

Petroleum system modeling in cenozoic sediments, Block 05-1a, Nam Con Son Basin

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Abstract—Based on the update of exploration data the oil and gas potential within block 05-1 are studied through define the source rocks, Hydrocarbon (HC) generation, expulsion and migration, focusing on source rock Oligocene /Early Miocene and Middle Miocene; Define the accumulation of hydrocarbon in Lower Miocene targets; The results of assessments for source rock, oil sampling analysis is used to determine the relationship between in-situ oil or oil migrated from other places. The workflow of basin modeling is assigned to get output (migration pathways, volume of accumulation), as well as data calibration. Main source rocks include H150, H125 shales and H150 coal with Total organic carbon (TOC)~1 and 47 respectively. These source rocks are medium to good potential. At the present time, most of the source rocks are in oil window, while the deep parts is in gas window. Oil started to be generated in Early Miocene, and started to be expelled in Late Miocene. Gas started to be generated in Quaternary, about to be expelled. The oil migrated mainly from the troughs at the West and minorly from the East and South to Dai Hung High. Gas started to migrate from West to East and South West to North East at the Western part. However, at the Eastern part, gas migrated from the opposite direction. The results of sensitive analyses show more oil in max source rock case, therefore, a 3D model development is

recommended and identify the differences in generation characteristics between Nam Con Son and Cuu Long basins.

Index Terms—Modeling, seismic interpretation, petroleum system, migration, hydrocarbon accumulation.

1 INTRODUCTION

Dai Hung oil field is located in Block 05.1a, Nam Con Son (NCS) basin. Up to now, Dai Hung (DH) oil field has 37 exploration/appraisal and production wells and 4 wells are ThN-1X and DHN-1X, 2X, 3X which locate outside of field area (Figure 1). The main objectives of this study are to re - assessment the petroleum system in block 05.1a and propose the upcoming exploration strategy [1].

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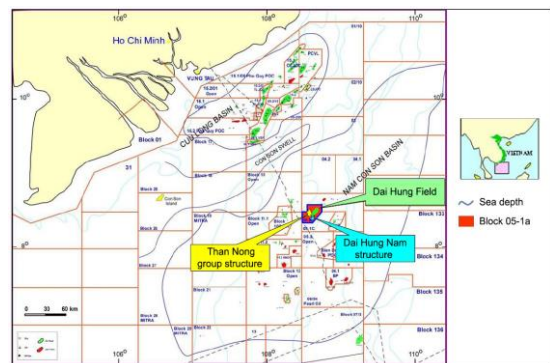


Figure 1. Location of block 05-1a [1]

The 3D geochemical model is conducted based on interpretation of well data, seismic data in block 05.1a and surrounding areas as well as evaluation of the potential for oil and gas in NCS basin within previous studies. This research included 2 phases: Collecting and updating the data of previous studies; Updating the seismic data outside of DH oil field, extending to the regional cluster as Than

Nong (ThN) and Dai Hung Nam (DHN) structures; 3D geochemical modeling for DH oil field, extending to the entire block 05.1a and surrounding areas. Model results will be used to estimate oil and gas potential, migration potential, accumulation for each structure, as well as assess the remain risks [1].

2 METHODOLOGY AND IMPLEMENTATION PROCESS

2.1 The methodology

Assessment for source rock: Overview of source rock within NCS basin, evaluating the richness of source rock, estimating the source rocks' quality, developing variation chart of Kerogen and Ro versus depth. Determining the relationship between oil and oil: for classification / comparison between in-situ oil or oil migrated from other places (based on oil sample analysis results) [2]; 3D geochemical modeling in researched area, identifying the hydrocarbon generation potential, migration, accumulation of oil and gas, Assessing the correlation characteristics of PVT parameters. The appropriate software: IP, Geo Frame/ Petrel, PetroMod/Petrel are used to determining the thickness of source rock, reservoir, seal; seismic interpretation; 2D, 3D geochemical modeling respectively.

2.2 Implementation process

2.2.1 Basin modeling workflow: Based on input data and range of study, the basin is modeled by following workflow (Figure 2).

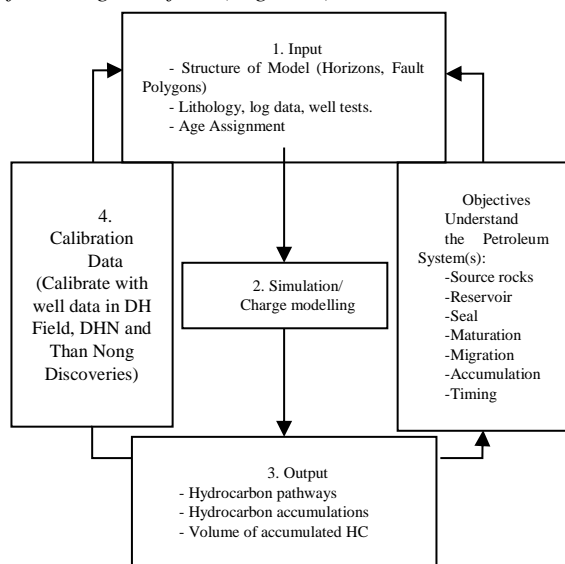


Figure 2. Work flow of basin modeling

2.2.2 Input parameters

Source rock parameter input: Based on the geochemical data of DH wells, the source rocks (SR) of the study area are determined as H150 Shale SR (Oligocene), H150 Coal SR (Oligocene), and H125 Shale SR (Early Miocene) [3]. The H150-H200 SRs including claystone, coaly claystone and coal are main source rocks in area. Kerogen is mainly types III/II and maturity (oil window). The H80-H150 SRs include claystone, silty claystone, coal and coaly claystone. The maturity of H125-H150 SR is mainly in oil and gas generation window while H80-H125 is mainly immature.

Reservoir parameter input: The reservoirs of H80 and H100 are used because they are main clastic reservoirs in DH field, where a great amount of hydrocarbon has been produced and found.

The depth of H100 reservoir is from 2,100 – 5,450mss. The porosity of this reservoir is from 4–17.5%, good porosity is located inside the red ring, >13% (Figure 2), and similar to the porosity from well logs (13 – 18%).

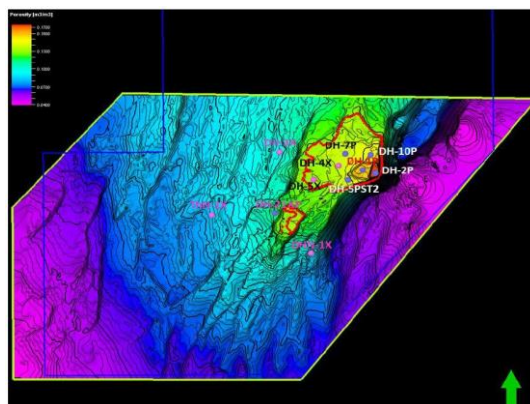


Figure 3. H100 Reservoir porosity map [4]

The depth of H80 reservoir is from 1,750 – 4,600mss. The porosity of this reservoir is from 6–21%, good porosity is located inside the red ring (>15%), Figure 3), and similar to the porosity from well logs (13–21%).

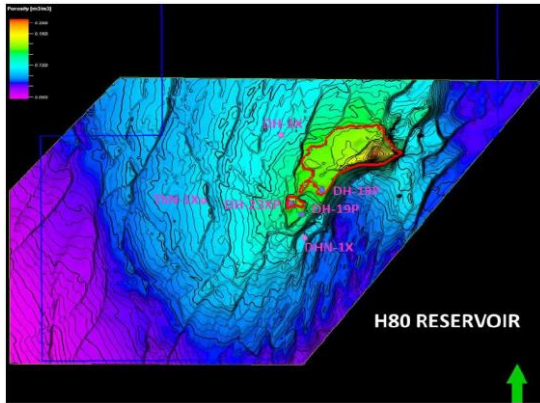


Figure 4. H80 Reservoir porosity map [4]

Seal parameter input

The top seal quality of H100 is from good to very good (capillary pressure from 11.5–18.7 bar) (Figure 4). The top seal quality of H80 is good (capillary pressure from 9.5–14.9 bar) (Figure 5).

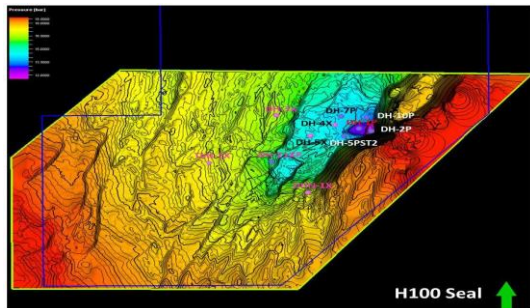


Figure 5. H100 Seal capillary pressure map [4]

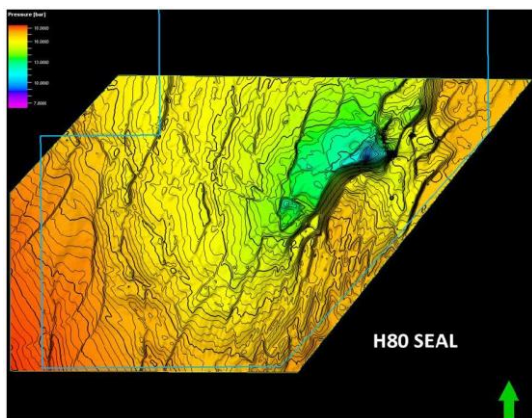


Figure 6. H80 Seal capillary pressure map [4]

Simulation: *Pressure-Temperature modeling:* Temperature is simulated based on the upper boundary condition determined as the surface (seafloor) temperature, the basement heat flow at the lower boundary of the model, and the thermal

conductivity of all layers in the model. For pressure modeling, various compaction laws can be modeled as defined in the lithologies and pressure boundary conditions can be assigned to account. **Petroleum generation:** Based on database of reaction kinetics, the phases and properties of hydrocarbons generated from source rocks of various types will be predicted. The models also describe the release of generated hydrocarbons into the free pore space of the source rock. Furthermore, the number of chemical components produced in this model can vary between 2 (oil and gas) and 20. **Migration modeling:** The 2D, 3D migration modeling technology uses flash calculations throughout the entire model and its geologic history, which improves the understanding and prediction of petroleum properties and oil versus gas probability assessments. Migration velocities and accumulation saturations are calculated in one step. Describing fluid migration across faults requires special algorithms.

In the block05-1a area, the P-T, petroleum generation and migration modeling is bounded by horizons from H80 to H200.

Charge modeling input data: *Source rocks:* H150 Coal (TOC=47, Average Thickness ~ 2m), H150 Shale (TOC=1, Average thickness=20-30m, H125 Shale (TOC=1, Average Thickness ~20m). *Reservoir:* H100 and *Seal:* H100.

3 MODELING RESULTS

The result of 2-D model will be shown in maturation, generation & expulsion timing, generated hydrocarbon mass, gas transformation ratio, migration pathway & accumulation in reservoir, as well as sensitive analysis.

3.1 Maturation maps

MATURATION MAP OF H150 SOURCE ROCK (SHALE)

Source rock type	Mature window (%)	Oil window (%)	Wet gas window (%)
III	~ 15	~ 55	~ 30

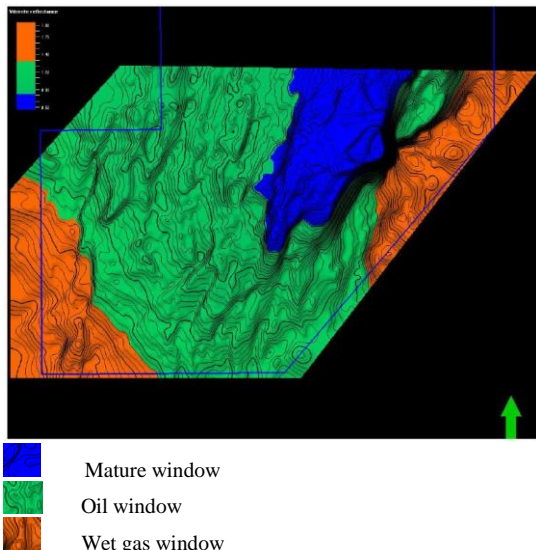


Figure 7. Maturation map of H150 SR (shale)

This output is based on TOC input as 0.96% and HI of 244.

MATURATION MAP OF H150 SOURCE ROCK (SHALE)

Source rock type	Mature window (%)	Oil window (%)	Wet gas window (%)
III	~ 15	~ 55	~ 30

This output is based on TOC input as 47% and HI of 298, due to low organic matter content and over maturation range hence it is not classified as source rock.

MATURATION MAP OF H125 SOURCE ROCK (SHALE)

Source rock type	Mature window (%)	Oil window (%)	Wet gas window (%)
III	~ 25	~ 55	~ 20

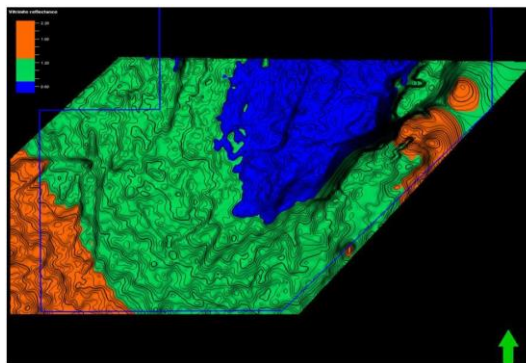


Figure 8. Maturation map of H125 Shale SR

This output is based on TOC input as 0.95% and HI of 231.

3.2 Source rock timing and generated hydrocarbon volume:

H150 Shale SR: The time for the H150 shale SR in study area started to enter the main oil window was approximately 13Ma in Middle Miocene (Figure 9). Most of the study area were in the main oil window in Late Miocene (green zone) while the area in yellow is in oil production in Quaternary.

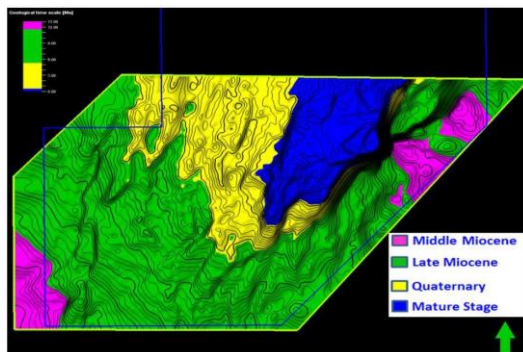


Figure 9. Main oil window generation timing of H150 Shale S

The oil only pushed out of the source rock if the oil transformation > 50% (outside red ring, Figure 10). Oil produced from the deep part (yellow and green zone) has been expelled where the oil from depth lower 4,800 mss (green zone) primarily migrated in Late Miocene and oil from 4,800–4,100 mss (yellow zone) started to move in Quaternary. The oil produced from the upper part (from 4,100 mss) properly still stays in the SR.

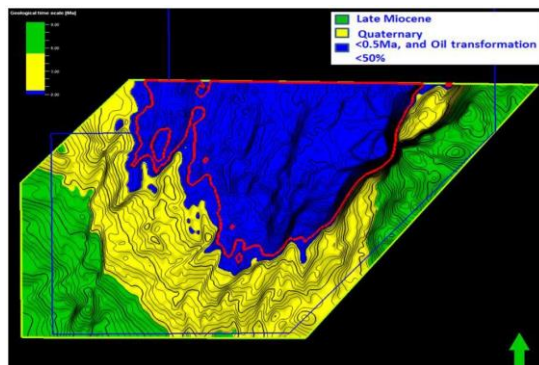


Figure 10. Oil expulsion timing of H150 Shale SR

The model result outlines the vertical window of oil migration timing. Oil from Oligocene Shale S.R in depth below 4,800mss section would be expelled from Late Miocene while those in 4,100-4,800mss interval started to migrate in Quaternary. Oil in sequence above 4,100mss has not been expelled from SR yet.

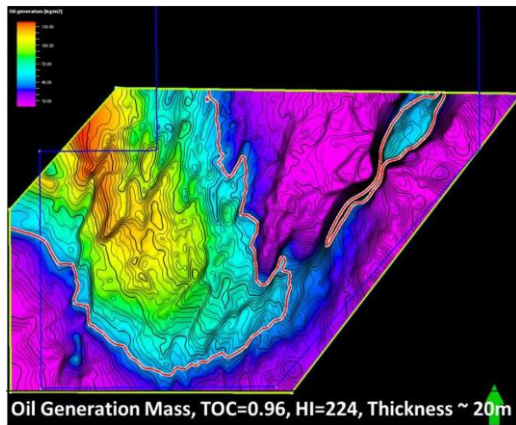


Figure 11. H150 Shale SR Oil generation mass

A mass of oil produced/m² is estimated very differently from 0,5 to 138 kg (Figure 11), mostly from interval of 3,700-4,950mss where the source rock is in the main oil window (inside the red ring). The mass of gas produced is estimated from 0 to 230 kg (Figure 12), and mainly from below 4,300mss.

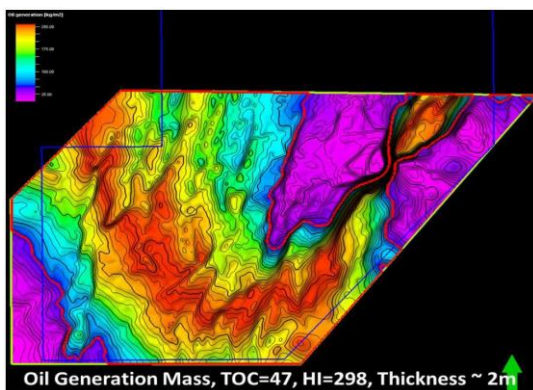


Figure 12. H150 Shale SR Gas generation mass

H150 Coal SR: The time for the H150 coal source rock in study area began to be in the main oil window was approximately 13Ma in Middle Miocene (Figure 13). Most of the study area were in the main oil window in Late Miocene (green zone) while the area in yellow is in oil production in Quaternary.

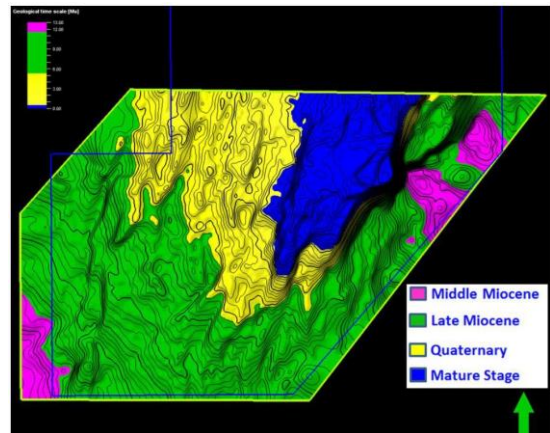


Figure 13. Main oil window generation timing of H150 Coal SR

The oil was expelled from the source rock outside the red ring (Figure 14). Oil from Oligocene Coal SR in depth below 4,800mss section would be expelled from Late Miocene (approx. 9.3Ma–green zone) while those in 4,100-4,800mss interval started to migrate in Quaternary (yellow zone), and oil in sequence above 4,100mss has not been expelled from SR yet (blue zone).

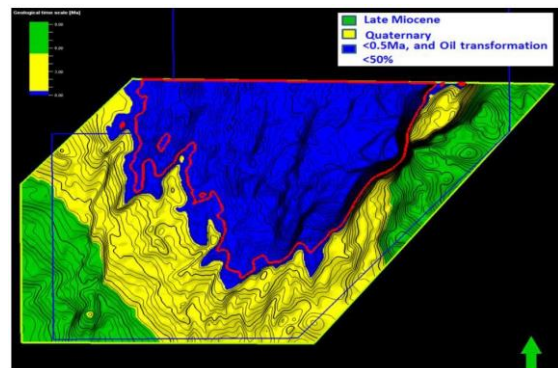


Figure 14. Oil expulsion time of H150 Coal SR

The rate of oil produced is estimated very variously from 0.5 to 138 kg, mostly from interval of 3,700-3,350mss where the source rock is in the main oil window (inside the red ring, Figure 15).

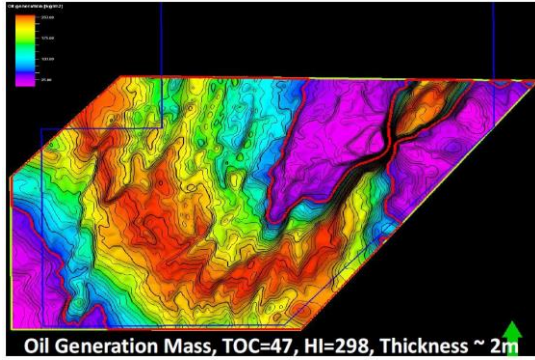


Figure 15. H150 Coal SR Oil generation mass

The mass of gas expelled is estimated from 0 to 470 kg, and mainly from below 4,060mss (Figure 16).

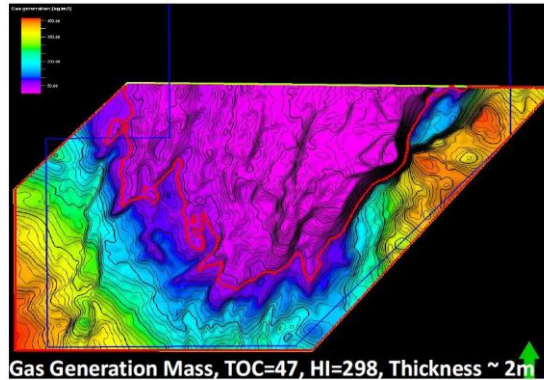


Figure 16. H150 Coal SR Gas generation mass

H125 Shale SR: Within the H125 shale SR started to enter main oil window approximately 7,5 Ma -Late Miocene (Figure 17). However, most of the area began to be cooked in the main oil window in Quaternary and about one third does not enter this state yet. Then, the primarily migration phase from this SR could be around 5,9Ma (Late Miocene) (Figure 18). Oil expelled in Late Miocene from H125 shale SR at depth below 5,500mss located at a very small section, at the edge of the South West corner (green zone) while those in 4,200-5,500mss interval started to migrate in Quaternary dominated nearly half of area (yellow part), and the biggest part is the place where oil has not been expelled from SR yet (above 4,200mss–blue zone).

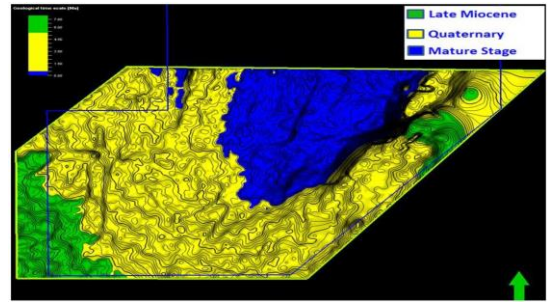


Figure 17. Main oil window generation timing of H125 Shale SR

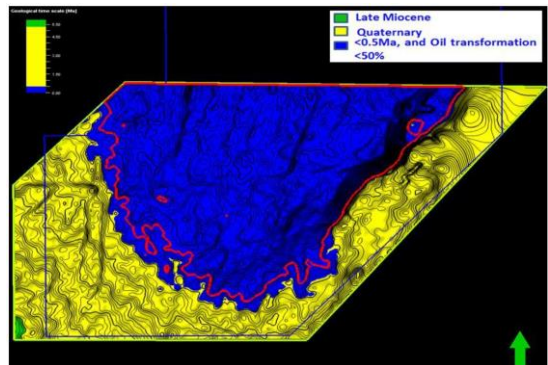


Figure 18. Oil expulsion timing from H125 Shale SR

Similar to other SRs, the H125 Shale SR also entered the Wet gas window somewhere from depth of 5,150m at approx. 0,53 to 3,2 Ma, inside the red ring. The rest of area is still not in the Wet gas window yet (Figure 19).

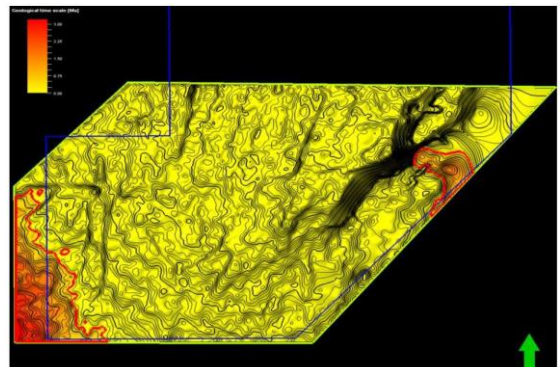


Figure 19. Wet gas window generation timing of H125 Shale SR

The mass of generated oil from the H125 Shale SR is less than the other SRs due to less time being cooked properly and estimated from 0.5 to 43 kg, and mostly from interval of 3,700-4,000mss (Figure 20). While for the volume of generated gas, this number is 0,5 to 84 kg, generally from below 4,800m (Figure 21).

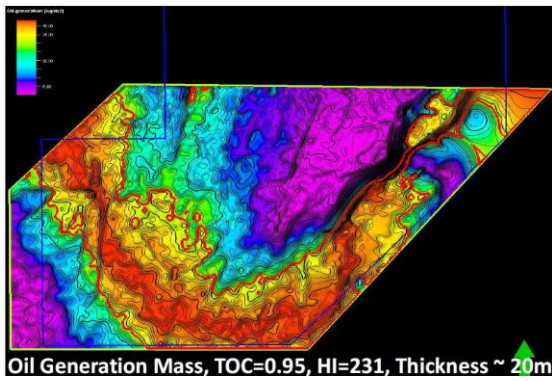


Figure 20. H125 Shale SR Oil generation mass

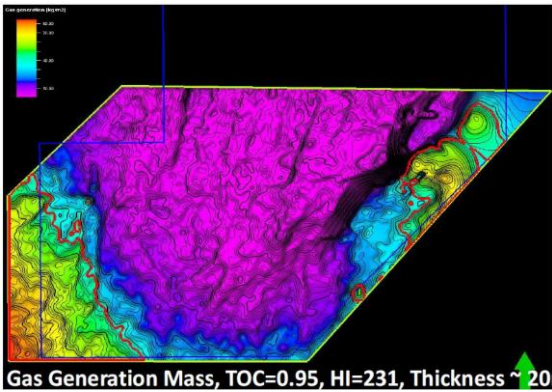


Figure 21. H125 Shale SR Gas generation mass

3.3 Migration pathways and accumulation in reservoirs

In H100 reservoir, expelled oil migrated from the west & east troughs to DH High by both faults and carrying beds, then trapped in production reservoirs at DH field (Figure 22). The oil accumulated to Northern area (blocks K, J, L, D respectively to well DH-1P, DH-10P, DH-2P, DH-7P & DH-4X; Southern area (blocks Z, T1, respectively DH-21XP, DH-23XP) as well as DHN discovery (DHN-1X). Meanwhile, there is no oil accumulation at ThN Discovery (ThN-1X) at H100. These phenomena are matching with the real production situation of DH field. However, those blocks next to block Z (B1) and South East of DHN happen to accumulate oil at H100 according to the model [4].

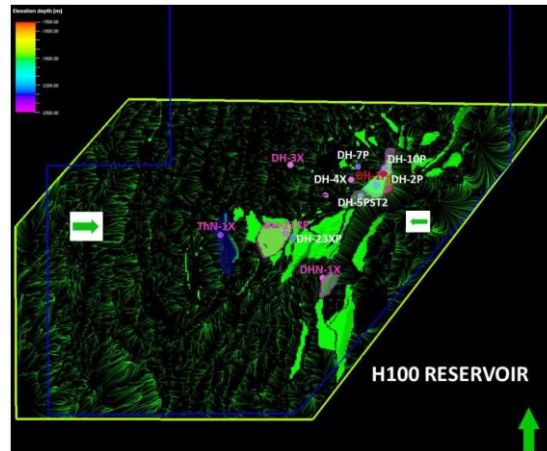


Figure 22. Migration pathway of oil into H100 reservoirs

In case of calculating accumulated HC at reservoirs, the model gives results as an estimate as in table below:

No	Blocks	Area (km ²)	HCIIP (MMbbls)
1	Block K + block J +block L	1.08 + 0.96 +0.47	~ 71
2	Block Z	2.9	~ 73.7
3	Block A7-1	1.8	~ 21

For gas migration and accumulation, it started to extract and move from West to East and Southwest to Northeast at the Western part of study area. However, at the Eastern part, gas migrated from the opposite direction, from East to West and South East – North West (Figure 23).

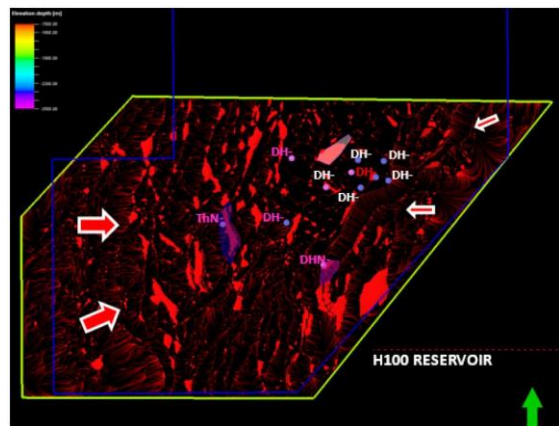


Figure 23. Migration pathway of gas into H100 reservoirs

The volume of gas accumulated at reservoirs based on the model is assessed as in table below:

No	Blocks	Area (km ²)	GIIP (BCF)
1	Block A7-1	1.8	~ 1.03
2	ThN 1A	4.07	~ 4.67
3	Block R	1.53	~ 10.9

In the case of H80 reservoir, expelled oil migrated from the west & east troughs to DH High by both faults and carrying beds, then trapped in produced reservoirs at DH field (Figure 24). The volume of accumulated oil at reservoirs at blocks which the model results show an estimate as in table below table:

No	Blocks	Area (km ²)	HCIP (MMbbls)
1	Block N1-N2	4.6	~ 75.8
2	Block T1 + Block A4	0.36 + 1.4	~ 19
3	Block A7-1	1.8	~ 0.19
4	ThN1A	4.07	~ 61.4

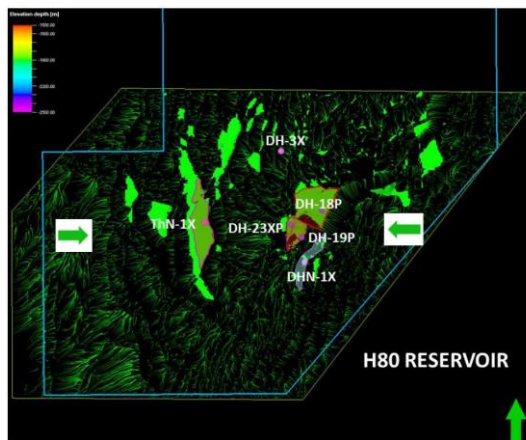


Figure 24. Migration pathway of oil into H80 reservoirs

Gas migrated from the troughs at the West and the East to DH High, accumulated to potential structures, mainly in ThN area (Figure 25), still not reach DH High yet. The amount of gas accumulation is as in table below:

No	Blocks	Area (km ²)	GIIP (BCF)
1	Block T1 +Block A4	0.36 + 1.4	~ 0.03
2	ThN1A	4.07	~ 0.3

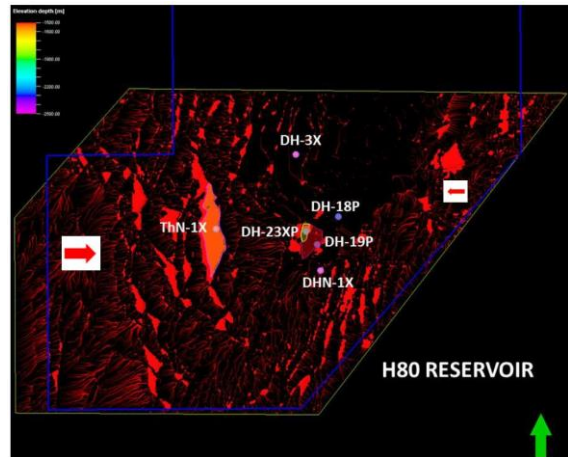


Figure 25. Migration pathway of gas into H80 reservoirs

5.4 Calibration data and sensitive analysis

The data of the PSM are calibrated by well data from DH, ThanNong & DHNam discoveries. Particularly, in the area, there are three main source rocks, the H80-H133 (Lo. Miocene), H133-H150 (Lo. Miocene) and H150-H200 (Oligocene). These formations have organic matter content ranging from 0.5% to 4%, average 2÷2.5%, HI from 150÷400, average 250mg / g, Kerogen mainly types II and III, it produces both oil and gas. The results of the geochemical analysis demonstrate the oil is produced at a depth of 3,300 ÷ 3,500m, the threshold of gas at about 4,800÷5,000m. At present, 70% volume of H150-200 SR, 50% volume of H133-150 SR, and 30% volume of H80-H133 SR fallen into the oil window respectively.

To understand the effects of source rock properties, fault seal capacity, this study has been carried out several scenarios as follows: Source rock optimized case: Source rock properties assigned with higher quality of source rock; Fault seal capacity: close and open faults cases.

The high TOC of 2% is input for sensitive analysis, other boundary conditions such as close fault, reservoir and seal of H100 remaining the same. The model output is represented in Figure 26. The oil in maximum case is mostly distributed in the North and East matching with the real situations. Nevertheless, gas accumulates in the DH field which should not be. This case gives the result of too much hydrocarbon trapped in structures at DH field, even places found no oil.

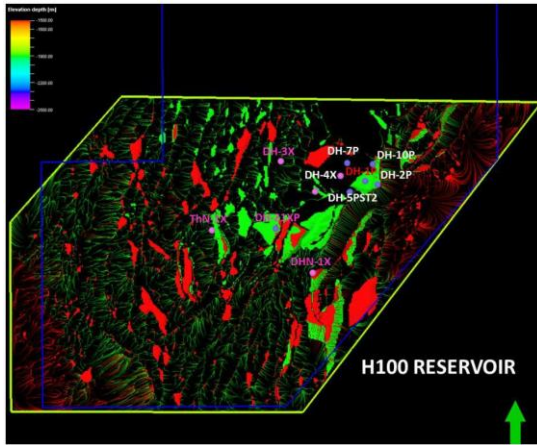


Figure 26. HC volume of maximum case

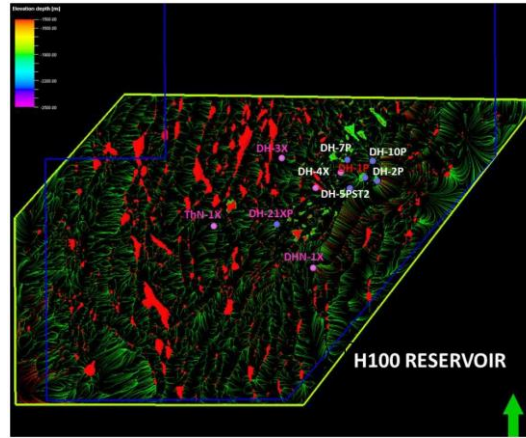


Figure 28. HC accumulation in case of opened fault

In case seal of fault (combine with condition of TOC=1), the model output results in an irrelevance in reality: too much HC accumulated in outside structures of DH field, whereas, inside the high blocks, where most oil are being produced at the moment, there is very little oil accumulated (Figure 27). On the other hand, the fault is assumed to open (Figure 28); it is too little HC to be accumulated in structures, even places found much oil in reality.

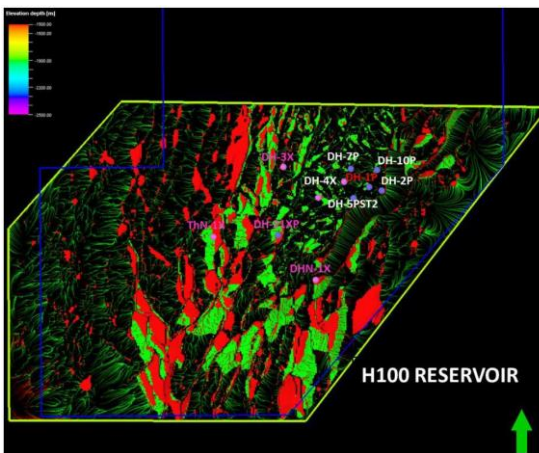


Figure 27. HC accumulation in case of close fault

4 CONCLUSIONS AND RECOMMENDATION

Based on the results of modeling oil and gas potential, the petroleum system within block 05-1 are defined, main source rocks in the study area are H150 shale, H125 shale with TOC~1 and H150 Coal with TOC~47. These source rocks are medium to good potential. At the present time, most of the source rocks are in oil window, while the deep parts are in gas window. At DH field, source rock is in mature stage only. Oil started to be generated in Early Miocene, and started to be expelled in Late Miocene. Gas started to be generated in Quaternary, about to be expelled. Oil migrated mainly from the troughs at the West and minorly from the East and South to DH High, accumulated to production reservoirs at DH field and potential structures outside DH field. Gas started to migrate from West to East and South West to North East at the Western part of study area. However, at the Eastern part, gas migrated from the opposite direction, from East to West and South East – North West. Oil and gas in DH field are either migrated from West, Southwest and East side but not from below source rock.

Uncertainties and recommendation:

Sensitive analyses show more oil in max source rock case: this is unrealistic, not fit with well results. The case of fault closed and open all the time show less oil in the field. Therefore, a 3D model, which allow to model fault properties at different time is recommended. The charge area not cover whole area; hence the study area should be open to adjacent blocks to achieve better and more accurate on source of hydrocarbon migrated to block 05-1a.

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Mô hình hóa hệ thống dầu khí trong trầm tích Kainozoi Lô 05-1a, bể Nam Côn Sơn

Trần Văn Xuân, Trần Như Huy, Nguyễn Đình Chức, Nguyễn Tuấn, Thái Bá Ngọc
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Tóm tắt—Trên cơ sở số liệu thăm dò cập nhật, tiềm năng dầu khí lô 05-1a, bể Nam Côn Sơn được đánh giá thông qua tiềm năng đá mẹ; sét, than tuổi Oligocen, Miocen sớm – giữa, xác định tích tụ dầu khí các đối tượng trong Miocen hạ; đánh giá quy mô phân bố (bề dày, tích khối) của lát cắt tầng chứa trong phạm vi nghiên cứu. Kết quả nghiên cứu địa hóa, phân tích mẫu dầu, đá mẹ và mối tương quan đã cho phép phân loại/ so sánh dầu tại sinh với dầu di cư từ nơi khác. Xác lập quy trình mô hình hóa hệ thống dầu khí từ đó xác định quá trình di cư, quy mô của tích tụ dầu khí, cuối cùng đánh giá độ tin cậy của kết quả. Trong khu vực nghiên cứu đá mẹ chủ yếu là các tập sét H150 và H125 với TOC xấp xỉ 1 và tập than H150 với TOC xấp xỉ 47. Tiềm năng sinh dầu được xếp hạng từ trung bình đến tốt. Vào thời điểm hiện tại, phần lớn đá mẹ rơi vào cửa sổ tạo dầu, phần đáy đã đạt ngưỡng tạo khí. Dầu bắt đầu được hình thành từ Miocene sớm, phóng thích trong Miocene muộn. Khí bắt đầu được hình thành từ Đệ Tứ, và đang bắt đầu phóng thích. Dầu di cư chủ yếu từ các địa lũy ở rìa Tây và một phần từ phía Đông và Nam lên khối nhô của mỏ Đại Hùng. Tại khu vực phía Tây, khí cũng bắt đầu di cư từ Tây qua Đông và từ Tây Nam qua Đông Bắc. Tuy nhiên, tại phần phía Đông thì hướng dịch chuyển hoàn toàn trái ngược. Các yếu tố không chắc chắn đá mẹ có thể sinh lượng dầu lớn hơn nhưng không khớp với kết quả khoan, chưa định lượng với trường hợp đứt gãy kín và hở, như vậy cần phát triển mô hình hệ thống 3D cũng như nhận diện và so sánh sự khác biệt của đặc điểm sinh dầu giữa bể Nam Côn Sơn với bể Cửu Long.

Từ khóa—Mô hình hóa, minh giải địa chấn, hệ thống dầu khí, di cư, tích tụ dầu khí.