Sedimentary Facies And Petroleum System Of San Sai Oil Field, Fang Basin

Running Head: SEDIMENTARY FACIES AND PETROLEUM SYSTEM OF SAN SAI OIL FIELD, FANG BASIN

Peerawat Kongurai[1] , Akkhapun Wannakomol[2*] and Chongphan Chonglakmani[3*]
[1,2]*School of Geotechnology, Institute of Engineering, Suranaree University of Technology, 111 University Avenue, Muang District, Nakhon Ratchasima 30000, Thailand.*

Abstract: *The San Sai oil field is an important oil field in the Fang Basin. The sedimentary facies and basin evolution have been interpreted using well data incorporated with 2D seismic profiles. The study indicates that the Fang Basin was subsided as a half-graben in the Late Eocene by regional plate tectonism. The deposit is thicker westward toward the major fault. The sedimentary sequence of the Fang Basin can be subdivided into two formations which comprise five associated depositional environments. The results of total organic carbon content (TOC), vitrinnite reflectance (%Ro), Rock-Eval pyrolysis and headspace gas analyses and the study of basin modeling using PetroMod1D software are compiled and interpreted. They indicate that source rocks of kerogen type II and III with 1.78 – 3.13%wt. TOC were mature and generated mainly oil at 5,600 – 6,700 feet deep (Middle Mae Sod Formation). Source rocks of kerogen type II and III with 2.07 – 39.07%wt. TOC locating deeper than 6,700 feet (Lower Mae Sod Formation) were mature to late mature and generated mainly gas at this level. According to TTI (Time Temperature Index) modeling using PetroMod11.1D software, hydrocarbon generation took place in the Middle Miocene and the generated oil and gas migrated through fractures and faults to accumulate in traps at 2,900-4,000 feet deep (Upper Mae Sod Formation).*
Keywords: *Rift basin, Basin modeling, Petroleum geochemistry, Depositional environment*

I. Introduction

Fang oil field was the first discovered field in Thailand and has been operated till today by the Defense Energy Department, Ministry of Defense. It is located in Fang district, Chiang Mai province of northern Thailand near Thai-Myanmar border. In Thailand, hydrocarbons are found in pre-Tertiary and Tertiary basins. Pre-Tertiary petroleum fields are in the Khorat Plateau (e.g. Sin Phuhom and Nam Phong field.) and its vicinity. Tertiary basins can be found both onshore and offshore (e.g. Phitsanulok, Songkhla basin.) (Figure 1), the central plain, the Gulf of Thailand and the Andaman Sea basins. The Tertiary basins began to accumulate sediments in the Oligocene. Most of deposits are accumulated in non-marine environment except the Andaman Sea sediments are mainly marine.

II. Geological setting of the Fang Basin

The Fang Basin is one of the Cenozoic intermontane basins of northern Thailand (Figure 1). The geology of the Fang Basin and the adjacent areas (Figure 2a and 2b) were previously studied by numerous workers, namely, Dutescu et al (1980), Bunopas and Vella (1983), Braun and Hahn (1976), Settakul (1985). The basin is located on the western side of the Sukhothai Fold Belt, which comprises Paleozoic to Triassic strata and volcanic rocks that were accumulated on the eastern margin of the Shan-Thai Craton prior to the Indosinian orogeny. This fold belt is complex and trends north and northeast-southwest. These rocks were uplifted, deformed and intruded by granite during the collision of the Indochina and the Shan-Thai Cratons (Bunopas and Vella, 1983). The Fang Basin was formed in early Paleogene by reactivation of these structures as the result of the Himalayan Orogeny. Braun and Hahn (1976) It was filled with rocks of Tertiary and Quaternary age. These Cenozoic rocks and sediments consist of shale, sandstone, conglomerate, sand, and gravel. Settakul (1985) classified sediments and rocks in the Fang Basin into two units. These units are the younger Mae Fang Formation and the older Mae Sod Formation. The depositional environment in the Tertiary time was fluvial-lacustrine and changed to fluvial and alluvial in Quaternary time. These sediments are covered by recent soil and lateritic sand. The pre-Tertiary basement rocks consist of sedimentary, metamorphic and igneous rocks. On the western side of the basin, the

rocks are consisted of Cambrian-Permian rocks and the Carboniferous granite. While on the eastern side, the rocks are Silurian-Devonian and Jurassic rocks together with the Triassic granite.

III. Structure of the Fang Basin

Zollner and Moller (1996) summarized the structural setting of Fang Basin and adjacent basins in northern Thailand as a series of intramontane basin generally trending NNE-SSW. These basins were formed in Early-Mid Tertiary time as pull-apart basins in a transtensional regime followed by Pliocene to Pleistocene compressional tectonics. Fang Basin is subdivided into three sub-basins separated by basement (Orientation) ridges. It is composed of the Huai Pa Sang, the Huai Ngu and the Pa Ngew sub-basins. The basin has an elongated rhombohedra outer shape. The southern part is trending N-S and the northern part is deflected to a NE-SW direction. The 3D seismic survey data indicates that the Fang Basin is bordered to the west by a steep dipping NNE-SSW trending basin margin fault. Petersen (2006) described the Fang Basin as an onshore Cenozoic rift-basin and is 2-4 km deep.

IV. Lithological Sequence

The sedimentary facies of the San Sai oil field can be divided into two formations. The upper part is Mae Fang Formation and the lower part is Mae Sod Formation. These two formations comprise five associated environments of deposition. The typical lithological sequence of San Sai area which is compiled from wells data is shown in Figure 3 and the overall lithological sequence is shown in Figure 4.

Mae Fang Formation

The Mae Fang Formation (Pleistocene to Recent in age), 2,500 feet thick, is composed mainly of clay, coarse- to very coarse-grained sandstones, gravel and carbonized woods which were deposited in fluvial environment. It overlies unconformably on the Mae Sod Formation. The uppermost portion of the Mae Fang Formation is represented by approximately 500 feet thick of mainly sand with some thin layers of gravel, clay and trace of coal and thin top-soil. The sand is generally light gray to dark gray, coarse- to very coarse-grained with some granule and moderately sorted. The gravel is light gray to gray, with some coarse- to very coarse-grained and poorly sorted sand. The clay is generally gray. The lithological succession is composed of texturally and mineralogically immature sand and gravel. Sand is poorly to moderately sorted with high angular grains. The overall geometry of sediment accumulation is tabular or wedge shape which was deposited in a high energy environment of braided stream system. Underlying the upper part is approximately 2,000 feet thick sequence of sandstone interbedded with shale. The sandstone is light gray to dark gray, medium- to very coarse-grained and mostly well sorted. The shale layers are 7 to 25 feet thick and are generally dark gray color. The sequence of sand and clay is fining upward.

Mae Sod Formation

The Mae Sod Formation, overlying unconformably on pre-Tertiary basement, can be divided into three sub units (A, B, and C) which comprise four depositional environments.

Sub-unit A (upper Mae Sod Formation). The unit can be divided into two parts. The upper part consists of interbedded shale with sandstone. It is about 1,400 feet thick. Shale is characterized by gray to dark gray and brown color, whereas the sandstone is generally light gray to gray color and is medium- to very coarse-grained and mostly well sorted. Oil show is present in some sandstone beds. The upper part is interpreted to be the marginal lacustrine facies (Late Miocene to Pliocene in age).

The lower part is composed of thick shale with fine-grained sandstone intercalations. The total thickness of this sequence is approximately 1,000 feet. The shale is characterized by dark gray, black and dark brown color and with some coal layers. It represents a shallow to deep lacustrine facies (Early Late Miocene in age).

Sub-unit B (middle Mae Sod Formaion). consists of extremely thick dark gray shale, fine-grained sandstone and coal. This lithological succession is interpreted to be deposited in low energy condition of fresh water paleo-lake. The products accumulated in this environment are sedimentary rocks of lacustrine facies (Oligocene in age).

Sub-unit C (lower Mae Sod Formation). The lower part of unit consists of sandstone and coal bed interbedded with black shale. The upper part comprises coal beds approximately 200 feet thick and some sandstone. Sandstone is generally red and gray color, fine- to very coarse-grained with some layers of very clean sand. It represents a marginal lacustrine facies (Late Eocene in age).

V. Structural Evolution

Structure evolution of the Fang Basin can be divided into three stages based on 2D seismic interpretation profiles as shown in Figure 5.

The initial stage of rifting occurred in the Late Eocene represents an early extensional rifting phase formed by north-south normal faults (Figure 6A).

The syn-rift stage Sandstone is accumulated at the basin margin and predominantly claystone at the basin center in the fluviatile environment.

The post-rift I stage represents a rapid subsidence phase in the Oligocene to Pliocene (Figure 6B). The basin accumulated mainly the lacustrine shale facies.

The post-rift II stage (post-rift) represents a slow subsidence stage in the Pleistocene (Figure 6C). The basin accumulated mainly the semi-consolidated gravel, sand, silt and clay of the alluvial facies.

VI. Petroleum system

Characteristics of sedimentary organic matter

In order to characterize source rock potential its maturity level, the cutting and core samples of Well no. FA-SS-35-04 were analyzed geochemically by the Core Laboratories Malaysia SDN BHL (Ablins, 1992).

The section of Mae Sod Formation below the depth of 2,500 feet was analyzed for the total organic carbon content (TOC). The values of TOC of upper Mae Sod Formation, at depth of 2,500 to 5,900 feet, are in the range of 2.05 – 4.27%. The values of middle Mae Sod Formation, at depth 5,900 to 6,700 feet, are in range of 1.78 – 3.13%. The values of lower Mae Sod Formation, at depth of 6,700 to 9,100 feet, are in the range of 2.05 – 39.07% (Figure 7). According to the headspace gas analysis as shown in Figures 8a and 8b, the result is consistent with the TOC values which are fair to excellent. It indicates that the potential of the Mae Sod Formation is a good source rock.

The modified Van Krevelen diagram comparing hydrogen index (mg HC/g TOC) and oxygen index (mg HC/g TOC) data obtained from rock-eval pyrolysis analysis is used for indicating the kerogen types of the source rock. The result of Mae Sod Formation indicates that the organic matter of the upper Mae Sod Formation is type I/II oil prone (Figure 9) and the middle and lower Mae Sod Formation are type II/III of mixed oil and gas prone kerogen (Figure 10-11).

VII. Thermal maturation

There are many criteria to indicate the thermal maturity level of source rocks, such as, vitrinite reflectance (%R_o) (Figure 12a), Tmax (Figure 12b), result of headspace gas analysis (Figure 13a), iC4/nC4 ratio (Figure 13b) and Production Index (Figure 14a).

The upper Mae Sod Formation has Ro values in the range of 0.31 - 0.61%, Tmax in the range of 428° – 447°C and PI in the range of 0.01 – 0.1. The middle Mae Sod Formation has Ro values in the range of 0.67 – 0.76, Tmax in the range of 447° – 458°C and PI in the range of 0.09 – 0.25. The lower Mae Sod has Ro values in range of 0.81 – 1.31%, Tmax 448° - 491°C and PI 0.04 - 0.17. In conclusion, the result of Ro indicates the source rock is early mature at a depth of 5,600 to 8,300 feet and is mature below 8,300 feet. The result of Tmax indicates that the source rock is early mature at a depth of 4,000 to 4,700 feet, mature at 4,700 to 7,900 feet and late mature below 7,900 feet. The result of PI indicates that most of source rock is immature and some samples below 6,400 to 7,600 feet are mature. PI (Production Index) values which are in a range of 0.15 – 0.40 indicate that the source rock is mature for hydrocarbon generation (Peters and Cassa, 1994). The result of gas wetness indicates that the source rock is early mature between a depth of 4,160 to 4,600 feet, mature at 4,600 to 6,800 feet deep and late mature at 6,800 feet to total depth. Finally, the result of iC4/nC4 ratio indicates that the source rock is mature below a depth of 4,180 feet to total depth. The result of burial history modeling from Well FA-SS-35-04 including TTI and Ro data indicates that the source rock is mature in middle Mae Sod Formation (Oligocene) below 5,900 feet and is over mature at lower Mae Sod formation below 6,800 feet as shown in Figure 15-16. In conclusion the source rock were mature and generate mainly oil at 5,600 – 6,700 feet. The source rock deeper than 6,700 feet were late mature and generate mainly gas.

VIII. Petroleum migration

The petroleum are migrate from the kitchen areas (approximately 7.7 km^2) under depth of 5,800 feet. The generated and expelled hydrocarbon migrated through fractures and fault zone to the reservoir rock in the combination of fault and structural traps. (Figure 17)

IX. Conclusion

1. The correlation of seven seismic profiles and lithological data of seven drilled wells indicates that the Fang Basin was subsided as a half-graben in the Late Eocene. The sedimentary fills of the basin can be subdivided into two formations which comprise five associated depositional environments.
2. The source rocks of middle Mae Sod Formation at 5,600 – 6,700 feet deep are composed of 1.78 – 3.13%wt. TOC of type I/II oil prone kerogen and were mature. The source rocks of kerogen Type II and III with 2.07 – 39.0%wt. TOC are located deeper than 6,700 feet (lower Mae Sod Formation). They were mature to late mature and generated mainly gas.
3. The migration of generated hydrocarbon took place in the Middle Miocene through fractures or faults and was accumulated in traps at 2,900-4,000 feet deep.

X. Acknowledgement

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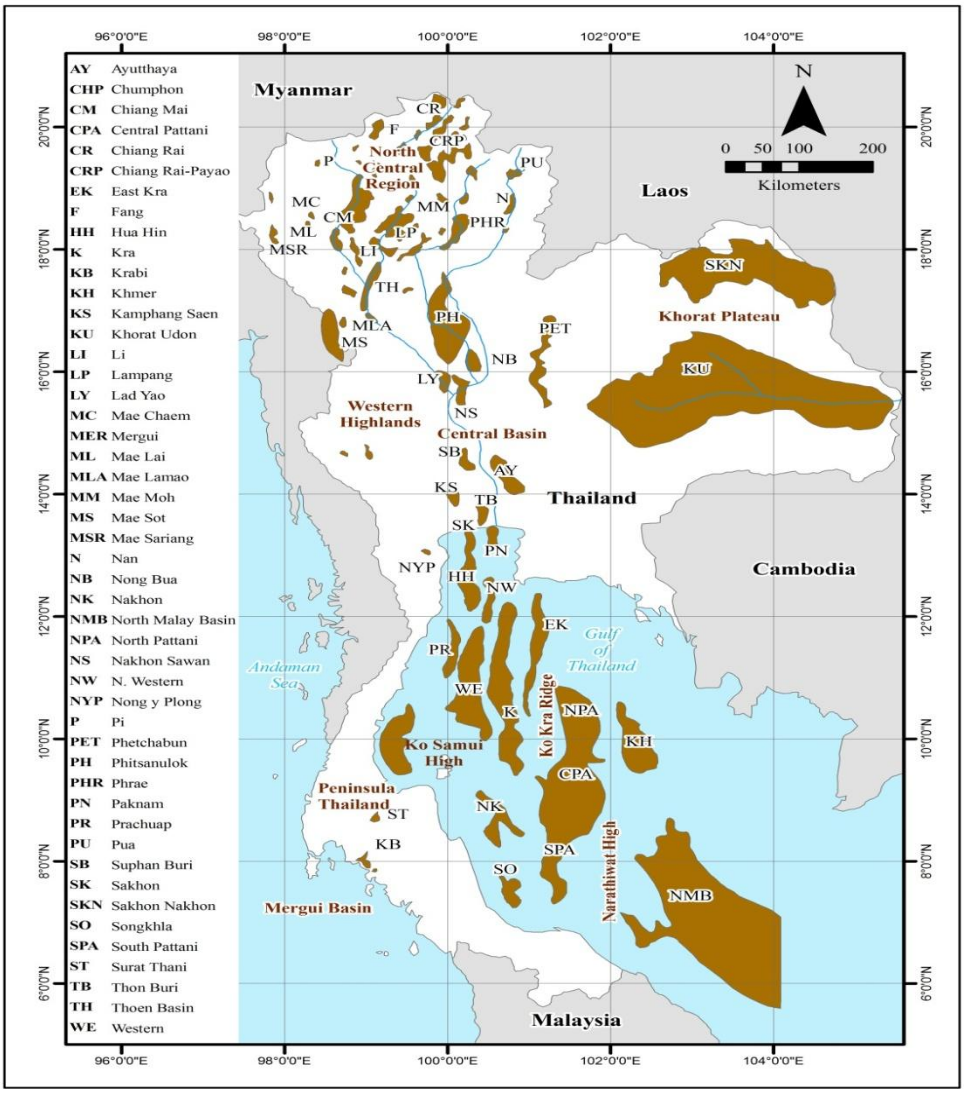


Figure 1. Map showing the Tertiary basins of Thailand. The lines onshore are the principal rivers draining Northern and Central Thailand and the Khorat Plateau (Morley and Racey, 2011).

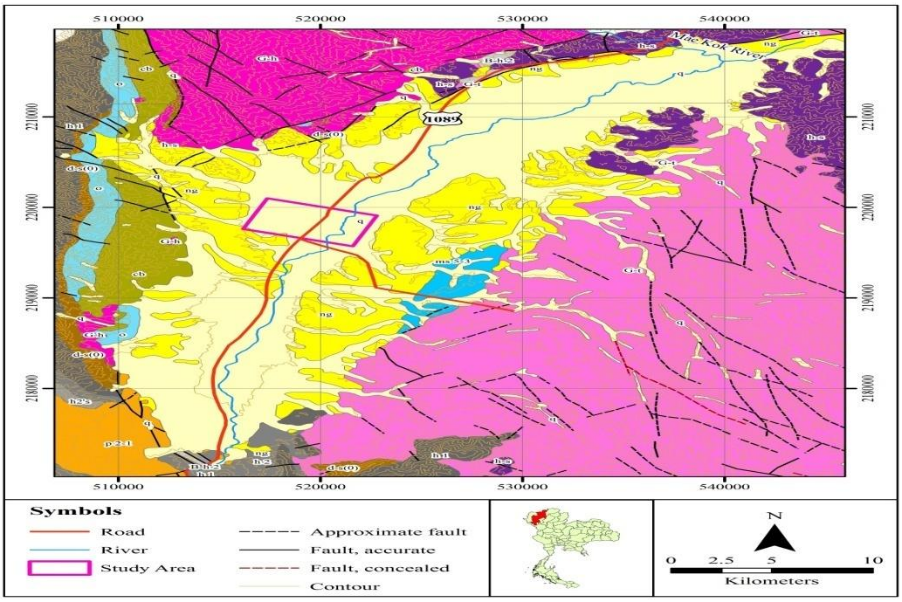


Figure 2(a). The geological map of Fang area (after Khantaprab and Keawsang, 1987).

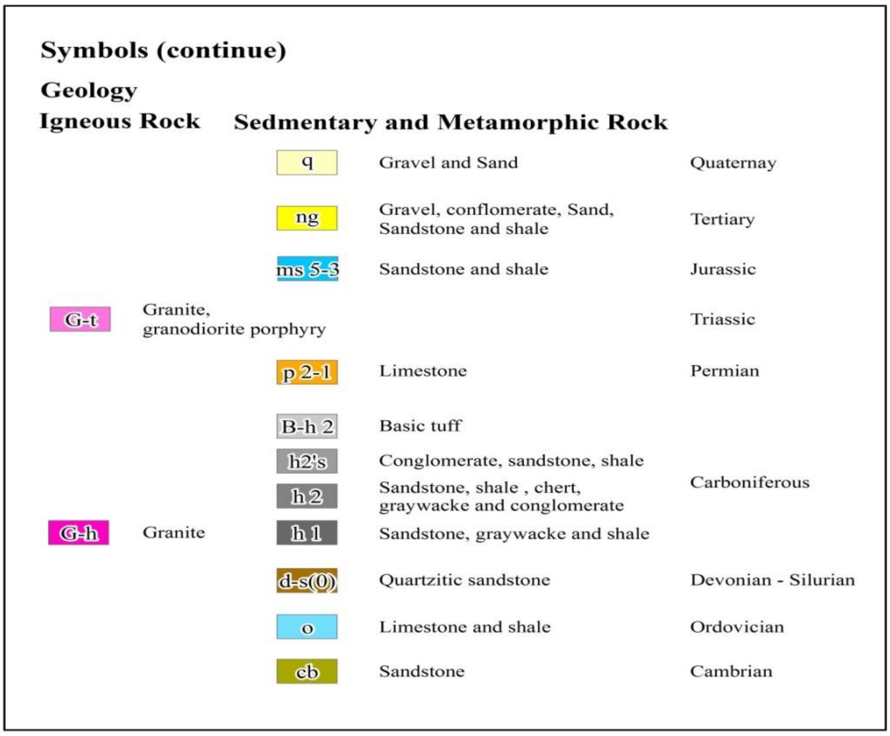


Figure 2(b). The geological symbols of Fang area (after Khantaprab and Keawsang, 1987).

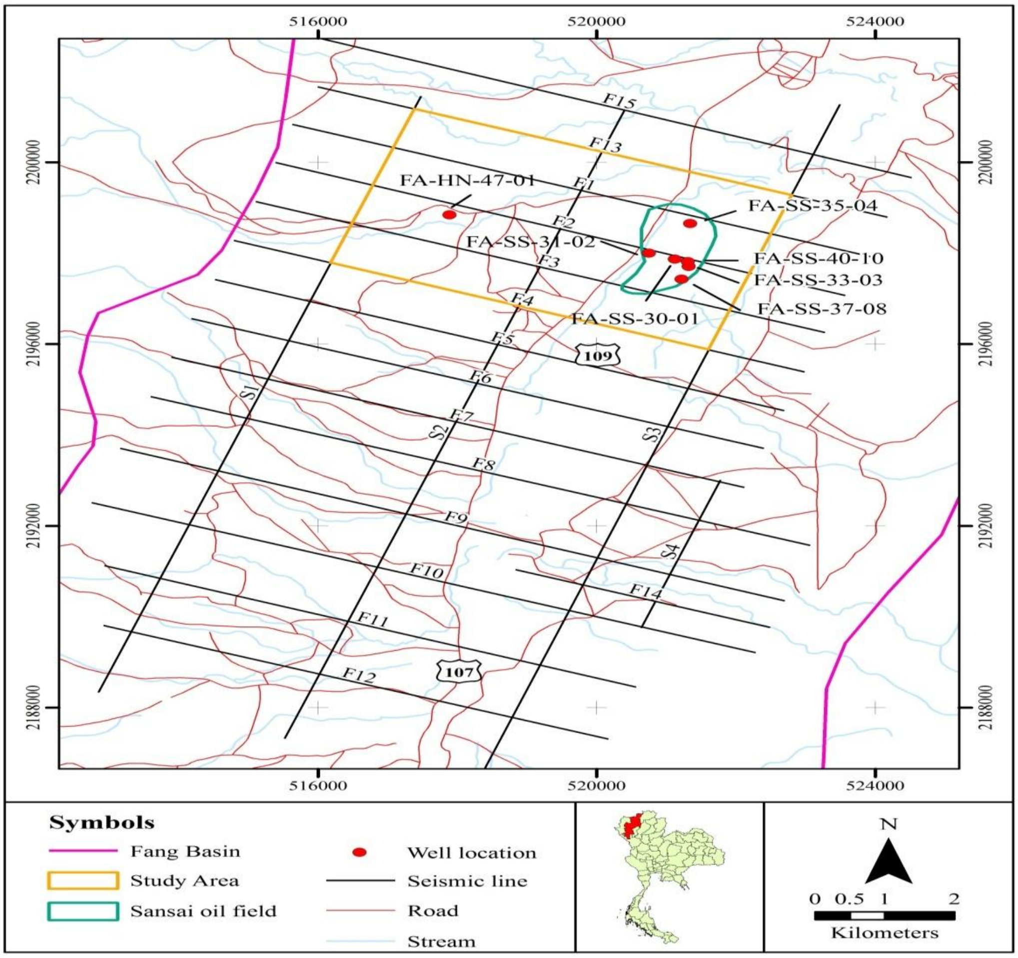
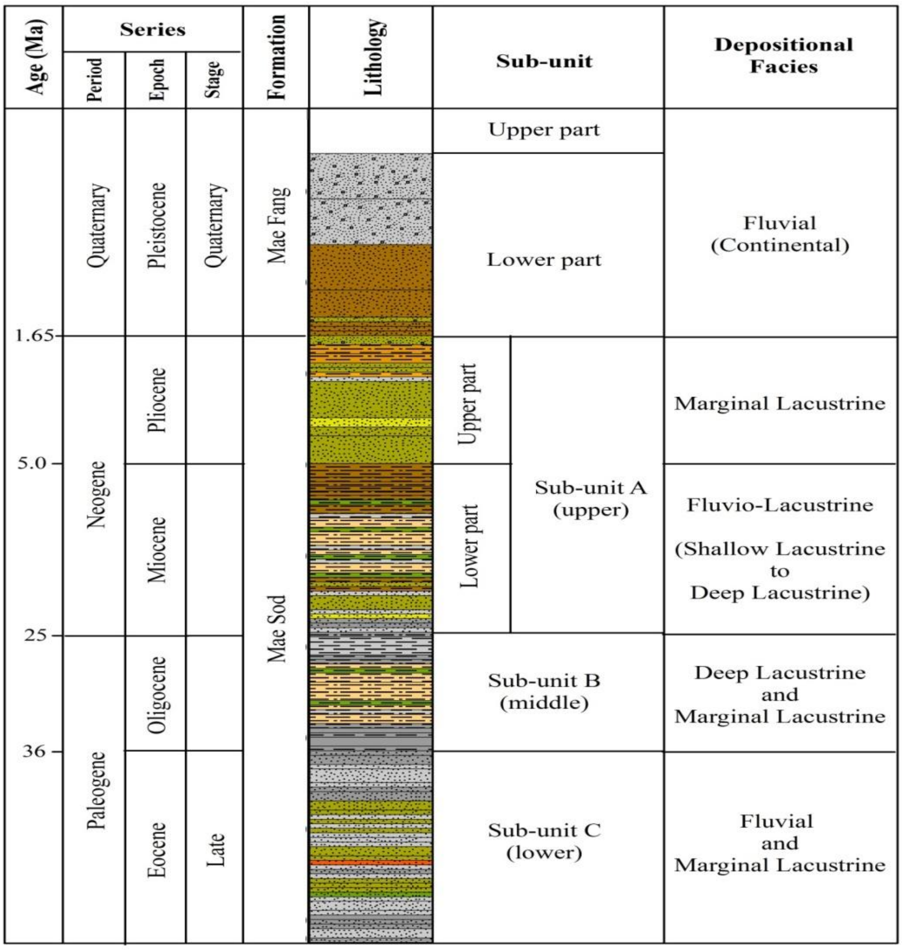


Figure 3. Map showing study area with seismic lines and well locations.



4. Composite lithological sequence of the San Sai area.

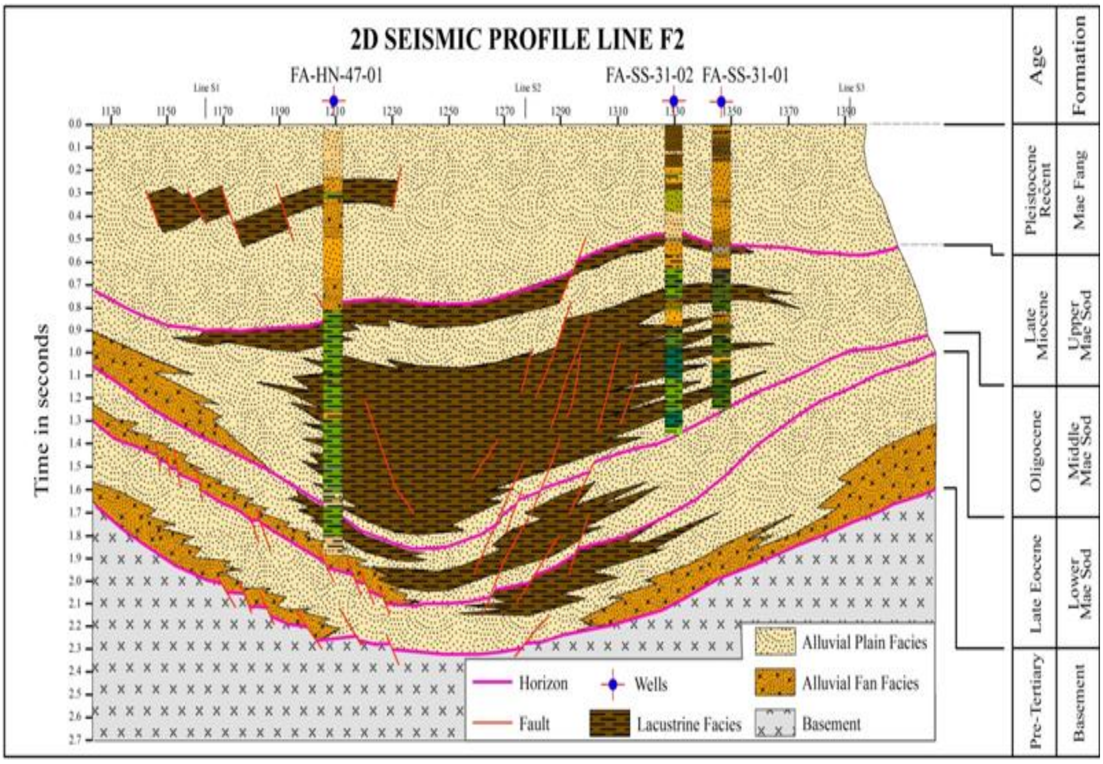


Figure 5. Facies interpretation from 2D seismic profile line F2.

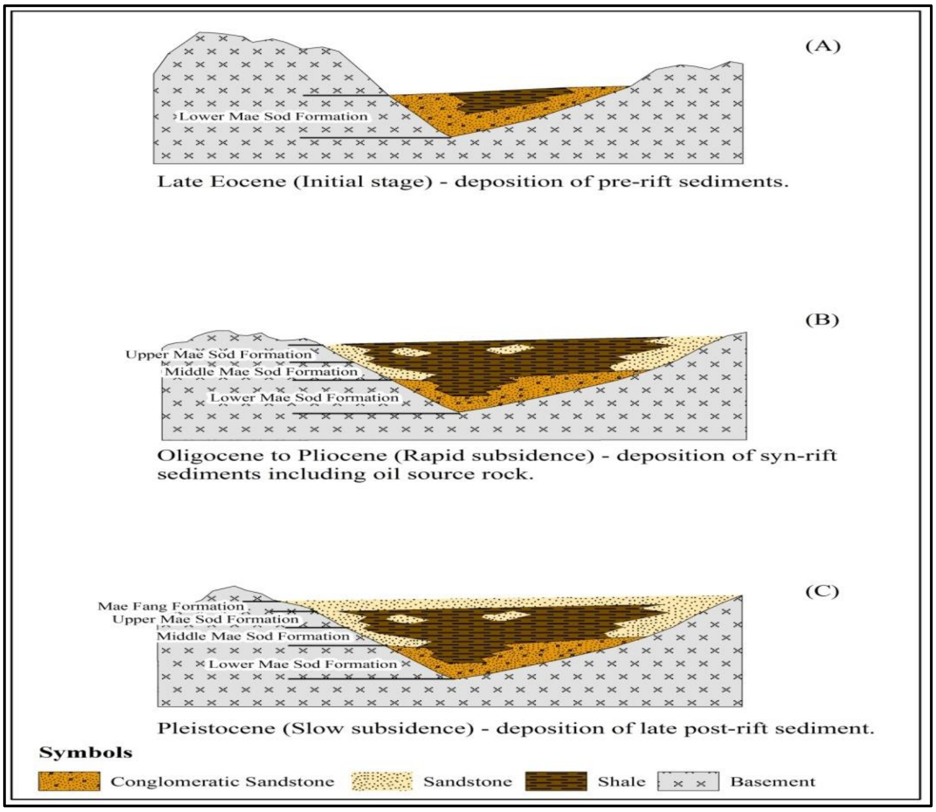


Figure 6. Basin evolution and sedimentary facies of the Fang Basin.

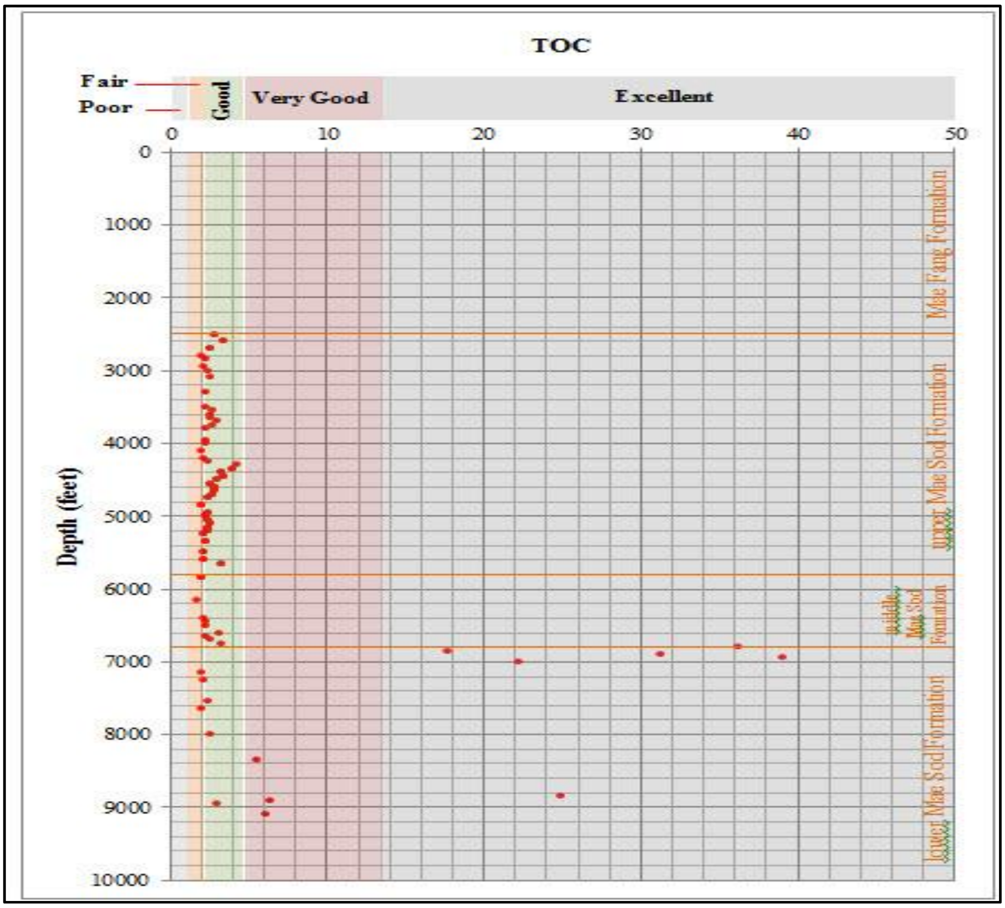


Figure 7. Total organic carbon content (TOC) in %wt. of the Mae Sod Formation.

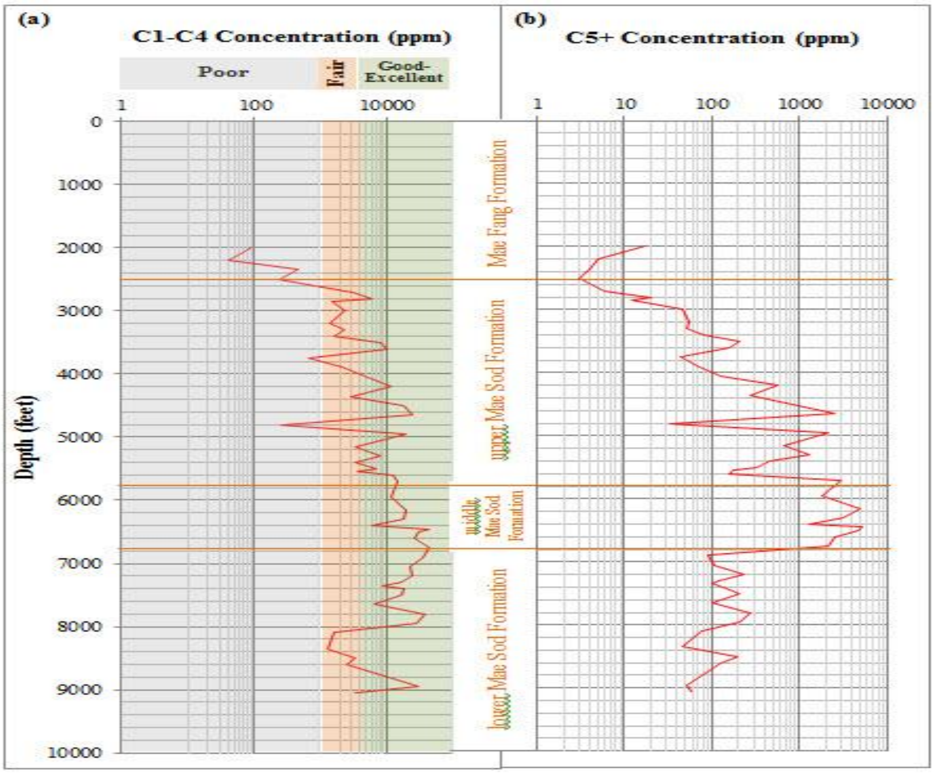


Figure 8. Headspace gas analyses of the Mae Sod Formation (a) C1-C4 concentration and (b) C5+ concentration.

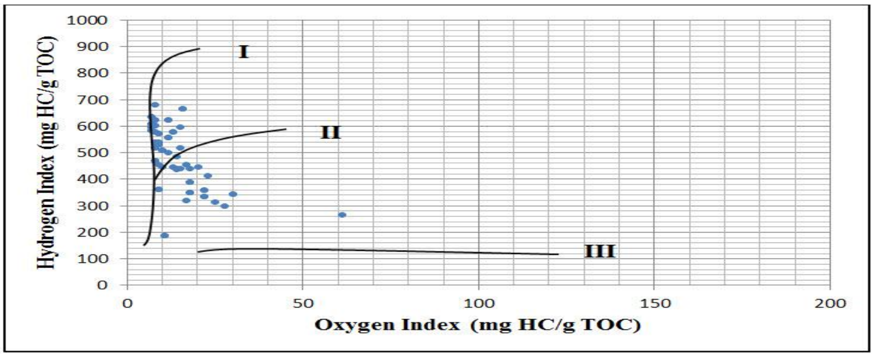


Figure 9. Plot of hydrogen index (HI) versus oxygen index (OI) of upper Mae Sod Formation.

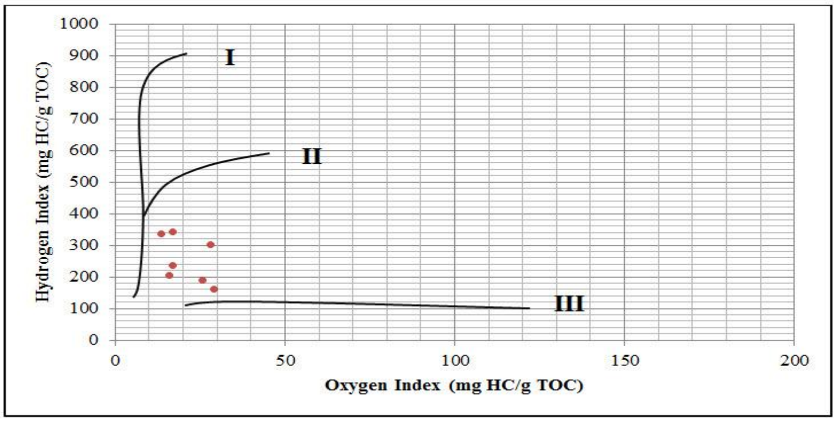


Figure 410. Plot of hydrogen index (HI) versus oxygen index (OI) of middle Mae Sod Formation.

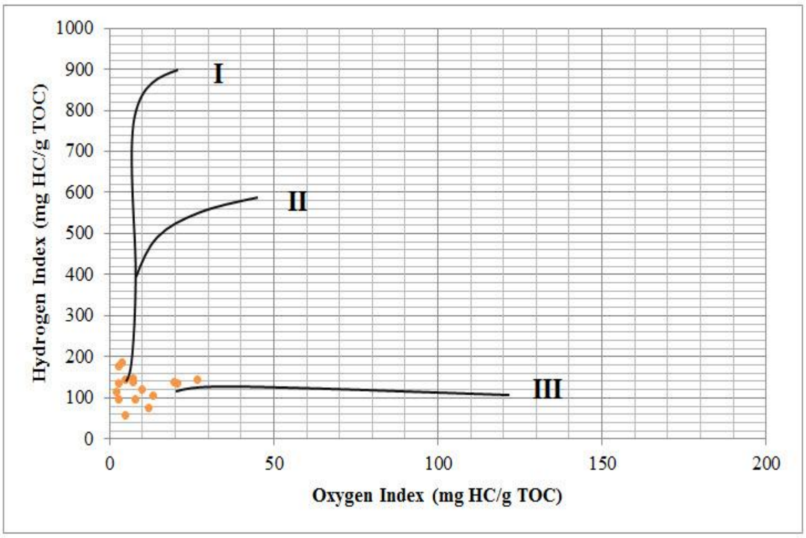


Figure 11. Plot of hydrogen index (HI) versus oxygen index (OI) of lower Mae Sod Formation.

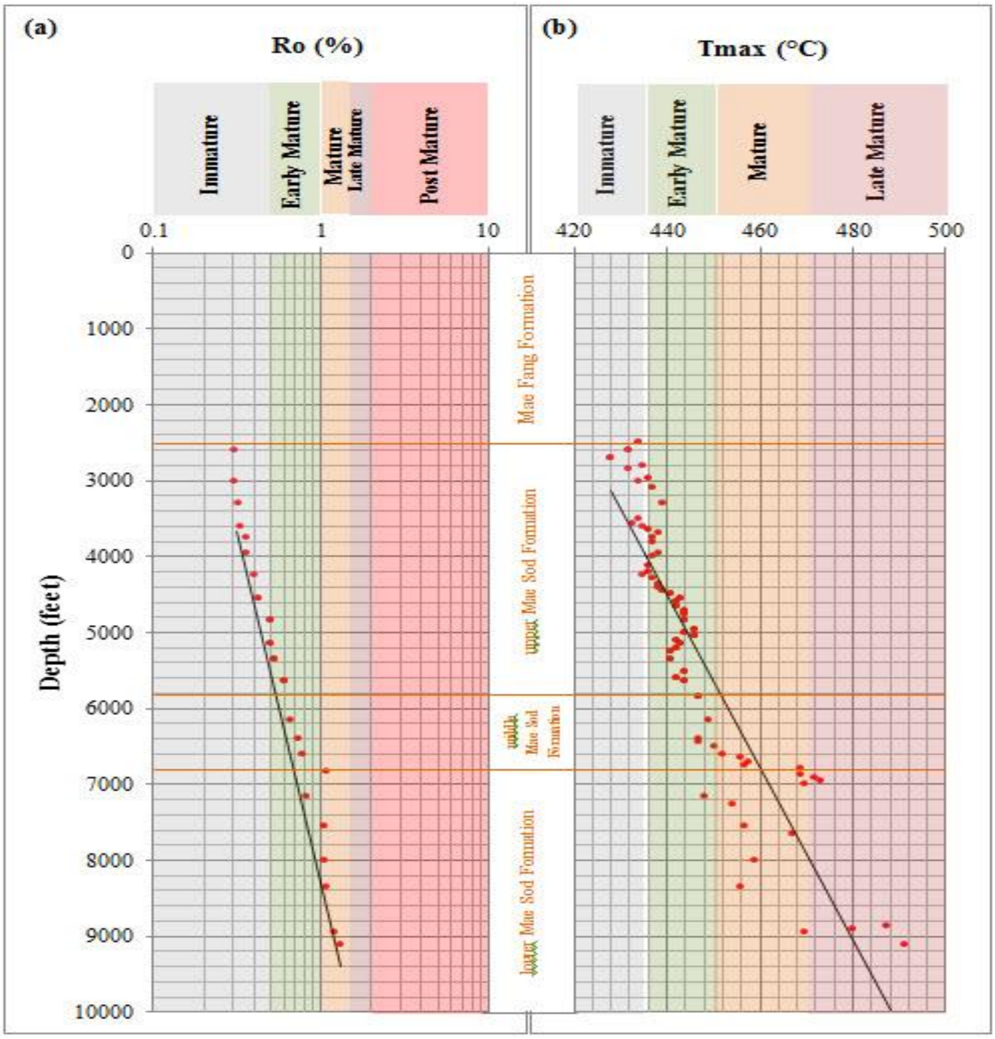


Figure 12. Maturity of source rock of Mae Sod Formation. (a) Ro (%) and (b) Tmax (°C).

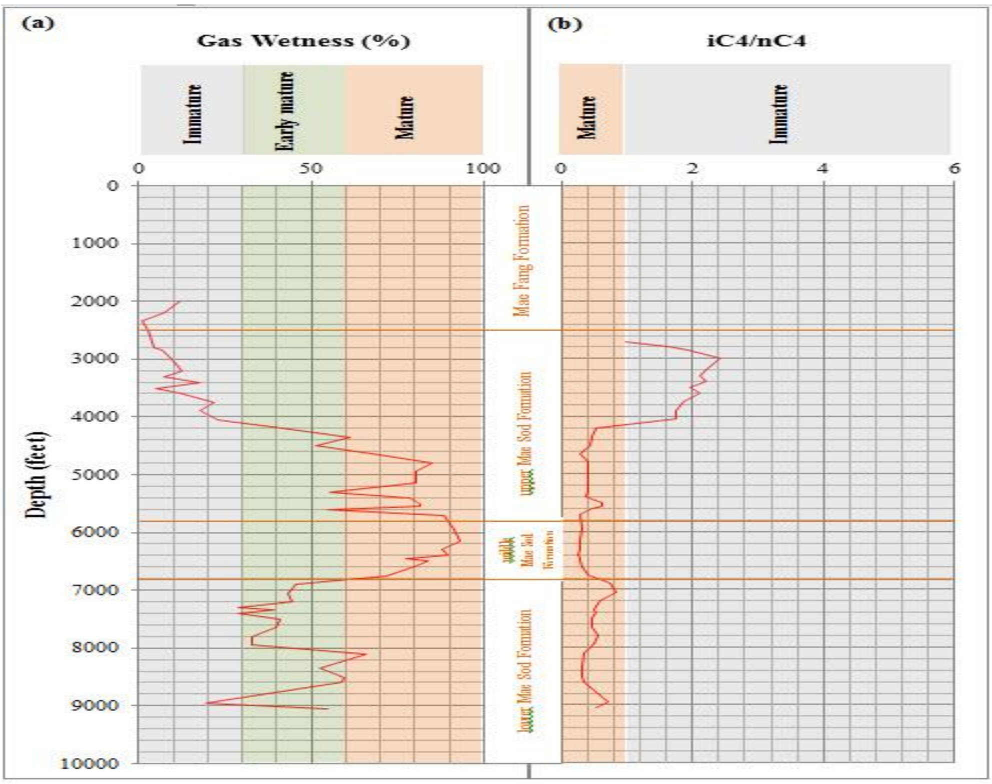


Figure 13. Headspace gas analysis for hydrocarbon maturation indicator (a) from gas wetness. (b) from of iC4/nC4 ratio.

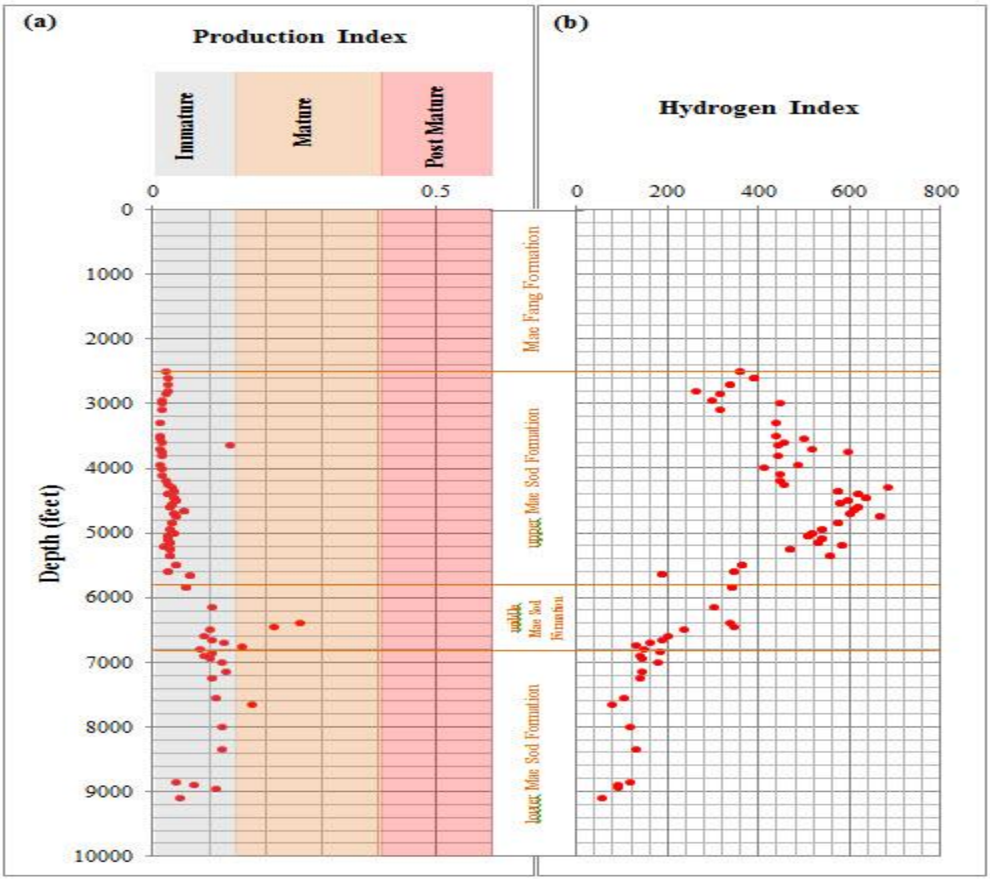


Figure 14. (a) Maturity of source rock of Mae Sod Formation from production index. (b) hydrogen index.

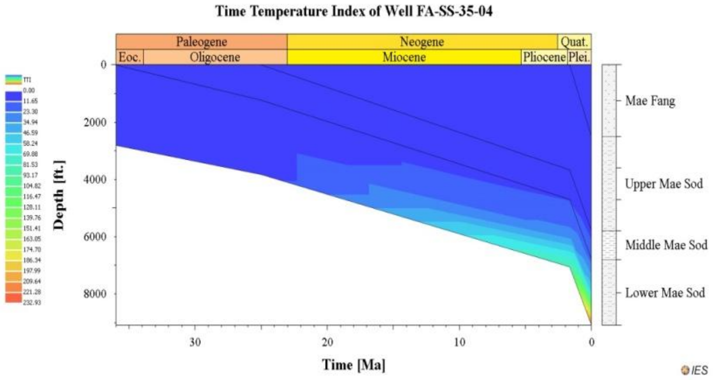


Figure 15. Burial history at the San Sai oil field. The overlay shows organic matter maturation calculated as time and temperature index model (TTI).

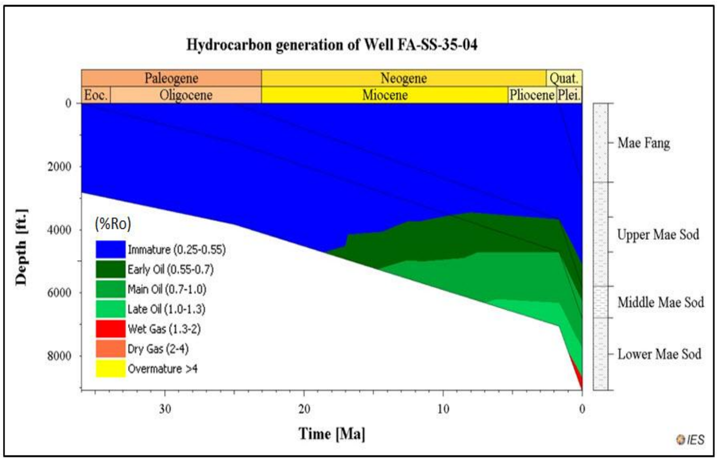


Figure 16. Burial history at the San Sai oil field. The overlay shows organic matter maturation calculated as vitrinite reflectance (EASY%Ro, Sweeney and Burnham 1990).

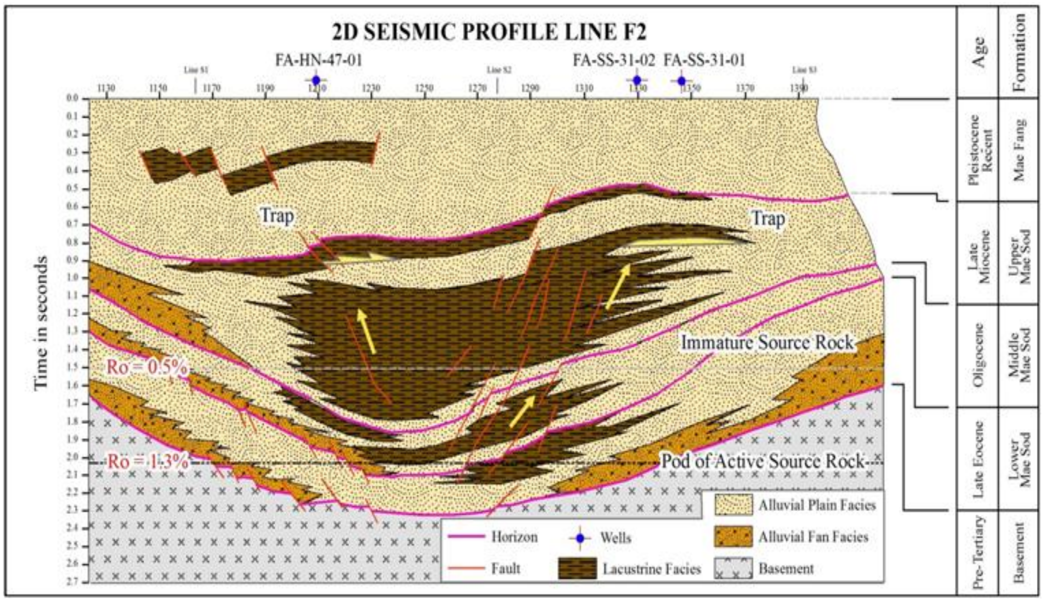


Figure 17. Cross section of the San Sai oil field showing the migration pathway and oil accumulations.