Integration of the outcrop and subsurface geochemical data: implications for the hydrocarbon source rock evaluation in the Lower Indus Basin, Pakistan

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Abstract

The present study details the hydrocarbon source rock geochemistry and organic petrography of the outcrop and subsurface samples of the Middle Jurassic Chiltan Formation and the Lower Cretaceous Sembar Formation from the Sann #1 well Central and Southern Indus Basin, Pakistan. The total organic carbon (TOC), Rock–Eval pyrolysis, vitrinite reflectance (Ro) % and Maceral analysis techniques were used and various geochemical plots were constructed to know the quality of source rock, type of kerogen, level of maturity and migration history of the hydrocarbons. The outcrop and Sann #1 well data on the Sembar Formation reveals poor, fair, good and very good quality of the TOC, type II–III kerogen, immature–mature organic matter and an indigenous hydrocarbon generation potential. The outcrop and Sann #1 well data on the Chiltan Formation show a poor–good quality of TOC, type II–III kerogen, immature–mature source rock quality and having an indigenous hydrocarbon generation potential. The vitrinite reflectance [Ro (%)] values and Maceral types [fluorescent amorphous organic matter, exinite, alginite and inertinite] demonstrate that maturity in both Sembar and the Chiltan formation at surface and subsurface fall in the oil and gas generation zone to cracking of oil to gas condensate zone. Recurrence of organic rich and poor intervals within the Sembar and Chiltan formation are controlled by the Late Jurassic thermal uplift preceding the Indo-Madagascar separation from the Afro-Arabian Plate and Early Cretaceous local transgressive–regressive cycles. From the current study, it is concluded that both Sembar and Chiltan formation can act as a potential hydrocarbon source rock in the study area.

Keywords Source rock geochemistry · Indus Basin · Pakistan · Jurassic-Cretaceous

Introduction

The Indus Basin is one of the major sedimentary basins of Pakistan comprising sediments of Precambrian to recent (Fig. 1). Potential hydrocarbon source rocks occur within the Middle Jurassic Chiltan Formation and the Lower Cretaceous Sembar Formation in the Sulaiman–Kirthar fold belt of Indus Basin. Exploration of hydrocarbons in this region faces the challenging complex geology of the area that hinders detailed investigation of the petroleum system

of the region. This study area is still underexplored and the advancement of petroleum exploration and production technology provides a hope for the discovery of economically viable hydrocarbon reserves. The petroleum generation, migration, and preservation potential of the strata exposed in the study area demands the integration of a detailed geological investigation at the outcrop and subsurface level. The Sembar Formation shows vertical variation in the lithofacies assemblage and very thick organic rich clays are reported in different parts of the Indus Basin. However, the available limited geochemical data from the Sann #1 well which was a wildcat exploratory well drilled in 1984 and studied by Robison et al. (1995), favor a Sembar source rock in the region. The Chiltan Formation also contains organic rich clays in the Indus Basin as reported from different outcrops (Shah 1977) and the Sann #1 well (Robison et al. 1995). This study, tries to investigate for the first time the outcrop based hydrocarbon source rock

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potential and comparison with the subsurface occurrence of the Middle Jurassic Chiltan and the Lower Cretaceous Sembar formation in the Mughal Kot Section and San #1 well, using bulk rock geochemical analysis and organic petrographic methods. The extrapolation of the results of outcrop data has added advantages of determining the lateral and vertical thicknesses of the potential organic shale intervals, variation in the depositional trends across the basin, quantifying the associated network of fractures for devising successful fracking strategies, comparison of outcrop, core, and log observed fractures, effect of depositional processes on geomechanical properties, integration of multidisciplinary properties observed, and the effects of depositional properties on hydrocarbon migration pathways.

In-place estimates with a robust connection to geological studies are widely considered an excellent tool for initial estimates of the Shale Gas reserves. The British Geological Survey (BGS) have employed the methodology of using outcrop based geological studies, volumetrics and gas contents to study the Carboniferous Bowland Shale gas geology and resource estimation. Similarly the success of the Shale Gas is greatly influenced by the detailed outcrop based geological investigation and utilization of the subsequent geo-modeling of the Antrim Shale, Michigan, the Antrim Shale of Upper Devonian age, Barnett Shale, Caney Shale, Oklahoma Conesauga Shale, Alabama Fayetteville Shale, Arkansas, Floyd Shale, Alabama, Gothic Shale, Colorado; Haynesville Shale, Louisiana, Collingwood-Utica Shale, Michigan; New Albany Shale, Illinois Basin; Pearsall Shale, Texas; Devonian shales, Appalachian Basin; Chattanooga and Ohio Shales; Marcellus Shale; Utica Shale, New York and Ohio; Woodford Shale, Oklahoma.

The results of this study are very important in knowing the source rock quality, type of kerogen, source rock maturity, the expulsive and non-expulsive history of the source rock and indigenous vs non-indigenous hydrocarbon character both at surface and depth of the Sembar and Chiltan formation.

Stratigraphic framework

The Mughal Kot Section

The oldest rocks exposed in the Mughal Kot Section (Fig. 1) are represented by the Middle Jurassic Chiltan Formation also known as the Suleiman Limestone Group. This unit is disconformably overlain by the Cretaceous Sembar, Goru, Parh, Mughal Kot formations and Pab Sandstone (Plate 1, Figs. 1–6). A brief description of these rocks is provided in the following paragraphs.

Chiltan Formation

The Chiltan Formation consists of hard, fetid, thin to massive bedded, dark gray to blue oolitic limestone, contains some secondary calcite and chert nodules (Plate 1, Fig. 1). Blue black calcareous claystone intercalations are common in the lower part of the unit (Plate 1, Fig. 2). The lower contact is not exposed and the upper contact is disconformable with the Sembar Formation. Macrofossils of the Chiltan Formation include ostracods, algae, corals, bryozoans, brachiopods, mollusks, crinoids and foraminifers. These fossils indicate that Chiltan Formation was deposited in a shallow carbonate platform (Shah 1977).

Sembar Formation

The Sembar Formation consists of black soft shale, claystone with thin beds of nodular limestone and sandstone (Plate 1, Fig. 3) (William 1959). The lower contact is unconformable with the Chiltan Formation and the upper contact with Goru Formation is gradational. Fossils in the Sembar Formation consist of belemnites, ammonoids, foraminifers and nano-fossils. The age of Sembar Formation spans the entire Neocomian (Early Cretaceous) time and the paleoenvironmental setting are interpreted as shallow marine to open marine (Bender 1995).

Parh Limestone

The Parh Limestone is a hard, well bedded, and lithographic to porcellaneous, limestone with marl intercalations (William 1959). The unit is light gray, and cream to tan in color (Plate 1, Fig. 4). The upper contact is conformable with the overlying Mughal Kot Formation. The Parh Limestone is highly fossiliferous and yielded abundant planktonic foraminifers and nannofossils. Based on the fossil assemblage present in the unit the Parh Limestone is Turonian to Campanian (Late Cretaceous) in age. The depositional environment is interpreted as open-deep marine.

Mughal Kot Formation

The Mughal Kot Formation is comprised of dark gray calcareous mudstone with scattered intercalations of sandstone, conglomerate, and argillaceous limestone (Plate 1, Fig. 5). The sandstone is dark gray sub litharenite to litharenite that contains volcanic rock fragments. Sandstone and conglomerate inter-beds fine upward and contain typical Bouma turbidite sequence. The Formation locally contains olistostromes and pebbles of basalt. The

Plate 1

Plate 1 The exposed lithostratigraphic units of Jurassic-Cretaceous age in the Mughal Kot Section. 1 The organic clays and carbonate facies within the Chiltan Formation. 2 Interbedded carbonate and organic clays within the Chiltan Formation. 3 Organic clays and sandstone interbeds within the Sembar Formation. 4 Carbonate facies of

the Parh Limestone. 5 Thin bedded, thick succession of carbonates of the Mughal Kot Formation. 6 A cross bedded sandstone facies within the Pab Sandstone. The lithologic log shows the dominant lithofacies in each stratigraphic unit

upper contact of the formation with the Pab Sandstone is gradational. Fossils in the Mughal Kot Formation include smaller benthic and planktonic foraminifers that indicate Late Cretaceous (Campanian–Maastrichtian) age. The deposition of Mughal Kot Formation is interpreted as occurring in an outer shelf-open marine environment.

Pab Sandstone

The Pab Sandstone is a gray to brown, thick to massive bedded quartzose sandstone (Plate 1, Fig. 6) with intercalation of clays and siltstone. The upper contact with Ranikot Formation is disconformable. In the Mughal Kot Section

Fig. 1 Topographic and structural map of Pakistan showing the location of Mughal Kot Section in the Central Indus Basin and the location of Sann #1 well in the Southern Indus Basin (various abbreviations used in the figure are explained here. *BO* Bela Ophiolites, *MBO* Muslim Bagh Ophiolites, *ZO* Zhob Ophiolites, *SR* Sulaiman Range, *WO* Waziristan Ophiolites, *KB* Kohat Basin, *PB* Potwar Basin, *KO*

Khost Ophiolites, *KF* Kirthar Fault, *KR* Kirthar Range, *DO* Dargai Ophiolites, *GF* Ghazaband Fault, *CF* Chaman Fault, *PS* Panjao Shear Zone, *HF* Herat Fault, *MFT* Main Frontal Thrust, *MBT* Main Boundary Thrust, *MMT* Main Mantle Thrust, *MKT* Main Karakoram Thrust)

the Pab Sandstone is devoid of fossils. However, based on the fossils recorded from other localities the Pab Sandstone is Late Cretaceous (Maastrichtian) in age (Shah 1977).

Stratigraphy of the Sann #1 well

The stratigraphic units encountered in the San 1 well includes the Eocene Laki Formation (94 m thick sequence of limestone), Ranikot Group of Paleocene age (940 m thick sequence of shale, sandstone and limestone), the Cretaceous Pab Sandstone (77 m thick sandstones), Mughal Kot and Parh Limestone (188 m thick limestone and marl), Guru Formation (1325 m thick shale and sandstone), Sembar Formation (877 m thick, shale and calcareous sandstone) and the Jurassic Chiltan Formation (314 m thick limestone and grey-black shale).

Materials and Methods

The detailed geochemical and organic petrographic investigations of the outcrop samples of Chiltan and Sembar formation were carried out at the Hydrocarbon Development Institute of Pakistan (HDIP) Labs, while the subsurface geochemical data came from the selected eighteen (18) samples of the Sann #1 well. The samples were analyzed using the TOC, Rock Eval Pyrolysis, vitrinite reflectance and Maceral analysis techniques.

The Rock–Eval parameters are calculated according to Johannes et al. (2006). The hydrocarbon source rock maturation level as a function of Production Index (PI) and Tmax for different types of kerogen (after Bacon et al. 2000) are used to construct various geochemical cross plots. These cross plots include the HI vs OI cross plot for determining the Kerogen type; the Tmax vs HI cross plot for both the kerogen type and maturation level; the GP vs TOC cross plot for the source rock quality; the Tmax vs PI cross plot for the maturation level and the S1 vs TOC cross plot for the knowing the indigenous or non-indigenous hydrocarbons generation potential of the source rock.

Based on the high TOC content, the selected samples of the Sembar and Chiltan formation were studied using the Carl Zeiss Axio Imager Z1M for the microscopic imaging of the Maceral types and vitrinite reflectance [Ro (%)] measurements at the HDIP. The analyses were carried out using the reflected white light. Relative abundance of inert and reactive constituents of organic clays was determined during this study. A polished block of rock sample is prepared and placed under the microscope to identify Maceral group in an immersion medium with the help of their reflectance, morphology and color, the quantitative composition is determined (ICCP 2001).

Results and discussion

Organic richness and source rock quality

The total organic carbon (TOC) analysis is used to measure the organic richness of a rock (Jarvie 1991). The TOC is reported in weight percent (wt%). It is useful as a qualitative measure of petroleum potential. It is important to consider that TOC decreases with increasing thermal maturity. The TOC of 0.5 wt% is widely regarded as the minimum value for defining a petroleum source rock, but most geochemists consider rocks with less than 1.0 wt% TOC as organically lean and unlikely sources for commercial hydrocarbon accumulations (Hunt 1996). The worldwide average TOC of all shale is about 0.9 wt% and the average TOC of source rock shale is 2.2 wt%. The average TOC of a calcareous shale source rock and carbonate (mudstone) source rock is 1.9 wt% and 0.7 wt%, respectively. The worldwide average TOC of all source rocks is 1.8 wt%, a value much higher than the often quoted minimum of 0.5 to 1.0 wt%. We use here a TOC of 1.0 wt% as a minimum value for defining a potential source rock.

The results of TOC analysis of the outcrop samples (Table 1) and subsurface samples from the Sann #1 well (Table 2) are presented. Based on the highest value of 2.08 TOC (%) from the outcrop samples and 5.43 TOC (%) at depth of 3680 m the Chiltan Formation is considered as a very good source rock. Similarly the outcrop samples of the Sembar Formation having the highest value of 1.54 TOC (%) and 9.48 TOC (%) at a depth of 3520 m suggest it to be a very good source rock (Bacon et al. 2000). The variations in TOC content in the samples from the Chiltan and Sembar Formation with the depths in the Sann #1 well also confirms an overall good–very good source rock potential for both formations as shown in the TOC vs Depth cross plot (Fig. 2) (Maky and Ramadan 2008).

Type of Kerogen and thermal maturity

The hydrogen index (HI) and the oxygen index (OI) are used to define the type of kerogen and approximate level of maturation (Ghori 1998). The oil prone kerogen have a high HI and low OI values while the gas prone kerogen are characterized by a low HI and high OI values (Tissot and Welte 1978). The HI vs OI cross plot (van-Krevelen 1961) show a mix of type II and III kerogen from the outcrop data (Fig. 3), while in the Sann #1 well the type II kerogen is found (Fig. 4).

To determine the maturity stage of the organic matter HI vs Tmax cross plot is used (Figs. 5, 6). The outcrop data from the Mughal Kot Section show mostly immature source rock for both Chiltan and the Sembar formation, while only one sample in the Sembar Formation reflects the mature nature (Fig. 5). The data in Sann #1 well also dominantly show an immature level for both formations (Fig. 6).

Table 1 Shows the TOC and Rock Eval pyrolysis results of the outcrop samples of the Chiltan and Sembar formation, exposed in the Mughal Kot Section

Formation	S. no.	TOC (wt%)	S1	S2	S3	GP	PI	HI	OI	T (Max)	BI
Sembar Formation	1	0.73	0.19	0.90	1.19	1.10	0.17	121	160	418	26.02
	2	1.25	1.20	2.80	3.50	4.05	0.30	215	265	405	96
	3	2.08	1.50	10.50	3.50	12.50	0.12	445	148	421	72.11
	4	1.45	2.20	7.25	3.00	9.50	0.23	490	210	415	151.72
Chiltan formation	5	1.50	0.08	0.11	0.48	0.19	0.42	06	30	410	5.33
	6	1.80	2.10	6.85	3.30	9.00	0.23	365	180	420	116.67
	7	1.05	1.60	0.63	0.13	2.23	0.71	60	12.30	311	152.38
	8	1.54	0.05	0.06	0.15	0.11	0.45	03.90	9.74	351	3.24
	9	1.19	0.06	0.12	0.28	0.22	0.33	13.45	23.53	392	5.04
	10	1.43	0.32	2.15	119	2.47	0.12	150.35	83.22	443	23.37

Table 2 Shows the TOC and Rock Eval pyrolysis results of the subsurface samples of the Chiltan and Sembar formation, in the Sann #1 well

Formation	S. no.	Depth (in m)	TOC	S1	S2	S3	GP	PI	HI	OI	T (Max)	BI
Sembar formation	1	3482	5.01	5.03	16.83	3.84	21.87	336	77	0.23	427	100.39
	2	6509	2.62	2.85	7.37	4.21	10.22	281	161	0.28	426	108.77
	3	3518	5.89	10.16	29.75	3.68	39.91	505	62	0.25	422	172.49
	4	3520	9.48	6.57	33.91	1.93	40.48	358	20	0.16	431	69.30
	5	3531	2.11	2.37	4.96	3.90	7.33	235	185	0.32	425	112.32
	6	3559	2.09	1.66	4.72	4.88	6.38	226	233	0.26	423	79.42
	7	3598	1.86	1.79	2.88	4.19	4.67	155	225	0.38	424	96.23
	8	3611	0.81	0.23	2.14	1.73	2.37	264	214	0.10	431	2839
	9	3631	1.55	1.68	3.41	4.26	5.09	220	275	0.33	422	108.38
Chiltan formation	10	3658	1.06	0.88	1.77	3.18	2.65	167	300	0.33	428	83.01
	11	3660	0.74	0.20	0.91	1.20	1.11	123	162	0.18	421	18.86
	12	3680	5.43	8.95	30.04	4.36	38.99	553	80	0.23	423	164.82
	13	3685	1.53	0.09	0.12	0.50	0.21	08	33	0.43	413	5.88
	14	3689	1.46	2.30	7.29	3.13	9.59	499	214	0.24	421	157.53
	15	3709	1.84	2.15	6.87	3.36	9.02	373	183	0.24	426	116.84
	16	3721	2.31	3.24	10.43	3.51	13.67	452	152	0.24	423	140.25
	17	3722	2.87	2.00	11.49	1.45	13.49	400	51	0.15	433	69.68
	18	3731	1.29	1.22	2.89	3.58	4.11	224	278	0.30	415	94.57

S1 distillable hydrocarbons present in the rock (mg/g rock), *S2* hydrocarbons generated from the pyrolysis of kerogen (mg/g rock), *S3* CO₂ generated from kerogen pyrolysis (mg/g rock), *GP* = (*S1* + *S2*) generation potential (total hydrocarbon generation potential of the rock, mg/g rock), *PI* = (*S1*/*S1* + *S2*) production index, *HI* hydrogen index (mg generated HC/g of organic carbon), *OI* oxygen index (mg CO₂/g of organic carbon), *Tmax* pyrolysis temperature at which a maximum yield of generated hydrocarbons occurs (*Tmax* increases with increasing maturation), *BI* Bitumen Index

Generation potential (GP) of the source rock

The generation potential (GP) gives a qualitative estimate of hydrocarbon resource potential; however, it cannot be used to predict the type of hydrocarbons (gaseous or liquid) produced during pyrolysis (Tissot and Welte 1978).

The quality of source rock and potentiality to generate hydrocarbons in the Chiltan and Sembar formation was determined from the cross plot between the TOC content and the GP values. The outcrop data of Chiltan and Sembar

formation from the Mughal Kot Section (Fig. 7) and the Sann #1 well (Fig. 8) show poor to very good source rock quality.

Hydrocarbon migration and expulsion history

The production index (PI) is often used to assess the relative thermal maturity of organic matter, and the presence of migrated hydrocarbons. The PI value for the Type I and II kerogen are > 0.1 while the Type III kerogen commonly have 0.1–0.2 range of PI values.

Fig. 2 The Depth vs TOC cross plot shows the variations in TOC content with changing depth of the Chiltan and Sembar Formations in the Sann #1 well (modified after Maky and Ramadan 2008)

Fig. 3 HI vs OI cross plot showing the distribution of different types of Kerogen in the outcrop samples of the Chiltan and Sembar formation at the Mughal Kot Section (modified after Espitalié et al. 1977)

Fig. 4 HI vs OI cross plot showing the distribution of different types of Kerogen in the Chiltan and Sembar formation in Sann #1 well (modified after Espitalié et al. 1977)

The production index (PI) and the Tmax cross plot suggested by Espitalié et al. (1977) is used here which shows that all samples are immature (Fig. 9). However, in the PI vs Tmax cross plot adapted from Ghori (2000) only few samples of both Chiltan and Sembar formation in the Sann #1 well are mature (Fig. 10), while only one outcrop sample of the Sembar Formation fall in the oil window (Fig. 11).

The main use of the Bitumen Index which is sometimes also called as the migration index (Hunt 1996), is to determine the depth at which a source rock begins to expel oil. By plotting the S1 and the TOC wt% values against the depth of the samples no expulsion of the hydrocarbons is inferred (Fig. 12). The S1 vs TOC wt% for the analyzed outcrop samples (Fig. 13) and Sann #1 well (Fig. 14) samples of both formations show an Indigenous source of the hydrocarbons.

Fig. 5 Tmax vs HI cross plot showing the maturity and type of Keroen in the outcrop samples of the Chiltan and Sembar formation, exposed in the Mughal Kot Section (modified after Hunt 1996)

Fig. 6 Tmax vs HI cross plot showing the maturity and type of Keroen in the outcrop samples of the Chiltan and Sembar formation, recorded in the Sann #1 well (modified after Hunt 1996)

Vitrinite reflectance measurements [Ro (%)] and Maceral analysis

The term vitrinite commonly refers to reflectance measurements of vitrinite Ro (%) for the reason that optical properties of vitrinite Maceral group change more consistently during the advancement of their grade as compared to those of the other Macerals. A more recent definition explains that vitrinite is a group of Macerals with distinct

optical and chemical properties varying with relative effect of temperature and/or time. The vitrinite reflectance [Ro (%)] measurements are commonly used for determining the maturity of rocks. The maturity levels based on vitrinite reflectance [Ro (%)] and Tmax (C) and the occurrence different Maceral types, i.e., fluorescent amorphous organic matter (OM), exinite and alginite (Tables 3, 4) demonstrate that source rock maturity in both Sembar and

Fig. 7 The cross plot shows the source rock quality, and the variations in TOC content and generation potential (GP) of the Chiltan and Sembar formation in the Sann #1 well (modified after Ghori 2002)

Fig. 8 The cross plot shows the source rock quality, and the variations in TOC content and generation potential (GP) of the outcrop samples of the Chiltan and Sembar formation in the in the Mughal Kot Section (modified after Ghori 2002)

Chiltan formation falls in the oil and gas generation zone to cracking of oil to gas condensate zone.

The organic rich and organic poor rock intervals within the outcrop and subsurface samples were frequently recorded. These may be controlled by the tectonics and associated sea level perturbations recorded in the form of shallowing-deepening cycles. The deepening and shallowing of facies within the Chiltan Formation was attributed to the Middle–Late Jurassic development of the rift basin and associated thermal uplift in response to the separation of the Indo-Madagascar from the Afro-Arabia. The renewed phase of marine clastic sedimentation is related to the Early Cretaceous sea level rise and local deepening of the basin in response to the local tectonics in the study area. This has resulted in the deposition of shallow-deep cycles of deposition, preserving the organic rich-organic poor intervals within the Sembar Formation.

Summary and conclusions

The detailed geochemical and petrographic analysis of the outcrop data from the Chiltan and Sembar formation exposed in the Mughal Kot Section and the subsurface well

Fig. 9 The cross plot shows variations in the Tmax and Production Index (PI) and thermal maturity and migration history of the hydrocarbons within the outcrop samples of Chiltan and Sembar formation in the Sann #1 well (modified after Espitali 1977)

Fig. 10 The cross plot shows variations in the Tmax and Production Index (PI) and thermal maturity and migration history of the hydrocarbons within the outcrop samples of Chiltan and Sembar formation in the Sann #1 well (modified after Espitali et al. 1977)

cuttings data from the Sann #1 well elucidate and summarizes the significance of hydrocarbon source rock potential in the study area.

In the Mughal Kot Section, the upper part of the Chiltan Formation (outcrop samples 1–2), the source rock quality range from poor to fair, type II Kerogen is recognized and the organic matter is immature. The upper part also

indicate indigenous hydrocarbon occurrence which is supported by S1 vs TOC cross plot. In the middle part of the Chiltan Formation (outcrop samples 3–4), the source rock quality ranges from very good to good. Type II Kerogen is recognized and the source rock is immature and indigenous hydrocarbon occurrence is suggested. In the lower part (outcrop samples 5–6), the source rock quality range

Fig. 11 The cross plot shows variations in the Tmax and Production Index (PI) and thermal maturity and migration history of the hydrocarbons within samples of Chiltan and Sembar formation exposed in Mughal Kot Section (modified after Ghori 2000)

Fig. 12 The S1/TOC (wt%) vs Depth cross plot of Chiltan and Sembar formation in the Sann #1 well indicate that S1/TOC (wt%) values do not fall within the expected range of 0.1 to 0.2, suggesting a non-expulsion of the hydrocarbons

from poor to good while Type II and type III kerogen, immature source rock and indigenous hydrocarbon occurrence are noted.

In the Sann #1 well, the upper part of the Chiltan Formation (represented by well samples 8, 9, 10, 11), the source

rock quality range from fair to good and Type II–III Kerogen are recognized. The hydrocarbon potentially is fair to poor. The organic matter is immature–mature, did not expel any hydrocarbons. The middle part of the Chiltan Formation (represented by the well samples 12, 13, 14, 15) the source

Fig. 13 The S1 vs TOC (wt%) Cross plot showing the indigenous occurrences of all the outcrop samples from the Chilton and Sembar formation, exposed in Mughal Kot Section (modified after Hunt 1996)

Fig. 14 The S1 vs TOC (wt%) cross plot showing the indigenous occurrences of all the samples from the Chilton and Sembar formation in the Sann #1 well (modified after Hunt 1996)

Table 3 Shows the vitrinite reflectance [Ro (%)], Maceral types, maturity level of the outcrop and subsurface samples of Chiltan and Sembar formation in the Mughal Kot Section and San #1 well

Data	Formation	Ro (%)	Maceral type	Maturity level
Outcrop	Sembar (upper part)	0.93	Fluorescent/amorphous (organic matter)	Cracking of oil to gas condensate zone
	Sembar (lower part)	0.60	Fluorescent/amorphous (organic matter)	Oil and gas generation
	Sembar (lower part)	0.88	Exinite, amorphous (organic matter)	Cracking of oil to gas condensate zone
	Sembar (lower part)	0.75	Exinite, amorphous (organic matter)	Oil and gas generation
	Chiltan (upper part)	0.90	Exinite, amorphous (organic matter)	Cracking of oil to gas condensate zone
	Chiltan (middle part)	0.80	Exinite, amorphous (organic matter)	Oil and gas generation
	Chiltan (lower part)	1.1	Exinite, amorphous (organic matter), inertinite	Cracking of oil to gas condensate zone
Sann #1 well	Sembar (upper part)	0.60	Fluorescent/amorphous (organic matter)	Oil and gas generation
	Sembar (lower part)	0.88	Fluorescent/amorphous (organic matter), alginite, inertinite	Cracking of oil to gas condensate zone
	Sembar (lower part)	0.75	Fluorescent, alginite, inertinite	Oil and gas generation
	Sembar (upper part)	0.9	Amorphous (organic matter), exinite	Cracking of oil to gas condensate zone
	Sembar (lower part)	0.8	Exinite	Oil and gas generation
	Sembar (lower part)	1.1	Inertinite	Cracking of oil to gas condensate zone

rock quality range from very good to good. Kerogen is type II except for sample 13 which is type III. The Hydrocarbon potentiality is good–poor. The organic matter is immature, however, the maturity level indicated by depth vs PI cross plot suggests that the organic matter is mature. The middle part of the Chiltan Formation shows no expulsion of hydrocarbon and indigenous hydrocarbon occurrence is suggested. In the lower part of the Chiltan Formation (represented by the well samples 16, 17, 18) the source rock quality is very good except in the lowermost part which is good. Kerogen recognized is type II. The organic matter is immature, however, the well sample 17 is mature and fall in zone of oil window.

In the Mughal Kot Section, the upper part of Sembar Formation is represented by the outcrop samples 1–7, the source rock quality is fair and Type III Kerogen is recognized. The Organic Matter is mature, and indigenous hydrocarbon occurrence is noted. In the middle part (outcrop samples 8 and 9), the source rock quality is poor. Type III Kerogen is recognized, the maturity plots indicate immature level and an indigenous hydrocarbon occurrence is suggested. In the lower part of the Sembar (outcrop sample 10), the source rock quality is fair, Type II Kerogen is recognized, the organic matter is mature, having an indigenous hydrocarbon occurrence.

In the Sann #1 well, the upper part of Sembar Formation (well sample 1 and 2) the source rock quality is very good and type II Kerogen is recognized. The organic matter fall in the immature–mature nature of the source rock, no expulsion

of hydrocarbon and an indigenous hydrocarbon occurrence is noted. In the middle part represented by well samples 3 and 4, the source rock quality is very good and type II Kerogen is recognized. The organic matter is of immature nature except for the Tmax vs PI cross plot that indicate oil window for the well sample 4. In the middle part non-expulsion and indigenous hydrocarbon occurrence is noted. The lower part of the Sembar Formation is represented by well samples 5 and 6, the geochemical parameters are similar to the middle part except the quality of the source rock degrades from very good to good.

The Vitrinite Reflectance [Ro (%)] values of the outcrop samples from the Sembar Formation range from 0.6 to 0.93, and range 0.6–0.88 in the samples of Sann #1 well. Similarly the Vitrinite Reflectance [Ro (%)] values of the outcrop samples of the Chiltan Formation range 0.9–1.1 and range 0.7–1.5 in the samples of Sann #1 well. The different Maceral types, i.e., fluorescent amorphous organic matter (OM), exinite, alginite and inertinite are recorded in the outcrop and Sann #1 well samples. The surface and subsurface Maceral data suggest that both Sembar and Chiltan Formation fall in the oil and gas generation zone to cracking of oil to gas condensate zone.

Based on the current investigations it is concluded that sufficient vertical thickness of organic rich facies, their lateral continuity, High TOC content, appropriate Kerogen type, thermal maturity reflecting oil–gas generation zone to cracking of oil to gas condensate zone, and indigenous hydrocarbon exists in the Chiltan and Sembar formation.

Table 4 The organic petrographic occurrences of the fluorescent amorphous organic matter (OM), Maceral types (alginite and exinite) demonstrate the source rock maturity both in the Sembar and Chiltan

formation falls within the oil and gas generation zone to cracking of oil–gas condensate zone

<p>Amorphous Organic Matter (OM)</p>	<p>Organic matter Type: Bituminite, as observed under fluorescence blue light, showing unstructured organic matter (bituminite) of probable algal origin fluorescing yellow, immersion oil objective, $\times 600$, scale bar = 50 μ m (Sembar Formation outcrop sample from the lower part)</p>
<p>Maceral Type Inertinite (Mineral matter-rich layer within organic shale is called Fusinite; a type of the Inertinite Group of macerals that occupies the major part of the image, where cell lumens are filled with argillaceous material). It is found in the Chiltan Formation, exposed in the Mughal Kot Section.</p>	<p>Reflected white light image of Inertinite (Fusinite), immersion oil objective, $\times 600$, scale bar = 50 μ m</p>
<p>Maceral Type *Liptinite (formerly Exinite) It is found in the Chiltan Formation from the Sann#1 well</p>	<p>Subtype Lamalginite: A polished section distinguished under the fluorescence blue light, immersion oil objective, $\times 600$, scale bar = 50 μ m</p>

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