Well Delivery Group

Good Practice Guide
Drilling of Well with
Challenging FG-WBS-FG Windows

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1. EXECUTIVE SUMMARY

This document outlines key insights and guidance notes for consideration, developed from an experienced group of practitioners who participated in a cross-industry workshop focused on improving the understanding and effectiveness of drilling of wells where navigating an increasingly challenging Fracture Gradient – Wellbore Strengthening – Fracture Gradient (FG-WBS-FG) windows is critical to success.

The report highlights importance of understanding of the subsurface prognosis, the range of potential pressures and the associated uncertainties which will drive the selection of the most appropriate drilling strategy.

Wellbore strengthening (WBS) techniques continue to develop to push the envelope in terms of fracture width and pressure differential that can be successfully treated.

The use of managed pressure drilling remains limited in the North Sea but has demonstrated significant benefit in the execution of tight drilling window projects.

The best technical solution is never sufficient in isolation, the need for collaboration and ensuring the right expertise within an open team environment were highlighted as critical to success.

This good practice guide is not intended to replace professional advice and are not deemed to be exhaustive or prescriptive in nature. Although the authors have used all reasonable endeavours to ensure the accuracy of these guidelines neither OEUK nor any of its members assume liability for any use made thereof. In addition, this good practice has been prepared on the basis of current good practice within the UK Continental Shelf and no guarantee is provided that these guidelines will be applicable for other jurisdictions.

2. INTRODUCTION

The Wells Task Force is an industry task force, supported by the NSTA, looking at the Wells value chain to integrate, streamline and add value to the well delivery, management and removal process. The Well Delivery Group is one of three groups currently operating under the Wells Taskforce, which aims to promote good practice in well delivery across the UK industry.

In Q3 2025, the Well Delivery Group agreed to investigate drilling of depleted reservoir intervals which present significant technical challenge associated with the narrow PFG-WBS-FG window with a view to understanding current best practice.

Increasingly, due to the mature nature of the North Sea basins, there are development opportunities that target resources at virgin reservoir pressure but to access require drilling through several geological layers that present drilling hazards such as overpressured shales with wellbore stability risks, overpressured sands, depleted reservoir sands above the targeted reservoir at virgin pressure. Often these sequences must be drilled in a single section. Additionally, there is often considerable uncertainty over the exact pressure regimes and the formation strengths. Experience has shown that these projects can present significant technical challenges with the implementation of wellbore strengthening techniques and/or managed pressure drilling used to achieve drilling success.

A cross-industry workshop was held with representatives from Well Operators, Regulators, industry groups and the service sector. Four different case studies were presented discussing different approaches and the lessons learned from past campaigns. Following a review of the case studies, the group was split into two sub groups to discuss key themes around drilling depleted reservoir intervals and the use of managed pressure drilling.

The aim of this brief document is to record good practices identified by the discussion groups, based on learnings from industry. It is not a formal guideline or an exhaustive guide to the subject, for which there is a wide body of existing material that can be referenced.

All the points identified have been categorized into the following groups and summarized in the following sections:

1. Subsurface Input
2. Well planning
3. Rig & equipment selection
4. Operational execution

1. SUBSURFACE INPUT

As with any drilling project the subsurface data is a fundamental and a critical input for the drilling team to effectively design, plan and execute a successful operation. With the nature of drilling through depleted reservoir intervals there needs to be a heightened focus by the integrated team on understanding the pressure regimes and the likely uncertainties such that the drilling team can evaluate different cases and quantify the associated risks, develop mitigations in order to select the most appropriate drilling strategy and develop sufficient contingencies.

- Subsurface should provide a Pore Pressure/Fracture Gradient (PPFG) range for example P10-P90, not just single case
- Offset study must include observations & data from producing & injection wells, last well drilled in field, mud weights, PWD, FIT/LOT, loss events and any downhole pressure and temperature monitoring
- Need for drilling team to understand the basis for the prognosed PPFG range, the accuracy and uncertainty within the prognosis
- Identify most likely scenario and risk & likelihood of other cases
- Considerable uncertainty can exist in Fracture Gradient (FG) due to depletion
- Identify location and size naturally occurring fractures and induced fractures
- Establish expected fracture width for design & testing of fluid design
- Drilling engineer due diligence on the subsurface data
- Challenge session with integrated team to ensure a common understanding of parameters and well value proposition
- Consider independent review of subsurface data
- Specialist geomechanics modelling should be performed
- Geomechanics modelling can be conservative (recommending higher wud weights) and can be challenged
- During operations, update modelling as new information becomes known
- Robustly challenge minimum requirements such as length of horizontal section required
- Whilst planning for MPD application, evaluate offset gas analysis and implications of H_2S
- Evaluate increased potential for sand production due to depletion
- Ensure latest data being used and part of a formal sign off and subject to Management of Change (MOC) if it changes

2. WELL PLANNING

Well planning is perhaps the most demanding aspect of drilling engineering. The planning phase of the well lasts from approval of the well design until operations start. [1]

- Both wellbore strengthening and Managed Pressure Drilling (MPD) have been deployed in North Sea
- North Sea region has experience of successfully drilling long reservoir intervals (several thousand feet) in single section which include balancing the risk of wellbore instability with that of severe reservoir depletion.
- Growing experience of utilizing MPD in the North Sea from Jackups. Demonstrating that MPD window significantly lower than conventional drilling window.
- In North Sea, typically MPD has been performed using Heavy Duty Jack Up (HDJU) rigs, with standard semi-submersibles utilizing non-MPD solutions
- Conducting MPD feasibility study early in planning cycle to demonstrate compatibility with the specific application. The install time associated with MPD can be large.
- Ensure due diligence on subsurface input data and ensure data is controlled (signed off)
- It may not be feasible to design to cover all PPFG cases – responsibility to communicate any risk of not achieving well objectives
- Typically plan for most likely outcome with sufficient reasonable contingencies for other (high, low) cases
- Well architecture consideration with MPD drilling window to be considered. i.e. longer sections or contingency options can be reduced with the use of MPD, Drill In Liner (DIL) with MPD to isolate short challenging areas.
- Consider Loss Circulation Material (LCM) circulation sub in Bottom Hole Assembly (BHA). It is important the scenarios where it could be used are understood prior to running.
- Consider disconnect sub in BHA. It is important the scenarios where it could be used are understood prior to running.
- Bit selection & nozzle sizing, balance between hydraulics and providing the contingency of being able to pump cement through bit
- BHA component modifications to improve tolerance to LCM may be required
- Line hanger components tolerance to LCM
- Allow time for additional testing of fluids and compatibility
- Awareness that standard test kit does not exist for wellbore strengthening material and formulations – may require test kit development
- Extensive onshore testing should be planned for to ensure compatibility of fluids with BHA (plugging and abrasion), shaker screens (blinding)
- Hole cleaning can be compromised in larger OD casings & riser (is this acceptable & manageable?) to ensure FG limits are not exceeded
- Consider the balance of risk when evaluating wellbore Stability, Influx versus lost circulation. Evaluate the time to recover from different scenarios.
- Wellbore strengthening techniques successful in field treating fractures up

[1] Well Life Cycle Integrity Guidelines - Issue 4

to 1200-1300 microns with standard LCM materials and up to 1500 microns by introduction of cellulose material in fluid.

- Cellulose can provide benefits over conventional LCM material in terms of thermal & mechanical degradation
- Wellbore strengthening fluids typically introduced prior to entering reservoir interval
- Wellbore strengthening fluids typically left in openhole interval prior running casing/liner. Target weight of fluid column can be adjusted with mud cap in cased hole.
- MPD may allow non-permeable zones to be drilled underbalanced, with no flow observed
- MPD can facilitate dynamic PP and openhole FIT testing. Initiating fracture breakdown pressure and fingerprinting of it
- MPD can facilitate LCM with a cement squeeze operations
- Managed pressure cementing (MPC) can be utilized to keep wellbore pressures with an established window at all times throughout a liner / casing cement job where not possible conventionally (unable to achieve density hierarchy). Need to understand where loss zone is and required TOC.
- MPC, bypass Coriolis meter as standard for circulating out excess cement as cement through Coriolis meter is not desirable. The Coriolis meter can be used as first indication of space at surface then is can be bypassed.
- Establish detailed decision trees with detailed and pre-agreed contingency responses
- Best technical approach alone does not bring success, the right capability and expertise as well as alignment both between with companies and between on & offshore personnel is required for success.
- Need to check compatibility of cement recipe with BHA provider(s)
- Contingency completion options may be required
- Any requirement for zonal isolation (such as swell packers)
- Consideration of the ability to recover from a well control event (major losses or gain) with or without MPD
- Minimum horizontal stress should drive decision on mud weight if possible
- Observed depletion could impact the perforating strategy
- Operators have different approaches for cement slurry design – selection of lightweight slurry versus conventional slurry weight and modified mud weight
- Kick tolerance, a number of factors to be considered to maximise volume such as annular volume, reservoir properties, kick intensity, crew response time with MPD etc
- MW selection and impact on kick tolerance
- Consider developing a specific well control matrix or influx management envelope

3. RIG & EQUIPMENT SELECTION

The suitability (pressure rating, etc) of the well control equipment supplied by the rig owner should be assessed by the well-operator as part of the contracting process. An independent inspection/audit of the equipment may be carried out.

The installation owner's SEMS should be reviewed, and a bridging document issued to align this with the well-operator's SEMS. The installation owner's well control procedures should be reviewed.

A full well life cycle wellhead bending analysis and riser analysis, which covers local environmental conditions, should be available for floating operations. This analysis should take account of wellhead stickup. Limits for the allowable wellhead angle should be set that are applicable to the equipment in use. A full well life cycle riser stress analysis and conductor analysis, which cover local environmental conditions, should be available for bottom supported offshore operations.[2]

- Rig selection can be influenced by the drilling strategy (requirement for MPD, capacity & handling of fluids, deck space for batch tanks, LCM).
- In North Sea, typically MPD has been performed using HDJU rigs, with standard semi-submersibles utilizing non-MPD solutions. Below tension Ring Rotating Control Device (RCD) can compensate for heave whilst drilling, but in tight windows, casing running casing with MPD would be an issue. Current solution of some rig floors which are compensated is niche and requires high capital investment.
- For MPD, rig with no experience of MPD may require investment in equipment and crew training. Training can be tailored to the specific well program by the MPD provider to include all relevant personnel.
- With less rigs in North Sea region this may limit choice considerably, and the ideal rig may not be an option.
- Availability of equipment and tooling to cover full range of scenarios. Long lead times on specialized equipment needs to be considered during the planning phase i.e. High temperature / high pressure rated downhole tooling.
- Not always able to justify covering all contingencies especially on smaller, marginal projects.
- Minimizing trips in & out of hole can be a key driver, consider overall section time rather than on-bottom ROP. It may be advantageous to drill slower but with a bit/BHA that can complete section on fewer runs. Optimisation of BHA and bit design specifically to reduce likelihood of vibration induced failure should be completed.
- Gather offset from service companies for high LCM tolerance tooling solutions – i.e. through bore MWD, high flow area pulsers, flow loop testing to provide reassurance of functionality. Offset information of through tooling cementing also be of benefit when selecting tools.
- Logging Whilst Drilling (LWD) that can take pressure points can add significant value. However, consider the max differential pressure LWD tool

[2] Well Life Cycle Integrity Guidelines - Issue 4

can accommodate and the static time required to take samples. If the well conditions are such that downhole LWD tools are not suitable to take pressure tests, MPD can be utilized to take dynamic PP tests.

- MPD equipment advances to improve control system / hydraulic model i.e. Coriolis flow meters on mud pump or stand pipe manifold. LWD that can see ahead of bit and enable 'geo-stopping' to enable

4. OPERATIONS

The detailed operations programme (e.g. drilling, completion, intervention) should describe in detail how the well objectives will be achieved while keeping risks ALARP.
For well integrity, the planning should concentrate on:

- Maintaining primary control of the well during all operations,
- Installation, removal, testing and monitoring of barriers during all operations.

Drilling contractor and service company personnel should be involved in the detailed planning, both to take advantage of their specialist knowledge and to encourage 'ownership' of the finished programme.
The operations programme should be accepted by a representative of the installation duty holder, or site operator, as they have the primary responsibility for safety on the installation or borehole site.[3]

- Equivalent Circulating Density (ECD) management is top priority during operations during narrow window drilling, and will likely be the factor that limits performance.
- Only when on top of pressure management can ROP & performance be optimized
- Ensure heightened awareness of risk of losses and agreed actions for loss events. Ensure loss decision tree available at wellsite. Similarly for Well control events.
- FIT to confirm fracture gradient & if you have the ability to drill ahead
- Static FIT (if no MPD) are preferred, although some operators do perform dynamic FIT to understand the ECD limits
- Pressure Whilst Drilling (PWD) can be used to confirm FIT pressure. PWD can send full pressure profile during FIT / LOT test and over connections. Be aware of the time to pulse high density data to surface or if min / Max / average is sufficient.
- Well monitoring with overall higher focus on drilling parameters
- Monitoring fingerprinted trend can include flowback, turning off agitators, wellbore instability, additional fluid checks, ECD, ESD.
- MPD can adjust equivalent Mud Weight to remain within the PPFG window without the need to adjust actual mud weight.
- Torque & drag modelling should be performed at wellsite during operations
- Vibration monitoring and mitigation to be implemented to protect drilling tools
- Fluid & LCM mixing at wellsite can be a risk and be a cause of tool plugging issues, ensure plan for appropriate mixing or pre-mix under more controlled

[3] Well Life Cycle Integrity Guidelines - Issue 4

conditions

- Awareness that taking pressure points during drilling may induce losses
- Tripping margin should be calculated and adjusted based on measured data from operations. MPD can mitigate swab.
- Experience of Thixotropic cement routinely pumped through BHA (recent North Sea job with example of 8 consecutive cement jobs pumped through BHA for lost circulation).
- Pumping cement through BHA should be 'get out of jail' option for major loss situation
- If balanced cement plug is required then POOH and run a cement stinger
- Digital twin of well is being used real time in other regions for directional control (automation to keep parameters within set ranges) and could be applicable to pressure management in the future
- Plan to have any mud weight changes as a full displacement rather than spiking / dusting into active system.
- Inconsistency on what constitutes a sequence being 'too gassy", difficult to have an absolute limit (number of factors including rig specific gas sensors). Industry may want to consider a common consistent approach with respect to flow checks and gas percentage on bottoms up to verify the well is static prior to POOH. i.e. what is the criteria for performing Horner Plots vs extended flow checks? Consistency would likely reduce the likelihood of chasing MW leading to losses.

5. CONTRIBUTORS

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6. ABBREVAITIONS

Abbreviation	Definition
ALARP	As low as reasonably practicable
BHA	Bottom Hole Assembly
DIL	Drill-In Liner
ECD	Equivalent Circulating Density
ESD	Equivalent Static Density
FG	Fracture Gradient
FIT	Formation Integrity Test
H_2S	Hydrogen Sulphide
HDJU	Heavy Duty Jack-Up
LCM	Loss Circulation Material
LOT	Leak-Off Test
LWD	Logging While Drilling
MOC	Management of Change
MPC	Managed Pressure Cementing
MPD	Managed Pressure Drilling
MW	Mud Weight
MWD	Measurement While Drilling
NSTA	North Sea Transition Authority
PFG	Pore Fracture Gradient
POOH	Pull Out Of Hole
PP	Pore Pressure
PPFG	Pore Pressure / Fracture Gradient
PWD	Pressure While Drilling
RCD	Rotating Control Device
ROP	Rate of Penetration
SEMS	Safety and Environmental Management Systems
TOC	Top of Cement
WBS	Wellbore Strengthening