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A review of silurian shale gas potential in North Africa's paleozoic basins: geological framework, resource assessment, sustainability outlook

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ABSTRACT

North Africa hosts some great, prolific Paleozoic basins with significant shale gas potential, particularly within the Silurian "Hot Shale" formations. In this review, we assess the unconventional resource prospectivity of key North African basins by evaluating their organic richness, thermal maturity, and mineralogical composition, framing their development potential within a global context. By synthesizing published literature, industry reports, and geochemical datasets, this study identifies the key parameters controlling shale gas potential. The Rhuddanian, Ludlow Pridoli, and Frasnian Hot Shale intervals record total organic carbon (TOC) contents typically ranging from 2-14 wt%, with localized peaks exceeding 20 wt%. Kerogen is dominated by Type II/III mixtures, while vitrinite reflectance values indicate maturity levels spanning early oil to dry gas windows. Mineralogical analyses reveal substantial quartz and carbonate fractions, enhancing brittleness and hydraulic fracturing potential. Marked variability is observed across the basins, reflecting differences in depositional settings, structural evolution, and post-depositional thermal histories. The Ghadames and Berkine basins host the richest and most mature intervals, whereas the Jaffara and Chotts basins have- less uniform successions. Beyond resource quality, environmental risks, including groundwater contamination, methane emissions, and induced seismicity, remain a key challenge. These challenges require basin-specific evaluation approaches that integrate standardized geochemical datasets, basin-scale petrophysical modeling, and real-time environmental monitoring to constrain resource quality and associated risks. Future development strategies may also incorporate carbon capture and utilization (CCU) within depleted reservoirs to reduce CO_2 emissions associated with shale gas exploitation. Integrating these insights with reservoir-scale mapping and petrophysical modeling provides a basis for optimizing hydrocarbon recovery and long-term CO_2 storage in North African basins.

Keywords: Thermal maturity, Hydrocarbon, Hot Shale, Gas, North Africa.

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1. INTRODUCTION

Over the past century, there has been a dramatic increase in demand for cleaner energy, particularly the economically and technologically viable resources, especially the unconventional reserves. Among these, shale gas has emerged as a major focus

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due to its widespread occurrence in sedimentary basins worldwide [1]. These shale gases, usually hosted in organic-rich fine-grained rocks, act as the source, reservoir, and seal simultaneously, unlike conventional reservoirs that rely on porous and permeable formations. Technological advancements, particularly in horizontal drilling and hydraulic fracturing, have enabled some successful developments of the resources recently in some U.S. basins such as Barnett, Woodford, and Eagle Ford [2]. These successes have stimulated a global growing interest, especially across the North African basins [3–8].

However, despite these challenges, shale gas reservoirs pose difficulty in characterisation due to their fine-scale heterogeneity and low porosity and permeability, often limiting the existing traditional evaluation methods. Improvements in the science of petrophysics and geochemistry, like chemostratigraphy and spectral log analysis, have helped in these assessments and risk reduction [9–11]. Despite that, problems such as water scarcity, induced seismicity, and socio-political resistance remain barriers to large-scale development [12, 13]. The U.S. shale exploration program provides useful models for sweet spot identification and resource estimation [11, 14–18]. Due to their continuous accumulation and challenging petrophysical properties, shale reservoir development demands tailored exploration strategies [19]. For instance, the vast Paleozoic Ghadames Basin, spanning Algeria, Libya, and Tunisia, has been assessed at 42.8 Tcf of wet gas and 176.2 Tcf of associated gas [20, 21].

This review synthesizes geological and technological insights into North Africa's shale gas potential, emphasizing Algeria and Libya's prolific prospects, and the emerging but technically constrained plays in Tunisia and Morocco. Peer-reviewed papers and reports associated with shale gas development were critically reviewed using global analogues in other to significantly identify research gaps, particularly in the lack of integrated basin-wide petrophysical, geochemical modeling, real-time environmental monitoring studies, and regional standardization of data.

2. REGIONAL GEOLOGY AND PETROLEUM SYSTEMS

Pan-African orogenies in the late Neoproterozoic (ca. 870-550 Ma) marked the final assembly of the Gondwana supercontinent commonly referred to as the Pannotia in North Africa [3]. This orogenic cycle set the stage for the region's Phanerozoic evolution, which is typically divided into three major tectonic phases (see Figure 1). A comparative outlook on the similarities and differences among these Paleozoic basins is presented in Table 1. While many of these basins share stratigraphic and geochemical characteristics, their petroleum generation, migration, and entrapment have been shaped by basin-specific tectonic histories [22].

One of the most prominent source rocks is the Lower Silurian hot shale, which is regionally equivalent to the Tanezzuft Formation within the Ghadames Basin and the Akkas/Acacus intervals in Libya. This unit formation is well known for its exceptional marine organic richness reaching up to ~18% TOC as well as for its broad geographical distribution across North Africa and into the Arabian Peninsula [11, 22]. Additionally, these hot shales display a high nuclear logging response, with gamma-ray values as high as 1,400 API, indicative of their high organic content and radioactive mineral presence [23]. These features underpin its well-documented effectiveness in generating and expelling large volumes of petroleum [24].

The Silurian hot shale and its equivalents (Tanezzuft/Akkas/Acacus formations, Marzuk Basin, etc.) across the North African Basin are regionally significant, organic-rich stratigraphic units commonly situated at the base of the Silurian sequence across the North African Basin (Figure 2). They can be sharply differentiated from the other adjacent cold shales owing to their high total organic carbon (TOC), ranging 2-17.5% (average 4-6%; Table 1). This characteristic allows for its easy identification in the subsurface profiles by enhancing its utility through regional stratigraphic correlation and petroleum exploration. Several North African basins, particularly the Ghadames and Murzuq basins, the Silurian hot shale represents the principal source rock that is widely accepted as the primary contributor to the hydrocarbon charge of Paleozoic reservoirs with maturity levels up to 2.4% Ro and dry-gas windows reached at burial depths of ~4-5.2 km [3, 25]. Its lateral continuity, coupled with qualitative geochemical characteristic have drawn comparisons to North America's prolific Barnett and Marcellus shale plays. Accordingly, it has been globally ranked among the top significant source rocks [5], while increasingly recognized as a strategic component of North Africa's unconventional hydrocarbon reserves (see Figure 1).

The sequence stratigraphic framework shown here in Figure 3 constrains the depositional setting of the Lower Silurian hot shales in the Jaffara Basin, presenting it as a regionally extensive and organic-rich interval linked to relative sea-level variations. Despite their shared tectonostratigraphic framework (Figure 3), these basins exhibit diverse hydrocarbon systems shaped by local tectonics, depositional environments, and thermal histories. Their further evaluation has potential in the conventional development as well as the emergence of competitive unconventional plays in the global energy landscape.

2.1. STRATIGRAPHIC AND GEOCHEMICAL CHARACTERISTICS OF TUNISIAN HOT SHALE UNITS AND GHADAMES BASIN

The Silurian and Devonian hot shales of southern Tunisia, notably from the Rhuddanian, Ludlow, Pridoli, and Frasnian intervals, constitute essential petroleum source rocks with considerable potential for unconventional hydrocarbon production. These formations exhibit notable mineralogical, geochemical, and thermal properties, with basin-specific variation that contributes to regional exploration strategies. The main tectonic domains of Morocco are the Atlas Mountains, Anti-Atlas, Mediterranean and Atlantic margins, Rif, and Mesetas domains (Figure 1: [26]). The Tarfaya Basin in Morocco is identified as a prolific basin and has more oil shale with limited gas potential that has a carbonate build-up from Triassic to Late Jurassic age [27]. The Jaffara Pelagian Basin has Triassic-Quaternary fill influenced by Alpine and Tethyan tectonics (Figure 3, Figure 4). Source rocks include Jurassic black shales (~2% TOC), Lower Cretaceous and Albian shales (up to 10% TOC), and Cenomanian-Turonian Bahloul Formation (7-13% TOC).

2.1.1. Case 1. Rhuddanian hot shales

The Rhuddanian Hot Shales are distributed southward to the TTPB structural high within the Berkine and Jaffara Basins, with

Table 1. Summary of key North African shale basins (Lucci and Bosworth, 2018).

Basin	Countries Involved	Main Formations	Est. TRR (Tcf)	TOC (%)	Thickness (m)
Ghadames	Algeria, Libya, Tunisia	Tanezzuft	140-200	4-8	20-50
Berkine	Algeria	Silurian, Ordovician	150+	3-6	30-70
Illizi	Algeria	Tanezzuft	100+	5-10	40-100
Sirte	Libya	Tanezzuft	~70	3-7	25-60
Tanezzuft	Algeria, Morocco	Unconventional Units	~50	2-5	10-40
Tarfaya	Morocco	Oil Shale Layers	<12	3-6	20-30

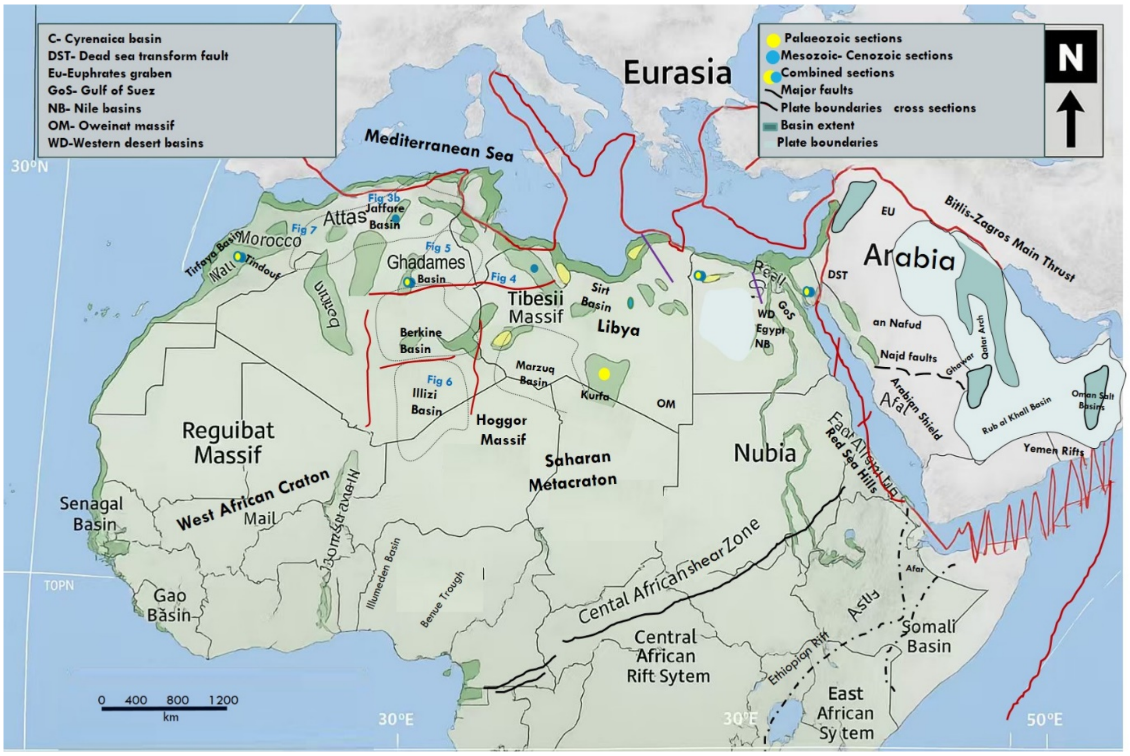

Figure 1. Major sedimentary basins of North Africa and their principal structural features. The map shows basin distribution, major faults, plate boundaries, and tectonic domains. Outlined blue Fig lines indicate the locations of Figures 3. Modified after Refs. [28, 29].

thicknesses ranging from 0 m to 160 m [5]. In the Berkine Basin, they attain 25-125 m, while in the Jaffara basin, thickness is generally between 25 m and 35 m (Figure 5). Mineralogically, these shales are enriched in brittle components, 40% quartz, 50% carbonate, and 20% pyrite with 35% clays including illite, chlorite, and kaolinite. High uranium enrichment factors (1-4.6) correlate well with Gamma Ray (GR) log iso-values, reflecting enhanced redox conditions and organic matter preservation (Figure 6). Good correlations are found between high uranium enrichment factors (1-4.6) and Gamma Ray (GR) log iso-values and indicate the presence of good redox conditions and preservation of organic matter (Figure 6). Thermal maturity based on vitrinite reflectance (Ro%) as well as Tmax data ranges from 0.65 to 1.85 (Figure 7). This ultimately divides the Berkine Basin into five maturity zones: (1) immature, (2) oil window, (3) peak oil, (4) late oil/wet gas, and (5) wet gas/dry gas. Vertical TOC and GR profiles from wells such as AMC-1, OZ-1, and HWA-1 suggest large lateral heterogeneity of organic richness. Their depths range from 3200 m in the north (e.g., CEM-1) to over 4475 m in the southeast (SET-1), suggesting a significant shale gas/oil potential.

2.1.2. Case 2. Ludlow-Pridoli (Haj Brahim) hot shales

The Ludlow - Pridoli Hot Shales, also referred to as the Haj Brahim Formation, are principally distributed northward of the TTPB structural high, predominantly in the Southern Chott Basin. These shales are geochemically and stratigraphically analogous to the Rhuddanian Hot Shales and have been proposed as the principal source rock for fields like Hassi Messoud (Balducchi & Pommier, 1970). Their thickness varies between 15 m and 100 m, with burial depths averaging 3500 m and increasing northward (Figure 8). As characterized, they have high natural radioactivity (up to 250 API), they also exhibit Ro% values from 0.7 to 1.0, placing them within the oil generation window [4].

2.1.3. Case 3. Frasnian hot shales

The Frasnian Hot Shales, which are relatively unexplored until recently, are important source rocks for the Devonian, and there are two distinct organic-rich intervals, which are probably correlated with the Kellwasser anoxic events [30]. Located in Southern Tunisia, they have been recently characterised by SpectroLith logging and Elemental Capture Spectroscopy (ECS),

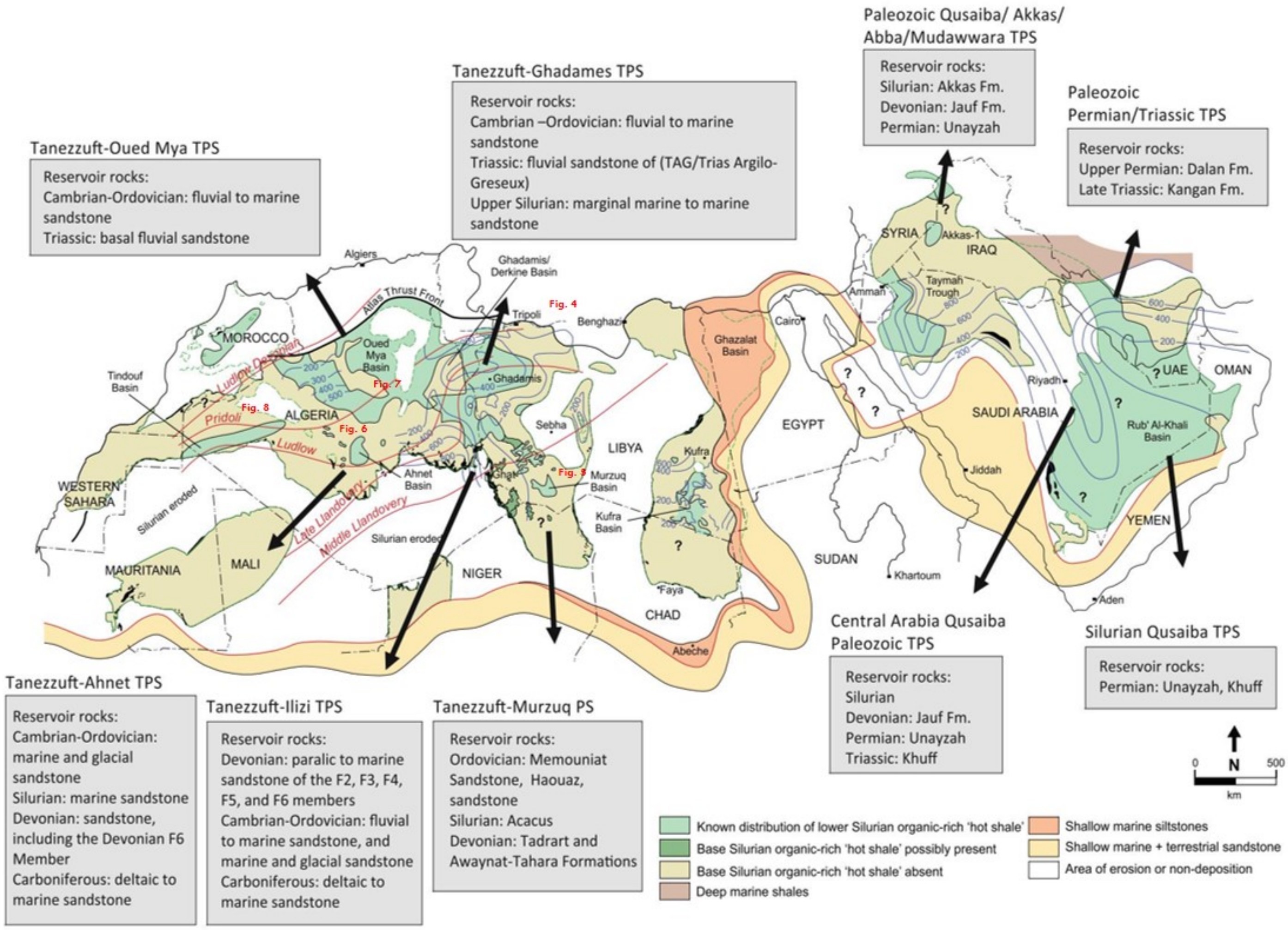

Figure 2. Distribution of the Silurian source rock and related petroleum systems after Ref. [24].

which shows the presence of high concentrations of quartz, pyrite and low clay content (Figure 9). These shales also exhibit prominent vertical variations in Si, Fe, Ca, K, U, and Th concentration, providing information on the depositional conditions (Figure 10).

A noticeable Th/K ratio is characteristic of a Frasnian unconformity, which is consistent with the regional events in the Berkine Basin as well as in other parts of North Africa basins [22, 31, 32] (Figure 10). Maturity levels range from 0.55% Ro in the northeast to 1.2% in the southwest, transitioning from late oil to wet gas window.

3. METHODOLOGY

This review adopts a multidisciplinary and integrative approach, combining qualitative and quantitative assessments to evaluate the shale gas potential of Paleozoic basins in North Africa. It involves a systematic synthesis and analysing collection of relevant materials from multiple sources, including:

1. Literature was retrieved between April and October 2025 from Web of Science, Scopus, and Google Scholar using keyword combinations such as "Silurian hot shale", "Tanezzuft Formation", "North Africa", "organic-rich shale", "TOC", "Rock-Eval", "thermal maturity", and "paleoenvironment". Only peer-reviewed articles from high-impact journals were considered, and reference lists of selected studies were screened for additional sources, e.g., [5, 21, 33].

2. Technical reports and industry publications, such as those from the [28, 29], national petroleum agencies, and confidential petroleum industry datasets, where available.

3. Studies included: (i) focused on the Silurian interval in North Africa, particularly the Ghadames Basin, Silurian hot shale, North Africa, and its equivalents, and (ii) reported primary geological, geochemical, or petrophysical data relevant to organic matter enrichment and gas potential. Studies lacking primary data, outside the study scope, or non-peer-reviewed were excluded.

4. Rock-Eval pyrolysis data, vitrinite reflectance (%Ro), X-ray diffraction (XRD), Elemental Capture Spectroscopy (ECS), and logging tools (SpectroLith, Gamma Ray, Resistivity, Neutron logs), which were interpreted from published datasets and figure-based analysis.

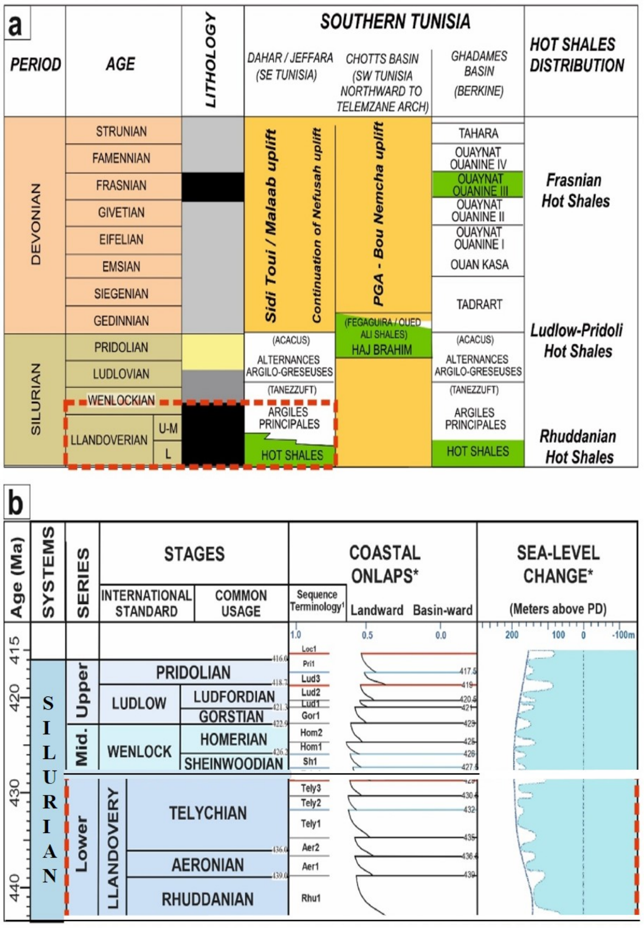

Figure 3. (a) Lithostratigraphy and (b) sequence stratigraphic framework of the Lower Silurian hot shales in the Jaffara Basin. Sea-level variations expressed in metres above present-day sea level (PD). Modified after Ref. [5, 33].

3.1. DATA EXTRACTION AND ANALYSIS

The key parameters used in extracting information from selected studies include the following: location, stratigraphy, Total Organic Carbon (TOC), Rock-Eval data (S1, S2, Tmax, Hydrogen Index), thermal maturity indicators, mineralogical composition, and depositional environment interpretations. Where possible, datasets were standardized to enable cross-basin comparison.

3.2. LIMITATIONS

Limitations include uneven spatial data distribution, variability in analytical methods, and differences in data resolution among studies, which may introduce uncertainty in regional comparisons.

4. DISCUSSION

4.1. GEOLOGY, GEOCHEMISTRY, PETROPHYSICS SYNTHESIS

The Silurian Hot Shale formations across North Africa basins represent a promising unconventional hydrocarbon system with complex geological, geochemical, and petrophysical characteristics. They exhibit high total organic carbon (TOC), generally ranging between 2-14%, with basin-specific averages around 4-6% in the Ghadames and Murzuq basins, and slightly lower values (~2-3%) in uplifted margins such as Cyrenaica and Kufra. While substantial data have been generated across the Ghadames, Jaffara, and Chotts Basins, a synthesized, basin-wide comparative assessment remains underexplored. In this section, the geochemical and petrophysical characteristics of Silurian hot shale units across North Africa are systematically analyzed and compared, with a particular emphasis on the basins of Tunisia, Algeria, and Libya (see Table 1).

Across the North African basins, thermal maturity varies significantly across the region. For example, in the deeper parts of the Ghadames and Murzuq basins, the hot shale has been recorded to have reached gas-window maturity, consistent with vitrinite reflectance values exceeding 1.2% Ro. However, this maturity interpretation cannot be uniformly applied region-wide. That is to say, in uplifted margin areas such as Cyrenaica and along the Kufra Basin flanks, the Silurian shale remains within the early oil to condensate window, with Ro values closer to 0.7-1.0%. These exceptions highlight the importance of particularly local tectonic and burial histories in controlling maturity. Consequently, even though the Silurian hot shale is widely regarded as the principal source rock of North Africa, basin-specific differences in TOC averages, kerogen type, and maturity windows underline the need for careful calibration in petroleum system models.

The Ghadames Basin has received considerable attention recently, including studies such as [11, 21], which applied Rock-Eval pyrolysis (Figure 12), thermal maturity modelling, and 1D-3D basin modelling to delineate shale gas sweet spots. They found TOC values ranging from 2% to 17.5%, averaging 6-8% (Figure 14) with Hydrogen Index (HI) (Figure 12) between 50 and 750 mg HC/g TOC, and maturity levels (%Ro) reaching up to 2.45%. This places parts of the basin within a dry gas window at depths of 4000-5200 m, Figure 15. Notably, their regional maturity maps and kerogen transformation ratios highlight thermal maturity gradients from basin margins to depocenters. This aligns with their finding of significant Gas-In-Place (GIP) estimates (120 bcf/km^2) and Retained Gas (TRG) values of up to 96 bcf/km^2, emphasizing the basin's dry gas potential. Overall, the hot shale thermal maturation study indicates a general maturation range from early to the post-mature stages with 0.45-2.45 %Ro and 380 °C-510 °C as pyrolysis temperature range.

Progressive maturity of the Early Silurian hot shale of the Ghadames Basin as a function of increased burial/depth and temperature is illustrated in the burial and thermal maturity model, Figure 15. Vitrinite reflectance values indicate a transition from early mature to over mature conditions across the basin, reflecting spatial variations in burial history and thermal regime. These observed maturity trends are consistent with regional depocenter development and support the interpretation of the Ghadames Basin as a mature to over-mature shale gas system.

Similarly, Ref. [33] have studied Jaffara Basin in south-eastern Tunisia, in which their work has revealed a much narrower maturity interval (0.4-1% Ro), though still being within the oil/gas generation threshold. The TOC values (0.54-23.86 wt%) have a mean value of 4-6%, with values of mg HC g^{-1} TOC (around 200 mg HC /g TOC) is indicative of mixed Type II/III kerogen. Petrophysically, quartz (~15%) and carbonate-rich intervals are consistent with moderate brittleness, which they com-

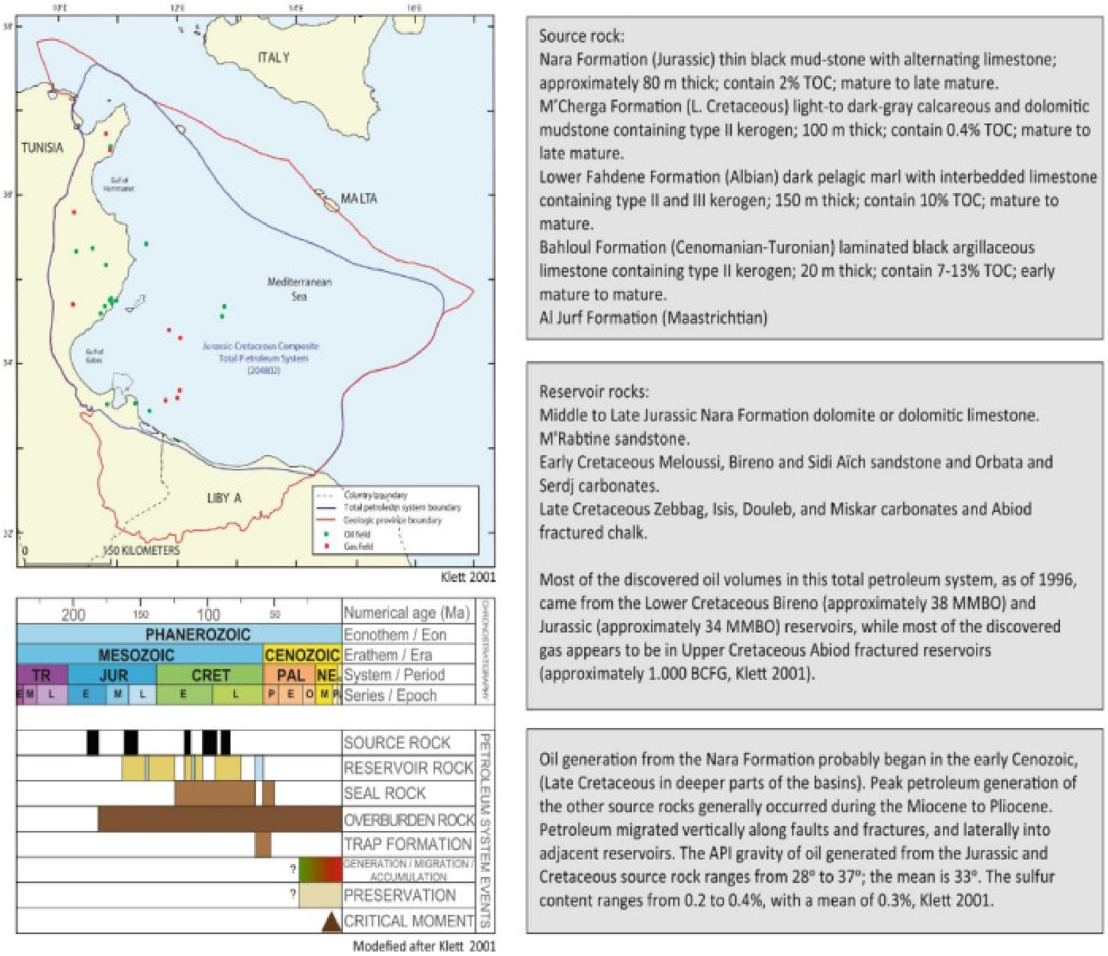

Figure 4. Pelagian Basin (offshore Libya and Tunisia) Jurassic-Cretaceous petroleum system after Luci and Bosworth 2019.

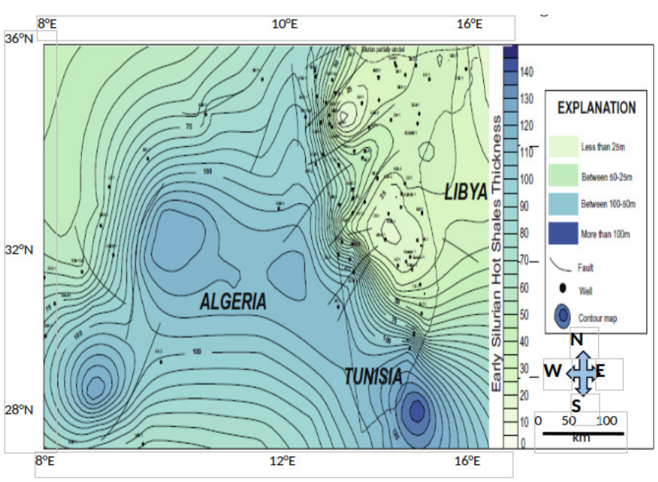

Figure 5. Thickness distribution map of the Early Silurian Rhuddanian hot shale unit. Modified after Ref. [5].

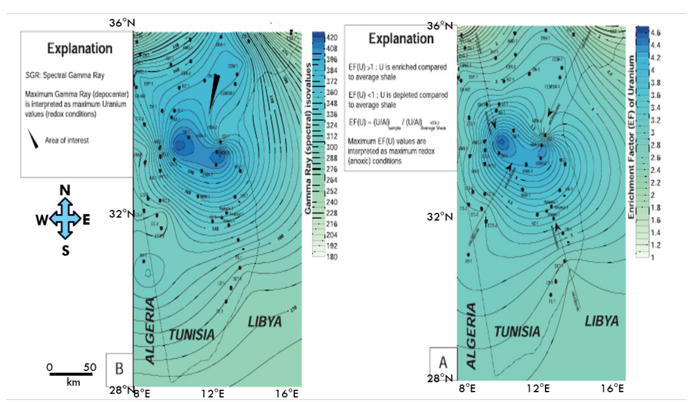

Figure 6. (A) Mean Uranium enrichment factor [EF(U)] distribution map, with maximum values interpreted as maximum redox conditions. (B) Gamma ray distribution. Modified after Ref. [5].

pared to analogues in the US like the Floyd Shale. Particularly, only 2 out of 3 analysed wells (B and M) had OSI values >100%, indicating that they had saturated with producible intervals suitable for hydraulic fracturing. These designated the Jaffara Basin to be a good, although still early stage, oil shale play in comparison to that of the more gassy Ghadames Basin in the area under study.

Meanwhile, Ref. [5] has undertaken a detailed re-evaluation of the Paleozoic shale systems of southern Tunisia and Algeria based on spectral gamma-ray and spectrolith, and ECS logs in order to get the mineralogical profiles, Figures 9 and 11. This

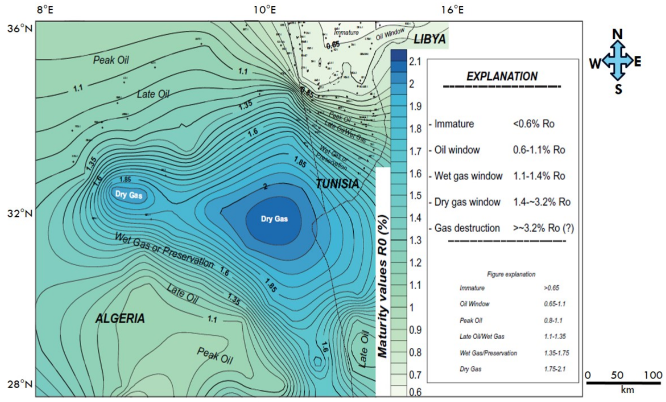

Figure 7. Maturity contour map of the Early Silurian hot shale (Ro%) with vitrinite reflectance values converted from Tmax values. Modified after Ref. [5].

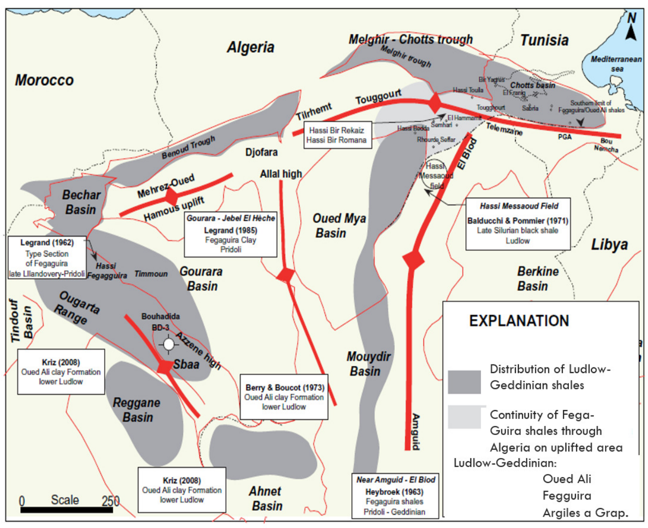

Figure 8. Ludlow-Pridoli organic rich (hot) shales distribution within North Africa (Modified after Ref. [5]).

approach provided a framework for refining the delineation of hot vs. cold shale intervals, thermal maturity zoning, and TOC variation across multiple wells (Figure 16). His work provides a geochemically and petrophysically rich dataset; however, it is yet underutilised in its integrated use for shale play analysis. In addition, Ref. [24] highlighted the importance of paleoenvironmental controls, e.g., eustatic sea-level fall, microbial mats, and marine snow macro aggregates that enabled OM preservation across North Africa. These broader depositional insights complement the geochemical findings and offer a predictive framework for identifying new sweet spots.

Despite this growing body of knowledge, knowledge remains fragmented, with limited cross-basin standardization and integration. There exist differences with some similarities amongst these range-wide basins . For instance, while Albriki *et al*. (2023) applied advanced basin modelling to the Ghadames Basin, similar workflows have not yet been broadly replicated in Tunisia or Morocco. The petrophysical comparability across basins also remains unclear, particularly regarding mineral brittleness indices, porosity-permeability relationships, and hydraulic fracturability. Furthermore, limited attention has been paid to integrating high-resolution biostratigraphy and chemostratigraphy with geochemical models, which could improve stratigraphic correlation and predictivity.

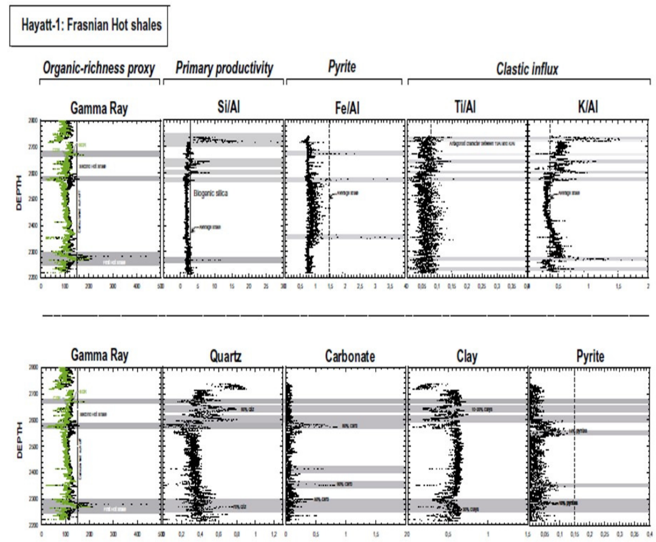

Figure 9. SpectroLith logging and Elemental Capture Spectroscopy (ECS) showing quartz, pyrite, carbonate and clay contents as well as major elements (e.g. Al, Fe, Si, K, Ti) for the Frasnian Hot shale intervals in the HYT-1 well, adopted from Ref. [5].

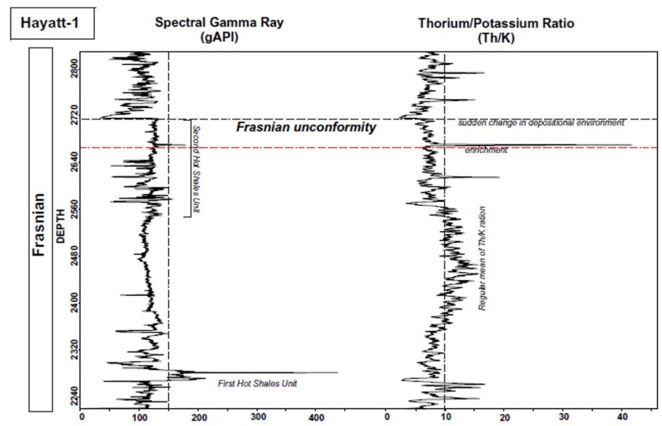

Figure 10. Results of gAPI and Th/K ratio showing the position of the Frasnian unconformity just above the two Hot shale levels equivalent of the Kellwasser anoxic events [5].

4.2. CROSS-BASIN RANKING AND INSIGHTS

Within the North African basins ranked by gas potential, the Ghadames basin leads due to its high maturity, large GIP estimates of 120 bcf/km^2, and Retained Gas (TRG) values up to 96 bcf/km^2, underscoring its strong dry gas potential. The extensive dry gas window makes it technically attractive for commercial unconventional gas exploitation. Jaffara basin, on the other hand, is the second with mixed potential of oil and gas with moderate brittleness, but still an earlier stage play with a need for targeted optimization of hydraulic fracturing.

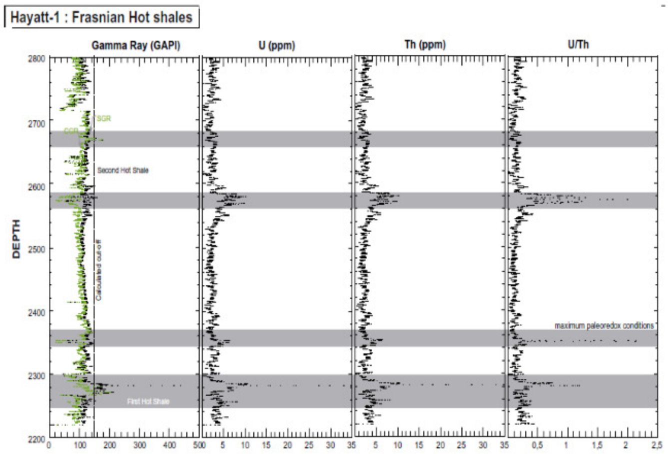

Figure 11. Gamma ray, total organic carbon and mineralogy (quartz, chlorite and illite) vertical distribution in the EC-2 well [5].

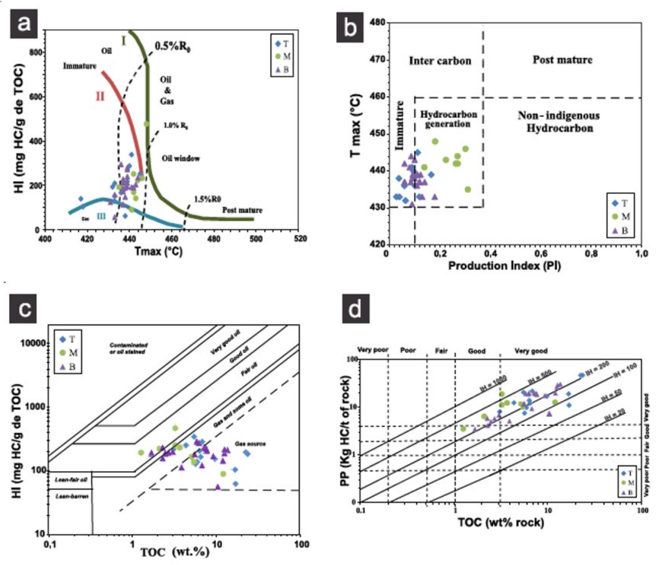

Figure 12. Integrated geochemical framework for identifying potential sweet spots. (a) Cross-plot of hydrogen index (mg HC g^{-1} TOC) versus Tmax used for organic matter type determination and thermal maturity assessment, including kerogen evolution pathways and vitrinite iso-reflectance curves. (b) Tmax versus production index (PI) diagram. (c) Cross-plot of hydrocarbon yield (mg HC g^{-1} TOC) versus TOC illustrating hydrocarbon generation potential (HGP). (d) Quantitative and qualitative source-rock assessment of the Tannezuft Formation in the studied wells (T, B, and M), showing organic matter type and petroleum potential. Modified after Ref. [33].

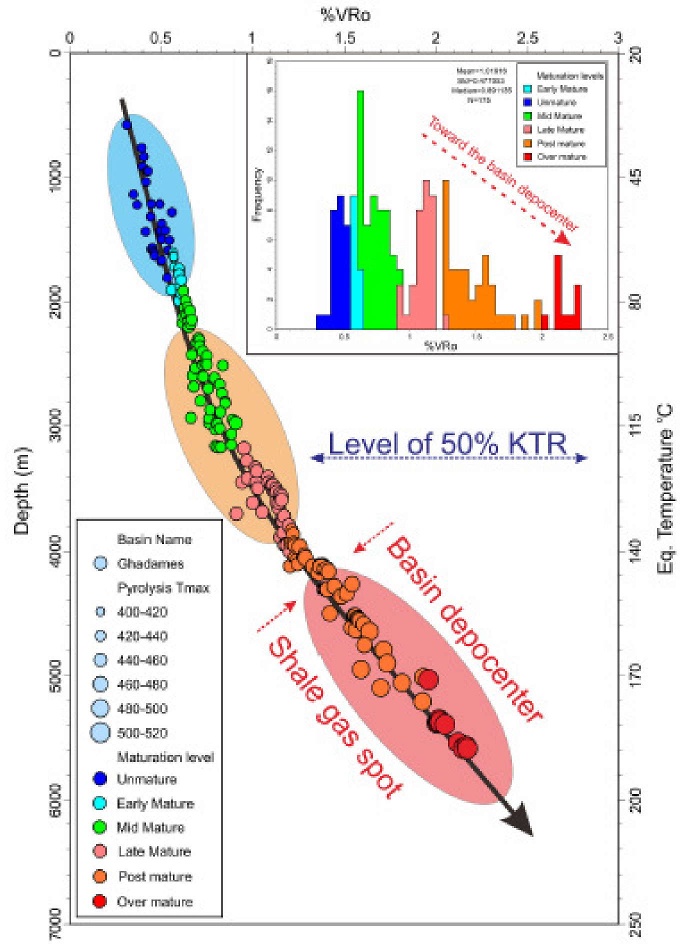

Figure 13. Maturation model of the hot shale in the Ghadames Basin based on key selected wells located in Libya, Algeria, and Tunisia. The top right frequency distribution represents the maturity range for each level of the 175 %Ro measurements used in this model. The kerogen transformation ratio (KTR), and the thermal and burial depth levels of the shale gas play of hot shale. Adopted from Albiriki 2023.

In terms of political and infrastructural feasibility, Ghadames suffers from cross-border geopolitical complexities; however, it has the benefit of an already developed exploration history. On the other hand, the smaller size and more localised development context at Jaffara could allow for more rapid early-stage deployment. Soua's integrated dataset from 2014, although not basin specific, has cross-cutting value that might add value to both plays if standardization is pursued.

4.3. RESOURCE ESTIMATES AND DISTRIBUTION

Estimation of Shale gas resource in North Africa has gained significant clarity in recent studies due to expanded exploration efforts, seismic surveys, and basin modeling reports [3, 11]. Countries like Algeria, Libya, Tunisia, and Morocco exhibit varying levels of technically recoverable resources, with Algeria being the most prominent contributor. According to a 2024 global overview by [26], Algeria and Libya together account for the majority of the region's recoverable shale gas reserves, positioning them as central players in Africa's unconventional energy landscape.

Algeria holds the third-largest shale gas reserves globally, with TRR estimated at ~706 Tcf. These resources are concentrated in the Ahnet, Illizi, Berkine, Timimoun, and Tindouf basins. The Lower Silurian shales in the Ghadames Basin (Tanezzuft Formation) serve as the primary source rock, with total organic carbon (TOC) values of 2-12% (average ~5%) and maturity between 1.0-2.2% Ro, placing much of the interval in the dry-gas window at depths of ~3.8-5.0 km (Lučić & Bosworth, 2019). While the EIA (2013) had estimated Algeria's TRR at ~707 Tcf, recent refine-

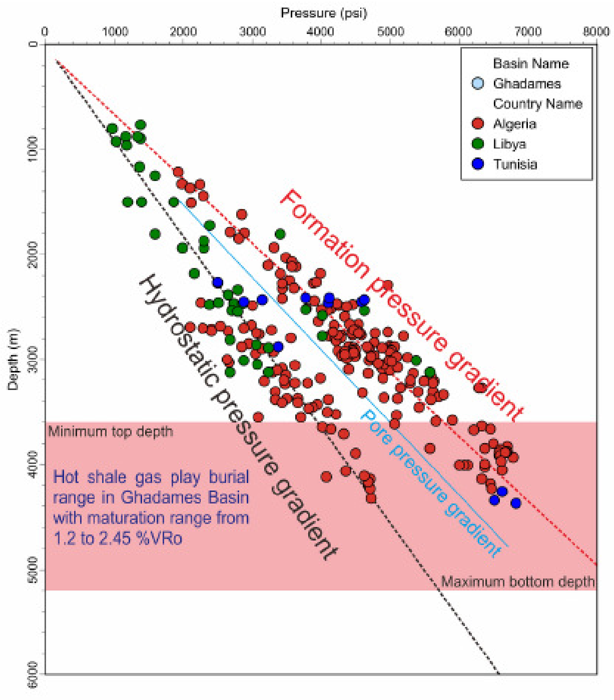

Figure 14. Model showing formation pressure versus burial depth (m) of Ghadames Basin from key selected wells (n = 57). The minimum and maximum burial depth defined here are mainly based on the maturity stages that define the presence of shale gas play of the hot shale in the Ghadames Basin (generally, >1.2 %Ro) [11].

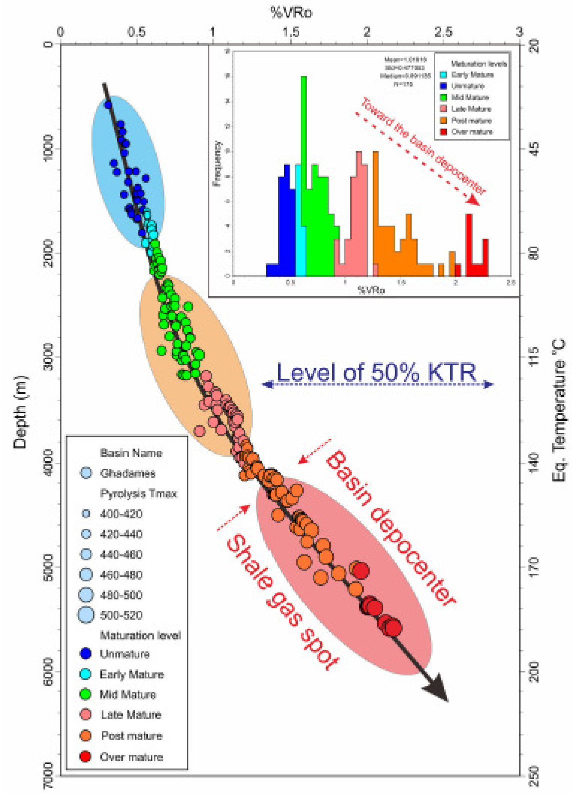

Figure 15. Burial and thermal maturity model of the Early Silurian hot shale in the Ghadames Basin based on selected wells from Libya, Algeria, and Tunisia. The diagram illustrates the evolution of vitrinite reflectance (%Ro) with burial depth and temperature, highlighting maturity stages and shale gas sweet-spot intervals. The inset histogram shows the frequency distribution of %Ro values defining the maturity ranges used in the model. Kerogen transformation ratio (KTR), burial depth, and thermal maturity thresholds relevant to shale gas generation are also indicated. Modified after [21].

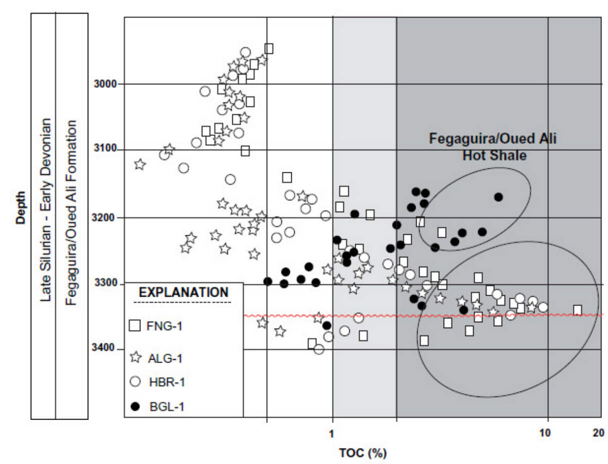

Figure 16. Total organic carbon (%TOC) of the Ludlow-Pridoli Hot shale vs. depth in the southern Chotts Basin using BGL-1, HBR-1, ALG-1 and FNG-1 (data compiled from Refs. [5, 24]).

ments from [26] remain broadly consistent, reflecting improved basin-scale modelling and resource confirmation.

Libya possesses ~290 Tcf of TRR, primarily in the Ghadames and Sirte basins [27]. This figure is lower than the EIA's 2013 assessment of 483 Tcf, but updated 2024 studies emphasize greater uncertainty in well performance and recovery factors due to infrastructure and security challenges. Despite this downward revision, Libya remains among the top shale-rich nations in Africa.

Tunisia's shale gas potential is modest, estimated at ~18 Tcf, mainly in the Jaffara Basin and the Ghadames extension [5]. This aligns with the earlier EIA (2013) estimate of ~23 Tcf, with minor adjustments attributed to refined mapping of Silurian shales and conservative recovery factor assumptions.

Morocco has ~11.9 Tcf of shale gas resources [27], concentrated in the Tarfaya, Essaouira, and Tadla basins. Earlier [28] estimates of ~11 Tcf remain broadly consistent, though national efforts have historically prioritized oil shale development.

In a short note, the updated 2024 figures largely align with earlier [28] assessments, though some discrepancies exist. Algeria's and Morocco's TRR values remain consistent, while Libya's estimates are revised downward, reflecting improved geological resolution and consideration of operational challenges. Tunisia shows a minor adjustment due to refined basin mapping. These revisions highlight the evolving nature of unconventional resource estimation, which depends on improved seismic coverage, drilling results, and changing methodological assumptions.

5. CONCLUSION

The unconventional shale resources in North Africa, just as others across the world, have attracted increasing scientific interest due to their regional abundance and energy potential. This review synthesizes the geological, geochemical, and petrophysical attributes of Silurian hot shales across the Ghadames, Murzuq, Berkine, and Jaffara basins. These shales are primarily sourced from marine-influenced organic matter, classified as Type II/III kerogen, with total organic carbon (TOC) contents ranging from 2% to 14%. Thermal maturity varies from the early oil window to the dry gas window, reflecting differences in burial history and geothermal gradients among the basins. Petrophysical properties, particularly brittleness, further differentiate their unconventional potential: the Ghadames Basin exhibits high TOC, optimal thermal maturity, and favorable fracturing characteristics; the Jaffara Basin, though less explored, shows moderate hydrocarbon potential; and both Berkine and Jaffara display lower gas-in-place volumes but mechanical properties amenable to hydraulic stimulation. Collectively, these findings demonstrate that Silurian shale systems in North Africa are geologically heterogeneous and prolific with resource potential governed by basin-specific controls on organic deposition, thermal evolution, and mineralogical composition. Future development strategies should incorporate a comprehensive evaluation of the effects of supercritical CO_2 ($ScCO_2$) solvent interactions on pore structure evolution and mineralogical transformations in shale, sandstone, and coal reservoirs. Such approaches enable assessment of the spatiotemporal heterogeneity of potential carbon storage systems and their suitability for coupled carbon utilization and storage. Integrating these processes with reservoir-scale mapping and modeling, based on structural architecture, petrophysical properties, and heterogeneity distribution, provides a basis for optimizing both hydrocarbon recovery and long-term CO_2 storage in North African basins.

DATA AVAILABILITY

The data will be available on request from the corresponding author.

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