Evaluation of Formation Pressure in Low-Permeability Tight Silicilyte Reservoirs Using Hydraulic Fracturing Data: A Novel Method for the South Oman Salt Basin Reservoirs

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Extended abstract

The development of Pre-Cambrian South Oman's tight silicilyte reservoirs is challenging due to their low permeability, which is typically less than 0.1 mD, and their laminated texture, which results in extremely poor vertical permeability. Evaluating the formation pressure changes related to production in these reservoirs is equally challenging because of the difficulty of using logging tools for pressure measurements and the long build-up time required for static gradient surveys. This paper presents a novel method for evaluating formation pressure in tight formations based on fracture pressure and geomechanical properties.

To successfully evaluate formation pressure based on fracture pressure, several input parameters are necessary, including reliable closure pressure, initial fracture gradient, initial formation pressure, and depletion coefficient. Each input parameter must be calibrated and validated, with a particular focus on the fracture closure pressure (FCP) and initial fracture gradient, which are the most critical parameters. The Diagnostic Fracture Injection Test (DFIT) was used to estimate closure pressure in a few wells for several stages located at different depths. The current depleted formation pressure was back-calculated from the difference between the initial and current fracture gradient. Ranges for input parameters and output results were assessed due to the uncertainty in each parameter.

The authors observed significant variation in the formation pressure, which confirmed the poor vertical permeability and differential depletion across the reservoir. Crestal areas of the field were found to be more depleted than the flanks. The estimated formation pressure was compared to valid static gradient survey results, and it was confirmed that the current formation pressure is within the predicted range from the base to the high case. Additional data, such as drilling events, production data, and crossflow observed from production logging, were used as extra validation evidence. The authors concluded that the results are reliable and fit for purposes and could be used for formation pressure prediction in drilling and hydraulic fracturing operation planning, field development planning, and understanding of field pressure and production behavior.

This paper provides a novel and additive method for evaluating formation pressure indirectly as a byproduct of hydraulic fracturing activities, without additional cost and time in challenging environments where direct measurements are difficult. The approach is valuable for many other tight and unconventional reservoirs across different regions. The critical success factors of using the DFIT method to estimate closure pressure during hydraulic fracturing operations, including accurate data acquisition, proper test design, proper data analysis, accurate rock properties, and appropriate calibration, are highlighted. Overall, this novel method presents significant improvements to the prediction of formation

pressure for drilling and hydraulic fracturing operation planning, field development planning, and understanding of field pressure and production behavior for tight reservoirs.

Introduction:

The Athel Salicylate is a primary reservoir rock for two fields in South Oman, formed in an anaerobic, stratified water column within a rift basin (Fig 1). The rock is characterized by its complex composition, predominantly quartz (80-90%) with varying amounts of organic matter and clays and is extremely layered with porosity variations at a microscopic level.

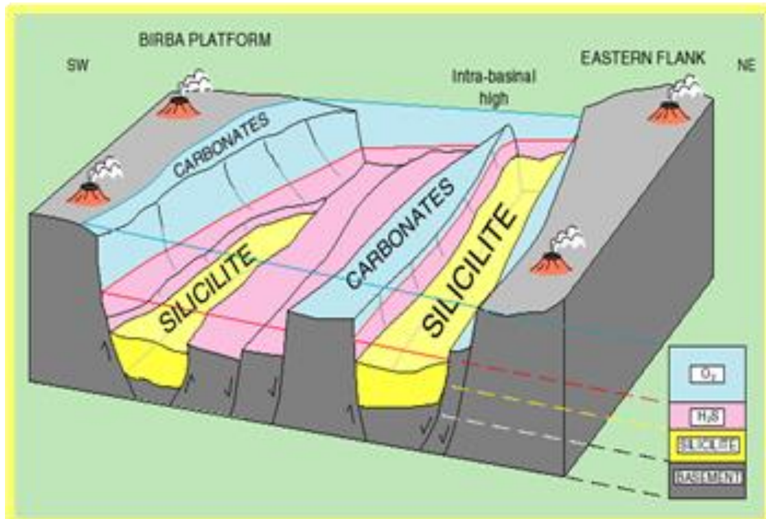

Figure 1: formed in an anaerobic, stratified water column within a rift basin

With average porosity at 20% and permeability as low as 0.07 mD, the Athel reservoir presents substantial challenges for pressure measurement, which is critical for field development and drilling planning. Traditional methods like XPT and MDT are ineffective due to the reservoir's tightness, leading to issues such as supercharging and prolonged pressure stabilization periods (Fig 2).

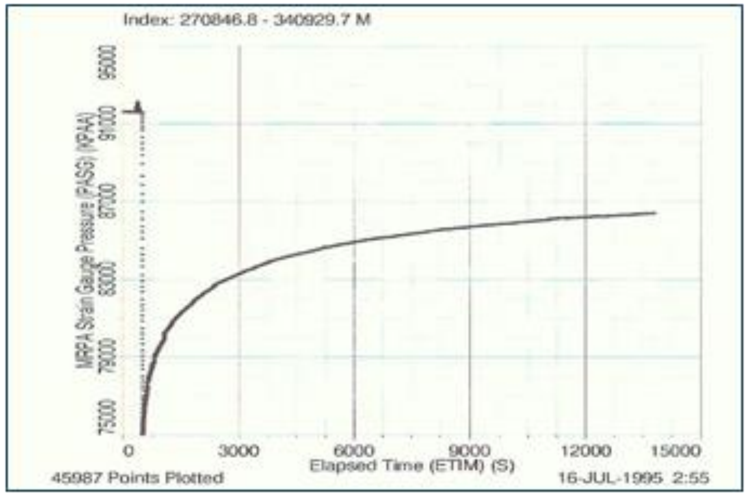

Figure 2: an example of Dual packer needed 3hr for stabilization

The inability to accurately measure formation pressure has significant implications for reservoir management. Understanding the current formation pressure is crucial for planning infill drilling and other interventions. Given the extensive hydraulic fracturing conducted across the wells, this study aims to develop a method to estimate formation pressure using the available fracture gradient data and other related parameters.

Methods:

The methodology developed in this study involves back-calculating the formation pressure from fracture pressure data. Key input parameters include reliable closure pressure, initial fracture gradient (obtained from LOT and FIT data), initial formation pressure (from PVT data), and a depletion coefficient. The depletion coefficient, which is crucial for this method, was derived from analogue data as there is no actual depletion coefficient available for the Athel reservoir. A theoretical value, based on carbonate stringers within the same region and stress regime, was used.

The study uses data from multiple sources, including LOT and FIT data points, and pressure measurements from hydraulic fracturing operations. Two primary data sets were utilized: LOT and FIT data (4 LOT, 4 FIT) and 33 data points from closure pressure, shut-in pressure, and breakdown pressure (Fig 3). These data points allowed for the determination of an initial fracture gradient, which served as the basis for the back-calculation of the current formation pressure.

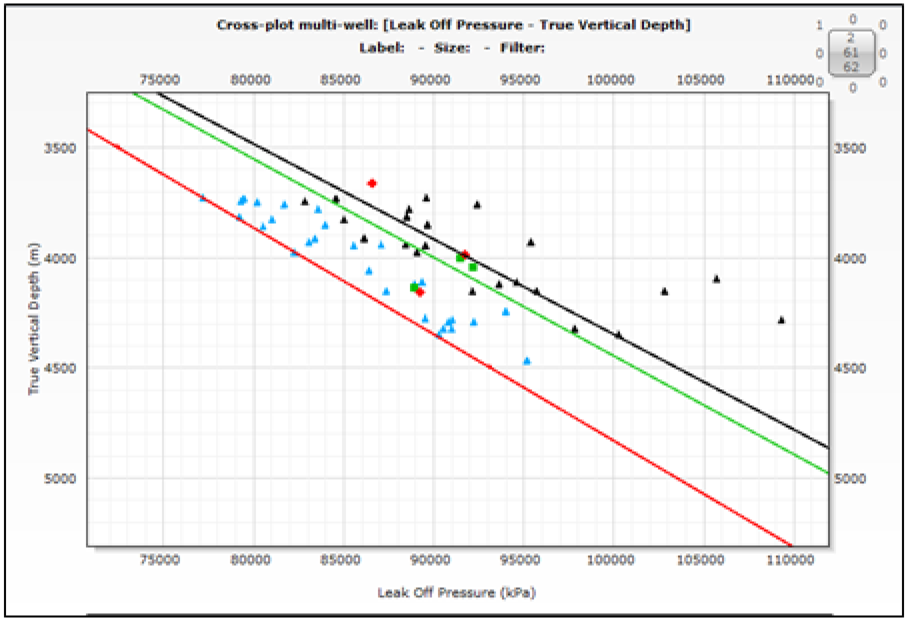

Figure 3: Red diamond – LOT, Green squares – FIT, Blue triangles – Frac closure pressure, Black triangles – Frac break down pressure

The equation used for calculating the current pore pressure incorporates the initial fracture gradient, the depletion coefficient, and the current fracture gradient derived from closure pressure. Three cases were considered: low, base, and high, with varying values for each parameter to account for uncertainties and provide a range of possible formation pressures. To estimate the current fracture gradient, the following equation is used:

$$FG_{\text{current}} = FG_{\text{initial}} - (\gamma_h \times (P_{\text{initial}} - P_{\text{current}}))$$

Where:
FG current = Current fracture gradient
FG initial = Initial fracture gradient (obtained from LOT & FIT data) γh= Depletion coefficient (derived from analogue data)
Pnitial = Initial formation pressure (from PVT data)
Pcurrent = Current formation pressure (unknown, to be calculated)

Results:
The developed methodology was applied to seven wells in the Athel Silicilyte reservoir. The estimated formation pressures were compared against valid static gradient survey results, and it was confirmed that the current formation pressures fall within the predicted range from the base to the high case. This alignment with field measurements demonstrates the robustness of the method and its applicability across the

reservoir. Three specific cases were analyzed—low, base, and high—corresponding to different values of the initial fracture gradient and depletion coefficient. The results showed good calibration with real reservoir pressure measurements (Fig4), confirming the method's accuracy.

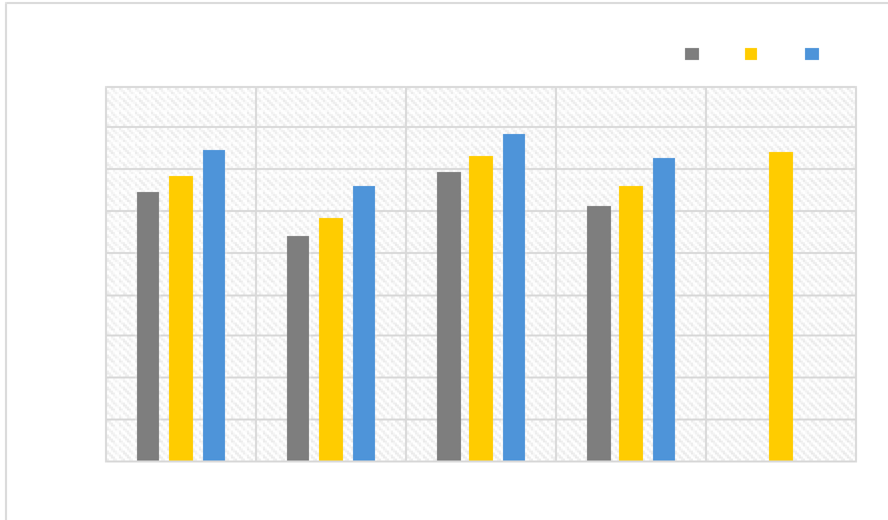

Figure 4: an example of estimated current reservoir pressure and compare it with Pintail

Also, notably, the findings revealed significant variations in formation pressure across the reservoir, suggesting poor vertical permeability and differential depletion, with crestal areas being more depleted than the flanks (Fig 5).

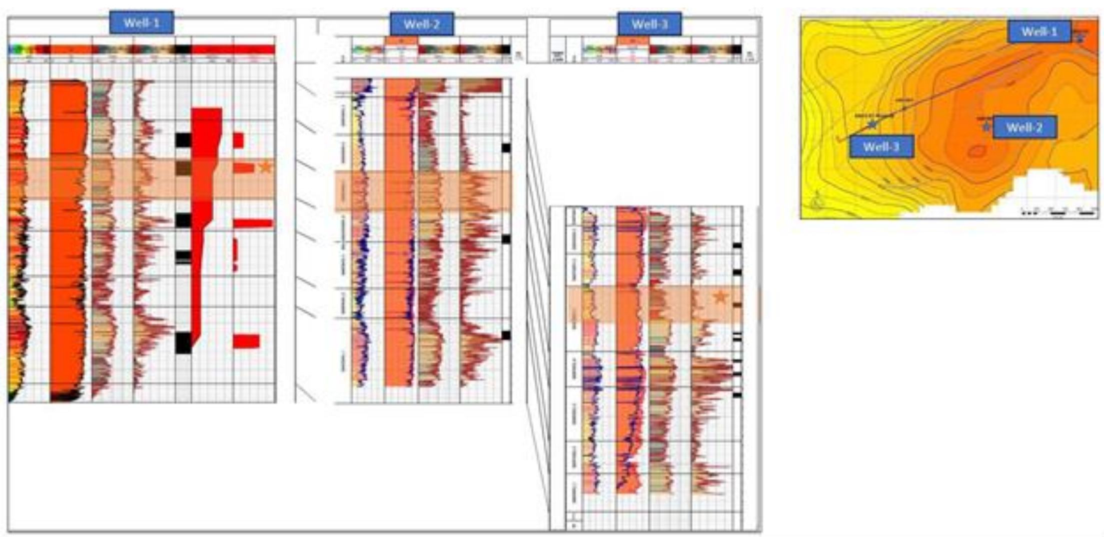

Figure 5: significant variations in formation pressure across the reservoir, suggesting poor vertical permeability and differential depletion, with crestal areas being more depleted than the flanks.

Conclusion & Recommendations:

This paper introduces an innovative and additional method for indirectly assessing formation pressure as a byproduct of hydraulic fracturing activities, eliminating the need for additional costs and time in challenging environments where direct measurements are difficult. This method is particularly useful for tight and unconventional reservoirs in various regions. Key success factors for using the DFIT method to estimate closure pressure during hydraulic fracturing include accurate data acquisition, appropriate test design, effective data analysis, accurate rock properties, and correct calibration. Overall, this new approach significantly enhances the prediction of formation pressure for planning drilling and hydraulic fracturing operations, field development, and understanding field pressure and production behavior in tight reservoirs. The authors assert that the results are dependable and suitable for formation pressure prediction in these contexts.

It is important to keep checking the back-calculated formation pressure against other pressure data sources like Surface Pressure Gauges (SPG) and Production Logging Tools (PLT). Additionally, it is recommended to update the depletion coefficient if new data becomes available, to ensure the assessment uses the most accurate and up to date information.

References:

Internal Report (FDP: Field Development Plan)