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Research paper

Evaluation of Eocene source rock for potential shale oil and gas generation in north Cambay Basin, India

Sumit Kumar [a], Keka Ojha [a,*], Rabi Bastia [b], Kapil Garg [b], Sumani Das [b], Debadutta Mohanty [c]

[a] Department of Petroleum Engineering, IIT(ISM), Dhanbad, India
[b] OilMax Energy Pvt Ltd, Mumbai, India
[c] CSIR-Central Institute of Mining and Fuel Research, Dhanbad, India

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ABSTRACT

Source rock potential of 108 representative samples from 3 m intervals over a 324 m thick shale section of middle Eocene age from the north Cambay Basin, India have been studied. Variation in total organic carbon (TOC) and its relationship with loss on ignition (LOI) have been used for initial screening. Screened samples were subjected to Rock-Eval pyrolysis and organic petrography. A TOC log indicated wide variation with streaks of elevated TOC. A 30 m thick organic-rich interval starting at 1954 m depth, displayed properties consistent with a possible shale oil or gas reservoir. TOC (wt%) values of the selected samples were found to vary from 0.68% to 3.62%, with an average value of 2.2. The modified van Krevelen diagram as well as HI vs. T_{max} plot indicate prevalence of Type II to Type III kerogen. T_{max} measurements ranged from 425 °C to 439 °C, indicating immature to early mature stage, which was confirmed by the mean vitrinite reflectance values (%R_o of 0.63, 0.65 and 0.67 at 1988 m, 1954 m, and 1963 m, respectively). Quantification of hydrocarbon generation, migration and retention characteristics of the 30 m source rock interval suggests 85% expulsion of hydrocarbon. Oil in place (OIP) resource of the 30 m source rock was estimated to be 3.23 MMbbls per 640 acres. The Oil saturation index (OSI) crossover log showed, from a geochemical perspective, moderate risk for producing the estimated reserve along with well location for tapping the identified resource.

1. Introduction

Shale gas or oil reservoirs, a self-contained source-reservoir system with continuous petroleum accumulations, can produce a large amount of oil and gas from the productive area (Jarvie et al., 2007; Schmoker, 1999, 2002; Kobek et al., 2015). These reservoirs, unlike conventional reservoirs, exhibit low porosity (<10%) and ultralow permeability with a wide range of compositional variations (Bolås et al., 2004). However, advancement in technology with supportive experience make the exploitation of hydrocarbons from such reservoirs feasible. Commercial production of shale gas and oil has witnessed the fastest growth in USA, Canada, China and Argentina (Aloulou, 2015). Exploration of shale gas and oil is gaining importance in India with the potential to provide Indian energy industry with abundant, cheap and clean fuel (Chakravarty and Mohan, 2012).

The Cambay Basin is considered one of most petroliferous basins in northwestern region of India (Singh, 2016). Lately, the basin has been given more impetus as a result of the shale oil/gas revolution. The Cambay Shale has gained importance for unconventional resource potential (Sharma et al., 2010; Shanmukhappa, 2011; Dayal et al., 2013; Mani et al., 2015; Padhy et al., 2016) with the lignites being an excellent source rock for hydrocarbon generation (Singh et al., 2010, 2012, 2016a, 2016b). Statistically, the basin contains a significant volume of unproven Indian shale oil and gas, in comparison with the other three Indian basins i.e. Krishna-Godavari, Cauvery and Damodar Valley that are considered to be prospective for shale oil/gas reserves. It is reported that approximately 30% of the risked recoverable shale gas and 70% of the risked recoverable shale oil reserves are present in this basin (EIA, 2015). The Cambay Basin, having a robust infrastructure facility compared to other basins in India, is at the top priority for government and

* Corresponding author. Department of Petroleum Engineering, IIT(ISM) Dhanbad, Dhanbad, Jharkhand, 826004, India.
E-mail address: keka_ojha@yahoo.com (K. Ojha).

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industry to explore for shale oil and gas.

Successful hydrofracturing case study presented by Sharma et al. (2010) of two wells (D-A and D-B), in Dholka field have shown modest shale gas production capability in the Tarapur block from shallow (~1310 m) Miocene sediments in the Cambay Basin. The presence of shale gas at shallow depth cannot be supported by the presence of the low thermal alteration index value of 2.25, i.e. low to marginal mature organic matter in the vicinity of pilot area (Shanmukhappa, 2011). Presence of oil in the Paleocene-early Eocene shale formation at around 3200 m depth in the nearby Broach-Jhambusar Block raises further questions about the presence of gas in the Miocene age shale of the Tarapur Block (Padhy et al., 2016). However, in absence of geochemical data, no further comment can be made on possible reasons for gas generation, even for biogenic gas, at shallow depth in Tarapur Block. Such inconsistency points towards multiplicity in the depressions and source rocks of the different blocks of Cambay. Lately, based on the review of a pilot exploratory well in south Cambay at Jambusar and Ankleshwar, Gujarat, another eleven wells have been planned for shale oil and gas exploration in Cambay Basin by Oil and Natural Gas Corporation Ltd. Though the north Cambay Basin is well known for producing conventional oil/gas, investigation to evaluate its source rock (Cambay Shale) as a potential resource for shale oil and gas production is at an incipient stage and needs further study to establish the feasibility of shale oil/gas production from the basin.

The aim of the present study is to evaluate the shale oil/gas potential in terms of charging aspect of source rock in Ahmedabad-Mehsana Block, Cambay Basin based on the data collected from a well drilled in a thick section of Cambay Shale. The loss on ignition (LOI) method was adopted for the preliminary screening of a large number of shale samples. Geochemical analyses and organic petrography studies were carried out subsequently to decode the organically rich identified zones in terms of an accurate total organic carbon (TOC), kerogen type, thermal maturity, Production index (PI), and generation potential (GP). Suitable prospective zones were then evaluated in terms of the amount of hydrocarbon generation, expulsion and retention followed by a unit oil in place estimation. The approach is expected to be an effective technique in the primary screening of the organically rich potential zones without performing a large number of time consuming and costly experiments.

2. Geology of study area

Shale samples studied in the present investigation were collected from the Cambay Basin. Fig. 1 shows the location of Cambay Basin along with depocenter and detailed fault system. The Cambay Basin has been one of the most petroliferous onshore basins in India located in the northwestern region of the country covering an area of about 53,500 km^2. It lies roughly between latitudes 21°00′ and 25°00′ N and longitudes 71°15′E and 73°30′E in the states of Gujarat and Rajasthan.

The basin, narrow and elongated with a NNW-SSE trend, is a half-graben intracratonic rift, with sediments ranging in age from Late Cretaceous to Tertiary (Bhandari and Chowdhary, 1975). Starting from the Gulf of Cambay in the southern Gujarat, the basin tectonically continues up to the Jaisalmer-Meri Ridge in central Rajasthan. It is situated between the Saurashtra Craton in the west, Aravalli to the north-east, and Deccan craton in the southeast. A unique fault system, aligned transverse to the general north-south axis, divides the basin into five major blocks. From north to south, these are Sanchor-Patan, Mehsana-Ahmedabad, Tarapur-Cambay, Broach-Jambusar and Narmada-Tapti blocks (Pandey et al., 1993). A detailed description of the tectonic framework of Cambay Basin has been presented by Mathur et al. (1968); Bhandari and Chowdhary (1975); Biswas (1982); Kundu and Wani (1992).

Fig. 2 depicts a schematic north-south and east-west geological cross-sections of the basin with major formations, fault systems, the main depression and major field locations. In the north-south geological cross-section, Warosan, West Kalol and Broach are the major depressions (Fig. 2). In the east-west geological cross-section, Virsoda, West Kalol/West Mehsana and East Kalol/East Mehsana are the main depression trends (Banerjee et al., 2002). Well#1, shown in Figs. 1 and 2, lies at the east edge of Kalol depression in the Ahmadabad-Mehsana block. These depocenters in the Cambay Basin are expected to have huge potential for gas or oil exploration (Mohan et al., 2006).

The basin evolved through three stages: Syn-rift stage (period of extension) during the Paleocene-early Eocene; Post-rift stage I (period of thermal subsidence) during the middle Eocene-early Miocene and finally, Post-rift stage II in the middle Miocene period (Singh, 2012). Generalized stratigraphy of Cambay Basin is presented in Fig. 3. Deccan Basalts, during the Late Cretaceous period, was extensive covering a large area of western and central India (Biswas, 1982). Subsequently, the Olpad Formation was deposited over basalt basement during the early Paleocene under fluvial to shallow marine condition. The Olpad Formation is comprised of mainly claystone, sandstones, siltstones, conglomerates and shale at some locations. In the late Paleocene, grey to black Cambay shales were deposited during a major marine transgression (Singh et al., 2010, 2012). The Cambay Shale, which is divided into younger and older by an unconformity, was deposited during a major marine transgression, with sand having been deposited during short regressive cycles. In the north Cambay Basin, a deltaic sandstone-shale-coal sequence named the Kadi Formation was deposited on top of the Younger Cambay Shale (YCS). In the regressive phase during the Eocene, another deltaic sequence of the Kalol Formation was deposited over the Kadi Formation, characterized by the presence of sandstones, shale and coals. Again, a major transgressive phase in the middle Eocene to early Oligocene period resulted in deposition of the Tarapur Shale, which acts as a regional seal. A major period of non-deposition/erosion took place during the later stage of the Oligocene which was followed by continuous deposition of Neogene sediments in the north Cambay Basin (Yalcin et al., 1988).

3. Materials and methods

3.1. Collection and preparation of samples

For evaluating the hydrocarbon prospects of the Cambay Shale, drill cuttings from a 322 m thick shale section were collected from a borehole drilled in the Ahmedabad-Mehsana Block of Cambay Basin. Well location has been marked in Figs. 1 and 2. Cuttings, collected from the well drilled with KCl-PHPA-Glycol water based mud (WBM) system, were wet sieved, thoroughly washed and macroscopically analyzed before being preserved in an air tight plastic bag at the drill site. In the laboratory, handpicking of extraneous materials from samples was followed by washing again with hot distilled water and air drying. Lastly, pulverization with an agate mortar and pestle was done to obtain the required particle size for the different tests. Particles with less than 1 mm diameter were used for petrographic analysis whereas particles passing through 200 BSS mesh were used for geochemical analyses.

3.2. Methodology

A multi-stage screening approach has been followed in the study to identify effective source rocks for the presence of shale oil and gas. Initially, an estimation of total organic carbon for the thick