Deep thermal regime, temperature induced over-pressured zone and implications for hydrocarbon potential in the Ankleshwar oil field, Cambay basin, India

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ABSTRACT

Ankleshwar oil field situated in the southern part of the Cambay basin, forms one of the prominent onshore Tertiary hydrocarbons bearing regions of western India. A detailed multiparametric lithological analysis of the well logs obtained from 16 deep wells, indicate conspicuous trend of inversion in density and transit time below a depth of about 1250 m, which coincides with the presence of moderately high overpressure zone within the reservoir and appear temperature induced. Estimated temperature gradient based on the corrected Bottom Hole Temperatures, recorded at different depths in the boreholes, are found to be quite high (∼53 °C/km) at deeper levels, especially in the overpressured zone, that contains low conductive Cambay shales. Estimated heat flow of 75.2 mW/m² at Ankleshwar, together with high Moho temperatures of about 880 °C and an extremely shallow depth to subcrustal melting (∼50 km), would suggest that not only the northern part, the entire hydrocarbon bearing Cambay basin, along with the Mumbai offshore region, is anomalously warm. In view of the presence of high thermal anomaly, low conductive shales of the Cambay basin might be a good target for shale gas investigation, as the prevailing in situ temperature is one of the crucial factors in oil-to-gas cracking.

1. Introduction

Knowledge of the pore pressure and temperature is crucial in assessing the sedimentary basins for hydrocarbon prospects, as well as future recovery potential of the already exploited reservoirs. Correct information on pore pressure distribution in a reservoir helps to monitor the reservoir performance by reducing the risk associated with drilling, selection of casing points, optimization of recovery rates, etc. In a similar manner, temperatures control the reservoir fluid properties. In particular, it plays an important role in density reduction of brine/ hydrocarbons and transformation of hydrocarbons from oil to gas (Fisher et al., 2003; Swarbrick, 2012). The impact of temperature can also be quite significant on pore pressure, as its increase in a fluid saturated porous medium, can lead to the formation of overpressured zones.

Occurrence of such zones, both above and below hydrostatic pressure, have often been encountered in many sedimentary basins throughout the world. This includes various oil and gas bearing fields of the Cambay basin of India, like Kalol, Gandhar, Nawagam, Ankleshwar, Kosamba, Brouch, etc., where they are understood to have been developed by the combination of hydrocarbon generation during thermal evolution, tectonic compression and clay dehydration (Sahay and Fertl, 1989; Buryakovsky, et al., 2002; Chennakrishnan, 2008; Das et al., 2015). Apart from that, several physical processes such as disequilibrium compaction, fluid expansion, tectonic stress, mineral transformation, osmosis, etc. are known to contribute towards building of such anomalous pressures, nevertheless, the most commonly cited mechanisms for abnormal pressure generation in petroleum provinces are disequilibrium compaction and hydrocarbon generation including oil-to-gas cracking (Fertl, 1976; Mann and Mackenzie, 1990; Luo and Vasseur, 1996; Osborne and Swarbrick, 1997; Law and Spencer, 1998; Van Ruth et al., 2004; Tingay et al., 2009). In general, such zones are buried at depths, which are effectively isolated from their surrounding formations in which the pressure in an isolated volume will increase more rapidly than that in the surrounding fluids (Barker, 1972). The impact of increasing temperature on the contents of isolated volume and on pressure is best described by pressure–temperature-density diagram for water, as discussed in detail by Barker (1972). These temperature-induced pore pressures will dissipate, if the isolated fluid system is allowed to drain.

The purpose of the present work is to augment the understanding of effect of deep-seated temperature regime, if any, on pore pressure evolution, tectonic compression and clay dehydration (Sahay and Fertl, 1989; Buryakovsky, et al., 2002; Chennakrishnan, 2008; Das et al., 2015). Apart from that, several physical processes such as disequilibrium compaction, fluid expansion, tectonic stress, mineral transformation, osmosis, etc. are known to contribute towards building of such anomalous pressures, nevertheless, the most commonly cited mechanisms for abnormal pressure generation in petroleum provinces are disequilibrium compaction and hydrocarbon generation including oil-to-gas cracking (Fertl, 1976; Mann and Mackenzie, 1990; Luo and Vasseur, 1996; Osborne and Swarbrick, 1997; Law and Spencer, 1998; Van Ruth et al., 2004; Tingay et al., 2009). In general, such zones are buried at depths, which are effectively isolated from their surrounding formations in which the pressure in an isolated volume will increase more rapidly than that in the surrounding fluids (Barker, 1972). The impact of increasing temperature on the contents of isolated volume and on pressure is best described by pressure–temperature-density diagram for water, as discussed in detail by Barker (1972). These temperature-induced pore pressures will dissipate, if the isolated fluid system is allowed to drain.

The purpose of the present work is to augment the understanding of effect of deep-seated temperature regime, if any, on pore pressure
dis-equilibrium in a hydrocarbon bearing region like Ankleshwar oil/gas field, which is situated in the southern part of the Cambay basin. Currently, almost the entire basin is associated with quite high heat flow and temperature gradients (Verma et al., 1968; Gupta et al., 1970; Gupta, 1981; Panda, 1985; Ravi Shanker, 1988; Sonam et al., 2013), indicating possibly a renewed rifting phase, associated with anomalous subcrustal melting, rise of isotherms and mantle updoming (Singh et al., 1991; Pandey and Agrawal, 2000; Pandey et al., 2017). Already there is a suggestion, that a large Miocene/Pliocene basic body did intrude at a depth of around 10 km below the Cambay-Mehsana area (Gupta, 1981), which is well reflected into high gravity anomalies. In fact, the entire basin is associated with positive gravity bias (NGRI, 1978), in spite of the presence of thick sediments. Moho is shallow at about only 33 km in the basin (including ~8 km thick magma layer at the bottom), as compared to more than 40 km thick outside the basin (Tewari et al., 1991). Interestingly, the magma layer is much thicker below the southern part of the Cambay basin, in which present study area of Ankleshwar is situated (Kaila et al., 1981).

2. Regional geodynamic evolution and tectonic settings

Continental margin of western India consists of three major rifted sedimentary basins, Kutch, Cambay and Narmada. Geologic development of all the three basins is intimately connected to the different evolutionary phases through which this active margin underwent after its break up from east Antarctica sometimes during the Early Cretaceous (i.e. about 145–150 Ma ago). This included a number of geodynamic and catastrophic events. At 90 Ma, it came into contact with the Marion plume, resulting into the breakup of Madagascar from the west coast. Subsequently at 65 Ma back, this region was involved with another plume, ‘Reunion’. At the same time, it was also struck by a large asteroid near offshore Mumbai, which shattered the entire upper crust, broken the Seychelles microcontinent from Gujarat coast, and ultimately led to eruption of 2–3 km basalt cover over the western India (Pandey et al., 1995). The western margin of India suffered maximum post breakup damage due to all these events, which resulted into rifting of the entire crust, magmatically underplated it and made unusually warmer and ductile (Pandey and Agrawal, 2000; Pandey et al., 2017). The Cambay rift basin was no exception.

2.1. Geology of the Cambay basin

This narrow intra-cratonic rifted basin, which is situated in alluvial plains of Gujarat, is one of the most extensively explored sedimentary basins of India. It extends between latitude 21°N to 25°N and longitude 71°30′E to 73°30′E and runs for about 425 km, covering an approximate area of 56,000 sq. km (Mohan et al. 2008). It is basically formed by discontinuous normal faults that run in an approximately NNW-SSE direction before taking a swing towards NNE-SSW direction near the Gulf of Cambay. It is bounded by the Saurashtra plateau on the western side, the Aravallis on its northeast and the Deccan traps in further south. Based on recognizable basement controlled transverse faults and fracture lineaments, the entire basin can be subdivided into several geotectonic blocks (Fig. 1); Sanchor, Tharar, Patan, Mehsana, Ahmedabad, Tarapur, Broach and Narmada (Kundu and Wani, 1992; Banerjee et al., 2002; Mohan et al., 2008). Ankleshwar oil field is situated in the southernmost occurring Narmada block. The deepest part of the basin is located in the Jambusar and Broach area, where sediments are more than 5 km thick. The geological sequence in the basin comprises mainly of volcanic conglomerates, greywackes, dark grey to back grey shales, siltstones, fine to medium grained sandstone and claystones. Some outcrops of Jurassic and Cretaceous sediments can also be seen on the basin margin, suggesting that the initial rifting possibly began sometimes during the Mesozoic period. The geology and tectonics of this graben has been discussed in great detail by many workers like Sen Gupta (1967), Mathur et al. (1968) and Biswas (1987), etc.

2.2. Ankleshwar oil field

The Cambay basin is known to contain several oil/gas bearing structures which are being commercially exploited by Oil and Natural Gas Corporation of India (ONGC). Ankleshwar oil field is just one of the major one, which is situated in the southern part of this basin, as mentioned earlier. It was discovered in May 1961 and put to production by ONGC since August 15, 1961. This oil field has produced cumulatively 65.35 million metric tons (MMt) as on April 2011, against the estimated oil in place (OIP) of 134.71 MMt (ONGC, personal communication). An additional oil production of about 10.4% of OIP is envisaged from this mature field, if continuous CO2 injection is implemented (Ganguli et al., 2016a,b; Ganguli et al., 2017; Ganguli, 2017). This field basically contains an asymmetric anticlinal structure of the deltic origin, housing sedimentary deposits of mainly Eocene to Pliocene age (Mukherjee, 1981). Deep seated fault systems, which...
formed horst and graben type structures, serve as traps in which the source rock consists of thick pile of fine grained clastic sediment of Lower to Middle Eocene age, commonly known as Cambay Shale, which is underlain by Olpad shaly formation that sits directly over the Deccan volcanic basement. This formation is also prevalent in all other major depressions of the basin like Hazira, Broach, Tarapur and Patan. The asymmetric anticlinal fold is believed to have been developed as a result of differential movement of the blocks across strike faults along the limbs of the fold. The middle to upper Eocene reservoir formation of the field has been further divided into four main member formation, Hazad, Kanwa, Ardol and Telwa, which are comprised of thick sequences of sands and shales. Out of them, the Hazad unit forms the major reservoir rock, consisting essentially sandstone, deposited in a prograding deltaic facies. The Kanwa shale acts as an effective cap rock for this deltaic sequence. The upper Eocene Ardol member also exhibit fairly good reservoir rock characteristics and accounts for about 15 percentages of volume of accumulated hydrocarbons. The Telwa shale member, which is devoid of coarser clastics, acts as cap rock for this sand unit. Further, conformably overliving the Telwa shale member of Ankleshwar formation is the Dadhar formation consisting interbedded sandstones, shales and bioclastic limestone. Non-conformably overliving Dadhar unit is the Tarkesvar formation (claystones, shales and poorly sorted sandstones), Babaguru formation (sands with interbedded clays and occasionally shales) and Kand formation (clays, sands, and clay conglomerates). At the top of all these formations, also lies a layer of alluvium.

In all, the multi-layered Ankleshwar reservoir contains 11 producing sand units of Eocene age, where $S_1$ to $S_6$ represents the middle sand group and $S_7$ to $S_{11}$, upper sand group (Mamgai et al., 1997). Out of all these pay sands, $S_3$ and $S_4$ sands are the major contributors for oil production in this mature field, thus as a whole referred as $S_3 + 4$ pay sands (Srivastava et al., 2015; Ganguli et al., 2016a; Ganguli, 2017). Based on the drill hole information from 16 boreholes, we have prepared a generalised lithologic section for the Ankleshwar oil field, which is shown in Fig. 2.

3. Well log data

All together data on 29 production wells from the Ankleshwar oil field were provided by the operator ONGC, however, P-wave sonic travel time data were available only in case of four wells for pore pressure analysis. By and large, borewell conditions were fairly smooth during the logging operations, except in a few cases, which were thus not considered in the present study. In all, we utilised four wells, ANK-1, ANK-2, ANK-3, and ANK-4, for pore pressure estimation, and another 16 wells for multiparametric lithological analysis. All of these boreholes were vertically drilled through the Ankleshwar formation to a maximum depth of about 1630 m. The well log data from the oil producing wells were acquired around 2009 (ONGC, personal communication), which were disseminated mostly on the eastern part of the anticlinal structure. Some of these borehole logs, contained in situ temperature information to the depths up to about 2000 m in the form of Bottom Hole Temperatures (BHT). In order to assess the effect of temperature gradient, as does the erosional process. But the effects are severe only in rapidly uplifting or subsiding young Tertiary basins. The Cambay basin, however, does not fall under that category.

Various attempts have been made, as early as five decades back to study this basin geothermally, using unproductive water-filled wells, drilled by ONGC for oil exploration purposes (Verma et al., 1968; Gupta et al., 1970; Gupta, 1981). Temperatures were measured at intervals of 20–25 m in various areas, till a depth of 1220 m using well calibrated thermost probe, coupled to a three conductor vector cable. Since the temperature measurements in boreholes were carried out after the lapse of several months to years (Gupta et al., 1970), the measured geothermal gradients would correspond to steady state.

Altogether, eight heat flow values have been reported so far from this basin that ranges between 55 and 93 mW/m² (Table 1). In the northern part of the basin, heat flow is reportedly higher (mean: 83 mW/m²; range: 75–93 mW/m²) compared to the southern part (mean: 61 mW/m²; range: 55–67 mW/m²), in which Ankleshwar oil field is situated. At Ankleshwar, the reported heat flow is about 67 mW/m², based on the temperature measurements carried out in four boreholes, till a depth of about 1200 m. No temperature measurements are reported below this depth, which is mainly comprised of the Cambay shales.

As stated earlier, in connection with Enhanced Oil Recovery (EOR) studies in Ankleshwar oil field, numbers of borehole logs from different locations were made available to us by ONGC (Dimri et al., 2012). We used the measured BHT information from these well logs, in order to see the changes in temperature gradient below 1200 m depth (i.e. below oil/gas pay zones), corresponding to the Cambay shale unit.

4.1. Bottom hole temperatures

BHT’s are usually recorded after 4–8 h from the cessation of drilling at the depths of about 5–10 m above the bottom of the borehole, during the course of routine logging operations. At those depths, thermal disturbances are expected to be minimal. In general, such measured temperatures do not correspond to static formation temperatures (Blackwell et al., 2007, 2010). Stabilized conditions are rarely reached by the time various logs are run and therefore, they are typically lower than the static in situ temperatures, the quantum of which depends mainly on the properties of the borehole fluid and surrounding rocks, drilling history, and the natural in situ temperature regime. Such temperatures therefore need to be corrected accordingly (Bullard, 1947; Pandey, 1981; Cao and Hermanrud, 1988; Pandey et al., 2014). For the present study, we use Kehle’s correction equation following Blackwell et al. (2010) to the measured BHT’s, which is given below:

$$\Delta F = \frac{-8.819 \times 10^{-12} \times Z_2 - 2.143 \times 10^{-8} \times Z_2 + 4.375 \times 10^{-3} \times Z - 1.018}{Z}$$

(1)

where $Z$ is depth in ft and $\Delta F$ is the amount of correction to be applied to the measured BHT.

Distributions of the corrected BHT’s with depth are shown in Fig. 3(a). They are also plotted along with conventionally measured static temperatures in Fig. 3(b), which includes data from Ankleshwar boreholes, ANK-28 and ANK-170. Temperature data from the another borehole ANK-2 has been excluded from this plot, as artesian ground water movements conditions prevailed in this borehole during the course of measurement (Gupta et al., 1970). As can be seen from Fig. 3(b), the corrected BHT’s conform very well to the conventionally measured borehole temperatures. Estimated temperature gradient of 38.2 °C/km from BHT’s in the depth range of 44–1306 m, matched very well with that of 39.5 °C/km, estimated using conventional temperature-depth data from boreholes ANK-28 and ANK-170.

An interesting aspect that emerges from this study is the sharp increase in temperature gradient below 1200 m depth (Fig. 3a). Temperature gradient between 1277 m and 1908 m is estimated to be about 52.9 °C/km, as compared to 38.2 °C/km in shallower section.
This suggests that the temperature gradient varies consistently with the lithology (i.e. from sandstone dominated to shale dominated; Fig. 2) at deeper depths.

4.2. Thermal conductivity and heat flow estimation

Borehole lithologs in Ankleshwar oil field are dominated by shale formation together with sandstone, clay and limestone (Fig. 2). Water saturated thermal conductivity of representative major rock types, obtained from the boreholes located in the Cambay, Ankleshwar and Kalol oil fields of this basin, as measured by divided bar apparatus (Gupta and Rao, 1970) is given in Table 2. Using these values, a weighted mean conductivity of 2.03 and 1.38 W/m°C is obtained for the rock formations occurring between the depths 44 and 1306 m, and 1277 and 1908 m, respectively. When we combine the thermal conductivity values with mean temperature gradients, we get a heat flow of 77.5 and 72.9 mW/m² for the upper and lower depth intervals respectively, with a mean of 75.2 mW/m² for the Ankleshwar oil field. In spite of the large differences in geothermal gradients, heat flow remains quite consistent with depth.

4.3. Deep seated thermal regime

To elucidate deep thermal regime, knowledge of structural disposition of different crustal layers along with their radioactive heat production and thermal conductivity, is a must. The south Cambay graben, within which Ankleshwar oil field is situated, is underlain by seismically anomalous crust (Kaila et al. 1981), which is totally degenerated and reworked due to crust-mantle thermal interaction and large scale sub-crustal melting. In such active areas, the long term process generating the bulk part of the lower crust is often magmatic accretion. Reportedly, this region is underplated by an unprecedented 22 km thick magmatic layer due to inland rifting and magma outpouring during Deccan volcanism. This layer is characterised by P-wave velocity of more than 7.0 km/s (Kaila et al., 1981). This may perhaps be one of the thickest magma layers recorded in anywhere in a rifted basin. Consequently, subcrustal erosion, originally formed Archean crust below this region is now only about 11 km thick, rest having been

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**Table 1**

Geothermal characteristics of different oil/gas fields in the Cambay graben. Heat flow and temperature gradient data are from earlier studies of Gupta (1981). Similar data from the present study is also included.

<table>
<thead>
<tr>
<th>Locality</th>
<th>Latitude and Longitude</th>
<th>Heat flow (mW/m²)</th>
<th>Mean temperature gradient (°C/km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Cambay graben</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mehsana</td>
<td>23°36’ 72°11’</td>
<td>80</td>
<td>46.7</td>
</tr>
<tr>
<td>Kalol</td>
<td>23°16’, 72°30’</td>
<td>78</td>
<td>43.6</td>
</tr>
<tr>
<td>Sanand</td>
<td>23°33’ 72°26’</td>
<td>75</td>
<td>49.4</td>
</tr>
<tr>
<td>Navagam</td>
<td>22°30’, 72°35’</td>
<td>82</td>
<td>58.5</td>
</tr>
<tr>
<td>Cambay</td>
<td>22°23’, 72°35’</td>
<td>93</td>
<td>53.9</td>
</tr>
<tr>
<td>Kathana</td>
<td>22°17’, 72°48’</td>
<td>89</td>
<td>50.7</td>
</tr>
<tr>
<td>South Cambay graben</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Broach</td>
<td>21°45’, 73°01’</td>
<td>55</td>
<td>26.9</td>
</tr>
<tr>
<td>Ankleshwar</td>
<td>21°35’, 72°55’</td>
<td>67</td>
<td>42.3</td>
</tr>
<tr>
<td>Ankleshwar oil field</td>
<td></td>
<td>75.2</td>
<td>43.1</td>
</tr>
</tbody>
</table>

*From bottom hole temperature data.

*Present study.

(44–1306 m). This suggests that the temperature gradient varies consistently with the lithology (i.e. from sandstone dominated to shale dominated; Fig. 2) at deeper depths.

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consumed by the thermal perturbations at the crust-mantle boundary. Thus, based on current geologic and geophysical information, we adopted a crustal heat production model, which is given in Table 3.

We used layered crustal model, with uniform distribution of radioactive elements in each of these layers corresponding to representative rock types, to calculate the steady state geotherms using following equation:

\[ T(Z) = T_{i-1} + \frac{1}{K_i} \left[ q_{i-1} - \frac{A_i}{2} (Z-Z_{i-1}) \right] (Z-Z_{i-1}). \]  

(2)

where \( T(Z) \), \( K_i \), and \( A_i \) are temperature, thermal conductivity, and radioactive heat production in the \( i \)th layer, \( Z \) is the depth; \( q_{i-1} \) and \( T_{i-1} \) are heat flow and temperature at a top of the layer at a depth of \( Z_{i-1} \). For the first layer (\( Z = 0 \)) these represent surface heat flow and surface temperature.

Calculated temperature-depth profile, following Eq. (2) is shown in Fig. 4. We adopt base of the lithosphere as the intersection point of the calculated geotherm with the peridotite incipient melting point curve (Gass et al., 1978), which results into a thin lithosphere of only about 50 km below this region, with a very high contribution of heat flow from the mantle (\( \sim 56 \text{ mW/m}^2 \)). Estimated temperature at the Moho is

Table 3

<table>
<thead>
<tr>
<th>Depth (km)</th>
<th>Vp (km/s)</th>
<th>Nature of crust</th>
<th>Rock Type</th>
<th>( A^* ) (( \mu \text{W/m}^3 ))</th>
<th>K(W/m °C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0–2.0</td>
<td>2.45</td>
<td>–</td>
<td>Sediments</td>
<td>1.5</td>
<td>3.5</td>
</tr>
<tr>
<td>2.0–3.0</td>
<td>–</td>
<td>–</td>
<td>Deccan volcanics</td>
<td>0.02</td>
<td>1.7</td>
</tr>
<tr>
<td>3.0–5.0</td>
<td>4.0–4.29</td>
<td>–</td>
<td>Mesozoic sediments</td>
<td>1.5</td>
<td>3.5</td>
</tr>
<tr>
<td>5.0–9.0</td>
<td>5.82–5.87</td>
<td>Upper crust</td>
<td>Granite-gneiss</td>
<td>1.82</td>
<td>3.0</td>
</tr>
<tr>
<td>9.0–16.0</td>
<td>6.41–6.57</td>
<td>Middle crust</td>
<td>Amphibolite-granulite</td>
<td>0.78</td>
<td>2.5</td>
</tr>
<tr>
<td>16.0–38.0</td>
<td>7.03–7.55</td>
<td>Underplated crust</td>
<td>Granite-gneiss</td>
<td>0.02</td>
<td>2.6</td>
</tr>
<tr>
<td>&gt; 38.0</td>
<td>–</td>
<td>Mantle</td>
<td>Ultramafics</td>
<td>0.01</td>
<td>3.0</td>
</tr>
</tbody>
</table>


Fig. 3. (a) Corrected Bottom Hole Temperatures (black star) versus depth below Ankleshwar oil field of the Cambay basin (Western India). (b) Temperature–depth distribution as conventionally measured in two wells, ANK-170, ANK-28 in the Ankleshwar oil field of the Cambay basin. Corrected Bottom Hole Temperature data are also included here for comparison. Higher temperature gradient correlates well with the overpressured zones beneath this oil/gas field.

Table 2

Adopted water saturated thermal conductivities of different sedimentary and limestone rocks, as measured on borehole samples from the Cambay, Kalol, and Ankleshwar oil fields in Gujarat (Gupta et al., 1970). Conductivity values of Deccan volcanics are taken from Roy and Rao (1999).

<table>
<thead>
<tr>
<th>Rock Types</th>
<th>Thermal Conductivity (W/m °C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Claystone</td>
<td>1.25</td>
</tr>
<tr>
<td>Shales and clayey shales</td>
<td>1.25</td>
</tr>
<tr>
<td>Sandstone</td>
<td>2.72</td>
</tr>
<tr>
<td>Limestone</td>
<td>2.17</td>
</tr>
<tr>
<td>Deccan volcanics</td>
<td>1.70</td>
</tr>
</tbody>
</table>

Fig. 4. Estimated temperature-depth distribution beneath Ankleshwar oil/gas field of the Cambay basin (Western India). Adopted parameters in the calculation are included in the figure as well as Table 3. Melting conditions can be expected at a quite shallow depth of about 50 km only below this oil field.
found to be around 880 °C. Melting conditions below this region thus may have reached just about 13 km below the Moho depth. Consequently, in spite of thick sediments, gravity anomalies are largely positive over this basin, due to inclusion of high density magma at sub-crustal depths (Dixit et al., 2010), as mentioned earlier.

5. Pore pressure estimation and overpressure distribution

Pore pressure is described as the pressure due to the pore fluids within the rock, which can be higher than the hydrostatic or dominant normal pressure of the region. The point at which fluid pore pressure exceeds the hydrostatic pressure, is known as the top of overpressure/geopressure (TOP), where large part of load of the overlying sediments is borne by the pore fluids. The fundamental theory for pore pressure prediction relies on Terzaghi’s hypothesis (Terzaghi, 1943), which is based on soil mechanics and defines the effective stress as the difference between normal or vertical stress and the pore pressure. Thus, knowledge of overburden stress is vital in order to estimate pore pressure of a formation. The overburden stress/vertical stress ($S_v$) can be calculated using the equation given by Plumb et al. (1991), which can be represented by

$$S_v = \int_0^Z \rho(Z) gdZ,$$

where $\rho(Z)$ is the bulk density of the rock, represented as function of depth ($Z$), and $g$ is the acceleration due to gravity. The pore pressure (PP) is calculated using Eaton’s sonic equation (Eaton, 1972), given by

$$PP = S_v - (S_v - P_{hyd}) \times (DT_n / DT)^3,$$

where $P_{hyd}$ is the hydrostatic/normal pressure; $DT_n$ is sonic travel time in a low permeable zone, i.e. shale formation, which can be calculated from normal compaction trend (NCT); $DT$ is observed sonic travel time.

In order to understand the overpressure mechanism in the oil field under study, we analysed in detail the borehole data from four wells as mentioned earlier. All of these boreholes were drilled through the Ankleshwar formation. Abnormal pressure and onset of overpressure zones have been realized by spotting deviations from NCT in P-wave sonic travel time and bulk density logs for the wells under investigation. Fig. 5 depicts the NCT in P-wave sonic travel time and bulk density, including the under compacted shale formation demarcated within the Ankleshwar oil field. Accordingly, a general relationship of normal compaction trend of P-sonic transit time with depth is established by combining and rearranging NCT and shale porosity with depth. The shale porosity is estimated using the corrected Wyllie relationship (Wyllie et al., 1956; Raymer et al., 1980), as given below:

$$\phi_{sonic} = \frac{(1/C_p)(DT - DT_{ma})}{(DT_D - DT_{ma})},$$

where $\phi_{sonic}$ is the calculated shale porosity from P-wave sonic log, $DT_{ma}$, $DT_D$ are the matrix and pore fluid interval transit time, and $C_p$ is an empirically determined correction factor for better estimation of porosity. Since the transit time in shale formation shows values greater than 100 microsec/ft, we estimated the correction factor using the following equation:

$$C_p = DT_{ma} / 100.$$

Assuming $DT_{ma} = 47.6$ microsec/ft, $DT_D = 189$ microsec/ft and on the
basis of the measured P-wave sonic transit time data within the normal pressured regimes of Ankleshwar oil field, we found the following relationship of normal compaction trend of P-wave sonic transit time with depth:

\[ DT_n = -0.0143Z + 143.45, \]

Moreover, the abnormal pressure zones are identified with excess sonic travel time and high porosity (low density) concurrently at a depth below about 1435 m, 1220 m, 1250 m and 1140 m, respectively, when compared to NCT. These two types of log illustrate correctly the relationship of normal compaction trend with pressure transition period. During unloading, a strong vertical density and transit time reversal as compared to the NCT is observed. In general, sedimentary formations are subjected to two broad types of overpressure configuration, i.e. either single overpressure configuration or double overpressure configuration. In case of the double over-pressure configuration, the overpressure increases with burial depth in the upper interval, then decreases in middle interval and then increases again in the lower interval. In comparison, in single configuration, overpressure usually increases systematically with burial depth (Shi et al., 2013).

Our studies indicate that the double overpressure configuration is prevalent in all the boreholes from this oil field, except in one well (ANK-4), which is dominated by single overpressure configuration. This implies that Ankleshwar oil field is promising for shale gas prospects since the lower overpressure regime in double overpressure configuration are found to be a good candidate to preserve or accumulate hydrocarbon, which has migrated from the bottom (i.e. high pressure regime).

5.1. Origin of overpressure zone

One of the widely used methodologies to identify overpressure generation in oil fields is the analysis of cross-plots between velocity and density. Fig. 6 illustrates the P-wave velocity vs. density cross-plot using the shale formation of the two wells, ANK-1 and ANK-2 which provide evidence for secondary processes in the generation of over-pressure in Ankleshwar oil field. We observed unloading trend (faster drops in velocity as compared to density), deviated much from the normal (or primary) compaction trend in this oil field. What is striking however is that in each well, the deeper overpressured shales are identified with much lower velocity, as compared to the shales at the shallow depth. Later on, as a matter of compaction or cementation, the deeper level shales appear aligned to the loading curve. This implies that the double overpressure configuration is very much relevant to this oil field, as discussed earlier. These mechanisms are identified to be classic example of fluid expansion or gas generation due to the temperature effect as signature of increasing and decreasing pressure gradient is clearly observed in the velocity vs. density cross-plots.

Fig. 7 illustrates the pore pressure variation including hydrostatic pressure, overburden stress, gamma ray log and lithologic variation along depth within available well logs. It is interesting to observe that the pore pressure magnitude is much below the hydrostatic pressure for the pay sands of Ankleshwar formation in the depth range of 1185–1298 m. The overburden stress and abnormal pore pressure values within the most productive sands of Ankleshwar oil field are found to vary between 20–23 MPa and 11.5–13.1 MPa, respectively. We further noticed a good correlation between the calculated pore pressure values and measured reservoir pressure within the Ankleshwar reservoir. In comparison to the above, a drastic increase in pore pressure is noticed (when compared to the hydrostatic pressure distribution) within the Cambay Shale formation at the average depths between 1300 m and 1450 m. This formation forms the source rock in the Ankleshwar reservoir, as mentioned earlier. In hydrocarbon bearing fields, oil-to-gas cracking itself may indicate excess pore pressure, when compared to the hydrostatic pressure (Barker, 1972).

6. Discussion

Biswas (1987) postulated that the Cambay basin may have been associated with repetitive thermal perturbations in the past and the present day thermal regime could be quite young, associated with a renewed rifting phase, which is consistent with the present day thermal field over the basin, as summarised in Table 1. This table suggests that the subsurface temperatures are extremely high in the Cambay basin. At 3 km depth, it could be as high as 175 ± 25 °C. As per the study of Ravi Shanker et al. (1991) recorded Bottom Hole Temperatures are quite
high and vary from 100 to 145 °C at only 1.7 to 1.9 km depth in the northern part of the graben. Their study further indicated that during the course of drilling, hot water with steam under pressure was encountered in the boreholes Cambay-15 and Kathna-4, respectively. In the former well, steam was struck at 750 m while in the latter borehole, it was encountered at 1958 m. The steam discharge was almost 3000 cu m/day, with a high bottom hole temperature of about 160 °C. In the southern part of the graben, we estimated a static temperature of 114 °C in the Ankleshwar oil field at only 1.9 km depth (Fig. 3a), which is similar to the northern part of the basin. Such higher temperatures can only be related to the elevated subsurface isotherms, caused by the shallow depth of melting (around 50 km; Fig. 4) below the Ankleshwar region. As mentioned earlier in situ temperature information in the Ankleshwar oil field were limited to only about 1200 m depths (Gupta et al., 1970; Gupta, 1981), which indicated temperature gradients from 32.3 to 53.1 °C/km in various depth segments, depending on lithologic variations. Present study suggests that temperature gradients are much higher (52.9 km/s) below this depth, although there are not much data to categorically substantiate it, however, indications are definitely there (Fig. 3a). Recent study of Sonam et al. (2013) too has found a similar behaviour. They noticed a sharp increase in temperature gradients in deeper sections of several boreholes (BH-19, BH-23, BH-69, BH-62, etc.) in the Narmada Broach block of the south Cambay basin, within which Ankleshwar oil field is situated. Interestingly, the occurrence of the high temperature gradient zone (Fig. 3) coincides one to one with the overpressured zones, demarcated below 1200 m depth. In this zone, in situ rocks are mainly the low conductive (1.25 W/m °C) Cambay shale that rests almost directly over the Deccan volcanic basement (Fig. 2). This shaly formation, which is about 475 m thick, forms the source rock in the Ankleshwar reservoir. These are characterised by relatively high pore pressure when compared to the pay sands of Ankleshwar formation. Such zones, which are usually isolated from the surroundings, have significant relevance to hydrocarbon generation/accumulation, in the sense that they are associated with significantly high in situ temperatures thereby making it favourable for gas generation.

In general, shale formations are rich in organic matter and having been exposed to higher temperatures and pressures, they are usually considered as prime target for shale gas exploration. In that perspective, the Cambay shale formation is quite thermally mature owing to high in situ temperature gradient and thus chances of shale gas may be quite bright in this region, as also indicated by Sain et al. (2014).

We believe that the presence of high in situ temperatures in the low conductive formations may have contributed to the formation of overpressure zones, as well as intrinsic velocity/density inversions in them. Thermally controlled mineral reactions have been found to be responsible for porosity reduction at temperatures greater than 100 °C (Hermanrud et al., 1998). This may lead to development of overpressure by reducing the permeability. The correlation between the occurrences of overpressured zones with the high temperature gradient within the Cambay shales would indicate existence of a hydrocarbon bound system with significant gas potential, as at high temperatures gas is generated from oil and thus may cause overpressure. However, since no measured pressure data from Ankleshwar oil field were provided to us by the operator, ONGC, we could not validate the pore pressure predicted values using proper Eaton’s exponent, especially when the overpressure distribution in this field is due to mainly unloading or fluid expansion mechanism. This aspect has been adequately discussed in Tingay et al. (2009) and Suwannasri et al. (2014), etc. Moreover, a concerted integrated study on vitrinite reflectance, TOC content, geo-mechanical aspects and hydro fracturing are desired to understand the resource potential of shale gas exploration in this region.

Besides above, this study also provides another important inference that the heat flow in the south Cambay graben may not be very different from the north Cambay graben, as hitherto believed (Gupta et al., 1970; Gupta, 1981). Our studies indicated a surface heat flow of 75.2 mW/m² for Ankleshwar, which is within the range of the heat flow (75–93 mW/m²) observed in the northern part of the Cambay graben (Table 1) or even Mumbai offshore region (56–83 mW/m²) (Pandey and Agrawal, 2000). Thus, there appears a possibility that the entire Cambay basin and adjoining Mumbai offshore region (specia
northern and eastern parts) may be associated with high order thermal anomaly, with melting conditions at shallow subcrustal depths. Ankleshwar oil field with high heat flow and extremely shallow depth to the melting (about 50 km) just forms one of the segments of this high thermal anomaly zone, which caused high heat flow at the surface and consequently higher temperature gradients in low conductive (1.25 W/m°C) over-pressed shale formations below about 1250 m depth.

7. Conclusions

The present investigation is based on well log information from 16 boreholes in the Ankleshwar oil field (the south Cambay basin), supplied by the operator ONGC. Following generalised conclusions can be made from this study.

(1) The Ankleshwar oil field in the Cambay basin, exhibits moderate overpressure zone with double overpressure configuration within the Cambay shale unit, that appear temperature induced due to rise of isotherms, consequent to shallow subcrustal melting. This zone is conspicuously characterized by density and transit time inversions. As such, the deeper lying overpressured shales are identified with much lower velocity, as compared to the shales at the shallow depths that follows the unloading trend.

(2) Temperature gradients are extremely high at around 52.9 °C/km below 1200 m in the overpressure zone due to lower conductivity of the shale formation. In comparison, temperature gradients are much lower at 38.2 km/s in the upper section, dominated by sandstone.

(3) It is likely that overpressured situation in the Cambay shales developed due to thermal generation of gas in the low permeability shales, where gas accumulation rates are higher than rates of gas loss. This region, thus, provides a good example of temperature induced fluid expansion and consequent gas generation in low conductive and low permeable sedimentary strata.

(4) Being quite thermally mature, the low conductive Cambay shale formations may form a good target for investigating shale gas prospects in the basin.

(5) Further, a high surface heat flow of 75.2 mW/m² has been estimated for the Ankleshwar oil field, using bottom hole temperatures, suggesting that the heat flow in the south Cambay graben may not be lower than the northern part, as envisaged in earlier studies. Rise of isotherms at subsurface levels, due to melting conditions at shallow subcrustal depths of only about 50 km, may have aided to the generation and maturation of hydrocarbons in this graben.

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