Pore pressure prediction in a carbonate reservoir: a case study from Potwar Plateau, Pakistan

Muhammad Younis Khan1 · Muhammad Awais2 · Farrukh Hussain3 · Matloob Hussain4 · Irfan U. Jan1

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Abstract
Deep sedimentary successions, which are usually over-pressured, require accurate prediction of abnormal pressures to avoid catastrophic incidents, e.g., well blowouts; thus, pore pressure prediction (PPP) makes an important step for efficient reservoir modeling, cost-optimization and safe well-planning procedures in the hydrocarbon exploration. The objective of this study focuses on the estimation of formation pore pressure (PP) within the Eocene Chorgali Formation, using well logs data (from MYL-X1 and MYL-X2 wells) of Meyal Oil Field, Potwar Plateau, Pakistan, and its integration with outcrop, microscopic and seismic data. The formation PP is estimated from geophysical well logs (gamma-ray and sonic logs), by applying the widely used Eaton’s method. The pore pressure gradient (PPG) indicates the presence of pressured zone(s) in the Chorgali Formation in both wells. In MYL-X1, Chorgali Formation PPG and PP ranged from 9 to 13 lbs/gal and 5800 to 8400 psi, respectively, at about depth of 3760–3800 m. The reservoir Chorgali Formation in MYL-X2 wells also displayed pressure zone at about depth interval of 3820–3890 m with PPG and PP values of 8.9–11.6 lbs/gal and 5700–7500 psi, respectively; however, it indicated less pressure than MYL-X1. The synthesis of outcrop, microscopic, well logs and seismic data sets illustrates variations in pore pressure within the Eocene Chorgali Formation that is influenced and controlled by depositional, diageneric and tectonic fabric among other factors. The variations in PP are necessary to determine to avoid any geologic disaster. Such incidents may cause potential loss during drilling operations in the geologically complicated settings of the Himalayan Fold-and-Thrust belt.

Keywords Pore pressure prediction · Sonic log · Gamma-ray log · Carbonate reservoir · Potwar Plateau · Pakistan

Introduction
Pore pressure (PP) is the fluid pressure in pores in a porous formation (Swarbrick and Osborne 1998). If the PP is lower or it exceeds the normal pore pressure (i.e., hydrostatic pressure), it is abnormal pore pressure. It is important to predict such abnormal pressures before drilling practice as it is considered as one of the most crucial parameters to ensure safe drilling plans and for geomechanical analyses. Drilling operations can seriously be affected due to overpressures in terms of economic as well as skilled human loss. They cause disastrous drilling incidents such as well blowouts and fluids influx. The drilling problems associated with over-pressured reservoirs include caving and uncontrolled production of formation fluids and may cause loss of mud filtrate. Therefore, it is of crucial importance to accurately predict these abnormal pressures.

Some researches focused on pore pressure prediction (PPP) from different parts of the world includes PP study in the Volve Field (Norwegian North Sea), Bai Hassan Oil Field (Iraq), South Pars Gas Field (Iran), Gabo Field (Nigeria), Illizi Basin (Algeria), Giant El Morgan and Al-Khilala hydrocarbon fields (Egypt), Asam and Cambay basins and Offshore Panna (India) (Azadpour et al., 2015; Azadpour and Manaman 2015; Qays and Wan 2015; Alam et al. 2019; Sen and Ganguli 2019; Baouche et al. 2020; Ganguli and...
Similarly, PPP has been analyzed by different workers in the Potwar Plateau, Pakistan (Law et al. 1998; Roghani 2013; Ashfaq 2016). In the Potwar Plateau, high (abnormal) formation pressures are considered main hurdles to hydrocarbon exploration. High pressures have caused intense drilling issues and consequently impacted costs of drilling and inhibited proper reservoir(s) evaluation (Law et al. 1998). Law et al. (1998) demarcated two pressure domains in the Potwar Plateau, i.e., in Neogene and pre-Neogene geological formations. The PP in the Neogene rocks is as high as lithostatic pressure. In the pre-Neogene rocks, the PP is less than Neogene rocks and pore pressure gradient (PPG) usually varies from 0.5 to 0.7 psi/ft (11.3–15.8 kPa/m). Both Neogene and pre-Neogene pressures are attributed to compressional tectonics; the Neogene pressure is influenced by compaction disequilibrium related to greater sedimentation rates, while the pre-Neogene pressure is raised by hydrocarbons generation (Law et al. 1998). Roghani (2013) investigated PPP based on Meyal-16 well logs using Eaton pore pressure method in the Meyal Oil Field and attributed that PP becomes problematic due to abnormal pressure in the formation caused by under-compaction and seals. Likewise, low-permeability intervals and traps avert escaping fluids as quickly as pore space reduces due to compaction, thus creating overpressure (Roghani 2013). Ashfaq (2016) reported high-pressure zone in Joyamair-04 well from the Potwar Plateau, suggesting enhanced mud weight for safe drilling in the study area to ensure safe drilling operations. All these studies in Potwar Plateau are focused on the PPP from wireline logs only; however, the current work deliberates on PPP using multiple-scale geological and geophysical measurements and results. The surface (i.e., outcrop) and subsurface (i.e., well logs and seismic reflection) data sets in conjunction with the petrographic microscopy and high-resolution scanning electron microscopy (SEM) provide an insight into the factors affecting the PPP in the study area. For the first time, integration of results from different sources shed light on the pressured zones in the Eocene Chorgali Formation.

Lithostratigraphy

The stratigraphy of the Meyal Oil Field represents Permian to Pliocene successions (Hasany and Saleem 2012; Awais et al. 2019; Fig. 2). The oldest stratigraphic successions include Permian rock unit(s), which are overlain by Triassic Mianwali, Jurassic Datta, Paleocene Hangu-Lockhart-Patala, Eocene Nammal-Sakesar-Chorgali-Kuldana-Kohat, Miocene Murree-Kamlial-Chinji and Pliocene Nagri formations (Hasany and Saleem 2012; Awais et al. 2019; Fig. 2). The Permian rock unit(s) is reportedly comprised of clays in the Meyal Oil Field; however, in the Upper Indus Basin in general the Permian successions are comprised of limestone with subordinate sandstone and shale intercalations (Shah 2009; Hasany and Saleem 2012). The Triassic Mianwali Formation consists of limestone, dolostone, sandstone, siltstone and marls (Shah 2009; Hasany and Saleem 2012). The Jurassic Datta Formation is dominated by variegated colored sandstone, siltstone and shale (Shah 2009; Hasany and Saleem 2012). The Paleocene Hangu Formation contains sandstone, shale, coal seams and laterite (Shah 2009). The Paleocene Lockhart Limestone is dominated by nodular limestone with shale intercalations and marls (Shah 2009; Hasany and Saleem 2012; Khan et al. 2018a). The Paleocene Patala Formation is dominated by shale with nodular limestone, marls, shale intercalations and sandstone (Shah 2009; Khan et al. 2018b; Kamran et al. 2021). The Eocene Nammal Formation contains limestone, marls and shale intercalations (Shah 2009; Hasany and Saleem 2012). The Eocene Sakesar Limestone is dominated by nodular limestone,
Fig. 1 Maps showing the Upper Indus Basin and Moyal Oil Field. a Geological map of the Kohat-Potwar plateaus with marked Moyal Oil Field (Kazmi and Rana 1982; Khan et al. 1986). At the top right corner index map with marked area of (a). b Simplified seismic base map of Moyal Oil Field showing the distribution of drilled wells and seismic lines (SL). MYL-X1 and MYL-X2 wells are shown by yellow stars with black circles in the center.
Fig. 2 Stratigraphic column of the Meyal Oil Field, Potwar Plateau, Pakistan (modified after Hasany and Saleem 2012; Awais et al. 2019). The Eocene Chorgali Formation (target of present study) is highlighted in yellow color.

| Age   | Formation          | Lithology          | Description                                                                                   | Legend                                                                 |
|-------|--------------------|--------------------|-----------------------------------------------------------------------------------------------|------------------------------------------------------------------------|
|       | Nagri Formation    |                    | Sandstone, siltstone and conglomerate in the lower and upper parts respectively.               | Limestone                                                              |
| Miocene| Chinji Formation   |                    | Sandstone and siltstone.                                                                       | Dolomite                                                               |
|       | Kamlial Formation  |                    | Sandstone, siltstone and conglomerate.                                                         | Nodular limestone                                                      |
|       | Murree Formation   |                    | Sandstone, siltstone, shale and intraformational conglomerate at the base.                     | Limestone having chert nodules                                        |
| Eocene | Kohat Formation    |                    | Limestone and shale.                                                                           |                                                                        |
|       | Kuldana Formation  |                    | Dominantly red clays with minor grey limestone and interbeds of brown to red sandstone.       |                                                                        |
|       | Chorgali Formation |                    | White to light grey, bedded, limestone, dolomite, shale and marl.                               |                                                                        |
|       | Sakesar Limestone  |                    | White to light grey, massive, nodular limestone with abundant chert nodules.                   |                                                                        |
|       | Nammal Formation   |                    | White limestone, marl and greenish-grey shale.                                                  |                                                                        |
|       | Patala Formation   |                    | Marl, shale with interbeds of limestone.                                                        |                                                                        |
| Paleocene | Lockhart Limestone |                    | Nodular limestone with marl and shale intercalations.                                            |                                                                        |
|       | Hangu Formation    |                    | Quartzose sandstone and shale with lenticular coal seams in the upper part.                    |                                                                        |
| Jurassic | Datta Formation    |                    | Variegated sandstone, shale and siltstone.                                                      |                                                                        |
| Triassic | Mianwali Formation|                    | Limestone, marl, sandstone, siltstone and dolostone.                                             |                                                                        |
| Permian | Permian Formation(s)|                    | Dominantly limestone with subordinate sandstone and shale intercalations.                      |                                                                        |
shale intercalations and chert nodules (Shah 2009; Hasany and Saleem 2012; Ishaq et al. 2019). The Eocene Chorgali Formation consists of limestone, dolostone, marls, sandy limestone and shale intercalations (Shah 2009; Hasany and Saleem 2012; Awais et al. 2020a). The Eocene Kuldana Formation is dominated by red clays with minor limestone and interbeds of sandstone (Shah 2009; Hasany and Saleem 2012). The Eocene Kohat Formation is dominated by limestone and shale (Shah 2009). The Miocene Murree-Kamlial-Chinji and Pliocene Nagri formations are comprised of sandstone, siltstone, claystone and conglomerate (Shah 2009).

The Eocene Chorgali Formation is the subject of present research, and it has conformable lower and upper contacts with the Sakesar Limestone and Kuldana Formation, respectively (Fig. 2). In the whole succession of studied wells, there are three unconformities, i.e., between: (1) Triassic Mianwali and Jurassic Datta Sandstone, (2) Datta Sandstone and Paleocene Hangu Formation and (3) Eocene Kohat Formation and Miocene Murree Formation (Fig. 2).

Methodology

The present study is focused on PPP within the reservoir interval(s), i.e., the Eocene Chorgali Formation based on available geophysical well logs of MYL-X1 and MYL-X2 wells of the Meyal Oil Field, Potwar Plateau, Pakistan. To estimate the pore pressure, gamma-ray and sonic log velocity information is used by applying Eaton’s model using the Interactive Petrophysics (IP). In addition, subsurface seismic reflection data, outcrop geology (i.e., from the nearest located Khair-e-Murat Range), petrographic and SEM studies of the Eocene Chorgali Formation are also performed to observe and report pore pressure affecting deformational (i.e., tectonic) and diagenetic features. The petrographic studies are performed considering deformational and diagenetic features using different (mostly five to ten) field of views. Likewise, SEM studies are conducted on specific spots in the thin section(s) which are cut and detached from main thin section(s) and then investigated under SEM. The lithology of the Chorgali Formation penetrated in MYL-X2 has been interpreted using composite of gamma-ray log (GR), neutron porosity log (NPHI) and density log (RHOB) and cross-plot of NPHI-RHOB. The GR Log (scale 0–100 API) is utilized to define shale and non-shale (i.e., carbonates) zones within the Chorgali Formation. The shale horizons are marked above 50 API, while carbonates are marked below 50 API (Rider 1996). The composite of density (RHOB) and neutron (NPHI) logs is generally used to differentiate limestone and dolostone in a carbonate sequence. The density and neutron logs will overlap for limestone and will be apart for dolostone, provided the correct log scale (Lucia 2007).

Eaton’s approach for pore pressure

There are different methods and data sets available for estimation of PPP (Fig. 3; Scott and Thomsen 1993; Chilingar et al. 2002; Gutierrez et al. 2006; Helset et al. 2009; Zhang 2011; Atashbari and Tingay 2012; Kumar et al. 2012; Yan and Han 2012; Kesarwani et al. 2013; Azadpour and Manaman 2015; Qays and Wan 2015; Wang and Wang, 2015; Green et al. 2016; Adam and Huy 2017; Ahmed et al. 2019; Oloruntobi and Butt 2019). Among the above-mentioned, Eaton’s method has been extensively used in petroleum industry and academic research. Eaton (1975) proposed the method, which relies on the dis-equilibrium compaction due to less permeable geological layer. For example, shale layer is considered as the main contributor to generate abnormal pressure. The Eaton’s method has gained popularity over the last decade and is currently the most employed scheme for PPP in its original and modified forms (Zhang 2011; Kumar et al. 2012). Based on the shale properties, Eaton’s approach has been commonly applied for pore pressure prediction, using two types of well-logging data, i.e., resistivity and sonic transit time.

For PPP, Eaton (1975) introduced the following relationship from compressional velocity/transit time:
where $P_{pg}$ is the pore pressure gradient; $OBG$ indicates the overburden stress gradient; $\Delta t_n$ is the sonic transit time or slowness ($\mu$s/ft) in shales at the normal pressure, i.e., against the normally compacted shale zones known as normal compaction trendline (NCT). A deviation of the sonic log response from the defined NCT for a given well indicates the amount of change in pore pressure in the affected shale intervals; $P_{ng}$ is the hydrostatic pore pressure gradient.

$n$ is an exponent, normally $n = 3$, and $\Delta t$ shows the sonic transit time in shales which can be obtained from geophysical well log.

This work presents PPP from sonic transit time using Eaton’s approach. In this method, shale NCT is established for input curve (i.e., sonic velocity), and based on the calculated overburden gradient, the deviation of the observed log response from the NCT is used to compute pore pressure. This estimated PP curve is used to define depth intervals displaying pressure zones. This PP estimation is shown for the target interval (i.e., Eocene Chorgali Formation), and pressure zones are marked. The PPP results are supported by other surface and subsurface studies and are discussed in the following section.

**Results and discussion**

**Outcrop geology, petrography and scanning electron microscopy (SEM)**

The Eocene Chorgali Formation consists of limestone, dolostone, algal laminations, shale and marls (Fig. 4). The studied outcrops showed folding and faulting, and the carbonate units (i.e., limestone and dolostone) are intensely fractured (Fig. 5). The petrographic and scanning electron microscopy (SEM) demonstrated that the microfabric of the Chorgali Formation is mud-supported, having different types of porosities, such as intercrystalline, moldic, micro-vuggy, fenestral and fracture (Fig. 6).

In the Khair-e-Murat Range, the depositional fabric of carbonates of the Chorgali Formation is comprised of mudstone (i.e., algal laminated, non-laminated, dolomitized and for scale), and d exposure of marls. In Fig. 4a, b, d, geological hammer is used for scale.

$$P_{pg} = OBG - (OBG - P_{ng}) \left( \frac{\Delta t_n}{\Delta t} \right)^n$$
siliciclastic) and wackestone indicating its deposition in tidal flat settings (Jurgan and Abbas 1991; Awais et al. 2020a). The Chorgali Formation carbonates are altered by a variety of diagenetic processes such as micritization, dolomitization, dissolution, microfractures, stylolitization, mechanical compaction, neomorphism and cementation (Awais et al. 2019, 2020b). The microfractures, stylolitization and mechanical compaction particularly attest to the tectonic compression and/or overburden of the succession (Norman 2015) amidst the highly compressed tectonic zone of the Khair-e-Murat Range, which is present in the north-eastern part of NPDZ.

**Lithology interpretation using geophysical logs**

In MYL-X2, the Chorgali Formation consists of dolostone, limestone, shale and evaporites (i.e., gypsum and halite) (Fig. 7). The lithology is dominated by dolostone and shale (Fig. 7). The intercalations of shale are present throughout the formation, and insignificant limestone is encountered in the upper part. The evaporites are present in lower and middle parts of the formation (Fig. 7). The depth interval between 3868.2 and 3875 m in the MYL-X2 represents the lithology of Chorgali Formation to be consisted of dolomite and shale (Mujtaba 2001; Fig. 8). According to Mujtaba (2001), in MYL-X2 (i.e., between depth interval: 3868.2 and 3875 m), the Chorgali Formation carbonates includes dolomitized intramicrite and finely crystalline dolomite (Fig. 8).

In the Moyal Oil Field (i.e., Meyal-01 and Meyal-02 wells), Khan et al. (2013) demarcated three distinct zones (i.e., shale, shaly and clean limestone) within the Chorgali Formation based on variations in the gamma-ray log. According to Hasany and Saleem (2012), the generalized lithology of the Chorgali Formation in the Moyal Oil Field is dolomite, limestone, dolomitic limestone, marl and shale. These lithologies are interpreted using various geophysical logs motifs, i.e., litho-density, neutron, resistivity, spontaneous potential (SP) and sonic (Hasany and Saleem 2012). The Chorgali Formation consists of four units, i.e., C1 to C4 from top to bottom. C1 is dolomitic limestone, having calcite-filled fractures, anhydrite inclusions and shale streaks, having 1–9% primary porosity. C2 is limestone (i.e., calcite-filled and vacant fractures), marls and shale; however, well log response of the interval is dolomitic. C3 is dolomitic unit, having pyrite, chert, carbonaceous shale and anhydrite inclusions and with primary porosity of 0–9%, but low log porosity (NPHI, PHID, PHIS). C4 is dolomitic limestone unit, having anhydrite inclusions and shale intercalations (Hasany and Saleem 2012).

The lithology of the Chorgali Formation in the outcrop and subsurface is quite similar, i.e., consisting of limestone, dolostone, evaporites (i.e., gypsum), shale and marls (Fig. 8). However, subsurface log-derived lithology is dominated by dolostone with very little limestone which is present in the upper part of the formation only. The dominance of dolostone is also exemplified by core-based lithology as reported by Mujtaba (2001) but it is for 07 m only (Fig. 8). The interpreted microfacies in the Chorgali Formation by Mujtaba (2001) and Awais et al. (2020a) are also shown in Fig. 8.

**Pore pressure prediction using Eaton’s method**

It is common practice to carry out the PPP analysis for whole length of the stratigraphic column in the drilled well which makes the predicted pressure fluctuations easy to observe and differentiate from the neighboring units. To this end, the computed PP curve for whole well in each well (MYL-X1...
and MYL-X2) is shown and then displayed in the depth interval(s) covering the Chorgali reservoir (Figs. 9, 10).

The overburden pressure (OBPres), overburden gradient (OBGrad), pore pressure gradient (PPG) and fracture gradient (FG) curves were plotted for two wells using well log data and available drilling information (Figs. 11, 12, 13, 14). We have demarcated several high-pressure intervals in the MYL-X1 well, i.e., Patala shales and Chorgali Formation (Fig. 9). The pore pressure plot shows pressure in the range of 7000–8400 psi (Fig. 13). In the MYL-X1 well, the high-pressure zones of Patala shales and Chorgali carbonates are clearly defined, whereas in other formations deviations of small magnitude are observed (Fig. 9). In Patala shales, PPG and PP attained maximum values of around 12 lbs/Gal and 8600 Psi. GR log motif clearly indicates an increase in the shale content against the high-pressure zones (Fig. 9). The high-pressure zone in the Patala Formation (a dominant shale succession), is probably due to the shale overburden. In case of Chorgali, PPG and PP ranged from 9 to 13 lbs/gal and 5800 to 8400 Psi, respectively, at about depth of 3760–3800 m. In MYL-X1, the Chorgali Formation upper part has pressured interval, while lower part is not showing any significant pore pressure and hence implying pore pressure variability in vertical direction (Fig. 9). In the MYL-X1, interestingly the Sakesar Limestone covering depth interval of about 3833–3920 m showed no high pressure as compared to the Chorgali Formation in the same well although there is little increase in PP in lower most part of the Sakesar Limestone (Fig. 9).
In the MYL-X2, the high-pressure zone starts from shallow depth in Murree Formation within depth from 2700 to 2800 m characterized by PPG and PP values of 8.55–10.4 lbs/gal and 4000–4800 Psi (Figs. 10, 12, 14). Similarly, Patala shales some pressure intervals characterized by PP values of 6200–6800 Psi, however, of less magnitude as compared to the PP values around 8600 Psi in MYL-X1 (Fig. 14). The reservoir Chorgali Formation also displayed pressure zone at about depth interval (3820–3890 m) with PPG and PP values of 8.9–11.6 lbs/Gal and 5700–7500 Psi, respectively (Figs. 12, 14). In this well, the main target interval covered by Chorgali Formation indicated less pressure than MYL-X1.

The overburden shales at different depth intervals in the Meyal Oil Field play a significant role in generating high formation pressure, which may be the result of factors such as disequilibrium compaction and tectonic stress. Overall, the predicted pressure gradient curves clearly mark pressured rocks at different depth intervals (Figs. 9, 10, 11, 12, 13, 14). The MYL-X1 showed high pressure in studied shales as well.
as reservoir formation in general which depicts the variation of PP of similar lithologies (Chorgali Limestone in our case) within the same oil field (Figs. 9, 11, 13).

The PP estimation is usually carried out for wells including source and reservoir intervals. Here, we mapped the PP with emphasis on Chorgali reservoir and support this pressured reservoir with outcrop, microscopic and seismic data. The PPG and PP show small change in the pore pressure at some portions of the reservoir in both wells (Figs. 9, 10, 11, 12, 13, 14). However, it can be seen that overall behavior of the pore pressure is not static throughout the logged section, and it attains maximum local value within the formation (Figs. 9, 10). This variability at particular depth intervals indicates the pressure changes which is important to estimate in order to avoid any incidence (i.e., geologic disaster) that may cause potential loss to drilling operations.
Pore pressure validation from geological and geophysical (seismic) data

Carbonate reservoirs are the prolific targets of various drilling plans in Pakistan like the Middle East (Xinmin and Yong 2018; Esrafil-Dizaji and Rahimpour-Bonab 2019). The development of carbonate reservoirs experiences a challenge of prospective abnormal pore pressure (geological hazard or risk) which should be mitigated. The abnormal (high) pore pressure can complicate the drilling operations as it enhances the friction between the formation and bit and thereby might create wellbore stability issues like borehole breakouts and kicks (Atashbari and Tingay 2012).

The pore pressure causing means includes loading, clay diagenesis, kerogen transformation, tectonics, aquathermal pressuring, hydrology and osmosis (Atashbari and Tingay 2012). In carbonates, pore pressure variations are caused by the availability of different porosity types controlled by diagenesis (fracturing and dissolution), depositional fabric(s)
Fig. 10 Log pore pressure plot for MYL-X2 well
and deformational mechanisms (stress) (Brasher and Vagle 1996; Anselmetti and Elberli 1999; Green et al. 2016). The structural deformation features, i.e., folding, faulting, halokinesis (salt diapirism), shale movements, lateral slipping and sliding, can affect pore pressures of geological formations (Chilingar et al. 2002). Chilingar et al. (2002) concluded that tectonics (local and regional) can lead to abnormally high fluid pressure. Atashbari and Tingay (2012) summarized that post-depositional compaction reduces the pore spaces, thereby imparting pressure on the fluids present in the pore spaces. Carbonate cements in the reservoirs make a tight fabric (grain to grain contact increases) leading to apparent compaction (lower pore pressure and high effective stress) in the well logs (Atashbari and Tingay 2012). Furthermore, carbonate cements occupying the pore spaces reduce the porosity and can impart enough pore pressure in sealed environments (Atashbari and Tingay 2012). It has been reported that pore pressure in carbonates is dominantly generated by compaction disequilibrium (controlled by rock physical properties and pore fluids) and further developed by expansion of fluids and other possible causes (Atashbari and Tingay 2012).

The Chorgali Formation is a producing reservoir rock in the Potwar Plateau in general and Meyal Oil Field in particular. It is difficult to pin-point a single factor responsible for producing pore pressure in the Chorgali Formation. There could be multiple controlling factors in such type of geological setting including structural/tectonic, diagenetic and intercalations of shale and even evaporites in carbonate sequences etc.

Structural features such as faults and folds may also contribute to generate high-pressured zones in reservoir formations (e.g., carbonates). The Chorgali Formation is also folded and faulted which can be the reasons for possible high pore pressure as per interpretation of Chilingar et al. (2002) (Figs. 5, 15). Interpreted 2D seismic reflection section clearly demonstrates the structurally deformed character of the Chorgali Formation in terms of well-developed anticline

Fig. 11 Pressure gradient and overburden plot for MYL-X1 well
bounded by thrust faults on each side (Fig. 15). Another evidence in the context of tectonic control on PP generation is coming from the field observations, i.e., marked fault and clearly visible fractures at outcrop scale (Fig. 5).

The microscopic-scale fabric is studied to visualize the porosities and fracture details that may be facilitating / adding to the generation of the pore pressure. The Chorgali Formation carbonates are dominated by secondary diagenetic (moldic and vuggy) and deformation (fracture) porosities and hence making pore pressure variations in the formation as described by Green et al. (2016) (Fig. 6). Different porosity types within the Chorgali Formation carbonates give an insight of variations in the pore pressure (Fig. 6c–p). Cementation in the Chorgali Formation carbonates can enhance pore pressure, as per Atashbari and Tingay (2012) remarks, provided it is sealed by impermeable lithology such is the case in the Khair-e-Murat Range (Fig. 6a). Chorgali Formation is comprised of shale and marls intercalations throughout the sequence in the outcrop sections and in the subsurface, so their presence and diagenesis can bring variations in the pore pressure (Figs. 4, 5, 6, 7, 8). Likewise, the presence of evaporites can also cause variation in pore pressure (Fig. 7). The Chorgali Formation is occupying higher position in petroleum system(s) and capped by seal rocks (dominantly shale and minor evaporites), which can be the main reason for variations in pore pressure (Fig. 15). Awais et al. (2019) classified diagenetic fabric of the Chorgali Formation into petrophysical facies discrimination, i.e., diagenetic processes enhancing porosity and diagenetic processes reducing porosity. The former category includes

![Fig. 12 Pressure gradient and overburden plot for MYL-X2 well](image-url)
dolomitization, dissolution and microfractures, while the latter category includes cementation, micritization, neomorphism and compaction (Awais et al. 2019). The porosity-reducing diagenetic features are the main reasons for developing highly compacted zones of lower reservoir quality. Hence, variations in diagenetic fabric and facies across the Chorgali Formation might be one of the reasons for pore pressure variability as demonstrated in the present study.

The interpretation of PPP using geophysical logs gave a direct indication of PP situation within the Chorgali Formation. In this connection, outcrop observations, microscopic details and seismic section interpretation portray the actual mechanisms of PP variations within the Chorgali Formation. The variation in PP reflects variations in depositional, diagenetic and deformational features within the formation. The geological data (outcrop observations, litho-logs and microscopic study) indicate heterogeneities within the Chorgali Formation which may be classified as bed/core-plug, lithofacies/well log/inter-well and stratigraphic/seismic/fieldwide scales (Weber 1986; Chiarella et al. 2017). These heterogeneities influence porosity–permeability response of reservoir(s) and thereby dictate the PP response across the formation. These reservoir heterogeneities generate reservoir compartments, and hence, there are different pressured zones within the formation(s). Such reservoir heterogeneities and reservoir compartmentalization are seen in the Chorgali Formation that generated pressured zones.

Different pore types have different pores aspect ratios (ratio of shorter axis to longer axis) (Kumar and Han 2005; Xu et al. 2007). For example, aspect ratios of interparticle, moldic-vuggy and microcrack(s) porosities are 0.15, 0.8 and 0.02, respectively (Xu et al. 2007). The pore aspect ratio is broadly categorized as high pore associated with moldic and vuggy porosities and low pore aspect ratios associated with microcracks (Kumar and Han 2005). The low pore aspect ratio (i.e., presence of cracks/microfractures) and high pore aspect ratio (occurrence of moldic and vuggy porosities) result in overestimation and underestimation of pore pressures, respectively. The former consequence can lead to lost circulation and reservoir formation damage, while the latter may cause well-kick and sometimes even blowouts (Ruihe et al. 2013). As there are a variety of pore types (i.e., intercrystalline, moldic, micro-vuggy, fenestral and fracture) within the Chorgali Formation, these pore types will have peculiar role in influencing and causing variations in PP throughout the formation. In the context of drilling problems, the Eocene Chorgali Formation reservoir may be at higher risk due to
the availability of both low and high pores aspect ratios that highlights the importance of integrated PPP estimation to avoid any unwanted incident on well site.

The multi-proxy assessment of mapped PP in Chorgali reservoir relying on wireline logs, seismic, outcrop and microscopic observations proved to be as a useful tool aimed at planning safe drilling operations in the unexplored surrounding areas within the Eocene carbonates of the Himalayan foreland basin.

**Conclusions**

Wireline logs data have been used for estimating pore pressure. The current work demonstrates the pore pressure prediction (PPP) using Eaton model from gamma-ray log and compressional velocity. The pore pressure gradient indicates the presence of pressurized zone in the Eocene carbonates. A case study from Meyal Oil Field was conducted to demonstrate that well logs provide acceptable results in the studied Chorgali Formation. Fluid volume and movement and tectonic stresses are the three mechanisms among others, which controls PPP. However, the obtained results can be considered as a useful tool to plan a safe well in the unexplored surrounding areas within the Eocene carbonates of Himalayan foreland basin. Such type of investigations can further be constrained by measured pressure data for more reliable and accurate modeling with necessary calibrations. Analysis of compaction trends and pore pressure gradients highlight the importance of such investigations in deeper sedimentary carbonate reservoirs in other adjoining sub-basins, which are ultimate targets of exploration companies. The variations in pore pressure in the Eocene Chorgali Formation seem to be affected by the interplay of depositional, diagenetic and tectonic processes, but these are not the only factors.
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Author contributions

MYK proposed the research idea and conducted the interpretation of present manuscript. MA performed all the geological studies and prepared and finalized the manuscript. FH and MH assisted in interpretation of the data. IUJ contributed significantly in preparation of final version of the manuscript.

Fig. 15 Structural elements (folds and faults) in the Meyal Oil Field. a Interpreted seismic section of dip line (SL-08) showing the presence of pop-up structure. The transect of SL-08 is shown in Fig. 1b; b structure contour map on top of the Chorgali Formation (after Hasany and Saleem 2012; Riaz et al. 2018, 2019). SP for shot points.
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Data availability  The data and material studied are present in the manuscript.

Declarations

Conflict of interest  There are no conflicts of interest/competing interests.

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