ENERGY GROUP

FRACTURE GRADIENT: FACT OR FICTION

25-26TH MARCH 2025

The Geological Society, Burlington House, Piccadilly, London

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An assessment of the magnitude of the minimum in situ total stress in rock formations is of major importance in various areas of petroleum engineering including wellbore stability and fracture geometry prediction in well stimulation applications. More recently, the Energy Transition requires full understanding of rock behaviour in terms of retention capacity.

It is clear the term "fracture gradient" means different things to different sub-surface disciplines, which may result from terminology not being standardised but also because different disciplines refer to alternative aspects of stress measurements in boreholes.

This workshop aims to bring the exploration, drilling, stimulation & development communities together, to establish what we know, how to standardise terminology, and how to establish the state of the art and best practice.

Topics to be included:

- Field/outcrop observations and fundamentals of rock mechanics
- Leak-off tests (LOT) and Extended Leak-off tests (XLOT)
- Alternative estimates of in-situ stress
- Ben Eaton Tribute - pore and fracture pressure algorithms
- Geology/lithology and other influences on fracture gradient
- Static vs dynamic data
- Depleted Reservoirs and Stress Paths
- Fracture gradient in tectonically active regimes
- Fracture gradient in deviated wells
- Remote methods to predict fracture pressure
- Applications of fracture gradient measurements

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Fracture Gradient – Fact or Fiction?
25-26 March 2025

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Final Programme

Day One	
08.30	**Registration**
08.50	**Welcome**
	Session One: Fracture Gradients: High-Level Observations
09.00	**KEYNOTE: Fundamentals of fracture gradient estimation: From exploration to field abandonment** Tony Addis
09.40	**Fracture pressure definition and application** Gareth Yardley
09:55	**Quantifying the Fracture Gradient from Leak-off pressure** Federica Ferrari
10.10	**Integrating physical models of borehole Leak-Off pressures** Matt Hauser
10:25 Virtual	**Fracture Gradients: How a 'Rule of Thumb' can lead to 40 years of Failure** Martin Rylance
10:40	***Discussion for 20 min***
11:00	**BREAK**
	Session Two: What do we see and Measure?
11.30 Virtual	**A repository of geomechanical data and fracture pressures for the North Sea** Juan Tovar
11.45	**Pick and Choose: Standardising Formation Pressure Integrity Test Interpretation** Roberto Peralta
12.00 Virtual	**Field measurement of fracture pressure in Extended Leak-Off test (XLOT)** Ira Ojala
12.15	***Discussion for 15 min***
12.30	**LUNCH**
	Session Three: What do we see and Measure? Cont.
13.30	**Leak-Off Tests vs In-situ Stresses in the East Irish Sea Basin** Tim Wynn
13.45	**Tensile strength - does it matter? Some Barents Sea cases** Thomas Birchall
14.00	**Fracture gradient exceeding overburden gradient in a complex stress state – A case study** Rajarajan Naidu
14:15	***Discussion for 15 min***
	Session Four: Alternative Estimates of In-Situ Stress

14:30	**Truths Hidden in Drilling Parameter Data, Relevance to Fracture Gradient, Loss-Events and the Following Discourse** Peter Momme
14:45	**Re-Examining Vertical Stress** Gary D Couples
15:00	***Discussion for 10 min***
15:10	**BREAK**
	Session Five: Operational Aspects of Fracture Pressure/Gradient
15:35	**KEYNOTE: Geomechanical aspects of fracture gradient modelling from 1D to 3D** Juliane Heiland
16:00	**Is wellbore breathing a true indicator of fracture gradient in HPHT wells?** Tommy Sheldrick
16:15	**Practical methods in defining Fracture Gradient in development fields** Emil Miraliyev
16:30	**The effect of mud additives on fracture gradient** Rajarajan Naidu
16:45	***Discussion for 15 mins***
17:00	**Discussion with Panel Q & A**
17:30	**Drinks reception**
18:30	**End of day one**

Day Two

08.30	**Registration**
09.00	**Review of Day One**
	Session Six: Static vs Dynamic Data
09.15	**Laboratory Investigation of Failure Criteria in Fractured Rocks in CO2 Storage Reservoirs** Rafael Mesquita
09:30	**Laboratory Research on the LOT and the XLOT tests** Aadnoy and Erik Karstad
09:45	***Discussion for 10 mins***
09:55	**BREAK WITH COFFEE (POSTER SESSION)**
	Session Seven: Reservoir Stress Path
10:45	**Pore pressure-minimum horizontal stress coupling estimation in Tunu Field, Lower Kutai Basin, Indonesia** Agus Ramhdan
11:00	**Discussion of uncertainty in fracture gradient stress path parameter and recovery factor in depleted and recharged reservoirs** Sam Green
11:15	**Predicting Reservoir Horizontal Stresses and Fracture Gradient in Depleted Reservoir** Eirik Kårstad
11:30 Virtual	**Learnings from Successful Drilling in Heavily Depleted HPHT Reservoir with Up to 460 Bar Depletion** Jamie Andrews & Trond Heggheim

11:45	Discussion for 15 mins
12:00	**KEYNOTE: What determines Shmin: Insights from 2300 stress measurements** Jorg Herwanger
12:30	**LUNCH**
	Session Eight: Fracture Gradient in Deviated Wells and Operational Aspects
13:15	**Navigating and Negotiating Fracture Gradient During Drilling and Cementing Operations** Alvin Chan
13:30	**Models of fracture gradient in boreholes in the presence of natural and induced fractures** Mahdi Heidari
13:45	**How the prediction of real fracture gradient saved a losses-prone sidetrack** Zhi Fang
14:00	**Interpretation and Inter-relationships of Extended Leak-Off Test Events: Applications in the Well Construction Process on the Norwegian Continental shelf** Devendra Kumar
14:15	***Discussion 15 mins***
	Session Nine: Prediction of Fracture Gradient Remotely
14.30	**Horizontal Stress Estimation during Subsurface Geomechanical Characterisation** Michael Anthony Addis
14:45	**Combining empirical modelling of fracture gradients with 2D and 3D modelling to reduce uncertainty in the planning and execution of wells.** Toby Harrold
15:00	***Discussion for 15 mins***
15:15	**BREAK**
	Session Ten: Applications of Fracture Gradient Measurements
15:50	**KEYNOTE: Interdependence of fracture stress with pore pressure - drilling windows, column heights and coupling?** Richard Swarbrick
16:15	**The application of the Matthews and Kelly (1967) stress ratio in the Barents Sea** Stephen O'Connor
16:30 Virtual	**Consonance of Surface and Subsurface Fracture Data in Vindhyan Basin, India, and Its Implications for Hydrocarbon Exploration** Dilip Kumar Srivastava
16:45	***Discussion for 15 mins***
17:00	***Discussion with Panel Q & A 20 mins***
17:30	**Closing remarks and end of conference**

Posters
Preliminary study into Mercia Mudrock mechanical stratigraphy and implications to fault structure Kathryn Page
A novel approach to enhance well design using minimum horizontal stress estimation by different methods, a case study from WDDM concession, Mediterranean Sea, Egypt Elsherbeny Akram

Fracture Modelling of Well Abandonment Edgar Castillo	
Re-Examining the Wellbore Stress Model and Responses to Internal Pressurisation Gary D Couples	

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ORAL ABSTRACTS
(In Programme Order)

Session One: Fracture Gradients: High-Level Observations

Fundamentals of fracture gradient estimation: From exploration to field abandonment

Tony Addis

The fracture gradient forms the basis of well design from exploration through development, re-development and abandonment. It also defines the pressures and limits required for the design of fracture stimulation, cuttings re-injection, produced water injection, hydrogen injection and storage and CO2 injection and sequestration.

The fracture gradient and its relationship to the in situ stresses is a primary aspect of the 1D Mechanical Earth Model (1D-MEM) used to characterise the subsurface stress and mechanical properties. These models and the estimation of the fracture gradient are used to calibrate 3D geomechanical models.

This overview discusses the industry standard methods for defining the fracture gradient along with the data used to define the fracture gradient profiles, for well design and fracture treatments, which include LOTs, XLOTs, DFITs and minifrac data. The dependence of the fracture gradient profile on the pore pressure and lithology-related mechanical properties are discussed along with the reliability of the underlying field data, the impact of production/injection related pore pressure and thermal changes on the fracture gradient profile.

The fracture gradients and data encountered in different basins, with different tectonic settings are presented, along with any associated stress data, to illustrate the variation of fracture gradient profiles. Industry best practices are discussed and areas of potential improvement for standard operations proposed based on the latest technologies.

Fracture pressure definition and application
Gareth Yardley

Fracture pressures are used in a variety of applications e.g. exploration seal assessment, drilling, water/gas injection, CO_2 storage, and abandonments. The concept of fracture pressure is straightforward: the pressure threshold for leakage through a fracture. However, the determination of fracture pressure is not unique and depends on: the size of zone (length of open hole in a well; reservoir top seal); bore hole shape; timescale; possible existence of natural fractures and uncertainty in input data. For seal integrity and abandonments, it is necessary to consider long timescales and the possible existence of closed fractures. In such cases, the minimum in situ stress may be the suitable “fracture pressure”. For drilling, short timescales are involved and typically a higher fracture pressure is used that incorporates aspects of rock strength, hoop stresses and the results of leak off tests (LOT). The risk profile and company rules of those involved also play a part. For example, fracture pressures may be defined based on the average LOT value in offset wells. This will result in leak off at or above the predicted fracture pressure only 50% of the time. It is also possible to define a lower fracture pressure that will result in an adequate formation integrity test being achieved 85% of the time. Either definition is acceptable as long as the consequences of the definition are recognised. The company rules for well design and contingency planning must be matched to the fracture pressure definition being used to maximise the chance that the well design and contingencies are adequate. The terminology used to describe what is meant by “fracture pressure” should be geomechanically well defined, appropriate for the application and widely communicated/understood.

Quantifying the Fracture Gradient from Leak-off pressure

Federica Ferrari

The correct quantification of the Fracture Gradient (FG) is crucial to optimize the mud weight, to maintain the wellbore integrity, and to safely and timely drill the phase ahead. In exploratory wells, at least two possible Fracture Gradient scenarios result from geopressure prediction to account for the uncertainty associated with the pre-drill estimate. Such uncertainty can be reduced while drilling with a careful analysis of Leak-Off Tests (LOT) and Extended Leak-Off Tests (X-LOT), which allow to calibrate the FG value at a given shoe depth.

Although the interpretation of LOTs should be a straightforward procedure, the raw LOT data acquired with the cementing unit during drilling operations are sometime noisy and, once plotted, they can differ from the standard graphs reported in bibliography. Consequently, the interpretation can be trickier than expected. Moreover, there are many factors that affect the Leak-Off Pressure, such as pump-rate, length of the exposed formation, fluid characteristics, occurrence of pre-existing cracks and so on.

In this study, many LOTs have been carefully analyzed in order to calibrate the Fracture Gradient and optimize the mud weight. The effect of different sampling frequencies on the plots and on interpreted Leak-Off Pressure values has been investigated. Although data have been collected in the same geo-structural setting, which is characterized by a consistent regional stress field, some wells show comparable LOTs values, whereas others deviate from the regional trend. For this reason, a further analysis has been carried out, aiming to understand the reasons of such variations.

Integrating physical models of borehole Leak-Off pressures

Matt Hauser

Observations from casing shoe tests and lost circulation events are key inputs to evaluate formation stress and strength for the planning of wells or of field management programs. Different approaches to interpret these data may be chosen depending on application requirements, with different levels of attention paid (or not) to the various physical processes involved in the events themselves. While fit-for-purpose analyses may yield the information needed for the work at hand, they can make communication between disciplines more difficult and may also limit our ability to understand departures from expected outcomes. This presentation describes a model which integrates fracture-reopening with both tensile and shear fracture creation mechanisms into a mixed-mode approach. This mixed-mode model matches a large global dataset of leak-off pressures quite well, with events clustering tightly around predicted initiation or re-opening pressures; it also provides some insight into the physical meaning of differences between some of the more common ways of looking at test results. The model extrapolates well and in tectonically relaxed areas it has proven to make good quality predictions for both vertical and deviated boreholes with little or no local calibration required. In complex stress regimes additional analyses may be required to construct the underlying stress model, but the mixed-mode approach still provides a useful tool with which to interpret variations in field data and use them to better evaluate and refine the stress model.

Fracture Gradients: How a 'Rule of Thumb' can lead to 40 years of Failure

Martin Rylance

The Sanga-Sanga Production Sharing Contract; was located onshore of the Mahakam delta, East Kalimantan, Indonesia. After the PSC had produced over 75% of the originally estimated hydrocarbon in place. The fields were very mature with the remaining resources locked up in the lower permeability reservoirs, where conventional hydraulic fracturing completion approaches had historically not been effective. A prize of several Tcf was readily achievable, if these lower permeability resources could successfully be developed by an appropriate recovery method.

The lower permeability formations are milli-Darcy but achieving an economic production rate has been problematic. Attempts at hydraulic fracturing, over almost four decades, had been spectacularly ineffective and rarely enjoyed any production improvement at all. Geologically the reservoirs are distributed river channels, in a lower delta plain environment and therefore the size of some of these individual sands can be very limited.

In late 2006 a very detailed review of the previous 35 Years of operations was performed, this review identified the hydraulic fracturing issues, related to regional tectonics, poro-elasticity and ultimately fracture gradient. The data was extremely convincing and a decision was made to implement a five well pilot in order to confirm the findings. This presentation will concentrate on describing the identification of those issues; and the implementation phase of the pilot.

Session Two: What do we see and Measure?

A repository of geomechanical data and fracture pressures for the North Sea

Juan Tovar

Determination of reservoir or formation's fracturing pressure is one of the most important task for well design, production operations and reservoir mechanical performance. Hydraulic fracturing, wellbore stability and sand production prediction are some of the most common tasks that require knowledge of fracturing pressures in the oil and gas industry. For water injection, geothermal and CCS applications knowledge of the fracture pressures required to induce or improve injection is even more important as the thermal effect takes place changing the near wellbore conditions and inducing changes in many rock properties. The use of fracture gradients as input parameters in geomechanical applications is a well established practice despite its inherent limitations. This work presents the use and application of static and dynamic data for the determination of fracturing pressures throughout the North Sea(Both, UKCS and Norway), this data is presented for different types of formations and from various sources. The data was captured from well drilling, completion and production/injection reports, laboratory tests of over 4000 wells, calibration took place with actual measured data from over 400 applications worldwide. For the purpose of this forum and the proposed discussion, data is presented in three (3) different formats: 1) raw data points (pressure versus depth). 2) Gradients for each and all rocks considered and 3) Continuous log-based fracture pressures compared with in-situ Sh. Applications of the data and comparison between both types is presented to promote discussion and debate so we the attendants can attempt to answer the question posed for the forum.

Pick and Choose: Standardising Formation Pressure Integrity Test Interpretation

Peralta Durango

Formation Pressure Integrity Tests are a key diagnostic test performed during drilling operations. They inform fracture gradient, minimum horizontal stress, wellbore stability, wellbore strengthening and provide constraints for forward drilling and completion parameters. Applications are dependent upon the type of test conducted and the different data obtained from them.
Tests are sensitive to numerous factors including pumping efficiency, formation properties, fluid properties and temperature variations – no two tests are identical and tests in different parts of the same formation can produce entirely different results. Therefore the test outcomes are ‘open to interpretation’ – two specialists may select entirely different ‘picks’ on the same tests, particularly where a test does not fit a standard form. This leaves us with significant uncertainty in our test results.
Bp have devised a novel method of test interpretation seeking to standardise the ‘pick’ process with a custom-built Tool. This method clears noise from the data and sets out stringent, data driven criteria for test interpretation and acceptance. This both simplifies and speeds up the interpretation process.
Here we demonstrate the use of this method to refine interpretations of several problematic tests.
This leads to clearer, more consistent results with fewer erroneous picks, giving a greater level of confidence in the bounds used for forward operations. This is significant for the reduction of loss incidents and better management of tight drilling windows.

Field measurement of fracture pressure in Extended Leak-Off test (XLOT)

Ira Ojala

Fracture mechanics or strength of materials approach can be utilized to make an estimate of the fracture pressure in rock. Both approaches have their limitations when they are applied to the initiation and growth of fractures in real rocks. For example, the strength of materials approach requires a perfectly circular hole and linear elastic material. Such conditions are not met at the field. Real rocks are not always linear elastic and drill holes in the field can assume other shapes than a perfect circle. We show examples of hydraulic fracturing measurements from the field. The extended leak-off measurements are analysed in terms of minimum horizontal stress, fracture pressure and the tensile strength of the rock. The fracture pressure is lower than what is predicted by the Kirsch equation. We suggest reasons why the field measurements can provide different fracture pressure estimates than simple theoretical predictions.

Session Three: What do we see and Measure? Cont.

Leak-Off Tests vs In-situ Stresses in the East Irish Sea Basin

Tim Wynn

The East Irish Sea Basin (EISB) contains a number of Triassic Sandstone oil and gas fields overlain by the Mercia Mudstone Group (MMG) comprised of mudstones and halites. Virtually all leak-off tests (LOTs) and formation integrity tests (FITs) taken within the MMG of the EISB display extremely high values that are well in excess of the calculated overburden stress. Significant uplift of the basin during the Cretaceous and Cenozoic has brought relatively lithified rocks closer to surface. This increased compaction may have caused the MMG mudstones to be significantly stronger than expected at the typical depths that the MMG is encountered by development wells (100 to 1000m). This increased strength coupled with high stresses linked to the interbedded halites may result in most of the rock sequence being intact with few weaknesses to be exploited by the tests. This means that the LOTs and FITs are more likely to be representative of the Fracture Breakdown Pressure (FBP) that is significantly affected by the rock tensile strength and near wellbore stress concentrations than the in-situ minimum principal stress (S3). Simple calculations using this assumption indicate that S3 is likely to be significantly lower than the LOT and FIT data if they are close to FBPs. This has implications for any planned operations in the basin such as drilling, stimulations, hydrocarbon production and Carbon Capture and Storage.

Tensile strength - does it matter? Some Barents Sea cases

Thomas Birchall

Geological uplift in the Barents Sea significantly impacts the mechanical properties of rock formations. Uplift leads to overcompacted rock formations at shallow depths, resulting in a higher proportion of the overall formation integrity being due to tensile strength. Consequently, defining the fracture gradient in the Barents Sea is complicated. This study illustrates the impact of uplift on several key factors and how they are implemented fracture gradient in well construction projects.

In Norway, Extended Leak-off tests (XLOTs) are routine. In the Barents Sea there is a clear link between uplift and elevated contrasts between formation breakdown pressures (FBP) and fracture closure pressures (FCP). However, uplift also does not simply freeze the rock properties either: elasticity plays an important role.

The appropriate definition of a fracture gradient is paramount for drilling in areas like the Barents Sea. To determine the appropriate fracture gradient formula, we highlight the importance of understanding the mechanical properties of rocks in uplifted areas and in how a fracture gradient may be used for very different well planning activities. The high contrast between FBP and FCP can lead to inaccuracies in such areas and careful XLOT interpretation and planning is required.

Fracture gradient exceeding overburden gradient in a complex stress state – A case study

Rajarajan Naidu

Fracture gradient is an important input for well planning (wellbore stability, casing design, mud design), drilling decisions (mud weight management, drilling parameters, mud properties) and improving production (completion fluid design, well stimulation). One of the recent wells drilled in Caspian sea in an area where the stress state is complex due to a combination of reverse and strike-slip fault illustrates the challenges associated with the application of conventional guidelines for constructing wells. In such scenarios, understanding the evolution of stress state plays a key role where geological correlations between wells in the region alone can be misleading. Accurate modeling of stresses in such complex areas can be achieved using modern numerical tools and methods but a systematic approach to defining and calibrating fracture gradient is also important.

This paper provides the background of the pre-drill planning, data acquired while drilling, real-time observations, drilling problems encountered, analysis of data related to in-situ stress state, data from hydraulic fracturing and lessons learned for a well drilled in Caspian Sea. The limitations of using conventional guidelines for well planning is explained with details. Best practices for acquiring data and calibrating fracture gradient models are discussed. Also, the reasons why “loss gradient” is more important than “fracture gradient” in the regional context is discussed. Practical aspects of the impact of fracture gradient for successful delivery of wells are described.

Session Four: Alternative Estimates of In-Situ Stress

Re-Examining Vertical Stress

Gary D Couples

Current practice asserts that vertical stress is determined as the integral, from zero to the height of the overlying rock column h, of the rock density rho(z), multiplied by gravitational attraction g. In a constant-density case, this reads as: vert-stress = rho.g.h. The dimensions (ML^-3)(LT^-2)(L) are equivalent to force/area, OR to energy/volume. Which is correct? The form of the classic expression is similar to the way that gravitational potential energy is expressed. But, the potential energy differs by a factor of two because the potential energy is based on the centre of mass, which is halfway up the column. Relating potential energy, to elastic energy-density within the rock, involves considering a small increment of additional column thickness, delta-h, and calculating what work this performs on the unit of rock at the base of the column, as well as on every overlying unit of rock. In a constant-density case, the work performed in straining each unit of rock leads to the ‘missing’ term h/2. Translating the vertical strain to stress involves the rock modulus, as well as consideration of the lateral strain constraints, with changes in horizontal stress components, and thus additional work terms in the balance expression. When fully formed, it is clear that vert-stress is NOT correctly calculated by the classic formula. Applying these results to a heterogeneous-density rock column, the profile of vertical stress does not show a monotonic increase with depth, although the physics is correct, and restores the role of material properties.

Session Five: Operational Aspects of Fracture Pressure/Gradient

KEYNOTE: Geomechanical aspects of fracture gradient modelling from 1D to 3D

Juliane Heiland, Ivan Diaz Granados (SLB)

Many geomechanical models predict the stress field in the earth using physics-based approximations that account for gravitational and tectonic loading. In 1D models this is done by applying strain terms in a poro-elastic horizontal stress equation. In 3D models a numerical simulator is used to calculate stress in each grid cell and equilibrate stress across the whole model. The numerical simulation is following the same physics of loading the model vertically by accounting for gravity and applying boundary conditions horizontally that account for tectonic stress. Both 1D and 3D stress models have been used successfully for many decades but can be cumbersome to manually calibrate to stress measurements and observations.

Stress measurements are generally only available for minimum horizontal stress, thus making it difficult to calibrate maximum horizontal stress. Wellbore failure observations such as breakouts and drilling induced fractures, breakout width, breakdown pressure and closure pressure on the other hand contain information on both minimum and maximum horizontal stress magnitude (as well as vertical stress when measured in deviated wellbores), if the stress model is combined with a wellbore stability model. By implementing an inversion workflow for wellbore models that can predict all pairs of tectonic strain parameters in a poro-elastic horizontal stress model that fit each stress measurement and stress observation, it is possible to create a heat map of tectonic strain parameters that explains stress observations across an area and create a calibrated poro-elastic horizontal stress model without the need for manual manipulation of the tectonic boundary conditions. The strain terms from the 1D stress model can then become an input for numerical stress simulations to generate an equilibrated stress field for a 3D geomechanics model.

We will present a workflow to simultaneously invert stress measurements and failure observations in wellbores to derive tectonic strain parameters for a poro-elastic horizontal stress model and discuss how this approach is linked to 3D numerical modelling including the application of thermo-hydro-mechanical coupling models for reservoir management or CCUS.

Is wellbore breathing a true indicator of fracture gradient in HPHT wells?

Tommy Sheldrick

"Gas responses due to wellbore breathing are usually considered warning signs, signaling the upper end of the available drilling window (= fracture gradient FG). However, in HPHT settings, the elevated fluid pressure and its effect on hoop stresses could masquerade as breathing events, possibly leading to an inaccurate real-time assessment of the fracture gradient and unnecessary interventions.

Data from a recently released HPHT well in the CNS indicate the importance of considering that wellbore breathing and minor losses may occur at values significantly below the expected low case fracture gradient. The real-time data from this well show early indications of wellbore breathing in the reservoir hole section. However, the well never suffered from significant fluid losses, even when being exposed to much higher downhole pressures during subsequent shut in events (~0.5ppg increase).

We explore the data from this well to investigate if this is indeed well bore breathing using the Wetness/Balance ratios of the Pump Off Gas vs Drilled Gas & drilling data e.g. ECD relationship with gas magnitude. We compare with an early exploration well which drilled equivalent sections with significantly lower ECDs and recorded lower gas levels.

By analysing SWC/Image Log information, with expected fracture gradient & regional knowledge of Shmin/SHMax magnitudes and orientations, we attempt to ascertain is this representative of the impact of hoop stress effects, an inaccurate appraisal of fracture gradient or something else?

Practical methods in defining Fracture Gradient in development fields

Emil Miraliyev

"The concept of Fracture Gradient (FG) has critical importance in operations, as it defines the upper bound of the Drilling Window. Beyond this, FG is also integral to applications including depletion and injection limit planning and fracture stimulation programs. Although it is linked with the minimum horizontal stress (Shmin), FG is a broad term with variable interpretations depending on context and application. For the purposes of drilling window designation, FG typically refers to the Fracture Initiation Pressure, in other scenarios, Formation Breakdown Pressure or Fracture Closure Pressure may also be described as FG.
This article presents a strategic approach to address the data acquisition around FG, starting at the early stage of field development and taking a holistic view of the set of potential areas of FG usage. These include, but not limited to drilling window in the overburden, depleted drilling limits in the reservoir, completion pressure limits, zonal isolation/well integrity, RDOL (Reservoir Design and Operating Limits), stimulation fracturing.
For various FG-defining parameters (stress data, rock properties – aPR, SPP etc.) potential methods of data acquisition in different lithologies are discussed along with their advantages, limitations and uncertainties. Techniques to assess the risk and VoI are presented and a general approach for data acquisition is proposed based on BP's extensive experience across various fields.
No confidential BP data is presented in the article, and it is intended to illustrate implications of some geomechanical concepts through practical application overview.

The effect of mud additives on fracture gradient

Rajarajan Naidu

Fracture gradient is an important data for a decision to drill ahead after setting a casing or liner. Often the aim is to target as high a value as possible (LOT/XLOT) or required (FIT) and inherent bias of operational team is to prove the shoe is competent especially when previous cementing operations were not perfect. Remedial cement jobs are often ineffective and time-consuming so alternative ways of achieving a high enough fracture pressure is desirable. Adding mud additives are believed to increase fracture gradient as popularized by StresscageTM and other approaches by various operators/service providers. While adding mud additives during drilling for controlling mud losses and examples where it helped to drill with ECD higher than fracture pressure of offset wells are published, detailed analysis of field tests on their effect on fracture gradient measured at shoe is limited. In this paper, 18 shoe tests were analyzed to understand the effect of “Shoe strengthening pills” on fracture gradient. The analysis shows majority of them showed marginally higher values compered with fracture gradient estimated from regional well data. Remedial squeeze treatments had to be performed to increase fracture gradient in these wells. However there were few cases where the use of these mud additives did not help. The impact of nano particles is analyzed. Interpretation of in-situ stress from these tests and the impact of mud additives on results is analyzed. Lessons learned from these tests and best practices are described in this paper.

Session Six: Static vs Dynamic Data

Laboratory Investigation of Failure Criteria in Fractured Rocks in CO_2 Storage Reservoirs

Rafael Mesquita

The Mohr-Coulomb failure criterion is widely employed to model shear slip reactivation along pre-existing fractures in geological formations. Traditionally, these models assume zero cohesion to represent the weakened state of faulted rock masses. However, precise adjustments to cohesion (co) and the coefficient of friction (μ) are often neglected, largely due to limited laboratory data. While experimental studies have investigated fault slip under various shear setups, most experiments focus on granite or sandstone with artificially saw-cut faults, leaving a gap in understanding naturally fractured rocks in diverse geological contexts.
To overcome this issue, this research addresses the failure criteria of fractured rocks commonly found in subsurface geoenergy systems, including sandstones, mudrocks or carbonates. Using triaxial laboratory experiments, we initially examined sandstone samples to study fracture formation and reactivation processes, integrating acoustic emission monitoring during testing. Post-experiment analysis of fractures was conducted using micro-CT scanning.
Preliminary findings suggest that cohesion in fractured rocks is not always zero and, may in some cases, even exceed that of intact rock. Additionally, distinctions between internal and sliding friction coefficients were observed. Porosity differences were also found to significantly influence the deformation behaviour and mechanical properties of samples from the Sherwood Sandstone Group in the UK. These insights contribute to refining failure criteria for fractured rocks, enhancing the predictive accuracy of models used in carbon storage and other geoenergy applications.

Laboratory Research on the LOT and the XLOT tests

Aadnoy and Erik Karstad

"The Fracturing Laboratory at the University of Stavanger was established 30 years ago, initially based on a 10 000 psi pressure cell testing concrete cores, but as it was found that the mud was critical and therefore specific mud testing cells were built.
It was observed that the Kirsch equation underpredicts the fracturing pressure, but using pure water with no filtrate control, the Kirsch works well. An elasto-plastic model was developed for drilling muds. The fracturing processes is here split into several stages like frac initiation, propagation and eventually mud cake collapse. It was found that filtercake particle strength was important.
Many different drilling fluids were tested and it was observed that they showed different fracturing pressures. Water-based and oil-based drilling fluids also behaved different. Experiments with initial fracturing and refracturing mimics the LOT-XLOT. Spread in XLOT pressures were allocated to mud cake properties.
A critical well in the North Sea was drilled using mud tests at the Frac Lab. At the U. of Stavanger. Twice a week used mud was brought onshore and tested at the lab., returning mud modifications for the offshore operation. The LOT tests obtained in this well are the highest ever reported in the North Sea. A review of this operation will be given.
The presentation will review some experimental results, in particular that the LOT and the XLOT level depends on the specific mud used. We will also propose new mud measurements to be added to develop “designer muds” in the future.

Session Seven: Reservoir Stress Path

Pore pressure-minimum horizontal stress coupling estimation in Tunu Field, Lower Kutai Basin, Indonesia

Agus Ramhdan

Quantifying the change of minimum horizontal stress (Shmin) in response to pore pressure is vital, particularly at the development stage of a hydrocarbon field. However, estimates of the coupling ratio between these parameters, either at basin or reservoir scales, are not well defined in Indonesia's sedimentary basin, such as Lower Kutai Basin. This study investigates the coupling ratio between Shmin and pore pressure in one of the gas fields within the basin, Tunu Field, using available evidence from an extensive data set of direct pressure measurement, leak-off test, extended LOT, Mini-Frac, and lost circulation. Previous studies have reported overpressured and depleted reservoirs. Nevertheless, the evolution of Shmin due to the change in pore pressure has yet to be well established. This study reveals a Shmin and vertical stress ratio of 0.87 which may relate to the stiffening of the shales via clay diagenesis/cementation. Coupling ratios between Shmin and pore pressure are 0.3 for the overpressured zone at the basin scale and 0.42 for the depletion at the reservoir scale. The approach used has been shown to produce similar coupling ratio (or stress path) results to other basins globally, thus providing a useful estimate of the Shmin and pore pressure relationship for the Tunu Field, and potentially other fields in the Lower Kutai Basin. For the application to infill drillings within the field, this study indicates Shmin decreases in response to pore pressure depletion due to production, ranging from 1.7 to 2.3 ppg within the hydrostatic zone and from 2.5 to 3.7 within the overpressured zone, equivalent to a Pore Pressure (PP)-Shmin window decrease of approximately 28% to 37% and approximately 40% to 88%, respectively. In addition, strike-slip faulting is suggested as the likely in situ stress regime in the Tunu Field.

Discussion of uncertainty in fracture gradient stress path parameter and recovery factor in depleted and recharged reservoirs

Sam Green

"Operators are increasingly targeting resources via infill drilling towards the late stage of a field’s lifetime. One challenge to drilling is encountering depleted reservoirs and/or recharged reservoirs. Depletion of the pore pressure (PP) reduces the fracture gradient (FG) and recharge will result in an increase in the depleted FG calculated via the stress path parameter (SPP) and the recovery factor (RF) respectively using the equation below.

Depleted FG = Virgin FG – (SPP * Depletion) + ((SPP * RF) * Recharge)

Magnitude of the FG has a direct impact on the mudweight (MW) window as depletion may reduce the FG below the required MW (e.g., manage wellbore stability), requiring incorporation of wellbore strengthening material to mitigate against losses, therefore, SPP and RF values are needed to calculate the FG accurately.

The SPP and RF values can be calculated if the PP and FG have been measured in both the virgin and depleted/recharged reservoirs. Whilst it is common to measure the PP, it is rare to measure the FG in the reservoir, so the SPP and RF often remain unknown. Therefore, the SPP and RF are often based on regional knowledge, practitioner experience or simply generic values which reduces the confidence in the resultant FG values. This paper aims to illustrate what the scale of the uncertainty range in SPP and RF could be and recommends that communication of risk and uncertainty relating to the MW window are the focus of discussion with the drilling and fluids teams.

Predicting Reservoir Horizontal Stresses and Fracture Gradient in Depleted Reservoir

Eirik Kårstad

"In situ stresses consist of vertical, maximum and minimum horizontal stresses and they are essential for subsurface engineering planning. For example, in depleted reservoirs, a reduction in both pore pressure and horizontal stresses will have a significant impact on wellbore stability with an increasing risk of mud losses with increasing depletion.

The key to determining the stress state is the collection of calibration points. In this case, we have high-quality XLOT tests from the overburden shale, while in the reservoir the only calibration available is from mud loss events.

In this presentation, we focus on predicting the horizontal stresses and fracture gradient in depleted sandstone reservoirs. The method combines the determination of horizontal stresses from poroelastic strain and compaction models that are calibrated against mud loss events. The main challenge is to establish a valid set of boundary conditions for the predictions. For example, the fracture gradient is highly sensitive to the drilling fluid properties and the effect on fracture resistance. Another critical factor is that theoretical derivations often assume simple boundary conditions that are often not valid in a real reservoir.

This case study will show how adapting real boundary conditions can improve the interpretation and understanding of theoretical derivations and how they can be used to explain and predict real mud loss incidents. It will also be demonstrated how this is critical for predicting the maximum depletion that can be allowed before wells become un-drillable due to a too-narrow MW window."

Learnings from Successful Drilling in Heavily Depleted HPHT Reservoir with Up to 460 Bar Depletion

Jamie Andrews & Trond Heggheim

Gudrun is a high-pressure, high-temperature (HPHT) field on the Norwegian Continental Shelf which has been in production since 2014. The initial development called for predrilling of the producers prior to commencement of production through depletion drive. In 2020 a second drilling campaign was initiated where the goal was to drill several infill producers and two water injection wells. The issue of drilling in heavily depleted reservoirs was highlighted as a major risk since depletion in some of the layers was expected to be in excess of 450 bar. The operational window was small and uncertain, and several risks were anticipated. Differential depletion in this highly layered reservoir, with the potential for penetrating both heavily depleted layers and non-depleted layers, meant that drilling and completion operations required wellbore pressures in excess of the minimum stress in the heavily depleted layers. There was thus a significant risk for lost circulation and escalation to possible well kick/underground blowout events. To mitigate these risks several actions were taken including Managed pressure drilling (MPD), splitting reservoir drilling into several sections, drilling of near vertical reservoir intervals and the use of active Wellbore Strengthening (WBS)/ Lost Circulation Material (LCM) particles in the mud. The use of optimal background WBS particles was complicated in the first two wells due to risk of plugging of lower completions upon production and so compromises were required to the particle sizes that could be used. This paper summarizes the experience from the successful drilling of these infill wells. It confirms that the use of WBS particles is critical in providing a robust drilling window against losses when the Fracture Gradient (FG) is reliant on near wellbore processes and elevated hoop stress around the wellbore to support downhole pressures that exceed minimum stress deeper in the "body" of the depleted layers. The experience on Gudrun also suggests that the FG is sensitive to the temperature of the mud when drilling the stiff Gudrun layers. The influence of depletion on the minimum horizontal stress, as determined from this drilling campaign, is also discussed and this is related to rock mechanical tests performed on core plugs from the field.

KEYNOTE: What determines Shmin: Insights from 2300 stress measurements

Jorg Herwanger

"We use more than 2300 stress measurements (from ISIP or FCP) together with ancillary geological and geophysical data to investigate the potential variations in Shmin-gradient by:
+ Variations in overburden
+ Pore pressure (i.e., PPFG or pore pressure - fracture gradient coupling, with some new datasets)
+ Lithology and elastic properties
+ Tectonic setting (comparison between passive continental margins, active continental margins, intra-continental basins and forearc basins)
Using this dataset, we can bracket the magnitude of Shmin variations from the range of sources above.

Session Eight: Fracture Gradient in Deviated Wells and Operational Aspects

Navigating and Negotiating Fracture Gradient During Drilling and Cementing Operations

Alvin Chan

Fracture gradients (FG) have been a challenge for the oil and gas industry during drilling and cementing operations for over 30 years. Yet, year after year, problems related to lost circulation, borehole instability (low mud weight due a low fracture gradient), and losses during drilling and cementing operations lead to significant non-productive time (NPT), and remedial work continues to rank as some of the top NPT events that companies face. In this paper, we will (1) present our integrated Fracture Gradient framework that demonstrate how the lost circulation threshold should be estimated based on both subsurface and engineering evaluations; and (2) present actual examples from both onshore and offshore operations that have successfully executed various strengthening programs highlighting how the impacts of drilling fluids and operational procedures can change this lost circulation threshold. Since incorporating our negotiated FG approach a decade ago, we have successfully delivered wells drilled in narrow margins from depleted reservoirs as well as within highly faulted (or fractured) formations globally. Through our global studies and operational experience, we aim to showcase our strategy on how to navigate complex drilling issues due to narrow margins and recover from a low lost circulation threshold.

Models of fracture gradient in boreholes in the presence of natural and induced fractures

Mahdi Heidari

We define the fracture gradient as the borehole mudweight at which a fracture opens both at the borehole wall and far from the borehole. We consider loss through natural and induced fractures by tensile (Mode-I) and shear (Mode-II) opening of the fractures. We derive analytical solutions for the fracture gradient for each mechanism for a vertical borehole in geologic settings where the maximum principal stress is vertical and. For each fracture type and opening mode, we calculate the mudweight to open the fracture at the borehole wall, where stresses are controlled by borehole-induced stresses, and the mudweight to open the fracture far from the borehole (far-field), where stresses are controlled by in-situ stresses. The fracture gradient is the maximum of these two values. Induced fractures (both tensile and shear) form at the maximum horizontal stress azimuth, where the tangential stress is the least around the borehole. In contrast, natural fractures may exist at any orientation (azimuth and dip angle), and the fracture gradient for these fractures varies with the fracture orientation. We apply our solutions to a case-study borehole running through a fault in the Gulf of Mexico and show that circulation loss would occur through shear opening of the fault at a fracture gradient lower than the least principal stress gradient. Our study illuminates that circulation loss in boreholes could occur under a different mechanism and fracture gradient from the commonly assumed, induced tensile fractures.

How the prediction of real fracture gradient saved a losses-prone sidetrack

Zhi Fang

"The recent drilling campaigns of an oil & gas operator encountered several cases of severe lost circulations resulted in losing the hole sections while drilling through the depleted intervals. A review of the losses events indicated that the lost circulations were wellbore trajectory dependent, except dependent on the stresses, formation pressure and rock mechanical properties. Among the methods of predicting the fracture gradient (FG) (Hubbert and Willis', Matthews and Kelly's, and Eton's etc), no one effectively captured the effects of well trajectories on the FG, and eventurally the prevention of the drilling losses remained a major issue to combat.

An integrated geomechanical approach was developed to predict the real FG of wellbores subject to various trajectories. The approach deployed the Kirsch equations with integrating the elaborated individual procedures for deriving the geomechanical input parameters from regional field data to form a FG model. The calibrated FG model was applied to than 30 new wells and significantly mitigated the drilling losses for those challenging wells penetrating heavily depleted reservoirs. In another drilling campaign, it saved the sidetrack of a lost hole section by revising the initially proposed trajectory as instructed by the real FG prediction.

The integrated geomechanical approach is now being applied to the wellbore stability analysis of the planned wells for redeveloping a depleted southern North Sea field.

How the challenging sidetrack was saved by predicting the real FG is to be presented for knowledge sharing at the workshop.

Interpretation and Inter-relationships of Extended Leak-Off Test Events: Applications in the Well Construction Process on the Norwegian Continental shelf

Devendra Kumar

"The Extended Leak-Off Test (XLOT) is conducted to gain a deeper understanding of downhole stress conditions and formation mechanical properties. Unlike standard tests, the XLOT is typically performed when detailed knowledge of the in-situ stress state is required, such as prior to a fracturing treatment or in scenarios demanding precise geomechanical insights. By deliberately inducing and monitoring fractures in the formation, the XLOT provides valuable data on stress magnitudes, formation integrity, and fracture behavior, making it an essential tool for optimizing well construction and reservoir management.

XLOT data available in public domain have been analyzed to assess the relationship between the various XLOT outputs. The results offer a data-driven approach to enhancing well design, drilling efficiency, and an optimized reservoir management.

LOP versus FPP: Understanding this relationship helps in predicting fracture initiation thresholds and the energy required for fracture growth during well construction or stimulation.

LOP versus FCP: This relationship is crucial for determining the lower limit of the formation integrity in well construction process.

FPP vs. FCP: This relationship aids in evaluating fracture mechanics, stress anisotropy, and reservoir permeability, which are critical for geomechanical modeling and well stimulation.

These relationships are interlinked through the mechanical properties of the formation, the in-situ stress regime, borehole and fracture geometry and the fluid-rock interaction during the XLOT. Analyzing these interdependencies provides a comprehensive understanding of the formation's stress behavior, enabling improved well planning, stability analysis, and hydraulic fracturing design.

Session Nine: Faults, Fractures and Fluids

Horizontal Stress Estimation during Subsurface Geomechanical Characterisation

Michael Anthony Addis

Geomechanical engineering involves comparing the present-day stress system acting at depth with the strength and material behaviour for different lithologies and geometries, ranging from perforations, wellbores to field-wide scales, and for different time scales from drilling (days) to production (years) to long term storage and injection (e.g. CCS) which will require integrity over decades or centuries.

The horizontal stress magnitude is one component of the subsurface 3D stress tensor and a basic component of fracture gradient profile in different lithologies.

This paper reviews the development of horizontal stress models used in subsurface developments. It addresses key aspects of how these models are used to construct 1D horizontal stress profiles, and include:

- Identifying the controls for horizontal stress magnitudes, and the calibration of the models to field data,
- Whether active faulting control stress magnitudes within fault blocks?
- How horizontal stress magnitudes change with depth, on the scale of centimetres, metres, or 10s of metres?

The focus of this paper is on the type of boundaries that control horizontal stress magnitudes in different geological environments; stress-based, ‘poroelastic’or passive basin. Using field data, the controlling boundaries are assessed using a new analytical method which is applied to field data sets in different geological settings and with different geological histories. The data analysis indicates that either stress or strain boundary conditions can control horizontal stress magnitudes, the selection of which can significantly affect the estimated horizontal stress profiles, and that these controls vary according to the basins and geological settings.

Combining empirical modelling of fracture gradients with 2D and 3D modelling to reduce uncertainty in the planning and execution of wells.

Toby Harrold

When planning and executing wells, many studies estimate a fracture gradient profile using empirical relationships derived from offset well analysis where measurements of fracture gradient are available. A standard approach is to calculate effective stress ratios from Leak Off Test (LOT) values in offset wells as described in Matthews and Kelly (1967). A profile of effective stress ratio can be built and then combined with the pore pressure and vertical stress estimates at the proposed well location to derive a fracture gradient profile. While this approach can be effective where there is good geological continuity between the offset and proposed well locations, it is often inaccurate when there are variations in minimum stress that are controlled by salt or thrust tectonics. In such situations, modeling of stress variations using 2D or 3D finite element models can be performed and has been shown to significantly reduce uncertainty in the fracture gradient around salt bodies and in compressional tectonic settings. This presentation will discuss examples of how different types of finite element modeling (2D, 3D, static and evolutionary) have been used to improve the accuracy of fracture gradient prediction in settings where simple empirical approaches were shown not to work. The presentation will also discuss the benefits and drawbacks of the different approaches taken and learnings that can assist with future pore pressure and fracture gradient studies.

Session Ten: Applications of Fracture Gradient Measurements

Keynote: Interdependence of fracture stress and pore pressure - drilling windows, column heights and coupling?

Richard Swarbrick

Compilation of LOT data to estimate fracture pressure/gradient shows variability at all scales and depths. Even well constrained regional data show 70 bar (1000 psi) variation typically at depths greater than 1000 m. One explanation for some or most of this variability is found in the notion of pore pressure-fracture pressure "coupling".   This contribution to the conference will look at our current understanding of how pore pressure and fracture pressure are dependent on each other and what we know about pore pressure-fracture pressure "coupling".   Poroelasticity as the explanation of coupling will be re-examined. Local (field specific) and regional data will be compared and explanations reviewed, both for increase in fracture pressure with increase in overpressure during basin evolution, and corresponding reduction in fracture pressure with reservoir depletion. What do the data show about the magnitude of coupling?   How are coupling values determined and applied?
Fracture pressure is also a key input into pre-drill hydrocarbon column height estimation/prediction, and features in the determination of CO_2 injection storage volumes linked to column height and seal capacity.   Uncertainty of fracture pressure at the crest of a structure or fault defining a trap will be examined in the context of column height prediction for a range of subsurface fluids. I will conclude by suggesting that the current methodology for hydrocarbon and/or CO_2 column height estimation requires a major re-think.

The application of the Matthews and Kelly (1967) stress ratio in the Barents Sea

Stephen O'Connor

Due to its complex geological history, including multi-phase uplift (and mixed lithologies), it is problematic to determine a predictive model of fracture pressure for the Barents Sea. Matthews and Kelly (1967) is arguably one of the most used algorithms to determine fracture pressure (gradient) globally. This relationship has the form:

$F = P/D + Ki\ \alpha / D$

Where, P = formation fluid pressure, psi, D = Depth, feet, α = matrix stress, psi, Ki = matrix stress coefficient and F = fracture gradient, psi/ft.

We "simplify" this to:

$F = P + Ki*VES$

Where Ki = horizontal effective stress / vertical effective stress

Matthews & Kelly produced depth trends for Louisiana Gulf Coast and South Texas where Ki increases and approaches a value of 1.0 at depths of 20,000 feet and is implicitly referenced to seabed.

This paper presents some of the results from analysis of LOT's etc from131 wells in the Barents Sea where stress ratio has been calculated for the shales above the Middle Jurassic Stø reservoir e.g. Fuglen, Hekkingen. Knurr, Kjole and Kolmule formations.

This analysis shows that (a) Ki decreases with depth, at least in an empirical sense and that (b) depth trends can be established, aiding the definition of a "fracture gradient" for both oil and gas exploration and storage of CO_2.

Consonance of Surface and Subsurface Fracture Data in Vindhyan Basin, India, and Its Implications for Hydrocarbon Exploration

Dilip Kumar Srivastava

Rock and natural fractures are created in response to tectonic activity, through diagenesis, and other factors. Understanding fracture distributions, networks, and orientations is vital because natural fractures impact the effective exploration and development of tight gas reservoirs. The Proterozoic Vindhyan Basin in Central India is positioned between two significant tectonic features: the Great Boundary Fault (GBF) to the northwest and the Son-Narmada Lineament (SNL) to the south. The geological structures observed in exposures of the Vindhyan Basin, resulting from shearing processes, include fault planes, shear fractures of varying sizes, microfractures, granulation, and foliations marked by mica alignment, mylonites, and slickensides. An analysis of fractures within the Upper Vindhyan Formations has identified two main orientations: approximately 55°±5° and 125°±5°, extending from Domarkhoka to the Deccan trap formations (Samal and Mitra, 2006)

Tight gas reservoirs have been established within the Proterozoic Rohtas Formation. A Discrete Fracture Network (DFN) Model was developed utilizing data from outcrop fracture and lineament trends, fracture intensity, orientation, stress directions derived from XRMI logs, and 3D seismic ant track attributes. It revealed two primary sets of fractures, namely NE-SW and NW-SE, based on ant-track images from seismic data. Analysis of ant track attributes along gas-bearing strata indicates that the prevailing fracture strike direction in one region is NE-SW. The other region exhibits two sets of conjugate fractures with orientations of NE-SW and NW-SE. This may be linked to variations in the orientation and magnitude of stress at the convergence of two significant fault alignments.

The fracture orientations observed in surface exposures are consistent with the subsurface fracture arrangements. This has prompted a strategy for finding productive sweet spots/fracture sets by integrating surface geological data with the DFN model and advanced 3D seismic attributes.

Reference

Samal and Mitra, 2006, Field Study of Shear Fractures – Its Tectonic Significance and Possible Application In Hydrocarbon Exploration – An Example from Vindhyan Basin,6th International Conference & Exposition on Petroleum Geophysics “Kolkata 2006”

POSTER ABSTRACTS

Preliminary study into Mercia Mudrock mechanical stratigraphy and implications to fault structure

Kathryn Page

The Mercia Mudrock Group (MMG) is a widespread prospective host rock for subsurface nuclear waste storage due it's low permeability, mitigating migration of radionuclides carried by gas and water through the rock matrix.
However, the MMG is composed of complex chemo-mechanical stratigraphy which complicates the prediction of response to tunnelling and tectonic stresses. This has implications as to the risk of fracturing, which could allow release of hazardous fluids into overlying aquifers and the surface environment. Systematic study of heterogeneity has not been completed and numerous chemical uncertainties remain.
This poster outlines the point load testing method, the resulting index strength values, and XRD mineralogy of outcropping Mercia Mudrock Group samples from the Bristol-South Wales and Wessex basins. We find an immediate lithological control on mechanical properties; outcropping sandstones are weaker than mudstones from the same basin, while marginal carbonates have a substantially higher index strength.
In addition, this has implications for the development and sealing of faults and fracture networks which are partially dependent on the mechanical properties, which further field study and mechanical testing will investigate in more detail. "

A novel approach to enhance well design using minimum horizontal stress estimation by different methods, a case study from WDDM concession, Mediterranean Sea, Egypt

Elsherbeny Akram

"1- INTRODUCTION

The west Delta Deep Marine Concession is located on the northwestern margin of the Nile Delta, approximately 90km offshore. Since 1998, +90 successful E, A&P wells were drilled. The wells have discovered and developed significant quantities of gas in a number of fields named Scarab, Saffron, Simian, Sienna, Sapphire, Sequoia, Saurus and Serpent. In addition to a number of smaller satellites around these fields. The gas discoveries in WDDM are all classified as Pliocene, Deep marine clastic turbidites that were deposited on upper-middle-lower slope setting except Mina which is Messinian, fluvio-marine clastic.

Fracture pressure and minimum horizontal stress estimation is a key factor to design a proper mud weight window (MW). In case where the MW exceeds the fracture pressure, the formation breaks and cause complete losses.

2- WELL STORY

SSc-Da well original hole was drilled with MW 13.5ppg, total losses, pack-off then plug and side track the well! Side Track-1 which was drilled with MW 13.5ppg, but again several tight spots encountered and differential stuck, then side track-1 was plugged back and drill Side Track-2 which was wisely managed and drilled with the previous MW 13.5ppg till certain depth and then set a casing and decrease MW to 11.5ppg and continue drilling until the target was safely reached

3- OBJECTIVES

In this study different methods applied on a real case in WDDM, SSc-Da well, where the MW exceed the fracture pressure and Shmin and break the formation and accordingly drilling challenges, to enhance well design using the most accurate method Of Fracture pressure and minimum horizontal stress estimation and applying lessons learnt for previous wells to the next drilling campaign safety recorders, NPT and cost would be enhanced.

4- MINIMUM HORIZONTAL STRESS PREDICTION METHODS

Jaeger & Cook

-Method 1: depend on overburden & pore pressure using a constant friction coefficient.

-Method 2: depend on overburden & pore pressure using the measure friction coefficient.

Horsrud

-Method 3: depend on overburden & pore pressure using the sand friction angle.

-Method 4: depend on overburden & pore pressure using the shale friction angle.

Matthews & Kelly

- Method 5: Depend on the overburden and pore pressure using the low-bound of measure effective stress

coefficient.

Hubbert & Willis

- Method 6: Depend on the pore pressure only

5- FRACTURE PREDICTION METHODS

Matthews & Kelly

- Method 1: Depend on the overburden and pore pressure using the average-bound of measure effective

stress coefficient.

Eaton

- Method 2: Depend on the pore pressure & the Poisson's ratio.

6- CONCLUSION & RECOMMENDATION

“Mathews & Kelly” method using the average trend of effective stress coefficient, showed reliability in estimating the fracture pressure which is matched with the actual well events. While the other method like “Eaton” did not show match with well events. Also the method showed reliability in minimum horizontal stress estimating; “Horsrud” method by using the shale friction angle and “Jaeger & Cook” method by using the calculated friction coefficient of actual data for 20 wells in WDDM.

While the other methods like “Hubert & Willis” did not show match with well events. By using “Mathews & Kelly” method in fracture estimation and “Jaeger & Cook” in minimum horizontal stress estimation and applying lessons learnt for previous wells to the next drilling campaign safety recorders, NPT and cost would be enhanced.

Fracture Modelling of Well Abandonment

Edgar Castillo

In well abandonment the default scenario is the abandonment plug depth is set where the highest pressure from the reservoir does not exceed the minimum horizontal stress.

However the practical reality is that this scenario can be difficult to achieve. Aspects such as lack of detailed planning in early well abandonments, or difficulty in well access lead to scenarios where some compromise may be required.

In such cases a better understanding is required of the implications of exposing the formation at the plug depth to a higher pressure. Fracture propagation extent and related risks become key aspects.

This presentation will describe a workflow undertaken to address potential risks highlighted by a review of a well abandonment plans. A comprehensive coupled reservoir-geomechanics-fracturing numerical approach was adopted. This included a dynamic fracturing calculation using a non-linear Barton-Bandis material model embedded in a coupled finite-element geomechanical and a multiphase thermal finite-difference flow simulator.

Case studies will be presented. In one case study the modelling analysis has served to de-risk the fracture propagation and containment in an abandoned well for a hypothetical case were failure of the first barrier plug exposes high pressure at a second plug depth. The model demonstrated that if such failure occurs, it was safer (and more cost-effective) to leave the second plug as its current depth rather than to attempt to perform a well re-entry to remove and set it deeper.

Re-Examining the Wellbore Stress Model and Responses to Internal Pressurisation

Gary D Couples

The established method of calculating the stress state around a uses the expressions of radial stress around a circular ‘opening’, developed by Kirsh at the end of 19thC. An alternative approach is to simulate the creation of the opening in a pre-loaded region. Via several methods (discrete-element and finite-element), simulations yield outcomes that show tangential and radial stresses that differ from the Kirsch model by a factor of at least two, and more at large differential stress. Total potential energy is much less in the simulations. Deeper examination exposes several factors that undermine the validity of the Kirsch approach. The primary one is that the ‘solution’ involves an infinite tension at the origin. Although this gets ignored, because it is ‘in the hole’, it is still a fundamental control on the resulting states. When the rock-mass is allowed to deform by non-elastic deformations, the resulting states depart even further from the Kirsch reference model. The simulation methods also permit an examination of how the rock-mass responds to internal pressurisation. The dominant response is a shear offset of the wellbore wall, which is consistent with the enlargement of the circumference caused by the loading. Some shears link with dilated zones that approximate the classic ‘mode I’ response, but many do not. Breakdown pressures in the simulations do not agree well with those predicted from the Kirsch/Hubbert hypothesis. Perhaps it is time to move beyond the convenience of the Kirsch expressions to a model that is phenomenologically closer to reality.

Geological Society
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