# MATURITY MODELING OF THE CHUM SAENG FORMATION, PHITSANULOK BASIN, THAILAND

Sureena Matha*

Petroleum Geoscience Program, Department of Geology, Faculty of Science,
Chulalongkorn University, Bangkok 10330, Thailand
*Corresponding author email: zaxnia@hotmail.com

**Abstract**

The Queen Sirikit Field, Phitsanulok Basin, Thailand has two previous source rock maturity studies with conflict-ing results. It is unclear whether the source kitchen is the Sukhothai Depression or the Bung Bon Depression. The present study used a 1-D BasinMod approach for nine wells and one pseudo well across the Sukhothai and Bung Bon Depressions. Burial and thermal histories during basin development were based on a rifting tectonic geosystem. Heat flow was calculated by applying the transient model. Sensitivity calibration used measured vitrinite reflectance and Tmax data. The maturity model closely matches the hydrocarbon discoveries in the study area. Modeling suggests that potential source rocks are in the early to middle oil window across most of study area and in the gas generation window within the Sukhothai Depression. Oil started to generate and expel during the middle to late Miocene, along with some associated gas in wells located near the Sukhothai Depression. As the geothermal gradient varies laterally, the source rocks entered an oil maturity level at different depths ranging from 2,000 to 2,500 m. The gas generation window was reached at depths around 4,500 m. There is remaining potential in the area at locations close to Sukhothai Depression.

**Keywords:** Maturity Modeling, Chum Saeng Formation, Hydrocarbon Generation

## 1. Introduction

The Queen Sirikit Field lies within the Phitsanulok Basin, which is a Tertiary rift basin, and is the biggest onshore oil field in Thailand. Two previous source rock maturity studies of the basin have conflicting results; one defined the source kitchen as the Sukhothai Depression (Bal et al., 1992; Pinyo, 2010) while the other concluded that the main source kitchen is the Bung Bon Depression (Figure 1) (Choowala and Ponthanom, pers comm, 2015). Consequently, it is uncertain whether hydrocarbons are generated, expelled and migrated from the main N-S trending depocentre (Sukhothai Depression) or from localized small sub-basins in close proximity to the field. The basin still has significant exploration potential, so understanding the distribution of mature source rock is important. Therefore, the present study modeled maturity of the Chum Saem Formation, which is recognized as the principal source rock.

The main objectives of the study consist of;

1) To construct a 1D maturity model.

2) To study Chum Saeng Formation source rock quality and thermal maturity.

## 2. Study area

The Phitsanulok Basin is the largest of a string of N-S trending late Cenozoic rift basins in central Thailand. The basin is about 140 km long and 40 km wide (Morley et al., 2007).

The stratigraphic succession in the Phitsanulok Basin has been subdivided into eight lithostratigraphic units from Oligocene to Recent (Bal et al., 1997) Figure 2. During the earliest stages of rifting in the Oligocene, sediment was deposited in alluvial fans and fan deltas (Sarabop Formation) and consists of gravel, claystone and brownish-red sandstone. The overlying deposits are fluvial-deltaic to lacustrine (Nong Bua Formation) and made up of claystone, dark-gray claystone and reddish sandstone. An alluvial plain unit (Khom Formation) is composed of gravel, claystone and reddish sandstone, and is restricted to the eastern part of the basin. All of the sediment units aforementioned are considered as the

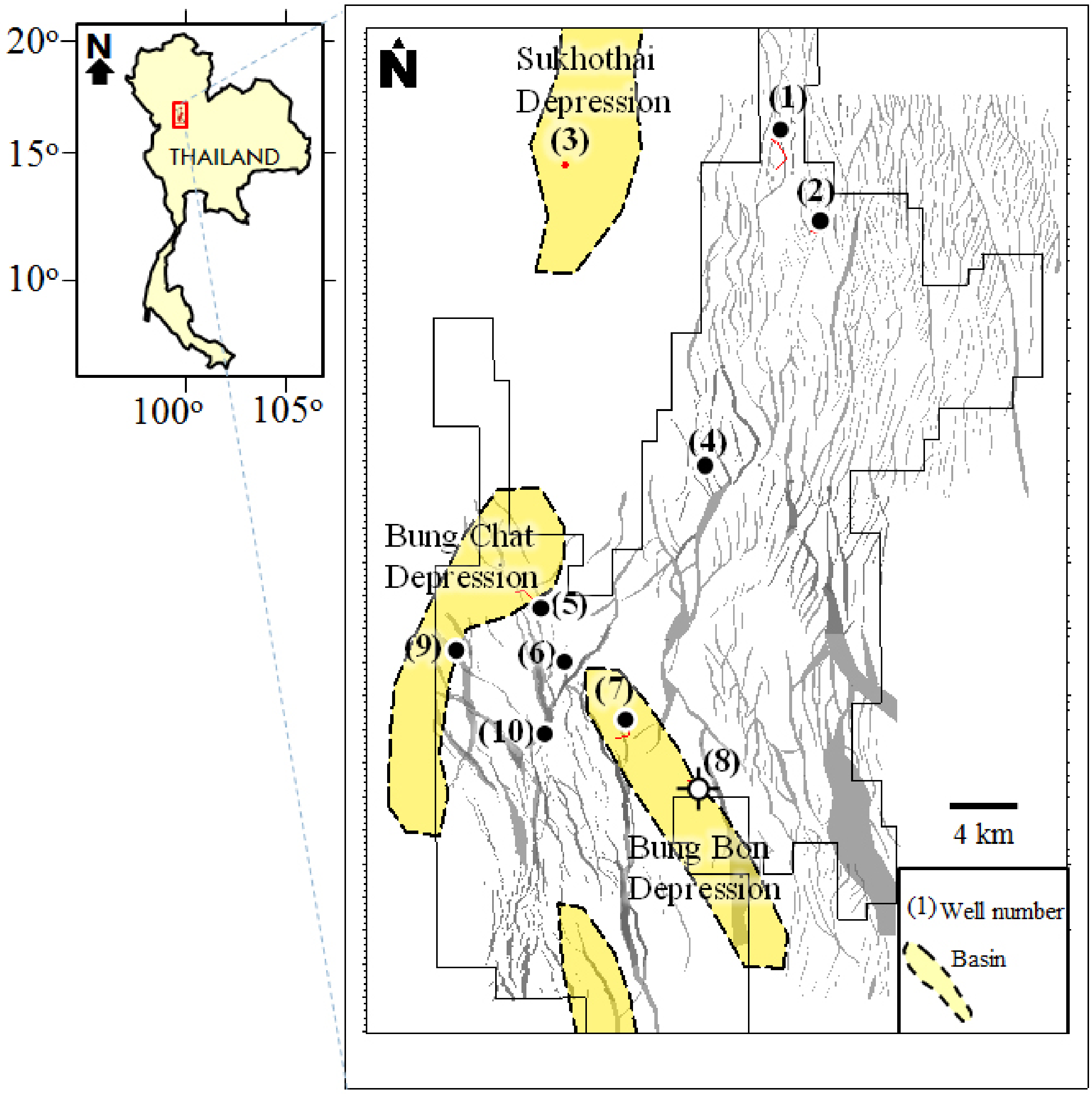



**Figure 1** Study area, well locations and basin location

Oligocene unit in the 1D basin model. They are followed by early Miocene, fluvio-deltaic sediments (Lan Krabu Formation; LKU) composed of thick claystone, siltstone and gray to brownish red sandstone that inter-finger with high-algal-content lacustrine open lake shales (Chum Saeng Formation). Thinner lacustrine shales punctuate the Lan Krabu Formation; in particular, the Lower Intermediate Seal (LIS) and Upper Intermediate Seal (UIS) units separate different reservoir zones within the Lan Krabu Formation (the K, L, and M zones), whereas the Basal Shale (BS) separates the underlying P sands from the Lan Krabu Formation (Figure 2). The middle Miocene, is made up of alluvial plain deposits (Pratu Tao Formation; PTO) that consist of claystone intercalated with sandstone, followed by alluvial plain sediments (Yom Formation) made up of coarse sandstone and brownish claystone, with few coal seams and alluvial fan (Ping Formation) deposits of gravel intercalated with yellowish claystone and a few coal seams (Morley et al., 2007; Pinyo, 2010).

## 3. Methodology

The study was done by constructing 1D maturity modeling of the source rock (Chum Saeng Formation) in order to identify the potential of further hydrocarbon generation in the area. To assess timing of generation and expulsion out of

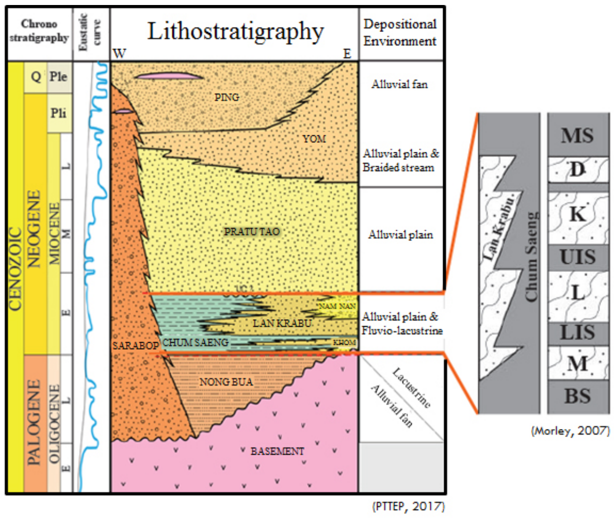



**Figure 2** Stratigraphic succession in the Phitsanulok Basin (modified after Knox and Wakefield, (1983) and Morley, (2007)).

the Chum Saeng source rock, nine existing wells, plus one pseudo-well model, were constructed. These wells are located across the shoulder of the basin from north to south, with one well in the main depression depo-centre (Figure 1). Burial history models have been calibrated with measured vitrinite reflectance and Tmax data in order to ensure that the results of modeling accurately determine the timing of onset of thermal maturity, hydrocarbon generation and expulsion. Well information available includes wireline logs (gamma ray, resistivity, neutron, and density), formation temperatures, mud logs, stratigraphy and data from geochemical studies from individual wells supplied by PTTEP.

This well data provides details of well formation tops and lithology that are necessary for burial history modeling to construct the subsidence curves with petrophysical properties specified by software. Where well penetrations are shallow, horizon depth interpretations by PTTEP were used to construct the formation tops in wells that did not penetrate deeper formations. Two wells in the study area were drilled to basement, namely, Well 2 and Well 4 (Figure 1); therefore, actual formation tops and lithologies could be used to construct the 1D model for these two wells. The age of basin rifting was taken from Morley (2011) and Utitsan, in press, (2017). There is no information available for the age of formation tops, so the event ages are modified based on Morley (2011) and Utitsan, in press, (2017).

Porosity values determined from petrophysical evaluation (neutron-density logs) were also used to control the modeled thermal conductivity and compaction in each well. Compaction was calculated by the mechanical method, assuming exponential porosity reduction with depth, because the sedimentary fill in Phitsanulok Basin is clastic sediment with a normal to high sedimentation rate.

The thermal conductivity of the rock and subsurface temperatureswere used to calculate present day heat flow. Thermal conductivities for modeled lithologies were estimated from a mineral mixture of sandstone, siltstone and shale conductivities

Corrected bottom hole temperature and temperature corrected from Repeat Formation Tester (RFT) measurements, were used to model true formation temperatures by applying the formula in the Waples Spreadsheet (modified from Waples and Ramly, 2001). The temperature error from the spreadsheet was around 6 degrees Celsius (Prueksuwat, 2014). Present day surface temperature were derived from a report of annual temperatures (www.worldclimate.com).

Geochemical data (Ngamlurdwongsakul, pers comm, 2017) provided information to calibrate paleo-heat flow and was used to determine the maturity of the study area. A thermal model was calculated using the transient method, which heat flow is calculated from measured temperatures. Calculated heat flow was varied based on a rifting heat flow model (McKenzie, 1978). A correction was applied, based on observed relatively high heat flows in Southeast Asian Tertiary rift basins (60-80 mW/m2) (Doust and Sumner, 2007).

Vitrinite reflectance (%Ro) from sidewall cores and cutting samples were used to determine source rock maturity across the study area. Some high reflectance values in Well 4, attributed to reworked material/oxidation during sediment transport, were excluded. Reflectance values generally are low, probably because of cuttings caving and/or suppression. In wells with suppressed vitrinite data, Tmax values were applied to calibrate the model.

The organofacies applied in the model is non-marine lacustrine < 570 my (Pepper & Corvi, 1995). The Phitsanulok Basin contains three source rock facies (Doust and Lijmbach, 1997) which are deep lake lacustrine with type I/II kerogen, fluvio-lacustrine with type II/III kerogen and rare marginal swamps with type II/III organic material. A mixed kerogen type of type I, II and III was applied in the model.

## 4. Results

Based on Peters (1986) the Basal Shale is the richest source rock in the study area. Burial history and maturity level (%Ro) were plotted to show the 1D maturity models for nine wells and one pseudo well. The example of maturity model of Well 4 (Figure 3).

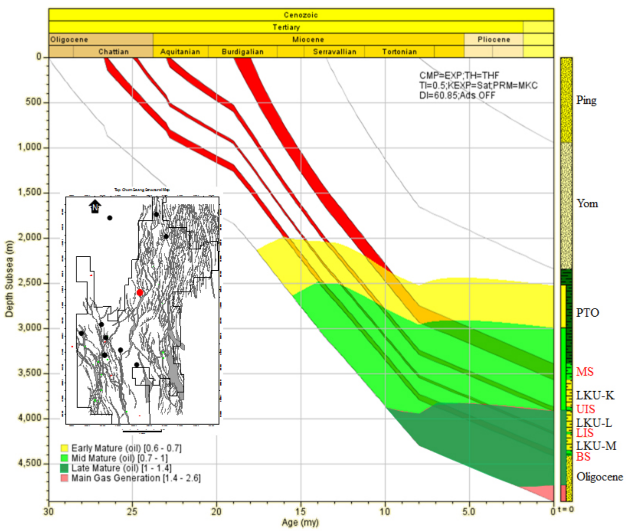



**Figure 3** Burial history curves from Well 4 (red dot)

### Maturity models

All maturity levels (%Ro) calculated for each source rock (BS: Basal Shale, LIS: Lower Intermediate Seal, UIS: Upper Intermediate Seal, MS: Main Seal) from 1D maturity models of nine wells and one pseudo well were plotted on the base map to determine the kitchen area (mature source rock zone)

### 4.1. Basal Shale (BS) maturity.

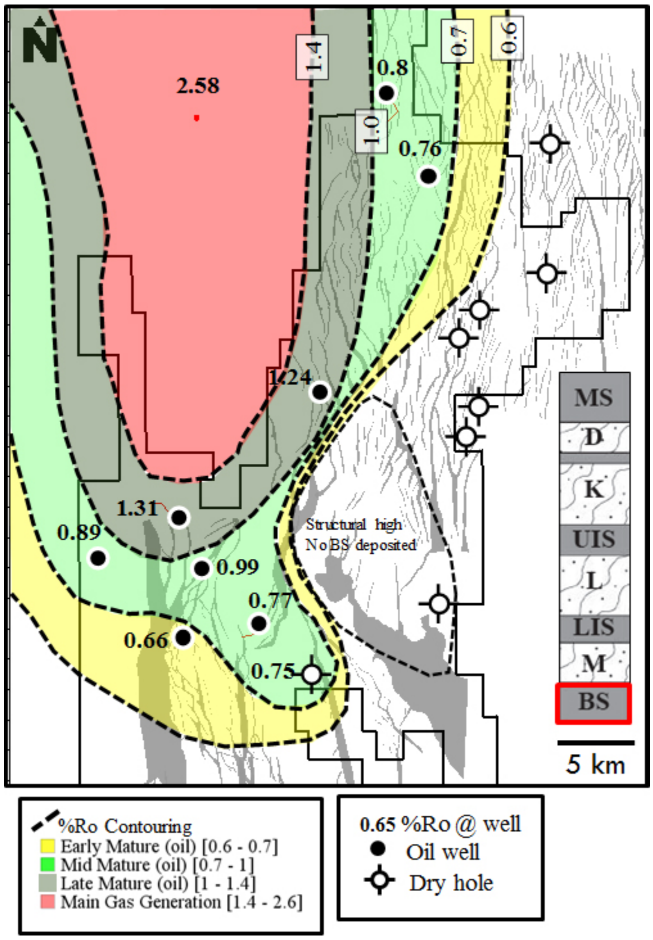



**Figure 4** Basal Shale (BS) maturity map

Based on burial history, with isomaturity levels from most of the study wells, organic matter in the Basal Shale (BS) source rock began generating hydrocarbon (top oil generation window 0.6% Ro) (Peters, 1986) during the early to middle Miocene (18 Ma – 12 Ma). The exception, Well 10, is situated in the south on a structural high (Figure 1), where the Basal Shale (BS) source rock reached the oil generation window in late Miocene (7 Ma). Gas generation occurred only at the pseudo well location, in the Sukhothai Depression where Ro reached 1.4 % during the middle Miocene (12 Ma). Generally, the highest maturation is in the Sukhothai Depression.

Hydrocarbon expulsion started in the middle Miocene (16 Ma – 13 Ma), near the Sukhothai Depression. Expulsion of hydrocarbon in the eastern part of study area, (Wells 1 and 2, Figure 1) occurred in the late Miocene to Pliocene (5 Ma – 3 Ma), which is similar to the Bung Bon Depression.

### 4.2. Lower Intermediate Seal (LIS) maturity.

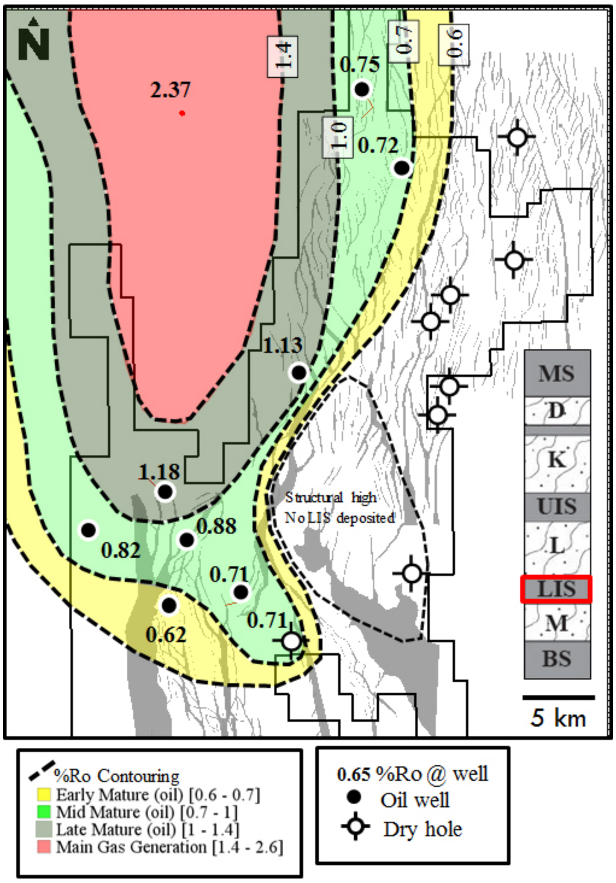



**Figure 5** Lower Intermediate Seal (LIS) maturity map

The Lower Intermediate Seal (LIS) source rocks started to generate oil during the middle Miocene (17 Ma – 14 Ma) based on wells located on the shoulder of the Sukhothai Depression and Bung Bon Depression. Consequently, the eastern basin flank was just starting to generate oil in the late Miocene (10 Ma – 9 Ma). Further south, the LIS in Well 10 (Figure 1), reached the oil generation window in the Pleistocene.

Hydrocarbon expulsion from LIS in the south and southeast, and situated close to the basin center, occurred in the middle Miocene (16 Ma – 11 Ma). However, Well 1 (Figure 1) expulsion occurred in the Pliocene (2 Ma) and no expulsion took place from the LIS in the Bung Bon Depression.

### 4.3. Upper Intermediate Seal (UIS) maturity.

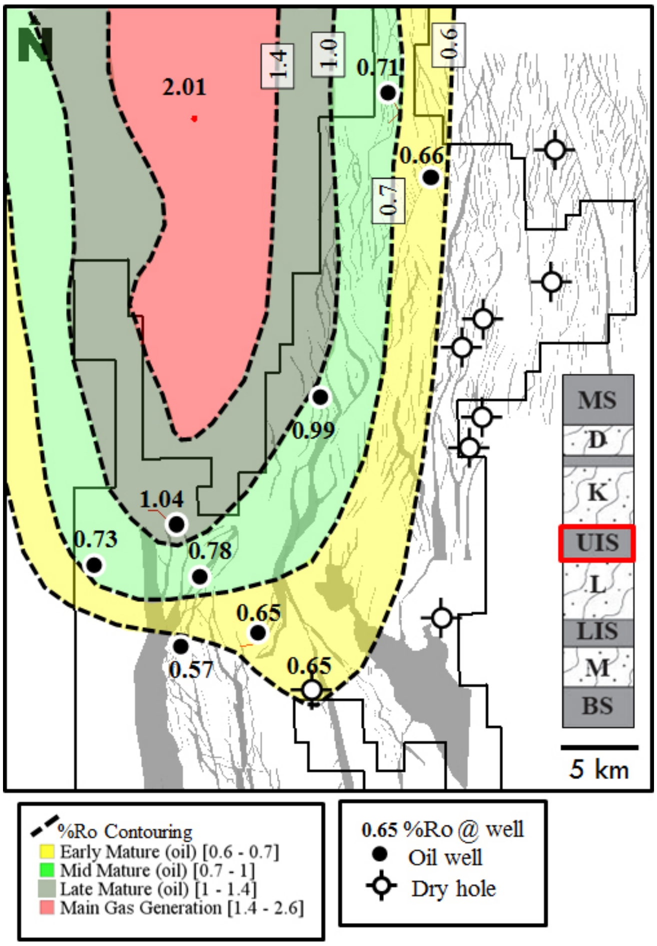



**Figure 6** Upper Intermediate Seal (UIS) maturity map

The Upper Intermediate Seal (UIS) reached the oil window during the middle Miocene (16 Ma – 13 Ma) in wells close to the basin center. Apart from that, the UIS source rock entered the oil generation window in late Miocene (9 Ma – 5 Ma). In the south, the UIS has not yet reached oil maturity. Only in Wells 3, 4, 5 and 6 (Figure 1), located near the Sukhothai Depression did the UIS source rock expel in the middle Miocene (15 Ma – 6 Ma)

The LIS and UIS in the pseudo well (located in the Sukhothai Depression) reached the gas generation window in the late Miocene (10 Ma – 8 Ma) and still generates gas.

### 4.4. Main Seal (MS) maturity.

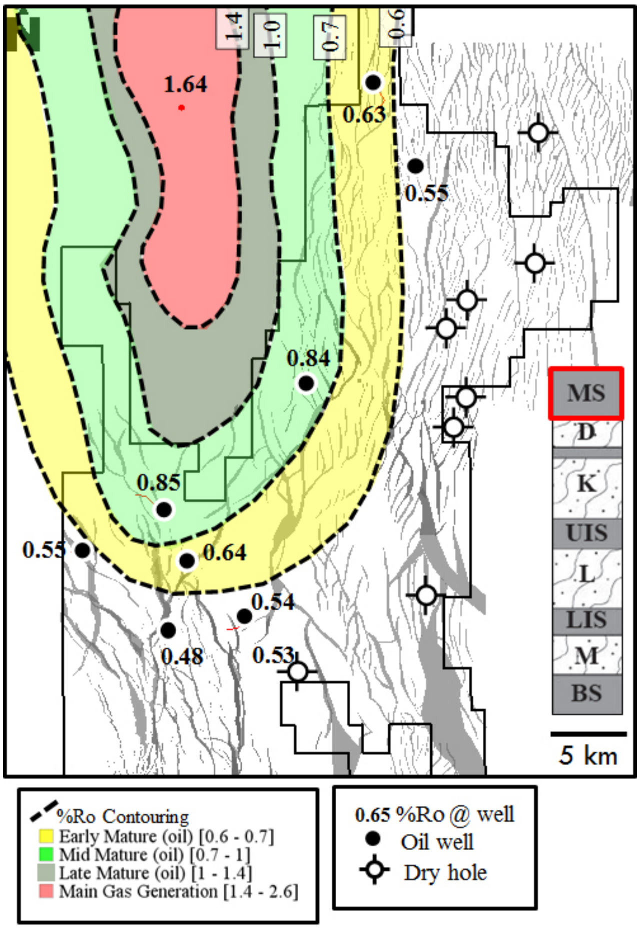



**Figure 7** Main Seal (MS) maturity map

The uppermost source rock, Main Seal (MS) started oil generation in the middle Miocene (14 Ma – 6 Ma) in wells located close to the basin center, Well 3, 4, Well 5 and 6 (Figure 1). Recently, oil has been generated (3 Ma) from Well 1, which is located in the northeastern part of the basin. The same source rock to the east, in Well 2, and wells close to the Bung Bon Depression, and far from the basin center have not reached the oil generation window. It is because the Main Seal in those wells is shallow and contains insufficient thermal activity to generate hydrocarbon. The MS expulsion occurred in the middle to late Miocene (13 Ma – 5 Ma).

Maturity results illustrate that maturity has reached its highest levels in the deep part of the basin. However, the maturity level is low on the eastern and southern flanks of the basin.

This study demonstrates that the Chum Saeng source rock passed through the oil generation window in both the Sukhothai Depression and Bung Bon Depression for the UIS, LIS and BS source rocks.

From this, it is concluded that the Sukhothai Depression is the main kitchen area, with the depth of the oil maturation window at approximately 2,500 m. The oil maturation window in the Bung Bon Depression is around 2000 m, which is a bit shallower, caused by differences in geothermal gradient/heat flow. The depth of gas generation window is about 4,500 m.

## 5. Discussion

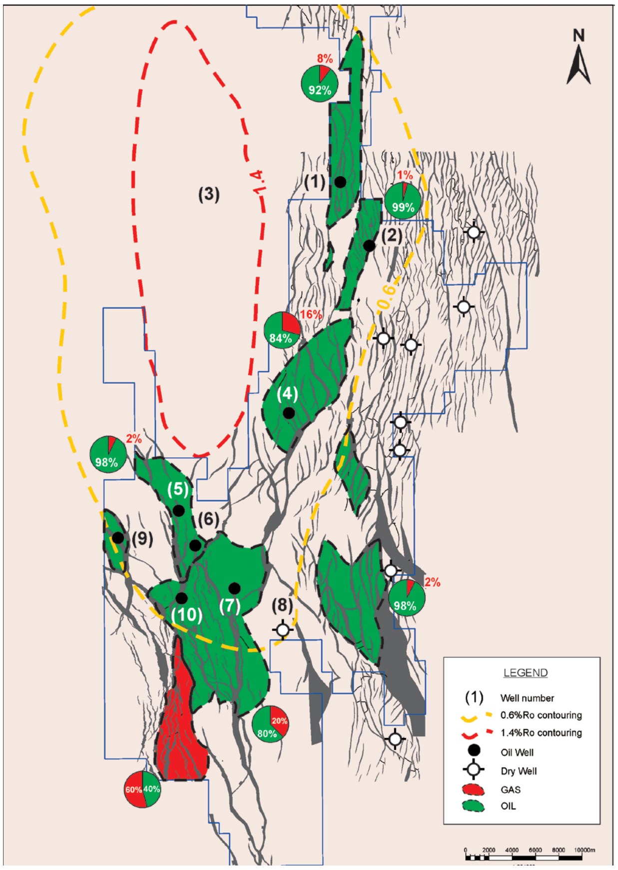



**Figure 8** Maximum limit of maturity from all source rock intervals overlain on Top Main Seal structural map.

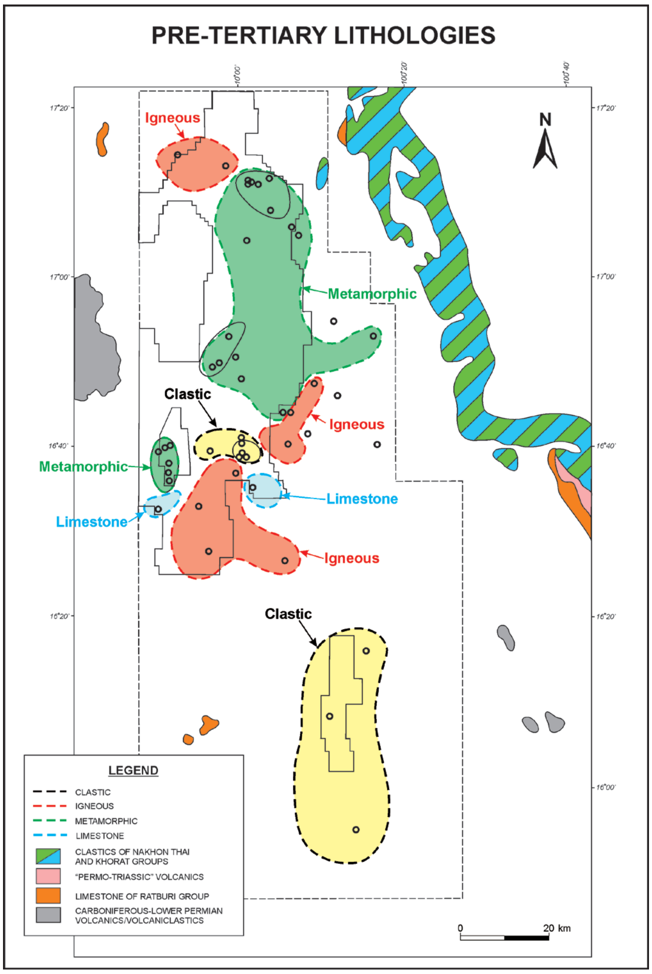
Figure 8 shows the maximum boundary of oil and gas generation from all source rock intervals, the area between the yellow dashed line and the red dashed line indicates maximum coverage area of oil maturation, the red dashed line is the maximum area of gas maturation and the pie chart illustrates the percentage of oil and gas which has been produced from the area. The maturity model for oil matches with the well results as the oil maturity level corresponds to the main oil producing area and oil also migrates into traps in higher structures; it is expected that migration took place along both faults and coarse clastic conduits. The dense north-south fault pattern on the eastern flank has caused migrating hydrocarbons to be deflected towards the north and south, leaving a shadow zone in the east (Bal et al., 1992), as confirmed by the dry well (Kempton, pers comm, 2016) in the east of the study area with a position corresponding to the boundary of oil maturation.

However, the big issue in the model is that if gas was generated from the Sukhothai Depression. Even though this model's results coincide with Bal et al., 1992 & Pinyo, 2010, there is no gas field to the east and south close to kitchen area. There are two possibilities for the location of the gas. One is the source rock which was deposited in the area of Sukhothai Depression was leaking volatiles before it was buried to a depth that can generate dry gas. Once the source rock in the main kitchen was buried to a depth that generated oil, then the product migrated updip driven by buoyancy and groundwater flow. This led to a situation of no dry gas generation in the field itself. Gas that is found in produced liquids is all associated gas, which came from the southeast and south of the Sukhothai Depression, as seen in Wells 4, 5 and 6. In addition, geochemical analyses of cuttings, core samples, and gas from wells located around Well 10, have a carbon isotope value (-46.9o/∞) that indicates the produced gas is associated with oil generation (Grantham et al., pers comm, 1982).

The second possibility is gas from the kitchen area migrated further south along the main north-south trending fault to reach the structural high which is producing almost 60% of the total amount of gas, implying that the main fault acts as the dominant migration pathway for gas and carries it laterally, in large volumes, away from the main source area.

**Factors influencing maturation**

There is variation in geothermal gradient across the study area, which likely causes differences in maturity level between the Sukhothai Depression and the Bung Bon Depression. The variation in geothermal gradient may be related to lateral variations in thermal conductivity from both the basement and the overlying sedimentary section. There is variation in basement lithology, which is a complex of pre-Tertiary igneous rocks, clastic rocks, metamorphic rocks and limestones (Figure 9).




There is also lateral variation in thermal conductivity throughout the Tertiary sedimentary section related to changes in the proportion of sand to shale. Therefore, in the areas where the basement is igneous rocks and sedimentary section is more sandstone than shale, the geothermal gradient is high.

The maturation model in this study implies that the area with most exploration potential is the area close to the Sukhothai Depression. In that area there are mature source rocks with shorter migration pathways, combined with fault and trap integrity.

## 6. Conclusions

The conclusions from the study are summarized as follows:

1. The hydrocarbons in the Phitsanulok Basin were generated mainly from the Basal Shale followed by the Lower Intermediate Seal, Upper Intermediate Seal and Main Seal units.
2. The Sukhothai Depression has a high maturity level and is the main kitchen area.
3. Hydrocarbons started to generate and expel during the middle Miocene (18 Ma – 3 Ma).
4. Variable geothermal gradients are caused by lateral variation in thermal conductivity across both the basement and the sedimentary section.
5. There is remaining potential in the areas close to the Sukhothai Depression.

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