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Organic matter identification in source and reservoir carbonate in the Lower Cretaceous Mauddud Formation in Kuwait

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ABSTRACT

The purpose of this study is to identify the source rock, reservoirs and non-productive zones in the Lower Cretaceous Mauddud Formation in Kuwait, using geochemical methods. This formation is one of the major Cretaceous oil reservoirs. It is composed mainly of calcarenitic limestone interbedded with marl and glauconitic sands. Its thickness ranges from almost zero in the south to about 100 m (328 ft) in the north. A total of 99 core samples were collected from six oil fields in Kuwait: Raudhatain, Sabiriyah and Bahra in the north, and from the Burgan, Ahmadi and Magwa in the south. Well logs from these fields (gamma ray GR, sonic, resistivity, density) were correlated and used in the study. The core samples were screened for the amount and nature of the organic matter by Rock-Eval 6 pyrolysis (RE6) using reservoir mode. A set of samples was selected to study the properties of the organic matter including the soluble and insoluble organic parts. The geochemical characterisation was performed using different methods. After organic solvent extraction of rock samples, the solvent soluble organic matter or bitumen was characterised in terms of saturates, aromatics and heavy compounds (resins and asphaltenes). Then the hydrocarbon distribution of saturates was studied using gas chromatography (GC/FID) and gas chromatography-mass spectrometry (GC/MS) for tentative oil-source rock correlation. After mineral matrix destruction of previously extracted rocks, insoluble organic matter or kerogen was analysed for its elemental composition to identify kerogen type.

The geology and the analytical results show similarities between the wells in the southern fields and the wells in the northern fields. Average Total Organic Matter (TOC) in the carbonate facies is 2.5 wt.% and the highest values (8.0 wt.%) are in the northern fields. The clastic intervals in the northern fields show higher total organic matter (1.3 wt.%) relative to the southern fields (0.6 wt.%). The total Production Index is higher in the carbonate (0.6) than the clastic section (0.3). This reflects the amount of extractable hydrocarbons, which are usually associated with the carbonate section in this formation, representing its reservoir section. Although the carbonate rocks are dominated by richer total organic matter, there are some intervals, with low total organic matter values (0.07 wt.%), representing its poor reservoir sections. The kerogen type varies between type II-III and III in the shales with a slightly better quality in the carbonate section. It is immature in almost all the studied fields.

The composition of the rock extract has no relation with the rock type. Some sandstone show similar extract composition to the carbonate rocks in the reservoir intervals. The extracts from these intervals show different genetic nature than those in the shales. The maturity level in the reservoir extract is much higher than in the shale intervals. Thus, the oil accumulated in the reservoir might be largely related to migrated oil from a more mature source rock deposited in a clearly different environment than the associated shaly intervals. The best candidates being a more deeply buried Early Cretaceous Sulaiy Formation and Upper Jurassic Najmah Formation.

INTRODUCTION

Kuwait is located in the northeastern part of the Arabian Peninsula, within the Arabian-Iranian basin. Recoverable reserves of oil and gas in this basin are about 64% and 31% of world reserves, respectively. In Kuwait, proven oil and gas reserves represent 17% and 4% of the total basin reserves, respectively. Oil is produced mostly from Cretaceous formations; while Tertiary and Jurassic reservoirs account for some minor production. The Mauddud Formation is one of the major Cretaceous oil reservoirs in Kuwait (Figure 1).

The Mauddud Formation is mainly composed of a whitish calcarenitic limestone with a thickness that varies between zero in the south to about 100 m (328 ft) in the north (Figure 2). The carbonates are interbedded with marl and fine, greenish-brown glauconitic sandstones, and contain abundant microfossils and some pyrite. The main reservoir facies consist of clean to clay-bearing packstones deposited in a mid-ramp setting. High-energy facies deposited in the form of grainstone and skeletal packstone form the major permeability reservoir zones and are likely to act as channels for fluid flow (Al-Ajmi et al., 2001; Abdul Azim et al., 2003).

Based on a study of two rock samples, Abdullah and Kinghorn (1996) identified an amorphous kerogen in the carbonate part of the Mauddud Formation. Additionally, geochemical studies of the Mauddud oil indicated that it was sourced from mature carbonate rocks (Abdullah and Connan, 2002). These studies suggest that the Mauddud Formation may be the source rock for part of the oil accumulated in the Mauddud reservoir. The purpose of this paper is to study the nature and distribution of the organic matter in the Mauddud Formation in Kuwait.

METHODOLOGY

A total of 99 core samples were collected from six Kuwaiti fields: Raudhatain (RA), Sabiriyah (SA) and Bahra (BH) in the north, and Burgan (BG), Ahmadi (AH) and Magwa (MG) in the south (Figure 3). In addition well logs from all six fields were correlated (GR, sonic, resistivity, density) and used in the study. The composition of these rocks is dominated by carbonates with rare clastic shales and glauconitic sandstone. The core samples were screened for the amount and nature of the organic matter by Rock-Eval 6 pyrolysis (RE6) using reservoir mode. In this method, the RE6 correspond to the following temperature program: isotherm 200° C during 5 minutes, followed by a heating ramp from 200–650° C at a rate of 10° C/minute, while in the classical RE6 method the isotherm 300° C during 5 minutes, followed by a heating ramp from 300–650° C at a rate of 25° C/minute.

RE6 (reservoir mode) quantifies the amount, and to some extent, the composition of organic matter present in a reservoir in the form of three pyrolysis peaks (S1, S2a, S2b) and the oxidised carbon residue (Rc) (Figure 4). S1 and S2a usually represent the thermovaporisable hydrocarbons. S2b represents the hydrocarbons formed as a result of thermal cracking of the NSO compounds (Lafargue et al., 1998). T_{max} and PI parameters results by the classical RE6 is given in RE6 reservoir mode as follows: T_{maxa} and T_{maxb} representing T_{max} for both peaks S2a and S2b, respectively; PI is given as TPIr ((S1+S2a)/(S1+S2a+S2b)). T_{maxa} and T_{maxb} do not represent maturity parameter for the source rock, both may reflect the nature of the hydrocarbons in the two peaks S2a and S2b. The T_{max} value used in this study to evaluate the maturity level is taken from T_{max} in the Classical RE6. For detailed explanation of these methods, the reader may refer to Trabelsi et al. (1994) and Lafargue et al. (1998).

Characterisation of the organic matter using the RE6 in reservoir mode enabled us to identify bitumen and kerogen rich zones. Based on the RE6 data, a set of rock samples was selected to study the composition of the soluble fraction (bitumen or C_{14+} rock extract), as well as the insoluble fraction (kerogen). The ground rock samples were extracted using dichloromethane (DCM), the bulk composition of the extractable bitumen (in terms of saturates, aromatics and NSO compounds: resins + asphaltenes) was determined. Then, the saturates of extractable bitumen were analysed by GC/FID and GC/MS. GC/FID analysis of saturated hydrocarbons was performed on a Varian 3800 gas chromatograph equipped with an on-column injector, a Flame Ionisation Detector FID (set at 300° C) and a DB-1 fused silica column (60 m x 0.25 mm i.d. x 0.25 µm film thickness). Helium was

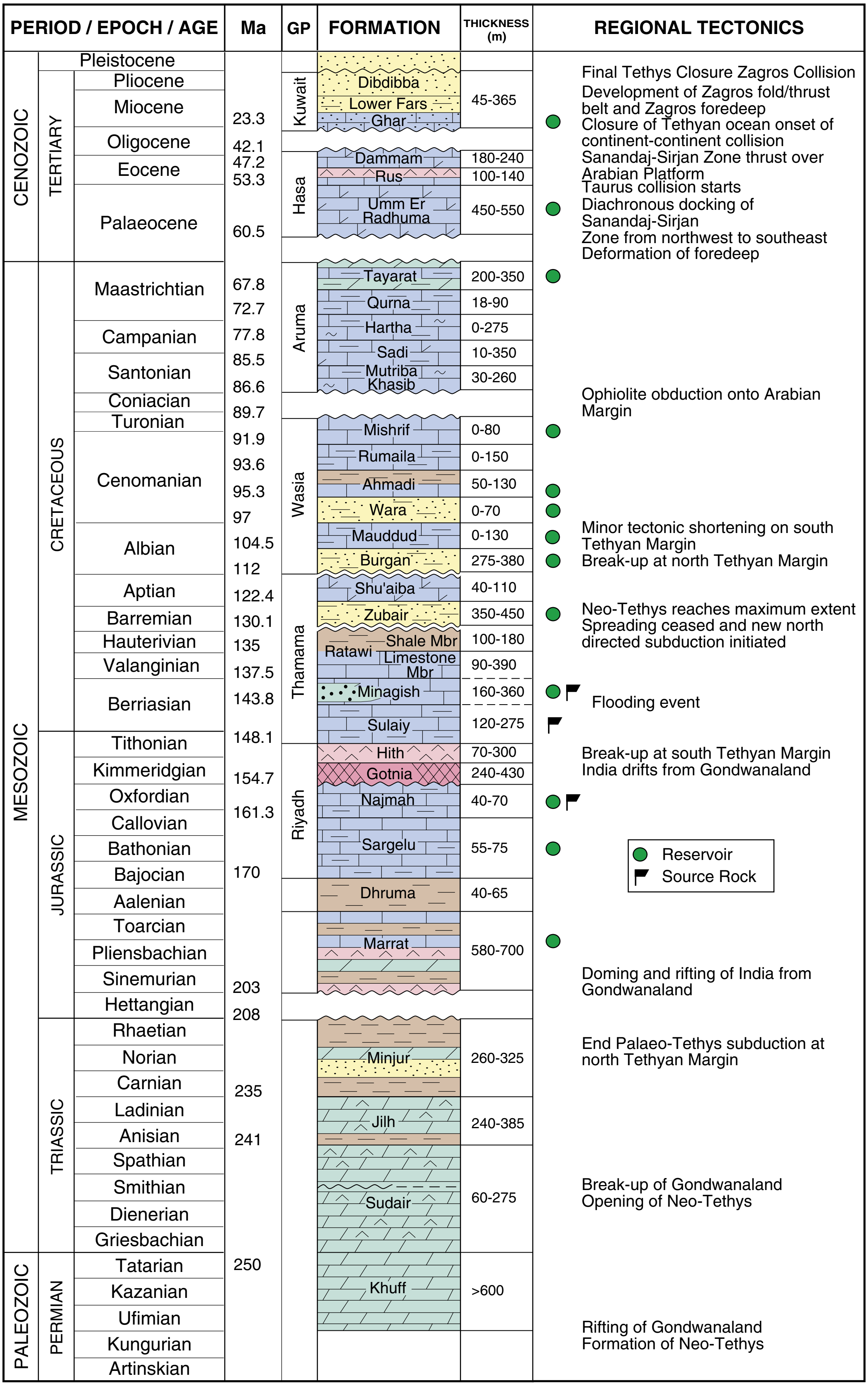


Figure 1: Stratigraphic column of Kuwait.

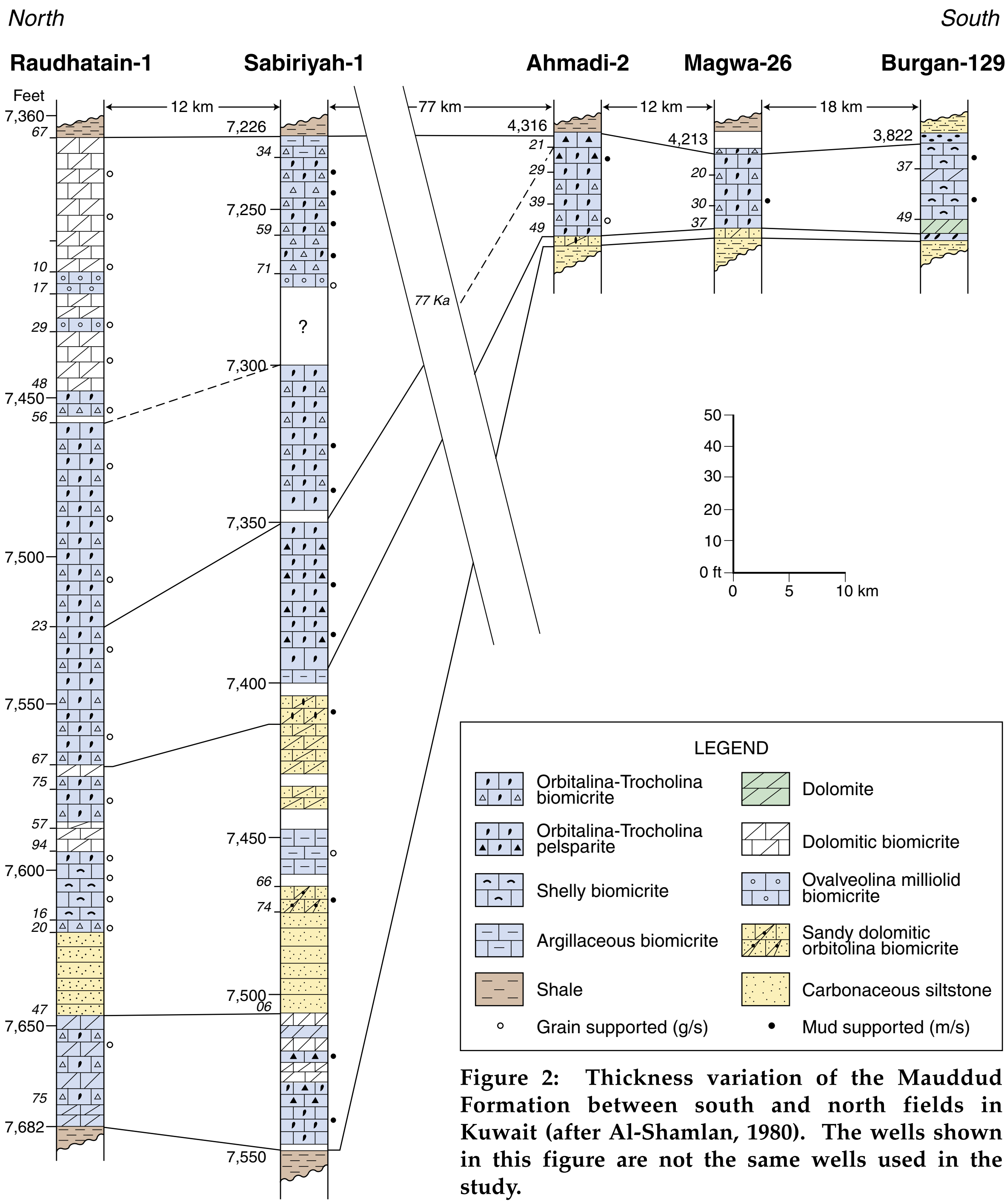


Figure 2: Thickness variation of the Mauddud Formation between south and north fields in Kuwait (after Al-Shamlan, 1980). The wells shown in this figure are not the same wells used in the study.

used as a carrier gas. Temperature program: 50–100° C (10° C/min.), 100–300° C (3° C/minute), isothermal 300° C (hold for 10 minutes). GC-MS analysis of saturates was carried out on MD800 mass spectrometer (Thermo-Finnigan) equipped with a GC 8000 series gas chromatograph using splitless injector at 320° C (helium carrier gas) and a J&W DB-1 column (60 m x 0.22 mm i.d., 0.25 µm film thickness). Temperature program: 50–150° C (35° C/minute), 150–320° C (2° C/minute). Mass spectra were produced at 70 eV electron energy, using a source temperature set at 300° C and in MRM (Metastable Reaction Monitoring) detection mode over the 50–600 amu range. Kerogen isolation was performed on the previously extracted rock samples using HF and HCl acids mixtures (Durand and Niçaise, 1980) and elemental composition (C, H, O, S, N) was measured to identify its organic matter type. The complete analytical procedure is summarised in Figure 5.

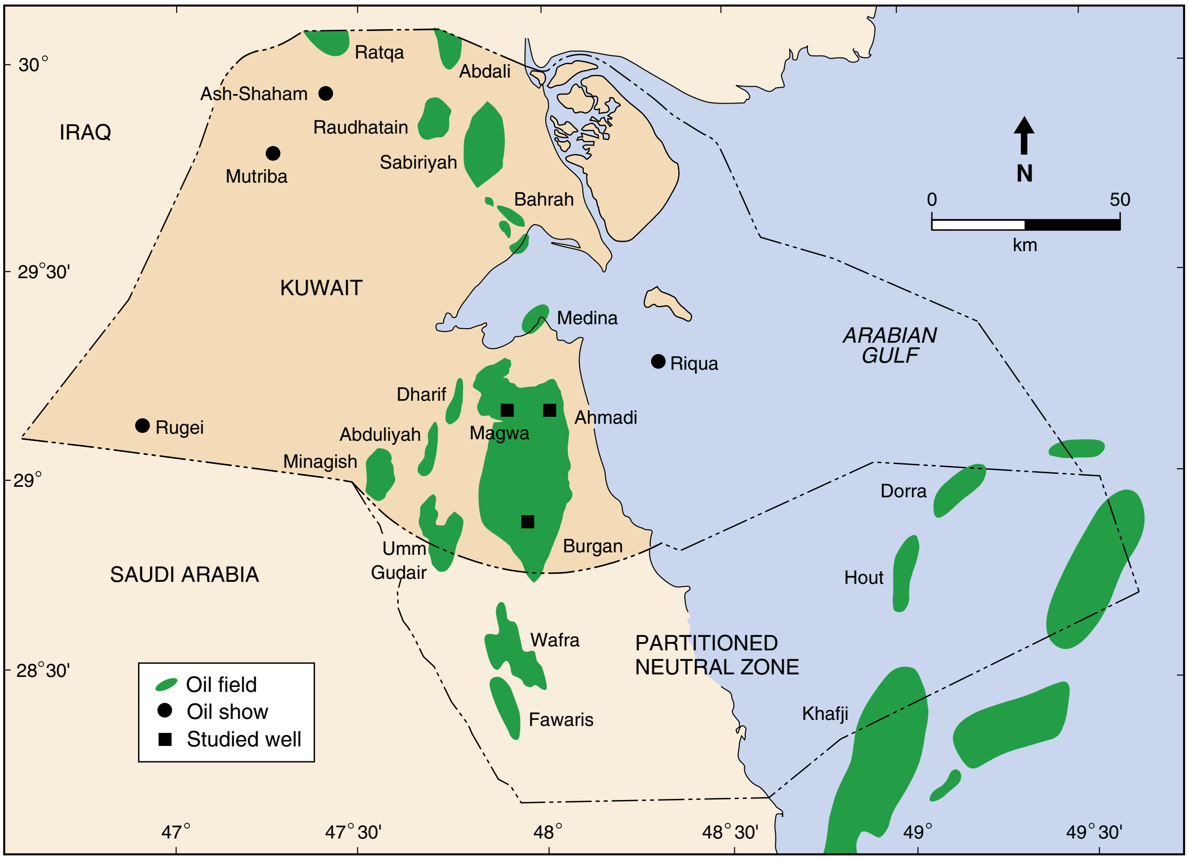


Figure 3: Location map of the studied wells.

GEOLOGY AND GEOCHEMISTRY

The Early Cretaceous succession in Arabia is characterised by nearly continuous sedimentation of carbonates on the Arabian side of the Gulf, and clastics towards the Arabian Shield (Al-Shamlan, 1980; Alsharhan and Nairn, 1997). The carbonates of the Albian Mauddud Formation are typical of this shallow-shelf environment (Figure 6). The Mauddud Formation is widespread in the Gulf region and can be traced from the Rub' Al-Khali in southern Saudi Arabia, to as far north as Iraq. It is composed of laminated crystalline limestone in Saudi Arabia, and wackestone, packestone and mudstone in Bahrain, Qatar, and the United Arab Emirates. Palynological studies of the Mauddud Formation in Qatar indicate that it was deposited on an inner- to middle shelf in waters depths of 20–100 m (Ibrahim and Al-Hitmi, 2000).

Sharland et al. (2001) used the *orbitolina sefini* Biozone foraminifera as an age diagnostic fossil, to conclude that during the Mauddud transgression, the clastic shoreline systems (including the Burgan delta) were pushed far back to southwestern part of the Arabian Plate. Accordingly, the lower contact of the Mauddud Formation can be correlated from Kuwait, Saudi Arabia, Qatar, and the United Arab Emirates, to the base Natih Formation in Oman and the base Sarvak Formation in Iran.

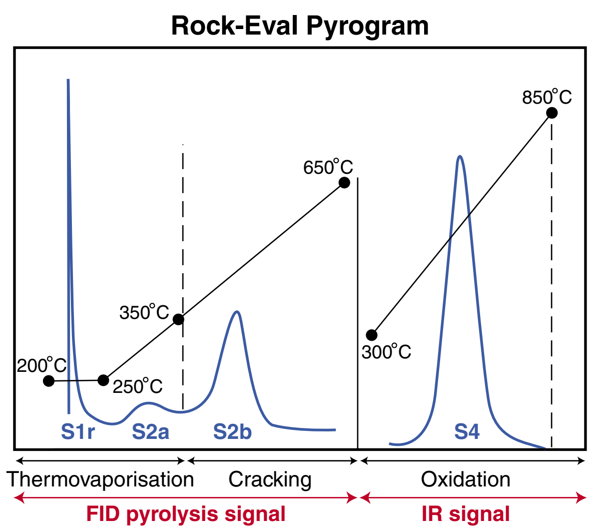


Figure 4: Principles of Rock Eval 6 using reservoir mode.

In Kuwait, the Mauddud Formation is composed mainly of packstone/wackstone and contains interbedded grey fine limestone; and some thin, interbedded with marl and fine, greenish-brown glauconitic sandstones. It contains abundant microfossils and some pyrite. The formation thickness ranges from nearly zero in the south to about 99 m (324 ft) in the north. It is overlain by the Wara sandstone Formation and underlain by the Burgan Formation (Al-Shamlan, 1980; Alsharhan and Nairn, 1997).

The Mauddud Formation is an oil reservoir in Bahrain, Kuwait, Qatar and Saudi Arabia. In Qatar the Mauddud is a potential source rock (Frei, 1984) with a thermal alteration index indicating it is early mature (Ibrahim and Al-Hitmi, 2000). In Iran, the age-equivalent Albian

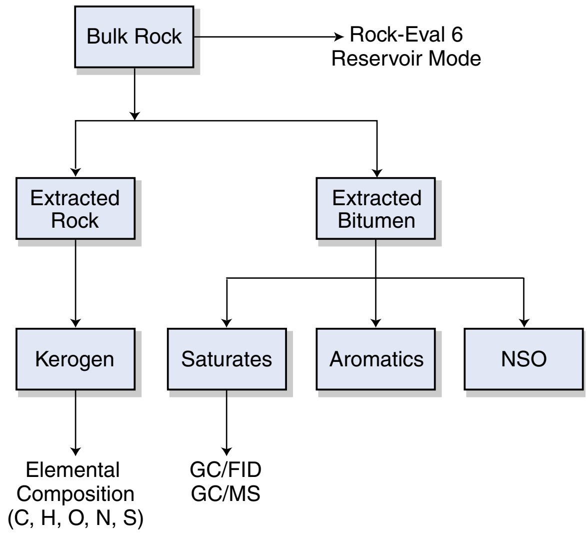


Figure 5: Flow chart for the analytical procedure used.

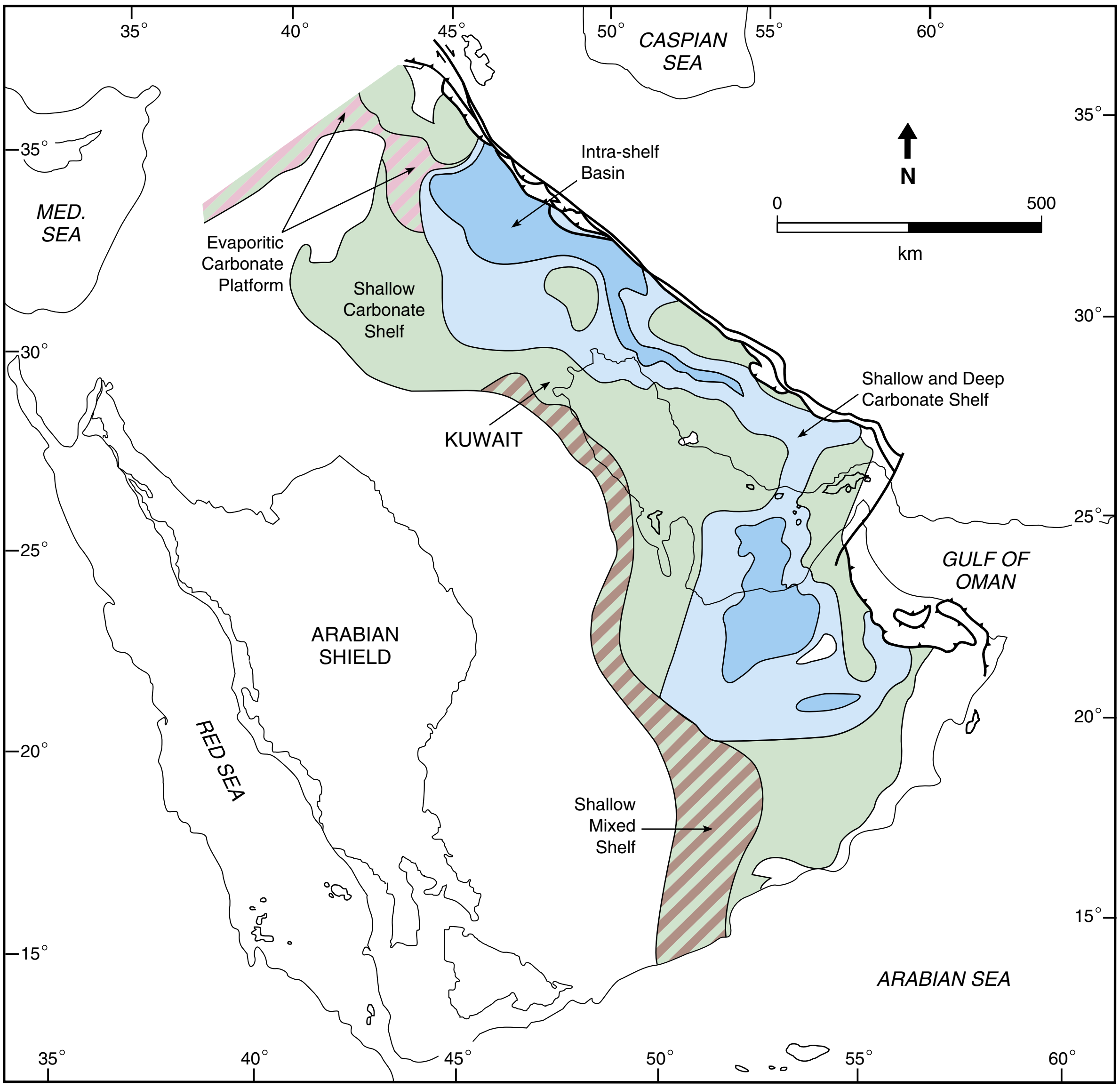


Figure 6: Late Albian depositional environment in the Gulf area (modified after Murris, 1980).

Khazhdumi Formation is also a source rock (Alsharhan and Nairn, 1997). It is composed of dark bituminous shale with subordinate, dark, argillaceous limestone (Beydoun, 1991). Its organic matter is mainly of marine origin with few spores and pollen. This formation also inter-fingers with the sandstone of the Burgan Formation and is believed to be the source for the oil in this reservoir (Ala, 1979).

Al-Ajmi et al. (2001) divided the Mauddud limestone into 13 carbonate facies and 6 clastic facies deposited in an environment ranging from inner ramp to outer ramp and deeper basin. Major reservoir facies consist of clean to clay-bearing packstones deposited in a mid-ramp setting. High-energy facies deposited in the form of grainstone and skeletal packstone form the major permeability contrast and are likely to channelise the fluid flow in the reservoir. According to Al-Ajmi et al. (2001), the variations in permeability of the reservoir units are related to cementation, after bioturbation producing reservoir barriers.

In Kuwait, the Mauddud Formation is one of the main oil reservoirs and it produces from: Raudhatain, Sabiriyah and Bahra fields in the north; Burgan, Magwa and Ahmadi fields in the south; and from the Khafji field in the offshore Neutral Zone (Figure 3). The thickness of the Mauddud Formation in Raudhatain and Sabiriyah fields ranges from 106–121 m (350–400 ft) (Al-Ajmi et al., 2001). The Mauddud reservoir is characterised by inter-granular porosity, with very little or negligible development of secondary porosity. The average porosity and permeability of this reservoir is 15–33% and 10–23 mD, respectively. The permeability is not homogenous. In the Raudhatain and Sabiriyah fields it varies between 30–500 mD and in the clastic unit it may reach as high as 1,200 mD.

The Mauddud oil gravity ranges between 17–30° API and the average sulphur content is 3.0% (Alsharhan and Nairn, 1997). Geochemical studies of the oil from Cretaceous and Jurassic reservoirs indicate that it was generated from a marine, algal type II-S kerogen (Abdullah and Connan, 2002). It is believed to be from carbonate source rocks. The nature of the organic matter accumulated in the carbonate sections of the formation is an amorphous, marine type (Abdullah and Kinghorn, 1996). It might play a role in sourcing the reservoir section with oil.

RESULTS: SOUTHERN FIELDS

The southern fields Magwa, Burgan, and Ahmadi fields form the Great Burgan field. The thickness of the Mauddud Formation in these fields ranges between 9–15 m (30–50 ft). The formation is composed of interbedded carbonates, marl, shales, siltstones and sandstones. The results of the geochemical analyses are shown in Figures 7a to c.

Magwa Field (Figure 7a): The thickness of the Mauddud Formation in the studied well is 20 m (66 ft). The upper 9 m (30 ft) is composed mainly of carbonate, while the rest is alternating shales, sandstones and carbonates. The TOC varies between 0.1–3.5 wt.%, where the highest values occur in the upper 9 m (30 ft). The RE results show that this zone is characterised by high S1, S2a, and S2b where the ratio of the three is similar.

The lowermost laminated shale layer is also characterised by high TOC, which reaches 3.2 wt.%. In this zone, the Rc/TOC is relatively high (0.6). The soluble organic content is relatively low (27.9%) and associated with a high NSO content (52.5%) (Figure 9). The shale is dominated by type III immature kerogen (Figure 10). GC/FID analysis of the saturates of the extract (Figure 11) indicates mature source (pristane (Pr)/nC_{17} = 0.23, phytane (Ph)/nC_{18} = 0.41), which was deposited in a reducing environment. This may result from oil impregnation from the surrounding reservoir in the upper carbonate section, as well as some sandstone layers in the lower part of the formation.

Burgan Field (Figure 7b): The upper 1.8 m (6 ft) of the Mauddud Formation in the studied well in this field is composed mainly of laminated shale. The remaining 6 m (20 ft) is carbonate. TOC measurements are lower than in the Magwa field, ranging between 0.3–2.0 wt.%. The average TOC in the shale is 0.6% with very low S1, S2a and S2b and high Rc/TOC ratio (0.9). They represent an immature type II/III kerogen (Figure 10). The TOC values increase slightly in the lower carbonate section of the formation. This zone also has the highest TPIr values (0.4–0.8), and the extracts represent 70.0% of the total organic matter. The extract has relatively similar saturates, aromatics and

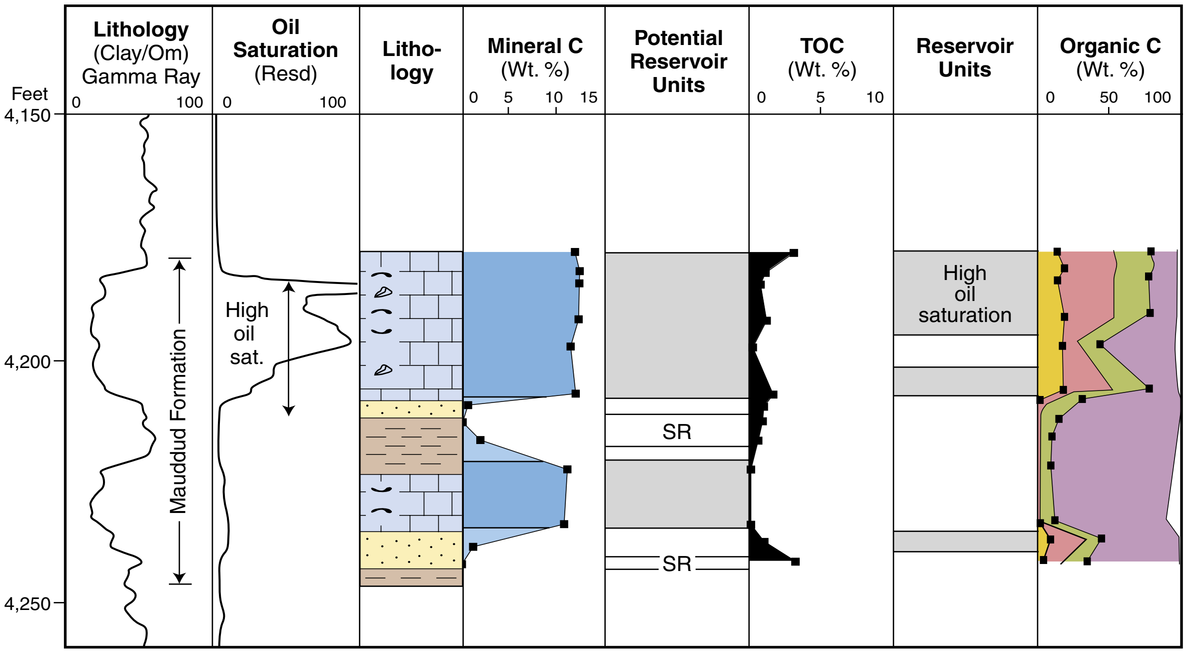
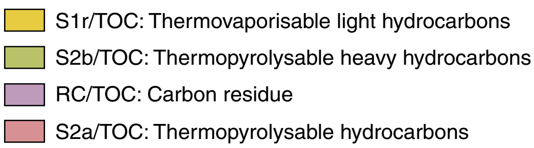


Figure 7a: Geologic and geochemical results of samples collected from Magwa field. Mineral carbon show two major carbonate intervals separated by a clastic interval. High TOC intervals in the clastic shale interval indicate source rock (SR). High pyrolysable hydrocarbon intervals (S1r/TOC, S2a/TOC, S2b/TOC) show reservoir parts of the formation.



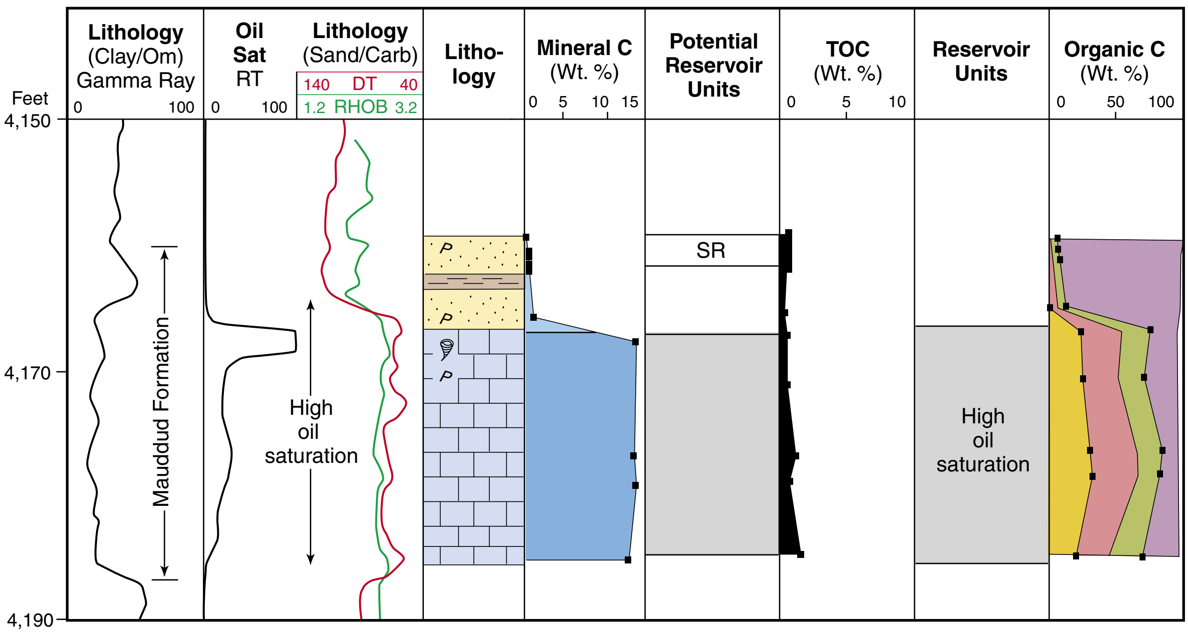


Figure 7b: Geologic and geochemical results of samples collected from Burgan field. Mineral carbon show one major carbonate interval. The high pyrolysable hydrocarbon results in this part indicate the reservoir interval. The TOC value in the thin shale clastic section indicates source rock (SR).

resins concentration (≅ 30%) (Figure 9). The low Pr/Ph ratio (0.65) indicates that the hydrocarbons were derived from a source rock deposited in a reducing environment.

Ahmadi Field (Figure 7c): The thickness of the Mauddud Formation in the studied well is 13 m (44 ft). The lithologies alternate between clastic and carbonate. The clastic sections are dominated by shale except for a thin layer of sandstone above the underlying Burgan Formation. The carbonate is located in the middle part of the formation with a thickness of 6 m (20 ft). The TOC in this zone ranges between 0.25–2.0 wt.% where the highest value occurs in the middle of the section. The S1, S2a and S2b represent about 70.0% of the TOC and are almost homogeneous along the section.

The clastic section has an average TOC value of 0.7 wt.% with the highest value in the sandstone layer. The Rc/TOC value in this section is around 0.9 and extracted part is 5.0% of the total organic matter. Its organic matter is immature type III kerogen (Figure 10) and NSO compounds (52%) dominate the extract composition (Figure 9).

RESULTS: NORTHERN FIELDS

The thickness of the Mauddud Formation in the Sabiriyah, Raudhatain, and Bahra fields ranges between 91–116 m (300–380 ft). The formation is dominated by carbonate rocks, but also contains intervals of clastic rocks. The highest clastic interval in these fields is in Bahra and the lowest is in Sabiriyah. The results of the geochemical analyses are shown in Figures 8a to 8c.

Sabiriyah Field (Figure 8a): The thickness of the Mauddud Formation in the studied well is 102 m (337 ft). The top 76 m (250 ft) and the lower 6 m (20 ft) are carbonate; a 15-m-thick (50 ft) clastic sandstone layer occurs between them. The rest of the formation is shale. TOC ranges between 0.1–9.0 wt.%. This sharp variation is recognised in the carbonate section. The RE6 results show that zones with high TOC are homogeneous in their S1, S2a and S2b, which represent a high TOC% (average 80.0%); while zones of low TOC have relatively high Rc/TOC (0.7) and consist of carbonates with very low permeability.

The clastic sandstone layer has a similar organic character to the carbonate high-TOC sections. The thin laminated layers within the clastic section have TOC 1.5 wt.% with Rc/TOC ratio around 0.7 and the lowest TPIr value (0.27) in the studied section.

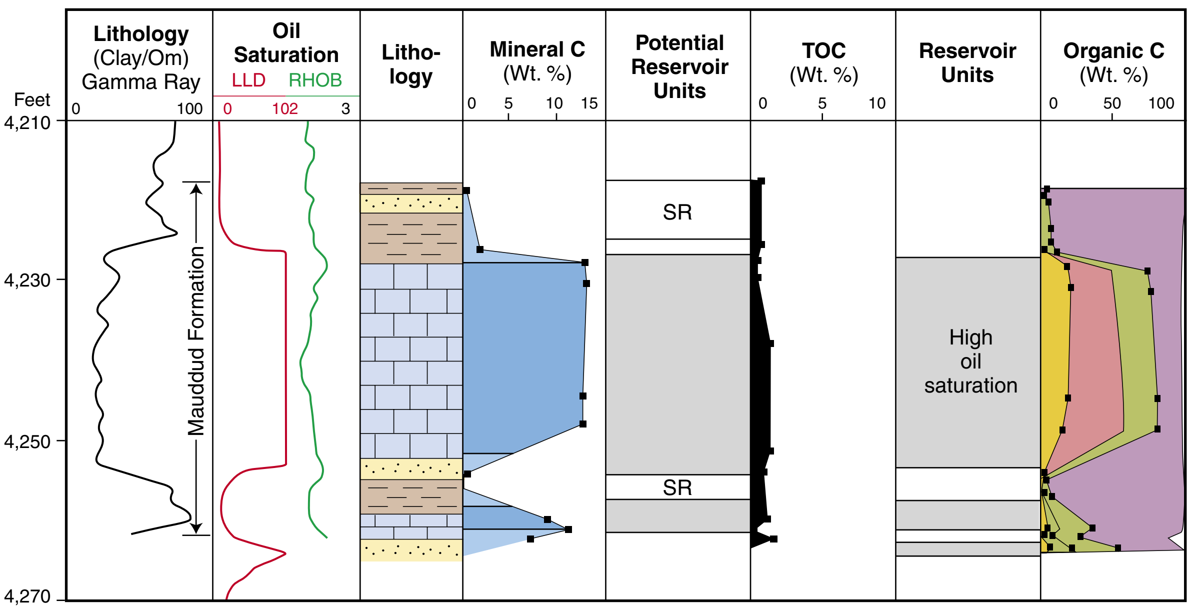


Figure 7c: Geologic and geochemical results of samples collected from Ahmadi field. Mineral carbon show major middle carbonate reservoir with high pyrolysable hydrocarbon shown by the organic C curve. The clastic shale interval in the upper part of the section is a source rock (SR).

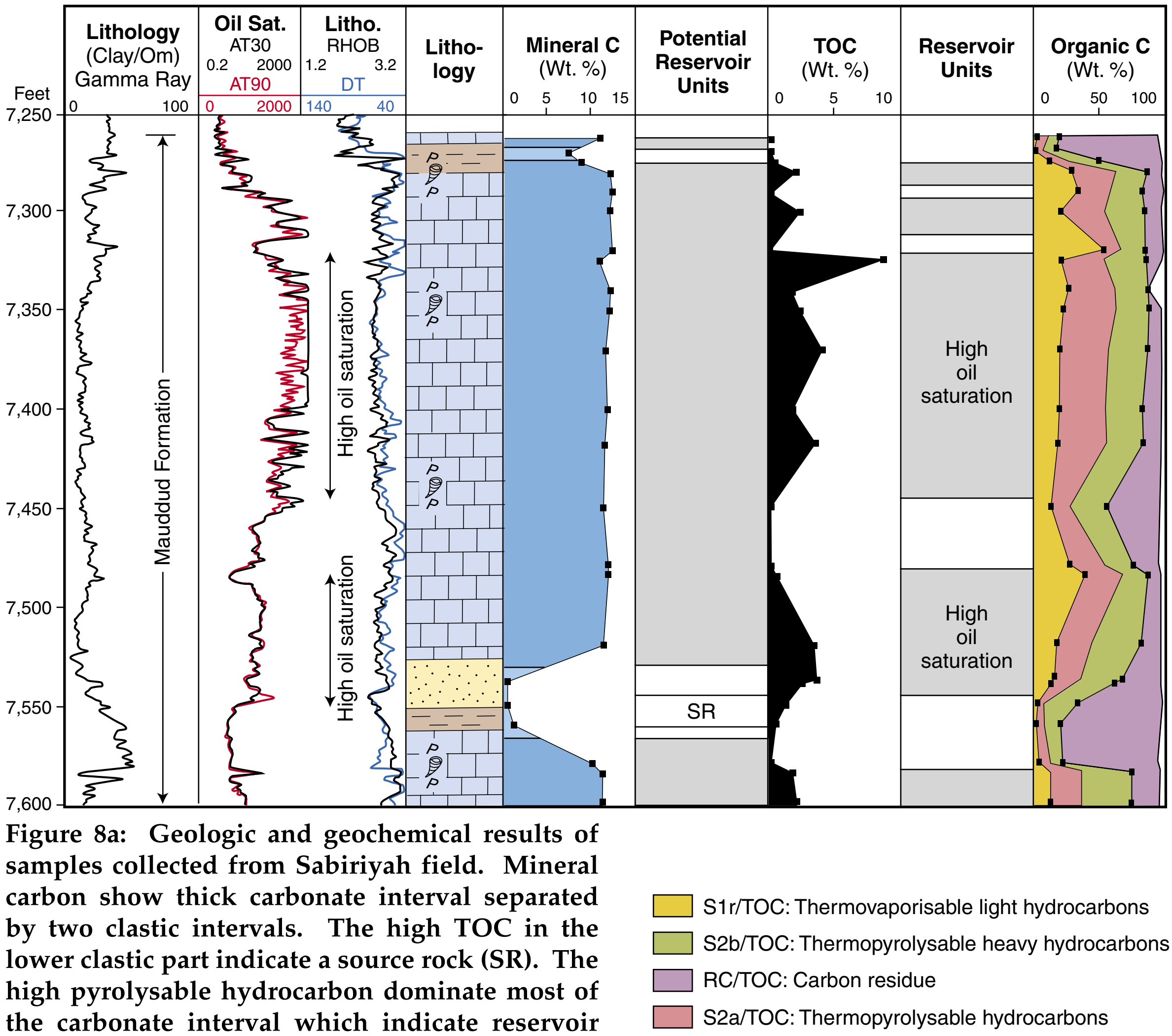


Figure 8a: Geologic and geochemical results of samples collected from Sabiriyah field. Mineral carbon show thick carbonate interval separated by two clastic intervals. The high TOC in the lower clastic part indicate a source rock (SR). The high pyrolysable hydrocarbon dominate most of the carbonate interval which indicate reservoir rocks.

The volume of extractable organic matter for samples from the carbonate section is high (90%). The analyses show NSO content vary between 31–53% (Figure 9). The Pr/Ph ratio (< 1) indicates that the oil has been generated from a source rock deposited in a reducing environment. Type II/III kerogen is incorporated within these carbonate sections (Figure 10). They are at the early stage of oil maturity. The Pr/nC_{17} and Ph/nC_{18} ratios in the extract indicate a mature oil.

Raudhatain Field (Figure 8b): The Mauddud Formation in the studied well has a thickness of 109 m (360 ft), where 70% of the section is carbonate and the rest is composed mainly of laminated shale and calcareous shale. The TOC ranges between 0.7 and 2.6 wt.% in the carbonate, and between 0.24 and 1.1 wt.% in the shales. The S1, S2a and S2b in the carbonate section is relatively high (70–90% of the TOC), but in low TOC zones they decrease to 30% of the TOC.

The shales show high Rc/TOC value (0.8). The soluble carbon represents 5–10% of the TOC. They are characterised by high saturates (≅ 60%) and low NSO contents (≅ 20%) compared to the other extracted samples in the above studied wells (Figure 9). The Pr/Ph show relatively higher values (0.8-0.9) compared to the other extracts, though the Pr/nC_{17} (0.23) and Ph/nC_{18} (0.33) have similar characteristics. They indicate mature source rock. The kerogen in the shale section is type III with a T_{max} of 430° C (Figure 10).

Bahra Field (Figure 8c): The Mauddud Formation in the studied well has a thickness of 82 m (270 ft). The lithology is not homogeneous and changes between clastic sandstone, siltstone, shale and carbonate. The continuous section of carbonate is about 43 m thick (140 ft). TOC maximum value (2.0 wt.%) is within the carbonate section, but sometimes it may be as low as 0.05 wt.%. The high TOC areas generally have high S1, S2a, and S2b, which indicates the reservoir oil. The TOC in the clastic

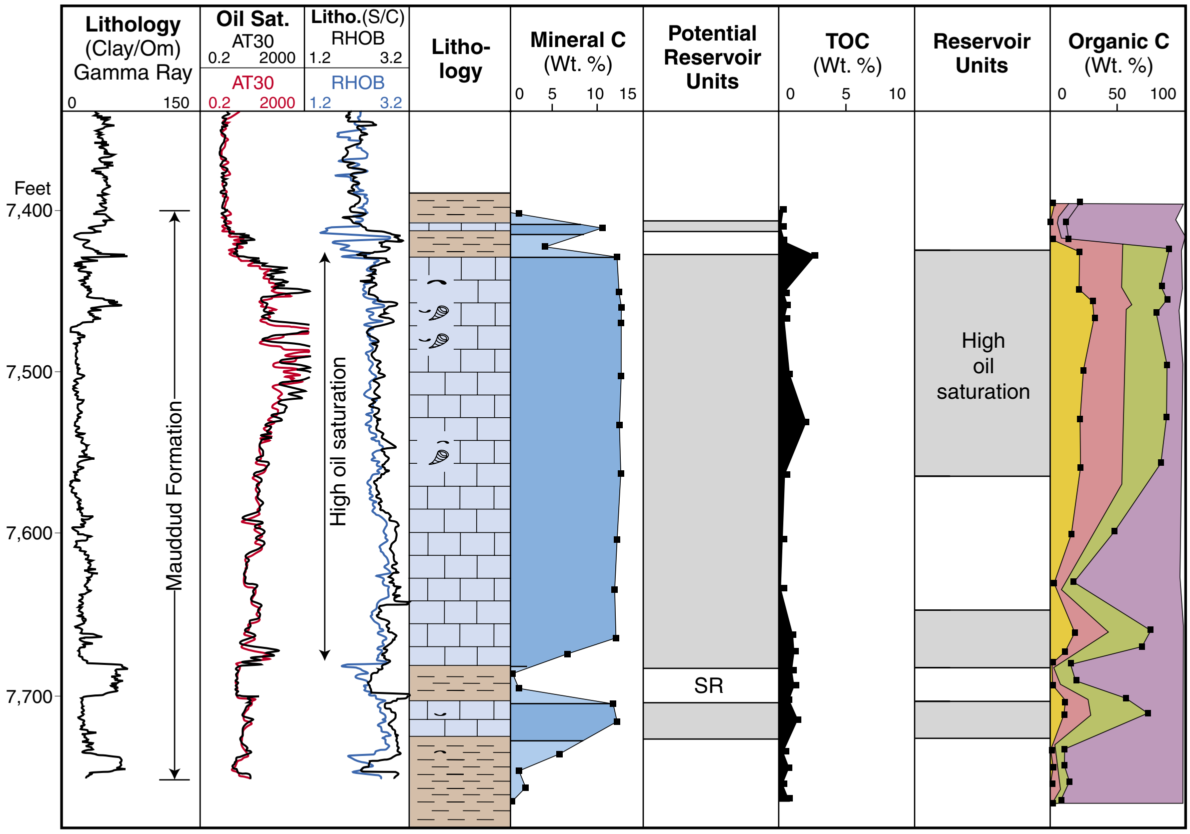


Figure 8b: Geologic and geochemical results of samples collected from Raudhatain field. Mineral carbon show four thin clastic intervals between major carbonate rocks. The high TOC and low pyrolysable hydrocarbon in the lower clastic interval indicate source rock (SR). Most of the carbonate rocks contain high pyrolysable hydrocarbon representing reservoir intervals.

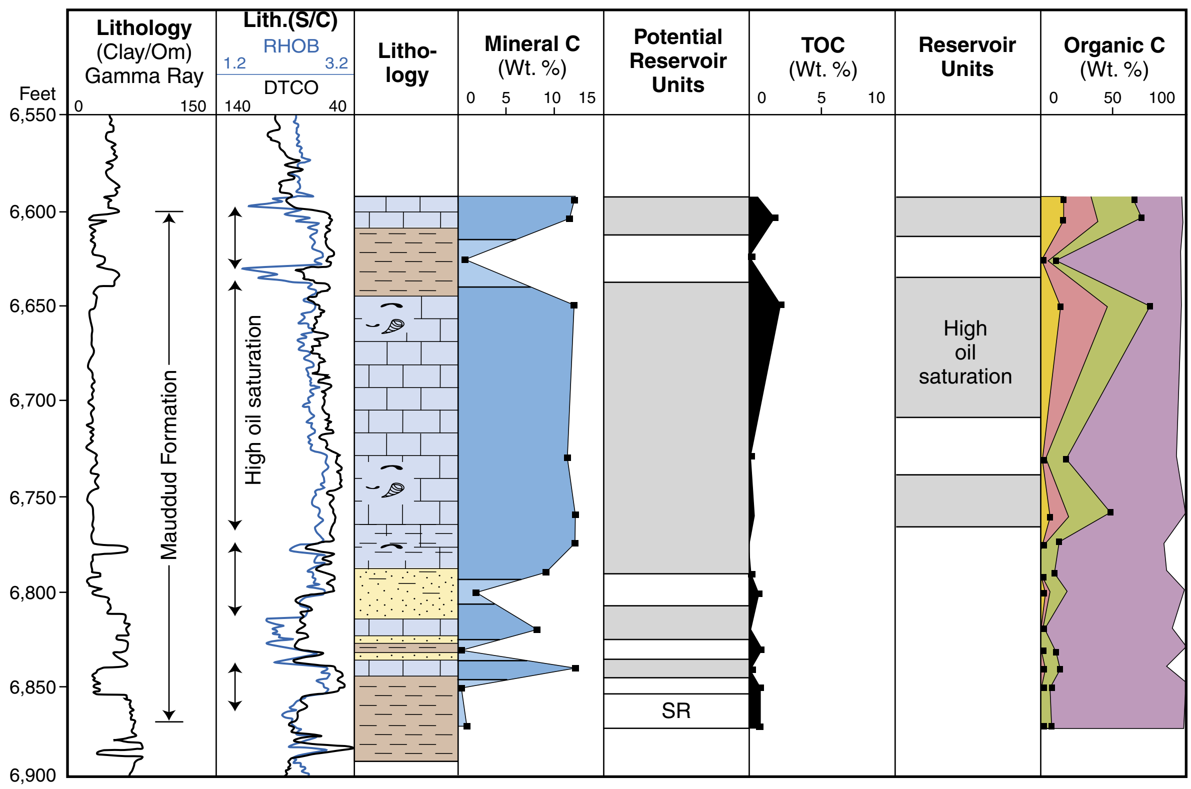


Figure 8c: Geologic and geochemical results of the samples collected from Bahra field. Mineral carbon show alternating carbonate and clastic intervals. The upper carbonate part show high pyrolysable hydrocarbon that indicate reservoir. The lowermost clastic rock is a source rock (SR) with high TOC and low pyrolysable organic carbon.

zone ranges between 0.13–1.13 wt.%, where the high values are in the sandstone layers. The Rc/TOC in the clastic section is relatively high and may reach as high as 0.93. The amount of extract from sandstone and siltstone is very low (1.0%). The composition shows similarity in the two rock types. The NSOs constitute the highest portion (44.0%), while the aromatics, the lowest (25.0%) (Figure 9). The kerogen is immature type III (Figure 10).

SUMMARY AND DISCUSSION

TOC and organic matter type are related to the lithology of the Mauddud Formation in both the northern and southern fields. The average TOC in the clastic zones ranges between 0.6 and 1.3 wt.%, and in the carbonate zones between 2% and 2.5%, with highest values in the northern fields.

In the clastic zones of the formation, the average TPIr is 0.1 in the southern fields and increases to higher values in sandstone, reaching up to 0.7. This indicates that the thermovaporisable hydrocarbons are relatively low in the clastic rock except for rare cases where it is represented by sandstone. The carbonate zones are similar to the sandstone clastic zones where the average TPIr is 0.6 in both the northern and southern fields. This is an indication that in this part of the formation, the extractable portion of hydrocarbons is higher when compared to the clastic shale parts (> 70% C is soluble, < 30% C insoluble), which is confirmed by the RE6 data (Rc/TOC < 0.2). There are some carbonate intervals where the TOC is very poor (0.1 wt.%) indicating very poor organic matter intervals (Table 1).

The ratio of residual carbon to TOC (Rc/TOC) is always higher in the clastic shale part than in the carbonate reservoir part. The average values are 0.8 and 0.3 in the shale and carbonate, respectively. Kerogen elemental analyses indicate type II-III to III in the shale source and type II-III in the carbonate rocks (Figure 10).

The dichloromethane (DCM) C_{14+} extracts of selected samples are characterised by a high NSO content (at least 30.0%) except for the Raudhatain field samples and one Sabiriyah field sample (Figure 9). The Raudhatain shaly interval extract is anomalously enriched in saturates compared to the other extracts. This is probably due to diesel contaminant as suggested by the GC/FID profiles (Figure 11) (74% of the nC_{15}-nC_{33} distribution is nC_{15}-C_{19}) as well as by

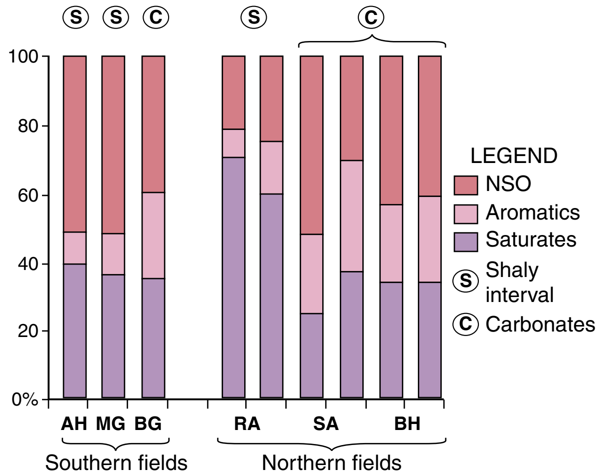


Figure 9: Geochemical characteristics of the C_{14+} soluble organic matter.

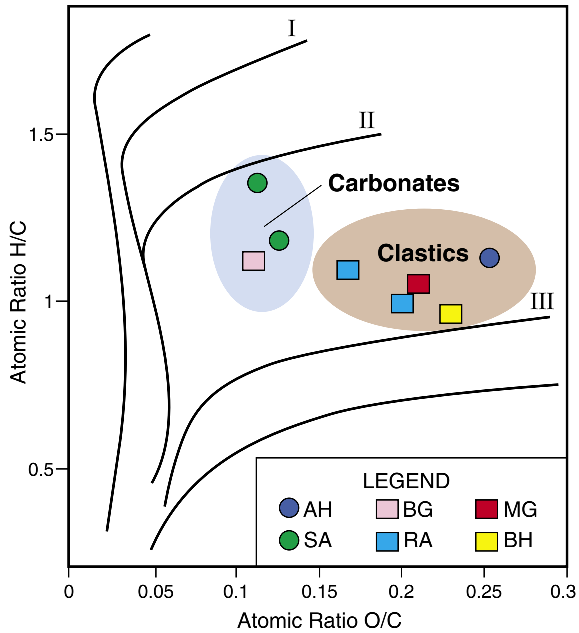


Figure 10: Geochemical characteristics of the insoluble organic matter.

Table 1
Comparison between the nature of the organic matter (OM) in the northern and southern fields.

			Southern Fields		Northern Fields	
			Clastic	Carbonate	Clastic	Carbonate
TOC			0.6	2	1.3	2.5
Soluble OM	TPI		0.1	0.6	0.4	0.6
Soluble OM	SARA	Sat	35	34	65	30
Soluble OM	SARA	Aro	13	25	11	28
Soluble OM	SARA	NSO	52	41	24	42
Insoluble OM	Rc/TOC		0.8	0.2	0.8	0.4
Insoluble OM	Kerogen Type		II-III, III	II-III	II-III, III	II-III

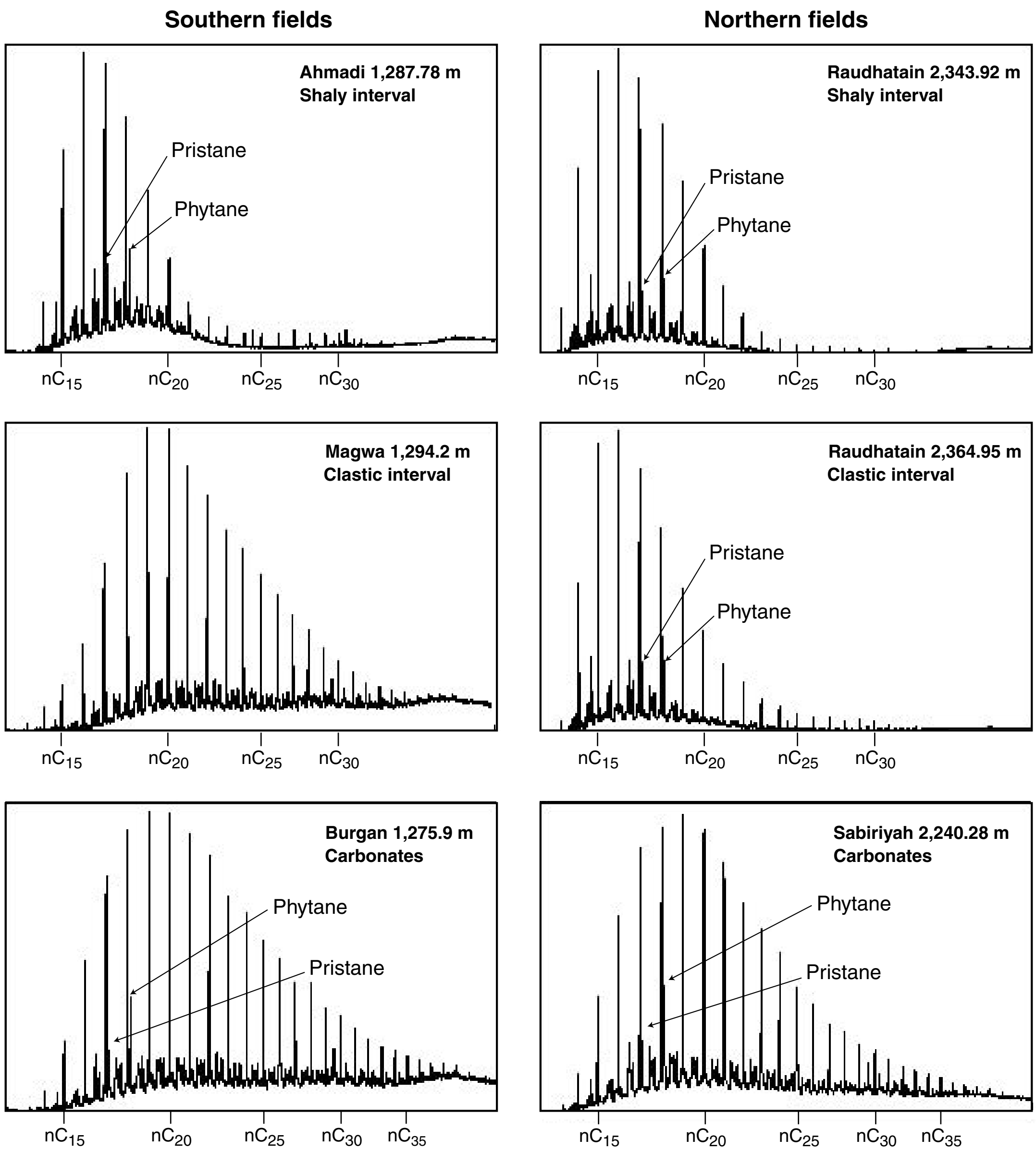


Figure 11: GC/FID of C_{14+} saturates of rock extracts.

the saturated/NSO versus saturates/aromatics plot in Figure 12. The aromatics content is lower in the reservoir (carbonate and sandstone) rock extracts than in the source rock (shale) extracts. The saturates distribution is different between the source-rock (shale) and the reservoir (carbonate) (Figure 11). The reservoir extracts are characterised by a large carbon range (until C_{40}), a lower Pr/Ph ratio (about 0.6 versus 1.0 for the shaly interval extracts), and a high abundance of isoprenoids and polycyclic biomarkers. The hopanes and steranes distributions obtained by GC/MS of the saturates of DCM C_{14+} rock extracts are displayed in Figures 13a and b, respectively. The biomarkers content in the saturates recovered from shaly extracts display poor signal/noise fragmentograms. However,

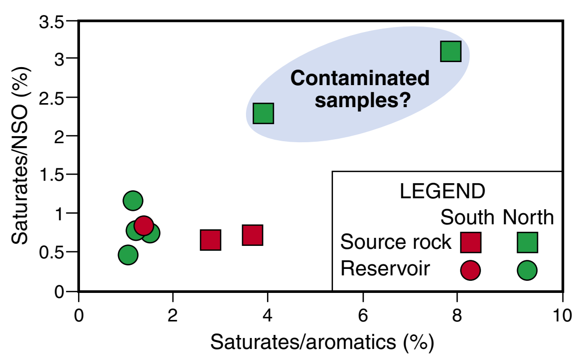


Figure 12: Comparison of bulk composition between northern and southern C_{14+} soluble organic matter.

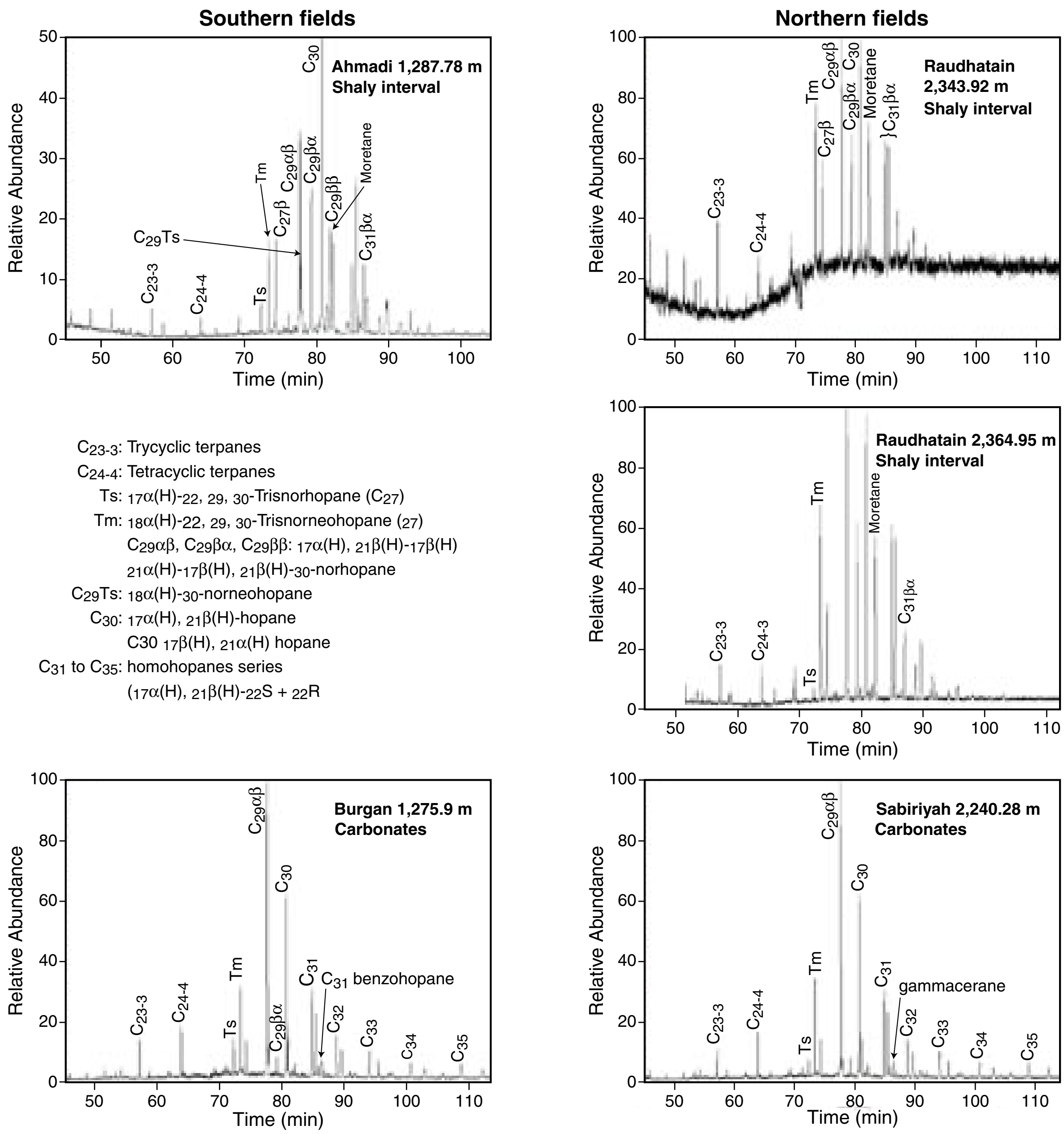


Figure 13a: GC/MS of C_{14+} saturates - Terpanes fragmentograms (Recorded Ion Current (RIC): 191).

the hopanes (m/z: 191) and steranes (m/z: 217) distributions clearly point to the similarity between the soluble organic matter in the southern and northern reservoirs and the differences between the carbonates and shales soluble organic matter.

The carbonates and shales soluble organic matter seem to be genetically unrelated and the shale group is much more immature than the carbonates group based on Ts/(Ts+Tm) ratio (very low) and the C_{29} steranes isomerisation level. The reservoir extracts are characterised by: (1) a high C_{21} sterane; (2) a predominance of $C_{29}\alpha\beta$; (3) a substantial amount of C_{23} and C_{24} tricyclic terpanes; and (4) C_{31} benzohopane. The presence of the series of extended hopanes with relatively high C_{35} points to a reducing depositional environment. The presence of C_{21} sterane confirms such a depositional condition. For the shaly interval extracts, the C_{30} hopane is predominant or equal to $C_{29}\alpha\beta$, the $C_{29}\beta\alpha$ is abundant, Ts (C_{27} trisnorhopanes) is nearly absent as well as the series of extended hopanes.

According to biomarker data, it is suggested that the organic matter associated with the shaly intervals is immature. The carbonate intervals, in both the southern and northern fields, are filled with mature

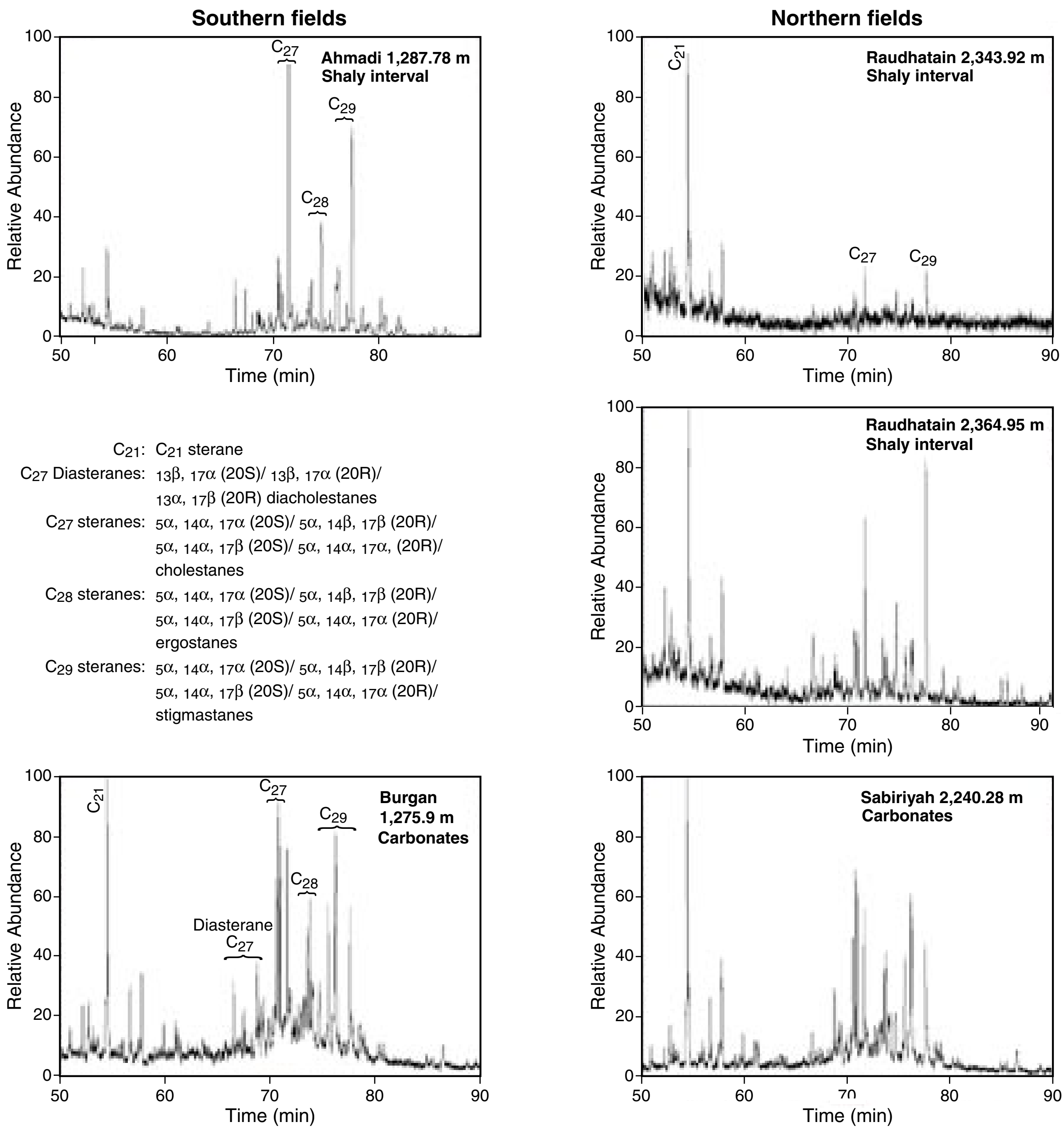


Figure 13b: GC/MS of C_{14+} saturates - Steranes fragmentograms (Recorded Ion Current (RIC): 217)

oil. Thus, this reservoir oil is derived from a more thermally mature source-rock, and probably more deeply buried than the studied shaly intervals. Both Ayres et al. (1982) and Abdullah and Connan (2002) suggested that the oils in the Cretaceous reservoirs in this area could be generated from Jurassic source rocks. Based on geochemical studies of oils, Abdullah and Connan (2002) concluded that the oils in Cretaceous reservoir belong to the same genetic family and were expelled from a source rock with a dominant carbonate lithology, which was deposited in an anoxic environment. They suggested the Jurassic Najmah Formation, as well as the Lower Cretaceous Sulaiy Formation, as probable source rocks.

CONCLUSIONS

The nature and amount of organic matter in the Mauddud Formation can be correlated with its host lithology. In general the carbonate zone represents a reservoir with low unextractable organic matter (low Rc/TOC), and high thermovaporisable (S1+S2a) and thermopyrolysable (S2b) values.

Due to the length of time and high temperature storage conditions for the analysed samples, the thermovaporisable hydrocarbons have partially been lost, which reduces the values shown in this study. The field that is richest in organic matter in southern Kuwait is Magwa, while in north Kuwait it is Sabiriyah.

Not all the carbonates in the succession are reservoirs; in some parts they are very lean in organic matter. Correlating these results with the logs indicates that these poor organic matter carbonate rocks have low porosity and permeability, partially as a result of cementation. The sandstone intervals show hydrocarbons with a character that is similar to the carbonate reservoir intervals. The greater thickness of the formation in the north indicates higher production volume.

The nature of the organic matter in similar rock types in the northern fields, is almost identical to the southern fields. Both areas show similar kerogen types in the carbonate sequence and similar types in the shale intervals within the reservoirs and the source rocks. The gross composition of the shale extracts seems to be similar in these fields. This is also true for the saturates distribution according to gas chromatography, as well as GC/MS analyses.

The Mauddud shaly intervals are dominated by kerogen quality of type II-III to III. The maximum maturity level measured (T_{max} = 430° C) indicates an early stage of generation. The organic matter associated with the shaly intervals is characterised by significantly immature kerogen and deposited in an oxidising environment. In contrast, the carbonate and sandstone reservoir intervals are filled with mature oil that originated from organic matter deposited in a reducing environment. Thus, this reservoir oil must have migrated from a more thermally mature and deeper source rock than the Mauddud shaly intervals, and most probably deposited in a different sedimentary environment. This alternative source rock may be the Lower Cretaceous Sulaiy Formation or the deeper Jurassic Najmah Formation in Kuwait.

The similarity in the kerogen type between the northern and southern parts of Kuwait indicates that the environmental conditions for the organic matter at the time of deposition in the shales were similar in both regions. On the other hand, the similarity of the reservoir extracts may indicate a similar migration and filling history from a similar source rock in both the southern and northern parts of Kuwait.

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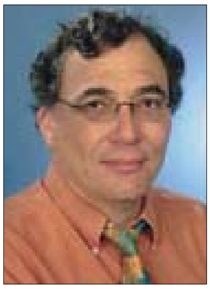

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