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Potential of shale gas in Cambay basin, Gujarat, India

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ABSTRACT
Carbonaceous shale is an organic rich sedimentary rock that forms the main source for all conventional and nonconventional hydrocarbons. Though, formation of oil and gas takes place in shale but due to very low porosity, it cannot be reservoir rock for hydrocarbons in case of conventional hydrocarbons. Shale is an excellent source rock for nonconventional natural gas and in the last one and half decade, the development of hydrofracturing and horizontal drilling has made it possible to exploit the carbonaceous shale as nonconventional gas source. The exploration and exploitation of shale gas changed the global economics of hydrocarbons and the oil prices came down from 110$ per barrel to 30$ per barrel. With the exploitation of shale gas, USA stopped importing oil and gas. It has now more than 2 million barrel of shale oil as surplus and thus exports it to various countries, including India.

In India, the Cambay basin, which is a oil producing basin, contains thick deposits of carbonaceous shale. These Tertiary shales are fine grained and organic-rich and thus considered a good source for shale gas. For shale gas exploration, the thickness of shale in subsurface and the type of organic matter it contains, are important parameters for the generation of nonconventional shale gas. Rock Eval pyrolysis of the shale, is one of the most important basic organic geochemistry to understand such parameters. As an initial study, interbedded shale samples from Middle Eocene lignite sequence of Cambay formation (Nagori et al., 2013) of Tadkeshwar in Surat and Rajpardi in Bharuch, were sampled and analysed using Rock Eval Pyrolysis system. Total organic carbon in these shales varies from 0.2% to 47%, which are indicative of good source of shale gas deposits. The T_{max} varies between 342°C to 450°C, and the hydrogen index (HI) ranges between 32 to 754 mg HC/ g TOC. The variation of HI vs. T_{max} suggests an immature to mature stage for the hydrocarbons. The organic matter in shales suggest Type II or Type III kerogen, which are responsible for the generation of these hydrocarbons.

Key Words: Shale, Shale gas, Total Organic Carbon, Rock-Eval pyrolysis, Cambay Basin

INTRODUCTION

Since the last one and half decades, the exploitation of shale gas has become very promising as unconventional source of energy. Carbonaceous shale is very fine grained sedimentary rock and has good potential for nonconventional source of energy. Being more environment friendly, it is considered one of the alternative source of energy for the future. With fast development in USA, shale gas is being further explored at many other places also, like Arizona (USA), China, UK, Australia etc. Carbonaceous shale, which is a fine grained clastic sedimentary rock, has good potential as source-cum-reservoir rock for natural gas, depending on richness and thermal maturity of organic matter (Curtis, 2002; Boyer et al., 2006; Horsfield and Schulz, 2012). The light hydrocarbon gases generated in the organic rich shales, remain trapped in the micro-pores and micro-fractures or in the thin layers of these rocks (Ross and Bustin, 2008; Milliken et al., 2013). With geological time and under pressure and temperature, the organic matter is converted into kerogen to produce hydrocarbons. Further, in marine conditions, biological activities produce large quantity of organic matter. In general, for any shale-gas system, the marine conditions support biologic activities, and thus produce large quantities of organic matter. The depositional conditions concentrate the organic matter, while post-depositional conditions allows their preservation and maturation to gaseous hydrocarbon (McCarthy et al., 2011). The storage conditions are governed by the micropores/ micro-fractures and the sorption surfaces of kerogen and clay minerals of the shales (Curtis, 2002; Ross and Bustin, 2008). Low permeable shales require extensive fractures to produce commercial quantities of gas. With advancement in techniques, such as hydro-fracturing, in conjunction with horizontal drilling, massive production of shale gas is being carried out in the United States since past decade (EIA, 2013, USGS, 2012). In comparision, the Shale gas exploration in India is at an early stage. Major oil company has identified the potential basins and plan to explored these basins with available data, as well as new data using geochemical, geological and petrophysics studies, which will allow them to initialize the exploration program in most promising zones to find the sweet spots, where it would be most beneficial to drill. Cambay basin is one such basin in their priority list, which is already a producing basin for conventional hydrocarbons. The Cambay Shale is the main source rock sequence in the basin, with contribution of oil from Kalol and Tarapur Formations and their

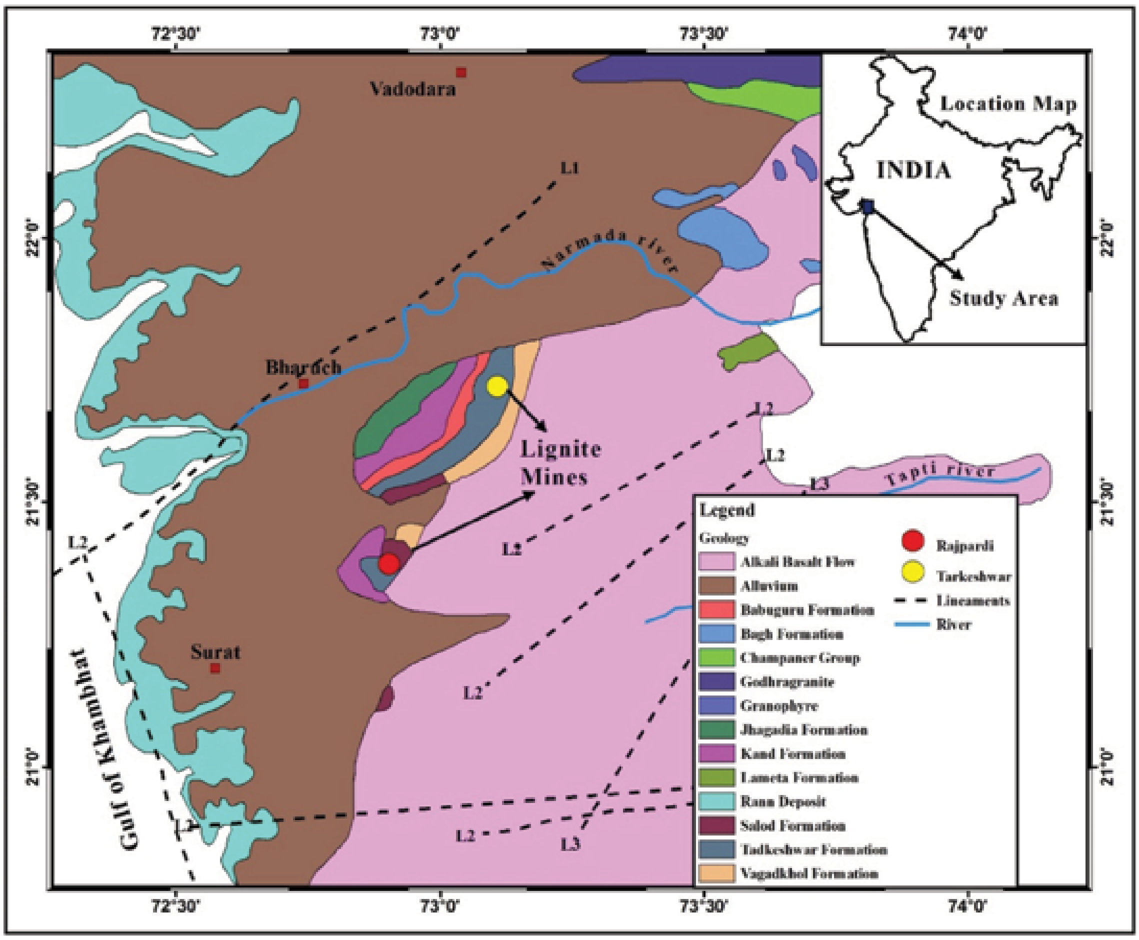


Figure 1. Geological map of South Cambay basin, showing the locations of sampled lignite mines (after Singh et al., 2012a).

equivalents in the Broach-Jambusar block (Chowdhary, 2004). Earlier, this basin has been explored extensively for conventional hydrocarbons. The available explored data suggests that about 20 trillion cubic feet (tcf) of shale gas can be produced from this basin (DGH, 2012; USGS, 2012). These estimates are based on already available exploration data but for shale gas exploration, there are certain other characteristics which are necessary for the exploitation. Like geochemical, petrophysical, petrological and mineralogy studies on these shales. Geochemistry of these shales for their organic richness, kerogen types and thermal maturity are basic requirement for shale gas exploration as these parameters control the gas generation in shales (Jarvie et al., 2007). Rock Eval Pyrolysis is one of the most important and basic technique to evaluate the hydrocarbon generating capacity of the source rocks.

In the present study, preliminary investigation on the geochemical properties of organic matter of the shales from the Cambay basin has been carried out using the above technique. The shale samples were collected from the open cast mines, namely Tadkeshwar and Rajpardi in Surat, Bharuch districts, respectively (Figure 1). The fossil data recovered from the sedimentary sequences in these mines suggest an analogy of Cambay shales for these shale horizons (Singh et al., 2012a, 2012b; Sahni et al., 2006; Nagori et al., 2013). As mentioned earlier, Cambay shales are well established hydrocarbon source rock in the basin. In the preset work, the shales associated with lignite mines, have been characterized for the organic matter present in the shales in terms of its TOC content, thermal maturity and kerogen type using Rock-Eval pyrolysis. The geochemical parameters studied here, provide basic information on the qualitative and quantitative aspects of the organic matter in shales, which are interpreted in the light of basin geology to assess the gas generation potential of these shales.

GEOLOGIC SETTING AND STRATIGRAPHY

The Cambay basin is a narrow elongated (NNW-SSE) intracratonic rift basin situated in the northern part of western India. It extends northward from the Gulf of Cambay in the south Gujarat to Jaisalmer-Mari ridge in the central Rajasthan (Kundu et al., 1997; Mathur et al.,

Table 1. Stratigraphic succession of the Cambay basin (after Agarwal, 1986)

Age		Formation and Thickness	Lithology
Quaternary	Holeocene	*Narmada Fm.*	Sandstone, silt,clay and gravels
……………	……………………	..Unconformity…...	…………………………………
	Lower Pliocene	*Jhagadia Fm.(200m)*	Sandstone, gritstone, conglomerate, breccia, clay, silt
	……………………	…Unconformity….	………………………………..
	Miocene	*Kand Fm. (200-400m)*	Conglomerate, fossil,limestone,calcareous sandstone and gravelly clay
Tertiary		……………………	……Unconformity……….……
		Babaguru Fm. (200-300m)	Conglomerate, sandstone,clays cherry red and highly ferruginous
	…………………..	…Unconformity...	…………………………………
	Oligocene	*Tadkeshwar Fm. (125 -346m)*	
	…………………..	..Unconformity….	…………………………………
	Eocene	*Ankleshwar Fm. (603m)*	
		………………… *Cambay shale (+1500m)*	…Unconformity……………….. Grey to dark grey thinly bedded shales.
	…………………..	..Unconformity…	…………………………………
	Paleocene	*Vagadkhol Fm (+50m)*	Conglomerate, grit, sandstone, variegated clays and siltstone
	……………………	..Unconformity……..	…………………………………
	Cretaceous	*Deccan Trap*	Basalt, trachyte etc.

1968; Biswas, 1982). The Saurashtra craton lies to its West, Aravalli to the north east and Deccan Traps to the south east. Cenozoic sediment outcrops are rare and occur only on the fringes of the basin. The basin is covered by Gujarat alluvium in the south and sands of Rajasthan desert in the north. The Narmada and Barmer depression are, respectively, the southern and northernmost part of the basin (Kundu et al., 1997; Mathur et al., 1968).

This basin evolved during Late Mesozoic era with the development of major tensional faults, following widespread extrusion of Deccan Trap basalts (Biswas, 1982, 1987), which form the basement for the Tertiary and Quaternary sediments in the Cambay basin. The sediments have a thickness of over 5,000 m in the deepest part (Jambusar-Broach area) of this basin. The sequence comprises greywackes, dark grey to black grey shales, coal seams, silts, fine to medium grained sands and grey reddish-brown clays (Biswas, 1987). The whole basin can be dissected into five major tectonic blocks demarcated by transverse basement faults within the traps, which continue to some extent into the overlying sediments also. These blocks are Sanchor-Patan, Mehsana-Ahmedabad, Tarapur-Cambay, Broach-Jambusar and Narmada-Tapti from north to south (Biswas, 1982, 1987). They are characterized by different types of folds, faults and basement depths. The manifestations of the major tectonic trends is evident from their parallelism to the Satpura trend between the Narmada and Tapti rivers and to the Dharwar trends in the northern and central part of the basin (Raju et al., 1971). The Cambay basin shows two major tectonic lineaments, NNW-SSE, probably related to the Dharwar orogenic belt and ENE-WSW, probably related to the Satpura orogenic belt, which are evident and extend into the Cambay basin. These two major trends are manifested both on the surface and in the subsurface as well (Raju et al., 1971).

Stratigraphically, the basin can be divided into eleven Formations with Deccan Trap as the basement (Table 1). The depositional floor is characterized by narrow linear horst and graben (Bhandari and Chowdhary, 1975). The older Olpad Formation overlies the Deccan Trap with an erosional unconformity. The sedimentation in these areas took place in fluviatile to shallow water environment under oxidizing conditions (Chandra and Chowdhary, 1969). The Olpad Formation is overlain unconformably by Cambay Shale Formation, which was deposited under deep marine and highly reducing condition. The Kadi Formation, which is present only in Ahmedabad-Mehsana Block, is an intervening non-marine clastic wedge, with a thickness of almost 300 m within the Cambay shale (Bhandari and Chowdhary, 1975). The sedimentation in the region took place in a deltaic environment. The Cambay Shale is conformably overlain by Kalol Formation of Middle Eocene age, which got deposited in alternating regressive and transgressive marine settings. The marine Tarapur Shale Formation conformably overlies the Kalol Formation. The former is unconformably overlain by Babaguru Formation of Upper Miocene age, which is further overlain by Kand Formation (Middle Miocene) and Broach Formation (Pliocene age), deposited under shallow marine oxidizing environment. The Jambusar Formation conformably overlies the Jhagadia Formation (Bhandari and Chowdhary, 1975).

In addition, Cambay basin contains four sedimentary source rocks. These are the Tarapur Shale and its coeval units of upper Eocene-Oligocene; Kalol Formation and its coeval units of middle Eocene; Cambay Shale of lower Eocene; and Olpad Formation of volcanic conglomerate, shale and claystone of Paleocene (Yalcin et al., 1987; Chowdhary, 2004). Some localized sandstone reservoirs (Unawa, Linch, Mandhali, Mehsana, Sobhasan fields), are also present within the Cambay Shale of this region. The lithological heterogeneity and associated unconformity in Olpad Formation, appear to have helped in the entrapment of such hydrocarbons. Besides, transgressive shales within deltaic sequences provided a good cap rock. The peak of oil generation and migration is understood to have taken place during Early to Middle Miocene (DGH, 2012).

The studied region of Tadkeshwar lignite mine in Surat and Rajpardi lignite mines at Bharuch districts, are situated in the southern part of the Cambay basin. Subsurface lignite bearing sequences are exposed in these open cast mines. The Rajpardi lignite deposits are associated with two major litho units: Babaguru Formation which is underlain by Tadkeshwar Formation, followed by Nummulitic Formation. The Tadkeshwar Formation begins with grey clay-bed which is overlain by the carbonaceous clay-bed, which in turn, is conformably overlain by a five-meter-thick lignite seam which is a marker bed (Singh, 2012). Based on relative stratigraphic position, depositional environment and occurrence of paleo-fauna of the lignite sequences, it has been considered analogous to the Cambay Formation (Singh et al., 2012a; 2012 b; Sahni et al., 2006; Nagori et al., 2013; Rust et al., 2010). The predominance of mud rich sediments, together with lignites and siderites in the Tadkeshwar and Rajpardi mines, suggest deposition in shallow marine condition (Rust et al., 2010). Well preserved, consolidated shales samples were collected after removing the weathered part in the exposed horizons.

METHODOLOGY

Rock Eval pyrolysis was carried out on shale rock samples collected from open cast lignite mines of Tadkeshwar in Surat district and Rajpardi in Bharuch district. The instrument was calibrated in standard mode using the French Institute of Petroleum standard, (IFP 160000), (T_{max} = 416°C; S2= 12.43). The shale samples were powdered homogenously (<63μ) and weighed in pre-oxidized crucibles depending upon the organic matter content (~50-70 mg of the shale; and 8-15 mg of coaly shale).

Rock Eval pyrolysis is used to estimate the petroleum potential of rock samples by cracking of organic matter according to a programmed temperature pattern in the Rock Eval pyrolyzer. Released hydrocarbons are monitored by a Flame Ionization Detector (FID), forming the peaks S1, the thermo-vaporized free hydrocarbons and peak S2, the hydrocarbons from cracking of organic matter. The CO and CO_2 released during pyrolysis have been monitored by an infrared cell. This data allows the determination of total organic carbon and mineral carbon content of the samples.

The basic cycle of Rock Eval analysis consists of two steps. Firstly, the pyrolysis is carried in pyrolysis oven, with an initial temperature of 300°C, which increases to 650°C at the rate of 25°C per minute. The samples are pyrolysed in an inert atmosphere of nitrogen. The free hydrocarbons evolved at lower temperature of 300°C, are detected by the FID, resulting in formation of S1 peak. This is followed by the hydrocarbon evolution through cracking of kerogen, which results in S2 peak. Thus, S1 and S2 represent milligrams of free and kerogen cracked hydrocarbons in one gram of rock sample (mgHC/gRock). The S3 peak corresponds to CO_2 formed from thermal cracking of kerogen during pyrolysis and is expressed in milligrams per gram of rock.

Following pyrolysis, residual organic carbon is oxidized in an oxidation oven. The oxidation oven is programmed with an initial temperature of 300°C, which increases to 850°C at the rate of 20°C per minute. The resulting S4 peak comprises of carbon dioxide and carbon monoxide components defined by $S4CO_2$ and S4CO peaks during

Table 2. Rock Eval pyrolysis data of shales from the Cambay basin.

Sample	S1	S2	Tmax	S3	TOC	HI	OI	MINC
	(mgHC/gRock)		°C	mgCO2/gRock	(%)	mgHC/gTOC	mgCO2/gTOC	(%)
Tadkeshwar								
TG-01	3.58	58.42	420	8	24.27	241	33	0.7
TG-02	0.12	1.75	434	2.04	3.19	55	64	0.41
TG-03	0.13	1.2	428	1.5	2.34	51	64	0.23
TG-04	0.09	1.57	425	2.43	4.69	33	52	0.22
TG-05	0.05	0.08	394	0.55	0.18	44	306	0.46
TG-06	0.18	4.35	432	3.07	7.21	60	43	0.3
TG-07	0.07	0.14	378	0.57	0.32	44	178	0.08
TG-08	0.04	0.17	342	0.83	0.19	89	437	0.93
TG-09	0.06	1.28	431	0.35	0.59	217	59	0.07
TG-10	0.07	0.18	450	1.62	0.21	86	771	0.79
TG-11	3.12	78.84	414	16.03	47.39	166	34	1.22
TG-12	2.82	68.42	415	14.34	42.28	162	34	1.13
Rajpardi								
RJ-01	7.12	190.11	435	3.69	25.21	754	15	0.35
RJ-02	6.62	184.6	429	3.79	26.03	709	15	0.36
RJ-03	3.29	60.6	432	1.51	9.35	648	16	0.19
RJ-04	4.04	102.61	432	2.08	14.42	712	14	0.25
RJ-05	4.94	106.76	430	2.15	14.73	725	15	0.26

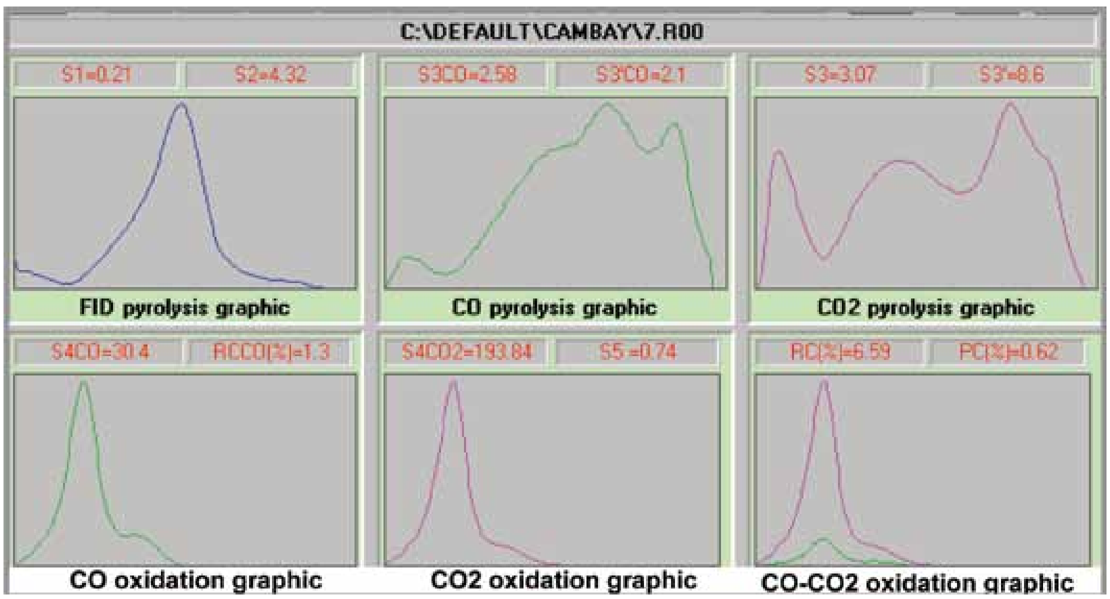
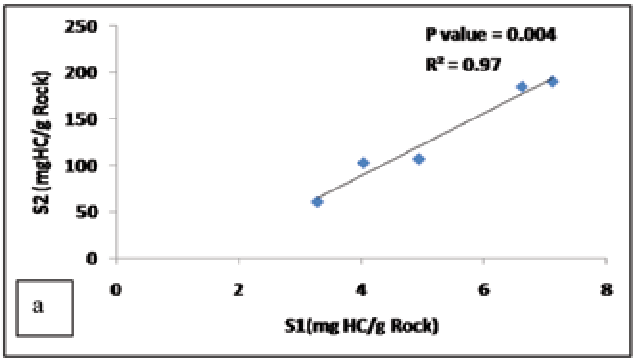


Figure 2. RE pyrolysis and oxidation curves for the shale sample (TG-07) from the Tadkeshwar lignite mines, Cambay basin.

oxidation. A separate CO_2 peak designated as S5 reflects decomposed carbon dioxide from carbonate minerals in the sample. T_{max}, which is the thermal maturity indicator, corresponds to the highest yield of S2 hydrocarbons, is recorded during the pyrolysis. Total Organic Carbon (TOC) is calculated by Rock Eval through the addition of the obtained values of pyrolised carbon and residual carbon. The relationship between these components forms the basis for various indices used for interpretation of rock characteristics. The hydrogen index, (HI) is defined here by $100 \times$ S2/TOC, while the oxygen index, (OI) is defined as $100 \times$ S3/TOC. These indices help in tracking kerogen types and maturation (User's guide, Rock Eval 6; McCarthy et al., 2011).

RESULTS

The important parameters obtained by the pyrolysis of shales from Cambay basin using Rock Eval, are given in Table 2 and representative pyrolysis and oxidation curves for the samples, are shown in Figure 2. In general, the shales from Rajpardi area show a high TOC content along



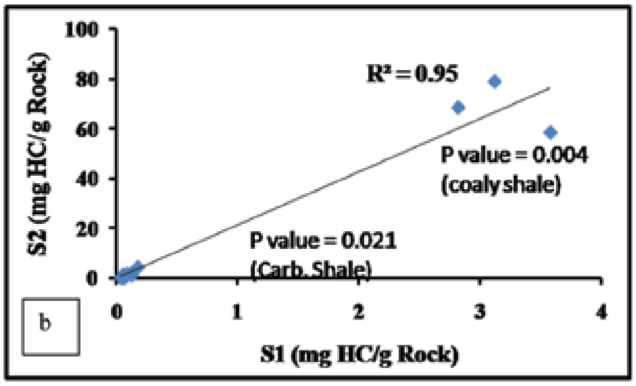


Figure 3. Correlation of S1 and S2 hydrocarbons released from the pyrolysis of shales from the (a) Tadkeshwar lignite mine, Surat, and (b) Rajpardi lignite mine, Bharuch, respectively, Cambay basin.

with other Rock Eval parameters, compared to that of Tadkeshwar (Table 2). The TOC content from Rajapardi shales ranges between 9.35 and 26.03%. The S1values range between 3.29 and 7.12 mgHC/gRock and are characteristic of the entire sample (Table 2). The S2 values show an elevated range from 60.6 - 190.11 mgHC/gRock. The T_{max} ranges from 429-435°C. The HI is high between 648 and 754 mgHC/gTOC, whereas OI for all the samples is near 15. The mineral carbon content is <0.5 %. For the Tadkeshwar shales, the TOC varies from 0.19 to 47.39 %. The S1 values are between 0.05 and 3.58 mgHC/gRock and the S2 values range from 0.14 to 78.84 mgHC/gRock. Similarly, the T_{max} varies from 342 to 450°C, whereas the HI values vary from 33 to 241 mgHC/gTOC.

DISCUSSIONS

In a shale gas play, high gas content is controlled by the amount and maturity of the organic matter. The total organic carbon content and pyrolysis parameters help in the evaluation of the sedimentary organic matter. A TOC content in wt % of sample < 0.50 is considered poor; 0.50 - 1.0 as fair; 1.0 - 2.0 as good and that > 2.0 as excellent for the source rocks (Hunt, 1996). The shales from Rajpardi show a TOC >9 %, whereas those from Tadkeshwar vary widely (Table 2). Three shale samples from Tadkeshewar area have very high TOC content (>58%). These shales are coaly in texture and can possibly have the contribution from adjacent lignite sequences. Rest of the shales from the area have relatively lower TOC (0.18 - 3.19%). The correlation analysis in coaly shales is constrained by less number of observations (n=3). Similarly, P-test and correlation analysis performed on S1 and S2 values of Rajpardi shales indicate similar source for the generation of the hydrocarbons (Figure 3). These values also vary linearly with the TOC content of the organic matter (Figure 4). With an increase of organic matter, the produced hydrocarbons are also increasing. These characteristics are observed in the organic matter derived from good/ potential source rocks. These observations also indicate that there is minimal surficial contamination of the organic matter in shales, which if happened, would have resulted in scattered and poorly correlated hydrocarbon variables and TOC contents. The quality and maturation state of kerogen is based on the hydrogen and oxygen indices (HI/ OI values) generated by the RE pyrolysis. HI is a measure of the hydrogen richness of the source rock, and is used to estimate the thermal maturity and petroleum generative potential of the rock (Tissot and Welte, 1978). OI measures the oxygen richness of a source rock and can be used in conjunction with the hydrogen index to estimate the quality and thermal maturity of source rocks. Organic rich shales deposited in reducing anoxic marine environments have high HI and quite low OI values (Tissot and Welte, 1978).

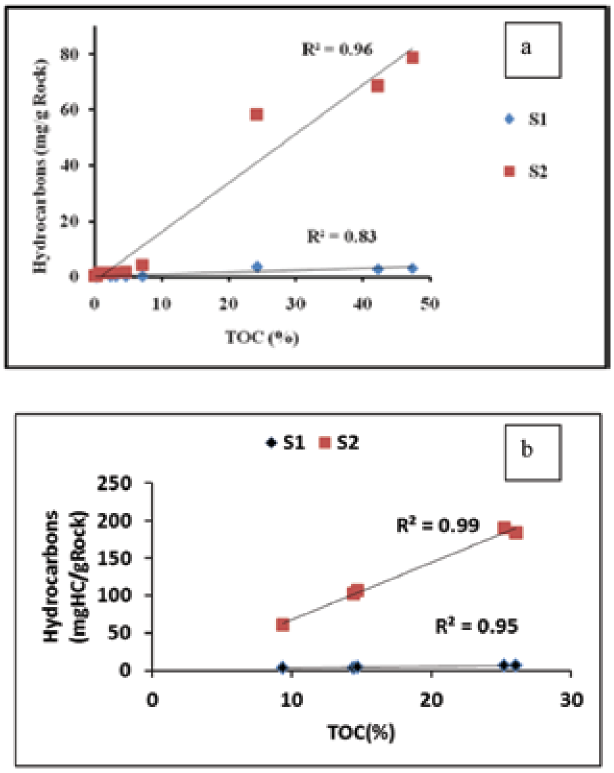


Figure 4. Correlation of S1 and S2 hydrocarbons with the TOC (%) of the shales from (a) Tadkeshwar lignite mine, Surat, and (b) Rajpardi lignite Mine, Bharuch, respectively, Cambay basin.

The shales from Rajpardi area show high HI values and low OI values, where as those from Tadkeshwar show moderate HI and a low OI values. An inverse correlation is observed between the hydrogen and oxygen indices with each other and that with the TOC content (Figure 5). The hydrogen and oxygen indices are characteristics type of kerogen and generally bear inverse correlation with each other. The HI value < 50 mg HC/ g TOC, suggests no oil and gas generation from the kerogen, whereas HI >600 mg HC/ g TOC suggests oil prone kerogen (Peters and Cassa, 1994). These indices indicate the source organic input and the environment of deposition, which is essentially reducing, characterized by low oxygenation conditions resulting in preservation of organic matter in shales. The high HI and low OI values represent a favourable depositional condition of Cambay shales in a reducing, hydrogen rich and low oxygenation environment.

Based on Carbon (C), hydrogen (H) and oxygen (O) contents, kerogens have been divided as Type I, II, III, and IV (Van Krevelen, 1961; Hunt, 1996; Tissot and Welte, 1978). Type I and II generate oil. Type I is generated in marine environments and is derived from algal lipids that are enriched in lipids by microbial activity. It contains several aliphatic chains and the H/C ratio is originally high (H/C >1.5) (Tissot and Welte, 1978; Peters et al., 2005). Type-II kerogen also contains aliphatic chains, but have more aromatic and naphthenic rings. The oil and gas potential in Type-II kerogen are lower (H/C= 1.2 to 1.5) than observed for type-I kerogen. Type-III kerogen with low H/C range (H/C= 0.7 to 1.0) generates primarily gas, condensates and some waxes. The organic matter is mostly derived from terrestrial higher plants. Type-IV kerogen generates only small amount of methane and CO_2.

The HI value < 50 mg HC/ g TOC suggests Type-IV kerogen (No oil and gas), those ranging between 50-200 mg HC/ g TOC suggests Type-III kerogen (Gas), 200-300 mg HC/ g TOC suggests Type- II/III kerogen (Mixed oil and gas), 300-600 mg HC/ g TOC suggests Type- II kerogen (Oil) and >600 mg HC/ g TOC suggests Type-I kerogen (Oil) (Peters and Cassa, 1994). The HI vs OI plot of the shales associated with the lignite mines from Tadkeshwar shows that the organic matter is characterized by Type III kerogen (Figure 6). The HI vs T_{max} values also indicate the presence of Type III kerogen, (Figure 7). These shales show an immature phase for the generation of hydrocarbons. With a high TOC characterized by Type III kerogen, these shales can be a potential source for the generation of gas at greater depths and burial. Couple of shales from Tadkeshwar, (TG-05, 07, 08, 09, 10) show high oxygen index (>100 mgHC/gTOC). These samples are also characterized by low TOC values and are possibly contaminated by weathering and oxidation. The shale from the Rajpardi area show very high HI values (>600 mg HC/ gTOC). The HI vs. T_{max} suggests that the organic matter is

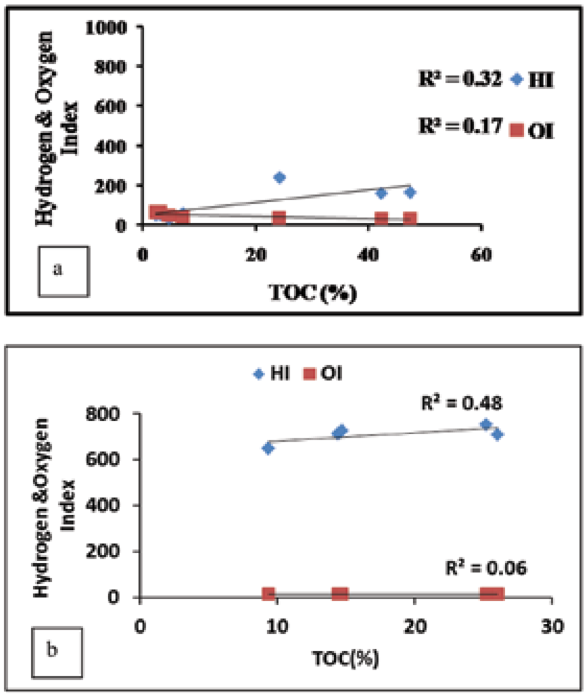


Figure 5. Correlation of HI and OI with the TOC (%) of the shales from the (a)Tadkeshwar lignite mine,Surat, and (b) Rajpardi lignite mine, Bharuch, respectively, Cambay basin.

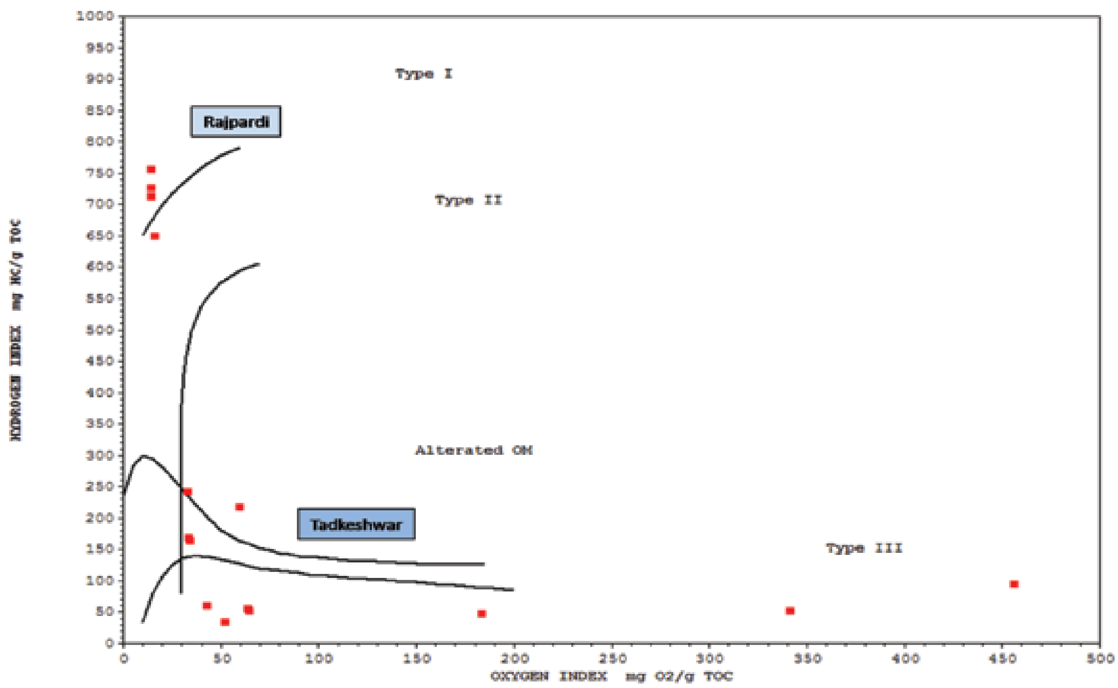


Figure 6. The HI vs OI plot for the shales from the Tadkeshwar and Rajpardi lignite mines, Cambay basin.

characterized by Type II kerogen, which has the potentially of oil and gas. The samples show an immature to mature stage for the hydrocarbon generation.

The Tadkeshwar lignites of Cambay basin belong to Early Eocene age. The data generated on nature, composition, origin, maturation and mineral matter contents of the organic deposits, through petrological investigations, show that these lignites are rich in huminite macerals, followed by liptinite and inertinite with moderate to high proportions of associated mineral matter (Singh

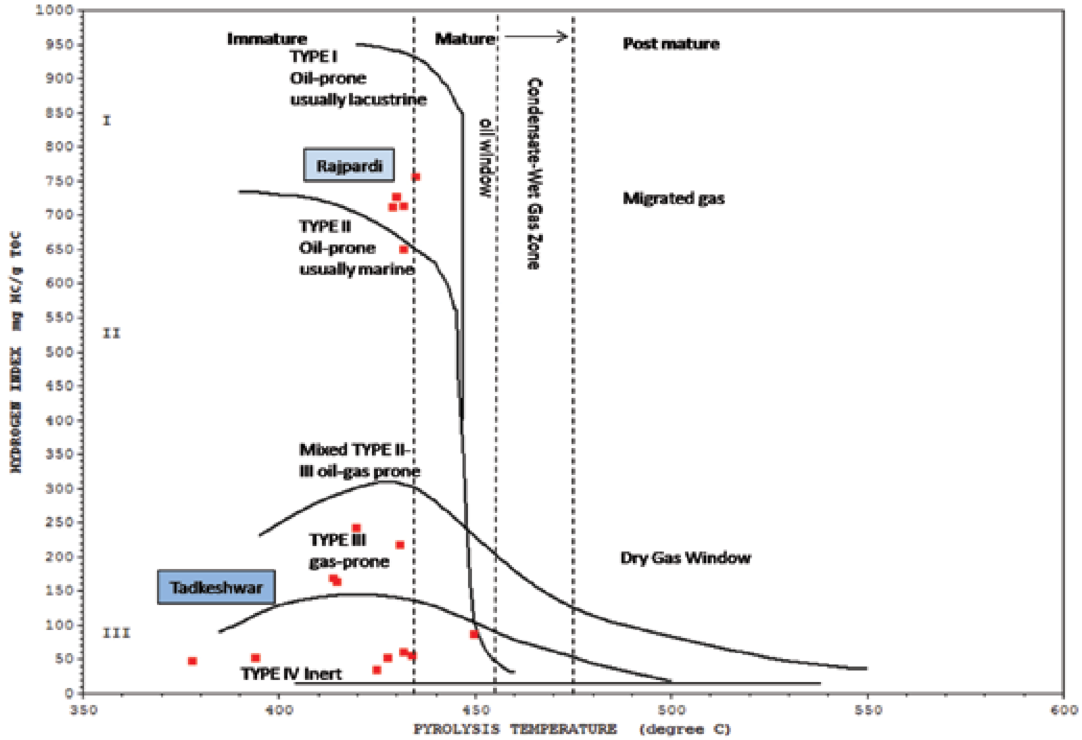


Figure 7. HI versus T_{max} Fig plot for the shales from Tadkeshwar lignite mine, Surat, and Rajpardi lignite mine, Bharuch, Cambay basin**.**

et al., 2012a; 2012b). Petrographical studies on Rajpardi lignites suggest that these are enriched in huminite and are low in liptinite and inertinite (Singh, 2012). Their elevated hydrogen content, in relation to carbon, has probably made them per-hydrous in nature and oil prone (Singh, 2012). This is also corroborated by the Rock Eval pyrolysis of the interbedded shale horizons, where the organic matter is characterized by the presence of type II/III kerogen, suggesting the oil/gas prone nature of these shales.

In the Cambay basin, each of the five blocks has multiple source rocks of different lithologic compositions at various maturity levels (Chowdhary, 2004). A direct correlation has been observed between the organic matter richness, its quality and the thickness of the source sequences. Central and axial parts of the depositional centers have best quality and greatest quantity of source rock (Yalcin et al., 1987, Chowdhary, 2004) The Cambay shale and its stratigraphic equivalents are the predominant source rock for the entire Cambay basin.

CONCLUSION

The pyrolysis results of the interbedded shales from Tadkeshwar Formation, exposed in the open cast mines of Rajpardi and Tadkeshwar in Surat and Bharuch districts of Gujarat, are encouraging. The TOC content is quite high and an immature to mature stage is inferred from the HI vs T_{max} data of the shales. The organic matter is characterized by Type II and III kerogen, which is suitable for the generation of gas. The lateral and vertical extents of these shale horizons and the petrological and petrophysical details in integration with the organic geochemical attributes of the shales on subsurface core samples, shall help further in precise delineation of horizons for the shale gas plays.

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Compliance with Ethical Standards

The author declares that he has no conflict of interest and adheres to copyright norms.

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