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Organic geochemistry and mineralogical characterization of the Paleocene Ranikot Formation shales in selected areas of Southern Indus Basin Pakistan

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Abstract

Southern Indus Basin is one of the promising regions in Pakistan as a commercially producing oil and gas perspective. The current research presents the geochemical characterization of the Ranikot Formation shales from Southern Indus Basin based on total organic carbon (TOC), Rock-Eval (RE) pyrolysis, organic petrography, gas chromatography-mass spectrometry (GC-MS), and x-ray diffraction (XRD) analyses. The average TOC of Ranikot shale is 4.6 wt. %, indicating very good hydrocarbon potential. Types III/IV kerogens were identified in the Ranikot shale. The maceral data also suggest that the Type of kerogen present in the Ranikot shale is dominantly Types II-III, with the minor occurrence of Type IV. The vitrinite reflectance, pyrolysis T_{max} and methylphenanthrene indices values specify immature levels of the shales. The normal alkane data reflect that marine macrophyte, algae, and land plants were contributed to the organic matter of Ranikot shales. Dibenzothiophene/phenanthrene ratio (0.11), phytane/n-C_{18} ratio (0.53), pyrite, and glauconite elucidate that the depositional environment of the Ranikot shale is marine.

The XRD analysis of the shale from the Ranikot Formation revealed that it is brittle shale and dominated by 39.5 to 50.9 wt. % quartz. The present study, integration with the US EIA report demarcated the Ranikot Formation influential horizon as a shale gas resource.

Keywords: Organic geochemistry ;Ranikot shales; shale gas; southern Indus Basin; source rock.

1. Introduction

Organic geochemical investigation of a petroleum source rock in a particular Basin indicates crucial information. Geochemical signatures are used to evaluate the type, age, depositional environments, and maturity of the potential source rock in a sedimentary Basin. The hydrocarbon potential of any source rock is strongly dependent on organic matter richness, volume, and maturity

(Tissot & Welte, 1984; Peters & Cassa, 1994; Bahman *et al.,* 2022). Southern Indus Basin is one of the prolific petroleum-producing regions in Pakistan, and the Basin is still being explored via modern hydrocarbon exploration techniques for the finding of sustainable hydrocarbon reserves. The Cretaceous age Goru Formation sandstone is the leading reservoir of all the commercial oil and gas innovations in the Southern Indus Basin. The Sembar Formation shales (Cretaceous age) are considered as an important source rock for all profitable oil and gas developments in the Southern Indus Basin. The Sembar and Talhar shales (Cretaceous age) are studied by various researchers for the hydrocarbon source rock potential, though to date no commercial and productive shale oil or gas wells have been drilled into Sembar shales (Quadri *et al.,* 1968; EIA, 2015; Sheikh & Giao, 2017; Ehsan *et al.,* 2018; Ahmad *et al.,* 2019; Awan *et al.,* 2021). The Ranikot Formation is also studied by Shah & Ahmed (2018) in Punjab Platform Middle Indus Basin Pakistan. According to their investigations, Ranikot Formation has poor potential as a source rock for oil but has a minor potential for gas aspect in Punjab Platform Middle Indus Basin.

The Paleocene Ranikot Formation shales in the Southern Indus Basin, which are specific attention of the current research have been cursorily investigated by the United States Energy Information Administration (EIA, 2015) for shale oil and gas. The technically recoverable shale gas resources of the Ranikot Formation are 4-Trillion cubic feet. Nevertheless, the shale of the Ranikot Formation is not being evaluated in detail from an organic geochemical perspective. Thereby no comprehensive research data is available about Ranikot Formation shales from Southern Indus Basin (EIA, 2015).

Thus more consideration should be paid to the Ranikot Formation shales in the Southern Indus Basin. In this research, the hydrocarbon source rock potential was assessed using organic geochemical techniques. The origin and type of organic matter were determined and their thermal maturity was evaluated. Additionally, the shale gas aspect of the Ranikot Formation is also studied. For geochemical and mineralogical examination of Ranikot Formation shales, three wells (Ranpethani, Hashim Kher & Sono Deep) are selected from Southern Indus Basin (Figure 1).

2. Geological setting

Southern Indus Basin is bounded by Mari-Kandkot High on the north, Indian shield to the east, offshore Indus on the south while its western boundary is confined by Chaman and Ornachnal faults (Figure 1). Southern Indus Basin experienced extensional tectonics in the Late Paleozoic (Powell, 1979; Zaigham, 1991). Different researchers have portrayed the tectonic history of the Southern Indus Basin (Powell, 1979; Biswas, 1982; Zaigham, 1991). According to Zaigham and Mallick (2000), rifting was initiated in Gondwana land in the Late Paleozoic. The progressive rifting resulted in thinning and stretching of the continental lithosphere, followed by up warping and extensional faults. The basaltic lava poured out along the rift. The rift opened into an ocean with normal faults. At the end of Paleozoic and in the Early Mesozoic with the cessation of basaltic lava flow spreading was stopped.

The failed rift became the site of deposition of sediments that formed the Southern Indus Basin. On cooling, the Basin subsidence occurred in Mesozoic and Tertiary (Shah, 2009). The sediments were deposited in a subsiding Basin forming a thick sequence of rocks. Stratigraphically the Southern Indus Basin covers an area of 250,000 km^2 with a 13 to 16 km thick sequence of Mesozoic and Cenozoic rocks (Shah, 2009). The northwestern margin of the Indian Plate remained submerged under the seawater during the Late Paleozoic, Mesozoic, Paleocene, and Eocene (Shah, 2009).

On regression of Tethys ocean, most of the area was covered with the epi-continental sea during Paleocene and Eocene Epochs (Shah, 2009). The marine sediments were deposited during this time in the Lower Indus Basin. Many thousand meter thick calcareous and argillaceous sediments of the Mesozoic are exposed in the Sulaiman-Kirthar Provinces and axial belts on the western margin of the Indus Basin (Shah, 2009). The Paleocene-Early Eocene rocks were deposited in the marine environments in the Basin. The Tertiary rocks are exposed in Khairpur and Hyderabad in the Lower Indus Basin (Zaigham & Mallick, 2000). On the eastern side of the Basin, Tertiary rocks are exposed in Jaisalmer and Rann Kutch areas (Biswas, 1982). The project area is comprised of sedimentary successions ranging from Triassic to recent (Figure 2).

The current study is restricted to shales of the Ranikot Formation and hence their lithology is briefly described. According to Shah (2009), the Ranikot Group comprises of Khadro, Bara, and Lakhra formations and is concisely discussed in this paper. However, during the current study, the Ranikot Group is considered as a Ranikot Formation of Shah (1977). The Khadro Formation comprises sandstone, shale, and limestone (Shah, 2009). The Bara Formation comprises abundant sandstone with minor shale and volcanic debris (Cheema *et al.,* 1977). Lakhra Formation comprises limestone and exhibits a variable color at some locations (Shah, 2009).

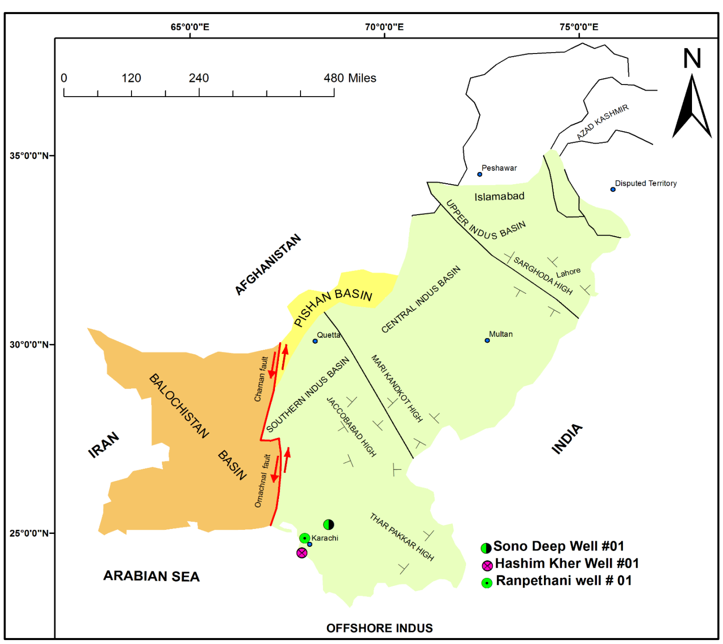

Fig. 1. Map showing sedimentary Basins of Pakistan (Farah *et al.,* 1984). The research area is represented by three wells.

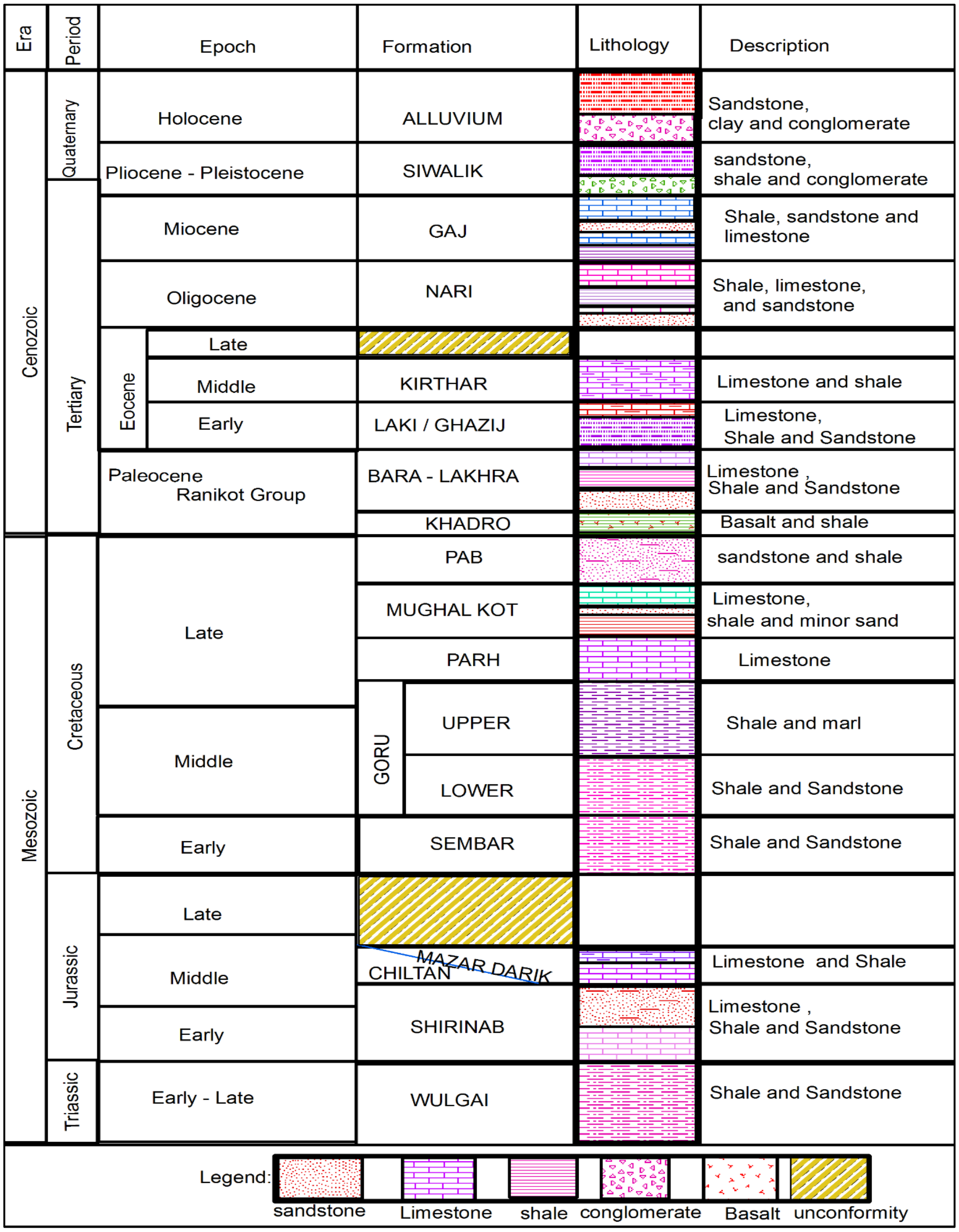

Fig. 2. Showing stratigraphy of Southern Indus Basin Pakistan (after Shah, 1977; Raza *et al.,* 1990).

3. Material and methods

For an organic geochemical characterization and bulk mineralogy 21 well-cutting samples (Table 1) of the Paleocene Ranikot Formation shales were provided by Oil & Gas Development Company Limited (OGDCL). The wells were drilled in Ranikot Formation Southern Indus Basin Sindh Province Pakistan (Figure 1). The well-cutting samples were washed with distilled water before geochemical analyses. Total organic carbon (TOC) and Rock-Eval (RE) pyrolysis analyses were carried out on 21 samples. TOC and RE were measured from Rock-Eval 6 instrument. The Soxhlet extraction process was used for extractable organic matter (EOM) of twenty gram pulverized shale of the Ranikot Formation in the Ranpethani well. Pulverized shale samples were treated with dichloromethane (DCM) and methanol in a ratio of 97:3 respectively at a rate of seven hours per day. The total time required to extract organic matter from one sample was 24 hours. A mixture of dichloromethane and methanol was taken in the round bottom flask, while samples were placed in thimbles and topped with glass wool. The solvent was heated at about 30°C and vaporized in boiling flasks. The sample was cooled (16°C) by using cooled water via a machine. This cooled solvent was used to extract EOM from the shale samples. The extracted EOM was then transformed into pre-weighed vials for deasphalting. Asphalt fraction was removed from extractable organic matter by adding n-hexane. The solution was then kept in a dark place for 8 hours and filtered. The asphalts were immiscible in n-hexane and extracted from EOM. Gas chromatography-mass spectrometry (GC-MS) analyses were carried out on 2 samples for biomarker data. GC-MS analysis of the whole oil was performed with Varian Ion Trap GC-MS 4000, an instrument with Column C98911, VF-IMS, and 30*0.25. The temperature of the injector was 300 °C. The initial temperature was set to 50 °C for 1.5 min, then ramped to 300 °C at 3.5°C/min. Helium was used as a carrier and was set to flow at a rate of 1.0 ml/min.

Organic petrography analyses were performed on two samples. The samples Ranikot Formation shales of 0.8 to 2mm particle size were embedded in Araldite and polish sections were prepared. Ranikot shale samples were studied under white and blue light using spectrometer system MCS CCD ZIM Zeiss microscope. For the standard of zero, 0.589%, YAG 0.907%, and GGG 1.711% reflectance were utilized for calibration. X-ray diffraction (XRD) analyses were performed on two samples. Ranikot Formation shales were ground to powder form by hand before being analyzed in an x-ray diffractometer (model X Pert PRO). XRD analysis was carried out using one gram of powder sample. The x-ray instrument was operated at the condition of an x-ray with wavelength Cu K alpha radiations 1.540598 nm, generating voltage 40-kilo volts, tube current 30 milliamperes, divergent slit fix, receiving slit 0.1, scan step size continuous, scan step size 0.01, and time per scan is 0.25.

4. Results and discussion

4.1 Hydrocarbon generation potential and Type of kerogen

TOC is one of the foremost elements in controlling source rock quality and organic richness (Peters, 1986; Jarvie, 1991; Peters & Cassa, 1994). The results of the TOC contents and pyrolysis parameters of the Ranikot Formation shales are illustrated in Table 1. The current TOC values are correlated with Jarvie (1991) to evaluate the hydrocarbon potential of the Ranikot Formation shales. The TOC values of the Ranikot shales are ranging from 0.65 to 37.62 wt. %. The values indicate that the Ranikot shales have fair to excellent hydrocarbon potential. The average TOC of the Ranikot shales is 4.6 wt. %. This value designates that the shales have very good hydrocarbon potential. The S_1 values of the Ranikot Formation shales vary from 0.00 to 2.82 mg HC/g rock. The values reflect that studied samples have poor to very good hydrocarbons generation potential.

The S_2 values of the shales are in the range of 0.02 to 87.97 mg HC/g rock. The values are indicative of poor to excellent hydrocarbon generative potential. S_1 and S_2 values of the Ranikot shales are correlated with Peters (1986). The hydrocarbon potential is further evaluated from the cross-plot relation between TOC versus depth (Figure 3). The diagram indicates most of the samples are in the range between good to very good hydrocarbon potential. The hydrocarbon generation potential of the Ranikot shale is also represented by pyrolysis parameter generation potential (GP). The poor and very good hydrocarbon generation potential of the source rock can be expressed by GP values. GP value less than 2 mg HC/g rock indicates poor, and GP value higher 10 mg HC/g rock shows very good hydrocarbons generation potential of the source rock (Ghori and Haines, 2007; Tissot and Welte, 1984). GP (Table 1) of the Ranikot shale varies from 0.23 mg HC/g rock to 90.79 mg HC/g rock, indicating poor to very good hydrocarbon generation potential. In the present investigation, Van Krevelen diagrams were used to deduce the Type of kerogen in shales (Van Krevelen, 1993). Types III-IV (Figures 4-5) kerogens were identified in the Ranikot shales. Type IV kerogen is inert and Type III kerogen can generate the gas. Hydrogen Index (HI) of the Ranikot Formation shales are ranging between 24 to 234 mg HC/g TOC. The values point out that the Type of organic matter is predominantly III/IV. The average value of the Oxygen Index (OI) of the Ranikot shales is 114 mg CO_2/g TOC suggests that organic matter can generate gas only. The HI and OI values of the Ranikot shales are compared with Peters (1986). HI and OI based on pyrolysis using source rock analysis apparatus do not always precisely indicate the Types of kerogen and types of hydrocarbon that may be produced by the source rocks (Dembicki, 2009; Abbassi *et al.,* 2016). Therefore the Type of kerogen of the Ranikot shale is further integrated with maceral analyses.

The dominant maceral type of Ranikot Formation shale of Ranpethani well (50 m) is vitrinite (Figure 6). The vitrinite content of this shale is higher than 50%. However, the shale is also characterized by 10% liptinite (Figure. 6) and 3% inertinite (Table 1). The maceral analyses of the Ranikot shale in Hashim Kher well (400 m) indicate that 50% is vitrinite (Figure. 7). The maceral examination of the shale also shows 20% liptinite (Figure 7). The inertinite of the shale is 4% (Table 1). More evidence came from maceral data that the Type of kerogen present in shales is Types II-III (mixed kerogen). The mixed kerogen Types (II-III) reflect a mixture of terrestrial and marginal marine organic matter with different capabilities to generate oil and gas (Peters *et al.,* 2005). The expected type of hydrocarbon of the Ranikot shale is inferred from the relative percentage composition of vitrinite, liptinite, and inertinite. The percentage composition of macerals (vitrinite, liptinite, and inertinite) is plotted in a ternary diagram (Tissot & Welte, 1984; Hakimi & Ahmed, 2016). The diagram (Figure 8) suggests that the Ranikot shales can be expected to generate gas since the organic matter is dominated by vitrinite.

Table 1. Showing Rock-Eval pyrolysis parameters, vitrinite reflectance, and methylphenanthrene indices of Ranikot Formation shales.

Well	Depth (m)	TOC (Wt. %)	S_1 mg/g	S_2 mg/g	HI mg/g	OI mg/g	Tmax (°C)	VR (%)	GP (S_1+ S_2) mg /g	MP-1 & MP-2	Inertinite (%)
Ranpethani	50	12.64	1	14.16	112	74	407	0.35	15.16	0.34, 0.44	3
	60	2.83	0.07	2.06	73	141	435		2.13		
	110	1.42	0.02	0.33	23	196	430		0.35		
	120	1.5	0.02	0.35	23	165	435		0.37		
	140	1.2	0.02	0.41	34	150	436		0.43		
	150	0.65	0.02	0.21	32	268	431		0.23		
	170	0.9	0.04	0.32	36	240	429		0.36		
	180	0.93	0.04	0.36	39	243	439		0.4		
	250	1.91	0.11	0.94	49	134	422		1.05		
Hashim Kher	400	37.62	2.82	87.97	234	115	414	0.54	90.79		4
	410	2.68									
	420	3.48	0.00	1.67	59	62	431		1.67		
	430	1.04	0.00	1.52	57	66	432		1.52		
	490	1.58	0.03	6.97	200	69	434		7		
	500	3.38	0.00	3.42	101	46	434		3.42		
	510	4.17	0.00	4.67	112	41	434		4.67		
	530	2.63	0.00	2.93	111	56	423		2.93		
	570	1.35	0.00	0.55	41	101	433		0.55		
Sono Deep	480	2.87	0.10	3.45	120	57	425		3.55		
	510	5.96	0.16	11.5	193	36	420		11.66		
	530	6.75	0.26	15.1	200	31	418		15.36		

TOC: total organic carbon; T_{max}: maximum temperature; S_1: free hydrocarbons; S_2: remainig potential; HI: hydrogen index; OI: oxygen index; VR: vitrinite reflectance (Ro); MP-1 & MP-2: methylphenanthrene indices; (GP): generation potential.

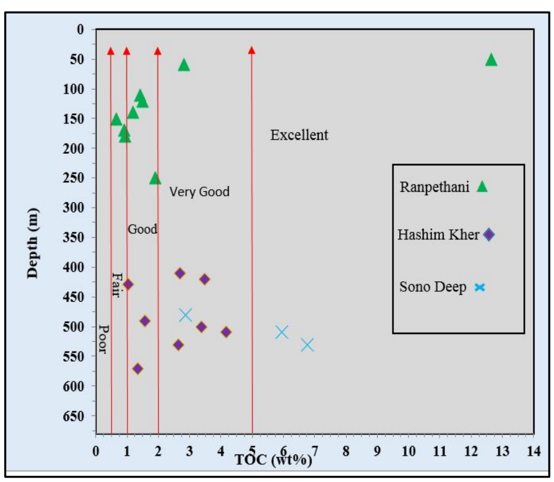

Fig. 3. Showing cross-relation between TOC and depth of the Ranikot shales (diagram boundaries are after Tissot and Welte, 1984; Peters and Cassa, 1994).

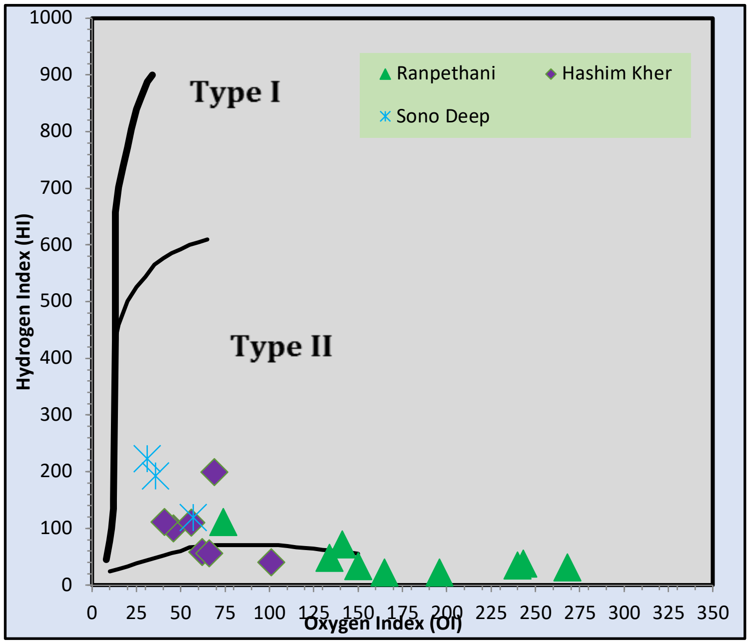

Fig. 4. Showing cross plot relation between HI and OI of the Ranikot shales (diagram boundaries are after Tissot and Welte, 1984; Peters and Cassa, 1994).

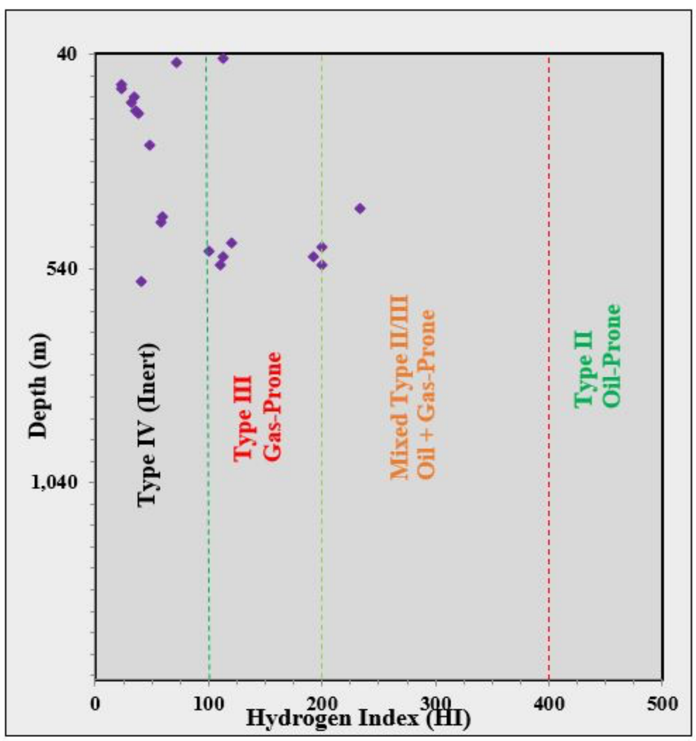

Fig. 5. Showing cross plot relation between HI and depth of the Ranikot shales (diagram boundaries are after Tissot and Welte, 1984; Peters and Cassa, 1994).

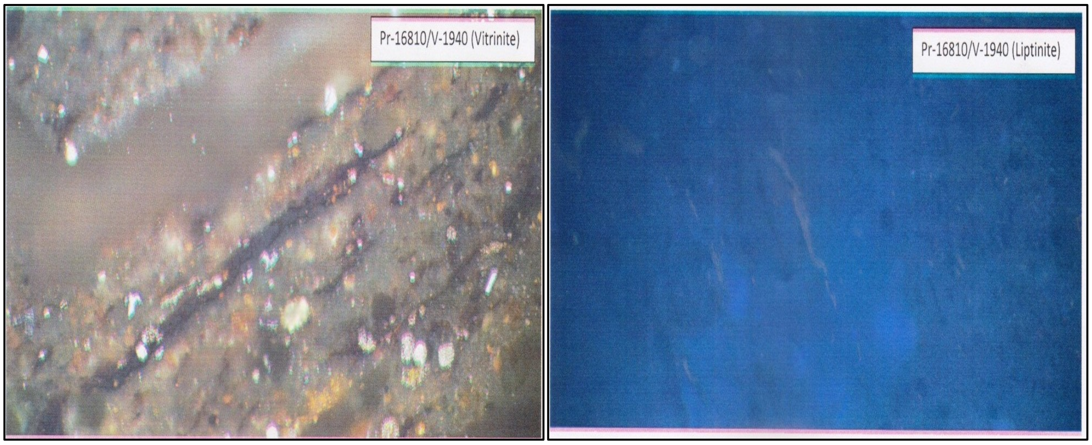

Fig. 6. Photomicrographs (Pr-16810/V-1940) of Ranikot shales in Ranpethani well-showing vitrinite and liptinite.

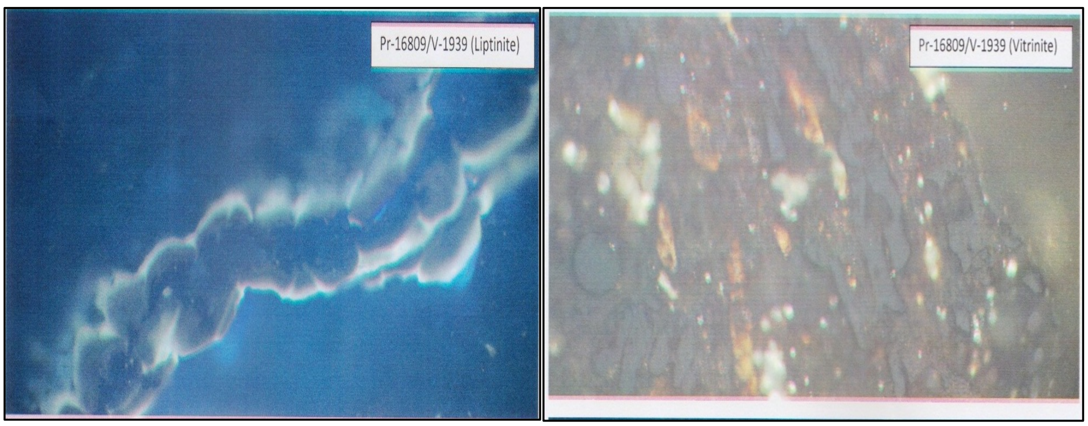

Fig. 7. Photomicrographs (Pr-16809/V-1939) of Ranikot shales in Hashim Kher well-showing vitrinite and liptinite.

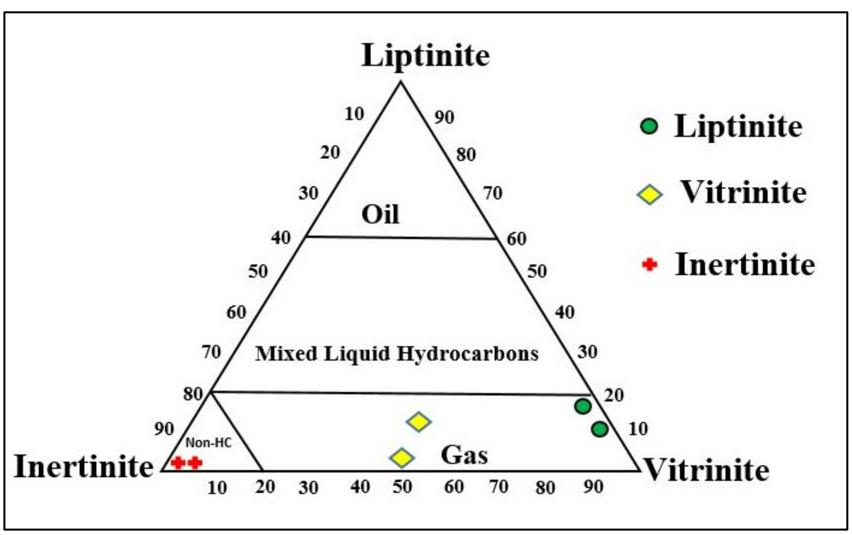

Fig. 8. Ternary diagram of the maceral composition, showing expected hydrocarbon phase of the Ranikot Formation shales (after Tissot and Welte, 1984).

4.2 Thermal Maturity

Vitrinite reflectance (Ro) values for oil window ranges from 0.6 to 1.3%Ro and values higher than 2.0% Ro show dry gas generation phase (Tissot & Welte, 1984; Teichmüller *et al.,* 1998; Killops and Killops, 2005). Vitrinite reflectance values of the Ranikot Formation vary from 0.35 to 0.54 %Ro (Table 1) and indicate that shales are immature for the generation of hydrocarbons. The Ranikot Formation has pyrolysis T_{max} values in the range of 407 to 439°C (Table 1) signifying predominantly that shales are immature for the generation of hydrocarbon. T_{max} values of the Ranikot Formation shales are correlated with Peters & Cassa (1994) and Bacon *et al.* (2000). T_{max} data of Ranikot Formation are plotted versus depth (Figure. 9), indicating that shales are immature for the generation of hydrocarbons. The thermal maturity of organic matter in Ranikot shale is also expressed by methylphenanthrene indices (MP-1 and MP-2). The ratios of alkyl Phenanthrene are significant parameters to evaluate the maturity of organic matter in the source rocks (Radke *et al.,* 1985; Radke, 1988). As reported by Radke (1988), the comparative abundances of the alkyl homologs of phenanthrene were applied to calculate the vitrinite reflectance (Ro %). The values such as 0.5%, 0.65-1.35%, and 1.35-2.0% are used for immature, oil windows, and higher maturity respectively (Radke and Welte, 1983; Boreham *et al.,* 1988). The MP-1 and MP-2 values of the Ranikot Formation range from 0.34 to 0.44 % (Table 1: Figure 10), showing shales are thermally immature for the generation of hydrocarbons.

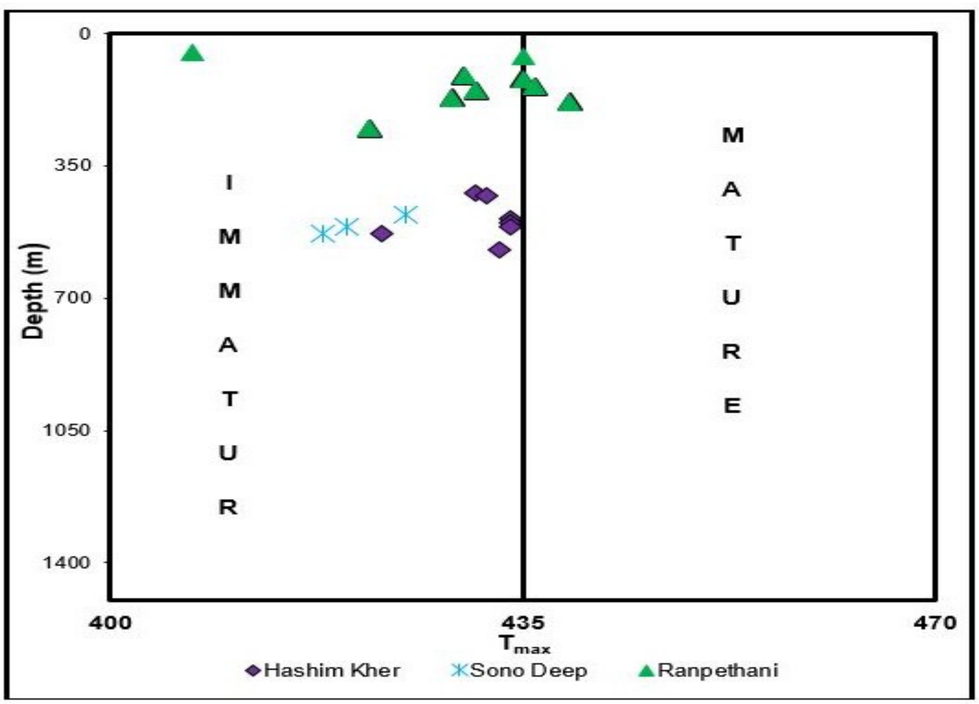

Fig. 9. A plot of Tmax versus depth for Ranikot shales (diagram boundaries are after Tissot and Welte, 1984; Peters and Cassa, 1994).

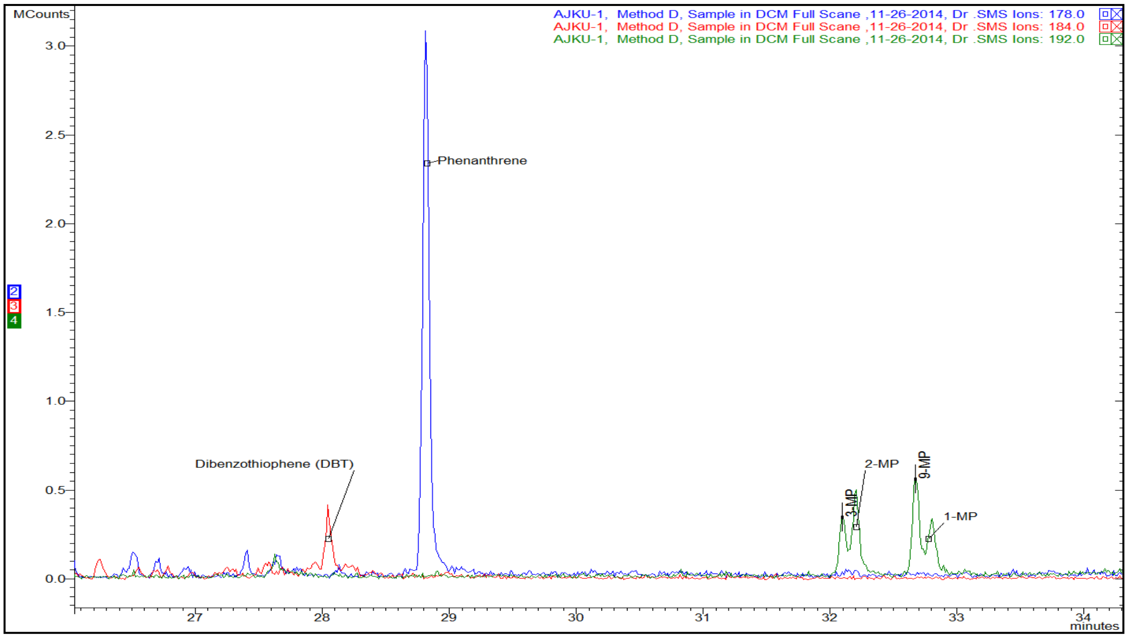

Fig. 10. Fragmentogram (m/z 178, 184, 192) of the Ranikot shale extracts showing the distribution of phenanthrene, methylphenanthrene (MP), and dibenzothiophene (DBT).

4.3 Source of organic matter and depositional environment

Normal alkanes of low molecular weight (< C_{20}) are principally originated from algae and microorganisms (Cranwell, 1977). The intermediate molecular weight (n-C_{21}-C_{25}) normal alkanes are derived from aquatic macrophytes (Ficken *et al.,* 2000). Eglinton & Hamilton (1967) suggested that long straight-chain alkanes (> n-C_{27}) are the diagnostic of higher land plants. The normal alkanes of the Ranikot shale in the Ranpethani well are dominated by n-C_{25} (Figure. 11). The n-C_{25} in the Ranikot Formation shows marine macrophytes were contributed to shales. The n-C_{25} in Ranikot Formation is followed by n-C_{19} and n-C_{18}, suggesting algae and microorganism input in shales. The lesser relative abundance of the normal-alkanes lie in the typical range of n-C_{20} to n-C_{32} were also recorded in the shale (Figure 11). These normal alkanes suggest the influx of terrigenous plants in the Ranikot shale. The mixed origin (Types II/III) of the organic matter of the Ranikot shale is consistent with maceral data.

The depositional setting of the Ranikot Formation shales in the Ranpethani well is deduced from geochemical and geological data. The dibenzothiophene/phenanthrene (DBT/P) ratio can be used to infer the source rock depositional setting and lithologies. Marine shales have a DBT/P ratio less than 1 and carbonates have higher than 1 (Hughes *et al.,* 1995). The DBT/P ratio for the Ranikot shale is 0.11, which indicates that the rock unit is marine shale. The phytane/n-C_{18} value for marine shale is greater than 0.3 (Peter & Moldowan, 1993; Palacas, 1984; Connan *et al.,* 1986). The phytane/n-C_{18} value of the Ranikot shale is 0.53. The value is the indicative of marine environment. The marine anoxic condition is further supported by pyrite and glauconite (Figure 12).

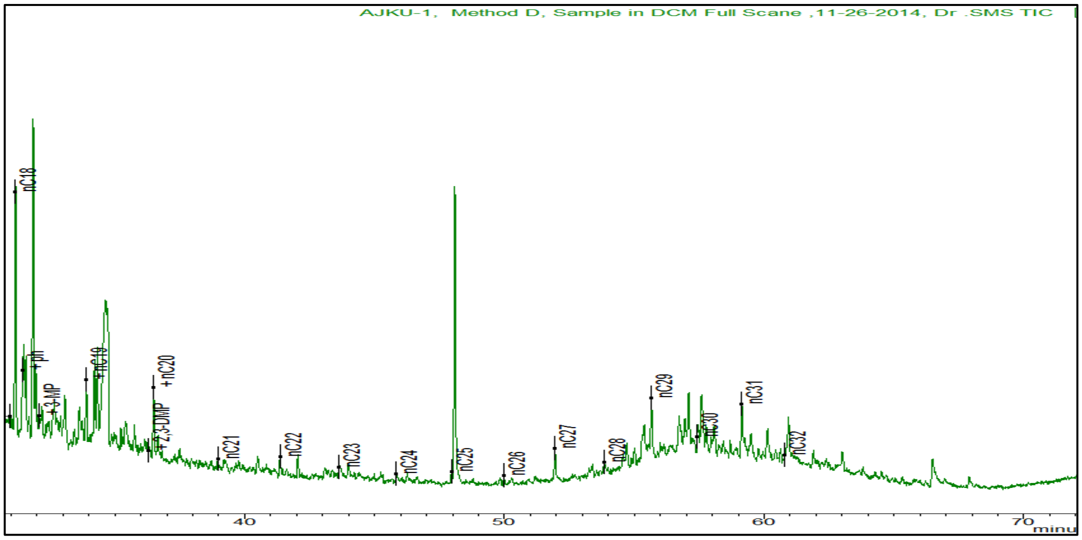

Fig. 11. Whole Rock Extract chromatogram of the Ranikot shale in Ranpethani well-showing distribution of saturates and aromatics hydrocarbons.

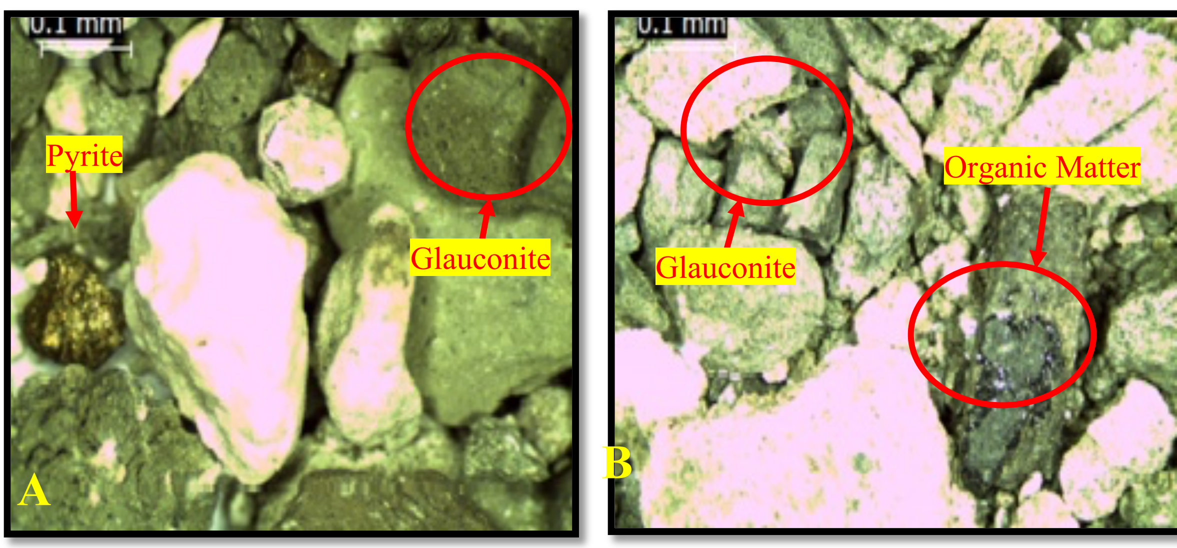

Fig. 12. Photomicrographs (A& B) of the Ranikot Formation shales showing pyrite, glauconite, and organic matter.

4.4 Mineralogical characterization of Ranikot shales

The XRD analysis of the shales of the Ranikot Formation is carried out (Hashim Kher & Ranpethani wells) to understand their mineralogy. The mineralogical composition of Ranikot shales is recognized by correlating the latticed-spacing values with the International Centre for

Diffraction Data (ICDD, 2001). The XRD results of the Ranikot Formation shales are demonstrated in Table 2: Figure 13. The quartz content of the Ranikot shales is ranging from 39.5 to 50.9 wt. %, with an average value of 22.6 wt. %. The clay content of the Ranikot shale varies from 18.2 to 36.9 wt. %. The average value of the clay is 11.02 wt. %. XRD of the Ranikot shales indicate the dominant clays are kaolinite and gibbsite. The total carbonate (calcite & dolomite) content value of the shale is 23.78 wt. %. According to Bowker (2002), the high gas production of the Barnett shale is due to its brittleness and response to stimulation. The Barnett shale is brittle because of the high percentages of quartz and carbonate contents (Gas Research Institute, 1991; Martineau, 2001). Martineau (2001) suggested that without these mineralogical characteristics Barnett shale gas would not be a successful play. In the light of Barnett shale gas, the Ranikot shales are mineralogically characterized by quartz, clay, and carbonate contents. Total quartz, clays, and carbonates (Table 2) contents of the Ranikot shales are plotted in the ternary diagram (Figure. 14). The diagram suggested that Ranikot shales are brittle as dominated by high quartz (39.5 to 50.9 wt. %) content.

Table 2. Showing XRD data of the Ranikot Formation shales.

Well	Standard d-spacing A^0	Observed d-spacing A^0	Mineral	Wt. (%)	Total Quartz Wt. (%)	Total Carbonates Wt. (%)	Total clays Wt. (%)
Hashim Kher	7.17	7.13	Kaolinite	10.80	50.9	23.78	18.2
	4.26	4.26	Quartz	9.4			
	3.568	3.56	Kaolinite	7.4			
	3.344	3.34	Quartz	34.6			
	3.036	3.03	Calcite	11.89			
	2.807	2.80	Dolomite	11.89			
	2.709	2.70	Pyrite	6.9			
	1.818	1.81	Quartz	6.9			
Ranpethani	7.17	7.1	kaolinite	18.5	39.5	-	36.9
	4.361	4.35	Gibbsite	6.4			
	3.514	3.56	kaolinite	12			
	3.344	3.344	Quartz	39.5			
	3.059	3.058	Gypsum	5.3			
	2.71	2.71	Hematite	12.6			
	1.633	1.633	Pyrite	5.3			

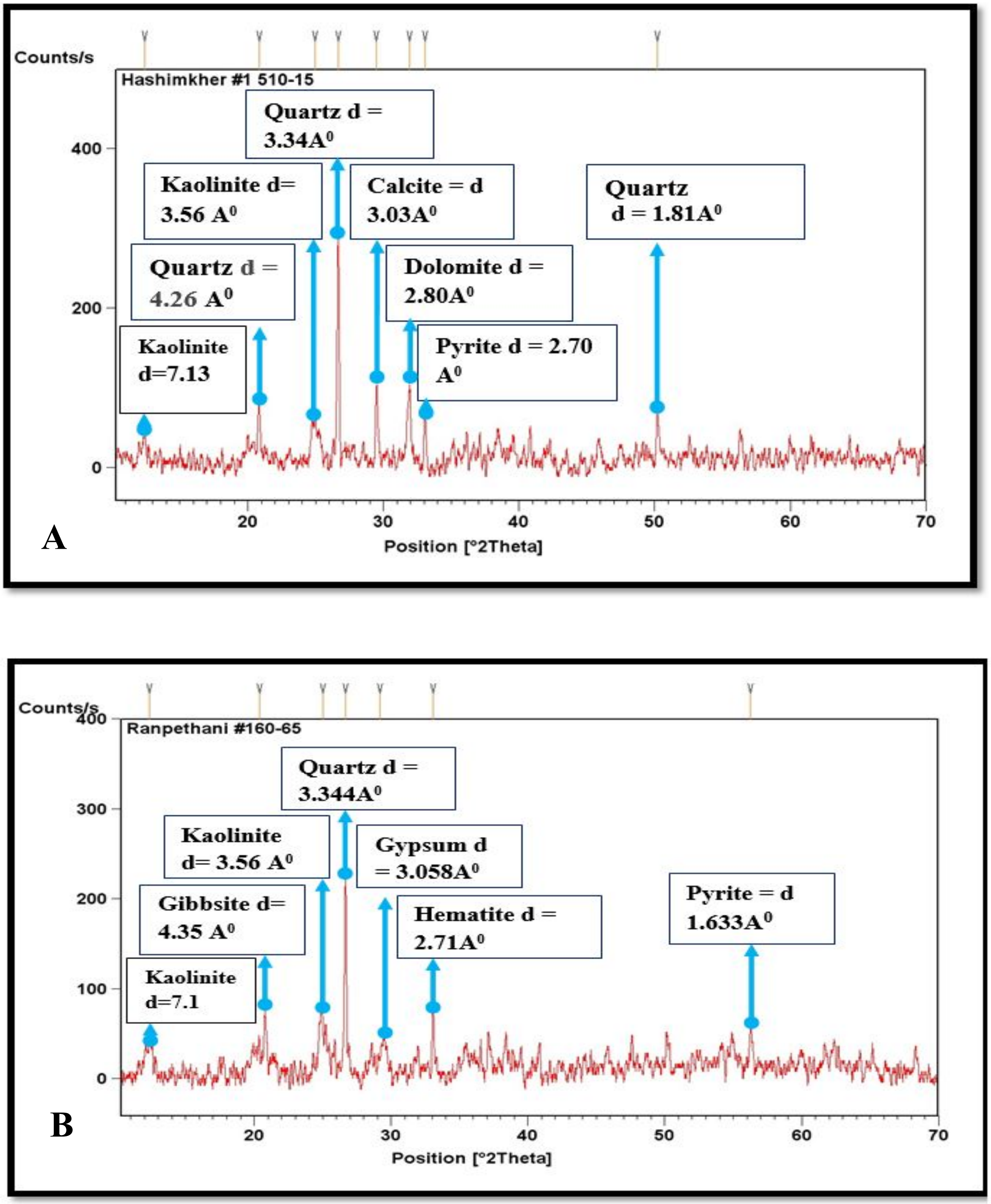

Fig. 13. Powder x-ray diffraction pattern of the Ranikot shales in Ranpethani (A) and Hashim Kher (B) wells.

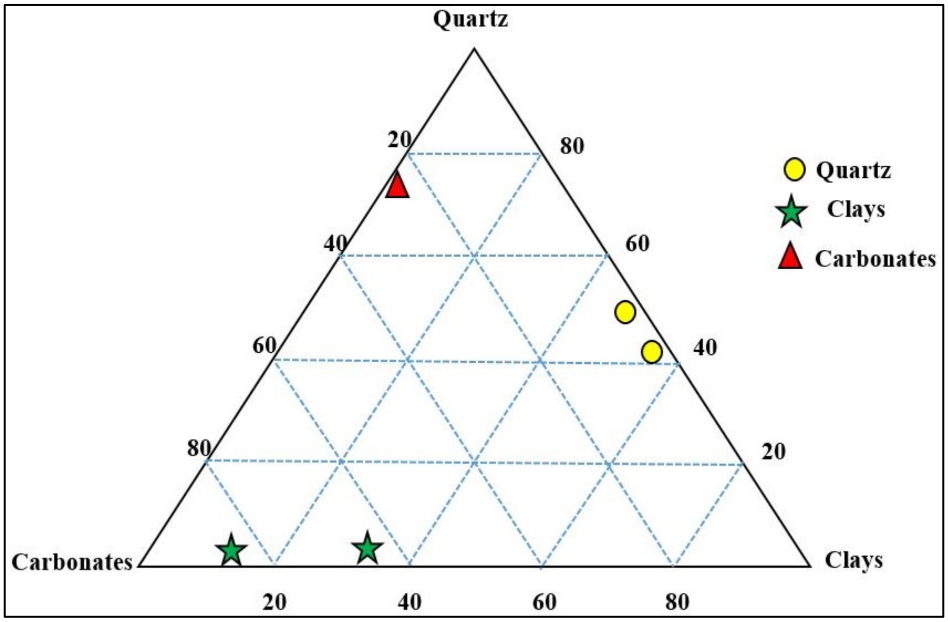

Fig. 14. Ternary diagram showing the mineralogical distribution of quartz, carbonates, and clays of Ranikot Formation shales.

4.5 Ranikot Formation as a shale gas plays

The prerequisites for a shale can become an unconventional shale gas resource are enough organic matter, maturity, porosity, permeability, pore anatomy, and the brittleness (Josh *et al.,* 2012). Slatt and Rodriguez (2012) suggested that productive shale gas has typically thickness greater than 200ft (65 m), with a TOC value higher than 3 wt. %. In the current research three aspects are studied for Ranikot shale to act as a shale gas resource. Based on high TOC content (0.65 to 37.62 wt. %) and GP (0.23 mg HC/g rock to 90.79 mg HC/g rock), the Ranikot Formation shales in Southern Indus Basin are expected to act as shale gas plays. In terms of brittleness, the Ranikot Formation shale is dominated by 50.9 wt. % quartz. This high quartz content marks the Ranikot shale brittle. Although geochemical parameters (T_{max}, vitrinite reflectance, methylphenanthrene indices) reflect that Ranikot shales are immature for the generation of hydrocarbon, moreover Antrim shale of USA is the most productive biogenic gas plays in the Michigan Basin although their organic matter is thermally immature (Shurr and Ridgley, 2002). In the present research, the Ranikot Formation shale is studied at very shallow depths (Table 1), consequently, no considerable thickness and maturity of the shales are documented. US EIA (2015) has been studied (well: Sann # 1) the Ranikot Formation shale in the Southern Indus Basin at a depth of 880 meters. US EIA (2015) reported net thickness of the Ranikot Formation shale is 200ft with vitrinite reflectance 0.7% to 1.0%, Ro. The present and US (EIA, 2015) investigations of the Ranikot Formation marked the shale a more attractive target for shale gas resources. However, a more comprehensive study of porosity, permeability, gas in place estimates, and type of shale gas system of the Ranikot Formation shale needs to be carried out .

5. Conclusion

Organic geochemical and mineralogical analyses were carried out in this research to evaluate the hydrocarbon source potential and bulk mineralogy of the Ranikot Formation shales from the selected areas of Southern Indus Basin Pakistan. The organic geochemical and mineralogical results of the Ranikot shales are summarized as follows:

1. The average TOC contents of the Ranikot shales indicate very good hydrocarbon source rock potential.
2. Rock-Eval pyrolysis data reflect that Ranikot shale is characterized by Types III/IV kerogen. Moreover, maceral data show Types II-III kerogen, and only 3-4% inertinite is recorded in Ranikot shales.
3. Maturity parameters indicate that the Ranikot shales are immature for hydrocarbon generation.
4. Marine macrophytes, algae, and land plant inputs in the organic matter of the Ranikot shales are evident from normal alkane data.
5. Dibenzothiophene/phenanthrene ratio, phytane/n-C_{18} ratio, pyrite, and glauconite collectively show that the depositional environment of the Ranikot shale is marine. The XRD analysis of the Ranikot Formation indicates that shale is dominated by quartz.
6. Based on high TOC content, GP, dominant quartz content, and previous US Energy Information Administration investigations, the Ranikot Formation is a reasonable target for shale gas resources.

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