014) were used to correlate and construct the formation tops from the existing wells to the pseudo-well.

A geochemical study of Well-1 indicated there are potential source rocks in the Oligocene succession. The unit is coals interbedded with dark grey claystones and coaly claystones. The study suggested that the

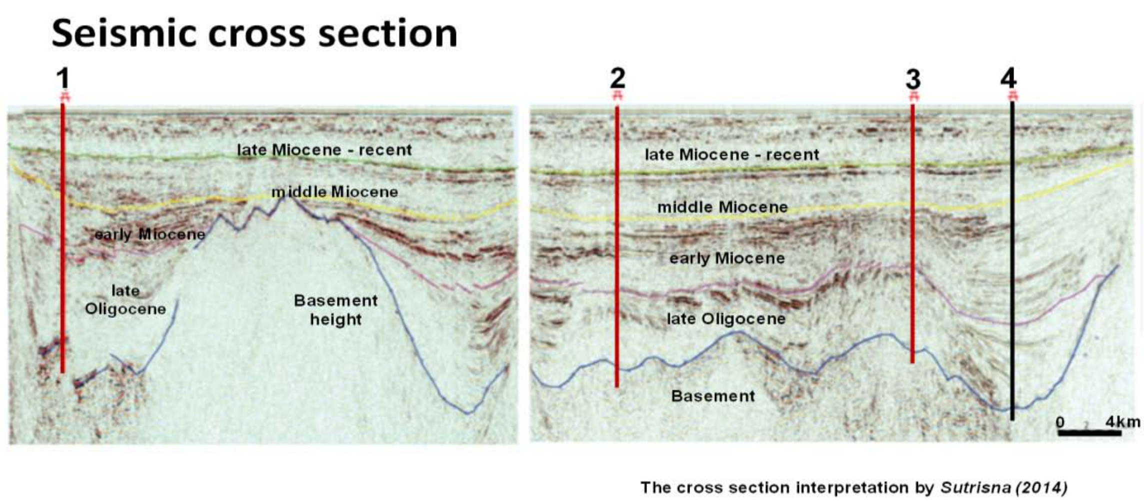


**Figure 2**. The seismic cross section along the wells in Figure 1

depositional environment during the late Oligocene was lacustrine to fluvio-lacustrine. The potential source rocks contain 39 - 60% and 8.37 - 18.6% organic matter for coal and claystone, respectively. The hydrogen to carbon and oxygen to carbon ratios from a Van Krevelen diagram were used to define kerogen type. Woody kerogen (Type III) and a significant proportion of herbaceous organic matter (Type II) are present in the Oligocene section. They generated 23.9 - 89.5 mg/g and 157 - 191 mg/g pyrolysate material, respectively. The claystones in the other sections are intepreted as poor source rocks because they have less than 0.2% - 0.3% TOC and some were oxidized and reworked.

Vitrinite particles (Ro) from sidewall core measurements in Well-1 were used to determine the maturity of the study area. There were 3 high vitrinite values at 1,376 m, 1,946 m and 3,037 m that were excluded from data set because the report interpreted them as unreliable data. The vitrinite data were from 2,366 m to 2,838 m in samples mainly from the sediments in the late Oligocene section. Most vitrinite samples are in the late Oligocene recorded 0.45 - 0.55 % Ro, with some up to 0.75 % Ro.

**Burial Modeling**

The burial history curves were constructed by inputting the formation tops and lithologies from the well reports. The rock compositions in each unit were assigned to 8 lithologies with petrophysical properties specified by the software. The mixed lithology of each formation was decompacted with a porosity reducing function. Compaction was calculated assuming exponential porosity reduction with depth because the Nakhon Basin had a normal to high sedimentation rate. The calculated porosities were calibrated to well log porosities, using porosity measurements in shale as a calibrator. These porosities were calculated from density logs in Well-1 and Well-3 only because the density log from Well-2 was not available. The compaction trend in Well-2 is similar to Well-3 which is located in the same sub-basin. The compaction trend in Well-1 was not clear in the BasinMod software so cross-plots in the Interative Petrophysics were used to determine compaction trends by plotting the frequency of shale density versus depth in both Well-1 and Well-3 wells.

Based on Pradiditan and Dook (1992), an unconformity was modeled at the end of the middle Miocene that marks the termination of rifting and separates the syn-rift from the post-rift on seismic data (Sutrisna, 2014). The amount of erosion was estimated as a simple case by assuming that the sedimentation rate during deposition of the eroded section was similar to the rate of deposition before erosion. A change in the compaction trend could not used to determine the unconformity depth and amount of erosion because there was no logging run above the middle Miocene section.

**Thermal Modeling**

Present-day heat flows were calculated from thermal conductivities of the rock properties and mineral compositions in each unit. Surface temperatures, and subsurface temperatures generated by correcting bottom-hole temperatures. Average surface temperatures were determined using ©2008 Paleomap Project (www.scotese.com). The bottom-hole temperatures from well logging were corrected in order to get the true formation temperatures. The formula in the Waples Spreadsheet (modified from Waples et al. (2004) and Waples and Mahadir (2001)) was used to determine the corrected present-day subsurface temperature. The temperature error from the spreadsheet was around 6.0 degree Celsius.

A thermal model was calculated using transient methods since heat flow values in SE Asia, especially the Gulf of Thailand, are high because there is significant heat from radiogenic sources within sediments. Basin development was modeled as a subduction-rollback back arc basin with non-uniform extension, which affected the heat flow complexity. Heat flow was assumed to increase during the long rifting period and decreased slightly during the post-rift.

The vitrinite was modeled using the $R_o$ model in which oil and gas generation, expulsion, and retention follow individual hydrocarbon components. The measured vitrinite data from claystone in side wall cores at 2,117 - 2,597 m are considered the most reliable maturity data and were used to calibrate the paleo-heat flow. There is no geochemical study available in the northern sub-basin tested by Well-2 and Well-3 so the heat flow model for Well-1 was used for Well-2, Well-3 and pseudo Well-4.

### Pseudo-well

One pseudo-well was constructed in the depocenter of the northern sub-basin near Well-3. Formation tops in the pseudo-well were defined by seismic horizon picks and correlated to existing wells. The lithologies were determined from the adjacent Well-2 and Well-3 wells which were located in the same sub-basin and on structural trend. The assumptions about present-day heat flow (Low = 57.5mW/m$^2$, Base Case = 63 mW/m$^2$, High = 68.5 mW/m$^2$) were the same as for Well-2 and Well-3 in order to construct the maturity model.

## 3. Results

### Burial histories of the existing wells

Burial curves of the 3 existing wells, Well-1, Well-2, and Well-3, generally have similar trends. However, Well-1 has a higher subsidence rate during the late Oligocene to the middle Miocene rifting phase than Well-2 and Well-3. After a period of non-deposition around 10 Ma, Well-1 has a low subsidence rate in the post-rift phase from the late Miocene to Recent, while the burial curves for Well-2 and Well-3 display high subsidence rates in the post-rift. The late Oligocene potential source rock unit is thickest in Well-1, where it is 986 m thick.

### Thermal models

In the model, heat flow value was in accordance with temperature data from corrected bottom-hole temperature data from wells. The highest heat flow is in Well-3 because the well is located on a structural high. The present-day heat flows have significant uncertainty because each was constructed from one value, the corrected bottom-hole temperature and accurate formation temperatures from logging require at least three data points.

The heat flow model was calibrated in Well-1 with its 62.5 mW/m$^2$ present-day heat flow. The best fit of the measured vitrinite data to the heat flow model was at 2,117 m because the sample was located at the shallowest depth that recorded maximum paleo-temperature and all 40 particles at this depth recorded 0.55% Ro. The vitrinite data from 2,117 - 2,597 m indicate increasing heat flow with depth while the samples from 2,117 - 2,837 m indicate decreasing heat flow with depth, which suggests there is some error in the data. The calibrated heat-flow model from Well-1 was used for Well-2 and Well-3.

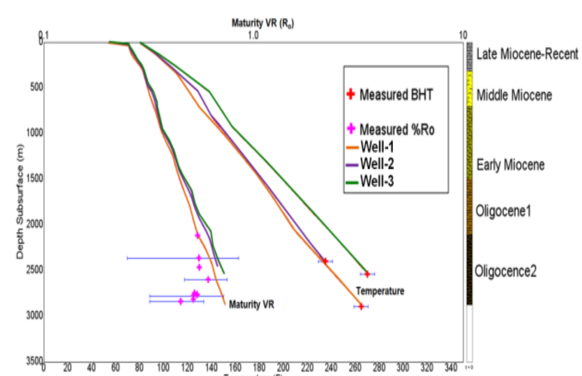


**Figure 3** Paleo-heat flow models of Well-1, Well-2, and Well-3 calibrated to the measured vitrinites from Well-1 and their temperature gradients

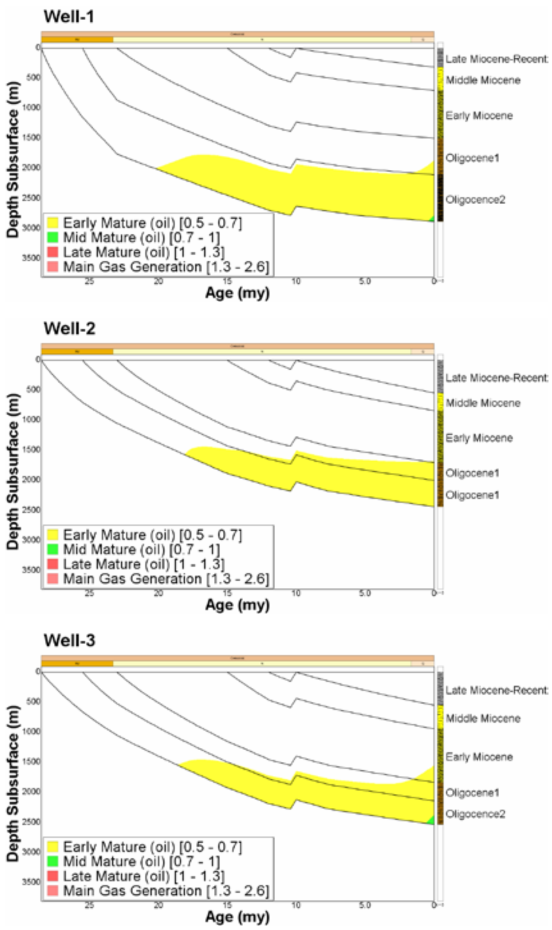


**Figure 4.** The burial history curves for Well-1, Well-2, and Well-3 with isoreflectance lines indicating the maturity windows

### Pseudo-well

Both sub-basins of Nakhon Basin are assumed to have had similar depositional environments that accumulated similar potential source rock and equivalent heat flow rates. Therefore, the thermal model for Well-4 has the best fit with the vitrinite data at the low case of 57.5 mW/m$^2$ for the present-day heat flow suggests that the early oil window starts at around 1,716 m and main oil window is at around 2,620 m.

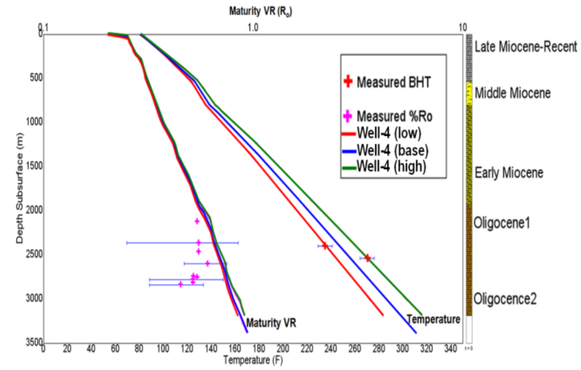


**Figure 5.** The 3 scenarios of low, base, and high present-day heat flows in pseudo Well-4.

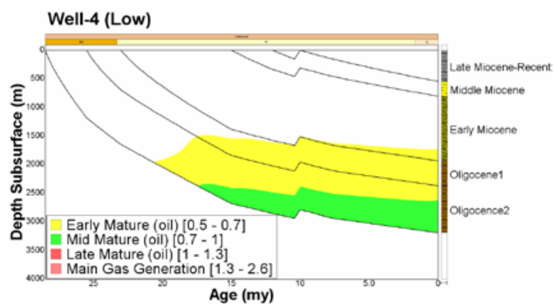


**Figure 6.** The burial history model of Well-4 with low case heat flow with isoreflectance lines indicating the maturity window

### Present-day oil window

The study suggests that the Well-1, Well-2, and Well-3 have all currently reached the early oil window with 0.5% $R_o$ at 1,826 m, 1,676 m and 1,622 m respectively. Only part of the source rocks in Well-1 and Well-3 have passed through the main oil window with 0.7% $R_o$ at 2,748 m and 2,481 m. The early oil window started 18-21 Ma and the main oil window from 0.18-17.45 Ma for the late Oligocene source rocks. The depocenter of the northern sub-basin presently is in the main oil window.

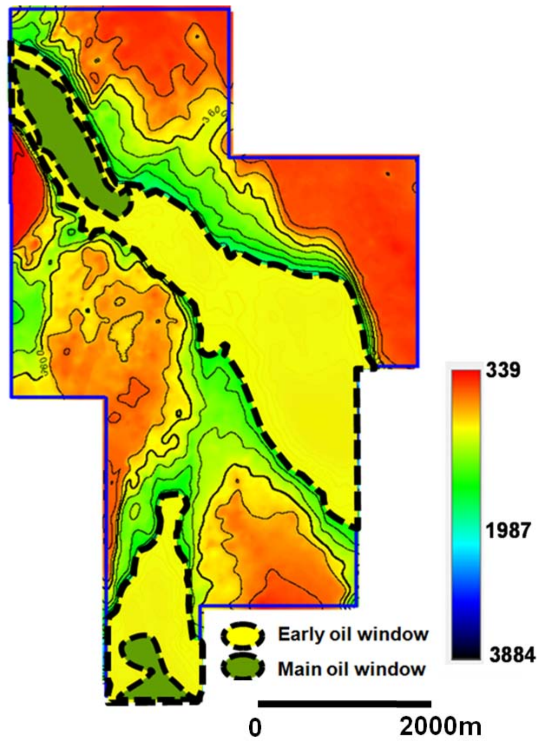


**Figure 7.** The current maturity level of the Oligocene source rocks in the Nakhon Basin

## 4. Discussion

This study suggests that the late Oligocene source rocks in both sub-basins have passed through the early oil window (0.5% $R_o$) and the main oil window (0.7% $R_o$) so that source rock maturity does not appear to be a problem in the Nakhon Basin. Moreover, the unsuccessful well results are likely due to other problems, such as the lack of sandstone reservoirs in Well-2 and possibly Well-3.

However, the results have significant uncertainty because of the limited data. The most important limitations are as follows: The geochemical analysis of potential source rock was available only for Well-1 which is separated from the other two wells by a structural high. The rock-eval pyrolysis data were usable in only the late Oligocene section. In Well-2, only a sonic log was accessible. The well had no neutron and density logs to determine the compaction trend because it lacked sandstone reservoirs and gas shows. There was no logging run in the late Miocene to Recent because normally there is no reservoir in this section. 2D seismic data was usable in the study to estimate the formation tops in the pseudo-well. The seismic cross-section in Figure 2 was not exactly through the actual well locations. There is little published information on the evolution and age of events in the Nakhon Basin.

Maturity levels were mapped on the structural map of the basement section, with equivalent vitrinite reflectance values ($R_o$) color coded to represent cut off values; no shading indicates the immature zone ($R_o$ 0.0-0.5%), yellow represents the marginally mature zone (Ro 0.5-0.7%), and green represents the oil window ($R_o$ > 0.7%). The main area that has been reached the oil window is in the northern sub-basin while much less of the southern sub-basin has been passed through the oil window. However, the thickness of source rock that has reached the main oil window (0.7% $R_o$) is an important concern because only 40% of the total potential source rock succession has reached maturity in the northern sub-basin and only 10% has done so in the southern sub-basin. In both sub-basins, most potential source rocks are still in the early oil window. Consequently, the volume of oil that has been generated may be insufficient for the occurrence of economically-viable accumulations.

## 5. Conclusions

Based on 1D maturity study, the burial and thermal histories were constructed using the concept of subduction rollback tectonic. Paleo- heat flow was calculated by a transient method and the model was calibrated by vitrinite reflectance data. The study shows almost potential source rocks in the Oligocene sediments in the Nakhon Basin have reached the early oil window. While approximately 40% of those source rocks in the northern sub-basin and around 10% of them in the southern sub-basin have passed through the main oil window. Therefore, the Nakhon Basin may not have enough source rock potential to generate oil at the present time.

## 6. Acknowledgements

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