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Pyrolysis Results of Shales from the South Cambay Basin, India: Implications for Gas Generation Potential

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Abstract: Shale, an abundant organic-rich sedimentary rock of extremely low porosity, is of lately being realized as a significant energy source, owing to the possibility of huge amount of natural gas which may be stored in it. Instigated by the enormous production of natural gas from the shale formations of Barnett, Marcellus and several other plays in USA, the Indian sedimentary basins are being looked assertively for their shale gas prospects. The petroliferous Cambay basin in western India with interbedded carbonaceous shales in its thick Tertiary sequence forms a potential prospect for the shale gas. Fine grained, clastic and organic-rich Cambay, Tarapur and other Tertiary shales have sourced the oil and gas for the basin.

The quality, quantity and type of organic matter play an important role in the generation of gas in shale horizons. Rock-Eval pyrolysis is one of the most basic organic geochemical methods to study these parameters. In the present study, the interbedded shale formations within the middle Eocene lignite sequences, referred to as Cambay Formation, (Nagori et al., 2013), of the Tadkeshwar and Rajpardi mines in Surat and Bharuch districts, respectively, have been sampled to study the organic matter properties using Rock-Eval pyrolysis. The sedimentary sequences exposed in the mines show the shales to be high in Total Organic Carbon (TOC) content, ranging between 0.2% to 47.3%. The S1 (free hydrocarbons) and S2 (hydrocarbons from cracking of kerogen) values range between 0.04 to 7.12 and 0.08 to 190.11 mg HC/g rock, respectively. The T_{max} (temperature at highest yield of S2) 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 is characterized by Type II / III kerogen, suitable for the generation of gas.

Keywords: Shale, Shale gas, Total Organic Carbon, Rock-Eval pyrolysis, Cambay, Gujarat.

INTRODUCTION

Shale gas is emerging rapidly as a promising unconventional energy source globally. Shale, which is a fine grained clastic sedimentary rock, can be a potential source-cum-reservoir rock for natural gas, depending on richness and thermal maturity of its organic matter (Curtis, 2002; Boyer et al., 2006; Horsfield and Schulz, 2012). The hydrocarbon gases generated in the organic rich shales remain trapped in the micro-pores and micro-fractures or in the thin layers by the virtue of the low matrix permeability of these rocks (Ross and Bustin, 2008; Milliken et al., 2013). Sufficient heat, pressure and geological time lead to the conversion of organic matters into kerogen, which, in turn under specific conditions of deep burial temperature, cracks to produce hydrocarbons. In general, for any shale gas system, the environmental conditions support biologic activities producing large quantities of organic matter, the depositional conditions concentrate the organic matter and post-depositional conditions permit its 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 (natural or induced) 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 India, the shale gas exploration is in its early stage. Potential sedimentary basins are being identified and the relevant geochemical, geological and geophysical data is being generated where required and/or assimilated from conventional exploratory studies for prioritizing the zones towards location of sweet spots where it would be most beneficial to drill. One amongst such potential areas is the Cambay basin in the western India, which is a petroleum rich province due to the presence of a favourable combination of organic-rich source sediments, reservoir rocks, regional seals and traps. The Cambay shale is the main source rock in the basin with some contribution of oil from Kalol and Tarapur Formations and their equivalents in the Broach-Jambusar block (Chowdhary, 2004). Having been explored largely for the conventional oil and gas prospect, these organic-rich shales are now being revisited for their gas generation potential. About 20 tcf (trillion cubic feet) technically recoverable shale gas has been estimated from the Cambay basin (DGH, 2013; USGS, 2012). However, these estimates reflect considerable geologic uncertainty in assessment and rigorous geochemical, petrological and petrophysical data are needed in defining the gas producing zones and their response to the fracturing techniques.

Geochemical parameters, such as organic richness, kerogen types and thermal maturity are prime requisites in shale gas exploration as these attributes control the gas generation in shales (Jarvie et al., 2007). Rock Eval Pyrolysis has become 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 pyrolysis technique. The shale samples have been collected from the open cast mines, namely Tadkeshwar and Rajpardi in Surat, Bharuch districts, respectively (Fig.1). The fossil biotas recovered from the sedimentary sequences exposed in these mines suggest an analogy of Cambay shales for these shale horizons (Singh et al., 2012 a; 2012b; Sahni et al., 2006; Nagori et al., 2013). Cambay shale is an established prolific hydrocarbon source rock in the basin. The objective of the present study is to characterize 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 and are interpreted in the light

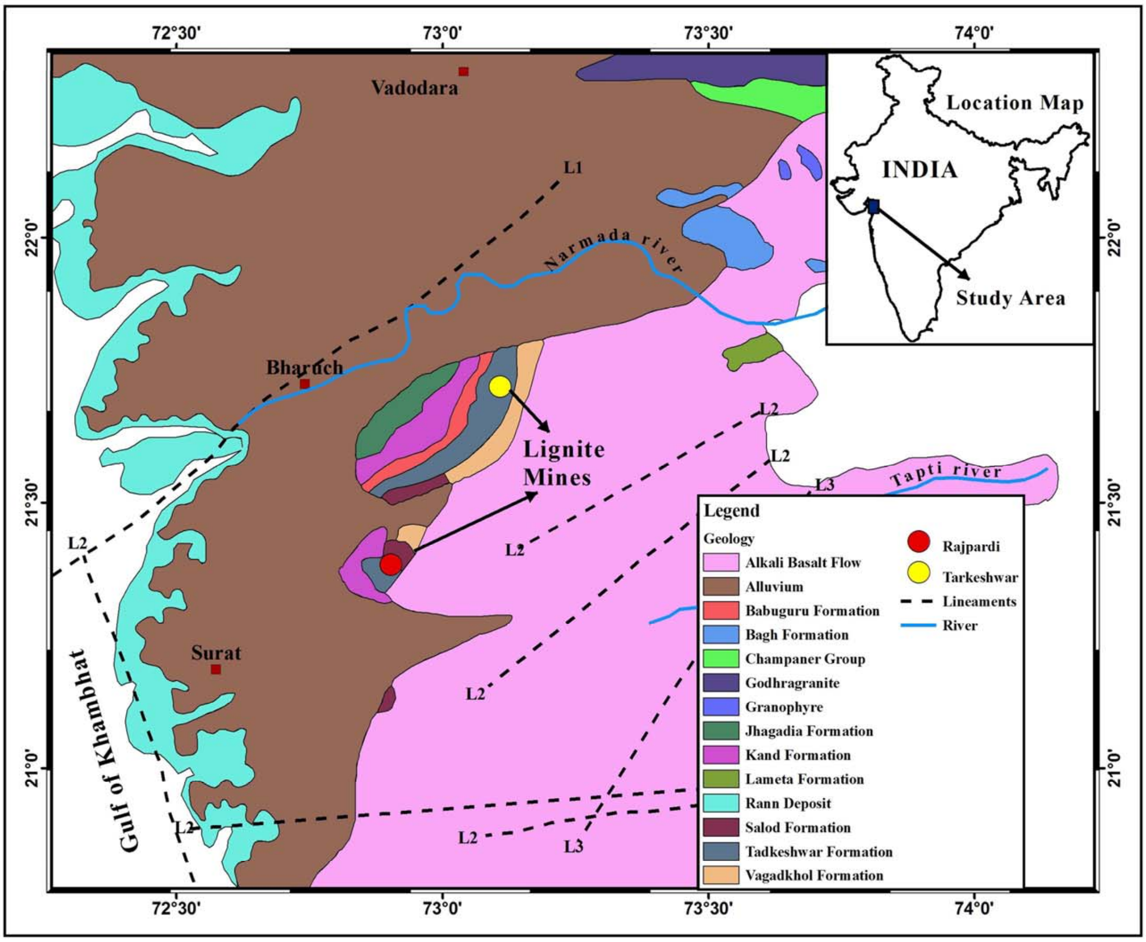

Fig.1. Geological map of South Cambay basin showing the location of sampled lignite mines (after Singh et al., 2012a)

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

The basin came into existence during late Mesozoic era with the development of major tensional faults following widespread extrusion of Deccan trap basalt (Biswas, 1982, 1987). The volcanics of the Deccan traps form the basement of the Tertiary and Quaternary sediments in the basin. The sediments have a thickness of over 5,000 m in the deepest part of the basin (Jambusar-Broach area). The sequence comprises of greywackes, dark grey to black grey shales, coal cyclothems, silts, fine to medium grained sands and grey reddish-brown clays (Biswas, 1987). The whole basin is longitudinally dissected into five major tectonic blocks by transverse basement faults within the Deccan traps, which continue to some extent into the overlying sediments. These are Sanchor-Patan, Mehsana-Ahmedabad, Tarapur-Cambay, Broach-Jambusar and Narmada-Tapti blocks from north to south (Biswas, 1982, 1987). These blocks are characterized by different fold and fault trends and basement depth. 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., 2013). The available data on the major tectonic lineaments, expressed as faults, flexures and dykes on the surface, are represented as fault zones in the Cambay basin (on land and offshore), and as structural features in the associated Tertiary sediments of the Cambay basin, shows two major tectonic lineaments with NNW-SSE trend, probably related to the Dharwar orogenic belt and ENE-WSW trend, probably related to the Satpura orogenic belt, extending into the Cambay basin. These two major trends are manifested both on the surface and in the sub-surface (Raju et al., 2013), due to which the pattern of sedimentation is controlled by the block pattern to a certain extent.

Stratigraphically the basin is divided into eleven Formations with Deccan Trap as the basement (Table 1). The depositional floor is characterized by narrow linear horst

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

Age		Formation and Thickness	Lithology
Quaternary	Holocene	*Narmada Fm.*	Sandstone, silt,clay and gravels
- - - - - - - - - - -	- - - - - - - - - - -	- - - - - Unconformity - - - - - -	- -
Tertiary	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
		- - - - - - - - - - - - - - - - - - - -	- - - - - - - - Unconformity - - - - - - - - -
		Babaguru Fm. (200-300m)	Conglomerate, sandstone, clays cherry red and highly ferruginous
	- - - - - - - - - - -	- - - - - Unconformity - - - - - -	- -
	Oligocene	*Tadkeshwar Fm. (125 -346m)*	
	- - - - - - - - - - -	- - - - - Unconformity - - - - - -	- -
	Eocene	*Ankleshwar Fm. (603m)*	
		- - - - - - - - - - - - - - - - - - - -	- - - - - - - - Unconformity - - - - - - - - -
		Cambay shale (+1500m)	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.

and graben (Bhandari and Chowdhary, 1975). The older Olpad Formation overlies the Deccan trap with an erosional unconformity. The sedimentation 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, 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 300 m within the Cambay shale (Bhandari and Chowdhary, 1975). The sedimentation took place in a deltaic environment. The Cambay shale is conformably overlain by Kalol Formation of middle Eocene, which got deposited in alternating regressive and transgressive marine settings. The marine Tarapur Shale Formation conformably overlies the Kalol Formation. The Tarapur Shale Formation is unconformably overlain by Babaguru Formation of upper Miocene age. It got deposited in fluviatile to shallow water environment under mildly oxidizing conditions (Chowdhary, 2004). The Kand Formation of Middle Miocene lies conformably over Babaguru Formation. The depositional environment is shallow marine.

The Kand Formation is conformably overlain by Jhagadia Formation of upper Miocene (Chowdhary, 2004). It is unconformably overlain by Broach Formation of Pliocene age deposited under shallow marine oxidizing environment. The Jambusar Formation conformably overlies the Jhagadia Formation and was deposited under regressive shallow marine to fluviatile conditions (Bhandari and Chowdhary, 1975). The Gujarat alluvium of Holocene age forms a cover of the Tertiary and Quaternary sediments and is having a gradational relationship with the underlying Jambusar Formation (Chowdhary, 2004).

Petroleum Geology

Four source rock units have been defined in the petroliferous Cambay basin. These are the Tarapur shale and its coeval units of upper Eocene-Oligocene age; Kalol Formation and its coeval units of middle Eocene age; Cambay shale of lower Eocene age; and Olpad Formation (volcanic conglomerate, shale and claystone) of Paleocene (Yalcin et al., 1988; Chowdhary, 2004). The reservoir rock constitutes the sand size basalt fragments within the Olpad Formation (DGH, 2013). Localized sandstone reservoirs within the Cambay shale as in the Unawa, Linch, Mandhali, Mehsana, Sobhasan fields are also present. The lithological heterogeneity and associated unconformity in Olpad Formation facilitated entrapment of hydrocarbons. 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, 2013).

Study Area

The study area forms part of the Tadkeshwar and Rajpardi lignite mines of Surat and Bharuch districts, respectively, in the southern part of Cambay basin. Sub-surface 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, 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., 2012; 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 low energy near shore coastal setting (Rust et al., 2010). Well preserved, consolidated shales were collected after removing the weathered part in the exposed horizons.

MATERIALS AND METHOD

Programmed pyrolysis was carried out on seventeen shales collected from open cast lignite mines of Tadkeshwar and Rajpardi, Gujarat, using the Rock Eval 6 pyrolyzer (RE6, Turbo version). After obtaining a stable signal of all the detectors, 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 (<63 m) 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). The shale samples were run under analysis mode using the bulk rock method and basic cycle of Rock Eval 6.

Rock Eval 6 Pyrolysis

Rock Eval pyrolysis is used to estimate the petroleum potential of rock samples by open laboratory cracking of organic matter according to a programmed temperature pattern in the Rock Eval 6 pyrolyzer. Released hydro-carbons are monitored by a FID (Flame Ionization Detector), forming the so-called peaks S1 (thermo-vaporized free hydro-carbons) and S2 (hydrocarbons from cracking of organic matter). The CO and CO_2 released during pyrolysis can be monitored in real time by an infra red cell. This complementary stage allows determination of total organic carbon and mineral carbon content of the samples.

The basic cycle of analysis consists of two steps. Firstly, the pyrolysis is carried in pyrolysis oven. The oven is programmed 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 the 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 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 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 temperature at 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 by 100 × S2/TOC. The oxygen index, (OI) is defined as 100 × S3/TOC. These indices help in tracking kerogen types and maturation (User's guide, Rock Eval 6; McCarthy et al., 2011).

RESULTS

The results of important parameters obtained by the pyrolysis of shales from Cambay basin using Rock Eval are given in Table 2. Representative pyrolysis and oxidation curves for one of the samples, TG-07, is shown in Fig.2. In general, the shales from Rajpardi area show a high TOC content along with other Rock Eval parameters compared to that of Tadkeshwar (Table 2). The TOC content from Rajapardi shales ranges between 9.35- 26.03%. The S1values range between 3.29–7.12 mgHC/grock and are characteristic of all the sample (Table 2). The S2 values show an elevated range between 60.6 - 190.11 mgHC/grock. The T_{max} ranges between 429-435°C. The HI is high ranging in values between 648-754 mgHC/gTOC, whereas OI for all studied samples is near to 15. The mineral carbon content is <0.5 %. For the Tadkeshwar shales, the TOC varies between 0.19 to 47.39 %. The S1 values are between 0.05 to 3.58 mgHC/grock and the S2 values range between 0.14 to 78.84 mgHC/grock. The T_{max} varies between 342 to

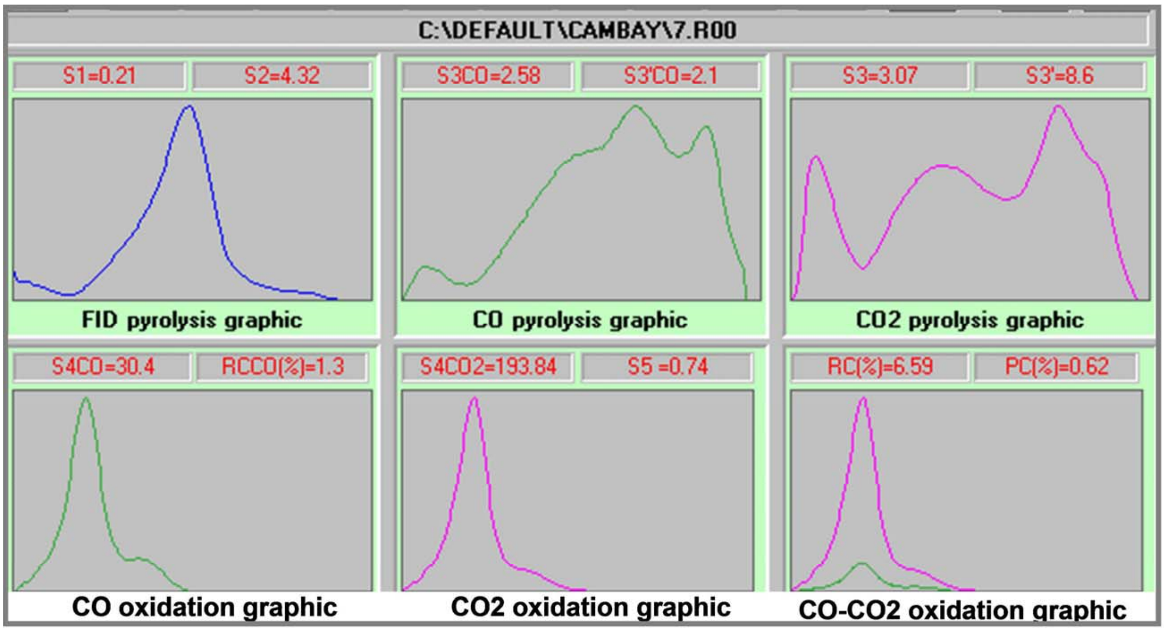

Fig.2. RE pyrolysis and oxidation curves for the shale sample (TG-07) from the Tadkeshwar lignite mines, Cambay basin

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

Sample	S1 (mg HC/ g Rock	S2 (mg HC/ g Rock	Tmax °C	S3 $mgCO_2$/ g Rock	TOC (%)	HI mg HC/ g TOC	OI $mgCO_2$/ g TOC	MINC (%)
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
Rajpadri								
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	0.23

450°C, whereas the HI values vary between 33 to 241 mgHC/ gTOC.

DISCUSSION

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 (wt %) < 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 shales 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 (n = 9) from the area have relatively lower TOC (0.18 - 3.19%). A P-test performed on the two groups of coaly shale and carbonaceous shale indicates a p-value of 0.004 and 0.021, respectively. Both the p-values obtained are significant and below the level of specified significance of 0.1%, indicating the relationship between the S1 and S2 values. This is also supported by the correlation coefficients (r^2) of the carbonaceous shales ($r^2_=$ 0.8). The correlation analysis in coaly shales is constrained by less number of observations (n=3). Similarly, P-test (p-value= 0.004) and correlation analysis (0.9) performed on S1 and S2 values of Rajpardi shales indicate similar source organic input for the generation of the hydrocarbons (Fig.3). These values also vary linearly with the TOC content of the organic matter (Fig.4). With an increase of organic matter, the produced

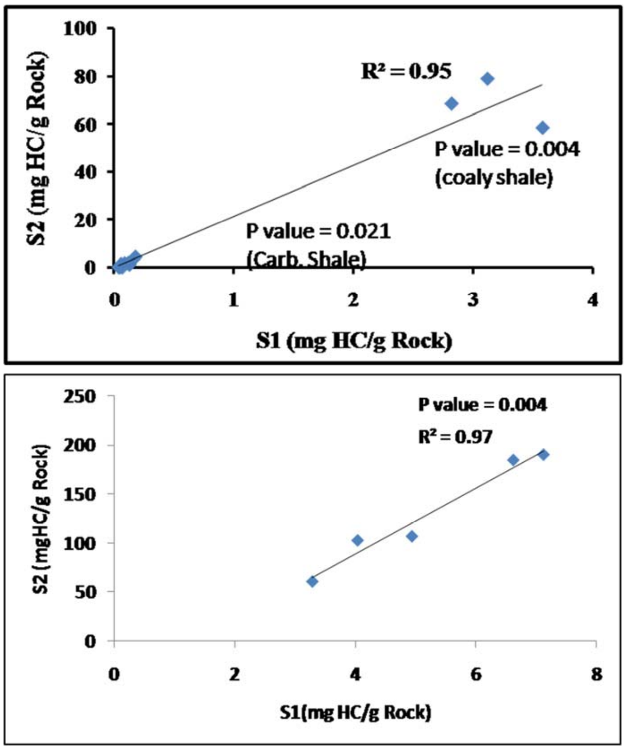

Fig.3. Correlation of S1 and S2 hydrocarbons released from pyrolysis of the shales from the (**A**) Tadkeshwar lignite mine, Surat, and (**B**) Rajpardi lignite mine, Bharuch, respectively, Cambay basin.

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). 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 (Fig.5). The hydrogen and oxygen indices are characteristics of kerogen type and generally bear inverse correlation with each other. These indices indicate the oil

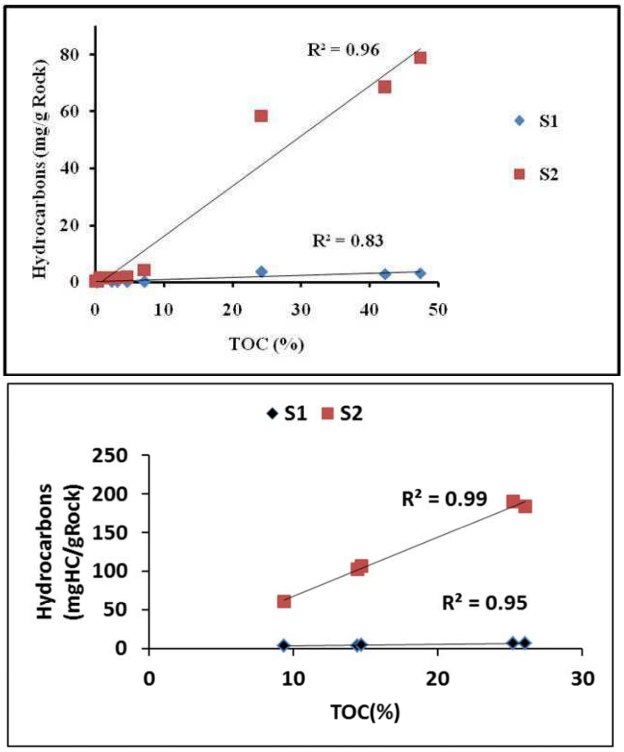

Fig.4. Correlation of S1 and S2 hydrocarbons with the TOC (%) of the shales from (A) Tadkeshwar lignite mine, Surat, and (B) Rajpardi lignite Mine, Bharuch, respectively, Cambay basin

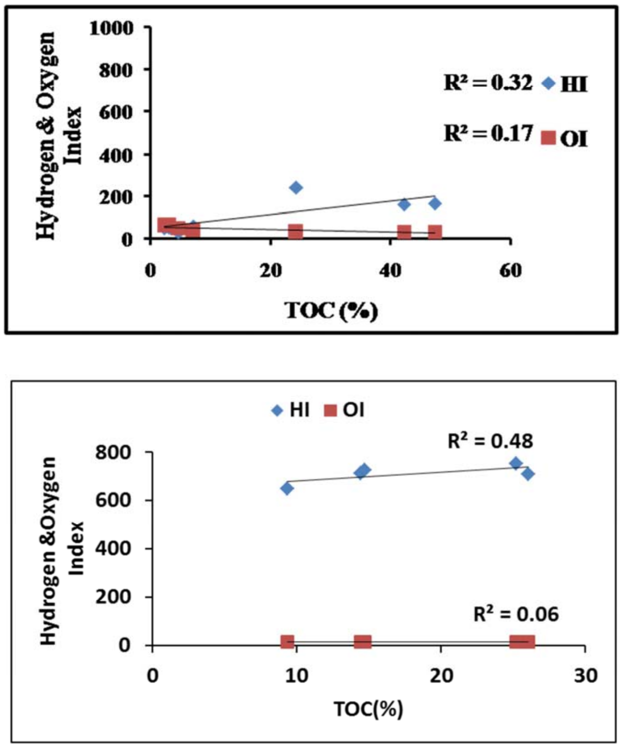

Fig.5. Correlation of HI and OI with the TOC (%) of the shales from the (A) Tadkeshwar lignite mine, Surat, and (B) Rajpardi lignite mine, Bharuch, respectively, Cambay basin.

and gas generation ability of the kerogen. The HI value < 50 mg HC/ g TOC, suggests no oil and gas generation from the kerogen where as 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 (suboxic/anoxic) resulting in preservation of organic matter in shales. The high HI and low OI values indicate a favourable depositional condition of Cambay shales in a reducing, hydrogen rich and low oxygenic environment.

The kerogens have been classified as Type I, II, III and IV based on their Carbon (C), hydrogen (H) and oxygen (O) contents (Van Krevelen, 1961; Hunt, 1996; Tissot and Welte, 1978). Type I and II generate most of the world's oil. Type I is generated predominantly in marine environments and is derived from algal lipids or from organism 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 HC range and the oil and gas potential in Type-II kerogen are lower (H/C= 1.2 to 1.5) than observed in 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 and contains mostly condensed poly-aromatics and oxygenated functional groups, with minor aliphatic chains. The organic matter is mostly derived from terrestrial higher plants. Type IV kerogen generates only small amount of methane and CO_2. A modified van Krevelen diagram (van Krevelen, 1961; Tissot and Welte, 1984) is used to evaluate the quality and maturation state of kerogen based on HI/OI in combination with T_{max} values.

The HI value < 50 mg HC/ g TOC suggests Type-IV kerogen (No oil and gas), 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, (Fig.7). These shales show an immature phase for the generation of hydrocarbons. With a high TOC

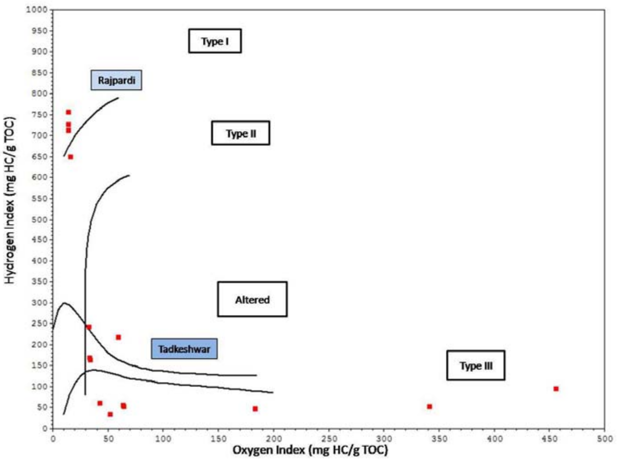

Fig.6. The HI vs OI plot for the shales from the Tadkeshwar lignite mine, Cambay basin.

characterized by Type III kerogen, these shales can be a potential source for the generation of gas at greater depths of 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 processes of 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 characterized by Type II kerogen, which has the potential for 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 et al., 2012a; 2012 b). Petrographical studies on Rajpardi lignites suggest that these are enriched in huminite and are low in liptinite and inertinite (Singh et al., 2012) Their elevated hydrogen content, in relation to carbon, has probably made them perhydrous 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

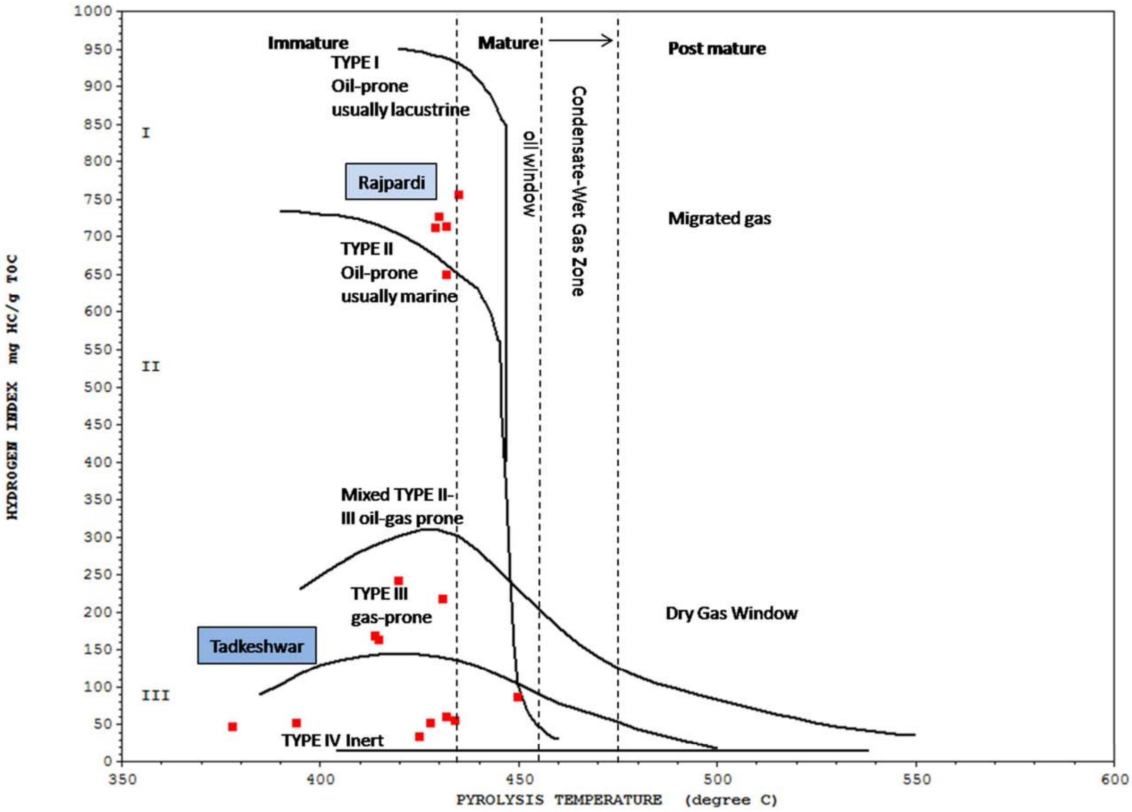

Fig.7. HI versus T_{max} Fig plot for the shales from (A) Tadkeshwar lignite mine, Surat, and (B) Rajpardi lignite mine, Bharuch, respectively, Cambay basin.

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., 1988, Chowdhary, 2004) The Cambay shale and its stratigraphic equivalents are the predominant source rock for the entire Cambay basin. Distribution of organic matter in interbedded shale sequences of Tadkeshwar and Rajpardi in South Cambay corroborate these observations.

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 these 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 along with petrological and petro-physical details in integration with the organic geochemical attributes of the shales on sub-surface core samples shall help further in precise delineation of gas prone horizons.

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