Research Article

Fracture Gradient Analysis for Lockhart Formation at Kohat–Potwar and Nizampur Sub-Basins, Pakistan

Rafiq Ali Khan[1], Sajjad Ahmed[1], Salim Raza[2*] and Shehla Gul[1]

[1]University of Peshawar, Khyber Pakhtunkhwa, Pakistan; [2]Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary, Canada.

Abstract: The Lockhart Formation is a proven hydrocarbon reservoir in the Kohat–Potwar areas of Upper Indus basin. The geomechnical properties of the formation varies laterally and are not uniform due to which the drilling and field development is a serious challenge for petroleum companies. The Lockhart Formation is categorized into three lithological units to assess its geotechnical characteristics. The representative samples of the units are used for Unconfined Compressive Strength (UCS) tests to establish the fracture pressure and fracture gradient of the formation in Kohat-Potwar and Nizampur Sub-Basins and adjoining areas. Based on the UCS tests and extrapolation techniques, a benchmark value for fracture gradient of Lockhart Formation is derived that is 0.91 psi/ft. This value is very important parameter in drilling operations and can be used in proper designing of drilling fluid to avoid losses and subsequent kicks/blow out for safe and successful drilling of wells. The Lockhart Formation has reservoir potential in the stratigraphic units lying on the southern side of the Main Boundary Thrust (MBT), however it becomes Geomechanical more tighter and compacted towards east in Potwar sub basin and southward into Punjab plains, while the reservoir potential and fracture densities increases towards the Kohat Sub basin and frontier regions of Samana Ranges. The Kohat Sub basin and adjoining areas are contributing more than 50% of to the current oil production of Pakistan.

Received: June 03, 2021; **Accepted:** June 25, 2022; **Published:** June 30, 2022
***Correspondence:** Salim Raza, Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary, Canada; **Email:** razas@ucalgary.ca
Citation: Khan, R.A., S. Ahmed, S. Raza and S. Gul. 2022. Fracture Gradient analysis for lockhart formation at Kohat–Potwar and Nizampur Sub-Basins, Pakistan. *Journal of Engineering and Applied Sciences,* 41: 24-32.
DOI: https://dx.doi.org/10.17582/journal.jeas/41.24.32
Keywords: Lockhart formation, Fracture pressure analysis, Kohat-Potwar and Nizampur sub-Basins, Extrapolation technique, Hydraulic fracturing

Introduction

The Paleocene Lockhart Formation is predominantly composed of limestone and is exposed in Kohat–Potwar and Nizampur Sub-Basins (Awais *et al*., 2019). It is a proven hydrocarbon reservoir in Kohat–Potwar Sub-Basin. The hydrocarbon potential of the reservoir is not uniform across the basins and the formation serves as a producing reservoir mainly in Kohat Sub basin and some wells of Potwar sub basins, while in the surrounding wells eastward into Nizampur sub basins and southward into Punjab plains it is either barren or tight reservoir for hydrocarbon that needs hydraulic fracturing and stimulation (Khan *et al*., 2018; Awais *et al*., 2019).

Drilling hydrocarbon wells are the most critical and costly projects that needs to be completed efficiently, quickly and safely, otherwise project's cost, workers lives, infrastructure could be affected badly. The drilling of a successful well is based on the knowledge and estimation of subsurface formation pressure and fracture pressure that are critical parameters in designing a well (Alberty and McLean, 2004). These parameters are expressed in pressure gradients as psi/ft. Fracture gradient calculations are critical for drilling mud design, minimizing or avoiding lost circulation problems and in selecting proper casing seat depths. Lack of proper understanding to the formation pressure and fracture pressure accounts for the lost circulation, well kicks which may lead to the blowout situations. Thus, the predicted fracture gradient gives an indication that how much the maximum possible mud weight could be maintained without inducing mud into the formation (Zhang *et al*., 2017). An understanding of the following parameters is critical in fracture pressure analysis for well design to reach a target safely and efficiently. Definitions of the key parameters for subsurface pressure estimation are discussed in the following sections.

Lithostratigraphic units of lockhart limestone

The Paleocene Lockhart Formation is exposed in Upper Indus Basin of Pakistan and is reported in Kohat–Potwar, Samana Ranges and Nizampur Sub-Basins (Malik and Ahmed, 2014). The formation is composed of predominantly limestone and is also called Lockhart Limestone. The formation is measured in different sections thickness of which is ranging from 32m to 84m. It is 32m thick in Tangi Thal Section of Kohat Sub Basin (KS). In Nammal Section- Salt Range (NS), the Lockhart Limestone is 37m thick, while in Nizampur Sub Basin (NZ) the Lockhart Limestone is 84m thick.

The formation is classified into three main lithological units including sandy and massive limestone unit, interbedded limestone, and shale unit, brecciated and nodular limestone unit (Hubbert and Willis, 1957) (Figure 1). The sandy limestone unit makes conformable contact with underlying Hangu formation, while nodular limestone unit marks the upper part of Lockhart Formation. The limestone units are stylolitic, fractured and jointed on outcrop (Figure 1).

Fracture gradient

Fracture pressure can be defined as the maximum pressure that a formation can sustains before its tensile strength reaches and it gets fail. The fracture gradient is not only critical parameter in selection of mud weight to avoid losses, well kicks, well control situations and reservoir damages, but also very important for hydraulic fracturing (Zhang and Yin, 2017). Moreover, the fracture pressure provides a base for casing designs, surface blow out preventer (BOP) stacks, and all calculations for hydraulic fracturing (Fatahi *et al*., 2016).

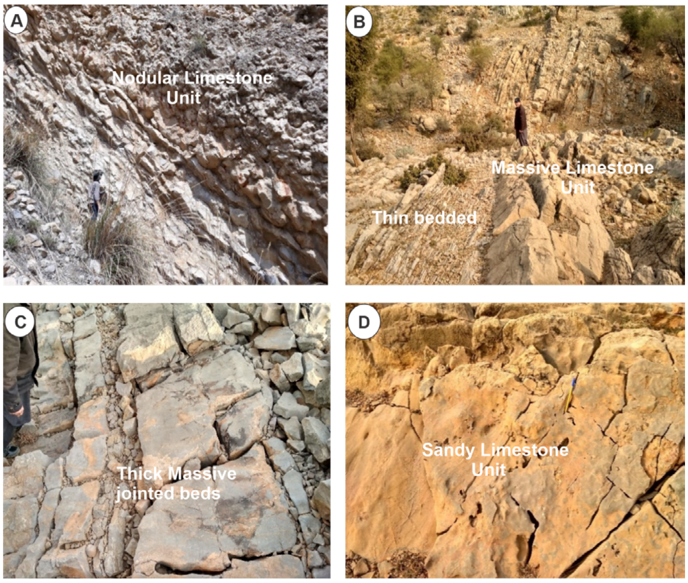

Figure 1: *Different lithological units of Lockhart Formation exposed in Nizampur Sub-Basin.*

The stress within a rock can be resolved into three principal stresses. A formation will fracture when the pressure in the borehole exceeds the least of the stresses within the rock structure. Normally, these fractures will propagate in a direction perpendicular to the least principal stress.

At sufficient depths with significant overburden pressure (usually below 1000 m or 3000 ft) the minimum principal stress is horizontal; therefore, the fracture faces will be vertical. For shallow formation with less compaction and overburden pressure, where the minimum principal stress is vertical (Figure 2), it will develop horizontal (pancake) fractures (McClure and Kang, 2018).

Pore pressure or formation pressure

Formation pressure or pore pressure is the pressure of the fluid within the pore spaces of the formation exerted by hydrostatic head of fluid column above it. All the formations in sub surface below ground water table contain fluids in their pore spaces between the sediments. The pressure of the fluid column with depth is expressed in the form of pressure gradient (Swarbrick *et al.*, 2010). Generally, a fluid gradient of 0.465 psi/ft is considered as a normal by assuming the pore spaces of all sedimentary rocks are filled with saline water of 8.94 ppg. Pore pressure gradient equal to 0.465 psi/ft is called normal formation pressure, while the higher than 0.465 psi/ft pore pressure is called abnormal the one less than 0.465 psi/ft is called subnormal formation pressure (McClure *et al.*, 2018).

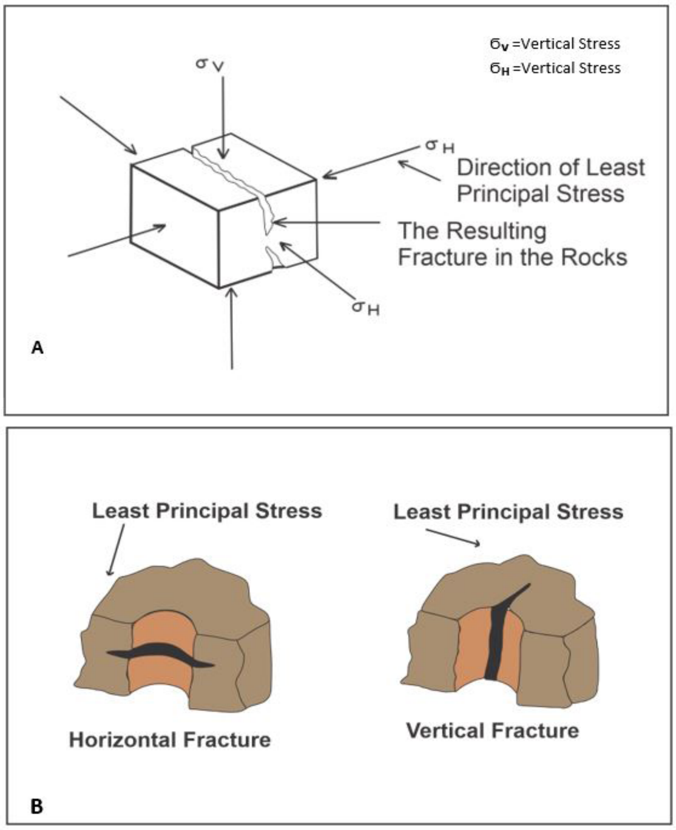

Figure 2: *Fracture propagation direction to least principal stress A and B (after Hubbert and Willis, 1957).*

Overburden pressure

The pressure exerted by the weight of the rock formations and fluid columns above the point of interest is called overburden pressure and is always in the vertical direction (Eyinla *et al.*, 2021). The higher the rock and the fluids densities, the greater the overburden pressure will be over the reservoir (Green *et al.*, 2016). It is always higher than the fracture pressure, generally the overburden gradient is considered as 1 psi/ft (Zhang, 2011; Figure 3).

Safe drilling or operating window

The drillable pressure profile, bounded on the low side by formation pressure below which formation fluids enter into the wellbore, while on the upper side by the fracture pressure above which the formation will fracture (Zhang, 2011). It shows the safe mud weight profile for drilling between fracture gradient and pore pressure gradient, which is called Safe Drilling or Operating Window (Mclean *et al.*, 1994). In the case of higher hydrostatic pressure than the fracture gradient, the formation fractures and loss circulation occur (Rocha *et al.*, 2004) (Figure 4). It is noticed that after complete losses, a sudden decrease in the hydrostatic head of mud allows formation fluid to enter the well bore as a kick. If a kick is not detected and monitored vigilantly and could not handle professionally, it may lead to blowout, consequently damages the human lives and assets (Gjorv, 2004). So, the mud weight is always kept higher than the pore pressure and less than the fracture pressure, therefore, pore pressure and fracture pressure are critical in safe drilling and achieving drilling objectives.

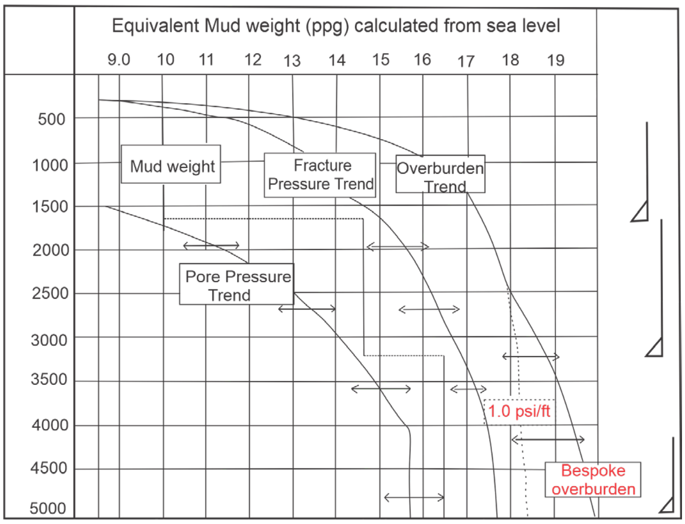

Figure 3: *Schematic depth vs mud weight (ppg) plot illustrating the key components of a well plan i.e. pore pressure, fracture pressure and overburden (after Aslannezhad et al, 2015).*

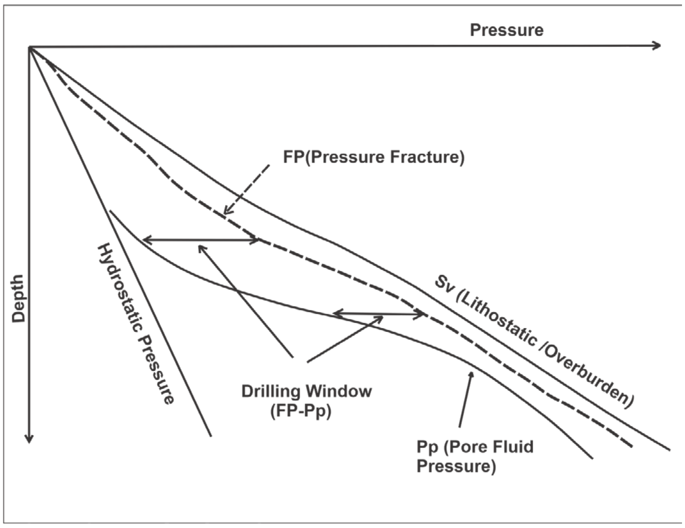

Figure 4: *Schematic depth pressure (ppg) plot illustrating the key components of a well plan i.e. pore pressure, fracture pressure, operating window and overburden. (after Zhang, 2011).*

Procedure for determining fracture pressure

The fracture pressure could be determined with the help of one of the following methods:

- Leak-off tests
- Formation breakdown tests
- Wire line logs and seismic data, drilling data.
- Hydrostatic head and mud weight at the time of losses
- Compression test of rock core samples (confined and unconfined tests).

The leak off test and formation breakdown tests are the direct methods of fracture pressure estimations for a formation at well site (Zoback, 2007). In these methods, the fracture pressure is calculated by applying surface pressure with the help of pumping fluid into the well at lower flow rated i.e., 0.25 bbl/minutes and observing the pressure trend. Once the fracture is initiated, the pressure profile deviates from the stable trend line and the pressure at this stage is considered as fracture pressure of the formation. Normally it is calculated after running casing and drilling out shoe and 3-5m of the formation (Eaton, 1969). The wireline logs, seismic data and drilling data can also be used to estimate the fracture pressure by evaluating the densities of the formation and analyzing fractures (Feng, *et al*., 2016).

In the present study, the formation fracture pressure is calculated by unconfined compression tests on the rock samples (cores) in laboratory. These fracture pressures are then compared with the well data for verification to achieve a regional scale baseline for fracture pressure of Lockhart Fomation in Kohat-Potwar and Nizampur Basins. Since Leak off tests results are not available for Lockhart formation, therefore the drilling data include mud weight and depth of losses are used for comparison and correlation. In this method the Hydrostatic Head (HH) of mud column prior to the occurrence of mud losses, is considered as fracture pressure of the formation and is compared with the formation breakdown strength (LOT- Leak of test) for calculation. As the formation will withstand the Hydrostatic Head (HH) of mud column till formation fracture pressure limit is exceeded and the maximum limit of formation pressure before fracture is an indicator of the formation fracture pressure (Edwards *et al*., 2002).

The fracture pressure calculated from the drilling data and mud losses will be compared with the fracture pressures data obtained from unconfined tests on core samples of Lockhart Formation in laboratory. If the results are matching, the obtained fracture pressure will be used to create a regional scale baseline for fracture gradient of Lockhart Formation. The resultant fracture pressure baseline can be used by petroleum companies in designing drilling fluids and well schematics and hydraulic fracturing of the Lockhart Formation for enhanced oil recovery.

Unconfined compression strength (UCS) test of core samples

The unconfined compression test is a laboratory test used to derive the compressive strength of a rock specimen. It is unidirectional stress test carried out over a cylindrical specimen, normally in axial direction. The core sample is tested under load in compression and resultant maximum stress required for the rock failure is taken as a compressive strength of the sample (Chau and Wong, 1996).

Mathematically, UCS can be determined by:

$$UCS = P/A \quad \ldots(1)$$

Whereas $A = \pi/4 * D^2$ and is the cross sectional area of the core sample in $(\text{inch})^2$ and P is the load at failure (psi).

Materials and Methods

In present study, the fracture pressure of lockhart formation is calculated ny using two methods for comparison and discussion as follows.

Method 1: Formation fracture pressure calculation from UCS data

Nine bulk samples are selected for the study of geomechanical properties of Lockhart Formation on the basis of different facies and lithological units identified during field fieldwork and petrographic studies using thin sections. Each section is represented by three samples from Kohat, Potwar and Nizampur basins. Two cores from each bulk sample are prepared and cut according to the ASCOE (Yalcin, 2013) specifications i.e., length to diameter ratio is kept equal to 2:1. Each section is represented by six cores to repeat tests and achieve the average results as per compression test procedure and total 18 core samples are processed for compressive strength tests. These samples are dried at 100-110°C for fifteen minutes to remove moisture and their end surfaces are polished and smoothened by using grinding machine. This ensured that a test core has smooth, parallel, and uniform bearing surface that is perpendicular to the applied axial load during compressive strength test. The UCS (Uniaxial Compressive Strength) of the rock specimens is measured with the help of Universal Testing Machine (UTM) by Equation 1. The results of the UCS tests on samples and their respective sections and locations are summarized in Table 1.

Table 1: *UCS tests results of the core samples extracted from Nammal Section (NS) from Salt Range, Nizampur Section (NZ) from Nizampur Basin and Kohat Section (KS) from Kohat Basin.*

Sample No.	Area ($inch^2$)	Load (lbf)	Strength (psi)	Strength (MPa)
Nammal section, salt range (NS)				
NS-1	1.6	7646	4779	32.95
NS-2	1.6	7378	4611	31.79
NS-3	1.6	6336	3960	27.30
NS-4	1.6	8688	5430	37.44
NS-5	1.6	5208	3255	22.44
NS-6	1.6	8602	5376	37.07
Nizampur section (NZ)				
NZ-1	1.6	8494	5309	36.60
NZ-2	1.6	6174	3859	26.61
NZ-3	1.6	8364	5228	36.04
NZ-4	1.6	7947	4967	34.25
NZ-5	1.6	4918	3074	21.19
NZ-6	1.6	8119	5074	34.99
Kohat section (KS)				
KS-1	1.6	7846	4903	33.81
KS-2	1.6	6234	3896	26.86
KS-3	1.6	84.83	5301	36.55
KS-4	1.6	7365	4603	31.74
KS-5	1.6	5864	3665	25.27
KS-6	1.6	8264	5165	35.61

The fracture pressure data derived from the Unconfined Compressive Strength (UCS) tests performed on dry core samples in laboratory with zero confining pressure (Waqas and Ahmad, 2020). These results are not indicator of the formation fracture pressure at subsurface, because the fracture pressure of a formation in subsurface is a function of overburden pressure, which reflects the total weight of the rock column and fluid column above the point of interest. The fracture in subsurface will initiate once the applied pressure reaches overburden pressure limit (Mogi, 2006).

To calculate the formation fracture pressure in sub surface, the fracture pressure obtained by UCS test on dry core sample in laboratory will be added to the formation pore pressure at the desired depth (Eaton, 1969; Radwan *et al*., 2019; Awais *et al*., 2019). The average fracture pressure (FPavg) calculated from the UCS test is considered as compressive strength of the rock sample with zero confining pressure. The strength of the rock sample is directly proportional to the compaction by the weight of overlying rock column and type of cementation. When this pressure is added to the formation pressure of Lockhart Formation for a desired depth in Kohat, Potwar and Nizampur Sub-Basins, it will reflect the fracture pressure of Lockhart Formation in subsurface.

Mathematically, it can be expressed as:

$$FPLM = FPavg + FP \quad \dots(2)$$

Whereas, FPLM is the formation fracture pressure (in psi) of Lockhart Formation at the desired depth, FPavg is the average unconfined compression strength (in psi) obtained in the laboratory by UCS test and FP is the actual formation pressure measured for Lockhart formation of Kohat sub-basin at the desired depth (psi)

The fracture gradient of Lockhart formation can be calculated with the help of fracture pressure and True Vertical Depth (TVD) by using the following Equation 3.

$$FGLM = FP / TVD, (psi/ft) \quad \dots(3)$$

Whereas; FGLM is the fracture gradient of Lockhart formation in psi/ft, FP is the fracture pressure in psi, and TVD is the total vertical depth in ft.

Method-2: Fracture pressure calculation by using the drilling data

In this method, the fracture pressure and fracture gradient of the formations in drilling wells are determined by Leak off test, Formation Break down test or Mini Fracture data. If the required data for these tests is not available, then losses while drilling and mud weight at the time of losses in a particular formation are used for fracture pressure and fracture gradient estimations (Mathew *et al*.,1967). Since the data for the above-mentioned tests is not available therefore, the alternate method (mud losses and mud weight) is used for calculating both the factors with the help of the following Equation 4.

$$HH\ (psi) = 0.052 \times TVD \times Mud\ Wt \ldots (4)$$

Whereas '*HH*' is the hydrostatic head in psi, '*TVD*' total vertical depth of the Lockhart formation, 0.052 is a constant and Mud Wt. is the mud weight in ppg.

Since, we have data for the Manzali well, therefore the fracture gradient for Manzali well at Kohat sub basin is calculated by using Equation 3 and considering its depth and HH of mud as a fracture pressure of the formation. This fracture gradient is considered constant for the entire Lockhart Formation across Kohat, Potwar or Nizampur sub-basins. The fracture pressure gradient of Lockhart Formation for its respective sub-basins are calculated by using Equation 3 and considering its depths and using fracture gradient calculated for Manzalai well.

Application of the fracture pressure analysis methods in the proposed study

Both techniques of fracture pressure analysis by using UCS results and drilling data is applied to calculate fracture pressure of Lockhart Formation in the present study area. Detail of the calculation is given below:

Fracture pressure gradient obtained from UCS results

In this method, the UCS results of dry core samples of Lockhart Formation from Kohat, Potwar and Nizampur Sub-Basins are used to calculate the fracture pressure. The laboratory test results are summarized in the Table 1. The data shows unconfined pressure required to fracture core samples at surface, however it is not reflecting the pressure required to fracture the same formation in the subsurface at reservoir depth, where there is also confining pressure in terms of formation pressure. So, for calculation of actual fracture pressure at reservoir depth, the formation pressure will be added to the unconfined pressure required to fracture a core sample at surface.

Based on the UCS results, the average fracture pressure for Lockhart Formation is calculated as 4585 psi which will be used as a baseline for the entire calculations. The formation/ reservoir pressure of Lockhart Formation obtained from the Schlumberger Wireline MDT results of Manzalai wells is ± 6300 psi, so by using Equation 2, the fracture pressure of Lockhart Formation at the depth of 11483 ft is calculated as 10885 psi.

The fractures gradient of Lockhart formation is calculated as 0.94 psi/ft with the help of Equation 3and by using 10885 psi fracture pressure at a depth of 11483 ft for Manzalai well of Kohat sub-basin. The resultant fracture gradient of 0.94 psi /ft is considered constant for calculation of fracture pressure of Lockhart Formation in Kohat, Potwar and Nizampur Sub basins. It can be used for planning wells and drilling fluids design to avoid mud losses, well flows and blow out.

Fracture pressure gradient obtained from drilling data

In this method, an indirect and extrapolation technique is used to calculate and validate fracture pressure of Lockhart Formation by using drilling data, because primary and direct data in terms of leak off test, break down test and mini fracture tests is not available. So, the mud losses and hydrostatic head (HH) during drilling in Lockhart Limestone will be used to calculate fracture pressure. In this method, mud weight and depth of losses (TVD) in Lockhart Formation is used to estimate the maximum pressure in terms of Hyrdostatic Head (HH), under which the formation fractured and mud losses initiated into formation.

In Kohat area, the Lockhart Formation encountered in drilling wells of Manzalai and Makori of MOL Company at a depth of 11483 - 12795 ft, while in Pakistan Oilfield Limited (POL) and Pakistan Petroleum Limited (PPL) exploration blocks of Potwar Sub Basin, the Lockhart Formation encountered at a depth of 10000 - 13000 ft. Moreover, at Kotsarang well of PPL, the Lockhart Formation 13015 ft deep (Haider *et al*., 2019). The formation pressure of Lockhart Formation measured in Kohat Sub-Basin by Schlumberger Wireline-Modular Dynamic Tester (MDT) is 6300-7000 psi at a depth range of 11483-12795 ft for MOL wells of Malazalai and Makori blocks.

The mud losses were observed in Manzalai well of Kohat Sub basin in Lockhart Formation at a depth of 11483 ft (TVD) with a mud weight of 17.49 ppg. So, the hydrostatic head (HH) of mud before losses in Lockhart Formation is calculated by using Equation

4. The resultant Hydrostatic Head of the mud column is 10443 psi, which is considered as the fracture pressure of Lockhart formation at Manzalai well of Kohat sub basin. Using this fracture pressure, the fracture gradient of Lockhart Formation is calculated with the help of Equation 3 as 0.910 psi/ft. This fracture gradient value can be used as a reference for calculating fracture pressure and drilling fluid design in drilling wells of Kohat – Potwar sub basins and adjoining areas.

Comparison and validation of both the methods

The first method is a direct method, in which the average fracture pressure of dry core samples is determined in laboratory by using UCS technique and added it to the formation pressure of Lockhart formation obtained from Wireline MDT with the help of Equation 3. The resultant fracture pressure is 10885 psi with a fracture gradient of 0.94 psi/ft. The 2nd method is an indirect method to calculate the formation fracture pressure by using mud weight and mud hydrostatic head before losses. The fracture pressure of Lockhart formation calculated by the indirect method is 10443 psi with a fracture gradient of 0.910 psi/ ft. On comparing results of both the methods, it can be observed that the results are almost matching, which confirms authenticity and reliability of the 1st method. The fracture gradients calculated by both methods slightly differs by a fraction of 0.03, it could be due to the slight variation in the mud weight at the time of losses, mud type, and dry core samples representing different lithological units. This minor difference is acceptable and can be ignored.

Industrial and academic importance of the research

The methods used for calculating fracture gradient can be applied to any field provided that all the required data is available. This will greatly help in reducing the problems related to loss circulation and consequently blow out. By accurately finding the fracture gradient the efficiency and production of a reservoir can be enhanced.

The proposed methods for finding pressure gradient are needed to be further verified by the applying it to other reservoir conditions. The other factors, did not addressed in this study should also be considered to further refine the methods. It is baseline, the researchers could develop a model on the basis of these methods which should give accurate results.

Conclusions and Recommendations

A good knowledge of the formation fracture pressure is very important tool in designing wells and selection of proper mud weights to avoid risks in drilling wells. The research documented here is intended to draw a baseline for fracture pressure analysis of Lockhart Formation in Kohat - Potwar and Nizampur sub basins and adjoining areas.

- The resultant fracture pressure and fracture gradient could be used for safe and successful drilling operations, in the region while the method could be applied to other areas as well.
- Based on the field observations, the Lockhart Formation is categorized into three distinct lithological units for fracture pressure analysis in Kohat, Potwar and Nizampur Sub basins and associated areas. The average UCS pressure obtained from the dry core samples of Lockhart Formation in the three lithological units is 4585 psi, which represents the fracture pressure of the core sample without pore pressure, as in subsurface the formation has pore pressure that was not simulated in the present study due to lack of available resources. This problem was resolved by adding normal pore pressure of Lockhart Formation at given depth to the pressure obtained from UCS tests. As a result, the fracture pressure and fracture gradient of the Lockhart Formation was calculated by using Equation 4.
- Based on this technique, a reference fracture gradient of 0.91psi/ft was calculated for Lockhart Formation which can be considered as a baseline for fracture pressure analysis of Lockhart Formation in Kohat, Potwar and Nizampur sub basins and adjoining areas.
- Depending upon the subsurface depth of Lockhart Formation in different areas, the fracture gradient and fracture pressure can be calculated by using this method.
- According to the correlation and analysis a safe operating window with a fracture gradient of 0.91-0.94 psi/ft, can be used for the efficient and safe design of mud to be used in drilling the Lockhart Formation of the proposed areas.
- The fracture gradient of 0.91 - 0.94 could be safely considered as a maximum fracture gradient of Lockhart Formation for fracture pressure analysis and drilling fluid design in drilling wells.
- It is recommended to keep drilling fluid

gradient below 0.91 psi/ft to drill the Lockhart Formation, otherwise there will be mud losses into the formation. Complete mud losses may cause reduction in hydrostatic pressure (HH) with subsequently well kick, which may lead to blowout if not monitored and controlled timely. Consequently, severe damages to the workers lives, infrastructure and surrounding environment may occur.

- The mud losses into the formation may damage the reservoir's porosity and permeability, which is known as skin effect, hence production from the reservoir can be affected.
- The proposed fracture gradient can be used as a reference value for planning acidization and fracturing job to enhance production from Lockhart Formation especially in the Kohat, Potwar and Nizampur sub basins for safe drilling operations.
- The extrapolation technique can be used to calculate the fracture pressure gradient of any sub surface formation and reservoir.
- It is proposed that the same methods should be applied to other formations and areas, so that the authenticity of the methods could be confirmed.
- For future researchers, it is recommended to model these methods by using a suitable software, so that the time and hard work could be reduced and the model will be affectively applied to any reservoir condition.

Novelty Statement

The research focuses on the fracture gradient determination by a new method and its verification by the field analysis.

Author's Contribution

Refiq Ali Khan contributed in collection of data, data analysis and geological investigation and writing. Sajjad Ahmed supervised the research and shared his ideas. Salim Raza contributed in the numerical investigation, writing and formatting where as Shehla Gul assisted in write and formatting.

Conflict of interest

The authors have declared no conflict of interest.

References

Alberty, M. and McLean, M., 2004. A physical model for stress cages. SPE Annual Technical Conference and Exhibition, Houston. http://dx.doi.org/10.2118/90493-ms

Aslannezhad, M., and H. Jalalifar. 2016. Determination of a safe mud window and analysis of wellbore stability to minimize drilling challenges and non-productive time. J. Petrol. Exp. Prod. Technol., **6**: 493-503. https://doi.org/10.1007/s13202-015-0198-2

Aslannezhad, M., Manshad., A., and Jalalifar., H., 2015. Determination of a safe mud window and analysis of wellbore stability to minimize drilling challenges and non-productive time. *J. Petrol. Explor. Prod. Technol.*, **6**(3). https://doi.org/10.1007/s13202-015-0198-2

Awais, M., Ullah, F., Khan, N., Ghani, M., Siyar, S.M., Wadood, B., and Mukhtiar, A., 2019. Investigation of reservoir characteristics, depositional setting and T–R sequences of the lockhart limestone of meyal oil field, Pakistan: A petrophysical approach. *J. Petrol. Explor. Prod. Technol.*, **9**: 2511–2530. https://doi.org/10.1007/s13202- 019-0730-x

Chau, K., and R. Wong. 1996. Uniaxial compressive strength and point load strength of rocks. Int. J. Rock Mech. Min. Sci. Geomech. Abst., *Pergamon*, **2**: 183-188. https://doi.org/10.1016/0148-9062(95)00056-9

Eyinla, D.S., Oladunjoye, M.A., Olayinka, A.I., Bate, B.B., 2021. Rock physics and geomechanical application in the interpretationof rock property trends for overpressuredetection. *J. Petrol. Explor. Prod.*, **11**(1): 75-95. https://doi.org/10.1007/s13202-020-01039-4

Edwards, S.T., Bratton, T.R., Standifird, W.B., 2002. Accidental geomechanics—capturing in situ stress from mud losses encountered while drilling. In: SPE/ISRM rock mechanics conference, 20–23. https://doi.org/10.2118/78205-MS

Eaton, B.A., 1969. Fracture gradient prediction and its application in oilfield operations. *JPT.* **21**(10): 25–32. https://doi.org/10.2118/2163-PA.

Fatahi, H., and M, Masood, 2016. Numerical simulation for the determination of hydraulic fracture initiation and breakdown pressure using distinct element method. *J. Nat. Gas Sci. Engin.*, **33**: 1219-1232. https://doi.org/10.1016/j.jngse.2016.03.029

Feng, Y., Jones, J and Gray, K., 2016. A Review on fracture-initiation and -propagation pressures for lost circulation and wellbore strengthening. *SPE Drill. Complet.*, **31**(02) https://doi.org/10.2118/181747-PA

Farhad, J., Pshtiwan, and Sarhad, F., 2014. Pore, abnormal formation and fracture pressure prediction. *WIT Transact. Ecol. Environ.*, **186**:579-593. https://doi.org/10.2495/ESUS140511

Fu, Y., 2014. Leak-off test (LOT) models (Doctoral dissertation), University of Texas.

Gjorv, B., 2004. Well control procedures for extended reach wells. Texas A and M University.

Green, S., O'Connor, S.A. and Edwards, A.P., 2016. Predicting pore pressure in carbonates: A review. *Search Discovery,* Article# 41830.

Haider, S.W., H.U. Rahim and H. Afzal. 2019. Evaluation of reservoir characteristics of well kot-sarang-2, Potwar Plateau, Pakistan using geophysical logs. Int. J. Econ. Environ. Geol., pp. 61-63.

Hubbert, M.K., and D.G. Willis. 1957. Mechanics of hydraulic fracturing. Transactions of society of petroleum engineers of AIME, 210: 153-163. https://doi.org/10.2118/686-G

Khan, M., M.A. Khan, B.A. Shami and M. Awais. 2018. Microfacies analysis and diagenetic fabric of the Lockhart Limestone exposed near Taxila, Margalla Hill Range, Punjab, Pakistan. Arab. J. Geosci., 11: 29. https://doi.org/10.1007/s12517-017-3367-4

Khoshnaw, F., P. Jaf and S. Farkha. 2014. Pore, abnormal formation and fracture pressure prediction WIT. Trans. Ecol. Environ., 186: 579-593. https://doi.org/10.2495/ESUS140511

Malik, A.M., and N. Ahmed. 2014. Palceocence caronate of Kohat-Potwar Sub-Basin of Upper Indus Basin, Pakistan. Sci. Int., Lahore, 26(5): 2337-2350.

Matthews, W.R. and Kelly, J,.1967. How to predict formation pressure and fracture gradient. *Oil Gas J.,* **65**(8):92–106.

McClure, W. Mark and C. Kang. 2018. Applying a combined hydraulic fracturing, reservoir, and wellbore, simulator: Staged field experiment #3, Cluster Spacing, and Stacked. https://doi.org/10.2118/190049-MS

Mogi, K., 2006. Experimental rock mechanics vol 3. CRC Press. https://doi.org/10.1201/9780203964446

Mondal, S., and R. Chatterjee. 2019. Quantitative risk assessment for optimum mud weight window design: A case study. J. Petrol. Sci. Eng., 176: 800-810. https://doi.org/10.1016/j.petrol.2019.01.101

Parent/ Child Frac Hits., 2018. Paper 190049, SPE Western Regional Meeting – USA, Garden Grove, CA.

Pascoe, K., 1956. American methods of materials testing. Nature, 177: https://doi.org/10.1038/177248a0

Radwan, A., A. Abudeif, M. Attia and M. Mohammed. 2019. Pore and fracture pressure modeling using direct and indirect methods in Badri Field, Gulf of Suez, Egypt. J. Afr. Earth Sci., 156: 133-143. https://doi.org/10.1016/j.jafrearsci.2019.04.015

Rocha, L., J. Falcao, C. Gonçalves, C. Toledo, K. Lobato, S. Leal and H. Lobato. 2004. Fracture pressure gradient in deepwater. https://doi.org/10.2118/88011-MS

Swarbrick, R., S. Green and D. Scott. 2010. Pore pressure prediction in challenging areas-reducing uncertainty by understanding rock behaviour. AAPG Ann. Conv., pp. 1-5.

Waqas, U., and M. Ahmed. 2020. Prediction modeling for the estimation of dynamic elastic young's modulus of thermally treated sedimentary rocks using linear–nonlinear regression analysis, regularization, and ANFIS. Rock Mech. Rock Eng., 53: https://doi.org/10.1007/s00603-020-02219-8

Yalcin, D., 2013. ADMET materials testing guide. https://doi.org/10.13140/RG.2.2.30075.52004.

Zhang, J., 2011. Pore pressure prediction from well logs: Methods, modifications, and new approaches. Earth-Sci. Rev., **108**(1–2): 50-63. https://doi.org/10.1016/j.earscirev.2011.06.001

Zhang, J., S.X. Yin. 2017. Fracture gradient prediction: An overview and an improved method. *Pet. Sci.*, **14**: 720–730. https://doi.org/10.1007/s12182-017-0182-1

Zoback, M.D., 2007. Reservoir geomechanics. (First ed.). Cambridge: Cambridge University Press. https://doi.org/10.1017/CBO9780511586477