Pore Pressure Uncertainty & Communication - Highlighting Awareness and Quality

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ABSTRACT

Pore pressure, fracture gradient and wellbore stability predictions are critical inputs to well design, safe execution and P&A. Despite a strong safety focus, the number of well-control events on the NCS linked to pressure prediction remains high. This report aims to provide insight on how pore pressure estimation uncertainty can be reduced and communication improved through the planning and execution phases of a well.

While comprehensive industry studies assessing the causality of events are limited, best practice indicates that pore pressure and stress prediction uncertainty can be reduced by:

- Multi-method pore pressure calibration to nearby wells combined with high resolution seismic velocity analysis for predictions.
- Integrating coupled pore pressure, wellbore stability and geomechanical stress predictions to understand stability problems, losses and well control events.
- Pore pressure and rock parameters calibration with in-situ and laboratory tests from offset wells and during execution.

Best available techniques (BAT) developed for "high-end" wells like HPHT or extended reach drilling demonstrate that uncertainty can be reduced by:

- MWD formation pressure measurements.
- In situ stress calibration including XLOT and DFIT.
- P and S-wave MWD velocity measurements to determine rock physics.
- Accurate mudgas systems providing early warning of underbalance.
- Accurate inflow and outflow control providing early warning of inflow and borehole issues.
- Managed pressure drilling to safely drill narrow drilling windows.

To improve communication with the well site the following recommendations can be considered:

- Pressure and subsurface stress predictions can be presented in measured depth (MD) in drilling documentation to allow all personnel involved in operations to compare realtime information with pre-drill predictions.
- Best Estimate (BE), Lower (LB) and Upper Bound (UB) of predictions can be presented in line with engineering practices (e.g. DNV-RP-C207), while avoiding probabilistic language (e.g. P95). Probabilistic labelling is often not statistically valid, confusing and poorly understood.
- A clearly communicated safe drilling window for static and dynamic mud weights for each operational step that can be clearly identified in plots and drilling programs.
- Established industry system sharing of depletion and injection pressure data across licenses to avoid inflicting major hazards to other teams or operators.
- Clearly communicated company standards, standardised terminology and plots with clear legends to improve the quality of communication. A traffic light colour scheme is understood by all and suggested. Standardization of plots, legends and symbols across the industry would be a significant improvement.
- A pore pressure and borehole stress checklist maintained by the well delivery team to improve consistency and transparency. A summary of the checklist can be used to communicate the uncertainty to the drilling team and highlight the importance of calibration. The checklist can be used in dedicated risk management sessions. An example is presented in this report.

ABBREVIATIONS

BAT	Best Available Technique
BE	Best Estimate
BHT	Bottom Hole Temperature
CPT	Cone Penetration Test
CTD	Conductivity Temperature and Depth
DFIT	Diagnostic Fracture Injection Test
DST	Drill Stem Test
ECD	Equivalent Circulating Density
EMW	Equivalent Mud Weight
ESD	Equivalent Static Density
FG	Fracture Gradient
FIT	Formation Integrity Test
FMI	Formation MicroImager
FWI	Full-Waveform inversion
HAZOP	Hazard and Operability Study
HP	High Pressure
HPHT	High Pressure High Temperature
LB	Lower Bound
LOP	Leak-Off Pressure
LOT	Leak-Off Test
LWD	Logging While Drilling
MDT	Modular Formation Dynamics Tester
MPD	Managed Pressure Drilling
MSG	The Minimum Stress Gradient
MSL	Mean Sea Level
MWD	Measurement While Drilling
NCT	Normal Compaction Trend
NMO	Normal-Moveout Analysis
OBG	Overburden Gradient
OBMI	Oil-Based Mud Imager
P&A	Plug and Abandonment
PEF	Photoelectric Factor
PP	Pore Pressure
PPFG	Pore Pressure and Fracture Gradient
PPG	Pore Pressure Gradient
PSDM	Pre-Stack Depth Migration
QC	Quality Control
RFT	Repeat Formation Tester
RKB	Rotary Kelly Bushing / Drill Floor Level
ROP	Rate of Penetration
ROV	Remotely Operated Vehicle
RTD	Resistance Temperature Detector
SWF	Shallow Water Flow

TD	Total Depth
TFT	True formation Temperature
TVD	True Vertical Depth
TVDSS	True Vertical Depth Subsea
UB	Upper Bound
VSP	Vertical Seismic Profile
VTI	Vertical Transverse Isotropy
XLOT	Extended Leak-Off Test
XPT	Extended Pressure Test

1. INTRODUCTION

1.1. Background

Well control incidents represent a breach of barrier(s) in a well with major accident potential. Havtil aims to contribute to a reduction in well control incidents on the Norwegian shelf.

Previous studies, such as the "Qualitative study - causal factors and measures for well control incidents related to Norwegian petroleum activities", as part of the 2022 RNNP main report, revealed that a dominant cause of well control incidents is uncertainty in the pore and fracture pressure estimates when preparing drilling and well plans. Incident investigations during the last decade have uncovered challenges in communicating well control risk from the planning phases to the personnel executing the operations.

Under the Norwegian Framework Regulations operators are responsible for reducing risk: *«In reducing risk as mentioned in Section 11 of the Framework Regulations, the responsible party shall select technical, operational and organizational solutions that reduce the likelihood that harm, errors and hazard and accident situations occur.»* and clear principles are outline in § 11 Risk reduction principles of the framework regulations together with guidelines and interpretation of the regulations.

https://www.havtil.no/en/regulations/all-acts/the-framework-regulations3/II/11/

Under the Norwegian Framework Regulations operators are also responsible to verify calculations like pore pressure and fracture gradient and that "*the unit carrying out the verification, shall have the necessary competence and resources to accomplish this.*"

https://www.havtil.no/en/regulations/all-acts/the-framework-regulations3/III/19/

The number of well control incidents have not displayed significant improvement and it is considered desirable to look at the current practices in the industry to identify new ideas and improvement potential in procedures and risk reduction related to uncertainties in formation pressure estimations.

Scope of Work

This report aims to provide practical, field-oriented advice for anticipating and managing well-control risks by improving the prediction of pore pressure and well stress. It aims to be a supplement to industry guidance documents by IOGP, API and IADC.

This work focuses on examining uncertainty in pore pressure and borehole stress prediction by looking at the available prediction methods based on industry data, published research, historical well data, and expert knowledge. For each step in a standard pore pressure and fracture gradient ("PPFG") workflow the basic prediction methods are discussed. Key sources of uncertainty, such as geological variability, data limitations, and methodological differences, are identified and uncertainty reduction discussed. From the available industry information key pit falls are outlined and QC measures are derived. For each main step in the PPFG workflow a checklist is presented which is summarized in Appendix A.

1.2. Limitations

Modern pore pressure and stress prediction in oil and gas wells properly started in the mid 70's with the onset of more modern logging tools and formation pressure measurements using the repeat formation tester (RFT). The number of publications and books addressing pore pressure and subsurface stress are substantial and this report only touches on part of the available body of knowledge. A full review of all available methods is outside the scope of this report and partially also counterproductive. While the strong method and technology focus significantly improved the understanding and prediction capability in the industry during the past 50 years, it also led to an increased mystification of the field. With the introduction of AI and machine learning models this trend is expected to continue, making training, procedures and quality control even more important.

This study is limited to providing an overview of the methodology and pointing to possible areas of improvements. It is not a standard and should not be used as such.

This study was also specifically made with focus on the Norwegian Continental Shelf.

2. PORE PRESSURE & STRESS PREDICTION

2.1. General Workflow

The pore pressure and stress prediction process is a logical sequence of activities including data gathering, model building, calibration, and operation. The purpose is to make a precise, uncertainty-bound prediction of the subsurface pressure and stress regime to guide safe and efficient well design and operation.

The initial step of the workflow involves gathering available geological, geophysical and drilling data for the area of interest. This includes stratigraphic models, seismic velocity models, offset well data, measured formation pressure data, core data, stress measurements. The collected data are quality controlled to avoid depth mismatches, bad data is removed and the data is compared across disciplines to ensure consistency between geological understanding, seismic and well data.

Once data conditioning is completed, baseline pressure and compaction trends can be determined. Offset wells are used to predict normal compaction trends, and empirical methods are employed to calculate pore pressure gradients from mainly drilling, resistivity, and/or sonic parameters. Vertical stress is determined by calculating the overburden gradient and horizontal stresses are derived from elastic stress ratios and direct measurement. An initial pore pressure–stress model is established at this stage.

The second step involves making a mechanical earth model (MEM) using pore pressure calculations, and elastic and strength properties in all stratigraphic units. Rock parameters are assigned depending on log interpretation, core testing, or empirical correlation. The model incorporates drilling angle and direction, lithology, anisotropy, faults and where needed poroelastic coupling for example in depleted reservoirs. Omission or simplification may cause miscalculations in stress or pore pressure magnitude.

Once the model is established, the findings are compiled into a combined pore pressure and stress gradient envelope that defines the operational drilling window. Uncertainties can be quantified by sensitivity analyses, probabilistic simulations, analysis of previous well data or alternative approaches like basin modelling. Areas of intersection of pressure and horizontal stress gradients or overlapping areas of uncertainty are identified as areas of critical casing design and operational control. To consider single deterministic curves alone is not sufficient to assess uncertainty.

Calibration is achieved by comparison with test data collected through leak-off tests, formation integrity tests, downhole pressure values, and real-time drilling data such as cuttings behaviour, gas content, and rate of penetration. Reconciliation of predicted and observed values results in iterative model calibration and it is key that the models can be demonstrated to work on nearby offset wells. Drilling events of offset wells like mud losses, borehole breaks outs, stuck tools and borehole collapse provide important independent means to validate the models.

Results are given on readily interpretable pressure–depth plots, generally both in true vertical depth (TVD) and measured depth (MD) to drill floor. These are supplemented by text summaries of assumptions, sources of data, and key uncertainties. The plots can be supported by visual representation of the planned borehole with expected hazard at specific depths, so called “Well Risk Chart” or “Pre-Risk Chart”. The forecast envelopes and associated geological hazards are reviewed at multidisciplinary HAZOP or risk review meetings so that drilling, geological, and operations personnel are informed of implications and required mitigation.

The approved and finalized model is incorporated into design and operational documents, such as the casing design, drilling program, well control and P&A plan. Values for mud weights, casing points, and contingency measures are well-defined. Detailed step-by-step operational work instructions are made for each major step in the drilling plan. While drilling, the team can detect deviations early by comparing measured and calculated pressures in real time. This allows the mud weight to be adjusted in time, set casing or implement other corrective measures. After well completion, an analysis is conducted that compares the actual performance with the forecasts. This process improves organizational learning and enhances model reliability for future wells.

2.3.1 Gradients Overview

Gradients underlie any subsurface pressure prediction or well design (API RP 92P, 2019). They establish the rate of change with depth and give the reference frame for defining pore pressure, fracture pressure, and the safe mud-weight window (Zoback, 2010). Although the concept is simple, confident estimation requires good quality data, the right reference depths, and an appreciation of the geological and mechanical processes that govern each gradient (Fjaer et al., 2008; Zoback, 2010). Gradients are usually expressed in terms of pressure per unit depth (bar/m or MPa/km) or as Equivalent Mud Weight (EMW, sg) for immediate application in drilling operations.

Hydrostatic Gradient

The hydrostatic gradient is the pressure generated by a column of stationary fluid in equilibrium with gravity. It is the foundation of normal pore pressure and is a function of fluid density alone (Zoback, 2010). For formation water, salinity, and temperature variations influence the actual gradient (Aadnøy & Looyeh, 2011). In drilling operations, the hydrostatic gradient of the mud system determines the static bottomhole pressure when pumps are off. Typical values of hydrostatic include freshwater: ≈ 1 sg, seawater or saline brine: ≈ 1.03 sg (0.101 bar/m) and drilling muds - depends on density (typically 1.03 to 2.5 sg).

A major limitation is the use of uniform fluid density with depth, without consideration of salinity, temperature, sag of weighting agent or compressibility changes that affect hydrostatic pressure.

Pore Pressure Gradient

The pore pressure gradient (PPG) specifies the fluid pressure in the connected pore space of rocks. It is equivalent to the hydrostatic gradient in normally compacted water-saturated sediments (Zoback, 2010). Overpressure is generated when fluid cannot escape during burial or is enhanced by internal processes such as hydrocarbon generation, clay diagenesis, or lateral pressure transfer (Swarbrick & Osborne, 1998; Bowers, 1995). Overpressure mechanisms are:

- Disequilibrium compaction - rapid burial precedes fluid expulsion (Swarbrick & Osborne, 1998).
- Fluid expansion - hydrocarbon generation, diagenesis or aqua thermal effects increase fluid volume (Swarbrick & Osborne, 1998).
- Tectonic compression - transmission of horizontal stress increases pore pressure (Swarbrick & Osborne, 1998; Zoback, 2010).
- Lateral transfer - movement of fluids from deeper or adjacent overpressured compartments (Swarbrick & Osborne, 1998).

A primary limitation is the misanalysis of log or seismic velocity trends that are caused by lithology, gas, or temperature rather than actual overpressure (Dutta, 2002).

Fracture (Leak-off) gradient

The fracture or leak-off gradient (FG) is the pressure at which the formation begins to fail, and a fracture is created. It is approximately equal to the minimum horizontal stress and dictates the safe maximum mud weight limit (Zoback, 2010; Fjaer et al., 2008). It is measured directly in Leak-Off Tests (LOT), Extended Leak-Off Tests (XLOT), or Diagnostic Fracture Injection Tests (DFIT), and indirectly from calibrated geomechanical models (Aadnøy & Looyeh, 2011). Fracture gradients can be derived from LOT/XLOT results in nearby geologically similar offset wells, mini-fracture or DFIT pressure fall-off analysis, geomechanical modelling using elastic parameters (E, ν, α) and in-situ stress ratio (Zoback, 2010; Fjaer et al., 2008).

A major challenge is overestimation of fracture gradients when leak-off tests are poorly interpreted or where depletion, fractures, layer interfaces and/or thermal stress effects are ignored. This can lead to induced losses or fracturing at the shoes of casing (e.g. Zoback, 2010).

Relationship Between Gradients

The crossover of the pore pressure and fracture gradients defines the pressure window within which safe drilling is possible (API RP 92P, 2019), the so called “safe drilling window”.

- Lower limit: pore pressure gradient — mud weight below initiates and increases risk of influx.
- Upper limit: fracture gradient — mud weight above initiates and increases risk of losses.

The accurate definition of these gradients is fundamental to the construction of reliable pore pressure and fracture window plots. Integration allows for real-time decision-making in terms of mud weight planning, casing design, and kick/loss control (Zoback, 2010).

Pore pressure prediction workflow

To define the pressure and stress in the subsurface a general workflow is established where each gradient is calculated and used as input for subsequent calculations. It is therefore of utmost importance to understand that uncertainty is propagated in the calculations and increases throughout the workflow. The different steps are outlined in the figure below.

Figure 1. Typical pore pressure prediction workflow.

2.2. Overburden Gradient

The overburden gradient (OBG) describes the increase in the lithostatic vertical earth stress with depth, due the weight of overlying fluids, sediments and rock. It is the starting point to predict pore pressure, fracture gradient, and wellbore stability in subsurface formations (Zoback, 2010, Fjaer et, al., 2008). To correctly predict the overburden gradient, it is key to understand the density variations in the subsurface.

2.2.1. Definition and Calculation of Overburden Gradient

The overburden pressure (σv) at a given depth is calculated by integrating the bulk density of the overlaying formations and fluids and is expressed in units of pressure (e.g. bar or MPa) (Aadnøy & Looyeh, 2019):

$$\sigma_{\mathrm{v}} = \int_0^z \rho(z) \cdot g \cdot dz$$

Where:

- $\rho(z)$ - bulk density at depth (z)
- g - gravitational acceleration (9.81 m/s^2)
- z - true vertical depth (TVDSS)

The overburden gradient is then:

$$OBG = \frac{\sigma_{\mathrm{v}}}{\mathrm{z}}$$

And is typically expressed in units of pressure per depth (e.g. bar/m) or specific weight (sg).

2.2.2. Prediction Methods

Reliable estimation of the overburden gradient depends on integrating diverse, high-quality data inputs that capture both in-situ formation properties and the regional geological context (Zhang & Yin, 2017; Ellis & Singer, 2007). Each data source contributes to the accuracy of bulk density profiles, which are essential for calculating borehole stress.

- **Gamma Density Logging:** This is the most widely used technique. Bulk density logs (RHOB) provide in-situ measurements of formation density in surrounding wells and are collected either via logging while drilling (LWD) or wireline. By integrating these values over depth, cumulative overburden pressure is calculated. The gradient is then obtained by dividing the overburden pressure with the true vertical depth. To ensure accuracy, the log data must be high quality. Corrections for borehole conditions such as mudcake, washouts, or tool standoffs are to be applied using caliper and density correction logs (Ellis & Singer, 2007). To check density assumptions and reduce uncertainty, physical measurements are used to calibrate log-derived or model-based profiles (Fjaer et al., 2008).

- **Compressional velocities:** In cases where density logs are missing or incomplete, velocity data offers a valuable alternative. Compressional wave velocities or p-wave velocities (Vp) from well logs, borehole seismic and/or seismic data are converted to density using empirical relationships like Gardner's or Nafe-Drake equations (Zoback, 2010; Aadnøy & Looyeh, 2019). This method is especially useful in pre-drill assessments or frontier basins, where direct measurements are limited. It enables regional overburden estimation based on seismic continuity. Note that the precision of these empirical equations like Gardner can be significantly improved by local calibration per lithology and/or formation.
- **Geological modelling:** A geological model of the subsurface is used to assign densities to each layer either directly or using depth trends. Layers are mapped from seismic and density information is derived from wells. The model can be fully 3D or can use formation tops and lithological markers. These are used to align log data with stratigraphic boundaries and correct depth mismatches caused by tool drift or borehole irregularities. Proper depth referencing ensures that density integration respects lithological transitions, improving the geological consistency of the prediction (Zhang & Yin, 2017).
- **Direct Measurement:** If sufficient direct data is available a density profile can be derived directly. In most cases, insufficient data is available and direct data is only used for calibration of the above outlined methods.
    - Seabed density provides reliable benchmarks for shallow formations, particularly in offshore settings. The information can come from direct measurement of seabed samples or indirectly using CPT data.
    - Core density measurements offer high-resolution validation across key intervals, anchoring the gradient baseline, and improving confidence in stress estimates (Havtil, 2022).
    - Cuttings densities are easily determined at low cost and are often overlooked as a source of density information.
- **Petrophysical and machine learning:** Other well logs can also be used to determine densities from petrophysical relationships including neutron and photoelectric factor (PEF) logs. While less exact they can be used to fill in data gaps. These methods have seen an increase in use with the rise of machine learning techniques (Pelemo-Daniels & Stewart, 2024)

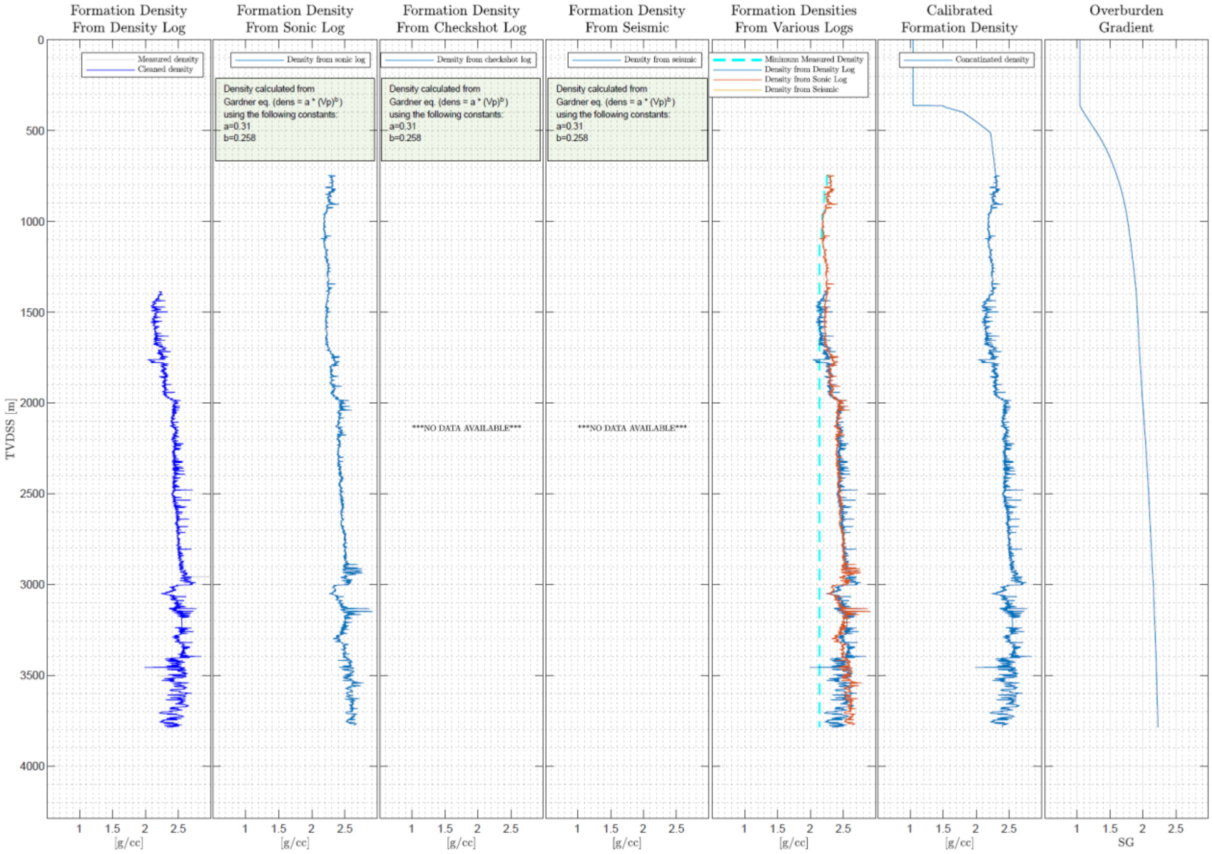


Figure 2. Example of different densities that are combined into a single final density as input the collapse gradient on the right.

2.2.3. Uncertainty Reduction

Uncertainty in the overburden gradient can significantly affect the accuracy of pore pressure and fracture gradient predictions—both of which are vital for safe and efficient well design (Zoback, 2010). To reduce the uncertainty the following methods are commonly applied:

- **Using Multiple Data Sources:** Combining different types of measurements strengthens the reliability of the overburden gradient model (Zhang & Yin, 2017; Ellis& Singer, 2007):
  - Wireline and LWD logs offer direct in-situ bulk density readings.
  - Seismic data can detect anomalies and helps interpolate density between wells or fill in data gaps.
  - Laboratory analyses, such as core plug testing, are used to validate and fine-tune log-derived density values.
- **Improving Log Quality with Corrections and Caliper Checks:** Accurate gradient calculations depend on high-quality logging data (Ellis & Singer, 2007). Two key practices help ensure this:
  - Density corrections account for borehole conditions like mudcake buildup, washouts, or tool standoff.
  - Caliper logs detect borehole enlargements and irregularities that may distort density readings.

- **Stratigraphic Alignment with Geological Models:** Adjusting the geological framework to match expected stratigraphy and lithology improves depth-density relationships (Han et al., 2025)
    - Stratigraphic Tops ("Top Tables") serve as reference points for key formation and lithology boundaries.
    - Lithology change is one of the main causes of density variation and the prognosed lithology density needs to be considered, especially where direct measurements are unavailable.
- **Calibration with Physical Samples:** Validating log-derived densities against real-world samples increases confidence in the model (Havtil, 2022):
    - Seabed samples (e.g. vibrocores) or tests (CPT) provide shallow benchmarks for extrapolating density trends.
    - Cuttings, core plug and core data offer direct measurements across stratigraphic layers, supporting calibration and trend verification.
- **Cross-Referencing with Offset Wells:** Comparing data across nearby wells helps identify inconsistencies, regional trends and refine interpretations (Selveindran et al., 2020):
    - Offset well data reveal broader regional patterns and geological variability.
    - Cross-validation ensures consistency in density modelling and flags of anomalies or localised effects.

2.2.4. Common Pitfalls

Even with access to advanced logging tools and sophisticated modelling techniques, overburden gradient calculations are still prone to technical and interpretational errors. Such pitfalss can distort vertical stress estimates, with propagating errors in pore pressure and borehole stress predictions discussed in later chapters, increasing the total uncertainty. It is common that overburden gradient calibration is overlooked due to the perception of good calibration in the reservoir. This can lead to unnecessary increased uncertainty in fracture, minimum stress and collapse gradients.

Below are typical issues encountered in the field:

- **Poor-Quality Density Logs:** Formation density readings may be compromised due to suboptimal tool or borehole conditions such as tool standoff, mudcake buildup, poor tool calibration or equipment malfunction, resulting in inaccurate log data (Ellis & Singer, 2007).
- **Uncorrected Borehole Washouts:** If washouts or borehole enlargements are not properly identified and corrected, they can lead to artificially low-density values, skewing the gradient calculation (Fjaer et al., 2008).
- **Lack of overburden calibration:** It is common industry practice to rapidly drill down through the overburden with minimum measurements. This is also partly due to the difficulty of doing good measurements in large diameter boreholes. Overburden variations can be very large due to changes in lithology and compaction. Seismic data and/or borehole seismic can partially fill in these gaps (Zoback, 2010).
- **Misalignment with stratigraphy:** Failing to adjust for stratigraphic, structural or lithologic variations can cause the model to diverge from reality, especially in complex geological faulted settings. Poorly calibrated lithologies like ooze, swelling clays, salt or carbonate need special attention (Han et al., 2025).
- **Methodological Over-Reliance:** Relying solely on one method (e.g. density logs) or too few data (e.g. only 1 reference well) without cross-checking against other data sources often leads

to a lack of uncertainty understanding and a limited ability to detect anomalies (Chacon-Buitrago and Pyrcz, 2025).

- **Non-specific models:** Using simplified models for the entire well like the Gardner equation to derive density from compressional velocity data is widespread. These relationships mix shale, sandstone and carbonates which generally have varying density (Aadnøy & Looyeh, 2019).
- **Inadequate Documentation and Communication:** Poorly documented data sources, or workflow steps can lead to miscommunication between teams and hinder troubleshooting or model refinement. Older well data is often missing key information, like tool corrections, and needs to be treated with suspicion (Musolino et al., 2022). Depth mistakes are also common, especially when data comes from large databases.

2.2.5. Quality Control

Quality control (QC) plays a vital role in ensuring that overburden gradient estimates are both geologically sound and dependable (Musolino et al., 2022; Han et al., 2025). Because the calculations are sensitive to variations in density, borehole conditions, and depth alignment, a structured QC process is essential to reduce uncertainty and avoid misinterpretation.

A typical QC workflow includes the following key steps:

- **Borehole Integrity Validation**: Caliper logs are reviewed to assess borehole shape and detect any enlargements, rugosity, or tool standoff that could compromise log accuracy.
- **Density Log Correction and Verification:** Raw density logs are corrected for borehole effects and cross-checked against expected lithologies to confirm consistency with geological models.
- **Calibration with External Data:** Seismic profiles and cuttings data are used to calibrate log-derived densities, helping to validate trends and identify discrepancies across stratigraphic intervals.
- **Input Consistency Review:** All data inputs such as logs, seismic, lab measurements—are systematically reviewed. Any anomalies, mismatches, or outliers are flagged for further investigation before finalizing the gradient model.

Identified poor or wrong data must be removed from the analysis and/or data gaps should be filled in using other methods.

2.2.6. Checklist

The following checklist highlights key points an integrated well delivery team should check for the overburden gradient.

Table 1. Overburden Gradient Checklist

	Overburden Gradient	**Documentation (add links to data sources)**
1	More than one method / input used & uncertainty assessed?	*Describe inputs (logs, Vp seismic...) & methods*
2	Density correction logs, depths and caliper checked?	*Describe data, source and quality of information*
3	Data corrected for prognosed stratigraphy, lithology and/or depth	*Describe methods e.g. Top Tables & name top set*
3	Calibration with seabed density data	*Name seabed samples, gravity cores or CPTs*
4	Calibration with cuttings density data	*Name well(s) and depth interval*
5	Calibration with core density data	*Core name(s) and depth interval*

2.3 Pore Pressure Gradient

The pore pressure gradients determine the rate at which the pore pressure changes with depth. Formation pressure predictions are a key input for determining the minimum stress, fracture and collapse gradient (Zoback, 2010; Fjaer et al., 2008). They define acceptable mud weights, influence borehole stability, and are key inputs to well control (API RP 92P, 2019; Aadnøy & Looyeh, 2011).

2.3.1. Definition and Calculation of Pore Pressure Gradient

The pore pressure gradient is determined from either direct pressure measurements or indirect log- and seismic-based methods that relate rock properties to effective stress. In the absence of direct formation pressure data, pore pressure is commonly inferred from deviations in sonic velocity, resistivity, or seismic velocity relative to a normal compaction trend (Eaton, 1972; Bowers, 1995; Dutta, 2002). Quite commonly these models are on valid for shales, assuming the non-shale reservoirs are in pressure equilibrium with the shales.

One of the most widely used empirical approaches is the Eaton method, which estimates pore pressure from sonic or resistivity logs:

$$P_p = S_v - (S_v - P_n)\left(\frac{X_n}{X}\right)^m$$

Where

P_p = pore pressure,

S_v = vertical stress,

P_n = normal pore pressure,

X= measured log value (sonic transit time or resistivity),

X_n = normal compaction trend value,

M = Eaton exponent (typically 3 for sonic, 1.2 - 1.5 for resistivity) (Eaton, 1972).

For velocity-based prediction that accounts explicitly for different overpressure mechanisms, the Bowers method relates pore pressure to seismic or sonic velocity:

$$V = V_0 + A(\sigma_v')^B$$

Where

V = measured velocity,

V_0 = velocity at zero effective stress,

$\sigma_v' = S_v - P_p$ = vertical effective stress,

A and B = empirically derived constants (Bowers, 1955).

Many other methods and variation exist that can be helpful to solve specific challenges. Also drilling parameters can be used to predict pore pressure and are especially useful as an additional source of pore pressure information and in more stiffer lithologies.

At the basin or regional scale, seismic velocity–based pore pressure gradients are derived using interval velocities calibrated to available well control, allowing extrapolation into undrilled areas (Dutta, 2002). Variations in the calculated gradient reflect the dominant geological overpressure mechanisms present, such as disequilibrium compaction or fluid expansion processes (Swarbrick & Osborne, 1998).

2.3.2. Prediction Methods

Strong subsurface pressure prediction depends more on the integration of several complementary methods than on any single dataset. Each method measures or calculates pressure through a different physical property and has, therefore, a distinct sensitivity and range of uncertainty (Zoback, 2010).

Most pre-drill pore-pressure models are founded on compressional velocity data (p-wave), providing a regional overview of compaction and effective stress. Intervals of velocity decline relative to a normal compaction trend (NCT) indicate possible overpressure (Dutta, 2002; Bowers, 1995). P-wave velocities are lithology, anisotropy, and fluid-type dependent and thus must be calibrated through the use of checkshots, VSPs, and density (Dutta, 2002). Following drilling initiation, LWD and MWD logs deliver real-time pressure monitoring from sonic, density, and resistivity responses, allowing instantaneous comparison of predicted versus observed trends. Wireline logs recorded in open hole collect higher-resolution data of compaction and porosity trends and are used subsequent to the drilling for adjusting stress and pore-pressure models (Zoback, 2010).

Direct pressure measurements (e.g. RFT, MDT, XPT) and DSTs define true formation pressures and fluid densities and therefore serve as the baseline for all indirect pressure estimates (Aadnøy & Looyeh, 2011; Zoback, 2010). Operational indicators such as mud gas, rate of penetration (ROP), torque, drag, and equivalent circulating density (ECD), provide real-time, qualitative confirmation of over- or underbalanced pressure behaviour (Fjaer et al., 2008; Aadnøy & Looyeh, 2011).

Integration is performed by bringing all the previously discussed approaches under one, depth-referenced system. Seismic data characterize the regional stress–velocity trend and outline large scale overpressure areas. LWD/MWD, wireline logs and mud-gas observations refine the model locally. Direct pressure tests validate the predictions against reality. LOT/XLOT data are included to constrain fracture pressures, and then complete dataset is balanced in a geomechanical model that honours effective-stress relations and geomechanical properties (Zoback, 2010). Each revision will have to maintain physical consistency, such as effective stress (overburden minus pore pressure) can never be negative, and fracture gradients should always be greater than pore-pressure gradients (Zoback, 2010; Fjaer et al., 2008).

High-Resolution Seismic Velocities

Using high-resolution seismic velocities as an additional input to the pore pressure prediction offer several significant advantages that include:

- Increased vertical discrimination between abnormally and normally pressured zones, especially where pressure increases steeply with depth.
- Increased spatial resolution, allowing identification of overpressured compartments or fault sealing effects.
- More precise depth control for time-to-depth conversion, reducing uncertainty in pre-drill models.
- Improved integration with rock-physics modelling and reduced uncertainty in effective stress vs. velocity relations.

With the presence of dense checkshots, high-fold seismic data, and advanced inversion methods, velocity models are now capable of attaining resolution sufficient for pressure modelling in finer details to the scale of tens of meters vertically. Note that as the compressibility of the rock decreases with depth, combined with increased frequency absorption of the seismic waves, the resolution and ability to resolve pressure differences decreases with depth.

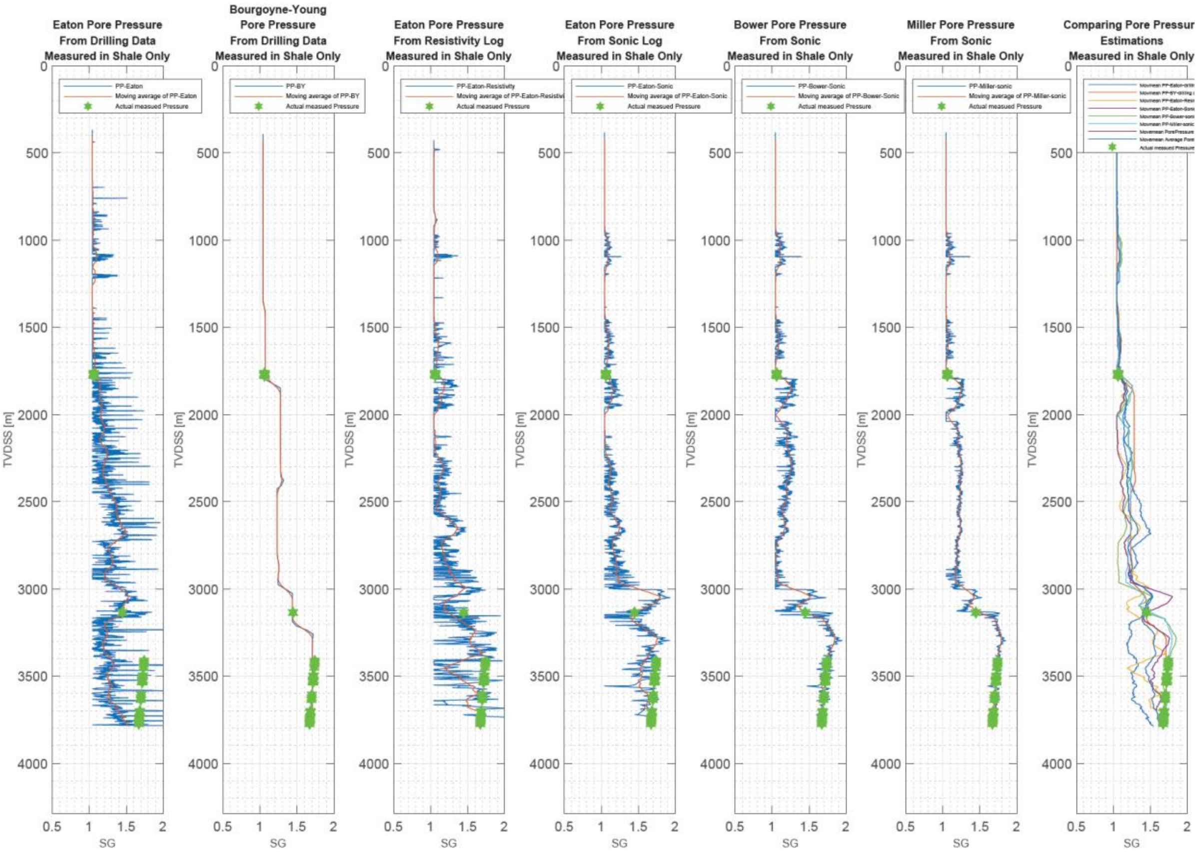


Figure 3. Example of comparing different pore pressure calculations using different methods and inputs. Note how this can help constrain the uncertainty of the overall prediction (right).

2.3.3. Swabbing

Swab pressure is the condition wherein upward motion of the pipe ("tripping out") reduces hydrostatic pressure within the wellbore, with potential to reduce bottomhole pressure below pore pressure of the formation (API RP 92M, 2016). This short-term underbalance can allow formation fluids to enter the wellbore, representing a kick and result in a well control situation, especially within narrow mud-weight windows. Assessment of swab risk becomes paramount in high-permeability formations, tight hole conditions, depleted reservoirs, or low-fracture gradient areas where margins to operate are thin.

Pressure of swabbing is controlled by several interactive parameters (Aadnøy & Looyeh, 2011):

- Pipe geometry and speed of tripping, which regulate the rate of displacement of the drilling fluid.
- Mud rheology and gel strength, which influence how freely fluid can pass around the pipe.
- Loading of cuttings and wellbore geometry, which increase resistance to flow.
- Mud density and viscosity, which influence the speed at which pressure recovery starts being effective when motion stops.

When tripping out too rapidly or using gels with extremely high yield stress, pressure losses due to swab can be enough to cause flow of liquids from overpressured or gas-bearing formations into the wellbore (API RP 92M, 2016; Aadnøy & Looyeh, 2011). Swab-induced underbalance will generally occur when tripping too rapidly or when downhole gel strength of the drilling fluid is greater than measured at surface conditions. Heavy accumulation of cuttings or tight annular clearances also restrict flow, raising swab pressure and sucking formation fluids into the wellbore. In tight pressure windows, swabbing may lead to influx or gas migration that may be confused with ballooning or thermal expansion, delaying the correct well-control action. Swab-induced influx when not rapidly recognized, may develop into a kick or blowout scenario.

2.3.4. Lateral Transfer

Lateral transfer and pressure communication refer to the movement of fluids and pressure horizontally between connected formations or compartments. This process can significantly influence pore pressure distribution, particularly in sandstone–shale sequences, where laterally continuous sands transmit pressure over large distances. Understanding lateral connectivity is critical for predicting pressure compartments, designing safe mud-weight windows, and assessing well-to-well pressure correlation within a field or basin (Swarbrick & Osborne, 1998).

Pressure transfer occurs when connected, permeable units such as sands or carbonates allow fluids to migrate horizontally from overpressured to normally pressured regions (Swarbrick & Osborne, 1998; Zoback, 2010).

Key controls include (Swarbrick & Osborne, 1998; Zoback, 2010):

- Sandbody continuity and permeability, which govern how efficiently pressure dissipates laterally.
- Fault and seal properties, including shale smear, cataclasis, or cementation, which determine whether faults function as barriers or conduits.
- Lateral burial variation, where differential loading creates pressure gradients between adjacent areas.
- Hydrocarbon generation and migration, which can elevate pore pressure regionally and equalize pressures across connected structures.

Properly characterizing these mechanisms is crucial for predicting whether pressure anomalies are isolated (compartmentalized) or connected across the field.

Incorrect assumptions about lateral pressure continuity can lead to significant drilling and development errors. Assuming full connectivity where faults or lithologic barriers exist can result in underestimating pore pressure and encountering unexpected kicks. Conversely, treating a connected sand system as isolated may cause overestimation of pore pressure and unnecessary overbalance, leading to formation breakdown or mud losses. Failure to recognize lateral pressure transfer through connected reservoirs or aquifers can also cause discrepancies between predicted and measured pressures in offset wells. These errors are often magnified in structurally complex or stratigraphically heterogeneous settings (API RP 92P, 2019; Zoback, 2010).

2.3.5. Shallow Water Flow (SWF)

Lateral pressure transfer in shallow unconsolidated formations can lead to shallow water flow (SWF) — a condition where overpressured, permeable sands are releasing formation water into the wellbore (API RP 92P, 2019; Zhang et al., 2018). These zones tend to occur within young, undercompacted deltaic or shelf sediments, where the effective stress is low and permeability remains high (Dutta, 2002). SWF is most common in basins like the Gulf of Mexico, North Sea, Southeast Asia and the Niger

Delta, regions of high sedimentation rate and good pore-fluid continuity (Zhang et al., 2018; Dutta, 2002).

Pressure transfer can occur due to rapid sedimentation, local compaction disequilibrium, or lateral migration from adjacent overpressured cells (Dutta, 2002). Shallow gas can also contribute to the overpressure and enhance the risk of flow (Dutta, 2002; API RP 92P, 2019).

Because pore fluids are continuous over great lateral distances, pressure generated in one area by quick burial or local loading can become transmitted laterally into adjacent areas, maintaining abnormal pore pressures close to the seafloor (Dutta, 2002; API RP 92P, 2019). It is crucial to comprehend and forecast these mechanisms for shallow casing design, well control, and seabed stability (API RP 92P, 2019).

If drilling intersects these sands, even a moderate underbalance can lead to high-velocity water influx, which subsequently can cause washouts, wellbore instability, or seabed cratering (Zhang et al., 2018). These flows, if not successfully controlled, can distort conductor casing cement job and cause conductor instability while riserless drilling (Zhang et al., 2018). Misinterpretation of seismic anomalies or the hydrostatic assumption can cause inadequate casing design or mud weight that can initiate loss of well control and structural failure near the seabed (API RP 92P, 2019). In most cases this has led to losing the well and in a worst-case scenario this can lead to an uncontrolled blowout at the seafloor if also gas is present in the aquifer.

2.3.6. Pressure Depletion

Reservoir depletion occurs where production lowers pore pressure and increases effective stress in the rock framework (Zoback, 2010; Fjaer et al., 2008). This change modifies the hydraulic and mechanical behaviour of both the depleted reservoir and adjacent units (Zoback, 2010).

Depletion will significantly lower pore pressure, locally decrease fracture gradient, and shift stress direction — all that must be accounted for when infill or offset well planning is performed (Addis, 1997; API RP 92P, 2019). Identification of depletion effects is necessary to achieve proper mud-weight choice, wellbore-stability prediction, and fracture-gradient calibration (Zoback, 2010; API RP 92P, 2019).

Drilling into a depleted zone without accounting for the reduced pore pressure can result in severe differential sticking, lost circulation, wellbore collapse and/or sand production (API RP 92P, 2019). At the same time, areas surrounding depleted wells may retain residual high pressure, resulting in complicated pressure gradients that make wellbore stability and cementing operations more challenging. Large pressure differentials across adjacent compartments may cause crossflow or influx via permeable zones (Zoback, 2010). Faulty stress modelling may even trigger fracture initiation at lower-than-anticipated mud weights, compromising zonal isolation. Under extreme conditions, the depletion-induced stress shifts may result in fault reactivation or casing deformation in producing wells.

Pressure depletion is quantified by comparing time-lapse formation-pressure with past production volumes and reservoir simulation output (Zoback, 2010). Direct calibration methods include:

- Repeat RFT/MDT measurements taken over the life of a reservoir to track pore-pressure depletion.
- Shut-in tubing and casing pressures from producer wells.
- Time-lapse (4D) seismic surveys, which yield compaction-related velocity and amplitude variations.

- LOT/XLOT results showing increased fracture gradients in depleted areas.
- Compaction or stress redistribution revealed by wellbore deformation logs or caliper logs.

2.3.7. High Pressure Conditions

High-pressure (HP) conditions occur when shut-in formation pressures exceed approximately 690 bar (10,000 psi) (API RP 92M, 2016; API RP 92P, 2019). Such conditions should be treated with specialized procedure, fluid, and equipment to manage hihg downhole pressures and narrow drilling margins safely (Zoback, 2010). HP intervals usually have a tendency to form in deep, tight basins or overpressured shales where rapid burial and fluid trapping enhance pore pressures, close to the overburden stress (Bowers, 1995; Swarbrick & Osborne, 1998). Precise pressure prediction and constant calibration are critical to maintaining well control and structural stability (API RP 92P, 2019).

As pressure rises, the safe mud-weight window becomes extremely narrow, often less than 0.5–1.0 ppg between pore and fracture gradients (API RP 92M, 2016; Zoback, 2010). Minor deviations in density or ECD can cause influx or induced losses. Wellbore stability margins are slim and thermal and pressure effects can modify mud density and annular pressure under circulation (Fjaer et al., 2008). Downhole and surface equipment, like BOPs, wellheads, choke manifolds, and pressure sensors, must be tested and rated for HP/HT service (API RP 92M, 2016). Hydraulic model accuracy, temperature compensation, and real-time pressure monitoring become essential to prevent control failure (API RP 92M, 2016; Zoback, 2010).

In HP wells, small errors in mud-weight or ECD control can cross the close margin between fracture pressure and pore pressure, leading to influx, loss, or blowout in the wellbore (API RP 92M, 2016; Zoback, 2010). HP conditions can destroy equipment not capable of withstanding such conditions under heavy loads, and miscalculated shut-in pressures or delayed kick detection can result in loss of well control or devastating casing collapse (API RP 92M, 2016; API RP 92S, 2019).

2.3.8. Uncertainty Reduction

Formation pressure measurements

Calibration to formation pressure measurements is key to validating and applying pore-pressure models. In-situ fluid pressure is determined by direct pressure measurements during drilling (e.g. XPT), wireline logging (e.g. RFT, MDT) or drill stem testing (DSTs). The in-situ pressure measurements define true pressure–depth relations for individual fluids (water, oil, and gas) and are reference points for calibrating pressure predictions. Formation-pressure data are also used to verify whether predicted effective stress and pore-pressure trends are physically reasonable and consistent with offset wells (Zoback, 2010).

Formation-pressure measurements are influenced by a range of factors including permeability, mudcake integrity, tool-seal quality and more. Most commonly formation tests may deliver incorrectly high pressures due to supercharging, to low readings due to a bad seal between the tool and the formation or due to very low formation mobility. Transient "supercharge" effects, where invasion of mud filtrate leads to temporary rise in measured pressure, are common in overpressured or low-permeability intervals. For quality control, mobility values are to be checked, formation pressure stability confirmed, before and after hydrostatic pressure compared and poor-quality seal or low-buildup readings are to be rejected. Accepted pressures are to be plotted against true vertical depth

(TVDSS) to establish pressure gradients for different reservoir fluids and to observe lateral compartmentalization or depletion.

Incorrect test depths or defective correlation of logs with pressure points can generate skewed gradients and need to be checked carefully, especially for measurements taken during drilling or DSTs. Incorrect assumptions of temperature or fluid type may also contribute to incorrect gradient interpretation. Without proper QC, model trends may be wrong by several tenths of a sg by calculations from uncalibrated or scattered test data and lead to unsafe drilling-margin forecasts.

Static Mud Weight Comparison

Static mud weight comparison is a critical process for the validation of pre-drill pressure and fracture-gradient predictions. Offset well mud weights, when reduced to equivalent static density (ESD) at true vertical depth subsea (TVDSS), serve as realistic indicators of pressures successfully controlled while drilling. By comparing actual-run mud weights with predicted pore pressure and fracture gradients, pore pressure specialists can ascertain if modelled values are realistically achievable to operate or if they must be recalculated. Static mud weight envelopes also aid in the identification of pressure compartmentalization or differences in lateral pressures between wells.

Offset mud-weight information provide lower and upper limits for expected formation pressures:

- The lowest stable mud weight that prevented influx defines the minimum pore pressure constraint.
- The highest mud weight used without creating losses serves as the approximate lower fracture gradient limit.

Because drilling conditions (ECD, hole cleaning, and temperature) influence pressure balance, these measurements must be corrected to static conditions to allow consistent comparison. All measurements are referenced to TVDSS and are expressed as equivalent mud weight (sg) or equivalent pressure (bar/, or MPa/km). Static mud-weight comparison is of greatest use when there are several nearby offset wells that cross the same stratigraphic and structural domains so a clear regional envelope of safe mud weights can be established.

Static mud-weight comparisons can be misleading when the data are not properly corrected and standardized. The most common errors are from static and circulating density mixing (ESD vs. ECD), giving false apparent changes of pressure gradients. Omission of temperature and salinity effects alters fluid density and introduces systematic bias, while the use of unverified offset information could include values tainted by wellbore instability, ballooning, or short-term control adjustments. Structural elevation differences between wells, if not accurately corrected, will also create the false appearance of lateral pressure variation. Errors so created will result in incorrect calibration of fracture and pore gradients, which result in unsafe mud-weight selection or excessively conservative design margins (API RP 92P, 2019).

Offset well calibration

Offset wells provide the best available ground truth for regional pressure calibration. Key offset data includes historical mud weights, well-documented kicks, losses, stuck pipe, overpull and ballooning that indicate pore or fracture pressure thresholds in line with Leak-Off Tests (LOT/XLOT) and RFT/MDT/DST pressure points. Converting offset data to Equivalent Mud Weight (EMW) at true vertical depth (TVDSS) enables the pressure and fracture limits to be compared directly to predictions for the offset wells. Agreement over a large range of wells provides confidence in the model and large differences may show lateral pressure variations or model bias.

High Resolution Seismic velocities

Seismic velocities are a key input for most pre-drill pore-pressure prediction procedures. By correlating interval velocity with effective stress, seismic data enable subsurface pressure predictions beyond areas with well control data (Dutta, 2002; Bowers, 1995). High-resolution seismic velocity models, constructed with modern seismic processing and inversion techniques, can reveal subtle pressure anomalies, particularly in thick shale sequences or deltaic basins where overlying control on velocity by compaction is dominant (Dutta, 2002). However, because seismic velocities are an indirect indicator of pressure, accurate interpretation is a function of well calibration and knowledge of the geological, petrophysical, and seismic acquisition factors. Seismic velocities can be calculated from different types of seismic surveys, vertical seismic profiling (VSP), and checkshot data. The most valuable velocity measurement for pressure work is interval velocity, which is the true velocity of every unit between seismic reflectors. This comes from normal-moveout (NMO) analysis, pre-stack depth migration, or by seismic inversion steps (Dutta, 2002). High-resolution velocity inputs are based on:

- Pre-stack depth migration (PSDM) for keeping true interval velocities.
- Full-waveform inversion (FWI) for improved near-surface and shallow-section resolution.
- Checkshots and VSPs for vertical correction and mistie-checking.
- Velocity filtering and anisotropy correction (especially VTI—Vertical Transverse Isotropy) to calibrate to measured well velocities.

Mud gas

Mud gas readings—total gas, background gas, and connection gas, are frequently measured by surface gas monitors during drilling. Mud gas readings are a semi-quantitative measurement of gas liberation into the wellbore during drilling, where the percentage of total gas is linked to the gas content and mobility of the formation and the degree of over or underbalance of the mud weight. Gas content is also affected by both operational parameters, such as drilling rate, annular flow, solubility of gas, type of mud, and surface degassing efficiency. Thus, mud gas must be understood in relation to drilling conditions, never in an absolute manner.

Mud gas readings in combination with mud weights, kicks, losses, and pressure readings allow identification of underbalance, which provide the pore pressure analysist to ascertain whether predicted pressure trends align with nearby wells. Stable mud weight with increasing background or connection gas under controlled conditions signals increasing formation pressure and/or traversing more permeable intervals.

Mud gas data are likely to be misread unless properly normalized or lag corrected. Gas peaks can appear at incorrect depths due to poor lag-time estimation, ineffectiveness of degassers, or ROP fluctuation, leading to erroneous interpretation. In oil muds, gas suppression masks genuine overpressure indications, while surface leaks or calibration drift can generate wild readings. When comparing offsets, mixing up circulating and static mud weights or leaving out structural elevation variations can generate wrong equivalent mud weight (EMW) correlations. All these can combine to create false overpressure alerts or underestimation of real pressure hazards that affect mud-weight and casing design decisions.

To avoid this, every gas reading needs to be ROP and lag-corrected, surface systems calibrated periodically, and offset pressures read back to consistent ESD at TVDSS. Cross-correlating gas behaviour with LWD/MWD log responses allows that only pressure-dependent changes are employed for calibration.

Additionally, normalized total gas (gas/ROP ratio), along with chromatographic make-up (C_1–C_4 ratios), provides information regarding gas origin, potential connection with overpressure and the presence of a rise with depth in normalized gas, and matching trends in resistivity or sonic slowness, will support discrimination of overpressure.

2.3.9. Common Pitfalls

Accurate determination of the pore pressure gradient is subject to several technical and interpretational challenges. If not properly addressed, these pitfalls can lead to incorrect mud weight selection, unsuitable well design and section lengths, ultimately leading to well control incidents, or unnecessary non-productive time.

Incorrect definition of the normal compaction trend

Pore pressure prediction methods rely heavily on the correct identification of a normal compaction baseline. Variations in lithology, burial history, uplift, or erosion can distort log and velocity responses, leading to erroneous gradient estimates if these effects are not recognized (Eaton, 1972; Swarbrick & Osborne, 1998). In many cases the compaction trends are set and adjusted by the analysist to match the data, while semi-regional trends are to be used. Faulty data can as such lead to incorrect compaction estimates.

Inappropriate transfer of empirical parameters

Empirical methods such as the Eaton and Bowers formulations require calibration to local geological conditions. Applying default exponents or velocity–stress relationships from offset fields or different basins without validation can result in systematic bias in predicted pore pressure gradients (Bowers, 1995).

Overreliance on a single data source

Dependence on one indicator, such as sonic velocity or resistivity alone, increases uncertainty and may fail to capture complex overpressure mechanisms. Best practice requires integration of logs, drilling parameters, formation pressure tests, and geological interpretation to constrain the gradient reliably (Dutta, 2002).

Limited resolution of seismic-based predictions

Seismic velocities are spatially averaged and may mask localized overpressure zones, particularly near faults or stratigraphic boundaries. Without careful calibration to well data, seismic-derived pore pressure gradients can underestimate peak pressures encountered during drilling (Dutta, 2002). To apply seismic velocities for pressure prediction they should be extracted at the wellbore, preferably from normal moveout corrected data and checked by processing geophysicists.

Delayed updating during operations

Failure to continuously update pore pressure models with real-time drilling indicators, such as connection gas, drilling breaks, or mud weight changes, can cause the predicted gradient to diverge from actual conditions. This lag may reduce the effectiveness of well control and stability management. Identification of cavings, adjustments in the geological model or stratigraphy, well trajectory etc. can take time to understand and discover. Especially during incidents, it takes time to fully assemble and integrate all available data.

2.3.10 Quality Control

All methods used in pressure and stress estimation are uncertain, have measurement limitations and calibration requirements. Accurate pressure prediction is therefore dependent on model convergence, checking of all available data sets and calibration to in situ data. Described in detail below are the main methods with their corresponding data integration and quality control (QC) considerations so that each dataset inputs into the overall pressure model and operational safety in a consistent way.

1. Pressure Gradients

Plot all gradient data (pore, hydrostatic, overburden, and fracture) depth-corrected to TVDSS and in a homogeneous pressure unit. Compare calculated gradients against offset well data, LOT results, and fracture limits to ensure physical realism (Zoback, 2010). Ensure all validated gradient trends are continuous, eliminating spurious points (Fjaer et al., 2008).

2. Multi-Method Integration and Uncertainty Assessment

Merge seismic, LWD/MWD, wireline derived pressure estimates into the common depth and pressure format. Compare the estimates to in situ pressure. Quantify uncertainty and convey model confidence using base, high, and low scenarios. Cross-disciplinary QC between geophysics, petrophysics, and drilling teams prevents interpretation bias and internal inconsistency (Zoback, 2010; Aadnøy & Looyeh, 2011).

3. High-Resolution Seismic Velocity Input

Calibrate seismic velocities to checkshot and sonic logs based on anisotropy and time–depth corrections (Dutta, 2002). Verify interval velocities against known stratigraphic markers, smooth spikes and/or eliminate migration artifacts. QC that estimated pressures produce physically realistic effective stresses against overburden (Eaton, 1972; Bowers, 1995).

4. Calibration Against Mud Gas and Offset Wells

Normalize mud-gas data for ROP, flow rate, and lag time before interpreting. Make sure offset mud weights and pressures are measured with respect to static conditions and TVDSS. Check against dynamic mud weights if data is available. Cross-check mud-gas and offset well data against log derived pressures to confirm true pressure-related behaviour (Zoback, 2010).

5. Static Mud Weight Comparison

Adjust all offset mud weights to equivalent static density (ESD) with temperature and salinity adjustment. Mark data affected by ballooning, losses, or influx. Compare modelled pressures to static and dynamic mud-weight envelopes to verify that predicted pore and fracture gradients are in line with operating experience (Zoback, 2010).

6. Swab Risk Assessment

If available, confirm surge–swab simulations with downhole-corrected rheology and tripping parameters. Compare predicted swab pressures with observed pit-volume and flow-out trends. Check stable mud properties, gel strength, and circulation models during tripping operations.

7. Calibration to Formation Pressure Data

Assess data quality of each RFT/MDT/XPT/DST pressure points as outlined in more detail in previous sections. Normalize pressure data to TVDSS and fluid density, i.e. correct gas or oil pressure points to provide formation pressures. Cross-verify against log-derived pressures, LOT data, and offset well gradients.

8. Lateral Transfer and Pressure Communication

Map pressure–depth relationships for each structural block to establish compartmentalization (Swarbrick & Osborne, 1998). Check lateral pressure cell continuity based on pressure data, seismically mapped geological units, fluid contacts, and fault-seal models. All lateral correlations should be geologically consistent with respect to mapped horizons, stratigraphy and fault architecture.

9. Shallow Water Flow (SWF)

Integrate shallow high resolution seismic (2D or 3D UHR) with 3D seismic, pore-pressure prediction, and drilling hazard data into one near-surface model (Zhang et al., 2018). QC seismic anomalies with well drilling and log data to confirm occurrence of overpressure. Verify SWF-prone locations by mapping aquifers in wells and on seismic, mapping seismic anomalies, seismic velocity, and shallow pressure observations.

10. Depletion

Depletion trends are tuned by repeat formation-pressure tests, production history, and 4D seismic (Zoback, 2010). The pressure decline predicted is confirmed versus measured compaction, LOT shifts, or change in stress regime. QC ensures that all the stress changes caused by depletion are consistent with reservoir production history (Fjaer et al., 2008; API RP 92P, 2019).

11. Calibration of Depletion

Vary dynamic production data, repeating RFTs, and shut-in pressures to update depletion models (Zoback, 2010). Cross-verify simulation with measured field pressures and compaction observations. Employ uncertainty limits to simulate spatial variability in depletion amplitude and reservoir connectivity. (API RP 92P, 2019; Fjaer et al., 2008)

12. High-Pressure Conditions (Shut-In Pressure > 690 bar / ~10,000 psi)

Included in HPHT models are downhole real-time pressure, ECD, and temperature measurements (API RP 92M, 2016). Calibration of all sensors is inspected and certified that equipment ratings will satisfy HP requirements. Live pressure monitoring, kill-simulation verification, and post-well analysis ensure safe operation by continuous quality control (API RP 92S, 2019; Zoback, 2010).

2.3.11. Checklist

The following checklist highlights key points an integrated well delivery team should check for the pore pressure gradient.

Table 2. Pore Pressure Gradient Checklist

	Pore Pressure Gradient	Documentation
1	More than one method / input used & uncertainty assessed	*Name methods and data sources*
2	High resolution seismic velocity input used	*Name data source cube*
3	Checked against mud gas offset wells	*Name wells*
4	Checked against Static Mud Weight offset wells	*Name wells*
6	Swab risk assessed	*Location of documentation*
7	Calibration to pressure data offset wells	*Name wells*
8	Lateral transfer assessed	*Specify methods and data*
9	Lateral pressure transfer expected (inc. SWF)	*Specify formation / zone and depth*
10	Depleted and/or injection effects included	*Specify formation / zone and depth*
11	Depletion calibrated	*Specify formation / zone, method and depth*
12	High Pressure (shut-in pressure > 690 bar)	*Specify formation / zone and depth*

2.4. Fracture Gradient

The fracture Gradient (FG) refers to the pressure per unit of depth at which a rock formation begins to fracture in the borehole due to the pressure in the borehole. It is typically expressed in sg and plays a vital role in drilling design, mud weight selection, casing programs, and wellbore integrity assessments (Aadnøy & Looyeh, 2019; Mbamalu & Andrew, 2024). Accurate FG estimation helps mitigate risks such as formation breakdown, fluid losses, loss of circulation, and pressure-related incidents, like lack of containment and subsurface blowouts.

2.4.1. Definition and Calculation of Fracture Gradient

Fracture Gradient is the pressure at a specific depth at which a fracture initiates in the rock. It is expressed in bar/m or sg (Aadnøy, 2010).

For direct measurements (e.g. LOT or XLOT):

$$FG = \frac{P_{fracture}}{TVD}$$

Where:

- $P_{fracture}$ - fracturing pressure (bar or MPa)

- TVD - true vertical depth (m)

For empirical models (e.g., Eaton):

$$FG = \sigma_h + P_p$$

Where:

- σ_h - horizontal effective stress
- P_p - pore pressure

(Eaton model referenced in Aadnøy & Looyeh, 2019; Zoback, 2007)

2.4.2. Prediction Methods

Accurate estimation of the fracture gradient is dependent on the quality and diversity of the data utilized in prediction workflows and during well operations (Economides et al., 2012; Dake, 2001). Three main approaches are used in the industry:

- **Direct assessment:** Using insitu test from surrounding wells, such as the Leak-Off Test (LOT), Extended Leak-Off Test (XLOT), Formation Integrity Test (FIT), mini fracture tests and Diagnostic Fracture Injection Test (DFIT) all provide formation strength and integrity at specific depths that are used to determine the expected FG (Aadnøy, 2010; Mbamalu & Andrew, 2024). The direct measurement data is often supplemented with loss data, with dynamic mud weight (ECD) (Kerunwa et al., 2021).
- **Empirical models**, including those developed by Eaton and Matthews-Kelly, offer FG estimates based on depth, lithology, and regional data, but must be calibrated to local conditions (Zoback, 2007; Aadnøy & Looyeh, 2019). Most commonly compressional velocity (p-wave) data measured in the borehole is used as an input, measure either during drilling (LWD) or by wireline logging. Corrected seismic velocities can also be used as an input (Zhang & Yin, 2017; Tang et al., 2024).
- **Geomechanical modelling** integrate stress, porosity, and rock properties into a single model, providing comprehensive analysis when high-quality input data is available (Zoback, 2007). In addition to field measurements, laboratory and geophysical analyses provide essential data that underpin geomechanically modelling:
  - Laboratory Tests: core analyses such as triaxial compressive tests, rock strength assessments yield fundamental mechanical relationships required for modelling the behaviour of a formation under stress (Economides et al., 2012).
  - Seismic and geophysical analysis: These methods are employed to estimate in situ stress conditions and determine fracture orientation, offering a broader geological context that supports fracture gradient estimation (Zoback, 2007; Aadnøy & Looyeh, 2019). Especially the combined acquisition of shear and compressional waves provides important information on the behaviour of the rock.

Lithology as an input parameter in a predictive model

The effectiveness of predictive models for fracture gradient is strongly influenced by the accuracy with which lithology is characterized and incorporated. Distinct lithologies, such as shale, sandstone, and carbonate, exhibit varying mechanical properties and respond differently to stress and pressure (Zoback, 2007; Aadnøy & Looyeh, 2019). Lithological information may be sourced from direct measurements such as core samples, sidewall cores, cuttings, and well logs, or can be derived from well log data (e.g., gamma ray, resistivity), seismic attributes, or machine learning algorithms (Tang et al., 2024; Chichinina et al., 2020).

Rock Physics as Input

Incorporating realistic rock physics parameters into predictive models is fundamental for simulating subsurface behaviour (Zoback, 2007). These parameters enhance model accuracy and serve as a bridge between geology, geophysics, and engineering (Economides et al., 2012).

Key properties include Young's modulus (stiffness), Poisson's ratio (strain response), density (mass per unit volume), P-wave and S-wave velocities, tensile strength (fracture resistance), and porosity and permeability. These inputs are routinely applied in FG estimation, geomechanical modelling, seismic elastic property analysis, reservoir simulation, and pore pressure prediction (Aadnøy & Looyeh, 2019; Dake, 2001).

Without these parameters, models risk oversimplifying subsurface behaviour, leading to unreliable forecasts. Their integration enables multidisciplinary workflows and improves the predictive power of models, supporting more accurate assessments of pressure regimes, fracture risk, and reservoir performance (Zoback, 2007).

2.4.3. Depletion and injection Effects

Reservoir depletion occurs when a significant volume of fluids, such as oil, gas, or water, has already been produced, leading to reduced pore pressure, shifts in effective stress, and changes in the mechanical behavior of the formation (Zoback, 2007; Aadnøy & Looyeh, 2019). These changes can lower the fracture gradient, increase the risk of fluid loss, and affect wellbore stability.

In some injection or depletion cases, the stress regime may shift from normal to strike-slip or reverse, further complicating drilling conditions (Economides et al., 2012).

To manage these risks, depletion effects must be integrated into geomechanical models, well design, and risk assessments. This includes adjusting mud weights, casing programs, and stability predictions based on updated pore pressure and stress profiles (Aadnøy, 2010).

A key part of this process is calibrating the depletion factor, a numerical coefficient that determined the fracture gradient reduction in response to the pore pressure reduction. The depletion factor is entered into modelling software and applied in pore pressure models, fracture gradient simulations, and wellbore stability analyses (Zoback, 2007).

Reliable calibration mainly depends on direct measurement. Measured pore pressure provides direct input, while LOT/XLOT results help track fracture gradient changes (Mbamalu & Andrew, 2024). Seismic inversion offers indirect insight into stress redistribution, and production history supports time-based correlation (Zhang & Yin, 2017; Aadnøy & Looyeh, 2019). Information from fluid losses can supplement the analysis. Finite element modelling can provide additional insight with sufficient lab test derived rock mechanical data as input (Aadnøy & Looyeh, 2019).

Injection effects occurs when fluid or gas are injected into the formation and the pore pressure increases. Fluid injection, whether for secondary recovery, pressure maintenance, or disposal, can also strongly influence fracture gradients. Injection of cold fluids, for example, induces thermal contraction in the reservoir rock. This thereby reduces the fracture gradient and increases the formation's susceptibility to fracturing at lower pressures (Hu and Sharma, 2024). Moreover, injection induced fractures can propagate unpredictably, leading to nonuniform injection profiles, reduced recovery efficiency, or even fault activation. In some cases, uncontrolled injection-induced fractures have been linked to induced seismicity, underscoring the importance of careful monitoring and modelling of injection operations (Hu and Sharma, 2024).

The combined effects of depletion and injection highlight the dynamic nature of fracture gradients. Depletion changes the stress environment, whereas injection can either stabilise or destabilise it depending on fluid properties, rates, and reservoir conditions. Understanding these mechanisms is critical for designing safe and efficient drilling, stimulation and reservoir management strategies. Engineers must account for both historical depletion and ongoing injection activities when estimating fracture gradients, as ignoring these factors can lead to inaccurate predictions and significant operational risks (Hu and Sharma, 2024).

2.4.4. Uncertainty Reduction

Fracture gradient predictions must be validated against field measurements, primarily using Leak-Off Test (LOT) data. LOT is performed after casing and cementing, recording the pressure at which fluid begins to leak into the formation—known as Leak-Off Pressure (LOP) (Aadnøy, 2010; Mbamalu & Andrew, 2024). This value provides a direct FG estimate at the casing shoe depth. LOT data must meet quality criteria: stable pressure curves, accurate LOP identification, valid cement and casing conditions, and correct test depth. Graphical analysis includes pressure–time and pressure–volume plots, with derivative curves used to confirm LOP and fracture initiation (Kerunwa et al., 2021).

Extended Leak-Off Test (XLOT) extend fluid injection beyond initial leak-off, allowing identification of the leak off point (LOP), fracture initiation, propagation, and breakdown pressures (Aadnøy & Looyeh, 2019). These values are used to calibrate the model's upper bounds and improve prediction of reliability.

The following methods are considered to reduce fracture gradient uncertainty:

- **Integrating Multiple Methods:** Combining data from Leak-Off Tests (LOT), Logging While Drilling (LWD), and geomechanical modelling creates a more robust framework for estimating fracture gradients. Each method provides unique insights:
  - LOT provides direct pressure thresholds (Aadnøy, 2010),
  - LWD offers continuous formation properties (Zhang & Yin, 2017),
  - Geomechanics result in a more comprehensive and cross-validated interpretation (Zoback, 2010).
- **Calibrating Models with Field Tests:** Model predictions should be routinely compared against LOT results to validate assumptions and refine input parameters. This calibration process helps align theoretical models with actual formation behaviour, reducing the risk of over- or underestimating fracture thresholds (Mbamalu & Andrew, 2024).
- **Incorporating lithology:** Fracture gradient predictions improve when lithology is integrated correctly, especially in complex formations where rock types exhibit varying mechanical responses (Zoback, 2007; Aadnøy & Looyeh, 2019). Calibrating key properties, such as Young's modulus and bulk density, using both lab and log data enhances model accuracy (Economides et al., 2012). Including lithological zonation helps define stress distribution more precisely,

particularly at transitions between stiff and soft rocks, where stress is concentrated (Drake, 2001).

- **Incorporating faults and fractures:** Natural fractures and fault zones can introduce local stress changes and pore-pressure variations, complicating predictions of fracture gradients (Zoback, 2007). Techniques like seismic mapping, borehole imaging, and pressure diagnostics help identify these zones and guide model adjustments (Tang et al., 2024; Aadnøy & Looyeh, 2019). Including these structural features in geomechanical models makes predictions more dynamic and better aligned with real subsurface conditions (Aadnøy & Looyeh, 2019).
- **Incorporating Seismic Data:** Seismic attributes, including velocity anisotropy, stress orientation, p-wave and derived s-wave velocities, can be integrated into geomechanical models to improve the spatial resolution of horizontal stress estimates (Zoback, 2010; Tang et al., 2024). This is especially beneficial in areas with sparse well control, enabling more accurate regional fracture gradient mapping (Aadnøy, 2010).

2.4.5. Common Pitfalls

Despite thorough planning, errors in fracture gradient (FG) estimation are common. These errors may affect well integrity, increase operational risks, or lead to costly interventions (Aadnøy, 2010; Mbamalu & Andrew, 2024). Below are typical issues encountered in practice:

- **Overestimating FG:** often results in using excessive mud weight, which may damage the formation and reduce reservoir quality. The resulting high mud weight can cause fracturing and loss of circulation, especially in weaker formations. Very common in overburden sandstone and cemented zones where the predictions are based on shale (Zoback, 2007).
- **Underestimating FG:** often results in using to low mud weight, which may destabilize the formation leading to pack off and getting stuck (Kerunwa et al., 2021). Often the case in overpressured zones where stress coupling increases both the pore pressure and the fracture gradient.
- **Misinterpreting LOT data**: confusing the leak-off point with formation integrity test or formation pressure can lead to incorrect FG assumptions. In many cases only the LOT value is available and direct QC is not possible due to the lack of build up plots and documentation (Aadnøy & Looyeh, 2019).
- **Poor model calibration:** Applying empirical models beyond their valid range can produce misleading results, especially in complex lithologies (Zoback, 2007; Dake, 2001).
- **Neglecting geological anomalies:** Features like salt intrusions or abnormally high pore pressure can distort FG predictions if not properly accounted for (Economides at al., 2012).
- **Neglecting faults and fractures:** In most cases faults and fractures lead to a reduction of the fracture gradient, bringing it to or close to the minimum stress (Zoback, 2007).
- **Unknown depletion or injection effects:** It is hard to fully quantify the effect of depletion or injection around the production / injection boreholes as it requires production data, advanced modelling and calibration together with in depth knowledge of geomechanical behaviour to both pressure, temperature and fluids. This information is in most cases not available (e.g. injection in overburden) or shared (e.g. neighbouring license with different operator).

2.4.6. Quality Control

Fracture gradient calculations are influenced by input factors such as overburden stress, pore pressure, and rock properties, making quality control essential for reliable estimates (Aadnøy, 2010; Zoback, 2007).

Main QC Steps:

- **Check Input Data:** Make sure overburden and pore pressure profiles are based on calibrated logs and models. Depth references should match stratigraphy to avoid errors (Zhang & Yin, 2017; George, 2020).
- **Select Appropriate Method:** Use a method suited to the formation type and pressure regime (e.g., Eaton, Matthews–Kelly). Avoid mixing approaches unless justified (Aadnøy & Looyeh, 2019).
- **Review LOT/XLOT Results:** Validate pressure readings and test conditions. Disregard tests with poor hole conditions or unclear responses. Compare results with model predictions (Mbamalu & Andrew, 2024).
- **Account for Lithology and Rock Mechanics:** Fracture gradient should reflect actual rock behaviour. Flag zones with mixed lithology or low log quality (Economides et al., 2012).
- **Compare with Offset Wells:** Look at trends across nearby wells in similar settings. Investigate any anomalies or outliers (Zoback, 2007).
- **Document Uncertainty:** Note where estimates are less certain due to data gaps or method limitations. Highlight these zones in planning.
- **Summarize QC Findings:** Clearly list validated intervals, excluded data, chosen methods, and calibration sources. Keep all inputs traceable for review (Aadnøy, 2010).

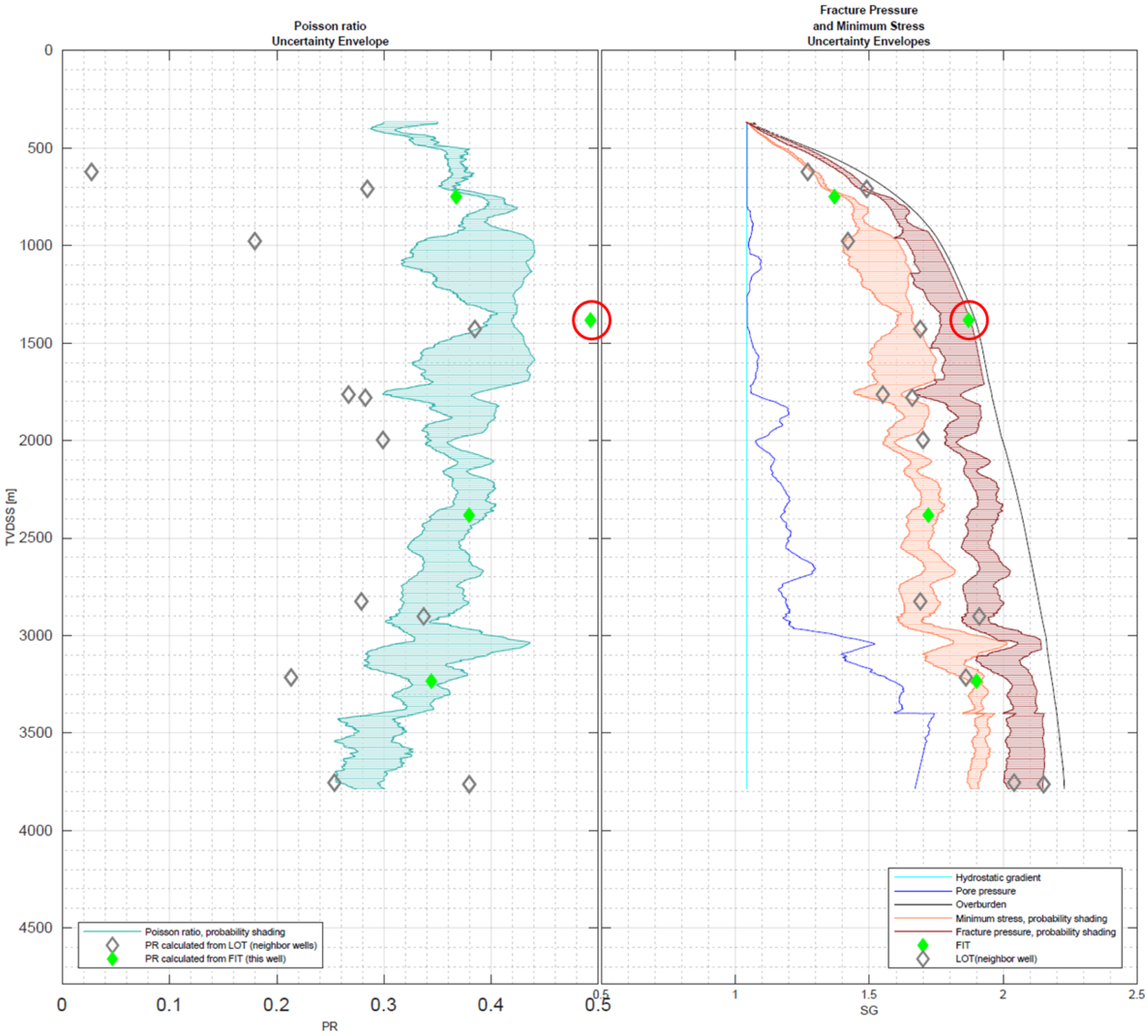


Figure 4. Example of FIT/LOT and PPFG model QC. FITs were checked for their validity by back calculating the Poisson ratio and comparing to log derived estimates (left) and compared to minimum stress and fracture gradient uncertainty ranges (right). Note erroneous FIT point marked with red circle.

2.4.7. Checklist

The following checklist highlights key points an integrated well delivery team should check for the fracture gradient.

Table 3. Fracture Gradient Checklist

	Fracture Gradient	Documentation
1	More than one method / input used & uncertainty assessed	*Name methods and data sources (e.g. pre-stack inversion seismic cube name)*
2	Lithology predicted & included in prediction	*Name methods*
3	Rock physics included as input	*Name method, parameters used (e.g. Poisson Ratio) & sources of data*
4	Data corrected for prognosed stratigraphy and/or depth	*Describe method e.g. Top Tables & name top set*
5	Fracture gradient checked against LOT data	*Wells and formations*
6	LOT data validity checked & LOT plots available	*Describe and link to documentation*

7	Calibration against XLOT data or well documented LOP in LOT	*State data source, wells and formations*
8	Depleted and/or injection effects expected and included	*State method, data source & date of estimate*
9	Depletion factor calibrated	*Wells, depth, method and date*

2.5. Minimum Stress Gradient

The minimum stress gradient (MSG) represents the rate at which the minimum principal stress (σ_{min}) changes with depth, typically associated with the horizontal stress in normal faulting regimes. It is a critical input for wellbore stability and avoiding losses.

2.5.1. Definition and Calculation

MSG is defined as the ratio of the minimum principal stress (σ_{min}) to true vertical depth (TVD), typically expressed in psi/ft or MPa/m. When derived from XLOT or DFIT, it reflects fracture closure pressure. When inferred from loss data, it represents the lower bound of wellbore pressure before losses occur (Subsurface Alliance, 2023) or when losses stop dynamically, i.e. by reducing pump or back pressure.

Minimum Stress Gradient (MSG) is defined as:

$$MSG = \frac{\sigma_{min}}{\mathrm{TVD}}$$

Where:

- MSG - minimum Stress Gradient
- σ_{min} - minimum principal stress (typically horizontal)
- TVD - true vertical depth

2.5.2. Prediction Methods

Estimation methods of minimum stress include:

- **Direct In Situ Measurements**
  Techniques such as Extended Leak-Off Tests (XLOT) and Diagnostic Fracture Injection Tests (DFIT) provide direct measurements of stress magnitudes. An XLOT determines the pressure at which the formation fractures and subsequently closes, offering a reliable estimate of σ_{min} (ARMA, 2021). DFIT, commonly applied in unconventional reservoirs, analyzes post-injection pressure decline to infer closure stress and reservoir properties (Whitson AS, n.d.; IHS Energy, n.d.; British Columbia Energy Regulator, 2023). These methods yield high-confidence data but are depth-limited and require expert interpretation (Zhang and Yin, 2017).

- **Indirect Derivations from Leak-Off Tests**
  Leak-Off Tests (LOT) and Formation Integrity Tests (FIT) are conducted during drilling to assess formation integrity. While not designed to measure stress directly, LOT can indicate fracture initiation pressure, and FIT confirms the wellbore's ability to withstand expected pressures. When calibrated with offset data, these tests can be used to calculate MSG values (Economides and Nolte, 2000).

- **Rock Physics Modelling Calibrated with Offset Well Data**
  Elastic properties such as Young's modulus and Poisson's ratio, derived from logs and core tests, are used to model stress behaviour. Calibration with known stress values from nearby wells (e.g., XLOT or DFIT results) allow extrapolation across intervals lacking direct measurements. This method is particularly useful in pre-drill planning and uncertainty reduction, especially when integrated with seismic and petrophysical data (Fjaer et al., 2008; Zoback, 2010).

- **Stress Inversion from Borehole Image Logs and Calliper Data**
  Stress inversion techniques interpret borehole deformation features to estimate stress orientation and magnitude. Image logs reveal breakouts and drilling-induced fractures, while calliper logs detect borehole enlargement zones. These features help infer MSG, especially in structurally complex settings (Moos and Zoback, 1990; Plumb and Hickman, 1994).

- **Loss-Based Back-Calculation Using Dynamic Loss Events**
  MSG can be inferred from dynamic loss events. Sudden fluid losses during drilling suggest that wellbore pressure exceeded the minimum stress. By analyzing the pressure at which losses are initiated and at when losses stop, the MSG can be back calculated. This method is particularly valuable in depleted or fractured zones (Subsurface Alliance, 2023).

To improve robustness and reduce uncertainty, multiple methods should be applied in parallel and cross-validated (Zhang and Yin, 2017; British Columbia Energy Regulator, 2023).

To ensure accuracy in estimating the minimum stress gradient, the following inputs are integrated:

- **MWD/LWD logs**: real-time pressure, caliper, and sonic data
- **In situ tests:** XLOT, DFIT, LOT/FIT from offset wells (ARMA, 2021)
- **Lab tests**: core-based mechanical properties (Young's modulus, Poisson's ratio) (Fjaer et al., 2008)
- **Rock physics models:** calibrated using petrophysical and seismic data (Zoback, 2010; Zhang and Yin, 2017)
- **Offset well data**:
    - **Loss circulation events,** recorded in daily drilling reports and mud logs, mark depths where wellbore pressure exceeded the local fracture gradient, offering empirical lower-bound constraints for the minimum horizontal stress gradient (S_{hmin}) (Subsurface Alliance, 2023).
    - **Borehole image logs** acquired using tools such as FMI, OBMI, or ultrasonic televiewers—reveal stress-related features including breakouts, drilling-induced tensile fractures, and natural fracture networks. Breakouts typically align perpendicular to (S_{hmin}), while tensile fractures follow the orientation of maximum horizontal stress (S_{Hmax}), allowing for statistical validation of regional stress regimes (Moos and Zoback, 1990; Plumb and Hickman, 1994).
    - **Caliper logs** further support stress interpretation by identifying borehole enlargement and deformation zones, which are cross-referenced with image logs and drilling records to confirm mechanical failure linked to stress redistribution (Tingay et al., 2008)
    - **Stratigraphic corrections** are applied to normalize depth references across wells, using formation tops, marker beds, and synthetic seismograms to ensure

consistent mapping of stress data within a unified stratigraphic framework (Zoback, 2010)

- **Reservoir depletion effects** are incorporated through production history, pressure monitoring, and simulation outputs. As pore pressure declines due to hydrocarbon extraction, stress redistribution occurs—often reducing (S_{hmin}) and increasing the risk of shear failure. These changes are quantified using poroelastic models, including Biot's coefficient, to adjust stress profiles in depleted zones with high fidelity (Fjaer at al., 2008; Zoback, 2010).

2.5.3. Uncertainty Reduction

Estimating the minimum stress gradient involves integrating diverse datasets and modelling techniques, each with inherent limitations. To reduce uncertainty and improve confidence in MSG values, the following methods are applied systematically and benchmarked against known failure zones (Zoback, 2010; Fjaer et al., 2008):

- **Multi-Method Cross-Validation (XLOT vs. Loss Data vs. Image Logs):** MSG estimates are validated by comparing results from independent sources:
    - XLOT tests provide direct measurements of fracture initiation and closure pressure, providing minimum horizontal stress. XLOT data from nearby wells is transferred to equivalent stratigraphic units, adjusted for depth and depletion effects (ARMA, 2021).
    - Loss-circulation data from offset wells indicate pressure thresholds at which fluid losses occur, serving as indirect lower bounds for MSG (Subsurface Alliance, 2023).
    - Borehole image logs reveal stress-related features such as breakouts and drilling-induced fractures, which correlate with low-stress zones (Moos and Zoback, 1990; Tingay et al., 2008).

  By overlaying these datasets, convergence zones are identified where MSG estimates are consistent across methods. Divergences trigger re-evaluation of input assumptions and stratigraphic alignment.
- **Stratigraphic Correction: Depth and Lithology Alignment.** MSG is depth-dependent and highly lithology-sensitive. To ensure geological consistency, all input data (e.g., loss events, logs) should be corrected for true vertical depth (TVD) and aligned with stratigraphy (Zoback, 2010). This prevents misapplication of offset data to mismatched formations and improved the vertical resolution of MSG profiles.
- **Loss Data**
  Loss data provides important constraint on the minimum stress model. However, losses can have multiple reasons and documentation is often poor. Dynamic loss data provide real-time pressure thresholds where losses initiate, helping define the lower bound of MSG (Subsurface Alliance, 2023).
- **Rock Physics Constraints: Elastic Moduli and Stress Behaviour**
  Elastic properties are used to constrain MSG modelling and reduce overestimation in stiff lithologies and underestimation in ductile zones. Young's modulus, Poisson's ratio, and bulk modulus are derived from logs and core tests (Fjaer et al., 2008). These parameters are integrated into rock physics models that simulate stress distribution across depth (Zoback, 2010).
- **Stress Mapping: Faults, Losses, and Cavings**
  Mapping of zones with faults, stress cavings and historical losses supports proactive risk mitigation and highlights intervals requiring conservative pressure margins. Sensitive regions

are plotted against depth and location (Tingay et al., 2008). These features function as stress anomalies and are used to flag intervals where MSG may deviate from regional trends.

- **Benchmarking Against Known Failure Zones**
  Zones with total losses, severe cavings, or fracture propagation can be used as operational benchmarks (Subsurface Alliance, 2023). If MSG values are aligned with observed failure thresholds, the model is considered validated. Discrepancies trigger re-analysis of inputs, recalibration, or exclusion of unreliable data. This ensures that MSG profiles were not only theoretically sound but operationally proven.

2.5.4. Common Pitfalls

Accurate estimation of the minimum stress gradient is critical for maintaining wellbore integrity and avoiding costly drilling complications (Zoback, 2010; Zhang and Yin, 2017).

Common issues include:

- **Overestimating the minimum stress gradient (MSG)** can result in highly overbalanced drilling conditions, leading to total circulation losses (Subsurface Alliance 2023) and increased the risk of premature fracturing during leak-off tests (LOT) or extended leak-off tests (XLOT) (ARMA, 2021).
- **Underestimating the minimum stress gradient (MSG)** can result in lower mud weights and pumping pressure leading to poor hole cleaning and/or instabilities. In extreme cases this can lead to inflow, especially in combination with swabbing and stuck equipment.
- **No or incorrect lithology input** often results in losses when drilling through sandstone or carbonate layers that were not included in the model. Often these zones have very different properties leading lower MSG than predicted.
- **Incorrect depth correlation** may cause a mismatch between log data and the actual formation, compromising interpretation accuracy (Zoback, 2010).
- **Depletion effect:** If depletion effects are ignored or underestimated, MSG values may be significantly lower in zones that have already been produced, potentially leading to large losses (Fjaer et al., 2008).
- **Poor image log quality** can lead to misinterpretation of breakout and caving indicators, thereby affecting the reliability of geomechanical assessments (Moos and Zoback, 1990).

2.5.5. Quality Control (QC)

Quality control is essential to ensure that minimum stress gradient estimates are technically valid and operationally dependable. This section describes the procedures used to verify input data, cross-check results using multiple methods, and compare predictions to known well failure zones. By applying rigorous quality control at every stage, from data collection to model calibration, the risk of misinterpretation is minimized and confidence in the final gradient profile is enhanced.

- **Cross-checking MSG estimates against offset well loss data** helps validate the lower bounds of the stress gradient (Subsurface Alliance, 2023). Loss circulation events provide direct evidence of pressure thresholds exceeded during drilling and serve as empirical constraints.
- **Validating borehole image log interpretations using calliper anomalies** ensure that breakout zones and stress-induced features are not misidentified (Plumb and Hickman, 1994). Calliper

data confirm the presence and extent of borehole enlargement consistent with mechanical failure.

- **Flagging structurally complex zones**, such as those intersected by faults, affected by caving, or associated with historical losses, allows for targeted scrutiny and risk mitigation in stress-sensitive intervals (Moos and Zaback, 1990).
- **Assessing surge and loss risk based on the MSG envelope** supports operational planning. By comparing expected pressure excursions to the stress gradient profile, engineers can anticipate instability and adjust mud and casing programs accordingly (Zhang and Yin, 2017).
- **Documenting all assumptions, corrections, and calibration steps**—including lithological adjustments, depletion effects, and tool limitations—ensures traceability and transparency throughout the analysis (Zoback, 2010).
- **Ensuring consistency between rock physics models and field-acquired data** is essential. Elastic properties derived from logs and seismic must align with observed stress indicators and pressure trends to maintain physical coherence (Fjaer et al., 2008).

2.5.6. Checklist

The following checklist highlights key points an integrated well delivery team should check for the minimum stress gradient.

Table 4. Minimum Stress Gradient Checklist

	Minimum Stress Gradient	Documentation
1	More than one method / input used & uncertainty assessed	*Name methods and data sources*
2	Rock physics input used	*Name method, parameters used (e.g. Poisson Ratio) & sources*
3	Data corrected for prognosed stratigraphy and/or depth	*Describe method e.g. Top Tables & name top set*
4	Checked against loss data offset wells	*Name wells*
5	Checked against cavings offset wells	*Name wells, is caving behaviour understood?*
6	Checked against caliper / borehole image offset wells	*Name wells*
7	Zones with losses, faults & stress cavings plotted	*Specify formation / zone and depth*
8	Risk of total losses identified	*Specify formation / zone and depth*
9	Surge & loss risk assessed	*Location of documentation*
10	Calibration with dynamic loss data offset wells	*Specify wells, formation / zone and depth*
11	Calibration with XLOT data offset wells	*Specify wells, formation / zone and depth*
12	Depleted reservoir effects expected and included	*Specify formation / zone and depth*

2.6. Collapse Gradient

Collapse gradient determination can combine independent methods to minimize uncertainty. As a best practice, analytical (Kirsch & Mohr-Coulomb), numerical elasto-plastic, and empirical / offset-based experienced based methods are run parallel and cross-validated. Each of these methods are based on a varying degree of physical complexity and data input, and their combination ensures a balanced and defendable mud-weight window (Zoback, 2007; Fjaer et al., 2008; Aadnøy & Looyeh, 2019).

Analytical Method

Analytical models use closed-form elastic solutions derived from the Kirsch equations and the Mohr-Coulomb failure criterion. They assume an isotropic, homogeneous, linear-elastic rock medium and an instantaneously applied stress state. These models estimate hoop and axial stresses near a circular borehole and calculate the mud weight required to prevent compressive failure (Zoback, 2007; Fjaer et al., 2008; Aadnøy & Looyeh, 2019).

Major strengths:

- Provides quick, clear, and physically intuitive results.
- Requires minimal input data (rock strength, stress magnitudes, and pore pressure).
- Perfect for pre-drill planning or preliminary screening of mud-weight windows.
- Allows easy sensitivity analysis to identify influential parameters on wellbore stability (Aadnøy & Looyeh, 2019).

Weaknesses:

- Assumes purely elastic behaviour—cannot model plastic deformation or creep.
- Ignores the effects of anisotropy, bedding planes, and weak layers.
- Oversimplifies geometry and stress distribution, decreasing accuracy in complex trajectories.
- Tends to underestimate collapse pressure in high-inclination or tectonically stressed formations (Bradley, 1979; Zoback, 2007).

Guidance on avoiding issues:

- Use analytical results only as a first-order estimate; verify against numerical or offset data.
- Correct for anisotropy by incorporating directionally dependent elastic moduli or using transformed stress tensors.
- For inclined wells, use modified Kirsch equations with inclination and azimuth corrections.
- Always plot analytical results with uncertainty bounds (±0.2–0.3 ppg typical) (Aadnøy & Looyeh, 2019).

Numerical Elastic-Plastic Method

Numerical methods (finite-element or finite-difference modeling, for example) solve the full stress–strain field around the borehole, with elasto-plastic constitutive laws. They simulate stress redistribution and progressive failure, and complex geometries, layered formations, and non-linear rock behavior are feasible (Aadnøy & Looyeh, 2019; Fjaer et al., 2008).

Main strengths:

- Captures non-linear, anisotropic, and plastic deformation mechanisms.
- Models complex geometries, high inclination, and stress reorientation around faults.
- Can include time-dependent (creep) and temperature effects if data are available.
- Produces full spatial outputs — failure zones, plastic radius, and breakout geometry (Cook et al., 2012; Li et al., 2024).

Weaknesses:

- Requires detailed input data: full stress tensor, strength parameters, elastic constants, and boundary conditions.
- The results are mesh quality, boundary size, and constitutive model sensitive.
- Computationally intensive and less transparent than analytical methods.

- Validation depends on the quality and representativeness of lab and log data (Fjaer et al., 2008).

Guidance on avoiding issues:

- Perform mesh sensitivity and convergence testing to determine numerical stability.
- Calibrate model parameters to laboratory tests, image logs, and offset well data.
- Use realistic constitutive models (e.g. Mohr-Coulomb, Drucker-Prager, or Modified Cam-Clay) suitable for the type of formation (Aadnøy & Looyeh, 2019; Detournay & Cheng, 1993).
- Compare numerical results with analytical solutions in stable regions as a cross-check (Zoback, 2007).

Empirical / Offset-Based Calibration

Empirical or offset-based techniques use previous drilling experience—mud weights, breakout observations, caliper logs, cavings, and stuck-pipe occurrences—to calibrate and constrain analytical and numerical models. They constitute a pragmatic empirical approach for bridging modelling results and field well performance (Moos et al., 2003; Allawi et al., 2021).

Principal strengths:

- Incorporates field evidence of collapse, stability, or overbalance directly.
- Minimizes uncertainty by checking models against observed drilling results.
- Provides insight into operational influences on borehole behaviour (e.g. exposure time, mud rheology).
- Easy to apply with offset data available, without needing complex modelling.

Weaknesses:

- Data quality is variable—offset wells may differ in trajectory, mud system, or formation properties.
- Operational records (e.g. stuck-pipe depth, overpulls) can be incomplete or misleading.
- Lacks predictive capability beyond the conditions represented in historical data.
- Cannot differentiate between geomechanical causes and operational or mechanical failures (Moos et al., 2003).

Suggestions on how to fix:

- Validate offset data carefully—ensure wells are operationally and geologically similar.
- Cross-plot cavings, breakouts, and stuck-pipe depths versus logs to confirm cause–effect relationships.
- Use empirical calibration as a validation step, but not as a stand-alone prediction method.
- Have a minimum of one offset well with full image logs and stress interpretation available for model tuning (Zoback, 2007).

Integrated Approach and Uncertainty Management

Inputs come from MWD and LWD logs (density, sonic, resistivity, caliper, image logs), laboratory tests (triaxial compression, direct shear, uniaxial compressive strength), and in situ stress measurements (LOT, mini-frac, leak-off, and image-log breakouts) (Horsrud, 2001; Fjaer et al., 2008; Moos et al., 2003).

Uncertainty is addressed by Monte Carlo or sensitivity analyses, varying stress magnitudes, pore pressure, cohesion, and friction angle in an attempt to identify the most critical parameters (Li et al., 2024; Cook et al., 2012).

Typical uncertainties in collapse gradient prediction are ±0.2–0.3 ppg in well-constrained intervals and ±0.5 ppg where rock strength or stress direction are poorly constrained (Aadnøy & Looyeh, 2019).

A summary of possible problems and solutions

What can go wrong:

- Over-reliance on one method (e.g. analytical) in plastically deforming formations.
- Inconsistent or conflicting laboratory, log, and in situ inputs.
- Underestimation of uncertainty ranges.
- Tool drift or calibration errors propagated through models.

Suggestions on how to fix:

- Run analytical, numerical, and empirical models in parallel and compare results.
- Cross-validate elastic moduli from sonic logs with laboratory measurements.
- Explicitly quantify uncertainty using Monte Carlo analysis.
- Rigorously enforce QC and calibration on all input data.
- Re-evaluate assumptions (elastic vs plastic, isotropy) if models differ significantly (Zoback, 2007; Fjaer et al., 2008; Allawi et al., 2021).

2.6.1. Definition and Calculation

The collapse gradient is a minimum pressure gradient that prevents a shear/compressive failure of the wellbore wall due to a stress concentration developed in the rock as a result of drilling a wellbore. A collapse happens when a shear/compressive strength of a rock at a borehole wall is exceeded (Fjaer, Holt, & Horsrud, 1992; Zoback, 2010).

Multiple models exist the estimate and calculate the collapse gradient. In an isotropic linear elastic formation, the collapse pressure for a vertical well can be calculated by integrating the Kirsch elastic stresses into the Mohr-Coulomb failure model(Fjaer et al., 2008):

$$\sigma'_{\theta\theta} = \sigma'_1 \frac{1+\sin\phi}{1-\sin\phi} + \frac{2c\cos\phi}{1-\sin\phi}$$

effective hoop stress at the borehole wall is (Fjaer et al., 1992):

$$\sigma'_{\theta\theta} = \sigma_{\theta\theta} - P_p$$

and the elastic hoop stress at the borehole wall is given by Kirsch as (Zoback, 2010):

$$\sigma_{\theta\theta} = 3\sigma_h - \sigma_H - P_w$$

Where:

σ_H and σ_h are the maximum and minimum horizontal stresses,
P_p is pore pressure,
c is cohesion, and ϕ is the friction angle.

Solving for Pw gives the collapse pressure, which is then converted to collapse gradient (mud weight) by dividing by true vertical depth. This formulation forms the analytical baseline for collapse prediction and is widely used for pre-drill wellbore stability screening before numerical or empirical calibration (Aadnøy & Looyeh, 2019).

2.6.2. Prediction Methods

Inclination and azimuth

Inclination and azimuth of the wellbore are dealt with explicitly by rotating the in-situ stress tensor into the borehole coordinate system.

Collapse pressure depends on the wellbore orientation relative to principal stresses — especially important for deviated and horizontal wells. Inclined wells are subject to an asymmetric hoop stress distribution, so the collapse gradient must be recalculated for each section of trajectory rather than applying one vertical model (Bradley, 1979; Zoback, 2007).

For inclinations above ~20–30°, the stress concentration on the low side of the hole has a tendency to rise, which raises the mud weight required to prevent compressive failure. Analytical solutions that use transformed Kirsch equations or full 3D numerical simulations are both used to model this effect accurately. Ignoring inclination can lead to collapse gradient underestimation by up to 10 - 20 % in extremely anisotropic or directionally stressed formations (Bradley, 1979; Li et al., 2022; Dosunmu et al., 2020).

Horizontal stress field and direction

Minimum and maximum horizontal stress magnitudes and azimuths (S_H and S_h) are critical to collapse pressure determination, especially for deviated wells. Stress orientation is obtained from borehole image logs (breakout azimuths, drilling-induced fractures), regional tectonic information, or mini-frac tests. Then the 3D stress tensor is rotated into the borehole frame to compute hoop and axial stresses (Moos et al., 2003; Zoback, 2007).

Collapse risk is most significant when the well azimuth is parallel to the direction of minimum horizontal stress, as this orientation maximizes borehole-wall compressive stress concentration. More advanced methods such as Mogi-Coulomb or Drucker-Prager criteria incorporate the intermediate stress term to improve representation of stress anisotropy (Al-Ajmi & Zimmerman, 2005; Al-Ajmi, 2006).

Quality control involves ensuring that breakout azimuths and magnitudes predicted are consistent with observed image-log data, and that stress directions are consistent between offsets. The neglect of proper stress orientation is a common source of gross under- or overestimation of collapse gradients (Zoback, 2007).

2.6.3. Uncertainty Reduction

Cavings

Offset wells provide valuable confirmation of collapse by records of cavings. The lithology and size distribution of cavings trapped at shakers can be compared with predicted weak zones or calculated collapse gradients.

Where large angular cavings coincide with intervals predicted to have small collapse margins, the reliability of the model can be confirmed. Conversely, unexplained cavings in supposedly stable regions indicate model or data deficiencies.

Cavings analysis is most useful in shales and weak claystones, where early collapse may not be evident on caliper logs. Collapse models cross-validated with multiple offset wells having similar caving intervals carry reduced uncertainty.

QC steps include verification of mud properties at the time of cavings, cuttings lag corrections, and that the cavings are formation-related and not the result of surface reaming or mechanical washouts (Horsrud, 2001; Fan et al., 2021).

Stuck tools / overpull

Offset well drilling reports are reviewed for stuck-pipe incidents, tight spots, or high overpulls, which are found to correlate with collapse zones. These operational indices are plotted versus depth and compared with predicted collapse pressure profiles. If these mechanical events are coincident with low-margin windows in the model, it validates the strength and stress inputs. But if stuck events did indeed occur outside of predicted weak zones, it may be indicative of other contributors such as differential sticking, hole cleaning, or local faulting.

QC entails making sure that incidents reported are properly depth-referenced and correlated with open-hole time, not completion or tripping phases. Coupling mechanical history with geomechanical modeling enhances collapse gradient prediction and provides safer mud weight windows (Moos et al., 2003; Allawi et al., 2021).

Faults, fractures or discontinuities

All known faults, fractures, and discontinuities along the planned trajectory are plotted and overlain on the collapse gradient profile. These zones are mechanical weaknesses and local stress perturbations that will lower collapse resistance. Faults are likely to be stress concentrators or pressure communication paths, while fracture swarms can be weakening anisotropic features in the rock. Collapse modelling captures these intervals through mechanical parameters with cohesion and friction angle reduced by 20–40 % or implementing a discrete joint model for numerical runs.

Cross-checking with seismic interpretation, image logs, and mud-loss intervals determines the actual extent of the fractured zones. QC is all about confirming fault positions, dips, and orientations relative to the well path to be accurately captured in the model (Zoback, 2007; Fjaer et al., 2008).

Intervals previously identified as fault or fracture problem areas in the earlier wells are provided with additional safety margins in the collapse gradient envelope. Such intervals usually have a history of borehole instability, partial hole collapse, or stuck-pipe problems.

For these intervals, the collapse gradient is re-calculated using reduced rock strength and, possibly, altered local stress direction since the stress field near faults can be significantly different from the regional field. Operational mud weight programs include a 0.3–0.5 ppg safety buffer through these zones, and tripping/logging times are minimized along with QC.

QC entails correlation with seismic attributes (fault throws, fracture density) and calibration versus image-log fracture interpretations. Disregard of localized stress re-orientation in the vicinity of faults is a common source of unexpected wellbore collapse in spite of an otherwise valid general model (Moos et al., 2003; Zoback, 2007).

Caliper Logs

Caliper logs and borehole imaging tools (acoustic or resistivity) are utilized to identify borehole enlargement (breakouts) or shrinkage due to compressive failure.

Oval or enlarged shapes of boreholes are compared with modelled breakout sizes from the collapse gradient calculation. The azimuth of enlargement has to be in a direction perpendicular to the direction of the maximum horizontal stress.

If image or caliper logs from offset wells exist, their depths and breakout widths are overlaid on predicted collapse pressure curves to validate mechanical parameters.

Quality control includes checking log quality (decentralization of tools, washout correction) and comparing multiple log runs to help distinguish between mechanical enlargement and chemical dissolution. Disagreement between model and measured breakout geometry is a key indicator that stress magnitudes, pore pressure, or rock strength must be recalibrated. (Zoback, 2007; Fjaer et al., 2008).

2.6.4. Common Pitfalls

High inclination (> 30 degrees)

In horizontal and high-inclination wells, the stress field around the borehole is entirely three-dimensional. The principal stresses on the borehole wall vary with inclination and azimuth, and the vertical well assumptions of simplicity no longer hold.

Collapse gradients are calculated from complete 3D stress transformations or elasto-plastic finite-element models that include anisotropy and gravity effects. Collapse in these wells is asymmetric, Localized on the low side of the borehole, and is very sensitive to well trajectory relative to SH and Sh.

QC is achieved by comparing predicted breakout azimuths with image-log measurements and ensuring that the direction of maximum stress concentration is coincident with observed breakouts. Use of vertical-well collapse gradients in high-angle wells is one of the most common causes of underbalanced drilling-induced collapse. Where there is high uncertainty, a conservative margin of safety (≥ 0.5 ppg) is maintained (Bradley, 1979; Li et al., 2022; Dosunmu et al., 2020).

Plastic zones (ooze, smectites, etc.)

Creeping or plastic formations, such as smectite-rich shales, oozes, or underconsolidated clays, are identified from mineralogical data, XRD analysis, and wellsite cuttings descriptions.

These formations possess time-dependent deformation (creep) and progressive weakening upon exposure to drilling fluids. In these intervals, static collapse gradient models may underestimate the actual requirement because failure may occur over time and not necessarily immediately. Mitigation includes the application of a time-dependent or viscoplastic correction to collapse pressure, using non-dispersive inhibitive mud systems, and minimizing open-hole exposure time.

QC includes verification of mineralogical composition, monitoring time-dependent caliper change, and correlation with shale reactivity tests (swelling, dispersion, capillary suction). Plastic zones are highlighted in the collapse gradient plot with lowered mechanical strength values and wider uncertainty envelopes (Horsrud, 2001; Fan et al., 2021; Aadnøy & Looyeh, 2019).

2.6.5. Quality Control (QC)

Collapse gradient is the most uncertain of all calculated gradients. Reliable collapse gradient prediction depend on the quality and consistency of input data, including in-situ stress magnitudes and orientations, pore pressure, and rock mechanical properties. Inaccurate or poorly calibrated data can lead to underestimation or overestimation of collapse pressure, risking wellbore instability or unnecessarily heavy mud weight.

Calibration of rock strength parameters: Laboratory triaxial and direct shear test results must be validated against field observations such as breakout patterns or cavings from offset wells (Fjaer et al., 2008). Variability in cohesion and friction angle due to mineralogy or anisotropy should be accounted for.

Verification of pore pressure estimates: Pore pressure profiles derived from well logs or formation tests must be cross-checked with mud losses, gas shows, or offset well data to avoid bias in effective stress calculations (Aadnøy & Looyeh, 2019).

Integration and sensitivity analysis: Input uncertainties should be quantified using sensitivity or Monte Carlo analyses to identify parameters with the greatest impact on collapse gradient (Fjaer, Holt, & Horsrud, 1992). This guide targeted data quality improvement and risk management.

Regular updating during drilling: Real-time data such as mud weight, caliper logs, and stuck-pipe reports should be used to update and refine collapse gradient models, ensuring timely detection of deviations from predictions (Aadnøy & Looyeh, 2019).

Implementing rigorous QC procedures reduces uncertainty and enhances confidence in collapse gradient models, enabling safer and more efficient well design and drilling operations.

2.6.6. Checklist

Table 5. Minimum Stress Gradient Checklist

	Collapse Gradient	Documentation
1	More than one method / input used & uncertainty assessed	*Name methods and data sources*
2	Inclination is included in calculations	*Name input file*
3	Horizontal stress field and direction included in calculations	*Name input file*
4	Checked against cavings offset wells	*Name wells*
5	Checked against stuck tools / overpulls offset wells	*Name wells*
6	Checked against caliper or well bore diameter log offset wells	*Name wells*
7	Zones with faults, fractures or discontinuities plotted	*Specify formation / zone and depth*
8	Known faults or fracture problem zone	*Specify formation / zone and depth*
9	Plastic zones identified (ooze, smectites, etc)	*Specify formation / zone and depth*
10	High inclination (> 30 deg)	*Specify depth range and formation / zone*

2.7. Temperature

Accurate approximation of the true formation temperature (TFT) is important in subsurface interpretation, and has important effects on pore pressure, wellbore stability, geomechanics, drilling fluid and cement behaviour. Downhole temperature measurements are rarely an accurate representation of in-situ conditions and are often disturbed by wellbore cooling caused by drilling fluid circulation, tool response time, tool position and operations. Therefore, temperature corrections must be applied to reproduce the in-situ temperatures accurately (Schölderle et al., 2022).

Several methods are used routinely to estimate or quantify TFT, each with distinct advantages and limitations and quality control implications (Liu et al., 2016). None of them are perfect in single use, and an understanding of their strengths and limitations is necessary for accurate interpretation (Förster et al., 1997).

2.7.1. Definition and Calculation

Bottom-hole temperature (BHT) measurements are perhaps the most used indicator of formation temperature. They are recorded during or shortly after drilling, when the wellbore is still affected by circulating drilling mud. Because the mud cools the formation, such measured temperatures are almost always lower than the true formation temperature (TFT). To correct for this effect, time-dependent correction methods are applied by engineers to estimate the undisturbed formation temperature (Liu et al., 2016; Carroll & Peters, 2009).

2.7.2. Prediction Methods

Two main methods are used, depending on the availability of temperature data after drilling stop:

Single BHT Correction (Empirical Method)

For most wells, only one value of BHT is obtainable per logging run. When this is the case, the Horner method is not possible, and an empirical correction is applied instead. The correction adds a temperature increment (ΔT) to the measured BHT, based on mud circulation time, well depth, and regional geothermal gradient. Common correction charts, such as those published by Dowdle & Cobb (1975) or AAPG (1979), are widely used for this purpose. This approach is quick and practical but carries uncertainty typically in the range of ±5 to 10 °C (Nanni et al., 2025; Förster et al., 1997; Schölderle et al., 2022).

Multi-Point Horner Extrapolation

When several temperature readings vs. time are taken during a shut-in period, the Horner method is directly applicable. Temperatures are plotted against the log ratio $\log_{10}[(t + \Delta t)/\Delta t]$, where t is the shut-in time and Δt is the total circulating time. The extrapolated line to infinite shut-in time gives the true formation temperature (TFT). This method is more accurate to within ±2 - 3 °C but requires multiple stable readings and so is less common in routine operations (Liu et al., 2016; Schumacher & Moeck, 2020).

In modern practice, hybrid or numerical corrections are also used—these combine sparse BHT data with thermal models that simulate heat transfer between the mud, casing, and formation. Such models improve accuracy in deep or HPHT wells where simple corrections may break down (Schölderle et al., 2022).

Main strengths of these methods are that they are available in nearly all wells as a part of routine logging data; they are inexpensive and simple to use, and they provide a fist estimate of the geothermal gradient for regional studies.

Limitations are mostly connected with drilling conditions including BHT values that can be too low due to wellbore cooling, accuracy directly connected with circulation time, flow rate, and mud temperature records. Other restrictions are connected by assumed homogeneous heat recovery, which may not be the case in layered or fractured formations, and short shut-in times that can produce incorrect extrapolations in data (Förster et al., 1997; Schölderle et al., 2022).

The focus during quality assessment should be:

- Plot Horner plots for linear recovery trends and remove early-time (transient) points.
- Check circulation time (Δt) and mud temperature history before corrections are made.
- Cross-check corrected BHT results against static log and DST temperatures where possible.
- Identify anomalies like plateaus or unrealistic changes in gradient that may reflect tool or operational issues.

Static Temperature Logging Tools

Static temperature logs are recorded with memory gauges or temperature probes once the well has been closed in and drilling fluid circulation has stopped. The temperature of the wellbore is slowly recorded back to thermal equilibrium with the neighbouring formation by the instruments as the measurement is taken without active circulation. Being taken without active circulation, static logs will be a better reflection of true formation temperature (TFT) than bottom-hole temperature (BHT) measurements taken during or immediately following drilling (Carroll & Peters, 2009; Schumacher & Moeck, 2020).

Static temperature readings are immensely valuable for the building of precise temperature–depth profiles and for calculating reliable geothermal gradients. Static temperatures are often used as a calibration or verification for other temperatures, such as corrected BHT or DST (Schölderle et al., 2022).

Drill Stem Test (DST) Temperature

Drill Stem Test (DST) temperature measurements are one of the more accurate and reliable determinations of true formation temperature. Recordings are taken directly inside the reservoir during flowing or shutting-in, when the formation is largely insulated from the cooling effect of circulating mud. By this means, DST readings reflect the natural thermal state of the formation with minimal impact from the other factors in the wellbore (Carroll & Peters, 2009).

DST temperature measurements are most helpful for the calibration of other temperature methods, such as corrected BHT or stationary temperature logs. These measurements usually become the benchmark against which all other downhole temperature data are validated (Schölderle et al., 2022).

One of the main limitations of DST temperature measurements is availability - measurements are only taken at partial test intervals, so they are discrete points, not a continuous temperature profile.

The other potential limitations include transient flow effects, such as gas expansion or incomplete cleanup, which can lower the measured temperature for a short time. Also, tool drift or slow sensor response in HPHT conditions can produce small but systematic errors, and short stabilization times that produce temperatures not representative of equilibrium conditions (Schumacher & Moeck, 2020).

LWD and MWD Temperature Sensors

Logging-While-Drilling (LWD) and Measurement-While-Drilling (MWD) tools both have downhole temperature sensors that record temperature in real time during drilling. LWD and MWD tools typically use platinum resistance (RTD) sensors or thermistors to record downhole temperature, with thermocouples being utilized in high-temperature or HPHT environments for better durability. RTDs and thermocouples are more accurate and stable, providing consistent long-term readings, but thermistors are more sensitive but can drift or fail at elevated temperatures. Generally, RTDs and thermocouples are preferred for dependable temperature measurement, especially in deep or high-temperature wells (Schumacher & Moeck, 2020).

Real-time measurements are highly useful for identifying relative temperature changes, such as thermal anomalies, fluid influxes, or lithology-related differences, and for following general temperature trends in the wellbore. However, such readings are closely controlled by circulating drilling fluids, tool movement, and transient thermal effects. They therefore represent a combination of operational and formation response, rather than an in-situ formation temperature reading. LWD/MWD readings are therefore best used for supplementing other temperature data, and not as a standalone measurement of true formation temperature (TFT) (Carroll & Peters, 2009; Schölderle et al., 2022).

Limitations of these methods are the fact that they are immensely affected by mud temperature, circulation rate, and borehole hydraulics. The other restrictions include high sensitivity tool heating, sensor lag, and transient temperature excursions while drilling. Additionally, it is exceptionally difficult to denoise formation-related temperature differences from the existing operational noise (Schölderle et al., 2022; Zhang et al., 2024).

To ensure meaningful interpretation, LWD/MWD temperature data needs to be thoroughly validated by removing operational noise, i.e., temperature spikes caused by pump stops, circulation changes, or drill breaks. On top of that, it is important to compare continuous LWD/MWD temperature profiles with static or DST data to confirm that trends are consistent. It is vital to assess anomalies, unexpected temperature deviations should only be accepted if supported by geological or fluid evidence and verify tool calibration and temperature response before and after drilling, particularly for HPHT wells (Schölderle et al., 2022).

2.7.3. Uncertainty Reduction

Temperature measurement limitations are strongly connected with timing on site. The well must be shut-in long enough for temperature to come into balance. Obtaining the measurement too soon will have recorded temperature still reflecting the cooling effect of the mud (Förster et al., 1997).

Other typically encountered sources of poor data include:

- Tool drift or calibration discrepancies introducing bias over extended runs.
- Poor contact between sensors and borehole wall.
- Cold mud invasion or conductive heat loss near the wellbore, which can alter the near-hole temperature profile (Förster et al., 1997).
- Injection or production effects

Rigorous quality assessment should be carried out to ensure reliable results including:

- Essential pre-log and post-log sensor calibration.
- Write down duplicate measurements at key depths to check for consistency and determine stabilization.
- Carefully inspect temperature–depth plots because sudden breaks or suspicious gradients usually indicate tool or operational problems rather than genuine geological variations.
- Compare static log results to BHT or DST data if available to confirm accuracy (Schölderle et al., 2022).

Effective quality assessment for DST temperature data focuses on making certain that measurements represent stable, equilibrium conditions:

- Always plot temperature vs. time in the shut-in time to confirm that the temperature curve has stabilized.
- Cross-plot DST data against corrected BHT and static log data to identify any systematic differences.
- Monitor tool calibration records before and after the test, especially in high-temperature environments.
- Monitor flow conditions, including cleanup efficiency and gas-to-liquid ratios, as these can affect temperature measurement.

Seabed Temperature

Seabed temperature, or mudline temperature, is the geothermal gradient's point of departure and needs to be known to calibrate downhole temperature models for offshore wells. Unlike the case of onshore wells, where surface temperature is identical to air temperature, deepwater wells begin with a very low starting point, typically 2 to 15°C, which also changes with depth and local oceanography. Although this difference seems minor, it becomes significant in calculating temperature and fluid properties in the shallowest sections, where gradients are minimal and minor errors in temperature cause extreme changes in pore pressure and wellbore stability predictions (Schumacher & Moeck, 2020).

Measurement-based modelling ensures the thermal profile properly represents field conditions. Mudline temperature is the upper boundary condition for geothermal and pore pressure modelling. When a generic seabed temperature value (e.g., 15 - 20°C) is used in place of the real 3°C value, the entire temperature–depth profile is distorted (Schölderle et al., 2022).

Temperature directly controls fluid density, viscosity, and compressibility, which govern both hydrostatic and pore pressure gradients. A lower initial temperature at the seafloor gently increases fluid density and shifts the gradient of the pressure and thermal curves. In dynamic conditions, such as when hot drilling fluids pass through cold seabed sediments, thermal disequilibrium will occur. Without seabed calibration, models can exaggerate downhole temperature and cause underestimation of the equivalent circulating density (ECD), misjudgement of collapse or fracture limits (Schölderle et al., 2022) and underestimate cement setting times.

Uncertainties are mainly linked to:

- Assumption of uniform seabed temperature, though local variations can exist due to current, seafloor irregularity, gas seep, or hydrate zone.
- Deeper water settings (>300 m) where vertical seawater layering can introduce measurable disparities between actual seafloor and water column temperatures.
- Transient heat effects due to warm mud briefly changing the near-seafloor temperature profile.

Sources of uncertainty include estimates based on regional means instead of site-specific data, temporal variations caused by seasonal or current-generated temperature oscillations in near-bottom water, and local anomalies resulting from hydrate formation/dissociation or gas seepage.

Measurement uncertainties may happen from poor seafloor contact, unmaintained instruments, or the application of non-uniform seabed temperature data to neighbouring wells without local verification. Seasonal and daily oscillations in near-bottom water temperature can significantly impact measurements, with daily temperature fluctuations often driven by tidal components and stratification patterns observed in marine environments (Carroll & Peters, 2009).

DST and Fluid Sampling Temperatures

Calibration of the temperature model using Drill Stem Test (DST) or fluid sampling provides the most precise and definite estimate of the true formation temperature at reservoir depth. They are sampled in in-situ conditions, typically during flow time or shut-in, and reflect the natural thermal state of the formation with minimum interference from wellbore effects (Carroll & Peters, 2009). They represent a significant lower boundary calibration point for geothermal models (Schölderle et al., 2022).

Model calibration against actual DST or fluid sample temperature ensures that temperature-sensitive parameters such as formation water density, hydrocarbon compressibility, and shale strength are correctly defined for real reservoir conditions. Without this calibration, models may over-estimate or under-estimate temperature gradients (Carroll & Peters, 2009; Schölderle et al., 2022).

Uncertainties can emerge from several factors. The first limitation is that the measurements are discrete points taken only at selected test intervals creating a situation of data sparsity. The second limitation is that the readings can be influenced by transient effects like gas expansion or insufficient cleanup during flow. Additionally, tool response lag or inadequate stabilization time may cause an underestimation of temperature. Fluid sampling tools, such as MDT or RFT, may record mixed wellbore and formation temperatures when sampling durations are short or when temperature gradients are steep (Schumacher & Moeck, 2020; Zhang et al., 2024). Other sources of uncertainty include fluid mixing during flow tool response lag, incomplete cleanup and calibration drift (Schölderle et al., 2022).

By tying down both ends of the gradient to the actual data, the geothermal model is physically constrained and better self-consistent. This two-point calibration largely eliminates uncertainty, particularly in deepwater environments, where vertical temperature gradients are sharp (Schölderle et al., 2022).

2.7.4. High Temperature (150 °C)

A reservoir or formation temperature of about 150 °C is a hot environment by drilling and reservoir engineering standards. Such conditions are typically found in deep or geothermal wells, HPHT basins, and mature hydrocarbon provinces with deep burial histories. Already temperatures higher than 120 °C will have a significant impact on most well data. Temperatures exceeding 150 °C have a large impact, influencing nearly every aspect of well design and pore pressure assessment (Schumacher & Moeck, 2020; Schölderle et al., 2022).

Thermal Effects on Fluids
Fluid properties undergo substantial change at high temperatures such as water and brines lose density and viscosity due to thermal expansion, leading to reducing hydrostatic head and extensive compositional and phase changes of hydrocarbons. The solubility of gases in water and oil increases altering the behaviour of fluids and reducing the ability to detect gas entering the wellbore. If temperature adjustments are not accounted for, low-temperature-calibrated models will overestimate pore pressure and density, leading to inaccurate mud-weight design and stability prediction (Carroll & Peters, 2009).

Impact on Drilling Fluids
Drilling fluids are extremely sensitive to temperature. High temperatures rapidly deteriorate polymers and emulsifiers, weakens thinners, and can induce barite sag in weighted systems. Thermal thinning reduces viscosity which reduces the cuttings carrying capacity and ECD during circulation, this can be followed by raised ECDs under static conditions — triggering cyclic stress on the wellbore. Thermal rheology modelling is therefore imperative in HPHT wells to provide bottom-hole pressure stability (Schölderle et al., 2022).

Effects on Rock Mechanics
High temperature alters rock strength and stress distribution during drilling. High temperature decreases strength and stiffness through thermal microcracking, and increased pore pressure. Thermal expansion of low-permeability shales can lead to increased pore pressure, leading to a reduction in effective stress. Hot formation cooling due to cold-mud invasion can produce tensile or shear fracturing near the wellbore. These thermal-mechanical responses are generally underestimated but are of utmost concern for accurate wellbore stability analysis. Proper consideration of these effects avoids surprise wellbore failure and improves the reliability of the drilling process (Schölderle et al., 2022; Schumacher & Moeck, 2020).

Tool and Material Constraints
Temperatures of >150 °C involve HPHT-rated electronics, elastomers, seals, and cement systems because they degrade rapidly above rated temperatures. It is necessary to recalibrate logging instruments and sensor drift is normal with extended high temperature exposure. Completion and casing design must compensate for thermal expansion stresses, and cement systems must be qualified for high-temperature strength and retrogression resistance (Schölderle et al., 2022).

2.7.5. Quality Control (QC)

Quality control of temperature profiles is absolutely necessary because of the important input on cement drying times and especially under HPHT conditions, where temperature, pressure, and fluid densities exhibit nonlinear behaviour. Small input errors can cause large discrepancies between predicted and real temperatures because of generally very few data points. Therefore, it is important to combine model DST, static, and seabed temperature data to construct an overall thermal model.

Tool calibration, material grades, and temperature-compensated log measurements need to be checked to confirm validity. Temperature-sensitive fluid and rock property correlations should be employed for realistic interpretations. Take note of any extrapolations outside tool limits and check these against laboratory measurement or offset well data (Schölderle et al., 2022).

Seabed temperature verification can include the following steps:

- Real-time measurement of mudline temperature using ROV-mounted or probe sensors before spudding, waiting for the readings to stabilize.
- Cross-check with local oceanographic data (e.g., CTD surveys or historical surveys) to determine representativeness.
- Compare with initial LWD/MWD temperature readings in near-surface intervals to validate near-surface gradient.
- Note local seabed properties, current trends, and hydrates which could influence temperature.
- Apply measured seabed temperature consistently as boundary condition in all thermal and pore pressure models.

Quality control for DST and fluid sampling calibration focuses on the validation of the data as representing equilibrium conditions and being compatible with other temperature data sets. Relevant checks are:

- Check for stabilization: Use late-time shut-in values, not early-time production data.
- Cross-check against static, LWD, or MWD data: Ensure that all data sets show a common geothermal trend.
- Check tool calibration: Check pre- and post-job records, especially for HPHT wells.
- Compare consistency across zones: Plot DST, static log, and sample temperatures vs. depth for trend correlation.
- Document flow conditions: Log flow duration, cleanup efficiency, and fluid composition to accurately interpret thermal behaviour.

If differences appear between measured and modelled temperatures, DST data would be given priority since it is the closest measure of the formation conditions. Models would then have to be recalibrated to validate these observed values (Schumacher & Moeck, 2020).

2.7.6. Checklist

The following checklist highlights key points an integrated well delivery team should check for the temperature estimation.

Table 6. Temperature Checklist

	Temperature	Documentation
1	Corrected tool temperatures used	*Name wells & describe*
2	Calibrated with temperature at seabed	*Name source of data*
3	Calibrated with DST or fluid sampling temperatures	*Name wells, depth and formations*
4	High Temperature (150 °C)	*Specify formation / zone and depth*

3. RISK ASSESMENT AND RISK INTERACTIONS

3.1. General Principles

To fully assess the well control risk during well planning depends on understanding how pore pressure, overburden stress, fracture gradient, minimum horizontal stress, temperature, and collapse gradients interact and influence the overall well integrity (Edan & Abdul Hussein, 2023; Aadnøy & Looyeh, 2011; Zoback, 2010). The input data define the calculated mechanical limits of the formation and establish the safe operating window for drilling operations. It is therefore critical that their quality and uncertainties are properly understood, for example a LOT data point from the 70s is not the same as a fully documented XLOT from 2010.

Subsurface hazards never occur in isolation. Pore pressure changes directly impact effective stress, and consequently, fracture and collapse gradients. Temperature variation can alter the strength of the rock and the properties of the drilling fluid and influence wellbore stability. Minimum horizontal stress is influenced by stress, pore pressure and lithology, which in turn determines fracture initiation and the probability of circulation loss with possible subsequent differential sticking risk and/or pressure control risk.

Due to these interdependencies, small variations in one parameter can trigger a cascade of operational issues, including:

- Simultaneous losses and influx through a very small mud weight window.
- Borehole instability, leading to stuck pipe and subsequent circulation loss.
- Temperature variations affecting mud rheology and ECD, adding further stress to the wellbore and casing.

The risk assessment's role thereby extends beyond quantifying individual hazards. It is a matter of comprehending how these risks interact, overlap, and evolve throughout the operations of the planned well. Examination of those interactions allows setting of safe drilling practice, casing setting depths, and contingency measures needed to maintain well control and structure integrity.

It is also important to highlight that the risk assessment should also go beyond looking at individual operations, but establish the link between drilling, casing, cementing and P&A where needed. Some typical examples of issues include:

- Cementing leading to fractured formation at the casing shoe leading to losses during drilling and potentially well control issues.
- Losses generated during drilling leading to poor cementing.
- Instable formation during drilling leading to stuck casing.
- Tight hole situations during drilling leading to stuck tools during wireline operations.

Due to complex nature of these events, often with a limited ability to fully measure and understand causal behaviour, cross functional learning is of key importance.

3.2. Risk Assessment

The following sections are descriptions of important risk interaction categories not commonly discussed that are relevant to pore overburden, fracture gradient, minimum stress, temperature, pore pressure gradient, and collapse gradient.

3.2.1. Interaction of Geological Risks

Geological risks are interconnected and usually have a tendency to appear simultaneously in conjunction with each other and not independently (Swarbrick & Osborne, 1998). For example, the interaction between abnormally high pore pressure in a sandstone due to later transfer and low fracture gradient provides a narrow drilling margin, where higher mud weight can lead to lost circulation and lower mud weight can lead to influx or wellbore instability (Bowers, 1995; Eaton, 1972; Dutta, 2002).

Drilling into stressed zones may cause simultaneous events such as wellbore collapse, differential sticking, or losses (Aadnøy & Looyeh, 2011; Fjaer et al., 2008). Structural features like fractures, faults, and bedding plane locally change stress regimes and pore pressure distribution which can cause a range of problems (Zoback, 2010; Zhang et al., 2018). This is also the case for depleted zones.

Examples of frequent risk combinations:

- Overpressure + low fracture gradient → risk of losses and influxes
- Reactive or unstable formation + permeable zones → borehole instability, losses and risk of influx and stuck pipe.
- Fractured zones & depleted sandstone → stuck pipe, losses and risk of influx

3.2.2. Operational or Technical Limitation

Operational or technical limitation can result in surface and downhole constraints that can exacerbate geological risks and affect the mitigation potential (API RP 92M, 2016; API RP 92S, 2019), these constraints are often well understood by the engineering community but less by the subsurface community.

Examples include:

- Neighbouring wells, depleted or injected zones, causing unexpectable change to fracture or collapse gradients.
- Topside or mud system restrictions, e.g., restricted mud density range, reducing flexibility in management of tight pressure windows.
- Casing design and cement integrity constraints, wherein poor isolation or burst/collapse ratings increase crossflow or casing failure risks.
- Casing, centraliser and tool diameters together with hole diameter and geometry affecting tool running, surge and swap pressures. Especially in deviated holes these are challenging assessments to make even for the most experienced team.

These interactions emphasize the need for integrated drilling design and risk assessment to avoid technical limitations interacting with well control or well integrity (Zoback, 2010; Fjaer et al., 2008). It also requires a deep cross functional understanding.

3.2.3. Combined Geological Risks

Combined risks are where two or more geomechanical parameters that act adversely on one another within the same interval (Bowers, 1995; Dutta, 2002). This is common where the rising pore pressure gradient is matched by a falling fracture gradient, resulting in a very narrow safe mud weight window (API RP 92P, 2019; Aadnøy & Looyeh, 2011).

Examples include:

- Shale-to-sand transition zones, where increasing pore pressure and decreasing fracture gradient combined with a weak interface enhance the risk of simultaneous kick and losses (Bowers, 1995).
- High temperature gradients above 3 °C/100 m, which can increase mud property changes, offering increased potential for stuck pipe and gains under static conditions (Zoback, 2010).

These intervals must be identified and carefully monitored real-time, with sufficient mitigation methods such as lost circulation material (LCM) readiness, controlled pressure drilling (MPD) and contingency casing depths planned in advance of drilling (API RP 92M, 2016; API RP 92S, 2019).

3.2.4. Multiple Hydrocarbon Zones

It is quite common that well paths traverse several hydrocarbon-bearing sections, often each with multiple phases, distinct pressure, stress, and temperature regimes (Fjaer et al., 2008; Zoback, 2010). Drilling through several pressure regimes contributes to the complexity of zonal isolation, cement design, and well control operations. The pore pressure, fracture gradient, and temperature profile of each interval are to be accurately determined and constantly updated to ensure safe drilling, effective pressure containment, and long-term well integrity (Zoback, 2010; Fjaer et al., 2008).

Examples include:

- Light oil with gas cap, with moderate overpressure in shallower sections, requiring good ECD control to avoid influx or gas breakout.
- Reservoir sections with tight gas sands or oil–water transition zones with high overburden stress and anisotropy, increasing the potential for collapse, differential sticking, and formation damage (Swarbrick & Osborne, 1998; Aadnøy & Looyeh, 2011).
- Fields with different compartments with different composition, contacts and pressures, make zonal isolation difficult and risk sudden overpressure or depletion if models are incorrect.

3.2.5. Checklist

The following checklist highlights key points an integrated well delivery team should check in relation of risk interaction, in relation to pressure and stress predictions.

Table 7. Risk Interaction Checklist

	Risk Interactions	Documentation
1	Interaction of geological risk assessed	*Problems often come in pairs or more, i.e. losses & getting stuck. Describe possible combination issues and depth.*
2	Interaction of technical risks assessed	*Nearby wells, top side limitations, integrity issues*
3	Combination of risks occurring at once	*State type and depth*
4	Expected to drill through multiple hydrocarbon zones	*Describe*

4. MITIGATION AND BEST AVAILABLE TECHNOLOGY

4.1. General Principles

As discussed in previous chapters, uncertainty in pore pressure and stress prediction presents significant operational and safety risks, particularly in complex geological settings or depleted reservoirs. To mitigate these risks, the application of structured workflows, calibrated models, and validated technologies is essential (Zhang and Yin, 2017; Zhang, 2018; Ogbu et al., 2024). This chapter outlines the guiding principles for uncertainty mitigation and highlights some of the best available technologies currently used in industry.

Effective mitigation begins with recognizing the sources of uncertainty—whether geological, petrophysical, or methodological—and addressing them through integrated data analysis and cross-disciplinary collaboration. Key principles include:

- **Early Identification of Risk Zones**: Mapping structural features, depletion effects, and historical failure intervals allows for proactive planning and conservative pressure margins (Subsurface Alliance, 2023).
- **Multi-Method Validation**: Combining direct measurements (e.g., XLOT, DFIT) with indirect indicators (e.g., loss events, image logs) improves confidence in pressure and stress estimates.
- **Stratigraphic Alignment**: Ensuring that all input data are corrected for true vertical depth and aligned with prognosed lithology prevents misapplication of offset data and enhances geological relevance (Ogbu et al., 2024).
- **Dynamic Calibration**: Real-time data from offset wells and drilling operations to continuously refine models and adjust predictions as new information becomes available (Zhang, 2018).

This supports a risk-awareness to well design, enabling anticipation of pressure-related challenges and implementation of appropriate safeguards.

4.2. Best Available Techniques (BAT)

The following overview of technologies and methods are considered some of industry best practice for managing uncertainty in pore pressure and stress prediction. New technology is continuously introduced and the list includes a basic overview:

- **Advanced Logging Tools**: Real-time MWD/LWD systems provide high-resolution pressure, sonic, and calliper data, enabling early detection of anomalies and stress concentrations (Ogbu et al., 2024). New 3D or even 4D LWD caliper systems allow detailed mapping of the borehole shape, location of enlargements, breakouts or restrictions which provide a much greater control of borehole condition and impact of operations.
- **Geomechanical Modelling**: Integrated software solutions allow for finite element (FEM) simulation of stress behaviour using elastic moduli, calibrated with core data and offset well results (Zhang and Yin, 2017). With sufficient model constraints mud weights, drilling angles and directions can be optimized pre-drill and drilling problems investigated.
- **Seismic-Petrophysical Integration**: Combining seismic inversion with petrophysical logs enhances pressure and stress models, especially in pre-drill planning (Ogbu et al., 2024). Seismic velocities are used to fill in gaps in the petrophysical data and property cubes are

derived from the seismic through seismic inversion techniques combined with well data, providing 3D pressure and stress cubes of an area.

- **Borehole Image Analysis**: High-quality image logs reveal breakout patterns, drilling-induced fractures, and caving zones, which are critical to understand subsurface stress, stress anisotropy and wellbore stability assessment (Subsurface Alliance, 2023).
- **Dynamic loss data analysis**: Analytical tools use dynamic loss data to estimate the lower bound of wellbore pressure, particularly in fractured or depleted formations (ResFrac, 2024).
- **QC Frameworks**: Structured quality control protocols ensure consistency across datasets, flag anomalies, and document all assumptions and corrections applied during modelling (Ogbu et al., 2024).
- **Realtime pore pressure and stress prediction:** uses live drilling data (mud logs, LWD, seismic) and advanced AI/ML (Artificial Neural Networks, LSTM) to continuously update models, enabling proactive adjustments and optimizing mud weights and drilling parameters.

When deployed systematically and benchmarked for local conditions, these technologies can significantly reduce uncertainty and improve the reliability of pore pressure and stress predictions. Their integration into operational workflows supports safer drilling, optimized casing design, and more accurate pressure management strategies.

4.3. Calibration & Monitoring

Mitigating uncertainty in pore pressure and stress prediction requires more than static modelling, it demands continuous calibration and real-time monitoring throughout the well construction lifecycle. It is key that predictive models remain aligned with actual subsurface conditions during operations and that deviations are identified and addressed before they escalate into operational risks (Zhang, 2018; Ogbu et al., 2024).

By combining calibrated modelling with continuous monitoring, operators can further reduce uncertainty, improve wellbore stability and enhance decision-making during operations and emergencies. An integrated approach transforms pore pressure prediction from static estimates into a responsive system to manage subsurface uncertainty and complexity.

4.3.1. Calibration with Offset and Real-Time Data

Calibration begins with the integration of offset well data, including XLOT profiles, DFIT results, and dynamic loss circulation records. These datasets provide reference stress values and pressure thresholds that help constrain model outputs in target intervals (ResFrac, 2024; Subsurface Alliance, 2023). Stratigraphic alignment is essential: stress data from offset wells are transferred to equivalent lithological units, corrected to true vertical depth and adjusted for depletion effects where applicable (Ogbu et al., 2024).

During drilling, real-time measurements from MWD/LWD tools, such as sonic velocities, caliper readings, and annular pressure, are continuously compared against predicted values. Discrepancies should trigger model updates, allowing for recalibration of stress gradients and adjustment of operational parameters. This dynamic feedback loop enhances the reliability of pore pressure and stress estimates, especially in structurally complex or pressure-depleted zones (Zhang, 2018; Ogbu et al., 2024; SPE Asia Pacific Oil & Gas Conference, 2024).

4.3.2. Monitoring for Early Risk Detection

Monitoring focuses on identifying early indicators of instability, such as unexpected pressure spikes, borehole enlargement, or anomalous mud losses. Borehole image logs are analysed for breakout patterns and drilling-induced fractures, providing insight into local stress anomalies (Subsurface Alliance, 2023). Caliper logs are used to detect hole enlargement, often associated with low-stress zones or mechanical failure.

Loss events are to be tracked in real time and interpreted as potential exceedance of the minimum stress threshold. When losses occur, the pressure at initiation should be back calculated to refine the lower bound of the minimum stress gradient (e.g. ResFrac, 2024). This information can be fed immediately into the model to update drilling margins and guide pressure management decisions.

4.3.3. Operational Integration

Calibration and monitoring are not isolated tasks, they are to be embedded within the broader geomechanical workflow and communicated across disciplines. Model updates, risk flags, and pressure adjustments are documented and shared with drilling engineers, geologists, and well planners (Ogbu et al., 2024). This ensures that all stakeholders operate with a unified understanding of subsurface conditions and can respond proactively to emerging risks.

5. COMMUNICATING PORE PRESSURE AND STRESS PREDICTION

5.1. Language

Communication around pore pressure and stress prediction should use consistent language, make uncertainty explicit, and link all technical statements to underlying data and methods to support safe and efficient drilling decisions. Clear terminology and structured briefings reduce the risk of misinterpretation between geoscience, drilling, and operations teams during time-critical offshore activities (Hougaz et al., 2012; Carpenter, 2013).

Role of communication

Effective communication is a critical barrier against well control incidents, drilling challenges, and non-productive time, because decisions often rely on interpreted pore pressure (PP) and fracture gradient (FG) models rather than direct measurements. PP/FG predictions are typically updated in real time using drilling data, logs, and LWD indicators, which increases the volume and complexity of information that must be shared and understood across disciplines.

Misunderstandings can arise when subsurface and drilling teams attach different meanings to common phrases such as “safe margin”, “operational window”, or “narrow PP–FG window”, potentially leading to inappropriate mud weights, casing points, or contingency plans. Establishing a shared “drilling language” and communication culture has been shown to improve safety outcomes and operational performance.

Objectives of PP/FG communication

Communication around PP/FG and wellbore stability should consistently aim to:

- Support safe, sound operational decisions (mud weight, casing setting depth, contingencies) under uncertainty.
- Make the basis for predictions, uncertainty and limitations explicit to decision-makers.

- Ensure that non-specialists (e.g. offshore supervisors) can correctly interpret PPFG plots and scenarios without relying on informal assumptions.

In practice this means that every key PPFG statement in reports, pre-spud meetings, and real-time briefings should be traceable back to its data sources, methods, calibration steps, and associated uncertainty range.

Clear communication standards also facilitate learning across wells and assets, because deviations between predicted and observed pressures can be analysed consistently.

Recommended language

The following is recommended for written and verbal communication of PPFG and stress models in offshore drilling projects.

- Tie technical phrases directly to data and methods. Connect terms such as “PP prognosis”, “updated PP”, “FG curve”, and “collapse limit” to the underlying workflow, e.g. “Eaton prediction from sonic and density logs, calibrated to RFT/MDT pressures in Well A and B”.
- Distinguish clearly between pre-drill models, real-time updates, and post-drill analysis when presenting results.
- Use clear labelling for values and predictions. Qualify all quoted PP and stress values as LB (lower bound)”, av (average)”, UB “upper bound”, to frame them as estimates.
- When showing PP–FG windows, state whether lines represent mean trends, uncertainty bands, or operating limits (“safe drilling window”, “kick tolerance limit”).
- Emphasize uncertainty and limitations. Always state key uncertainties (e.g. quality of sonic data in salt, scarcity of direct pressure measurements, poorly constrained minimum stress) and how they impact the reliability of the model in each interval.
- Avoid definitive language (“will be”, “is equal to”) for predictions; instead use “is expected to”, “is estimated to”, or “is likely within the range”.
- Align terminology across disciplines. Explicitly check and document the agreed meanings of terms such as “safe margin”, “operational margin”, “fracture limit”, “kick margin”, “ECD limit”, and “ballooning”, as these can differ between subsurface, drilling, and rig crews.
- During pre-spud and section-TD meetings, review critical phrases and confirm that all parties can restate them in operational terms (e.g. equivalent mud weight, standpipe pressure, flow-check criteria).
- Use structured meeting and reporting formats and templates:

    Present PP/FG information using standardized slides or report sections: objectives, data sources, methods, calibration, predicted envelopes, uncertainties, operational implications, and recommended mitigations.

    For real-time operations, adopt a consistent format for status updates (e.g. “Observed PP indicator”, “Deviation from prognosis”, “Proposed action”, “Residual uncertainty”) to make changes easy to track.

Glossary and documentation

To prevent ambiguity and reduce reliance on informal interpretations, each company and project should maintain a concise, controlled glossary for PP, FG and stress terminology.

The glossary should be:

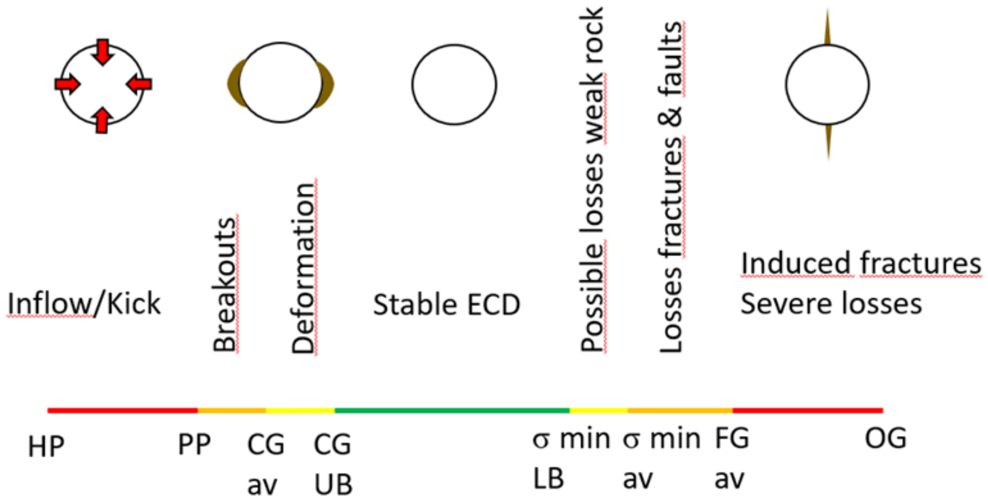
- Developed jointly by geoscience, geomechanics, drilling, and operations teams, with clear, operationally relevant definitions and units for each term.
- Included as an appendix in all PPFG reports, well planning documents, pre-spud and section-TD briefing packs, and referenced during onboarding and training of new personnel.

The glossary should also reference key external standards and training resources, such as industry best-practice courses in pore pressure and fracture pressure prediction, well control manuals, and SPE guidance on drilling uncertainty, to align project language with wider industry usage. Periodic review and update of the glossary at the end of each well, informed by lessons learned and incident investigations, strengthens organisational learning and improves communication quality over time.

5.2 Plots and visual aids

Plots and visuals are a central part of understanding the relationship between the well design, geology and stress gradients. The gradients in the plots are commonly shared among different software platforms and the data forms the input to critical well engineering deliverables like the well barrier schematic. It is critical that all plots are updated and use the same versions. Therefore version control should be part of technical plots and drawings.

To improve the understanding of pore pressure and stress at the well site standardised risk colouring can be used to communicate the pore pressure and stress predictions. These can be linked to observations in the well that provide feedback from the drillsite on the predictions.



HP – Hydrostatic Pressure
PP – Pore Pressure
CG – Collapse Gradient
σ min – Minimum Stress Gradient
FG – Fracture Gradient
OG – Overburden Gradient
av – Average
LB – Lower Bound
UB – Upper Bound

Figure 6. Example of Safe Mud Window

5.2.1 Communication Uncertainty

Due to the complexity of the different curves in a pore pressure and fracture gradient plot it is essential to simplify the representation while still communicating the uncertainty in the predictions. A key challenge observed in the industry is oversimplified pore pressure and stress prediction not linked to geology and missing resolution in the pore pressure and fracture gradient with overly optimistic predictions by an underlying assumption of conservatism in predictions. While it is important to challenge assumptions to enable technological and industrial progress, it is key for all involved to understand when risk is being taken. Including uncertainty bands in predictions checked by sensitivity analysis and calculated safety factors is the basis of good engineering. A key challenge is that many pore pressure and fracture gradient analysists are not trained in geotechnical engineering practises.

In most cases it can be beneficial to display this in two versions of the same plot. One focused on the actual best estimate predictions which forms the basis of the well design, and one visualization the uncertainty together with the available data and different sensitivity. Additionally, all uncertainty including depth uncertainty should be communicated in text and tables of the well program documentation.

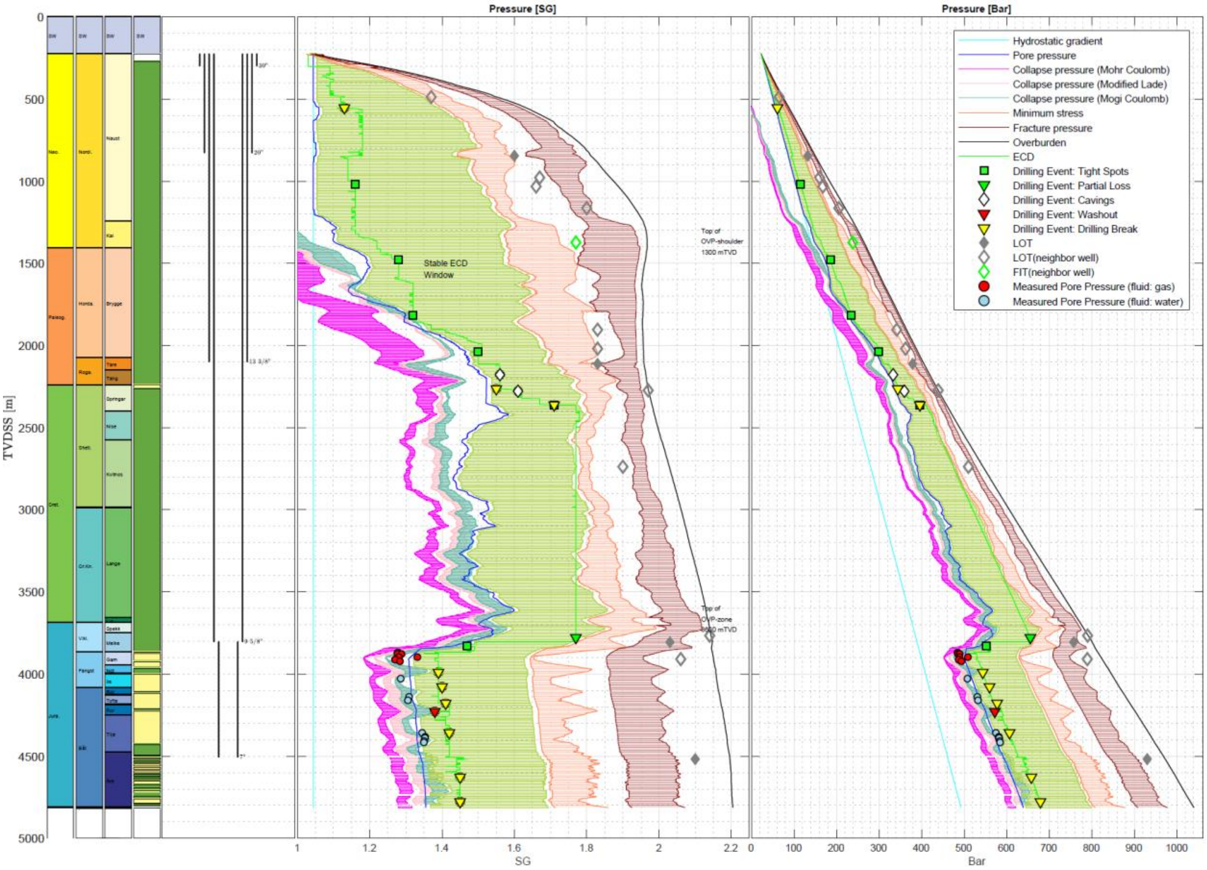


Figure 5. Example of Well pressure profile with LOT/XLOT results. Predicted pore pressure, collapse pressure, fracture pressure, overburden, and the hydrostatic pressure of the water column. "The stable ECD window", ECD, measured LOT data points, casing design and information regarding formation names, formation age, and lithology of the formations are also illustrated.

Without a clear view on the PPFG uncertainty during the well design stage key hazards can be missed. During well planning and in HAZID / HAZOP meetings PPFG uncertainty can be presented as separate scenarios leading to design deviations (e.g. "higher-than-forecast PP", "lower-than-projected FG") which allows the examination of consequences for each scenario (e.g. connections, tripping, casing run). Proposed safeguards should be recorded and integrated in the final PPFG plots and operational plan.

5.2.2 Plots in m TVD and m MD vs Drill Floor (RKB)

Dual-plot or dual-axis helps to correlate geological depth (TVD) with measured depth (MD). One of the frequent pitfalls is inconsistent datums or misaligned MD and TVD curves. It is therefore important to always present the well geometry tabulated and visualized. Since most work on the drillsite is done in MD it is essential for the drill crew to follow progress of the well and mud parameters in relation to PPFG prediction in the same depth scale.

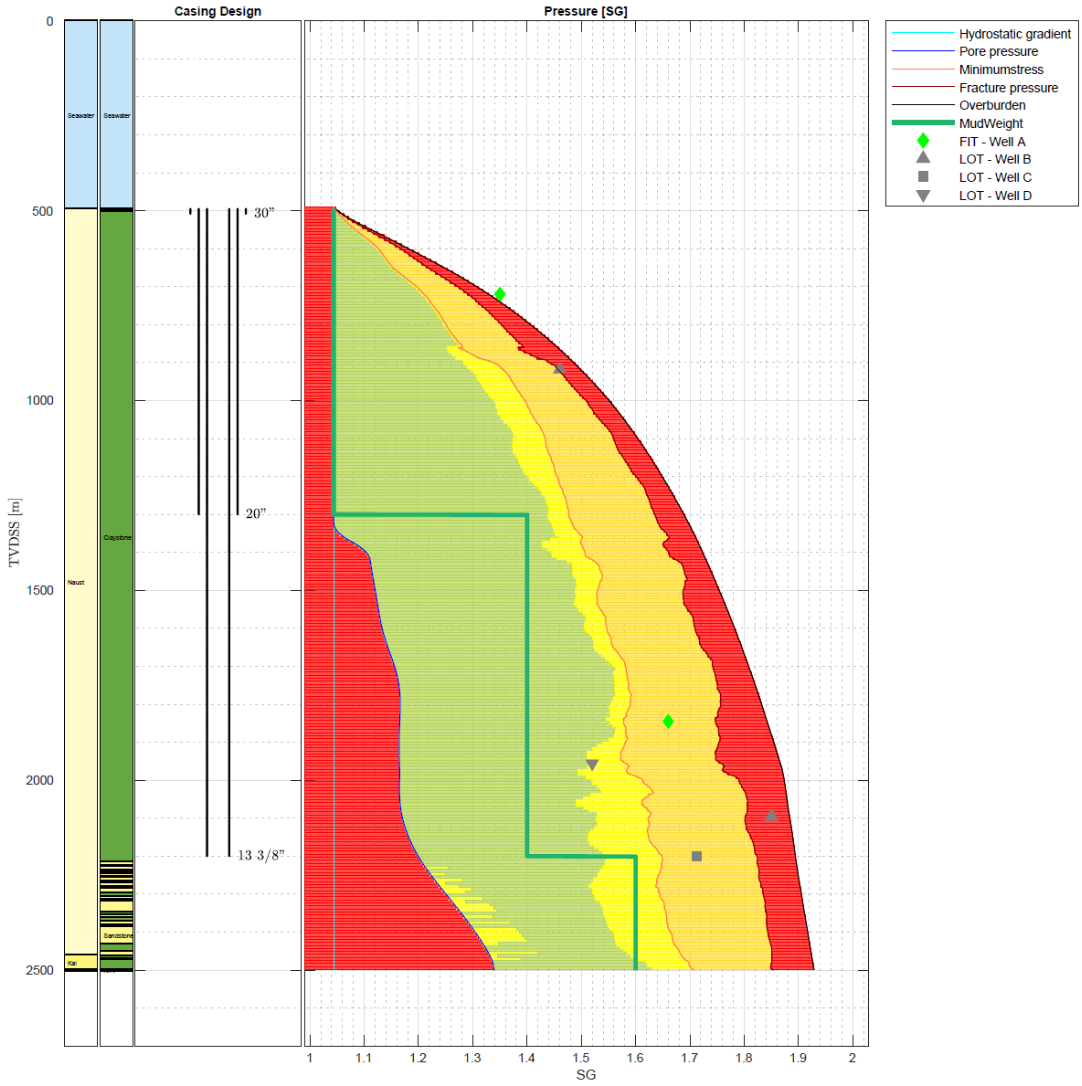


Figure 7. Example of Stable ECD window

Pitfalls include utilize the MD axis for planning but the PP/FG curves are plotted in relation to TVD, leading to incorrect mud weight ramps or casing setting depths. The depth axis should always be marked clearly, provide datum references (e.g. drill floor, RKB or MSL), and provide reference to the trajectory information used.

5.2.3 Geological Hazards

Key geological hazards should be plotted alongside pore pressure and fracture gradient prognosis to check for possible interaction and risk escalation. This includes features like gas zones, faults, weak zones, overpressured shales, or salt intrusions along the MD axis. In the analysis of drilled wells PPFG anomalies should be checked against drilling response to help monitor drilling of planned wells.

When hazards are overlooked or located in the wrong depth this can lead to surprise kicks, stuck pipe, or losses. When such events occur unexpectedly there is a higher change of other barriers being compromised e.g. during casing running, cementing, BOP connection, wireline operations etc. Cross-checking subsurface hazards between seismic, offset wells, and in-situ logs allows for early warning, mitigation and correct response in case of undesired events. Up front early identification of hazards allows the introduction of buffer zones and additional safety margins.

Identified hazard and uncertainty that can impede the safety of the operation should be associated with implementable mitigation (e.g. change casing schedule, use MPD, apply backpressure, use narrow ECD control) and trigger points should be provided for when a certain mitigation must come into effect. This can often take the form of decision trees. It is key that these are open to the complete team so they can be scrutinized prior to well operations.

5.2.4 Interaction of geological risk

Isolated treatment of hazards can underestimate their combined effect, e.g. overpressure + weak zone. Therefore, to visualise interaction of possible geological risk, zones where two or more hazards might overlap should be clearly marked in plots e.g. a fault intersects an overpressured zone, or a steep stress gradient traverses a shale pinch. Often this is a challenge due to the limitation of most software used in pore pressure and fracture gradient predictions. Suitable work around and processes should be in place to address these issues on a company level.

During well planning and HAZID / HAZOP work sessions, different plausible subsurface scenarios can be stacking to check the robustness in the plans and "worst-case composite" PPFG made to design mitigations that consider overlapping threats.

5.2.4 Mitigation

Mitigation is often suggested in a standardised way without an assessment if the mitigation is adequately strong to deal with the problem or sufficiently adapted to the situation (e.g. LCM). Therefore it is imperative that proposed mitigation have explicitly determined margins of use, that drills and simulations are conducted during planning and that mitigations are included into operational procedures.

Once mitigations are selected, they need to be wired into day-to-day operating practices, the Drilling Program, Well Control Plan. Trigger tables, ramp curves, and contingency plans should all be based on the same PPFG envelope/uncertainty. With different onshore and offshore teams it is key to avoid a disconnect between mitigation plans in well programs and site practice e.g. operators do not honour thresholds, follow usual practise, etc. Pre-operation walkthroughs for each operation steps, PPFG simulation scenarios during training, real-time checks and daily briefings between specialist and offshore counterparts are important measures to deal with PPFG uncertainty and mitigate associated risk.

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APPENDIX – CHECKLIST EXAMPLE

Example - Pore Pressure & Wellbore Stability Checklist

Well Name	
Section / Hole Size	
Company	
Date	
Data location for Review / Audit	
PPFG plots	*Location of PPFG Plots*

Legend

Uncertainty Reducing	☐
Calibration	☐
Additional Risk	☐

0	**PPFG prediction and data checked by**	**TRUE**	**Name, company & comments**
1	Pore pressure / Wellbore stability analysist	☐	
2	Well Engineer	☐	
3	Ops Geologist	☐	
4	Reservoir Engineer	☐	
5	Geophysicist	☐	
6	Petrophysicist	☐	
7	Shallow Hazard / Overburden specialist	☐	
8	Project Manager	☐	

1	**Overburden Gradient**		**Documentation (add links to source info)**
1	More than one method / input used & uncertainty assessed?	☐	*Describe inputs (logs, Vp seismic,...) & methods*
2	Density correction logs, depths and caliper checked?	☐	*Describe data, source and quality of information*
3	Data corrected for prognosed stratigraphy, lithology and/or depth	☐	*Describe methods e.g. Top Tables & name top set*
3	Calibration with seabed density data	☐	*Name seabed samples, gravity cores or CPTs*
4	Calibration with cuttings density data	☐	*Name well(s) and depth interval*
5	Calibration with core density data	☐	*Core name(s) and depth interval*

2	**Pore Pressure Gradient**		**Documentation**
1	More than one method / input used & uncertainty assessed	☐	*Name methods and data sources*
2	High resolution seismic velocity input used	☐	*Name data source cube*
3	Checked against mud gas offset wells	☐	*Name wells*
4	Checked against Static Mud Weight offset wells	☐	*Name wells*
6	Swab risk assesed	☐	*Location of documentation*
7	Calibration to pressure data offset wells	☐	*Name wells*
8	Lateral transfer assesed	☐	*Specify methods and data*
9	Lateral pressure transfer expected (inc. SWF)	☐	*Specify formation / zone and depth*
10	Depleted reservoir effects included	☐	*Specify formation / zone and depth*
11	Depletion calibrated	☐	*Specify formation / zone, method and depth*
12	High Pressure (shut-in pressure > 690 bar)	☐	*Specify formation / zone and depth*

3	**Fracture Gradient**		**Documentation**
1	More than one method / input used & uncertainty assessed	☐	*Name methods and data sources (e.g pre-stack inversion seismic*
2	Lithology predicted & included in prediction	☐	*Name methods*
3	Rock physics included as input	☐	*Name method, parameters used (e.g. Poisson Ratio) & sources of data*
4	Data corrected for prognosed stratigraphy and/or depth	☐	*Describe method e.g. Top Tables & name top set*
5	Fracture gradient checked against LOT data	☐	*Wells and formations*
6	LOT data validity checked & LOT plots available	☐	*Describe and link to documentation*
7	Calibration against XLOT data or well documented LOP in LOT	☐	*State data source, wells and formations*
8	Depleted reservoir effects expected and included	☐	*State method, data source & date of estimate*
9	Depletion factor calibrated	☐	*Wells, depth, method and date*

4 Minimum Stress Gradient		Documentation
1 More than one method / input used & uncertainty assessed	☐ 🟩	*Name methods and data sources*
2 Rock physics input used	☐ 🟩	*Name method, parameters used (e.g. Poisson Ratio) & sources*
3 Data corrected for prognosed stratigraphy and/or depth	☐ 🟩	*Describe method e.g. Top Tables & name top set*
4 Checked against loss data offset wells	☐ 🟩	*Name wells*
5 Checked against cavings offset wells	☐ 🟩	*Name wells, is caving behaviour understood?*
6 Checked against caliper / borehole image offset wells	☐ 🟩	*Name wells*
7 Zones with losses, faults & stress cavings plotted	☐ 🟩	*Specify formation / zone and depth*
8 Risk of total losses identified	☐ 🟧	*Specify formation / zone and depth*
9 Surge & loss risk assessed	☐ 🟩	*Location of documentation*
10 Calibration with dynamic loss data offset wells	☐ 🟢	*Specify wells, formation / zone and depth*
11 Calibration with XLOT data offset wells	☐ 🟢	*Specify wells, formation / zone and depth*
12 Depleted reservoir effects expected and included	☐ 🟧	*Specify formation / zone and depth*

5 Collapse Gradient		Documentation
1 More than one method / input used & uncertainty assessed	☐ 🟩	*Name methods and data sources*
2 Inclination is included in calculations	☐ 🟩	*Name input file*
3 Horizontal stress field and direction included in calculations	☐ 🟩	*Name input file*
4 Checked against cavings offset wells	☐ 🟩	*Name wells*
5 Checked against stuck tools / overpulls offset wells	☐ 🟩	*Name wells*
6 Checked against caliper or well bore diameter log offset wells	☐ 🟩	*Name wells*
7 Zones with faults, fractures or discontinuities plotted	☐ 🟩	*Specify formation / zone and depth*
8 Known faults or fracture problem zone	☐ 🟩	*Specify formation / zone and depth*
9 Plastic zones identified (ooze, smectites, etc)	☐ 🟩	*Specify formation / zone and depth*
10 High inclination (> 30 deg)	☐ 🟩	*Specify depth range and formation / zone*

6 Temperature		Documentation
1 Corrected tool temperatures used	☐ 🟩	*Name wells & describe*
2 Calibrated with temperature at seabed	☐ 🟢	*Name source of data*
3 Calibrated with DST or fluid sampling temperatures	☐ 🟢	*Name wells, depth and formations*
4 High Temperature (150 °C)	☐ 🟧	*Specify formation / zone and depth*

7 Risk Interactions		Documentation
1 Interaction of geological risk assessed	☐ 🟩	*Problems often come in pairs or more, i.e. losses & getting stuck.* *Describe possible combination issues and depth.*
2 Interaction of technical risks assessed	☐ 🟩	*Nearby wells, top side limitations, integrety issues*
3 Clear risk of combination of risks occurring at once	☐ 🟧	*State type and depth*
4 Expected to drill through multiple hydrocarbon zones	☐ 🟧	*Describe*

8 Mitgation		Documentation
1 Realtime pore pressure prediction	☐ 🟩	*Describe methodology and location*
2 LWD/ MWD Density from seafloor	☐ 🟩	*Tooltype*
3 LWD/ MWD velocity measurements	☐ 🟩	*Tooltype*
4 LWD/ MWD velocity from seafloor	☐ 🟩	*Tooltype*
5 Advanced mudgas system with temperature and flow control	☐ 🟩	*Tooltype*
6 High resolution inflow and outflow control	☐ 🟩	*Tooltype*
8 Well documented field barrier above section	☐ 🟩	*Description USIT/CBL & location*
9 Other:	☐ 🟩	
10 LWD/ MWD pressure measurements	☐ 🟢	*Tooltype*
11 XLOT or clear LOP in previous section	☐ 🟢	*Tooltype*

9 Communication with drilling crew		Documentation
1 Plots are shown with uncertainty & discussed	☐ 🟩	*Date of meeting & location of presentation*
2 Plots are shown in m TVD **and** m MD vs Drill Floor	☐ 🟩	*Date of meeting & location of presentation*
3 Geological hazards are plotted, in m MD, described and discussed	☐ 🟩	*Date of meeting & location of presentation*
4 Interaction of geological risk discussed	☐ 🟩	*Date of meeting & location of presentation*
5 Mitigitation are discussed, understood	☐ 🟩	*Date of meeting & location of presentation*
6 HAZOP meeting held incl. PPFG	☐ 🟩	*Date of meeting & location of presentation*
7 PPFG & mitigations are implemented in operation plans	☐ 🟩	*Location of plans*

Best Practise Score	🟩	**Can we do better?**
Calibration Score	🟢	**Do we know enough?**
Increased Risk Score	🟧	**Is the increased risk acceptable? Additional mitigation?**