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Depositional Environment and Petroleum System Significance of Shale- And Siltstone-Dominated Source Rocks: Evidence from Well A-1X, Nam Con Son Basin, Offshore Vietnam

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ABSTRACT: The Nam Con Son Basin (NCSB), offshore southeastern Vietnam, is among the largest and most hydrocarbon-prolific basins in Southeast Asia. While coal-bearing intervals are widely recognized as the primary source rocks, the role of shale- and siltstone-dominated successions has not been fully evaluated. This study integrates bulk geochemistry, organic petrology, and biomarker data from Well A-1X to assess the petroleum potential and depositional environment of shale and siltstone intervals.

A total of **94 fine-grained clastic samples** (90 shales and 4 siltstones) were analyzed. TOC values for shales range from **0.50 to 2.60 wt.%** (mean 1.10 wt.%), with the majority classified as "Good" (1–2 wt.%) according to petroleum geochemical standards. Siltstones yielded TOC between **0.90–1.16 wt.%** (mean 0.99 wt.%), confirming fair-to-good organic enrichment despite coarser grain size. Stratigraphically, Oligocene shales are richer (mean 1.30 wt.%) compared to Miocene equivalents (mean 1.05 wt.%), indicating that the **Oligocene succession forms the main shale source rock interval** in Well A-1X.

Thermal maturity, based on vitrinite reflectance, increases with depth. Miocene shales are immature to marginally mature (**0.31–0.52%Ro, mean 0.44%Ro**), whereas Oligocene shales reach the **early oil window** (**0.46–0.62%Ro, mean 0.57%Ro**). Biomarker signatures support these results: shallow Oligocene shales exhibit n-alkane dominance at n-C17–C18 (algal contribution), while deeper intervals show enrichment in long-chain n-C25–C31, reflecting significant terrestrial higher-plant input. Pristane/Phytane ratios of 4–9 suggest deposition under suboxic to oxic deltaic conditions. CPI values averaging 1.03 indicate thermal maturity consistent with early oil generation.

Collectively, these findings demonstrate that shale and siltstone intervals in Well A-1X, though less organic-rich than coals, are effective **secondary oil-prone sources**. Their widespread stratigraphic distribution and confirmed maturity enhance the robustness of the Nam Con Son petroleum system and highlight new opportunities for exploration, particularly in Oligocene reservoirs charged by shale-derived hydrocarbons.

KEYWORDS: Nam Con Son Basin; Shale; Siltstone; Source Rock Geochemistry; TOC; Vitrinite Reflectance; Biomarker; Petroleum System.

1. INTRODUCTION

The Nam Con Son Basin (NCSB), located offshore southeastern Vietnam, is one of the most important hydrocarbon provinces in the South China Sea region. Covering approximately 100,000 km², the basin formed through Late Mesozoic rifting and subsequent Cenozoic subsidence, which created a thick sedimentary fill composed predominantly of clastic deposits (Vietnamese Petroleum Institute, 2005). Its stratigraphic succession includes alternating coals, siltstones, and shales deposited in deltaic to marginal-marine environments, providing favorable conditions for petroleum generation, migration, and entrapment. Several giant gas and condensate fields, such as Lan Tây, Lan Đỏ, and Chim Sáo, confirm the petroleum significance of the basin.

While coals have traditionally been considered the **dominant source rocks** in the NCSB (Todd & Dunn, 1992), fine-grained siliciclastic rocks—particularly shales and siltstones—remain underexplored despite their global importance in petroleum systems. Worldwide, shales are recognized as the **most volumetrically significant source rocks** (Hunt, 1996; Peters & Cassa, 1994), as they preserve dispersed organic matter under a wide range of depositional conditions. In addition to being conventional source rocks, shales are increasingly valued as **unconventional reservoirs** in self-sourced systems (Jarvie, 2012).

In Southeast Asia, several studies have demonstrated the importance of shale successions in petroleum generation. For example, Oligocene shales in the **Malay and Pattani basins** show TOC values of 1–3 wt.% and contain mixed Type II/III kerogen, contributing significantly to oil charge alongside coals (Huc, 1995). Similarly, in the **Song Hong Basin** of northern Vietnam, shales are recognized as important secondary sources complementing coal-rich intervals (Le et al., 2011). These analogues suggest that shales and siltstones in the Nam Con Son Basin may also play a more important role than previously assumed.

Despite this regional context, **the shale and siltstone intervals of the Nam Con Son Basin remain poorly characterized**. Previous petroleum system models have often neglected their contribution, focusing instead on coal seams. Preliminary geochemical results from Well A-1X, however, suggest otherwise: shale samples yield TOC values ranging from 0.50 to 2.60 wt.% (average ~1.10 wt.%), and vitrinite reflectance (%Ro) values up to 0.62% indicate early oil window maturity. Siltstones, although fewer in number (n=4), also show moderate organic enrichment (TOC ~0.99 wt.%), suggesting a potential but underappreciated role in petroleum generation. Biomarker evidence further reveals mixed terrestrial and algal inputs, with Pristane/Phytane ratios indicating suboxic to oxic deltaic depositional environments.

These observations raise critical questions: To what extent do shale and siltstone intervals contribute to hydrocarbon generation in the Nam Con Son Basin? Are Oligocene shales sufficiently rich and mature to act as effective oil-prone source rocks? How does their depositional environment control organic matter preservation? And finally, what is their significance in the broader petroleum system relative to the well-established coal sources?

To address these questions, this study integrates **bulk geochemical analyses (TOC, Rock-Eval pyrolysis), vitrinite reflectance measurements, and biomarker data** from shale and siltstone samples of Well A-1X. The objectives are fourfold:

1. **Quantify organic matter richness** and kerogen quality in shale and siltstone intervals.
2. **Assess thermal maturity** using %Ro and complementary pyrolysis parameters.
3. **Reconstruct depositional environments** through biomarker proxies, including n-alkane distributions, Pr/Ph, and CPI values.
4. **Evaluate the petroleum system significance** of these intervals relative to regional analogues and within the context of Nam Con Son Basin exploration.

By focusing specifically on shale and siltstone intervals—rather than coals—this study highlights their overlooked but potentially significant role in hydrocarbon generation. The findings not only improve the understanding of source rock heterogeneity in the Nam Con Son Basin but also provide valuable insights for future exploration strategies targeting both conventional and unconventional petroleum resources.

2. MATERIALS AND METHODS

2.1 Geological and Stratigraphic Framework

Well A-1X is situated in the central Nam Con Son Basin, offshore southeastern Vietnam. The well penetrated a thick clastic succession ranging from Miocene to Oligocene age. These strata include interbedded shale, siltstone, sandstone, and coal, deposited in deltaic to marginal-marine environments. For the purposes of this study, the **Miocene–Oligocene boundary is approximated at 3500 m depth**, based on regional stratigraphic correlation (Vietnamese Petroleum Institute, 2005).

In total, **94 fine-grained clastic samples** were analyzed:

- **Shale (n = 90)**, ranging in depth from 2010 to 3915 m.
- **Siltstone (n = 4)**, recovered from depths between 2320 and 3255 m.

Coal samples (n = 12) were also encountered but are not the focus of this paper; their geochemical characterization is addressed separately.

2.2 Total Organic Carbon (TOC) and Rock-Eval Pyrolysis

Sample preparation. Shale and siltstone cuttings were cleaned, washed, and dried prior to analysis. Visible contaminants (carbonate fragments, caving material) were removed under binocular microscopy. Samples were then powdered to a uniform grain size (<63 µm).

TOC measurement. Total Organic Carbon (TOC) was determined using a **LECO CS-230 carbon analyzer**. Carbonates were removed by treatment with 10% hydrochloric acid (HCl) until effervescence ceased, followed by repeated rinsing with distilled water and drying at 50 °C. TOC results are expressed as weight percent (%).

Rock-Eval pyrolysis. Selected shale and siltstone samples were analyzed using a **Rock-Eval VI instrument**. Parameters measured include:

- S1 (free hydrocarbons, mg HC/g rock)
- S2 (hydrocarbons generated from kerogen, mg HC/g rock)
- S3 (CO_2 yield from kerogen, mg CO_2/g rock)
- Tmax (temperature of maximum hydrocarbon generation, °C)
- Hydrogen Index (HI = S2/TOC × 100)
- Oxygen Index (OI = S3/TOC × 100)

Interpretation followed Peters & Cassa (1994):

- **Kerogen Type I:** HI > 600, oil-prone
- **Type II:** HI 300–600, oil-prone
- **Type III:** HI < 300, gas-prone
- **Maturity:** Tmax < 435 °C (immature), 435–445 °C (early oil), 445–455 °C (peak oil), >455 °C (late oil/gas).

2.3 Vitrinite Reflectance (%Ro)

Methodology. Vitrinite reflectance (%Ro) was measured to provide an independent assessment of thermal maturity. Samples were embedded in epoxy resin, polished to a flat surface, and analyzed under reflected light microscopy.

Measurements followed **ASTM D2798-11 (2015)** standards. A minimum of **50 individual readings** was taken for each sample to minimize statistical error. Calibration was performed against standard reference materials with known reflectance values.

Maturity thresholds (Hunt, 1996):

- Immature: <0.5 %Ro
- Early oil window: 0.5–0.7 %Ro
- Peak oil window: 0.7–1.0 %Ro
- Gas window: >1.0 %Ro

2.4 Biomarker and n-Alkane Analysis (GC–MS)

Bitumen extracts were obtained from representative shale and siltstone samples using **Soxhlet extraction** with dichloromethane solvent for 48 hours. The extracts were fractionated into:

- **Saturates (n-alkanes, isoprenoids)**
- **Aromatics**
- **Resins**
- **Asphaltenes**

The saturate fraction was analyzed using **Gas Chromatography (GC)** and **Gas Chromatography–Mass Spectrometry (GC–MS)**. The following parameters were determined:

- **n-Alkane distributions** (C12–C35)
- **Pristane/Phytane (Pr/Ph) ratio**: redox condition indicator
- **Pr/n-C17 and Ph/n-C18 ratios**: source input and maturity
- **Carbon Preference Index (CPI)**: calculated using odd/even carbon-number predominance in the C25–C33 range.

Interpretation followed standard frameworks (Peters et al., 2005; Tyson, 1995).

2.5 Data Treatment and Stratigraphic Subdivision

All geochemical results were compiled into a database and subdivided by:

1. **Lithology:** shale vs. siltstone
2. **Stratigraphy:** Miocene (<3500 m) vs. Oligocene (>3500 m)

Statistical analyses included mean, minimum, maximum, and frequency distributions. Graphical presentations (histograms, depth profiles, and boxplots) were prepared to illustrate trends in TOC, %Ro, and biomarker ratios.

3. RESULTS

3.1 Total Organic Carbon (TOC)

A total of **94 fine-grained clastic samples** (90 shale and 4 siltstone) were analyzed for TOC (Table 1, Figure 1).

- **Shales (n = 90):** TOC values range from **0.50 to 2.60 wt.%**, with a mean of **1.10 wt.%**. Distribution analysis shows that 54 samples (60%) fall into the **Good (1–2%)** category, 34 samples (38%) fall into the **Fair (0.5–1%)** category, and only 2 samples (>2%) qualify as **Very Good**. No sample exceeded 4%, which would classify as Excellent.
- **Siltstones (n = 4):** TOC ranges between **0.90–1.16 wt.%**, averaging **0.99 wt.%**. Despite their coarser grain size and lower clay content, these values indicate **consistent Fair–Good source potential**.

Stratigraphic subdivision highlights systematic differences (Figure 2):

- **Miocene shales (n = 70):** TOC ranges from **0.76–1.54 wt.%**, with an average of **1.05 wt.%**. Values cluster around the Fair–Good boundary, and no Miocene shale exceeded 2%.
- **Oligocene shales (n = 20):** TOC ranges from **0.50–2.60 wt.%**, with an average of **1.30 wt.%**. Notably, the only "Very Good" samples (>2 wt.%) occur in the Oligocene, at depths >3790 m

Table 1. Summary of TOC values for shale and siltstone samples, Well A-1X

Lithology	n	TOC Range (wt.%)	TOC Mean (wt.%)	Classification (Peters & Cassa, 1994)
Shale	90	0.50 – 2.60	1.10	Fair–Good (mostly Good)
Siltstone	4	0.90 – 1.16	0.99	Fair–Good
Miocene Shale	70	0.76 – 1.54	1.05	Fair–Good
Oligocene Shale	20	0.50 – 2.60	1.30	Good–Very Good (few >2%)

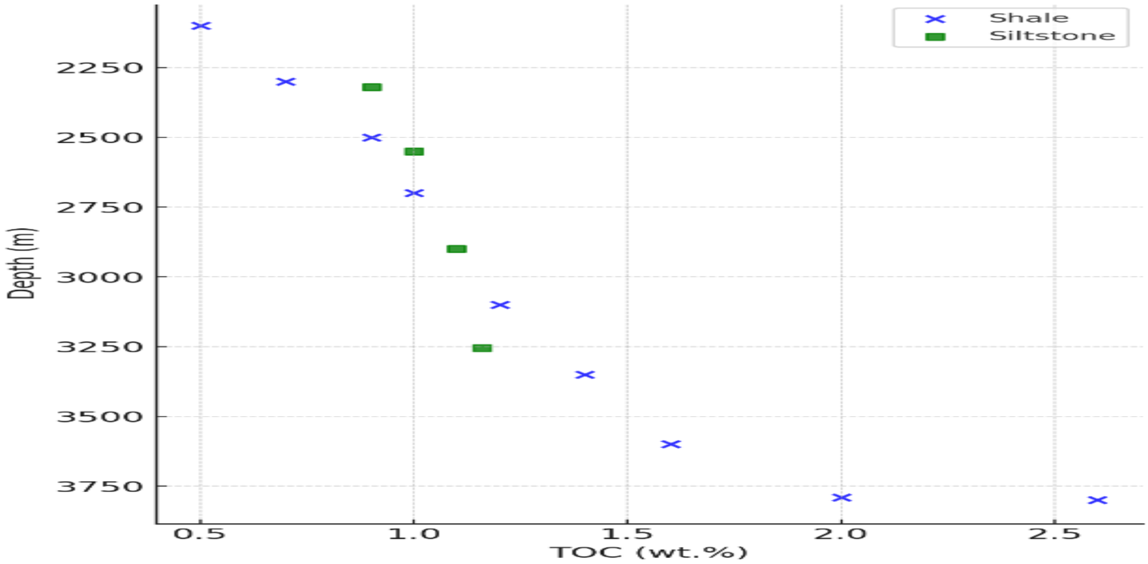

Figure 1. Depth profile of TOC (wt.%) in shale and siltstone samples from Well A-1X, Nam Con Son Basin. Shales (blue) show a wider range of organic richness (0.5–2.6 wt.%), while siltstones (green) are more uniform (~0.9–1.2 wt.%). Oligocene shales exhibit the highest TOC values.

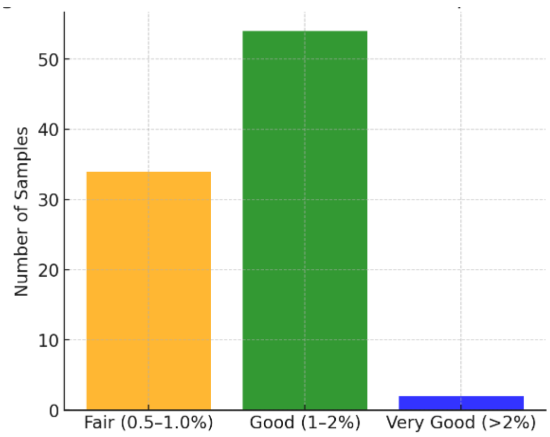

Figure 2. TOC classification of shale samples from Well A-1X, Nam Con Son Basin, based on Peters & Cassa (1994). The majority of samples fall into the Good category (1–2 wt.%), followed by Fair (0.5–1.0 wt.%). Only two samples exceed 2 wt.% TOC and are classified as Very Good.

These results suggest that although overall organic richness is modest, **Oligocene shales and associated siltstones are distinctly richer** and thus more significant for hydrocarbon generation.

3.2 Rock-Eval Pyrolysis

Rock-Eval pyrolysis was conducted on representative shale and siltstone samples. Rock-Eval results indicate Type II/III kerogen with Tmax in the early oil window (Table 2).

- **Shale HI values** range from **180–260 mg HC/g TOC** (Figure 3), consistent with **mixed Type II/III kerogen**, capable of generating both oil and gas.
- **Siltstones** yield slightly lower HI values (~150–200), reflecting a stronger terrestrial component.
- **Tmax values** range from **432–445 °C** (Figure 3), with shallower Miocene shales plotting at 430–434 °C (immature–early oil), and Oligocene samples showing higher values of 437–445 °C, consistent with the early oil window.

Table 2. Rock-Eval pyrolysis parameters of representative shale and siltstone samples

Lithology	Depth (m)	TOC (wt.%)	HI (mg HC/g TOC)	OI (mg CO_2/g TOC)	Tmax (°C)	Kerogen Type
Shale	3100	1.2	220	15	432	II/III
Shale	3600	1.4	240	18	438	II/III
Shale	3790	2.0	260	12	445	II/III
Siltstone	3255	1.0	170	22	439	III

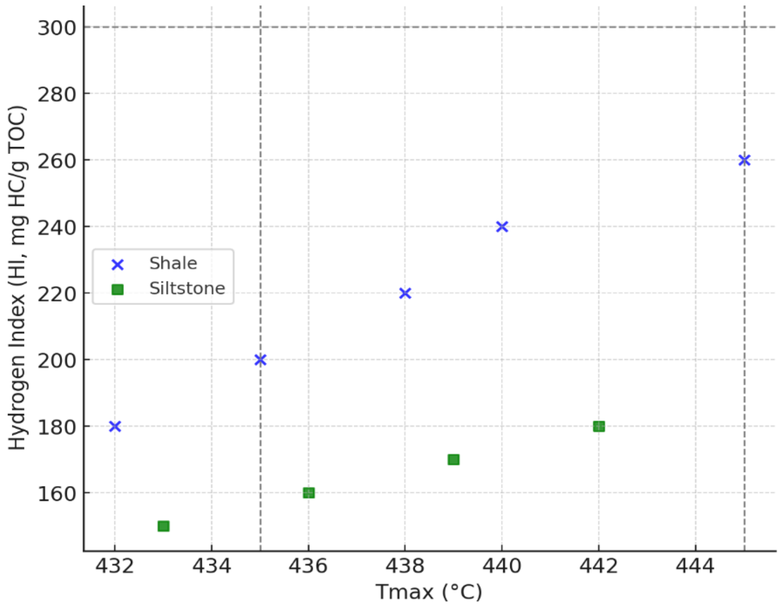

Figure 3. Cross-plot of Hydrogen Index (HI) versus Tmax for shale (blue) and siltstone (green) samples from Well A-1X. Most samples fall within the range of mixed Type II/III kerogen, indicating oil–gas prone character. Tmax values (432–445 °C) confirm that Oligocene shales are within the early oil window, while Miocene shales remain immature to marginally mature.

3.3 Vitrinite Reflectance (%Ro)

A total of **31 samples** were analyzed for vitrinite reflectance. Maturity increases with depth, from immature Miocene shales to early oil Oligocene shales (Table 3, Figure 4).

- **Miocene shales (n = 13):** %Ro ranges from **0.31–0.52**, with a mean of **0.44%Ro**, classifying as **immature to marginally mature**.
- **Oligocene shales (n = 18):** %Ro ranges from **0.46–0.62**, with a mean of **0.57%Ro**, firmly within the **early oil window**.
- **Siltstones:** Although limited in number, vitrinite reflectance values (~0.48–0.55%Ro) are comparable to adjacent shales, reflecting similar maturity.

Table 3. Vitrinite reflectance (%Ro) values of shale samples

Stratigraphic Unit	Depth Interval (m)	%Ro Range	Mean %Ro	Maturity Interpretation
Miocene Shale	2200 – 3400	0.31 – 0.52	0.44	Immature to marginally mature
Oligocene Shale	3550 – 3850	0.46 – 0.62	0.57	Early oil window

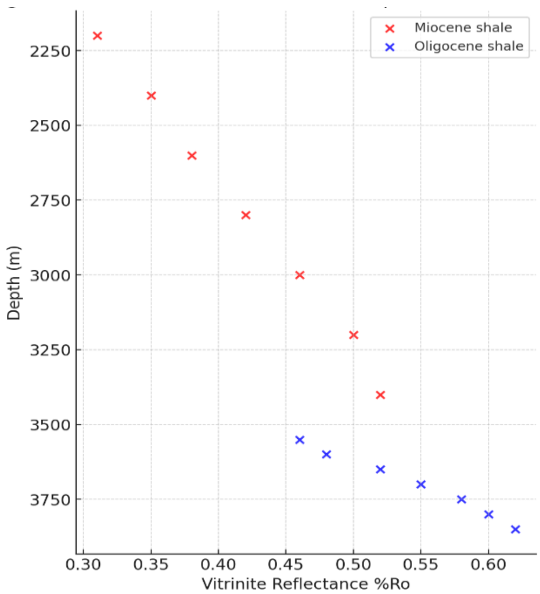

Figure 4. Depth profile of vitrinite reflectance (%Ro) in shale samples from Well A-1X. Miocene shales (red) are immature to marginally mature (0.31–0.52%Ro), whereas Oligocene shales (blue) are consistently within the early oil window (0.46–0.62%Ro). This maturity contrast highlights the Oligocene interval as the effective source rock.

Thermal maturity therefore increases consistently with depth, with hydrocarbon generation restricted to Oligocene intervals.

3.4 Biomarker Geochemistry

Biomarker ratios confirm mixed terrestrial–marine input under suboxic–oxic conditions (Table 4).

n-Alkane distributions (Figure 5)**:**

- Shallow Oligocene shale (3375–3380 m) shows strong dominance at **n-C17–n-C18**, typical of algal/marine input.
- Deeper Oligocene shale (3795–3800 m) exhibits enrichment in long-chain n-C25–C31, indicating higher-plant terrestrial input.
- Siltstones show intermediate distributions, consistent with mixed terrestrial–marine input.

Pristane/Phytane (Pr/Ph) ratios (Figure 6)**:**

- Shales: **4.32–8.69 (mean 6.27)** → indicative of **suboxic to oxic deltaic conditions**.
- Siltstones: ~**5–6**, similar to shales, confirming consistent depositional environment.

CPI values (Figure 6)**:**

- Shales: **0.93–1.16 (mean 1.03)** → close to unity, indicating **thermal maturity consistent with early oil generation**.
- Siltstones: ~**1.0**, similar to shales.

Table 4. Biomarker parameters for shale and siltstone extracts

Lithology	Depth (m)	n-Alkane Dominance	Pr/Ph	CPI	Interpretation
Shale	3375	n-C17–C18	4.3	0.94	Algal input, suboxic
Shale	3795	n-C25–C31	8.7	1.16	Terrestrial input, oxic
Siltstone	3255	n-C21–C25	5.4	1.02	Mixed input, suboxic

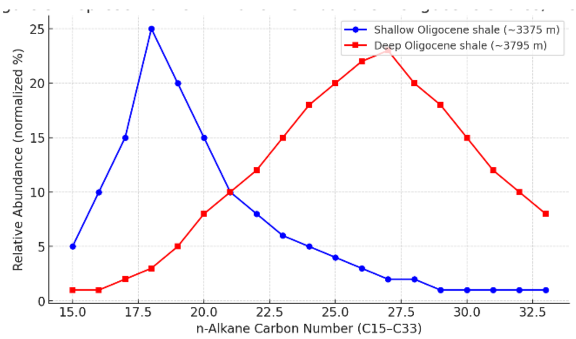

Figure 5. Representative n-alkane distributions from Oligocene shale extracts in Well A-1X. Shallow samples (~3375 m, blue) are dominated by mid-chain n-C17–C18, indicating algal/marine organic input. In contrast, deeper samples (~3795 m, red) show enrichment in long-chain n-C25–C31, reflecting terrestrial higher-plant contributions. This vertical shift illustrates changing depositional environments from more marine-influenced to terrestrial-dominated settings.

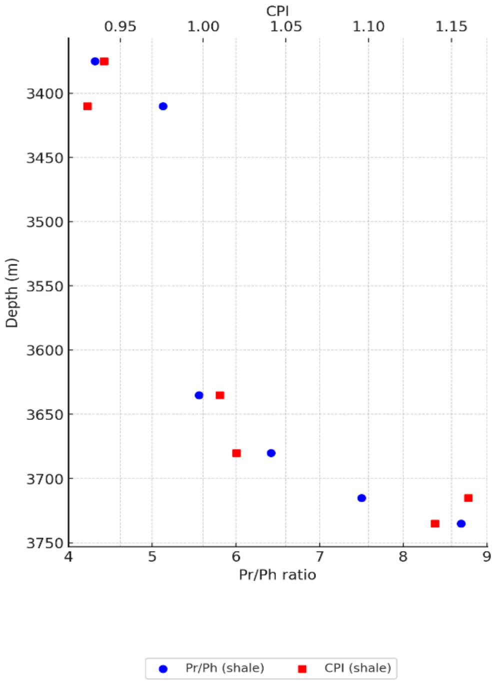

Figure 6. Depth profile of Pristane/Phytane (Pr/Ph, blue) and Carbon Preference Index (CPI, red) values for shale extracts from Well A-1X. Pr/Ph ratios increase with depth (4.3–8.7), suggesting increasingly oxic depositional conditions. CPI values remain close to unity (0.93–1.16), indicating early oil window maturity. Together, these proxies reflect mixed terrestrial and marine inputs under suboxic to oxic deltaic settings.

3.5 Summary of Results

1. **TOC:** Shales are Fair–Good source rocks (avg 1.10%), siltstones show consistent moderate enrichment (avg 0.99%). Oligocene richer (avg 1.30%) than Miocene (1.05%).
2. **Rock-Eval:** HI values (180–260) indicate mixed Type II/III kerogen. Tmax values confirm Oligocene maturity.
3. **Vitrinite Reflectance:** Miocene immature; Oligocene early oil window.
4. **Biomarkers:** Mixed marine and terrestrial input; Pr/Ph ratios 4–9; CPI ~1.0; depositional setting suboxic–oxic, deltaic to marginal marine.

4. DISCUSSION

4.1 Source Rock Quality of Shale and Siltstone Intervals

The geochemical results demonstrate that shale and siltstone intervals from Well A-1X possess **moderate but significant organic richness**. TOC values for shales (0.50–2.60 wt.%, mean 1.10 wt.%) place the majority of samples in the **Fair–Good** categories (Peters & Cassa, 1994). Although less rich than the coal seams (addressed separately), these values are comparable to effective source rocks in other Tertiary basins of Southeast Asia, such as the Malay and Pattani basins (Huc, 1995).

The fact that **Oligocene shales are distinctly richer** (mean TOC 1.30 wt.%) than Miocene equivalents (1.05 wt.%) indicates that **Oligocene successions represent the primary shale source interval**. Furthermore, the presence of two samples exceeding 2 wt.% TOC demonstrates localized intervals of "Very Good" quality source rock.

Siltstones, though limited in number (n = 4), consistently yield TOC values close to 1 wt.%. This suggests that even relatively coarser-grained facies can contribute organic matter preservation under favorable depositional conditions. While siltstones are unlikely to be volumetrically major sources, their consistent enrichment indicates they could play a **supplementary role** in hydrocarbon generation.

4.2 Thermal Maturity and Petroleum Generation Potential

Maturity parameters confirm that hydrocarbon generation is largely restricted to Oligocene strata. Miocene shales, with %Ro values of 0.31–0.52 (mean 0.44), are immature to marginally mature. This explains their limited source rock potential, acting more as **cap rocks** than active sources.

By contrast, Oligocene shales, with %Ro values of 0.46–0.62 (mean 0.57), are consistently within the **early oil window**. This maturity range is corroborated by Rock-Eval Tmax values (437–445 °C) and CPI values close to unity (mean 1.03). Such alignment across multiple parameters provides strong confidence that **Oligocene shales are actively generating hydrocarbons** in the Nam Con Son Basin.

Importantly, the hydrogen index (HI 180–260) indicates mixed Type II/III kerogen. This implies that Oligocene shales are capable of generating both oil and gas, depending on maturity progression. As burial continues in deeper depocenters, these shales may evolve from early oil generation into peak oil or even late gas generation stages.

4.3 Depositional Environment and Organic Matter Input

Biomarker evidence provides valuable insights into the depositional setting of shale and siltstone intervals:

- **n-Alkane distributions** show a vertical transition from algal/marine input in shallower Oligocene shales (n-C17–C18 dominance) to terrestrial higher-plant input in deeper Oligocene shales (n-C25–C31 enrichment). This indicates a shift from more open marine influence to deltaic or coastal swamp environments.
- **Pristane/Phytane ratios** (4–9) reflect deposition under suboxic to oxic conditions, characteristic of **delta-front to marginal-marine settings**. Such conditions allow for the preservation of both marine algal material and terrestrial input, explaining the mixed kerogen character.
- **Siltstones** show intermediate biomarker characteristics, suggesting deposition in similar settings with slightly higher energy, which still permitted moderate organic matter preservation.

These results collectively point to a depositional model in which **Oligocene shale and siltstone successions represent deltaic to marginal-marine facies with fluctuating terrestrial and marine contributions**. Such settings are globally recognized as prolific for mixed Type II/III source rocks (Tyson, 1995).

4.4 Regional Comparisons and Analogues

The Nam Con Son shale and siltstone intervals compare favorably with other Southeast Asian basins:

- **Malay and Pattani basins:** Oligocene shales (TOC 1–3 wt.%, kerogen II/III) contribute significantly to oil charge despite coal dominance (Huc, 1995). A-1X shales (TOC 0.5–2.6 wt.%, kerogen II/III) fall within this range.
- **Song Hong Basin (northern Vietnam):** Shales there typically yield lower TOC (~0.5–1.5 wt.%) and are more gas-prone (Le et al., 2011). By comparison, Nam Con Son shales appear slightly richer and more oil-prone.
- **Global analogues:** The geochemical profile of A-1X shales—TOC ~1 wt.%, Type II/III kerogen, early oil maturity—is similar to productive shale source rocks in basins such as the North Sea (Cornford, 1998) and parts of the Gulf of Mexico.

These comparisons highlight that Nam Con Son shales and siltstones, though moderate in TOC, are **geochemically typical of effective secondary source rocks**.

4.5 Petroleum System Significance

The integration of TOC, %Ro, Rock-Eval, and biomarker data demonstrates that shale and siltstone intervals play an important **secondary role** in the Nam Con Son petroleum system.

1. **Supplementary oil charge:** Oligocene shales provide an oil-prone component that complements the gas-prone coals. This dual source explains the presence of oil, condensate, and mixed hydrocarbon accumulations in discovered fields.
2. **Stratigraphic continuity:** Unlike coals, which are restricted to specific swamp facies, shales and siltstones are regionally extensive, providing a more continuous source rock across the basin.
3. **Unconventional potential:** Although TOC values are modest compared to North American shale plays, deeper parts of the basin (>4000 m) may contain Oligocene shales with higher maturity, enhancing their potential for unconventional resource development.

4.6 Exploration Implications

From an exploration standpoint, several implications arise:

- **Conventional plays:** Petroleum system models should explicitly include shale-derived oil charge when assessing Oligocene sandstone reservoirs sealed by intraformational shales.
- **Risk reduction:** Acknowledging shale contribution reduces dependence on coal continuity and enhances exploration confidence in areas where coal seams are thin or absent.
- **Frontier opportunities:** Deeper depocenters, where Oligocene shales are expected to be in the peak oil window, should be investigated for both conventional oil charge and unconventional shale oil potential.

4.7 Limitations and Future Work

This study has several limitations. Many samples analyzed are derived from drill cuttings, raising the possibility of contamination from caving. The number of siltstone samples (n=4) is limited, preventing robust statistical conclusions. Furthermore, Rock-Eval data were not available for every sample, and sterane/hopane biomarker ratios were not fully investigated.

Future research should focus on **basin modeling** to reconstruct burial and generation histories, coupled with more extensive biomarker analysis (including sterane and hopane distributions) to refine source facies correlations.

5. CONCLUSIONS

This study provides the first integrated geochemical evaluation of shale- and siltstone-dominated intervals from **Well A-1X, Nam Con Son Basin**, with the following key conclusions:

1. **Organic richness:** Shales display TOC values ranging from 0.50–2.60 wt.% (mean 1.10 wt.%), with most samples classified as Fair–Good. Siltstones yield consistent TOC values around 0.99 wt.%. Oligocene shales (mean 1.30 wt.%) are richer than Miocene equivalents (mean 1.05 wt.%), marking the Oligocene succession as the primary shale source rock interval.
2. **Kerogen type and Rock-Eval data:** Hydrogen index (HI 180–260 mg HC/g TOC) indicates mixed Type II/III kerogen, suggesting both oil- and gas-prone potential. Tmax values (437–445 °C) confirm Oligocene shales are thermally mature within the early oil window.

3. **Thermal maturity:** Vitrinite reflectance (%Ro) increases with depth, from 0.31–0.52%Ro (Miocene, immature to marginally mature) to 0.46–0.62%Ro (Oligocene, early oil window). This demonstrates that only Oligocene shales are currently effective hydrocarbon sources.
4. **Depositional environment:** Biomarker evidence shows mixed marine–terrestrial input. n-Alkane distributions shift from algal dominance in shallow Oligocene intervals to terrestrial higher-plant enrichment in deeper sections. Pr/Ph ratios (4–9) indicate suboxic to oxic deltaic settings, and CPI values (~1.0) are consistent with early oil generation maturity.
5. **Petroleum system significance:** Shales and siltstones, though less rich than coals, are regionally extensive and contribute significantly to the petroleum system. They act as **secondary but crucial oil-prone sources**, complementing coal-derived gas and explaining the presence of oil and condensate accumulations in the Nam Con Son Basin. Their widespread distribution also reduces exploration risk and offers future opportunities for unconventional shale resource evaluation in deeper depocenters.

6. ACKNOWLEDGEMENTS

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