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Silurian hot shale occurrence and distribution, organofacies, thermal maturation, and petroleum generation in Ghadames Basin, North Africa

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ABSTRACT

The Silurian hot shale in one of the African superglobal petroliferous sedimentary basins (Ghadames) were studied to provide new regional insights regarding the organofacies type, occurrence and distribution, thermal maturation levels, and the timing of petroleum generation and expulsion. Based on regional integrated geochemical data such as Rock-Eval and Leco TOC, the evaluation of hot shale organofacies was carried out to characterize the type, occurrence and distribution and to obtain present-day regional maps of total organic carbon content (%TOC_{pd}), hydrogen index (HI_{pd}) and kerogen transformation (TR_{pd}). The hot shale thermal maturation levels were obtained using pyrolysis Rock-Eval Tmax, equivalent vitrinite reflectance (%VRo), and one, two and three-dimensional calibrated basin modeling approaches. Results show that the hot shale was entirely dominated by typical marine organofacies type B (kerogen type I/II) with %TOC ranging from 2% to 17.5%, and hydrogen index ranged from 50 to 750 mg HC/g TOC with apparent systematic trends throughout the basin margins, and depocenter for both %TOC and HI. The hot shale thermal maturation study indicates a general maturation range from early to the post-mature stages with 0.45–2.45 %VRo and 380 °C–510 °C as pyrolysis temperature range. The one and two-dimensional kerogen transformation study based on the obtained refined thermal model shows a general range from 20% to 98% transformation levels with a systematic increase from the basin margins toward the basin depocenter. The hot shale oil window (top and bottom) is defined to be in the range of 1,400 m–4,000 m burial depth, while the dry gas window of the hot shale is presented at a burial range of 4,000 m–5200 m. Such an observation and current geological and geochemical conditions rank the hot to be an attractive potential sweet spot area as an unconventional shale oil/gas play target in Ghadames Basin for future exploration activity in western Libya, eastern Algeria, and southern Tunisia.

1. Introduction

The greater intracratonic sag basin (Ghadames) covers a wide area that exceeds 450,000 km^2 in the North Africa region between western Libya, southern Tunisia, and eastern Algeria (Echikh, 1998; Hallett, 2016). Because of the vast area and significant oil and gas discoveries, the basin ranked as one of the superglobal petroliferous basins (Fig. 1). The petroleum accumulation in Ghadames Basin, which predominantly comprises oil, gas, and few condensates, was discovered in Libya, Tunisia, and Algeria; the petroleum exploration activity since the 1950s has made 223 discoveries (van de Weerd and Ware, 1994; Gumati et al., 1996; Macgregor, 1996; Macgregor and Moody, 1998; Macgregor et al., 1998; Booth et al., 1998; Klett, 2000; Rusk, 2001; Dixon et al., 2010; Hallett, 2016). Such petroleum discoveries are attributed to the excellent Paleozoic petroleum system discovered during the exploration of the basin, making the Ghadames Basin a rich petroleum province for conventional and future unconventional resources in North Africa (Macgregor, 1996; Lučić and Bosworth, 2019).

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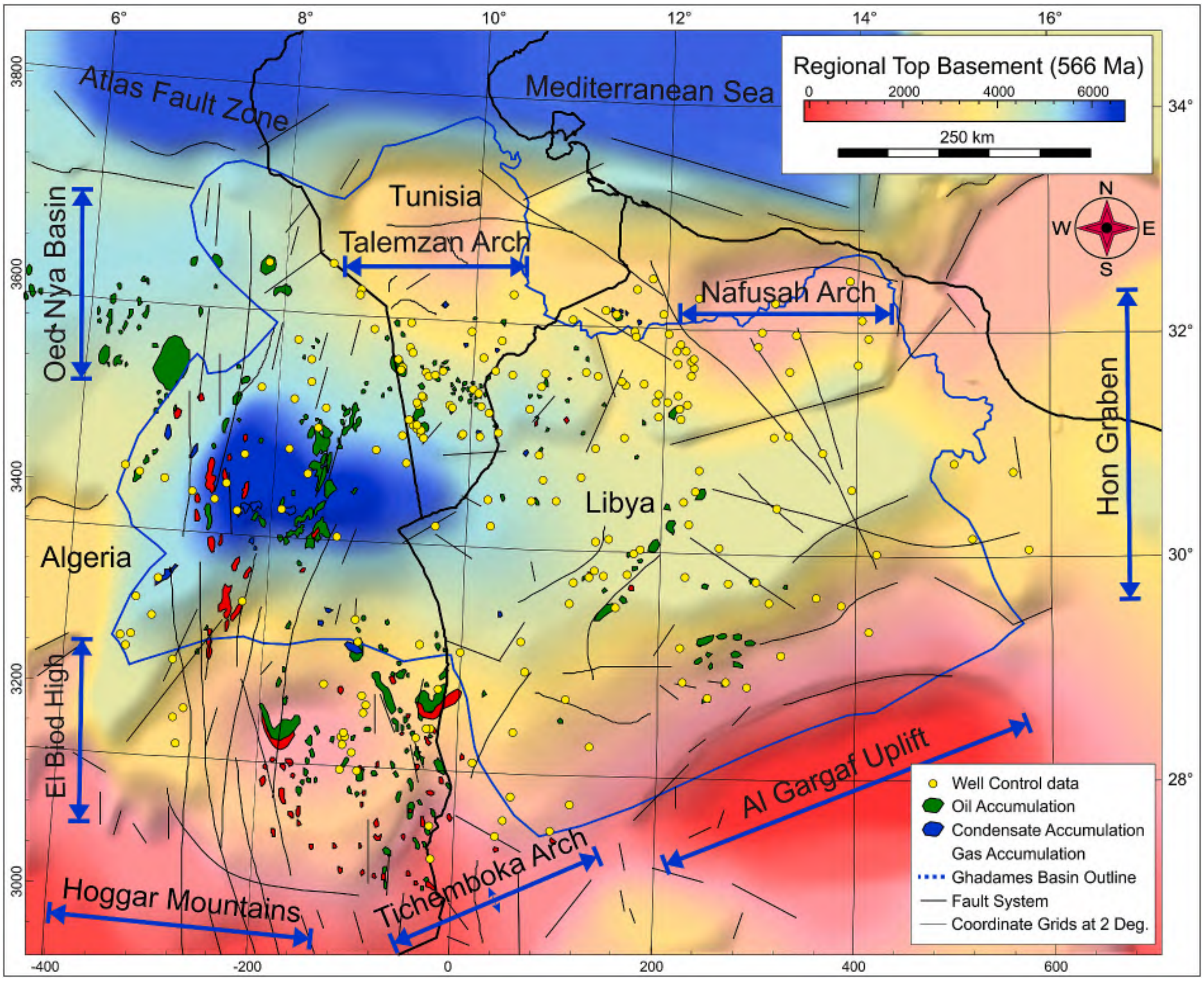

Fig. 1. The location of the study area (Ghadames Basin). The tectonic setting of the basin is defined by using the top of the basement, fault system, and key adjacent uplifts and grabens. The well control locations used in this study are marked with aqua circles. The basin boundary location is based on the AAPG digital database of basin geographic information. The oil, condensates, and gas accumulation locations are defined based on various sources (published and unpublished).

The Silurian "hot shale" has the characteristics of a high-quality concentration of marine organic matter (up to 18% TOC), considerable thickness, vast distribution in North Africa and the Arabian region, high nuclear logging response (Gamma-ray reaching 1,400 API), and high efficiency in generating and expelling substantial petroleum yields (Klemmme and Ulmishek, 1991; Macgregor, 1996; Lüning et al., 2000b; Klett, 2000; Lüning, 2003; Luning et al., 2004; Loydell et al., 2013a; Hallett, 2016; Lučić and Bosworth, 2019). The hot shale can be easily detected, defined, and separated from the cold shale (lean or poor source facies), which is usually present within the same sedimentary unit as the hot shale. In the case of the North African Silurian shale, the unique hot shale interval at the bottom of the Silurian sedimentary section with excellent geochemical properties distinguishes the hot shale from the cold shale, causing it to be a significant target for petroleum exploration as the primary source rock interval that charges many traps in the region (e.g. Basins such as Ghadames and Murzuq).

The current study analyzed the organofacies type, geochemical characteristics, thermal maturation stages, petroleum generation and expulsion history, and expulsion efficiency of the Lower Tanezzuft shale formation (Rhuddanian–Telychian hot shale). The study also focused on providing the initial integrated research for understanding the importance of the Silurian hot shale, because shale oil and gas play a key role in the economic unconventional petroleum system (UPS) in the North African region and also to provide a critical geochemical definition, which is required for further future exploration and development plans in the Ghadames Basin either in western Libya, southern Tunisia, or eastern Algeria. The Lower Tanezzuft Formation from the Llandoverian (~443.8–433.4 Ma) is distributed throughout the greater Ghadames Basin. The basin has another prominent source rock, the Aouinet Ouenine Formation, that was deposited during the Paleozoic, primarily during the Late Devonian Frasnian stage (382.7–372.2 Ma), which is also a significant part of the Paleo-Mesozoic petroleum system of the Ghadames Basin.

In the last twenty years, international and national petroleum companies who have acquired exploration blocks in Libya, Algeria, and Tunisia, such as Anadarko, Occidental, British Petroleum (BP), Woodside, Eni, Medco, Sonatrach, OMV, Repsol, Gazprom, Sirte, Arabian Gulf Oil Company (AGOCO), and independent researchers, have conducted research in the Ghadames Basin and have made remarkable contributions to understanding the nature, distribution, and occurrence of the Silurian hot shale in the basin. Significant studies have been published regarding the Silurian hot shale, including (Akrout et al., 2011; Loydell et al., 2013a; Aissaoui et al., 2016; Gambacorta et al., 2016; Mahmoudi et al., 2017; El Diasty et al., 2017a; Shukry et al., 2019; El Diasty et al., 2019a). However, these studies were predominantly localized or limited in scale. Alternatively, conducting research based on integrated regional data throughout the entire Ghadames Basin (e.g., geochemistry and geology) would be valuable for such large intracratonic sag basins and can provide a regional understanding and precise interpretation of the presence, characteristics, and distribution in time and space of the

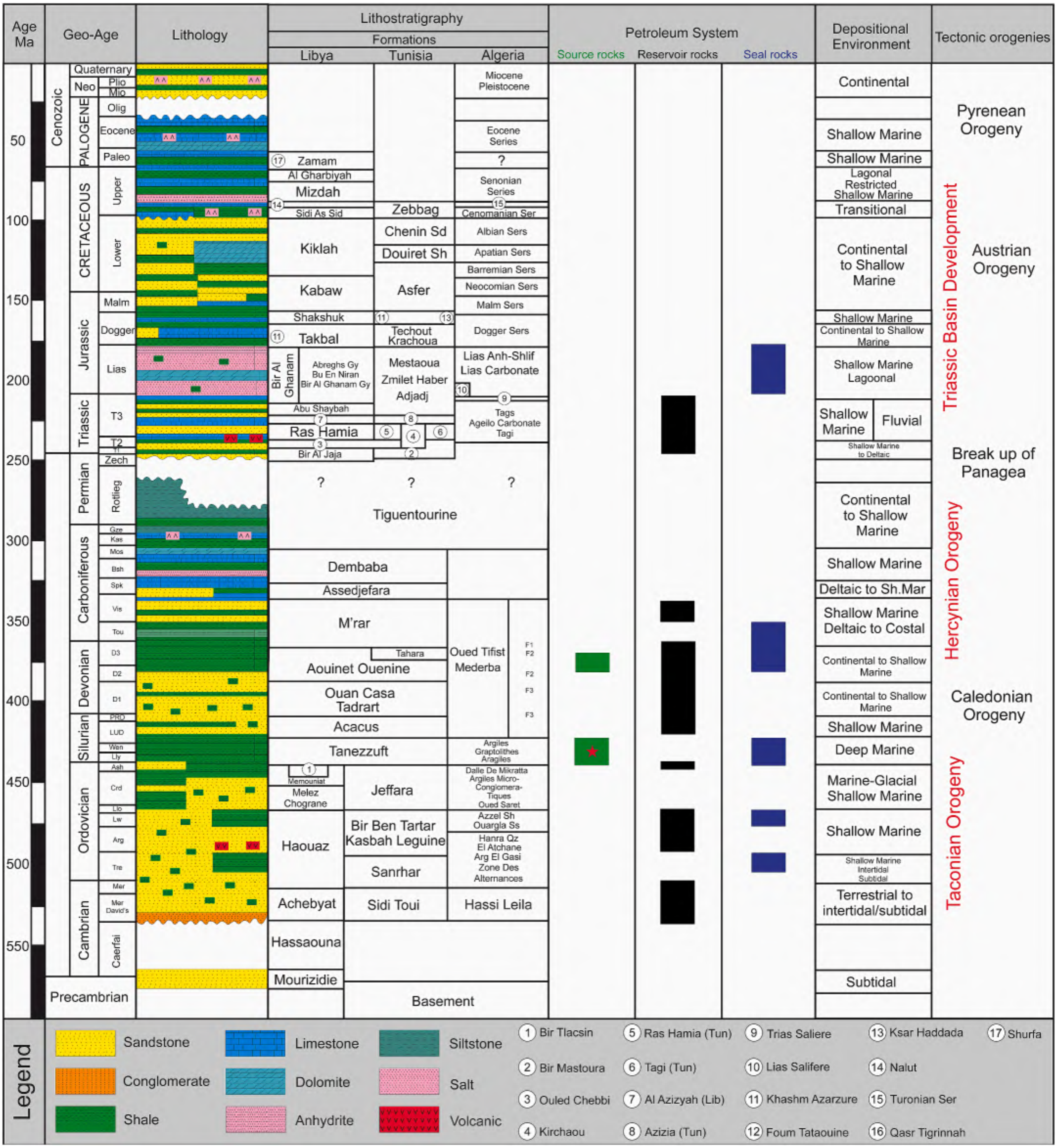

Fig. 2. Generalized regional stratigraphic column of the Ghadames Basin throughout Libya, Algeria, and Tunisia, illustrating the stratigraphic units, including the studied source interval marked with a red star, petroleum system (source, reservoir, and seal rocks), dominant depositional environments, and major tectonic orogenies that recorded and shaped the present-day structure of the Ghadames Basin (modified from various sources).

source rocks. Dixon et al. (2010) investigated the regional petroleum system in the Ghadames Basin based on integrated data. They presented the most likely petroleum system and explained the significance of the Silurian hot shale as a primary source rock that caused considerable oil and gas accumulation. Two other studies by Underdown and Redfern (2008) and Bora and Dubey (2015) used a 2D petroleum system analysis to understand the regional petroleum system that controls the distribution of the oil and gas accumulation in Ghadames, emphasizing the role of the Silurian hot shale in such mega systems in North Africa. They concluded that the lower Silurian hot shale was active in three out of the five systems existing in the basin.

The primary scope of this study was to provide a regional integrated geochemistry and basin modeling study of the Lower Tanezzuft Formation (hot shale) in the Ghadames Basin by defining the key relevant

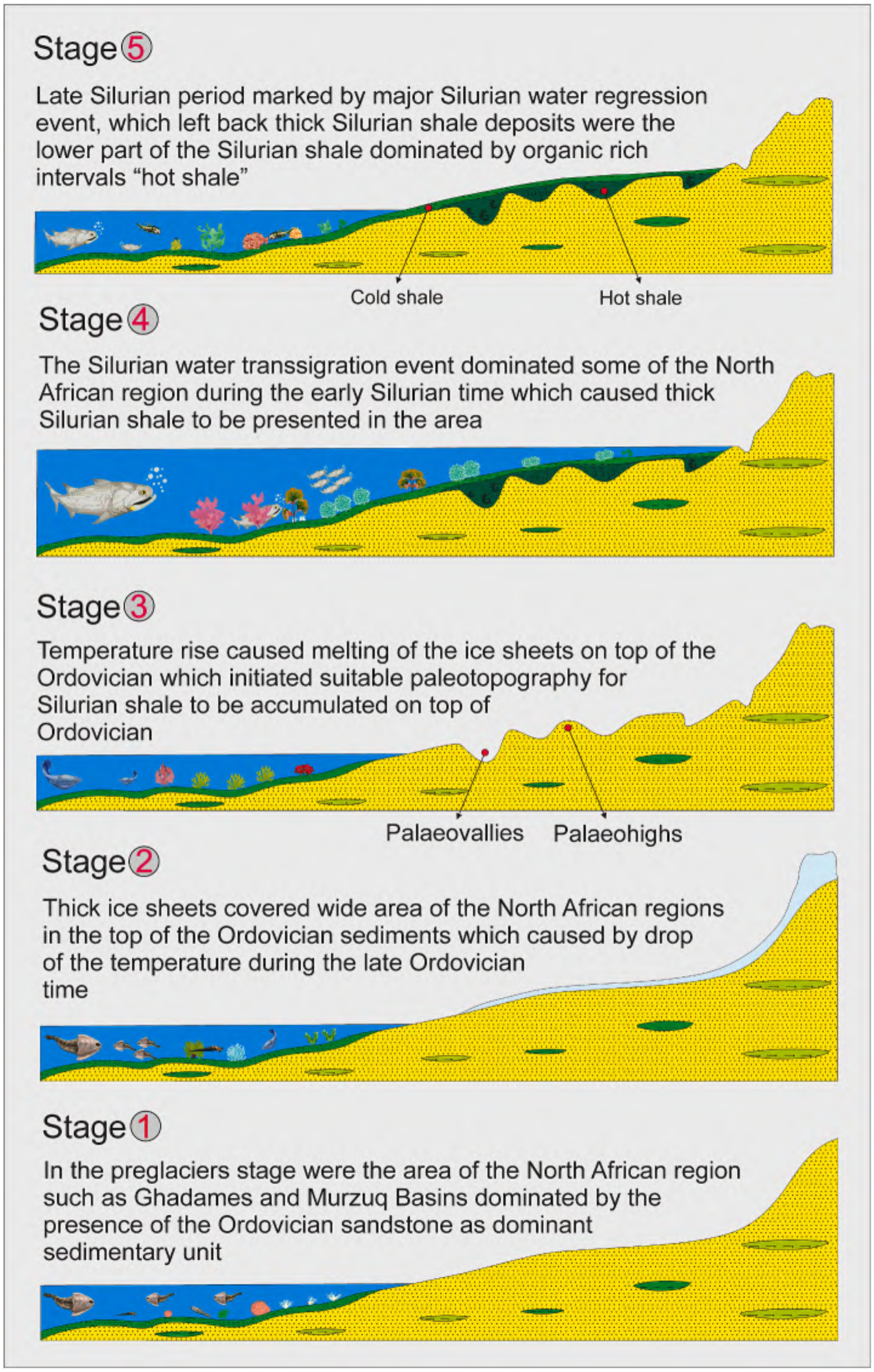

Fig. 3. Conceptual representation of the Ordovician and Silurian life, depositional process, and setting of the hot shale in the North African region, specifically in the Ghadames and Murzuq Basins (modified from Lüning et al., 2000b).

regional source rock parameters, such as determining the richness and quality based on mapping approaches, organofacies occurrence and distribution, the kerogen transformation ratio levels based on calibrated thermal models (multi-dimensional), and petroleum generation windows for oil and gas phases that generated from hot Silurian hot shale at different levels of thermal stress, which have been critical factors in recent advanced regional petroleum system analysis (PSA) and the unconventional shale oil/gas prospecting studies. Such regional knowledge based on enough database of geochemistry and regional geology with the use of the recent available technology, the petroleum system of the Ghadames Basin can be better estimated and explored.

2. Geological background

The greater Ghadames Basin evolved as an intracratonic sag area in the North African region with the present-day structures controlled by main primary tectonic orogenies, including (1) Caledonian (Early Devonian), (2) Hercynian (Late Carboniferous), (3) Basel Cretaceous (Neocomian), (4) Austrian (Aptian), and (5) Alpine (Eocene–Oligocene), which impacted the basin evolution by different mechanisms

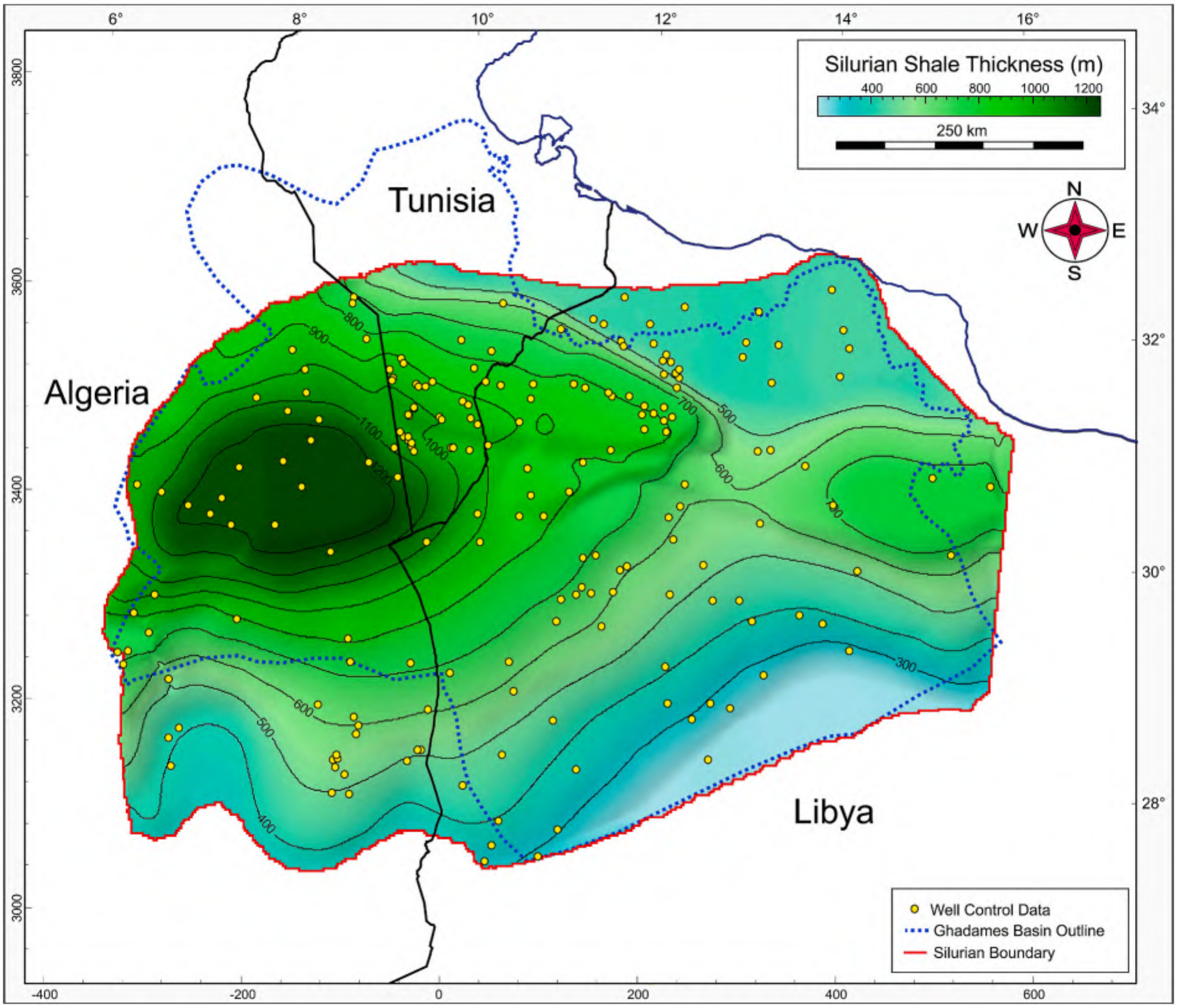

Fig. 4. Regional total Silurian shale thickness map (isopach) in the Ghadames Basin.

throughout geological time (Underdown and Redfern, 2007; Coward and Ries, 2015). Echikh (1998) explained the geology and hydrocarbon occurrence in the Ghadames Basin, describing the key geological control factors, such as the tectonic orogenies that have influenced the changes in the structural style of the depocenter, the pattern of trap formation, and the current activity.

The basin was subjected to the Hercynian orogeny, which activated extensive structural deformations and caused severe subsidence on the North African platform, forming exceptionally wide depositional sags (Bishop, 1975; van de Weerd and Ware, 1994). During the Late Carboniferous–Permian, the basin was exhumed, and some of the Paleozoic strata changed entirely, while during the Triassic, an extensional phase occurred in the basin, which activated the subsidence process and the depositional cycle, introducing more clastic material into the basin stratigraphic record (Yahi, 2001). The thermal process that led to the development of the titled NW Mesozoic basinal depressions effectively caused severe erosion of the remnants of the Paleozoic basin sections (Echikh, 1998). In the Ghadames Basin, during the Oligocene and Eocene, the collision of two plates, African and Arabian, initiating alpine tectonics, causing uplift and erosion at different locations in the basin (Guiraud et al., 1987; Booth et al., 1998).

Previous investigations in the basin have indicated that a dense sedimentary fill is present in the Ghadames Basin, aged from the Paleozoic to the present (Fig. 2). The sedimentary fill near the basin depocenter has an overall thickness of approximately 6,000 m (Underdown and Redfern, 2008). The Ghadames Basin Mesozoic and Cenozoic sections are thinner, no more than 700 m thick, with thick stratal intervals on the north and west side of the basin, and erosional activity has removed a considerable thickness of the Paleozoic section due to the Hercynian orogeny (El-Rweimi, 1991). Bishop (1975) and van de Weerd and Ware (1994) explained that clastic materials were deposited during the Cambrian Period in the Ghadames Basin, followed by pronounced marine transgression throughout the basin during the Ordovician Period, with glacial deposition dominating during the Late Ordovician.

In the Triassic-aged rocks, which were deposited due to the braided fluvial depositional process, the continental sandstones represent the major reservoirs in the Ghadames Basin. The overlapping rocks of these sandstones represent depositional input during the Jurassic, induced by general lithological input originating primarily from a marine transgressive phase, which includes mudstones interbedded with carbonate materials. Dense marine evaporites were also deposited due to the seawater regression event that caused the Paleozoic section to be superimposed by a strong regional seal (Belhaj, 1996, 2000; van de Weerd and Ware, 1994). Belhaj (1996) determined that during the continental Cretaceous section of the Ghadames Basin was positioned unconformably over the Mesozoic and Paleozoic sections. Hammuda (1980) mentioned that the Austrian tectonic event that caused the unconformities also caused a separation of the Paleozoic and part of the Cretaceous strata from the lower part of the Cretaceous section, while

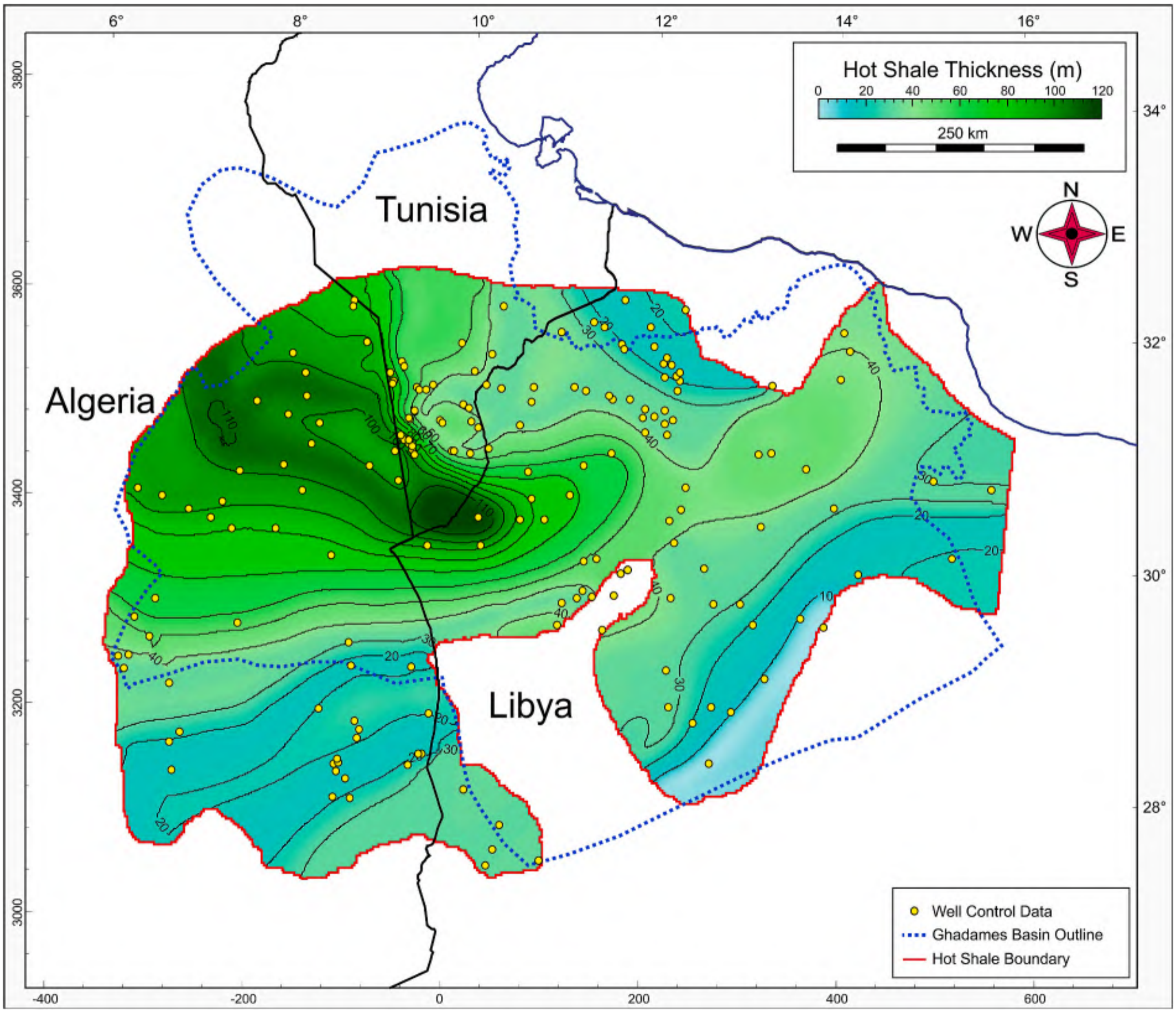

Fig. 5. Silurian hot shale total thickness map (isopach) in the Ghadames Basin. The hot shale thickness in the current map is based on %TOC ≥2.

the Cretaceous and Paleocene sections of the Ghadames Basin were predominantly from evaporitic and siltstone inputs that correspond with the transgression process that occurred in the Cenomanian.

Yahi (2001) reported that the shallow marine carbonate deposits are not defined in many North African sites and are superimposed by siltstones, mudstone, and evaporites. The Alpine orogeny also introduced unconformity into the greater Ghadames Basin, which was primarily associated with the African–Arabian collusion and movement with the European plate in the Late Cretaceous–Eocene (Underdown and Redfern, 2008). The Tanezzuft Formation, a post-glacial depositional system (Fig. 3), which is primarily thick shale depositional cycles, was introduced in the Silurian Period (Luning et al., 2000a). When the Silurian sea level decreased, the well-known reservoir unit was developed within the Acacus Formation in the Ghadames Basin and adjacent basins, such as the Murzuq Basin (Klitzsch, 1981). The Silurian and post-Silurian sediments exhibit truncational positions toward the southern Ghadames Basin, opposite of the Caledonian orogeny effects (Hammuda, 1980; Acheche et al., 2001; Jabir et al., 2020). The influence of the Caledonian unconformity strongly separated the Silurian section from the Devonian strata. Meanwhile, the seawater regression during the Late Devonian and Carboniferous led to the input of shallow-water sediments, which were predominantly deltaic sediments (Belhaj, 1996).

The Mesozoic clastic and carbonates took the unconformable position, and evaporites overlapped the Paleozoic portion. The rifted Tethys Sea and the opening of the Atlantic was caused by the Triassic extension forces (Bishop, 1975; Boudjema, 1987; Guiraud et al., 1987; Guiraud and Maurin, 1992; Yahi, 2001). The tectonic setting and stratigraphic filling of the Ghadames Basin is apparent when the tectonostratigraphic architecture is compared with some of the complex adjacent basins, such as the Meso-Cenozoic rifted Sirt Basin. The basin is characterized by multi-regional troughs and platforms that control the nature of the petroleum formation (Albriki et al., 2021). For example, the petroleum accumulations and distribution in the Ghadames Basin demonstrate less complexity than those in the Sirt Basin due to the presence of one major regional depocenter.

3. Methodology and data source

To provide an integrated regional assessment of the Silurian hot shale in the Ghadames Basin, vitrinite and equivalent vitrinite reflectance (%VRo) and pyrolysis Rock-Eval Tmax were used to calibrate two thermal models, ARCO (BP model) and LLNL (Lawrence Livermore National Laboratory), for the 1D and 2D thermal maturity study. The present-day thermal gradient utilized to calibrate and generate a regional maturity map was based on the LLNL model obtained using Trinity software (T3). More than 60 typical wells were selected for further regional geochemical screening to provide the present-day source rock geochemical parameters, such as total organic carbon content (%TOC), hydrogen index (HI), and kerogen transformation ratio (TR).

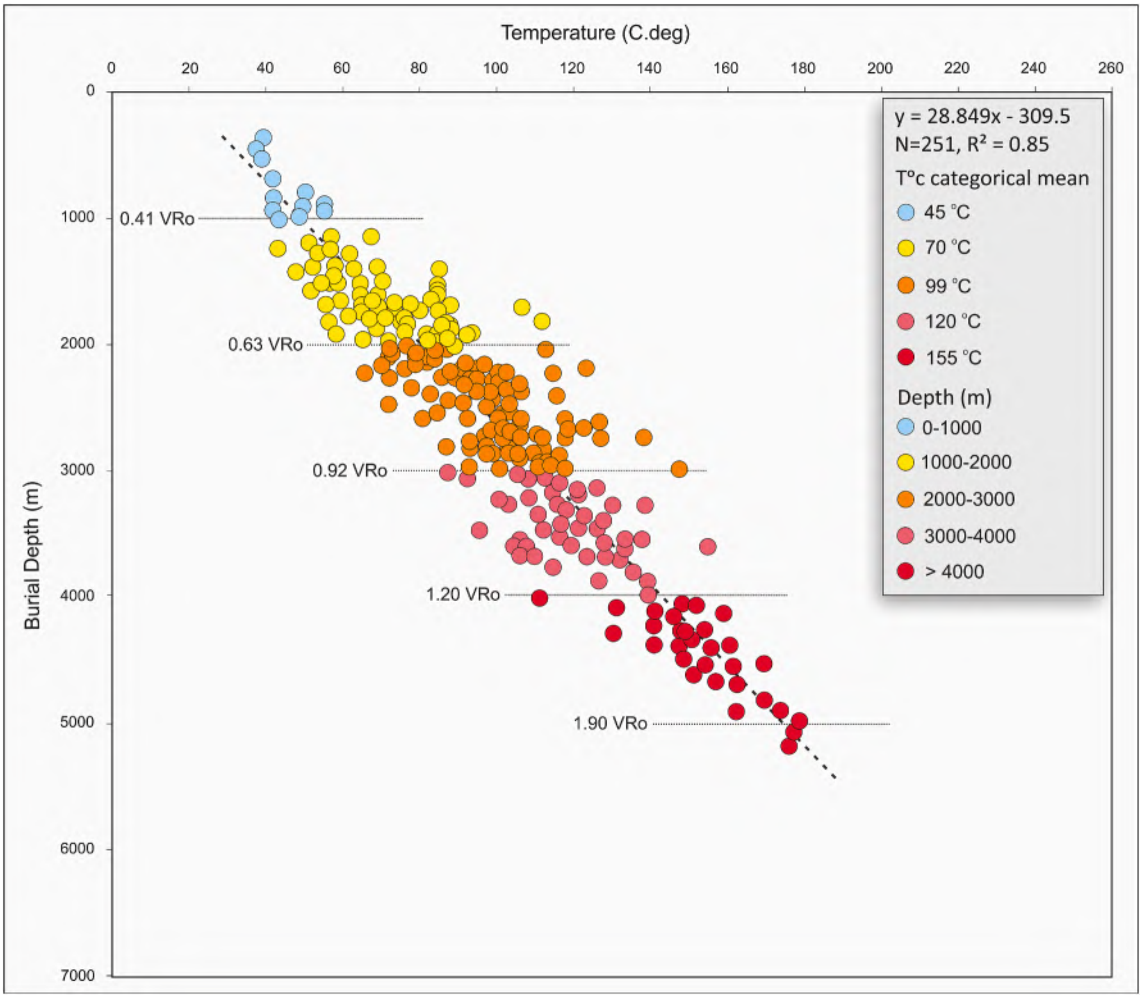

Fig. 6. Bottom hole temperature data (BHT) plotted versus burial depth (in meter) in the Ghadames Basin used to obtain a suitable geothermal gradient to calibrate the present-day thermal maturity of the Silurian hot shale (data source: Dixon et al., 2010 and other unpublished company reports).

The organofacies study that includes the dominant facies types, sedimentary environments, and their influence on the generated petroleum from the Silurian hot shale (Lower Tanezzuft Formation) was defined based on simplified and geochemical evaluation criteria, such as the Rock-Eval data, calibrated in the geological context of the hot shale in Ghadames Basin. Simplistic top and bottom oil generation window model of the Silurian hot shale were defined based on some selected key thermal and geochemical parameters as a function of the hot shale burial depth to better define the early oil and gas model of the hot shale in Ghadames Basin.

The source and origin of the calibrated and integrated dataset we utilized during this study were based primarily on data collected from technical reports from various oil companies in the Ghadames Basin. Additionally, data from different published research papers were used with the authorization gained via personal communications. The digitized well information, including the stratigraphy and bottom hole temperature (BHT) database, was also from different sources.

4. Results

4.1. Hot shale distribution

Many of the previous attempts determined that the Silurian shale in the North African and Arabian regions developed with a considerable thickness deposited during the Early to Middle Silurian (443–427 Ma). Macgregor (1996), Luning et al. (2000a), Lüning (2003), and Lučić and Bosworth (2019) provided useful regional information about the distribution and the value of the hot shale in North Africa as potential source rocks, with emphasis on the depositional timing and mechanisms in some of the North African petroliferous sedimentary basins, such as Ghadames and Murzuq Basins. Galeazzi et al. (2010) established a regional thickness map of the Silurian shale on the Algerian side of the Ghadames Basin (western part). They concluded that the thickness surpassed 1,200 m in the basin depocenter. Discriminating the Silurian hot shale thickness from the total Silurian shale thickness is critical in this study to define the source distribution and volume of the Silurian hot shale in the Ghadames Basin to estimate the petroleum generation and expulsion reliably, based on volumetric approaches.

The total thickness map of the Silurian shale in Fig. 4 is primarily based on collected well data from several published and unpublished sources for the Ghadames Basin to provide a regional definition of the total and hot shale thickness of the Silurian shale based on the thickness and %TOC data. However, Fig. 4 indicates that the total Silurian shale thickness ranged from 200 m to 1,400 m, beginning in the basin margin (up to 500 m) and increasing toward the basin depocenter. The basin depocenter location on the Algerian side of the basin allows the highest depositional rates to occur in this part of the basin. The hot shale thickness was defined based on the well control data and utilizing the % TOC with cutoff values ≥ 2. The utilization of cutoff ≥ 2 was to ensure that we eliminated the presence of the nonhot shale (lower quality) from the total thickness. In addition, the choice was also based on picking higher values of the corresponding hydrogen index, which is

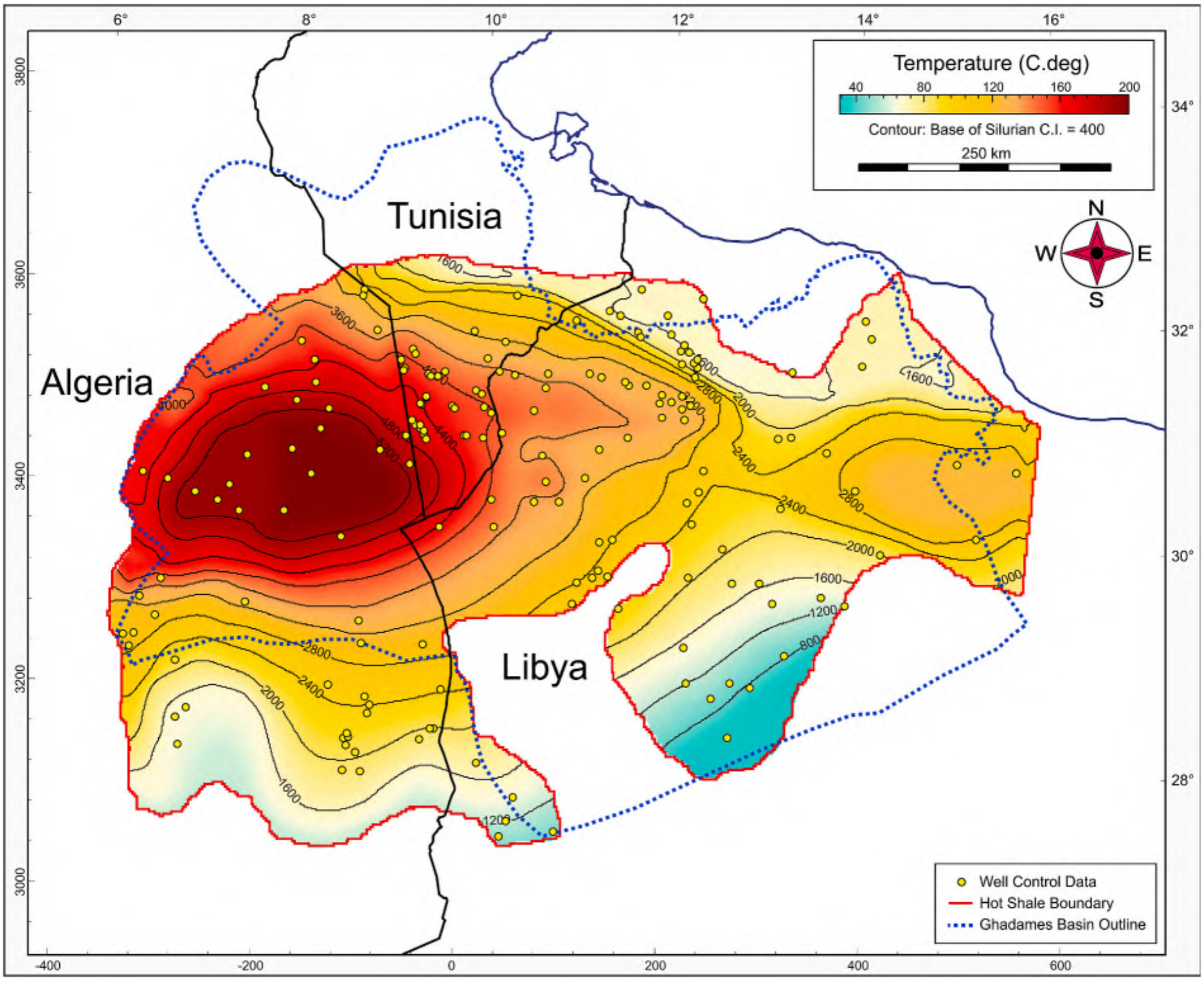

Fig. 7. Depth–temperature map of the Silurian hot shale in the Ghadames Basin.

predominantly greater than 100 mg HC/gm TOC when the %TOC is 2%, so that we could use this thickness of the hot shale for quantitative assessments, such as the expelled versus remaining petroleum amount. The hot shale thickness in the Ghadames Basin ranged from 0 to 120 m (Fig. 5), with an apparent systematic increase toward the basin depocenter. Significantly, we established the Silurian hot shale regional thickness map, which can be used for screening studies, such as defining the source area and its regional relationship to the occurrence and distribution of the discovered/undiscovered petroleum accumulations in the Ghadames Basin. The hot shale on the Libyan side of the Ghadames Basin was eliminated in some parts of the map, primarily on the northern and southeast edges of the basin, due to a lack of organic material (%TOC <2), which could be related either to the quality of the preservation conditions or to an inadequate source of organic matter to provide a sufficient quantity of TOC in this area.

4.2. Thermal maturity

4.2.1. Geothermal gradient

Defining sedimentary basins, most likely geothermal gradients, is the primary concern and critical first step in the recent basin analysis and modeling approaches (Tissot et al., 1974, 1987, 1987; McKenzie, 1981; Tissot et al., 1987; Hantschel and Kauerauf, 2009; Harris and Peters, 2012; Allen and Allen, 2013). The first heat flow analysis was introduced by (Lesquer et al., 1989) for the central Sahara region and provided evidence that the heat flow values exceeded 53 mW/m^2. Then, a study based on burial history modeling was conducted by Makhous and Galushkin (2003). They provided a regional thermal investigation in the eastern and southern Sahara sedimentary basins, predominantly on the Algerian side, to reconstruct the geothermal and heat flow patterns. The conclusion was that geothermal temperatures in the Sahara sedimentary basins ranged from 20 to 50 °C/km. This range represents the lowest and highest geothermal gradient of the Ghadames Basin. In addition, similar regional work recently published by Macgregor (2020) based on 1813 deep well measurements determined that the highest recorded values reached 100 mW/m^2 in the African sedimentary basins; for example, in the Ghadames Basin, the geothermal gradient and heat flow were 22–45 °C/km and 120 mW/m^2, respectively.

The obtained geothermal gradient in the Ghadames Basin first was based on using the corrected bottom hole temperature data plotted versus the burial depth. The relationship between the burial depth and the temperature was established using the fitting equation of the first order linear relationship $y = ax + c$ with correlation factor R^2 equal to 0.85 (Fig. 6). The thermal gradient was determined at a single value, and then the mean was calculated as 35 °C/km, which is similar to previous studies. The geothermal gradient values obtained for the Ghadames Basin are relatively higher than those for the Sirt Basin (Albriki et al., 2021). This might be due to a direct relationship with the higher present-day burial depth and the type of sediments and their distribution in the Ghadames Basin. The systematic changes in the thermal gradient are controlled by certain parameters, such as the basal heat flow, rock conductivity, lithosphere thickness, and the porous and permeable rocks in the basin that can conduct and transfer sufficient heat. The geothermal gradient and heat flow pattern in the Ghadames Basin may

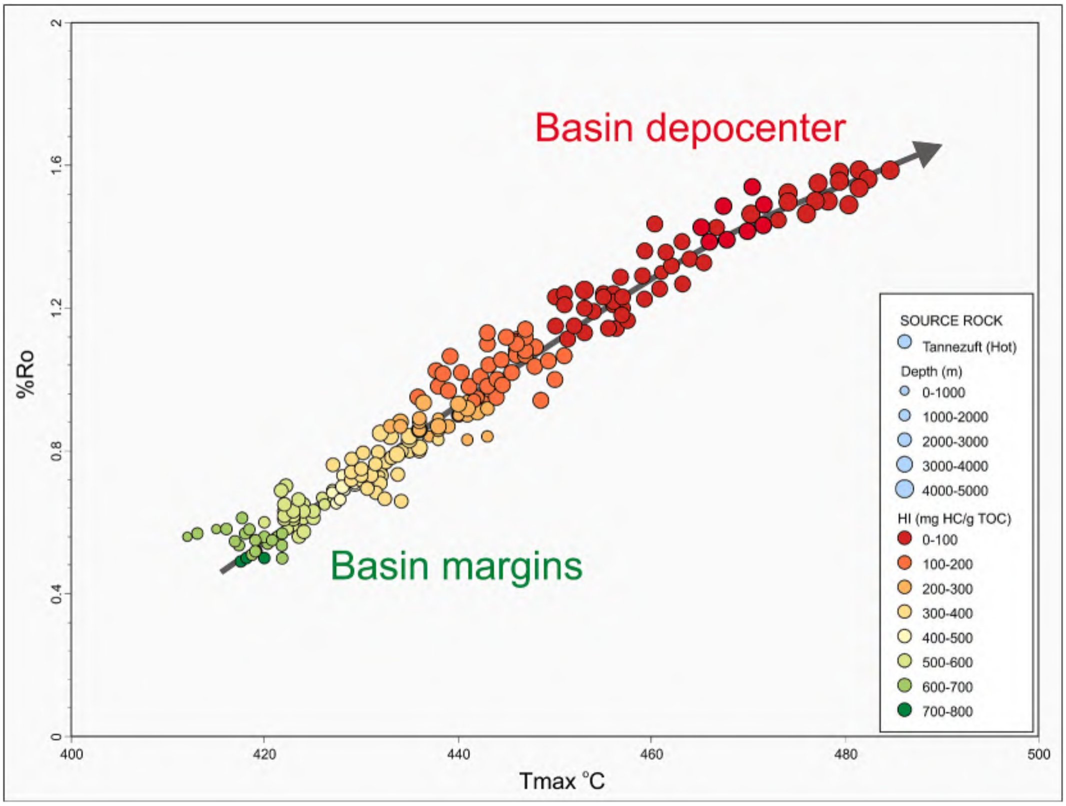

Fig. 8. The relationship between the pyrolysis Tmax and vitrinite reflectance data of the Silurian hot shale. Data sorted by HI color code and sized by burial depth of the hot shale in the Ghadames Basin.

also be affected by other parameters, such as groundwater availability and its presence in various water aquifers (water reservoirs). Unlike the Sirt, Marzuq, and Kufra Basins, the Ghadames Basin is the deepest intracratonic sag basin in the area, the other basins are shallower, and the area is subjected to lower geothermal gradients.

The heat flow of the Ghadames Basin was also calculated in this study using Genesis modeling software (calibrated with Trinity T3 for further corrections of the heat flow, geothermal gradient, and heat conductivity), selecting 15 typical wells. The results from the obtained models provided the same results as the previous findings of (Makhous and Galushkin, 2003) and (Macgregor, 2020). We used the previously established thermal gradient based on a one-dimensional approach to analyze the current maximum thermal maturation degree attained in the Ghadames Basin (Fig. 6) to describe the conditions in the deepest sections of the basin using the regional thermal map overlaid with the bottom of the Silurian hot shale (Fig. 7). To some extent, the current obtained regional map is helpful once the bottom horizon of the Silurian hot shale was utilized to establish an initial understanding of the maximum thermal situation, providing the initial step toward assessing the thermal maturation in areas where there is no representative thermal maturation data (e.g., %VRo and pyrolysis Tmax).

4.2.2. *Vitrinite reflectance (%VRo) and pyrolysis Tmax*

The two widely used thermal maturation parameters for source rocks in sedimentary basins are the vitrinite reflectance and Rock-Eval pyrolysis Tmax. Both methods are used to calibrate models that are often used to develop the applicable scenarios of the petroleum system in frontier or well-explored areas (Barker, 1974; Waples, 1980, 1994; Peters, 1986; Tissot et al., 1987; Horsfield, 1994; Suárez-Ruiz et al., 2012; Hackley and Cardott, 2016; Burnham et al., 2017). However, using vitrine reflectance and pyrolysis Tmax data to identify the systematic trends (e.g., increase or decrease) of hot shale thermal maturity is required to develop a reliable understanding of the current hot shale thermal maturation levels in the basin margins and the depocenter in the Ghadames Basin. Sufficient vitrinite reflectance and equivalent vitrinite data were utilized in this study to calibrate and generate a useful refined 2D thermal maturity model of the Silurian hot shale using the LLNL model.

The relationship between the vitrinite reflectance and pyrolysis Tmax is positive, providing a widely accepted method to evaluate and predict the thermal maturity of the source rock in sedimentary basins (Katz, 1983; Cooles et al., 1986; Peters, 1986; Mackenzie and Quigley, 1988; Quigley and Mackenzie, 1988; Burnham and Sweeney, 1989; Braun and Burnham, 1990; Conford et al., 1998; Peters et al., 2006; Suárez-Ruiz et al., 2012; Hackley and Cardott, 2016; Burnham et al., 2017; Katz and Lin, 2021). The Tmax and VRo correlations were recently well established by regression equations from a global database (Evenick, 2021). The study presented a large dataset of the Tmax and VRo relationship of 33,732 samples from 903 open access sources, identifying the nature of the relationship between these two parameters. The study also determined the uncertainty levels in the correlations between Tamx and VRo data that can be used for further predictions. However, similar techniques and evaluation criteria have been established for the entire Silurian hot shale formation in the Ghadames Basin, which are useful to provide a refined thermal maturation interpretation in which the presented relationship between the Silurian hot shale pyrolysis Tmax and the vitrinite reflectance data exhibit a positive correlation pattern (Fig. 8). The established correlation pattern demonstrates early and postmature stages thermal maturity of the hot shale, primarily from the early to postmature stages.

The obtained correlation in Fig. 8 was used to calibrate and predict the regional present-day hot shale thermal maturation map in Fig. 9 using the 2D LLNL model, which indicates that the maturation levels in the Ghadames Basin reached 2.45 %VRo at 200 °C, which is equivalent to a 5,200 m burial depth at the basin depocenter. In this case, the hot shale entered the postmature stage of thermal maturity, indicating that

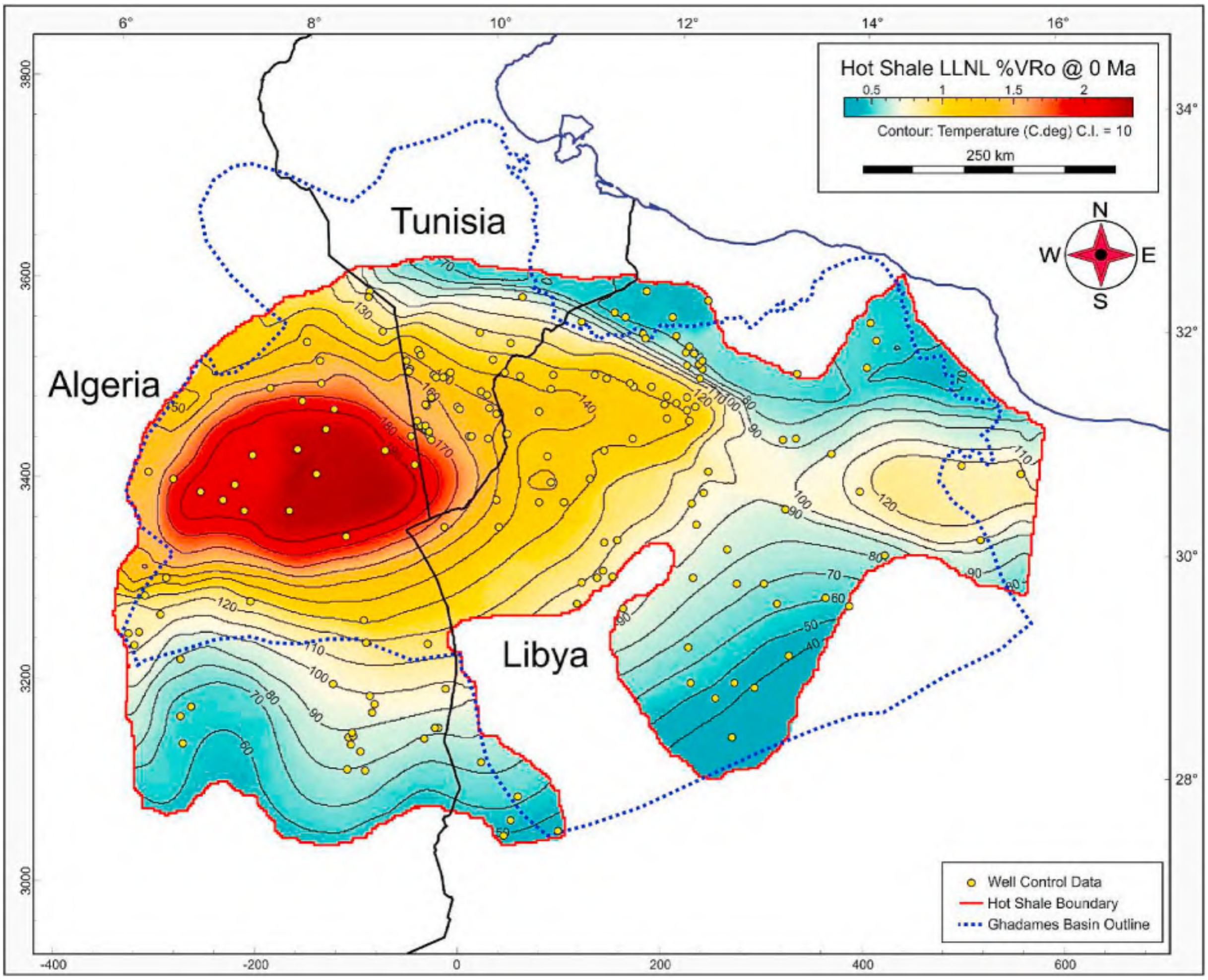

Fig. 9. Regional Silurian hot shale calibrated thermal maturation map. The map overlaid with the equivalent temperature map (thermal stress) using measured vitrinite reflectance data.

the hot shale has presently reached the dry gas window at this burial level. In contrast, the hot shale has reached early thermal maturation levels toward the basin margins (%VRo <0.6), this is mainly related to the burial depth that the hot shale was subjected to in this part of the basin. The hot shale middle maturation levels were within the range of 0.6–1.1 %VRo. This is equivalent to 120–140 °C. The thermal model in Fig. 9 was obtained using the bottom of the Silurian hot shale rather than the top horizon because this represents the maximum burial depth that the hot shale attained in the Ghadames Basin.

The Silurian hot shale maturation levels are sensitive parameters and need careful data integration and calibration to provide the most likely thermal maturation scenario. However, the regional pyrolysis Tmax data can be used to understand better the current thermal maturation levels. Fig. 10 presents the regional thermal maturation map obtained for the Silurian hot shale in the Ghadames Basin using the pyrolysis Tmax data. The range of the Tmax data indicates general levels from 400 °C to 515 °C, demonstrating maturation levels from early to post-mature. The utilization of the pyrolysis Tmax data overlapped with burial depth to better explain the systematic trends of the thermal maturity levels of the Silurian hot shale with the burial depth throughout the Ghadames Basin, which exhibits a systematic increase toward the maximum burial levels (basin depocenter), where the pyrolysis Tmax reaches 520 °C. The pyrolysis Tmax indicated that hot shale has attained the postmature level, which is similar to the results obtained when utilizing the vitrinite reflectance data. The pyrolysis Tmax data is more readily available than the vitrinite reflectance, which offers enough reliability to establish a valid 2D refined thermal maturation model that can be to extrapolate the maturity information and predict the thermal maturation levels in areas with less data available.

4.3. Hot shale organofacies type, occurrence, and distribution

Defining the Silurian hot shale organofacies type, nature of occurrence, and their distribution in the Ghadames Basin is a critical task for a better definition of the source distribution and the relationship with discovered and undiscovered petroleum accumulations. Recently, the concept of the organofacies and their applications play an essential role in defining the source rock quality, origin, and distribution in lateral and vertical scales in the sedimentary basins, which helps to define and characterize the source rocks (Rogers, 1979; Philp, 1987; Peters and Cassa, 1994; Pepper and Corvi, 1995b; Mendona Filho et al., 2012; Pepper and Roller, 2021). Five global organofacies, types A, B, C, D/E, and F, based on their organic type and sedimentary origin, were introduced in the simplified description of global organofacies by Pepper and Corvi (1995b). Evenick and Mcclain (2013), Evenick (2016) provided global insights for classifying the source rocks dominant organofacies utilizing the geochemical biomarkers and XRD database to emphasis their regional similarities and differences in various sedimentary basins. Each organofacies impacts the nature and phase-type of the petroleum that will be generated and expelled from the source rocks differently. We used the concept introduced by Pepper (1991) and Pepper and Corvi (1995b), which is based on a simple geochemical approach to defining

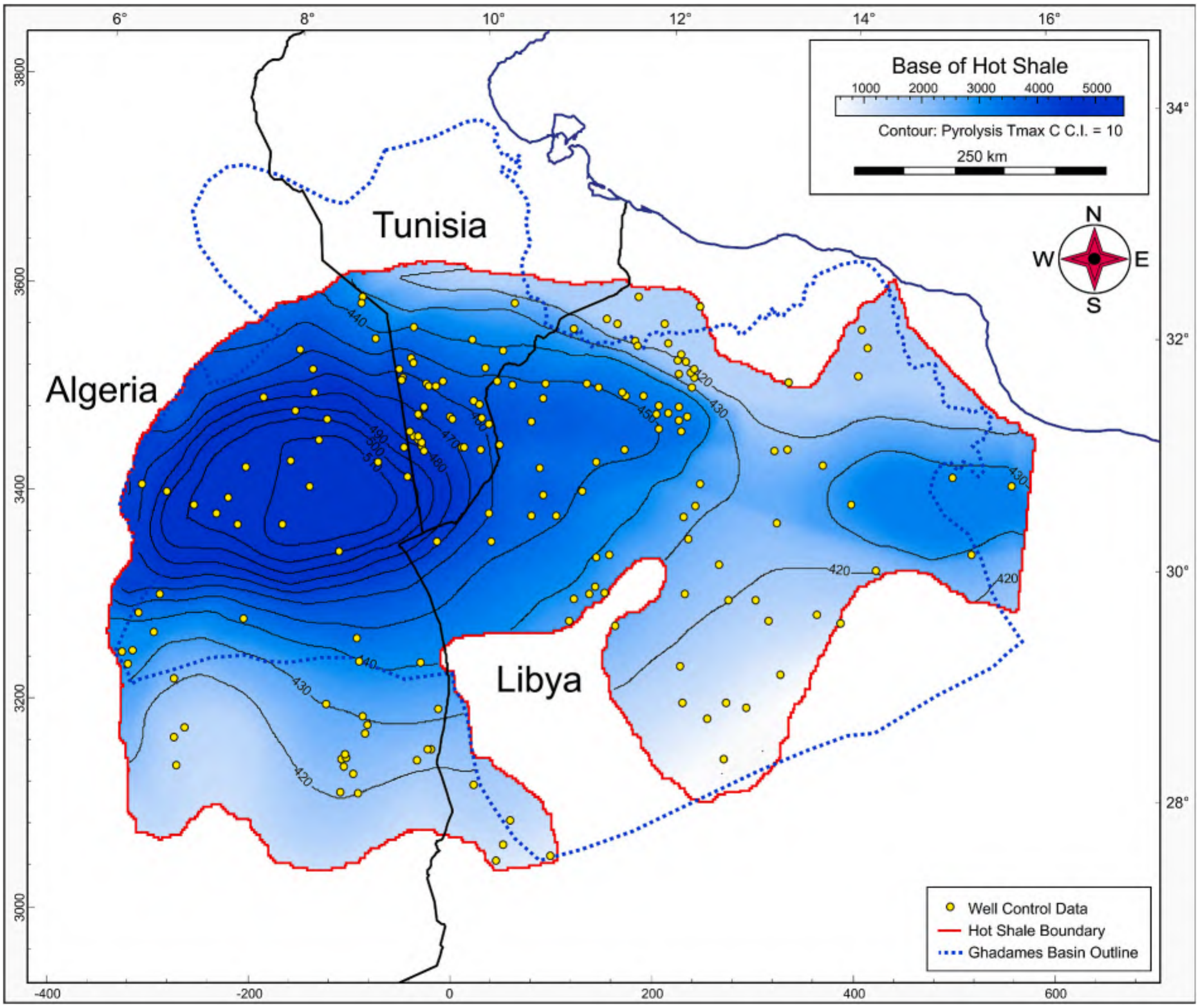

Fig. 10. Regional pyrolysis Tmax map of the Silurian hot shale overlaid with depth horizon map of the base of hot shale in the Ghadames Basin.

the type of the organofacies, by utilizing the Rock-Eval data to screen and provide a better understanding of the Silurian hot shale facies type and their regional systematic distribution and occurrence in the Ghadames Basin.

In the eastern Ghadames Basin (western of Libya) (El Diasty et al., 2017b, 2017c, 2019), provided evidence based on an organic geochemical study on the Silurian hot shale using three selected oil fields NC2, NC4, and NC7, and concluded that the Silurian hot shale in the Ghadames Basin originated from typical marine environments with dominant kerogen type II/III. In the eastern part of the basin (southern Tunisia), geochemical investigations have indicated that the Silurian hot shale is dominated by kerogen type I/II with a marine origin, with TOC reaching 16% in some locations in the basin (Akrout et al., 2011; Loydell et al., 2013a; Soua, 2014; Gambacorta et al., 2016). The hot shale of the western part of the basin (eastern Algeria) has similar geochemical characteristics to those in Libya and Tunisia. Chaouche (2013) presented evidence of type II marine kerogen dominating the Silurian hot shale on the western side of the Ghadames Basin, demonstrating the possible depositional nature and preservation mechanisms of the hot shale organic materials. Yahi (2001) also reported that kerogen type I/II mainly dominates the Silurian hot shale in the eastern Ghadames Basin.

The previous studies conducted in the Ghadames Basin still suffer from a lack of regional knowledge regarding the type of organofacies and their systematic trends in terms of distribution and richness within the basin margins and depocenter. Pepper and Corvi (1995, part one) provided a simple way to define the organofacies type based on the Rock-Eval data, such as %TOC and hydrogen index and proposed a suitable global kinetic model that could be used as the default values to simulate the convergence of organofacies to petroleum yields. However, for this purpose, we utilized 700 selected regional pyrolysis Rock-Eval samples from the Silurian hot shale to define the special organofacies type that dominates the hot shale in the Ghadames Basin. The results indicate that the Silurian hot shale in the Ghadames Basin demonstrates a typical type B organofacies with a general range of 2–17.5 %TOC and 50–800 mg TOC/g HC hydrogen index (Fig. 11), where values less than these are considered as lean or poor quality source rock intervals, not considering mapping the thickness of the Silurian hot shale in the Ghadames Basin (see Fig. 5). The data we used were sorted by country to provide adequate information of the hot shale in three different regions (Libya, Algeria, and Tunisia). Fig. 12 presents a good correlation between the %TOC data and S2 mg/g pyrolysis Rock-Eval with a general range of S2 values from 0 to 54 mg/g.

According to this study, the hot shale in the Ghadames Basin is dominated by marine organic matter with kerogen type I/II, with little influence from kerogen type III. For this purpose, we utilized the pseudo-Van Krevlen diagram by plotting the hydrogen and oxygen indices (OI and HI) to demonstrate the different kerogen types that dominate the Silurian hot shale (Fig. 13). The majority of the presented data in Fig. 13 fall in the zone of kerogen type I/II. This is because the hot shale is known to be an organically rich sedimentary unit throughout the Ghadames Basin.

To better understand the organofacies of the hot shale, we also

Fig. 11. Plot of the collected data of %TOC versus the Hydrogen index of the Silurian shale in the Ghadames Basin, with data sorted by country.

utilized the present-day HI map of the Silurian hot shale based on the regional data, demonstrating the systematic variation in the hydrogen index versus the burial depth (Fig. 14). It was evident that the hot shale was exposed to less burial depth and less thermal maturity in the basin margin, which displayed higher HI values of up to 800 mg HC/g TOC. In contrast, the hot shale HI exhibits a continuous decrease from the basin margins toward the depocenter, and the values reached 30 mg TOC/g HC, which is equivalent to a burial depth of 5,200 m. This regional map can also provide a clear understanding of the special type of the organofacies within the Silurian hot shale, which can be a useful model to understand the petroleum generation and expulsion mechanism of the Silurian hot shale because the hydrogen index can serve as a thermal maturity indicator. Increasing burial depths cause an increased thermal maturity, subjecting the kerogen of the Silurian hot shale to higher thermal stress, which means the hydrogen loss process will be activated, and the kerogen will lose a considerable amount of hydrogen, generating petroleum, indicating that the Silurian hot shale has been subjected to higher levels of thermal maturity (generally, < 2.5 %VRo) at the basin depocenter, where the hydrogen concentration in the hot shale kerogen is at its minimum levels with higher kerogen transformation ratio levels.

The presence and occurrence of the marine organofacies type B that dominates the hot shale in the Ghadames Basin could also be explained utilizing a regional calibrated map of HI versus %TOC (Fig. 15), which exhibits clear consistency with the systematic trends observed with the presence of the HI values in the basin margins toward the basin depocenter, where higher %TOC values are detected in the margins of the basin (generally, 10–18 %TOC), exhibiting.

A systematic decrease toward the basin depocenter, where the Silurian hot shale is subjected to a higher burial depth and thermal maturity. Fig. 15 provides a useful example of understanding such a process in one of the key petroliferous sedimentary basins of North Africa over a vast region. Three essential parameters are considered to characterize such a process based on the burial depth levels, total organic carbon content, and hydrogen index. Additionally, other parameters can be considered, such as the kerogen transformation ratio. The relationship between %TOC and HI of the Silurian hot shale also provides an initial understanding of the mechanisms that control the oil and gas distribution in the Ghadames Basin, which helps to define the present-day location of the potential shale oil and gas resource targets in the Ghadames Basin. However, mapping the %TOC and HI of the Silurian hot shale as critical parameters helps to evaluate the amount of the expelled and retained hydrocarbon in the source area (source kitchen). The retained hydrocarbon resources (volumes), such as the original oil and gas in place (OOIP and OGIP), can be estimated to understand better the unconventional petroleum systems to allow better planning of future oil exploration and production activities.

The relationship between the thermal maturation represented by the measured and modelled vitrinite reflectance %VRo and hydrogen index in Fig. 16 can best describe the maturity influence on the richness at different stages of burial. Fig. 16 clearly illustrate that the increase in the hot shale thermal maturity from the shallow stages were higher values of the HI presented up to 800 mg HC/gm TOC and up to 16% were at higher thermal maturity the hot shale in deeper levels exhibit very less %TOC up to 2% and 30 mg HC/g TOC which is equivalent to more than 1.6 VRo. Similar trends to that of the current obtained model were observed when the pyrolysis Tmax data were utilized instead of the vitrinite and equivalent vitrinite. Other parameters could also be utilized to determine the relationships, such as Rock-Eval S2, burial depth, burial

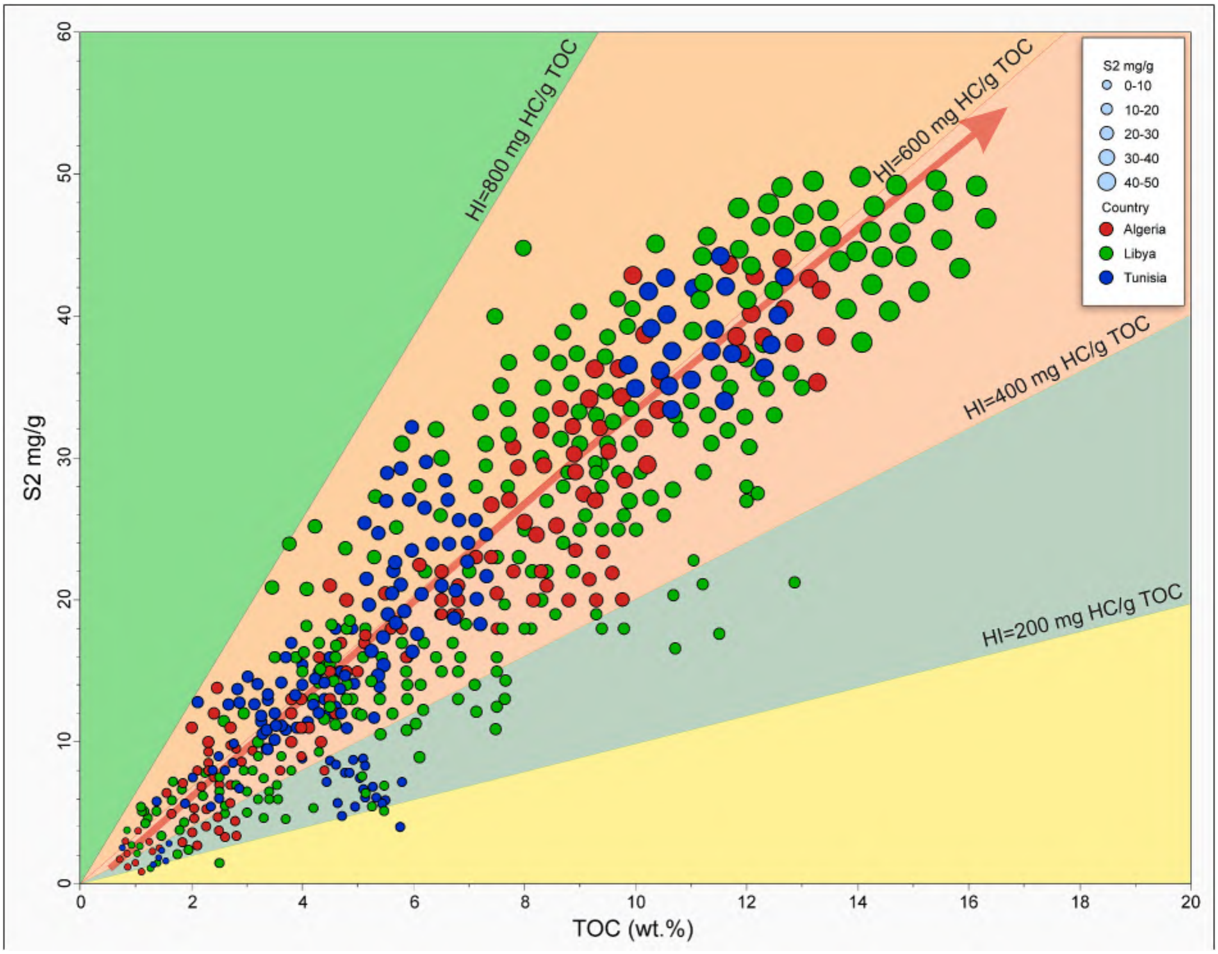

Fig. 12. Plot of S2 Rock-Eval versus %TOC used to define the hot shale petroleum charge levels in the Ghadames Basin.

temperature, and kerogen transformation ratio. However, the obtained model describes the behaviors of the organofacies type B of the hot shale to lower its quality during the increase of the burial and maturation stages, which is a specific model for such kind of very low Sulphur marine organofacies when it's compared with the other organofacies types such as A (marine rich Sulphur), C (lacustrine), D/E (mixed transitional), and F (woody terrigenous). Excellent similar examples for such relationships from the petroleum systems of south Viking Graben in the United Kingdom (U.K) shown by Cornford (2018), Cooper Basin (Australia) by Hall et al. (2019), Sirt Basin (Libya) early to middle Cretaceous source rocks (unpublished research work), and other global examples as investigated recently by Lohr and Hackley (2021).

4.3.1. Hot shale kerogen transformation ratio

The kerogen transformation ratio (TR) is a critical parameter that needs to be carefully considered for a better understanding of the source rock petroleum generation ability and efficiency in the sedimentary basins (Waples, 1980; Waples and Marzi, 1998). The application of the kerogen TR in the analysis of the source rocks has recently played a valuable role in the basin analysis and especially the petroleum system analysis (PSA) and their relevant modeling approaches (Peters, 1986; Peters and Cassa, 1994; Peters et al., 2006, 2016, 2018; Peters and Nelson, 2009; Harris and Peters, 2012). Once we developed a regional understanding of the Silurian hot shale organofacies type, occurrence and distribution, thermal maturity, and the most likely geothermal gradient in the Ghadames Basin, we still need to understand the levels of the kerogen transformations of the Silurian hot shale attained in the basin over geological time. For this reason, with the help of Trinity T3 and Genesis software (ZetaWare, Inc), we used 1D and 2D calibrated basin modeling approaches to acquire the necessary calculations of the TR once the refined thermal maturation model of the Silurian hot shale in the Ghadames Basin was established.

The timing of the Silurian hot shale kerogen transformation in the Ghadames Basin is a critical parameter for evaluating the conventional and unconventional Paleozoic petroleum system. The timing of the kerogen transformation has not been considered before in the previous literature for the Ghadames area utilizing multi-dimensional basin modeling approaches, which provides a better understanding of the timing of the petroleum generation and expulsion histories and helps to constrain a reliable scenario to investigate the charge timing from the hot shale toward the Ordovician traps in different locations in Ghadames Basin. However, for this purpose, we utilized six typical wells from different locations in the basin. These wells were used to construct geohistorical models (1D) and time-kerogen TR models to better investigate and obtain the timing of the kerogen TR of the hot shale in the Ghadames Basin. Each well represents a region of the basin, for example, the Libyan side (X1-66 and B1-NC100), Tunisian side (PDG2 and AMIC-1), and Algerian side (HAD-1 and WT-1). These six wells represent different thermal maturities in the shallow (margins) and deeper part of the Ghadames Basin (depocenter) to better demonstrate the systematic changes of the kerogen transformation with an increase in the burial depth toward the Ghadames basin depocenter.

The dominant factors of the hot shale kerogen TR are the type of the organofacies and the attained thermal maturity at different levels of the subsidence. The organofacies type plays an important role in this case. The hot shale is characterized by the presence of the very low sulphur/normal marine type B. This type of organofacies has been demonstrated to exhibit faster transformation levels when subjected to enough thermal

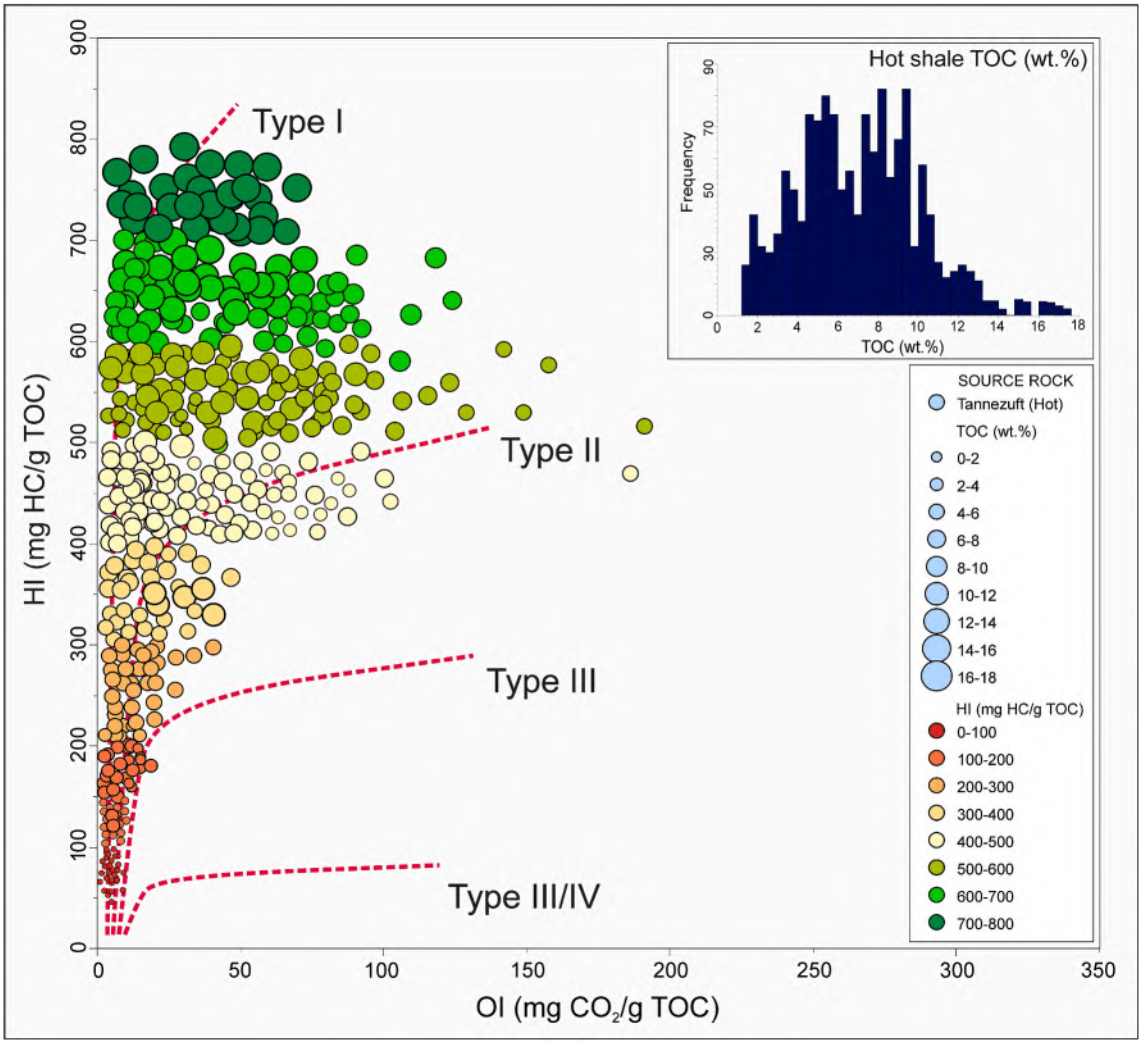

Fig. 13. Pseudo Van Krevlen diagram and histogram of the total organic carbon for the Silurian hot shale. Data color-coded by hydrogen index and sized by %TOC.

stress, unlike other organofacies types, such as A (high sulphur marine organofacies type), C (lacustrine), D/E (transitional), and F (terrestrial) (Lafargue and Behar, 1989; Pepper, 1991; Behar et al., 1992; Pepper and Corvi, 1995a; 1995b; Pepper and Dodd, 1995; Werner et al., 1996; Pepper and Roller, 2021). The maturity also has a great impact on the hot shale kerogen transformation ratio because it works as thermal driver affecting the organofacies and converting the organic matter to petroleum over geological time. In this part, the kerogen transformation and their related timing were obtained for the chosen six wells utilizing the Genesis software tool. Data were assigned for each well in the Genesis software based on the prepared stratigraphy sheets that included the formation tops, time of deposition, and lithology type. The BHT data, vitrinite reflectance, and pyrolysis Tmax were also assigned to each well to calibrate the thermal model and other geochemical data, such as the initial kerogen type, environment, and TOC_O and HI_O of the hot shale, were estimated based on Conford et al. (1998) and Cornford (2018) models.

The results indicate that the wells located in the eastern part of the Ghadames Basin (X1-66 and B1-NC100) were in the range of kerogen transformation up to 20% in X1-66 and up to 96% in B1-NC100 (Fig. 17). The timing of the hot shale kerogen transformation is quite different in X1-66, which reached 20% (~60 Ma). While toward the western side (B1-NC100), such values were attained as 320 Ma. The well B1-NC100 is deeper than the X1-66 and this allowed the hot shale to attain an earlier transformation in older time at higher thermal maturity stages and the kerogen of the hot shale in this location is transformed up to 94%. Toward the northern side of the Ghadames Basin (western of Tunisia), for two wells (PDG2 and AMIC-1) located far from each other, different timings of transformation were detected. In the case of well PDGS, located further north than AMIC-1, the hot shale exhibits early transformation stages of 20% during the Middle Mesozoic (Early Cenomanian, 100 Ma). While in well Amic-1, the hot shale attained an early transformation level in the Upper Carboniferous (Lower Pennsylvanian, ~320 Ma). At this well site the hot shale exhibited higher levels of transformation (up to 95%), as demonstrated in Fig. 18.

Further to the west (Algerian side), the hot shale timing of the kerogen transformation were studied based on two deeper wells (HAD-1 and WT-1). These two wells are located near the Ghadames Basin depocenter and provide valuable information regarding the hot shale transformation levels. However, in Had-1, the lowest levels of

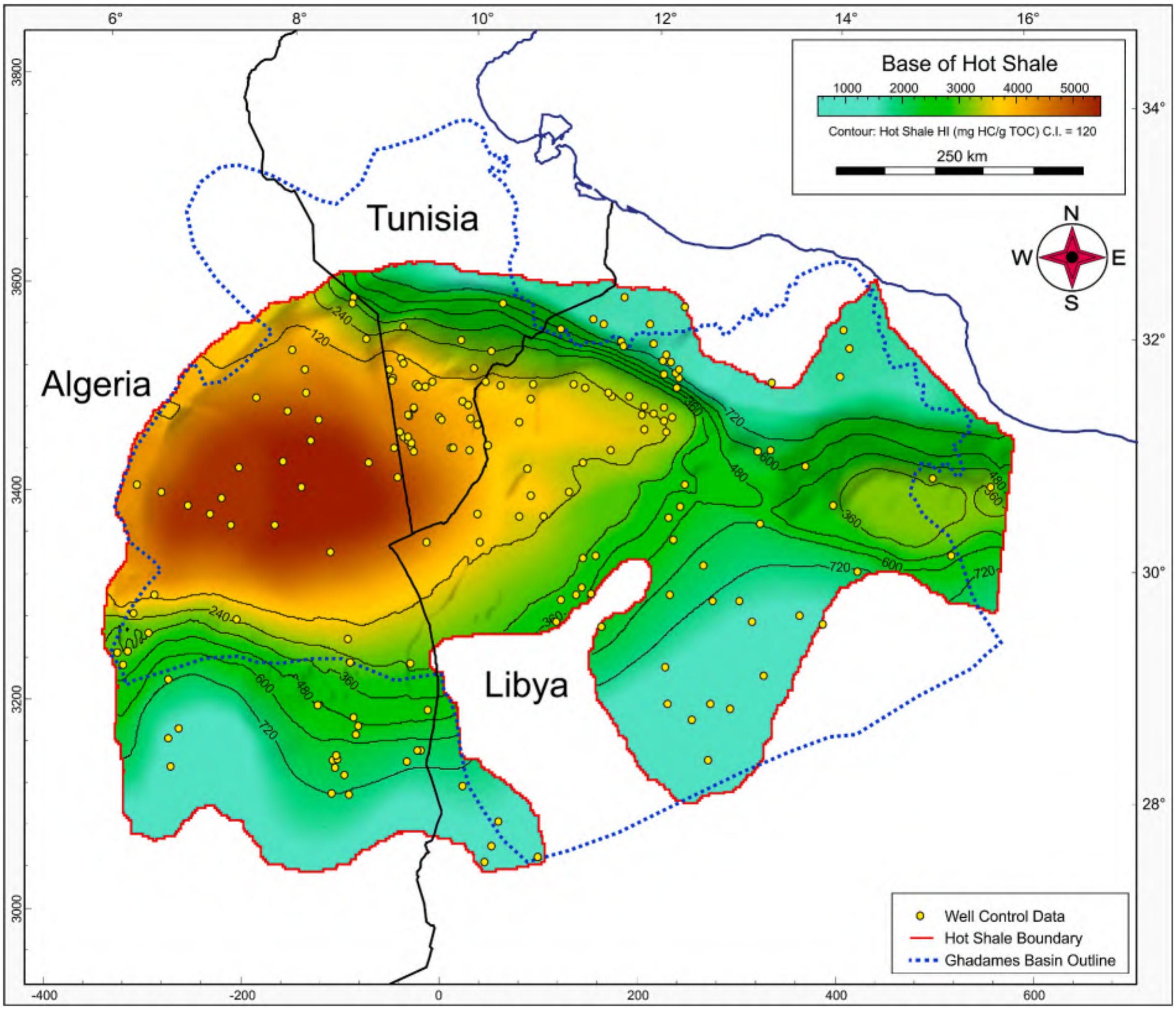

Fig. 14. Obtained regional map based on depth–hydrogen index relationship of the Silurian hot shale in Ghadames Basin.

transformation of the hot shale reaching 20% were attained in the Middle Carboniferous (Middle Mississippian, ~340 Ma). In contrast, the transformation levels of the hot shale WT-1 wells presented in the Middle Devonian (Early Eifelian, ~391 Ma). In both wells, the kerogen transformation of the hot shale presently reached 98% (Fig. 19). In Fig. 20, the kerogen transformation of the hot shale was plotted versus the geological time for each well in Figs. 17, Fig. 18, and Fig. 19 to better visualize and explain the timing of the kerogen transformation represented by the bottom of the hot shale in the Ghadames Basin.

To understand the timing and levels of the hot shale kerogen transformation levels based on the calibrated burial models, we also utilized a regional present-day kerogen transformation map (Fig. 21). This map is a 2D model of the kerogen transformation of the hot shale to better identify the most probable kerogen transformation scenario in the Silurian hot shale in the Ghadames Basin. The map was obtained using the petroleum system tool (Trinity T3 software), where we utilized the bottom structure of the hot shale for the calculation, and with the previously defined geochemical and thermal conditions of the hot shale, including several key wells that were constructed as burial models in the previous sections. Fig. 21 indicates that the maximum present-day transformation exceeds 98%. The model shows that the transformation ratio demonstrates a clear systematic trend from the Ghadames Basin margin (up to 20%) toward the basin depocenter, where the maximum present-day transformation occurs. Key factors that govern such systemic transformation patterns in the Ghadames Basin include the subsidence levels and rate, the time that hot shale spent in such conditions, and the thermal maturity level achieved.

5. Discussion

Understanding the nature of the spatial presence and the geochemical characteristics of the Silurian hot shale in the Ghadames Basin and the adjacent basins, such as the Murzuq and Kufra Basins, helps to estimate the remaining/grounded potential of such classic source rock. The hot shale has recently exhibited a significant and promising future for petroleum exploration regarding the shale oil/gas in north Africa. The improved depositional model of the hot shale in Fig. 3 explains the accumulation mechanisms of the hot shale on the top of the Ordovician, based on five conceptual stages. Such regional distribution is controlled by the paleoclimate conditions and paleotopography (paleovalleys and paleohighs), which offers an excellent host environment to accumulate a

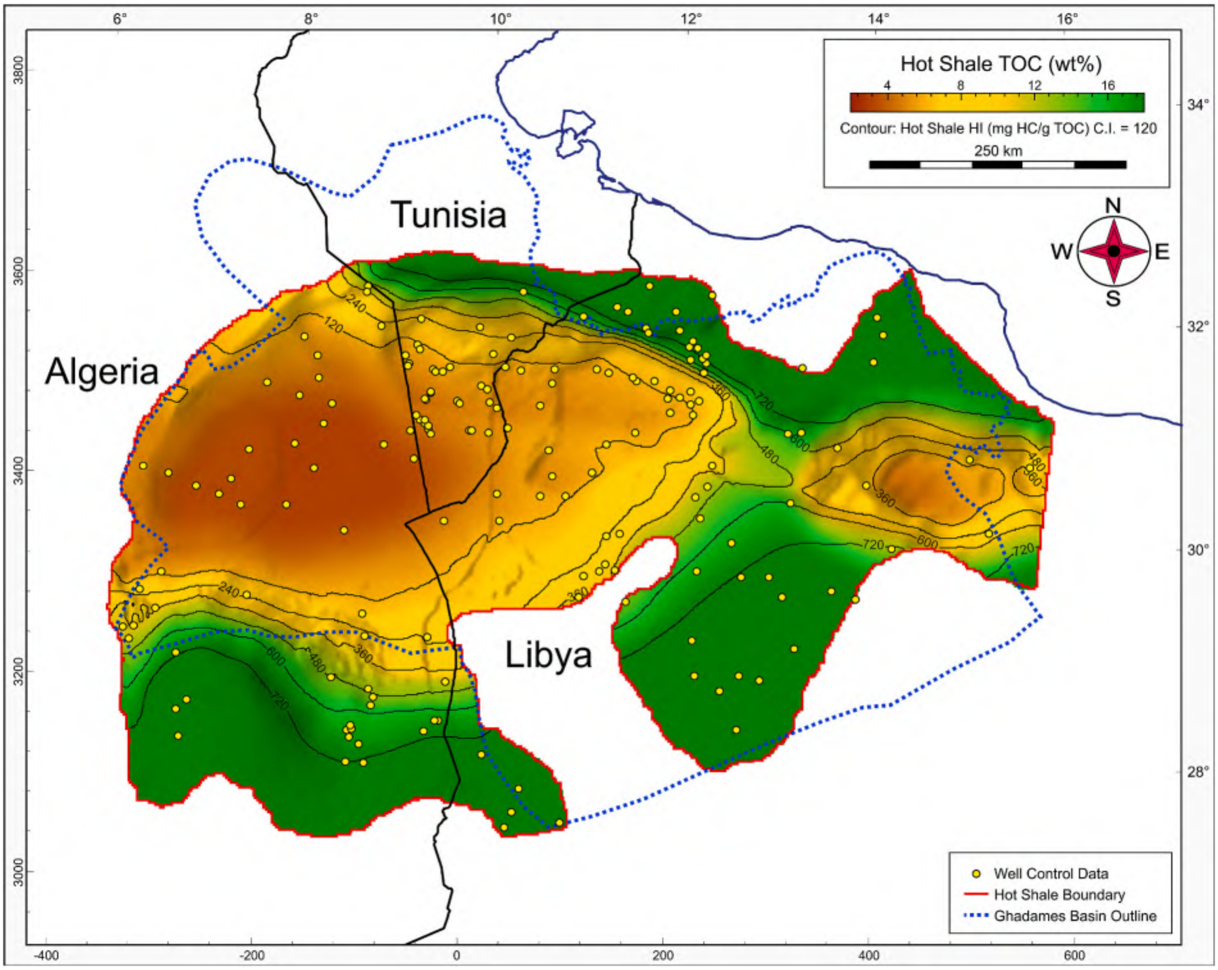

Fig. 15. Obtained regional map of the %TOC and HI relationship of the Silurian hot shale in Ghadames Basin.

considerable thickness of the hot shale in the lower part of the Silurian section. The typical marine type B organofacies dominate the hot shale in the Ghadames Basin, with a considerable thickness toward the basin depocenter with a total obtained thickness up to 120 m (Fig. 5).

The present-day maturation levels of the Silurian hot shale utilizing mapping techniques of the vitrinite and equivalent vitrinite reflectance and pyrolysis Tmax (Figs. 9 and 10) exhibit a general range from early to post mature stages (~2.5 VRo and 515 °C in basin depocenter). Both maturities are helpful to provide regional knowledge of the maturity of the hot shale in the Ghadames Basin. The present-day maturity trends of the hot shale in Figs. 9 and 10 demonstrate an increasing pattern toward the deeper part of the basin, such kind of systematic increase initially controlled by the subsurface temperature (see Fig. 7), structural configuration, and burial depth. Although, many other factors should be considered besides the obtained results, such as the relationship between the major tectonic regimes that affected the basin and their influence on the present-day attained maturity levels (Underdown et al., 2007; Underdown and Redfern, 2007, 2008). provided a useful explanation on the influence of two major tectonic events, the Hercynian (Late Carboniferous) and Alpine (early Eocene), based on utilizing vitrinite reflectance, isopach maps (total thickness), and sonic velocity data, and they concluded that the maximum exhumation occurred due to these two tectonic events. Galushkin et al. (2014) utilized calibrated 1D burial history approaches to reconstruct the thermal history of the Ghadames and Murzuq Basins. The exhumation stages and their related eroded sections from the sedimentary basins could be precisely measured using apatite fission track, sonic porosity, and vitrinite reflectance data (Burns et al., 2005; Iyer et al., 2021). Because our data were limited for the Ghadames Basin and the scope of this study was different, we only assigned the calculated amount from public domain data and company reports in our 1D models.

The role of the thermal maturation that we defined based on pyrolysis Tmax, vitrinite, and equivalent vitrinite reflectance data on the richness and quality parameters (e.g., %TOC and HI) of the hot shale in the regionally exhumed sedimentary basins, such as the Ghadames Basin, still need more detailed investigation and calibration data from other sources, such as well logging data and the apatite fission track, to better address such relationships because organic geochemical data may not be sufficient to address and solve such regional issues, while the type, quality, and size of the data also play a critical role in defining such relationships.

The results we obtained are similar to the findings of Underdown et al. (2007), Underdown and Redfern (2008), mainly in the number of the 1D burials we used (see burial models in Figs. 17, Fig. 18, and Fig. 19). The acquired 2D LLNL VRo (Fig. 9) utilized with the calibrated vitrinite reflectance data, 1D burial history models, and depth–temperature relationship (Fig. 6), demonstrate that the 2D regional presentation to the

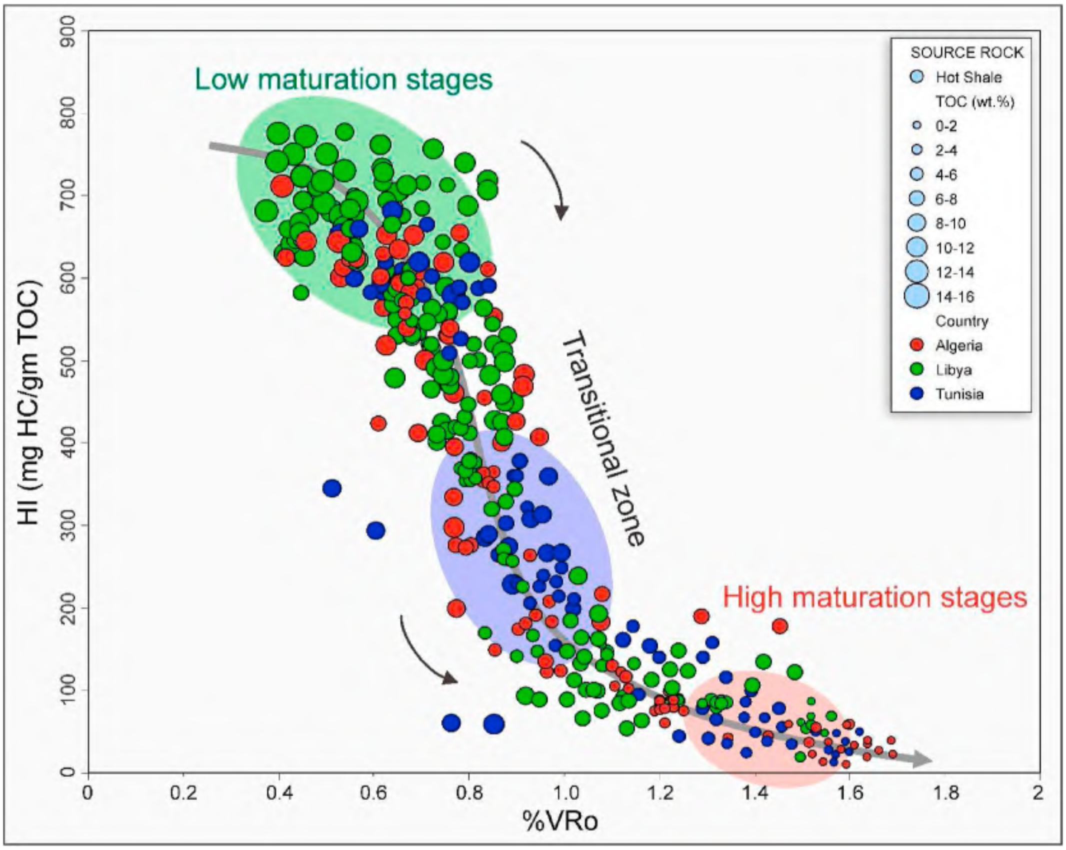

Fig. 16. The relationship and the systematic change between the %VRo and the hydrogen index data of the hot shale in the Ghadames Basin (data sorted by size based on %TOC).

present-day thermal maturity of the hot shale is useful to explain the maturity variations in the shallow and deeper parts of Ghadames Basin. The sudden increase in the maturity from 0.6 to greater than 1 VRo in the north and northeast of the basin (Tunisian and Libyan parts) probably occurred due to the effect of the Hercynian orogeny that (Underdown et al., 2007; Underdown and Redfern, 2007) identified. The established 2D maturity model in Fig. 9 was utilized as thermal input to obtain the present-day kerogen transformation ratio (at 0 Ma) of the hot shale in Fig. 21, which provided useful parameters for understanding the current hot shale kerogen transformation situation. The timing of the kerogen transformation ratios and their relationship with major tectonic events such as Hercynian and Alpine were demonstrated in Figs. 17, Fig. 18, Fig. 19, and Fig. 20. The kerogen transformation ratios of the hot shale and their related changes in the geological time is key for understanding the regional petroleum charge from the basal source rock in Ghadames Basin, which also provides fundamental steps toward a better assessment of the presence of the conventional/unconventional resource system of the shale oil/gas in the Ghadames Basin.

The spatial occurrence and the distribution of this well recognized global organofacies type is attributed to the Silurian marine transgression event toward the host accommodations spaces in the Ghadames Basin. The marine type B organofacies is characterized by the spatial presence of the specific type of organic precursors with dominant biomass, mainly algal and bacterial, which marked the Silurian hot shale to reach up to 18% TOC and HI up to 800 mg HC/g TOC (Figs. 11, Fig. 12, and Fig. 13) with very low sulphur content and very high tendency to generate considerable of petroleum. A detailed discussion on the presence, type and quality, and petroleum phase predictions using suitable kinetic modeling on such marine organofacies were introduced by (Ungerer, 1990; Pepper and Corvi, 1995b; Pepper and Dodd, 1995; di Primio and Horsfield, 2006; Baur, 2019; Murray and He, 2019; Pepper and Roller, 2021). The organic richness and thermal maturity of the Silurian type B organofacies is higher than the adjacent marine Cretaceous type B presented in the Sirt Basin (Albriki et al., 2019, 2021).

The established relationship between the hydrogen index, vitrinite and equivalent vitrinite, and total organic carbon of the hot shale in Fig. 16 show the systematic decrease in the hot shale quality from the immature sections of the Ghadames Basin to the deep mature parts (near to basin depocenter), which also can be used to describe the state of the hot shale kerogen transformation and oil and gas generation. The higher hydrogen index values (~800 mg/g TOC) of the hot shale represent the lowest mature section of the hot shale (0.42–0.55 VRo), with the total organic values in range of 12%–16%. In contrast, in the higher maturity stages, the hydrogen index suffered an extreme loss due to higher thermal maturity and higher burial depth with values up to 30 mg HC/g TOC). This relationship could not only be used to understand the relationship between the thermal maturity and quality of the hot shale but could explain the extent of the top of the oil/gas windows. The hot shale in the main basin depocenter reached a lower hydrogen index (HI less than 20 mg HC/g TOC) in the maximum thermal maturity stages (~2.45

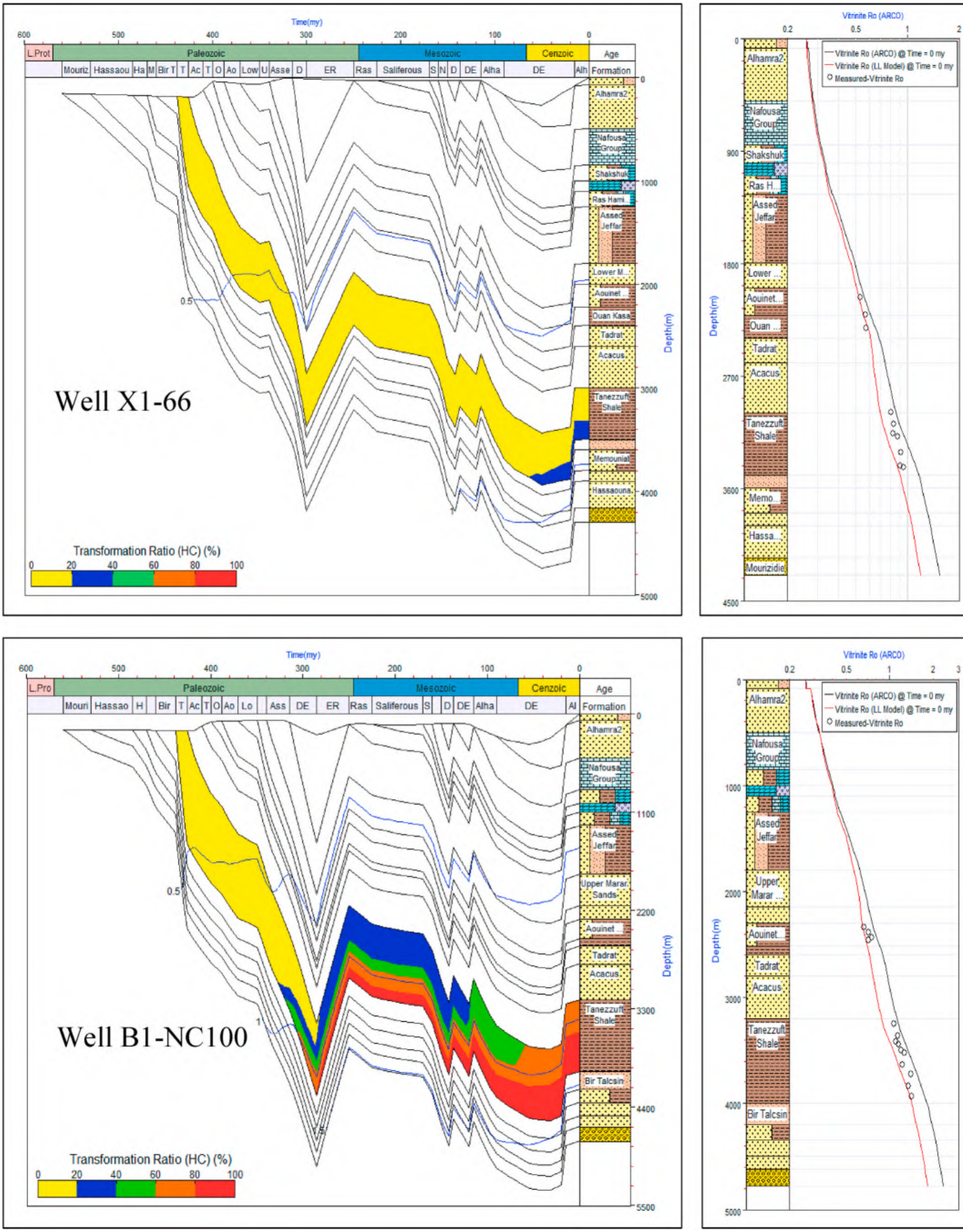

Fig. 17. Kerogen transformation ratio obtained utilizing the geohistorical models in two wells located in the eastern Ghadames Basin (Libya). Well location marked on Fig. 21 with blue stars.

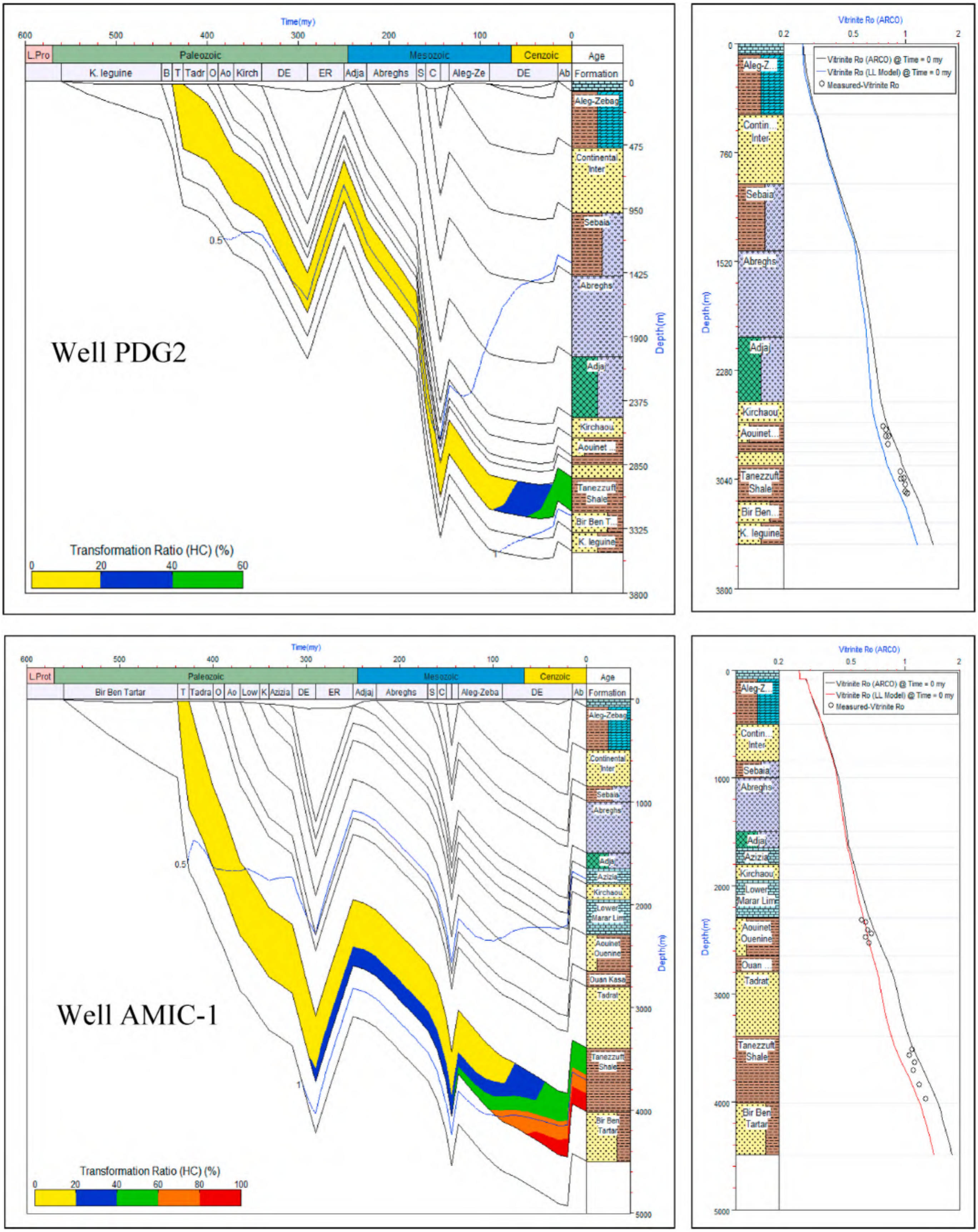

Fig. 18. Kerogen transformation ratio obtained utilizing the geohistorical models in two wells located in the northern Ghadames Basin (Tunisia). Well location marked on Fig. 21.

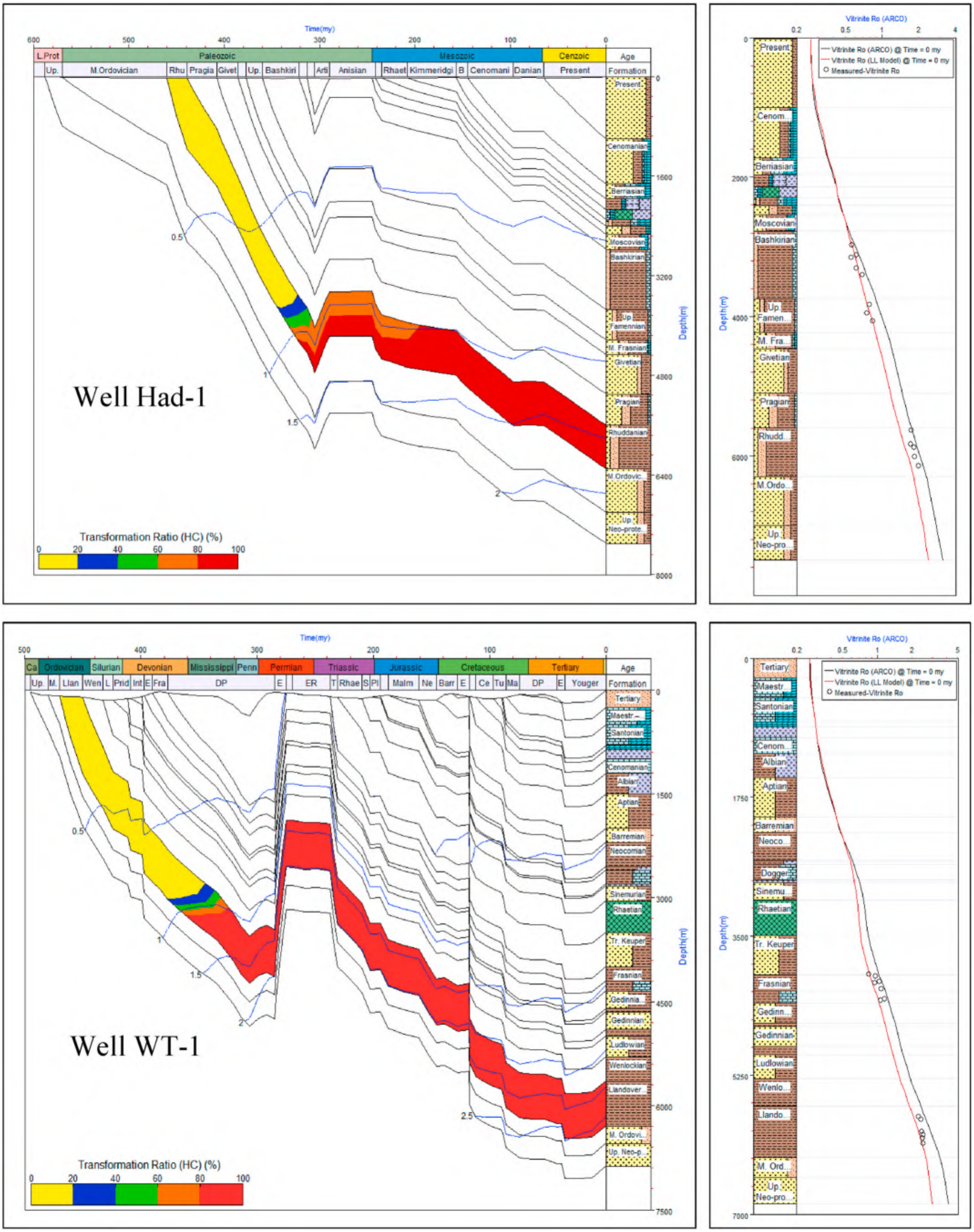

Fig. 19. Kerogen transformation ratio obtained utilizing the geohistorical models in two wells located in the southern Ghadames Basin (Algeria). Well location marked on Fig. 21.

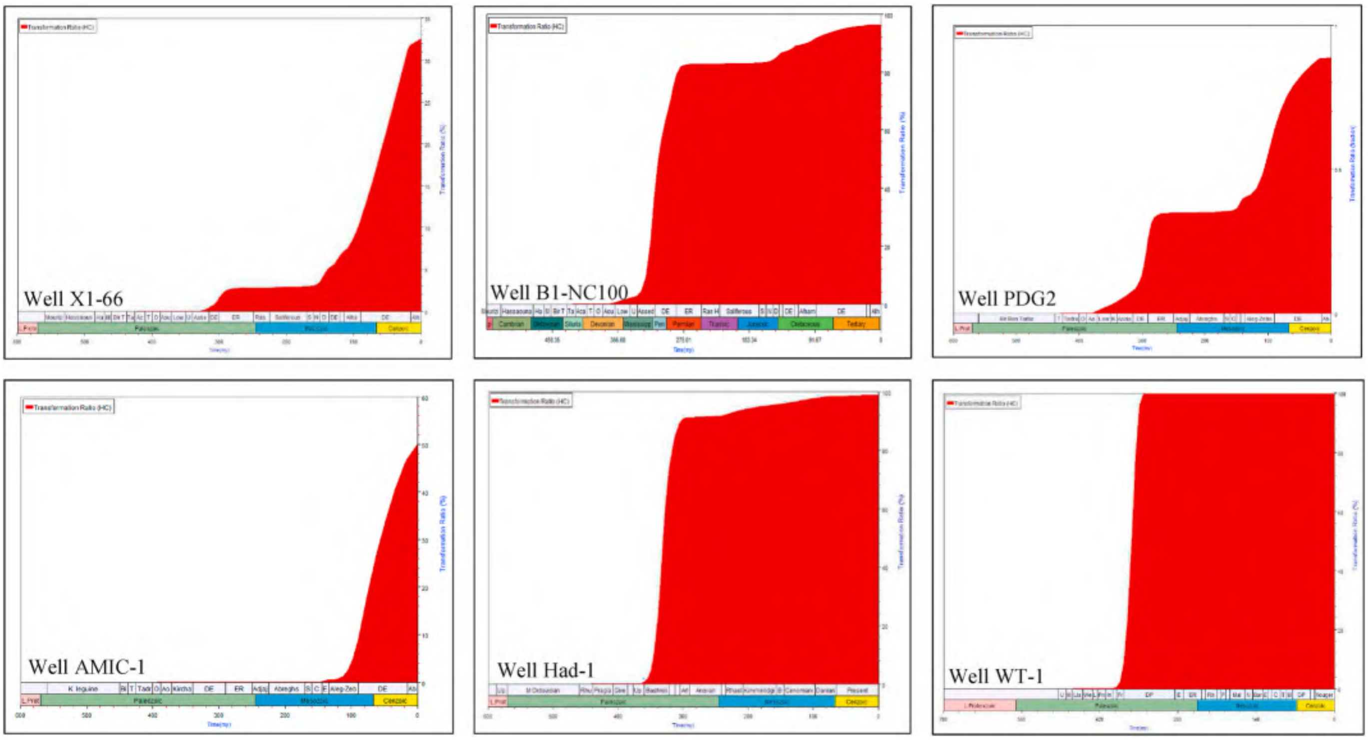

Fig. 20. Time-kerogen transformation relationship of the Silurian hot shale in Ghadames Basin.

VRo) in this area of the basin where the hot shale is presently in the dry gas window. The relationship between these three parameters are mapped in Figs. 14 and 15 to explain such lateral variations from the basin margins to deeper areas of the Ghadames Basin.

The increase in the burial stages allowed the hot shale to enter the appropriate thermal conditions at considerable depth, which forced the hot shale to be dominated by the dry gas phase in certain areas of the basin (basin depocenter). These are the most likely generated volumes from hot shale in Ghadames Basin utilizing the previous defined kinetic model for the Silurian hot shale organofacies type B in North Africa, which is quite different from the hot shale that presented in the Arabian region, for example, the Qusaiba hot shale. The Silurian hot shale in this region is quite different from the hot shale in north Africa were the previous studies regarding the Paleozoic petroleum system analysis and modeling in middle east indicate that Qusaiba early Silurian hot shale influenced by rich Sulphur content, which is indicated that many petroleum traps in this rich petroleum region show higher Sulphur content and low API values (Abu Ali et al., 1991, 1999; Cole et al., 1994; Carrigan et al., 1998; Abu Ali, 2005; Arouri et al., 2010).

The petroleum generation windows in Fig. 22 were established based on certain monitored geochemical and thermal maturity data as a function of the burial depth. The main purpose is to define the petroleum generation windows of the early oil and dry gas from the hot shale when the burial reached such levels. Furthermore, this explains the most likely variations in the richness and maturity parameters of the hot shale when attained such deeper burial levels. Understanding such a process in one of the largest oil and gas-bearing basins in North Africa is critical. It offers a solid platform to investigate the retained volumes of oil and gas in the hot shale because the geological nature of the hot shale offers a self-petroleum system, which means the source, reservoir, and seal were present in one sedimentary unit, which generates and hosts petroleum at the same horizon (Tanezzuft). Based on this study, we expect that a large amount of oil and gas has been retained in the hot shale, which requires further intensive investigations to estimate such retained petroleum volumes and to develop future successful shale oil/gas exploration strategies in the region like the other world key source rocks such as Marcellus, Barnett, Muskwa, Woodford, and Eagle Ford in the USA, the Canadian Montney, and the Silurian LongMaxi hot shale in China.

To understand the Silurian hot shale geochemical and thermal properties that allowed different petroleum generation windows (e.g., oil and gas) to occur in different locations in the Ghadames Basin systematically, which can be helpful to better predict the petroleum charge histories from Silurian hot shale, we developed a generalized petroleum generation model based on four major thermal maturity parameters, such as temperature, vitrinite reflectance, pyrolysis Tmax, and kerogen transformation ratio (Fig. 22). The model in Fig. 22 was established to answer key questions: **1)** how the Silurian hot shale thermally becomes mature and at what stages of burial these levels are attained; and **2)** does the geochemical properties show systematic changes when the Silurian hot shale entered different generation windows? However, Fig. 22 shows that the hot shale oil window presently exists at a burial depth range from 1,200 m to 4,000 m. These ranges are defined based on the richness and different thermal stress (e.g., 55 °C–150 °C and 0.54–1.2 % VRo). These monitoring parameters are beneficial to obtain the petroleum generation windows instead of using the conceptual models to define the top and bottom levels of oil versus gas generation stages that have be used recently by petroleum geologists in many sedimentary basins, which may be less reliable to use for further detailed studies of the petroleum systems. The model also explains that the hot shale entered the present-day gas window stage with a burial depth greater than 4,000 m, which is mainly related to the areal part from the hot shale presented in the Ghadames depocenter.

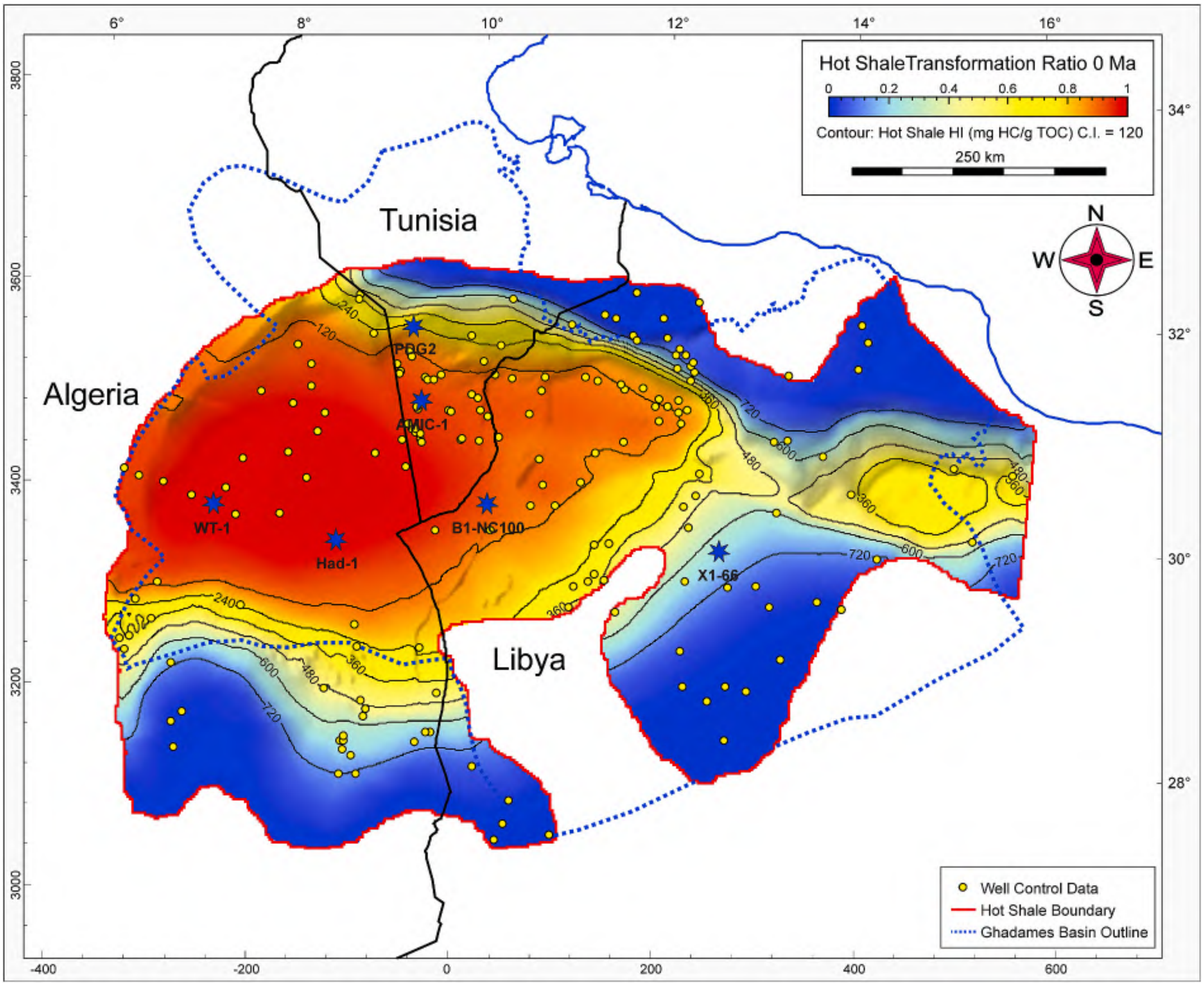

Fig. 21. Regional kerogen transformation ratio map of the Silurian hot shale in Ghadames Basin calibrated utilizing hydrogen index data to identify the systematic trends of the kerogen transformation versus the hydrogen index from the basin margins to the basin depocenter.

6. Conclusion

1. The hot shale is one of the primary source rocks in the North African region distributed in the Paleozoic sedimentary basins, such as the Ghadames Basin, with considerable thickness reaching 120 m in the basin depocenter. The hot shale depositional mechanism in the Ghadames Basin is based on typical marine conditions during the postglacial event and Silurian water transgression episode during the early Rhuddanian time (~443.8–443.4 Ma).
2. The investigations were carried out to define the organofacies type of the Silurian hot shale in the Ghadames Basin, indicating that type B marine organofacies dominate the hot shale with a high %TOC reaching 17.5, and the hydrogen index reached 800 mg HC/g TOC.
3. The refined integrated and calibrated thermal maturity study of the Silurian hot shale demonstrated that the hot shale in the basin margins is in an early mature stage, as indicated by pyrolysis Tmax and vitrinite reflectance data. In contrast, the hot shale has reached the highest thermal maturity levels (postmature) in the main basin depocenter with systematic changes from the basin margin toward the depocenter, as shown by the obtained maturity maps.
4. Modeling the kerogen transformation ratio based on 1D geohistorical models and map-based approaches of the Silurian hot shale indicate that up to 20% of the hot shale kerogen were transformed in the basin margin, while in the deeper parts, the hot shale transformed and converted to petroleum yields with levels reaching 98%.
5. The defined oil and gas window of the Silurian hot shale in the Ghadames Basin using the hot shale base demonstrates that the top and the bottom oil window ranged from 1,500 m–4000 m, and below this level, the hot shale has entered the dry gas window.
6. The Silurian hot shale in the North African cratonic sag basins such as Ghadames are considered as the primary source rocks that actively participated in the Paleozoic petroleum system, and recently, the hot shale in the Ghadames basin is primary target resource as unconventional shale oil/gas production in three regions (Libya, Algeria, and Tunisia), as indicated in this study.
7. We recommend future regional investigations to define the Silurian hot shale unconventional sweet spots and original oil and gas in place (OOIP & OGIP) in Ghadames Basin.
8. To better understand the hot shale's self-petroleum system, future research is required to cover the geomechanical properties such as the brittleness nature, natural fractures, and the fracking ability where the sweet spots of the shale oil and gas play exist.
9. Multi-dimensional modeling studies of the generated and expelled versus the retained amount of the oil and gas from the hot shale are

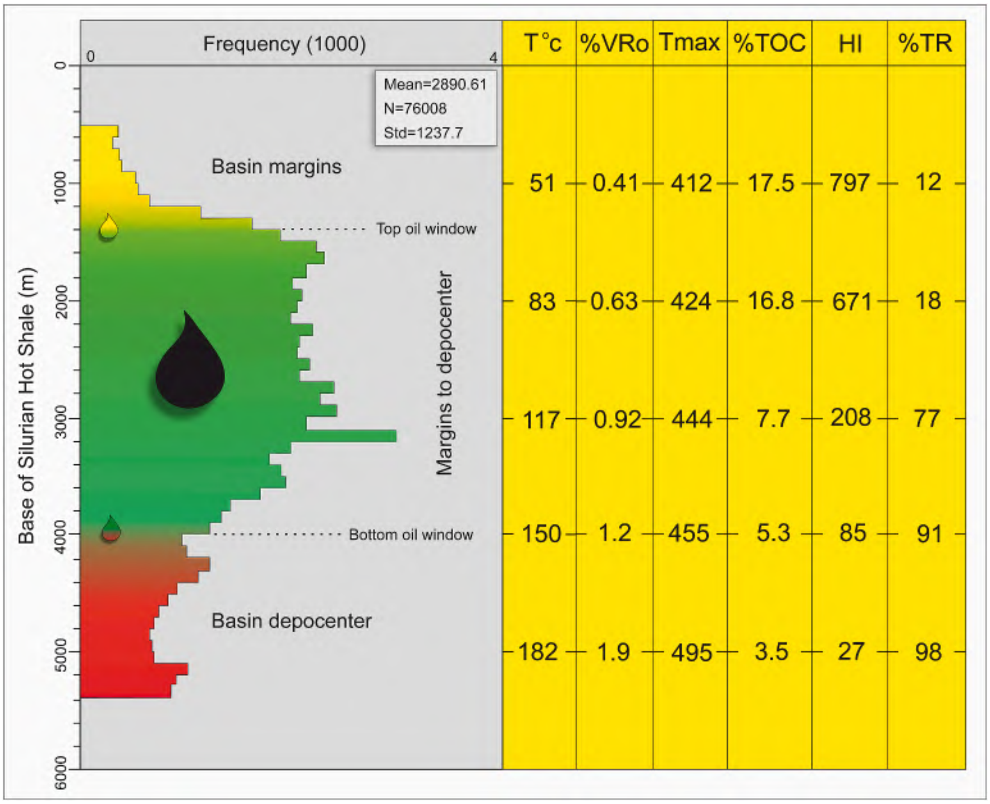

Fig. 22. Monitored petroleum generation model of the Silurian hot shale in Ghadames Basin (T°C = temperature, %VRo = vitrinite reflectance, Rock-Eval maximum S2 pyrolysis temperature, %TOC = total organic carbon content, HI = hydrogen index, and %TR = transformation ratio).

needed to develop successful future drilling programs in Libya, Algeria, and Tunisia.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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