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Abstract

Old platforms are not well known for extended-reach drilling (ERD) operations mainly due to rig and hydraulics limitations. ERD wells demand robust rig capabilities, good hydraulics systems, and equipment reliability. In addition, the well profile, rotary steerable system (RSS), measurement-while-drilling (MWD) and logging-while-drilling (LWD) tools, surveying, and new technologies are extremely important to the success in drilling an ERD well. RSS and drillpipe selection are important factors for hydraulics optimization. Surveying techniques are also important for time saving and improved efficiency. An ERD well in the North Sea Statfjord field was kicked off in the 17 ½" section from the openhole cement plug through a 50m window between the 20" casing shoe and 13 3/8" casing stump, ensuring a smooth well profile and reduced doglegs compared to the whipstock window exit. The 17 ½" section was drilled and landed at a 79° inclination using point-the-bit RSS technology, and the 12 ¼" section was drilled in two runs as planned using the point-the-bit RSS withstanding more than 550 hours down hole. The 9 5/8" liner was run and floated successfully in the ~6000m section. Strict adherence to surveying techniques and quality control processes proved very helpful to meet Operator technical requirements. The 8 ½" section was drilled and landed on top of the reservoir with an inclination decrease from 88° to 35°. New MWD technology was successfully used in drilling the 6" section. These latest technologies as well as employing appropriate techniques help to drill ERD wells on aged platforms like those in the Statfjord field.

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List of Abbreviations

ERD	Extended reach drilling
MWD	Measurement while drilling
LWD	Logging while drilling
RSS	Rotary Steerable systems
MD	Measured depth
TVD	True vertical depth
BHA	Bottom hole assembly
ECD	Equivalent circulating density
HWDPS	Heavy weight drill pipes
RPM	Rotation per minute
T&D	Torque & Drag
OBM	Oil based mud
WBM	Water based mud
SBM	Synthetic based mud
OD	Outer diameter
ID	Inner diameter
WOB	Weight on bit
FF	Friction factor
CHFF	Cased hole friction factor
OHFF	Open hole friction factor
PHAR	Pipe hole area ration
ROP	Rate of penetration
GPM	Gallons per minute
LPM	Liters per minute
PV	Plastic viscosity
YP	Yield Point
PWD	Pressure while drilling
POOH	Pull out of hole
RIH	Run in hole
BU	Bottoms up
P/UP	Pick up
Kips	Kilo pounds
SPP	Stand pipe pressure
HP	Horse power
GR	Gamma ray
PD	Power Drive
RKB	Rotary Kelly bushing
AHD	Along hole depth
SR	Steering ratio
HCI	Hole cleaning index
CRI	Cuttings re-injection
TD	Target/Total depth
WOC	Weight on cement
MW	Mud weight
MSA	Multi-station analysis

NPT	Non-productive time
SPT	Stand pipe pressure transducer
QC	Quality Check
EDI	Estimated drill string interference
TDS	Tope drive system
LGS	Low gravity solids
OEDP	Open ended drill pipe
W2W	Weight to weight

1 Introduction

Currently, Oil and gas industry is facing history's deepest downturn and struggling to recover. Oil price is hovering around 50 USD/barrel and Operators are not willing to make investments in high risk and exploration areas. To exploit the existing known reserves using existing and cheaper infrastructure is the key to success in this tough market situations. Extended Reach Drilling (ERD) is a vital technique to access reserves lying at longer distances from platforms. ERD wells are challenging in many aspects and drilling from old platform can further make it complex simply due to design limitations. With robust planning & design ERD wells can still be drilled from old platforms such as Statfjord C.

1.1 Objectives and Thesis Structure

This thesis will describe the planning and execution phases of a challenging ERD well drilled in the Statfjord field.

Below are some of the main points addressed in this thesis;

- History of Statfjord field
- Fundamentals of ERD wells;
    1. What is ERD?
    2. Well Design
    3. Torque and Drag (T&D)
    4. Buckling
    5. ECD management
    6. Hole Cleaning
    7. BHA design
    8. Casing/Liner Floatation
- Planning and Execution of 17 ½" section
    1. Open Hole Cement plug kick off
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    3. Backreaming
    4. Surveying
- Planning and Execution of 12 ¼" section
    1. BHA design

ii. Hydraulics and Torque and Drag
iii. Backreaming
iv. Wellbore Tortuosity
v. Surveying
vi. Road Maps

- Planning and Execution of 8 ½" section
- Planning and Execution of 6" section

2 Introduction to Statfjord Field

The Statfjord field is one of the largest and oldest fields on North Sea Continental Shelf (NCS), and Statoil operates 3 platforms (A, B, and C) with a total of nearly 400 wellbores. Each platform has 42 drilling slots and on an average, each slot shares three or more wellbores, making it challenging to drill reentry ERD wells. The Statfjord field was estimated to contain original recoverable oil reserves of 576.10 million Sm3 liquid production volume and remaining oil reserves of 5.6 million Sm3 [1] & [11].

The Statfjord field has an average water depth of 150m, and is located in the North Sea Tampen area near the Norwegian and UK sectors. This field has been developed with three fully integrated facilities, including Statfjord A, B, and C. The Statfjord A facility is centrally located and production began in 1979. Statfjord B, located in the southern portion, and Statfjord C in the northern portion began production in 1982 and 1985, respectively. The satellite fields, Statfjord Øst, Statfjord Nord, and Sygna have a dedicated inlet separator on Statfjord C [1] & [11].

The Statfjord field originally produced by pressure support from water alternating gas injection, water injection, and partial gas injection. A late-life plan for development of the Statfjord field was approved in 2005 and depressurization of the reservoir in the Brent group began in 2008. Facilities modification was performed as a part of Statfjord Late-life project with the goal to increase oil and gas recovery and prolong the field's lifetime [1] & [11].

2.1 Background of Statfjord Field

The Statfjord field was discovered by Mobil in 1974 and being operated by Statoil since 1987. This field covers an area of 580 km2 in the United kingdom-Norwegian boundary of the NCS at a water depth of 145m. Statfjord set the record for the highest per day production ever recorded for a European oil field: 850,204 barrels (crude oil plus natural gas liquids) were produced on January 16, 1987.

Statoil is operating Statfjord field under the late life and plans to exploit oil reserves with 68% recover factor out of which 60% is already produced leaving behind approximately 300 million barrels. Statfjord is scheduled to remain active beyond 2020 [12].

3 Fundamentals of ERD

3.1 What is ERD?

According to K&M Technology Group [2], in text books literature, ERD is defined as when the step out/vertical depth ratio exceeds 2:1. However, this is critical and depends on the vertical depth. ERD is a systematic approach to developing reservoirs that are a significant distance from an existing pad or platform. Sakhalin-1 Project, world's longest ERD well was drilled from Orlan Platform in the Chayvo Field with a total measured depth of 13,500m measured depth (MD) and a horizontal displacement of 12,030m.

According to petrowiki [3] below are a few of longest ERD wells drilled by the industry so far:

- 25 wells drilled by Exxon Neftegas Limited on the Sakhalin-1 project, Sakhalin Island Russia, (MD/TVD = 3.9 to 6.9)
- 1 well drilled by Maersk Oil Qatar in the Al Shaheen field, Qatar (MD/TVD = 11.1)
- 2 wells drilled by BP on the Wytch Farms project, England (MD/TVD = 6.9 to 6.6)
- 1 well drilled by Total in Argentina, Cullen Norte #1 (MD/TVD = 6.7)
- 1 well drilled by ExxonMobil in the Santa Ynez Unit, offshore California, USA (MD/TVD = 5.36)

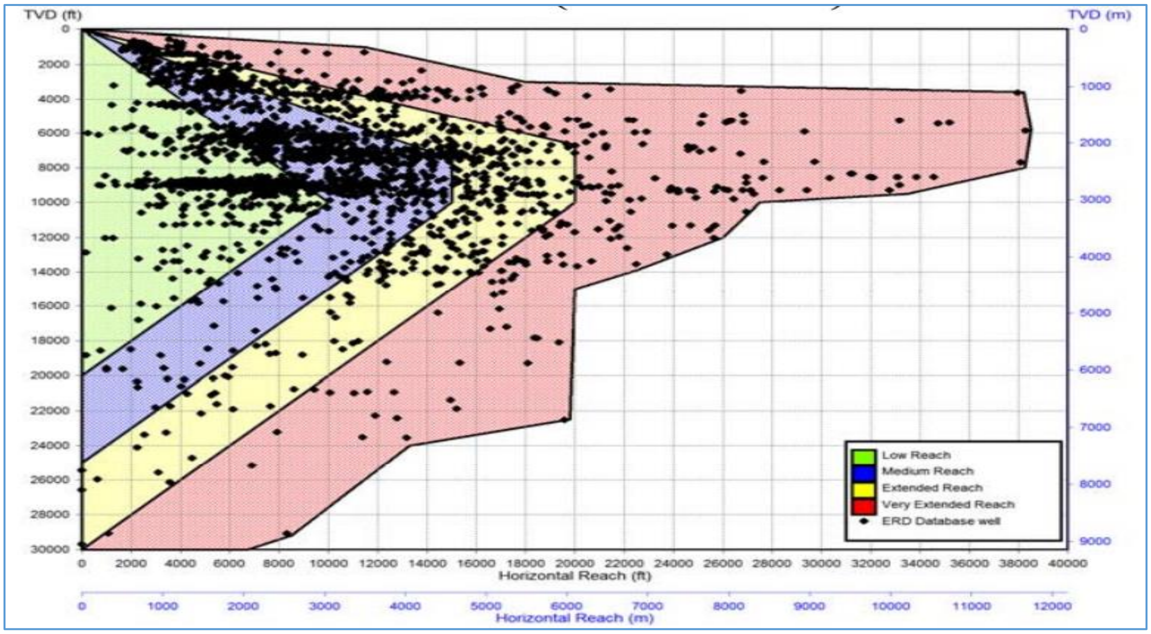

Figure 1 (Courtesy K&M): Global ERD wells record [2]

3.1.1 ERD Well requirements

ERD wells are much more complex than normal horizontal wells. Rig capabilities are the key to success of ERD operations. They require high torque and pressure capabilities, more pipes and volume. But it does not mean that small rigs cannot drill ERD wells, 1500 horsepower (HP) rig has drilled World's 2nd longest ERD well [2].

3.1.2 How ERD wells are different than normal Wells?

ERD wells are different from normal wells in the following aspects [2]:

- Hole Cleaning

  Hole cleaning is the most important parameter and the number one priority in drilling successful ERD wells. In low angle wells hole cleaning is easy to achieve but still it's important. In ERD wells hole cleaning is extremely important and difficult to achieve. Flow rate, rotation per minute (RPM) and other required parameters will be discussed more in details in coming chapters.
- Wellbore Instability

Wellbore instability depends on the formation and type of mud in use. If formation is time sensitive like swelling shales in water based mud then wellbore stability can be a big issue. Use of Oil based mud (OBM) can create a big difference, as an example Shetland shale on Statfjord can remain stable upto 1.5 month time as seen on one of the offset well. High angle wells require higher mud weights for stability than low angle wells. In general wellbore stability reduces with time.

- ❖ Equivalent Circulating Density (ECD)

  Due to shallow TVD's and longer MD's ECD's are often higher in ERD wells. Consequence of losses (as a result of higher ECD) are catastrophic in ERD wells compared to normal wells mainly due to high cost.

- ❖ Bottom hole assembly (BHA) Design

  BHA design is extremely important in ERD wells. A good BHA design in normal wells might be the worst BHA design in ERD wells. Jar placement and its effectiveness in ERD wells is a debate in itself. Use of Drill collars or Heavy weights drill pipes (HWDPS) must be looked in details as they affect BHA stiffness as wells as stand pipe pressure. BHA design in ERD wells must take into account the hole cleaning and ability to trip through cutting beds (Junk slot area) and capable of withstanding high on-bottom and off-bottom RPM.

- ❖ Bit Selection

  In ERD wells bit stability, steerability, directional control and durability are the most important features. Rate of penetration (ROP) is not the high priority in most of the cases due to hole cleaning and ECD limitations so generally aggressive bit is not a good choice.

- ❖ Tripping

  Tripping practices in ERD wells are different from normal wells. Backreaming can be common on ERD wells. Stuck pipe and jar operating practices are also critical. Wiper trips made for hole condition monitoring are not recommended as there are other and better ways of condition monitoring. Wiper trips actually generate more cuttings and disturb wellbore stability so must be avoided.

❖ Mud Properties

Mud rheology is the most important ingredient in hole cleaning system. Mud rheology affects hole cleaning, ECD & pressure. Barite sagging and ECD is common problem in ERD wells and must be addressed proactively. Adding lubricants is also common when issues seen with torque & drag (T&D). Care must be taken when adding lubricants as it might affect the mud rheology.

❖ Drilling Parameters

Drilling parameters in ERD wells have more importance and different approach than normal wells. High flow & high RPM is the key to hole cleaning. ROP is normally driven by hole cleaning efficiency. Making connections and breaking circulation (breaking gell) are special in ERD wells. Number of bottoms ups and hole cleaning parameters (RPM and flow rate) prior to tripping are different in ERD wells.

❖ Hole Condition monitoring

There is a difference in important data for ERD well than a normal well. In normal wells, ECD and torque are the main indicators of hole cleaning which is not the case in ERD wells. Torque & ECD are not the most important hole conditioning parameters in ERD wells. Pickup and slack off weights are most important for hole condition monitoring in ERD wells and these are monitored on roadmaps developed with theoretical values.

❖ Cementing

Cementing is most challenging job in ERD wells. Cement displacement, cement channelling & centralization is complex to understand & execute. Cementing of liner with liner rotation requires aggressive planning & risk assessment.

❖ Casing running & Design

Casing design may call for casing floatation techniques to be used based on drag & buckling simulations. If casing is floated, then casing design must take into account the high collapse casing in interval where casing is planned to be empty. Casing floatation means casing is not filled with mud while running in hole & is kept empty for certain length. This reduces weight of the casing and hence reduces drag.

- Surveying & Geological uncertainty

  TVD certainty is extremely important in ERD wells. Accidentally drilling into reservoir due to TVD uncertainty can lead to losses which can be catastrophic in ERD wells. Several techniques may be used to increase TVD certainty & will be discussed in coming chapters.

- Well Control

  In ERD wells it is more likely to accidently drill into reservoir due to high TVD uncertainty. There is always risk of swabbing an influx while tripping out of hole. Influx may migrate faster or slower than vertical wells depending upon inclination. For well killing operations, Driller method is better suited to ERD wells than Wait & Weight method.

- Completions

  Buckling & Drag are the most serious concerns with completions in ERD wells. Completion design, completion running and interventions must be looked into details and with proper risk assessment.

4 Torque & Drag (T&D) and Buckling

4.1 Torque & Drag Misconceptions

According to K&M Technology Group [2] Common misconceptions related to Torque & Drag are:

i. Low angle wells have low T&D
ii. Build rates of 2° – 3°/30m are "low enough"
iii. That all dog legs are created equal
iv. That tortuosity will inevitably lead to higher torque and more difficulty running casing/completions

4.2 Torque & Drag Fundamentals

Torque & Drag are caused by normal forces (also Known as side forces). Normal force is created by 4 different mechanisms [2]:

i. Weight of pipe on the low-side (Low-Side T&D)
ii. Tension-related side-forces through build, turn & drop doglegs (Brake Drum T&D)
iii. Pipe pushing into the side of the hole due to helical buckling (Buckling T&D)
iv. Pipe pushing into the side of hole, driven by stiffness and diametrical clearance (Stiffness T&D)

4.2.1 Low Side T&D

Low side T&D is created because of the resistance to movement created from "friction", as a result of being pushed into the low-side of the hole. It is sensitive to angle, weight & buoyancy. Each joint creates T&D independent of each other & the same side force, independent of direction (RIH (run in hole), POOH (pull out of hole) & Rotating) [2].

Drag Force = N x μ, Torque moment = N x μ x Reff

Normal force = Cosθ x W

Where:

Reff= Effective Radius

N = Contact Force (i.e. Normal Force)

θ = Inclination of component

W = Buoyed weight of component

μ = Coefficient of Friction

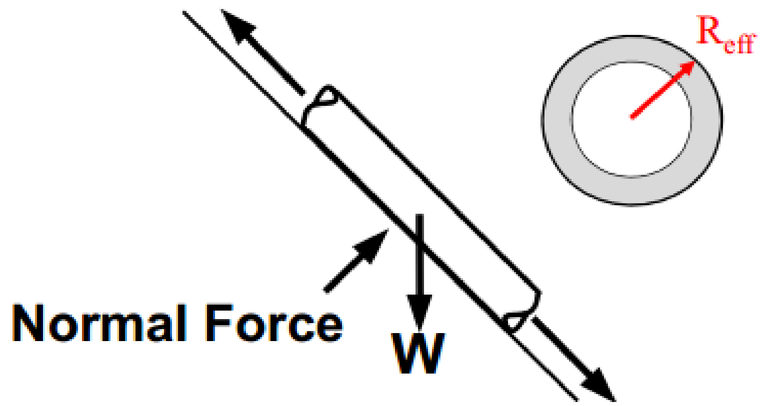

Figure 2 (Courtesy K&M): forces components acting on pipe [2]

4.2.2 Brake Drum T&D

In curved sections, string tension creates additional contact force and friction, much like a Brake Drum. T&D forces are created via the tension of other elements below this interval. Pickup, slack off and rotating forces will be different in curved sections, since string tension is different [2].

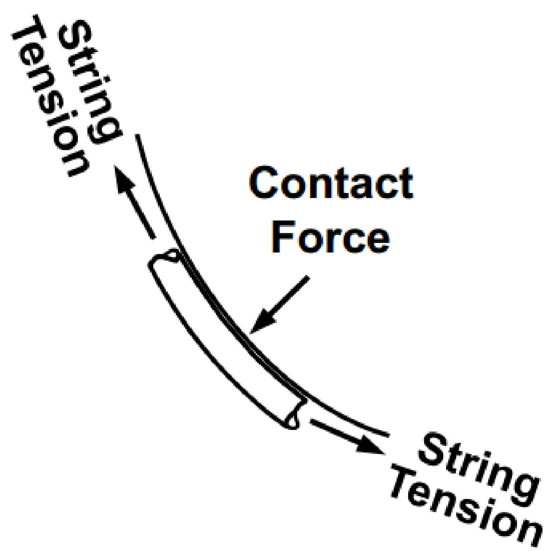

Figure 3 (Courtesy K&M): Brake drum effect on pipe [2]

4.2.3 Buckling T&D

Buckling T&D is created when the compression in the pipe exceeds the helical buckling limit. When sliding or tripping in, the additional normal force quickly compounds on itself and eventually may cause "lockup", resulting in the inability to move downward. When rotating or rotary drilling, the additional normal forces cause a rapid increase in torque. However, downward motion and efficient weight transfer is still possible [2].

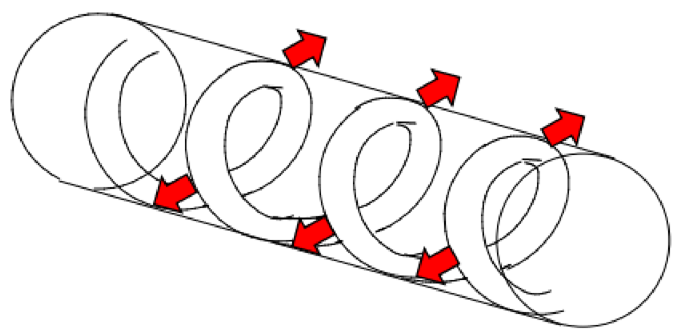

Figure 4 (Courtesy K&M): Buckling effect on pipe [2]

4.3 Buckling Fundamentals

According to K&M Technology Group [2] buckling is when the pipe bends or coils downhole. Usually buckling causes no damage to pipes as long as pipe is not rotated. Rotation causes back and forth bending which quickly leads to fatigue damage/failure (like a paper clip). Therefore it is highly recommended to never start rotation with the pipe buckled. It is easier to buckle the pipes in a big hole as pipe is not as well confined & higher weight on bit (WOB) may be desired in a large hole. It is easier to buckle small OD pipes. Stiffness increases rapidly with OD & 5" drill pipes (DPS) is twice as stiff as 3½" DPS.

It is harder to buckle pipes at higher angles, but not impossible. However any compression in a vertical hole results in buckling. 5" DPS helical buckling occurs at 38 k-lb (17 tonnes) for 75° inclination, but only at 11 k-lb (5 tonnes) for 5° inclination (12¼" hole).

Also, it is harder to buckle in a curved hole, but not impossible. Bending forces exerted by hole help pipe resist buckling. Pipe will always buckle first in a straight section

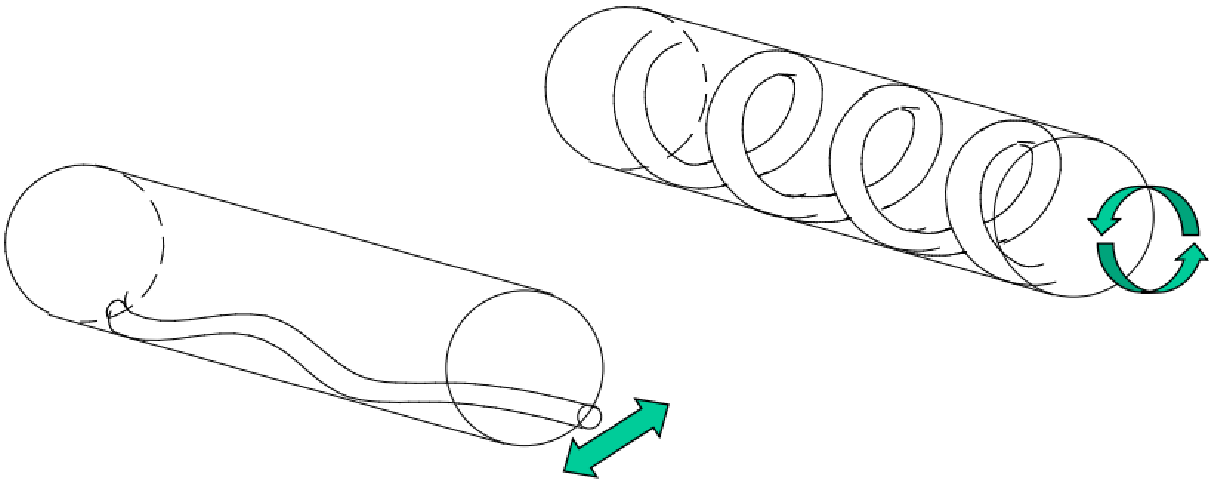

Figure 5 (Courtesy K&M): Helical (top right) & sinusoidal (bottom left) buckling [2]

4.3.1 Sinusoidal Buckling

This is first phase of buckling & occurs at lower compression load than helical buckling. Pipe "snakes" from side-to-side along the low side & gravity keeps pipe from climbing to the top of the hole. Sinusoidal buckling still allows weight transfer (inefficiently) [2].

4.3.2 Helical Buckling

This is 2nd phase of buckling: as compression increases, pipe suddenly snaps into a full coil. It prevents all further transfer of weight. More compression just gives the coil a better grip on the hole (like a set of slips) [2].

4.3.3 Avoiding Pipe Buckling

Below are possible techniques which can be used to avoid buckling [2]:

i. HWDP can be used above KOP in short horizontal wells (less applicable in ERD or long laterals)
ii. Use larger OD drill pipe (increased stiffness)
iii. Use a tapered drill string (less weight to push)
iv. Reduce friction to reduce compression
v. Use lubricants or OBM rather than water based mud (WBM)
vi. Use a rotary steerable systems not Motors to avoid sliding

5 T&D and Buckling Modeling

5.1 Common Beliefs [2]

- T&D friction factors from offset wells are appropriate for planning high angle wells
- Use of Rotary Steerable BHAs improves T&D
- That cased-hole friction factor (FF) is slipperier than open-hole FF
- That cased hole friction factor should be used for T&D calculations
- That stiff-string models are more accurate than soft string models

5.2 Friction Factor

A FF is a “catch all”– it captures many unknowns that are un-measurable with current technology [2].

- Hole geometry – Ledges, spiraling, washouts, filter cake, etc.
- Pipe stiffness – Connection effects, centralization, pipe wear
- Cuttings Beds – Thickness, roughness, sand/shale content
- Differential Sticking Effects
- Pipe Weight errors
- Tool joints / coupling interaction

Friction factor is usually confused with “Coefficient of Friction”. The coefficient of friction is measured in a laboratory, often to compare various mud systems or lubricants under controlled conditions. The Coefficient of friction value measured in the lab is almost never the same as what is measured in the field [2].

5.3 What is required for accurate T&D Modeling?

- Good input data (Wellpath, Drill-string especially pipe weight, and pipe OD-ID for buckling calculations, Block Weight, Hole size description, Mud weight , FF inputs i.e. Cased hole, Open hole, or Average FF)
- Understanding of What scenarios to Investigate
- Understanding of How to Interpret Model Output

5.4 How do the T&D Software Models Work?

Most models use common algorithms for T&D modeling i.e. C.A. Johancsik, et al – SPE 11380 (Exxon, 1984).

- Buckling models are more specialized
- Stiff string models also tend to vary
- Well Plan (Landmark) – Soft String or Stiff String mode
- Drilling Office (Schlumberger) – Stiff String only
- Advantage (Baker Hughes) – Soft String or Stiff String mode

Most T&D models assume "flexible member" theory which does not allow for stiffness or geometry of the pipe. Stiff string models work differently. It attempts to normalize friction factors by allowing for stiffness.

Soft String model assumes pipe follows the shape of the hole (like spaghetti) [2].

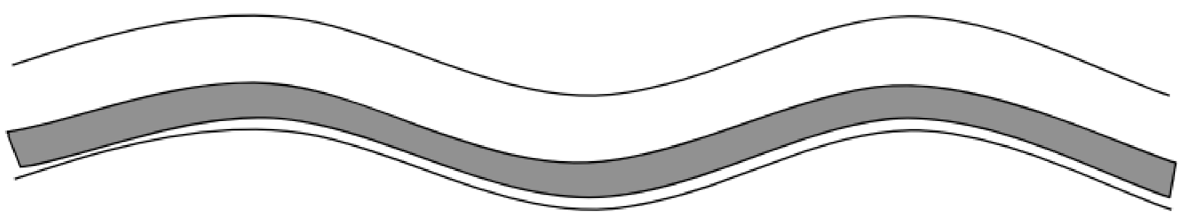

Figure 6 (Courtesy K&M): Soft string model [2]

Stiff String model attempts to account for additional side forces caused by stiffness / relative hole size [2].

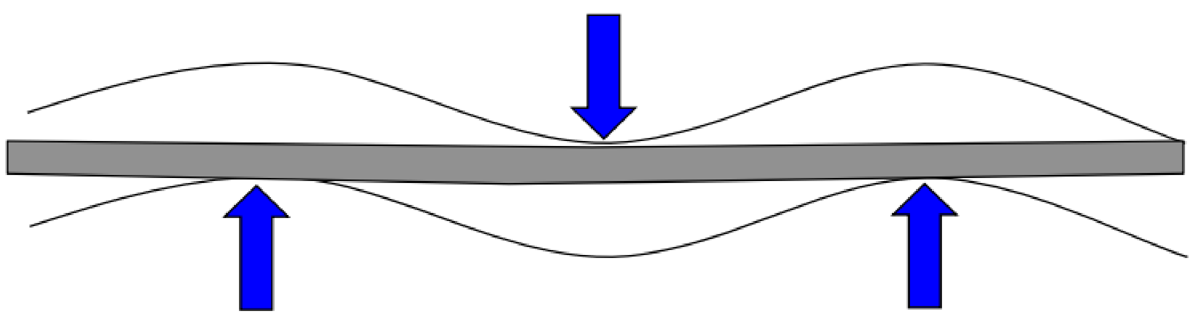

Figure 7 (Courtesy K&M): Stiff string model [2]

5.5 Is a stiff-string model better for ER wells?

K&M Technology Group [2] contend that such models are not any more accurate than soft string for ERD wells. Use of stiff string model is actually invalid and dangerous if higher friction factors are not used for “stiffer” operations. Unknowns that are critical to accuracy can never be known:

- Hole size & shape
- Cuttings bed height, and how it interacts with pipe
- Doglegs between surveys
- Pipe weight (new pipe is wrong, let alone used pipe)
- How couplings, centralizers interact with the wellbore

5.6 Using Block Weight in T&D Calculations

Block weight is almost always wrongly used, and it can have a big impact on interpretation of results. A “hookload” or “weight” measurement is taken on the rig but the T&D program doesn’t work with hookload or weight – only tension is important. The Block weight is subtracted from the hookload & the FF is then calculated from this block-adjusted number. This is where the error occurs, because the block weight is usually wrong and we can’t back-calculate the correct FF with an incorrect block weight. The block weight must be measured as a separate weight in each direction. Due to sheave friction, hoses etc. it will be different for slack off, pick up and stationary and this difference can be typically upto 10-11 Ton. It can make a big difference in ERD wells [2].

5.7 Using Cased Hole FF in T&D Calculations

Cased hole FF (CHFF) & open hole FF (OHFF) are not independent variables. It is not possible to have wrong CHFF, and expect meaningful OHFF results. CHFF is valid concept only when we can measure a meaningful CHFF like for casing runs, etc. But it cannot be measured accurately for drilling calculations (or other dynamic environments). For Drilling calculations one must use average FF [2].

5.8 Understanding Friction Factors

According to K&M Technology Group [2] there are three types of friction factors (not just one) i.e. Slack-off, pick-up and torque & each should use different FF numbers. Typical "Drilling FF's" for 12¼" section in OBM / synthetic based mud (SBM) are:

- ❖ Torque FF = 0.16 – 0.18
- ❖ Slack off FF = 0.25 - 0.30
- ❖ Pick up FF = 0.20 - 0.25

Dynamic FF's are driven by annular clearance, tortuosity, fluid lubricity, wellbore & cuttings materials. The key issue that drives FF is the pipe / hole clearance. If it's a "big pipe & small hole" situation a step change in FFs occur. Different FFs need to be used for different operations:

- ❖ Running casing has much higher FFs than for the drilling operation (in the same hole section)
- ❖ Drilling SO typically 0.25 – 0.30
- ❖ Casing / Liner / Screens run may be 0.4 – 0.5 (for a good run)
- ❖ 8½" drilling FFs are typically higher than for 12¼" hole (especially TQ), Say 0.30 – 0.35 vs. 0.18 – 0.22
- ❖ We cannot estimate or assume FFs for a casing / liner run based on drilling T&D, unless annular clearance is large
- ❖ Enlarging a hole (say from 8½" to 9½", or 12¼" to 13½") can have a significant FF benefit when running casing

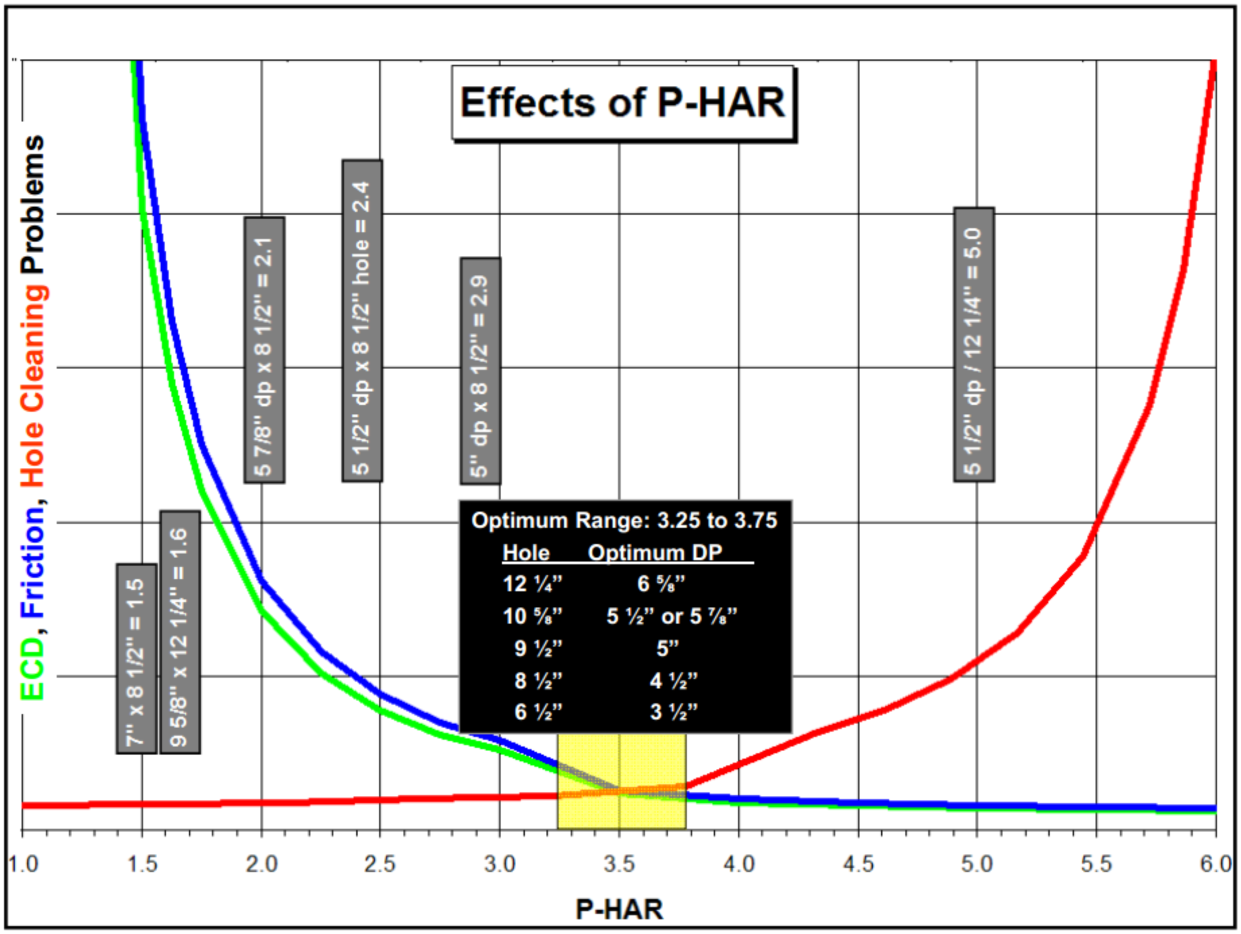

Figure 8 (Courtesy K&M): Effects of PHAR [2]

5.9 Myths / Misconceptions about what drives FFs [2]

i. That improved hole cleaning will reduce T&D
- ❖ Not true for torque (often neutral or worse as hole gets cleaner)

ii. Reducing contact area reduces T&D (i.e. using centralizers)
- ❖ Not true.
- ❖ Casing still weighs the same, but is now point-loaded
- ❖ Contact area is a non-issue, except when differential sticking is present, Then centralizers are a critical stuck-pipe prevention tool

iii. That cased-hole is more slippery than open hole
- ❖ Sometimes not true, especially for drilling FFs, It has been regularly seen that drilling FFs increase (torque by 50% - 70%) when hole is cased
- ❖ Running casing does tend to have lower CHFF, but not drilling operations

iv. That friction factors don't change while drilling

- ❖ Lithology changes often affect the natural friction factor (even in "clean" hole)
- ❖ Claystone is often slippery
- ❖ Sands can be slippery or very high friction
- ❖ Carbonates can be high or low
- ❖ Local experience is required to know what "normal" FF behavior is

6 Hole Cleaning

6.1 General Observations

According to K&M Technology Group [2] followings are common observation linked to ERD wells:

i. Cased holes should not be treated as problem free
ii. Circulation sweeps don't work as well when reach and angle increase
iii. Drilling is easy– Can drill ahead without problems at very fast ROP & even with no cuttings coming to surface. These cuttings will pile up in the wellbore.
iv. But tripping-out is difficult. Back-reaming is required to trip out, especially in high angle wellbores.
   - ❖ Once we start back-reaming… we can't stop
   - ❖ Often we don't see any cuttings while back-reaming for a long time, then we see a lot all of a sudden
   - ❖ After difficult trip out, the trip in is often "easy"
v. Industry Perceived Recipe for success in ER wells. To clean the hole, the following is essential:
   - ❖ High flowrate (say >1000 GPM (3800 LPM) in 12¼" hole)
   - ❖ Gauge hole
   - ❖ Continuous rotation, and that RSS is a necessary requirement for hole cleaning
   - ❖ Slow ROP
   - ❖ Ideal mud properties

6.2 Hole Cleaning Factors

According to K&M Technology Group [2] the main hole cleaning factors include:

- ❖ **Rotary speed**
- ❖ **Flow rate**
- ❖ **Mud rheology**
- ❖ Hole size
- ❖ Washouts

- ❖ Drill pipe diameter
- ❖ Wellbore Angle
- ❖ Turbulent or laminar flow
- ❖ Cuttings size
- ❖ Mud weight
- ❖ Pipe reciprocation
- ❖ Sliding Percentage
- ❖ Penetration rate
- ❖ Wellbore stability
- ❖ Mud solids (colloidal)
- ❖ Cuttings Dispersion

Rotary speed, Flow rate & mud rheology are the most important hole cleaning factors.

6.3 Key elements of the Hole Cleaning System [2]

i. Drilling Fluid properties
   - ❖ Rheology, inhibition, colloidal solids

ii. Bit & BHA Designs
   - ❖ Allowable RPM and rotation, bypass area, ROP

iii. Hydraulics
   - ❖ Available gallons per minute (GPM), pressure limits, ECDs, BHA requirements & limits, shaker loading limits

iv. Rig Systems
   - ❖ Limitations for top drive (RPM vs torque), solids control, pumps, electrical power

6.4 Hole Cleaning Mechanism

Cuttings behave differently depending upon well angle i.e. 0° to ± 30°, ± 30° to ± 65° & greater than ± 65° [2]. This will be explained in the followings.

6.4.1 Vertical Hole Cleaning

In the figure below fluid is moving upwards (say, 100 ft/min) – called "Annular Velocity". But gravity is pulling downwards (say, at 5 ft/min) – called slip velocity. So cuttings move slightly slower than the fluid (Mud rheology controls efficiency of this). Gel Strength is a key mud property. As the cutting falls, it displaces its own volume of fluid upwards. In a "crowded solids environment", a mechanism Called "hindered settling" occurs. For each cutting that drops, another is forced upwards [2].

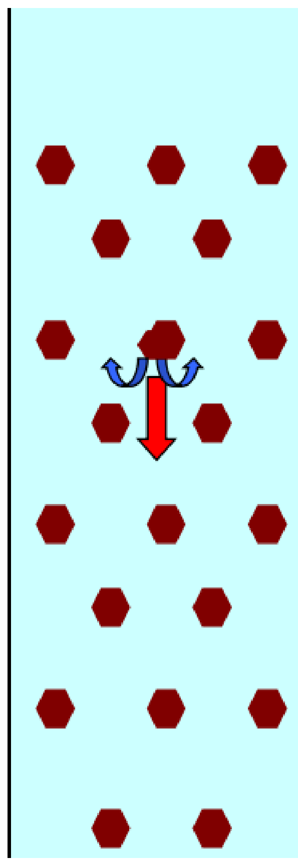

Figure 9 (Courtesy K&M): Hindered settling principle [2]

6.4.2 Horizontal Hole Cleaning

Everything is the same, except flow is now horizontal. Gravity is still pulling the cuttings downwards. There is no longer any fluid velocity direction to combat slip velocity & Cuttings fall to bottom within 1-2 stands (maximum). So in a laminar flow environment, the mud cannot carry the cuttings out of the hole. It also means that cuttings are on the low-side, regardless of whether we are pumping or not. Cuttings now have only inches to fall. "Hindered Settling" mechanism fails quickly as each layer of cuttings touches the bottom. Now cuttings cannot be suspended in a high angle wellbore, no matter what type of mud is used. Situation is the same whether the pumps have been off for 5 sec, 5 min, or 5 days [2].

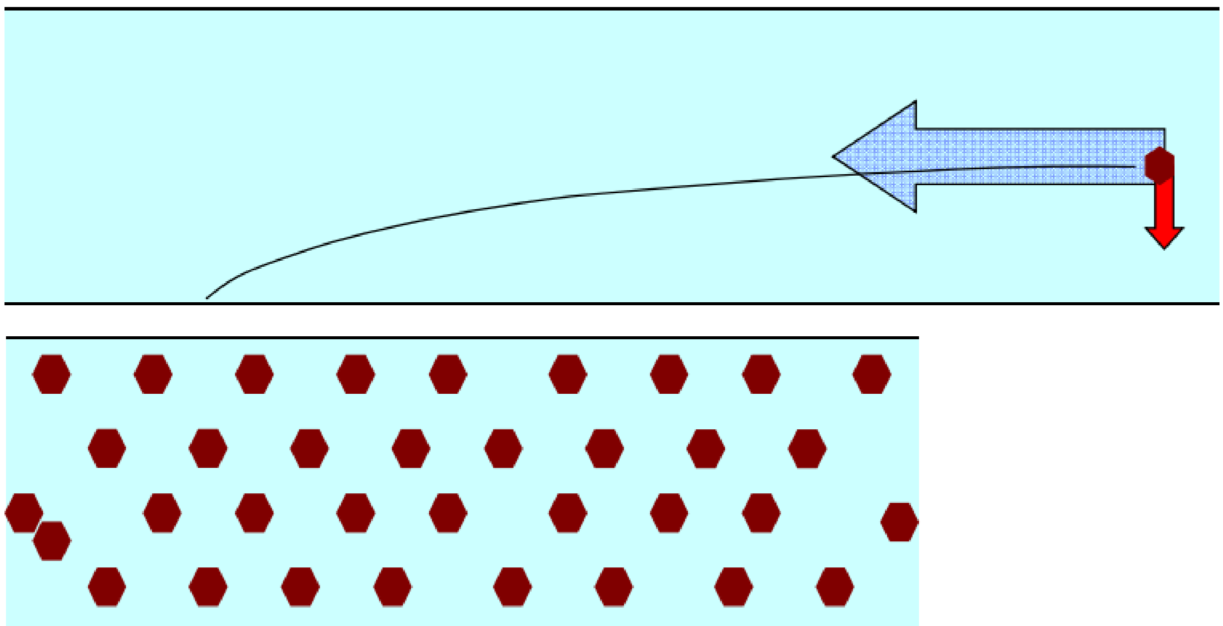

Figure 10 (Courtesy K&M): Horizontal hole cleaning [2]

6.4.3 Medium Angle Hole Cleaning

In this case, the fluid velocity is partly acting against gravity. The cuttings still cannot be carried out of the hole, but will now travel farther than in horizontal well, Say, 3-4 stands, instead of 1-2 stands for high angle wells. So, a medium angle well is a more efficient "conveyor belt" than a high angle hole. As for the high angle hole, the cuttings cannot be suspended in the medium angle hole but now we have the risk of avalanche of the cuttings bed. The cuttings bed does not automatically avalanche (just like snow doesn't automatically avalanche on a mountain side). Avalanche can be triggered by too thick bed-height (too fast ROP for too long) or disturbed by trip in or trip out [2].

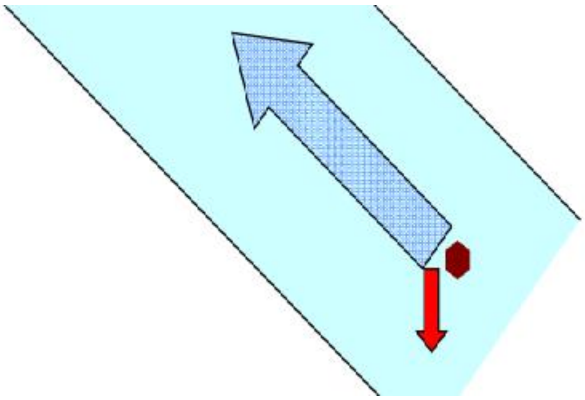

Figure 11 (Courtesy K&M): Hindered settling principle [2]

Figure 12 (Courtesy K&M): Cuttings behavior in different parts of the well [2]

6.5 Cuttings Transport

High velocity fluid on top of the hole acts like a conveyor belt transporting cuttings out of the hole. Cuttings will travel so far and then fall off (into low flow zone) due to gravity. The length travelled on the conveyor belt is a function of angle, flowrate, rpm and fluid rheology. Speed of the conveyor belt is a function of flowrate [2].

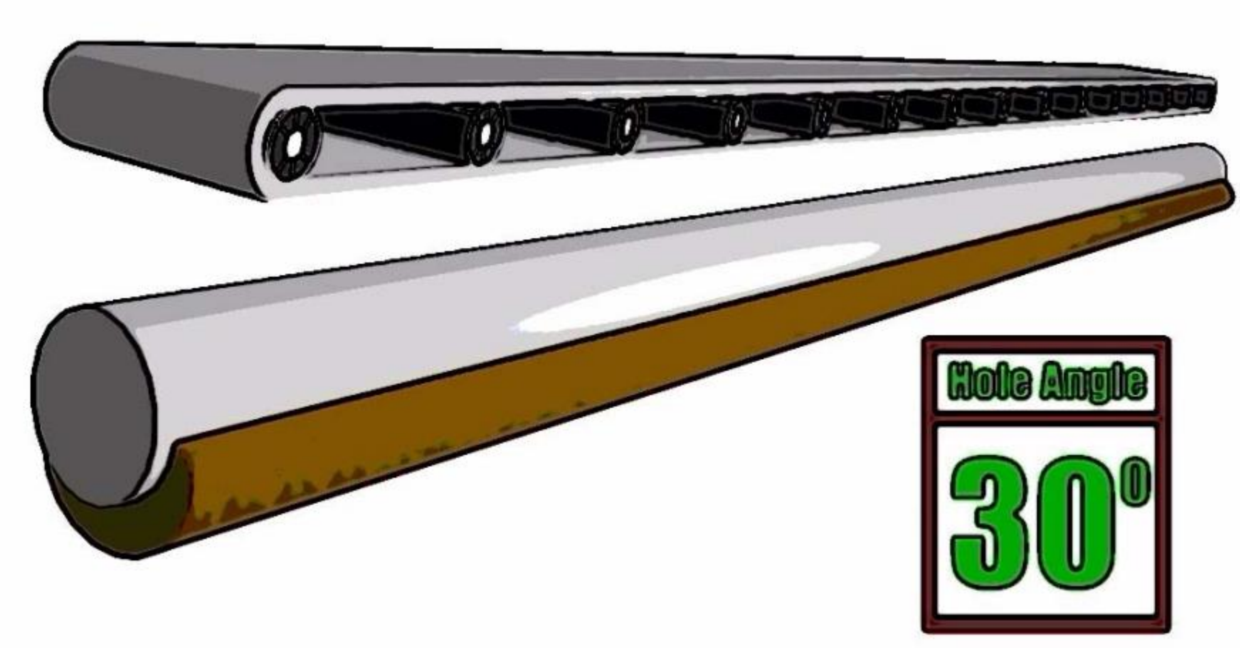

Figure 13 (Courtesy K&M): Conveyor Belt principle [2]

6.5.1 Rotation Effects

Rotation is the key factor in hole cleaning efficiency for high angle holes [2].

- Active flow area is at top of hole
- Pipe and cuttings lay along bottom of hole
- Agitation is required to get cuttings into the fluid flow
- Required rotary speed is dependent upon hole size & ROP

It's not actually the pipe rotation (nor the tool joints) that cleans the hole [2]:

- It's the fluid "film" rotating around the drillpipe
- This film is called the "viscous coupling"

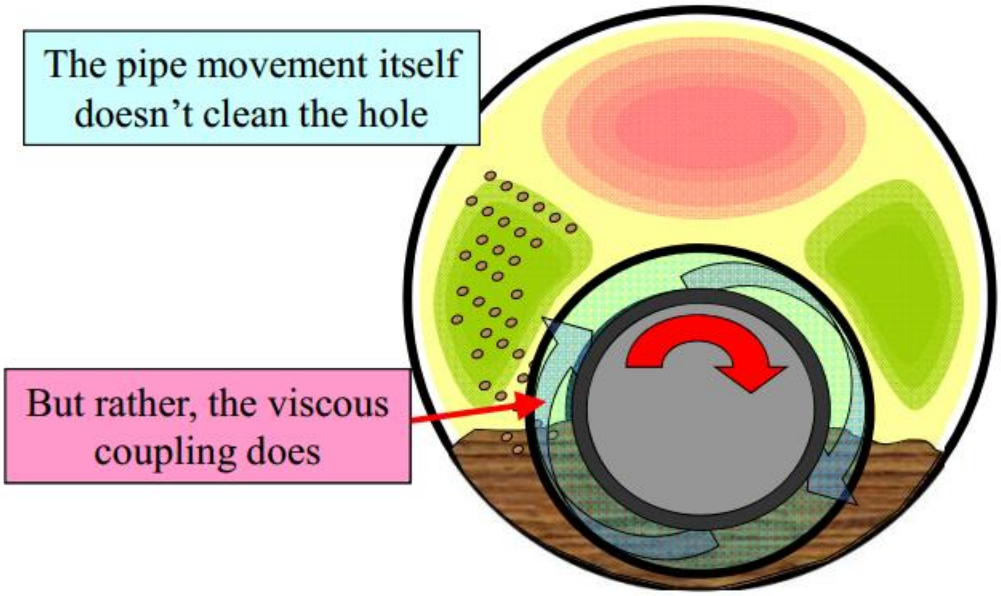

Figure 14 (Courtesy K&M): Concept of Viscous coupling [2]

Rotation alone is not sufficient. Rotary speed is critical [2].

- ❖ There is a huge difference between 100 rpm & 120 rpm, for high angle hole cleaning in 12¼" (and larger) and also 8½", if drillpipe is small (say 4½")

6.5.2 Step change Behavior:

According to K&M Technology Group [2] there is a dramatic change in cuttings flow at ±120 rpm (and later again at 180 rpm). This was discovered by accident, adjusting RPM to "smooth" vibrations. This phenomenon is called step change behavior.

- ❖ Independent of hole size, drillpipe size, mud type
- ❖ Importance, however, depends on hole size, 120 RPM Minimum to clean "big" hole
- ❖ All drilling & circulation at > 120 RPM
- ❖ 120 RPM is a minimum acceptable speed, and NOT a recommended speed
- ❖ If operating near critical speed, ensure your RPM-counter is accurate
- ❖ Note that this does NOT match the hole cleaning experiments or models in the industry i.e. experiments & models do NOT match reality
- ❖ Hole cleaning models say: Don't need to rotate fast i.e. 80 – 100 RPM will give very good hole cleaning performance

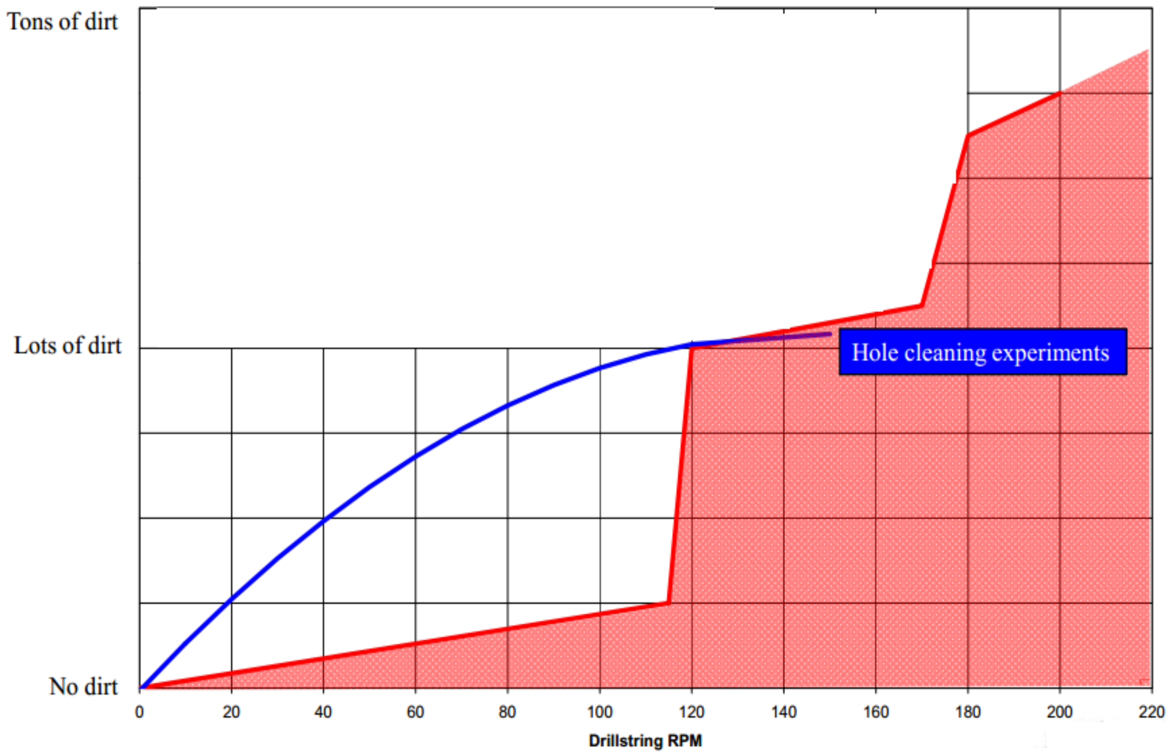

Figure 15 (Courtesy K&M): Step change occurs at 120 & 180 RPM [2]

Behaviour is different in "Big Hole" vs. "Small Hole" (Figure below) [2]:

❖ Very good performance in "Small Hole" at 70-80 RPM

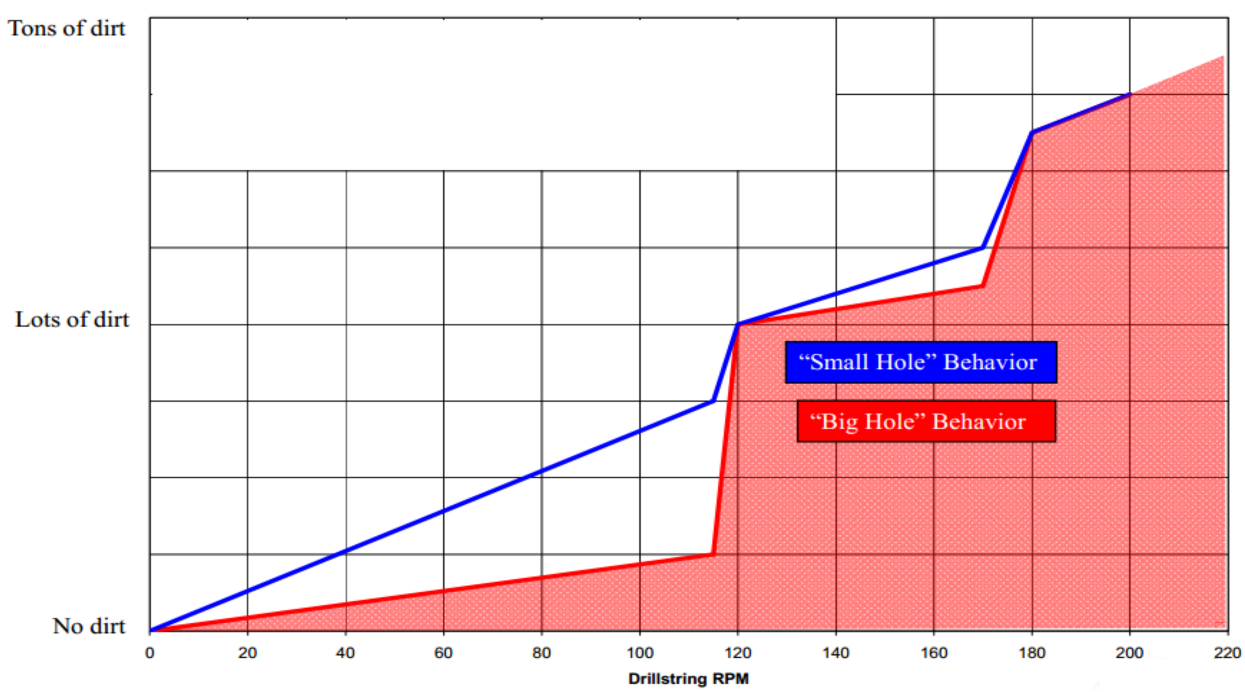

Figure 16 (Courtesy K&M): Step change in small & big hole [2]

At low RPM [2]:

- ❖ Viscous coupling film is thin
- ❖ Not much energy in the system

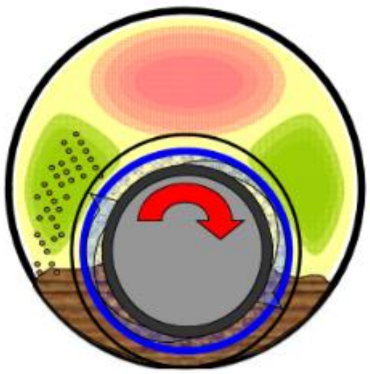

Figure 17 (Courtesy K&M): At low RPM [2]

At medium RPM (say, 100 rpm) [2]

- ❖ Pipe begins to walk up the hole a little
- ❖ Viscous coupling film gets thicker, but still "thinner" than tool joint upset
- ❖ Still laminar flow at bottom of the hole

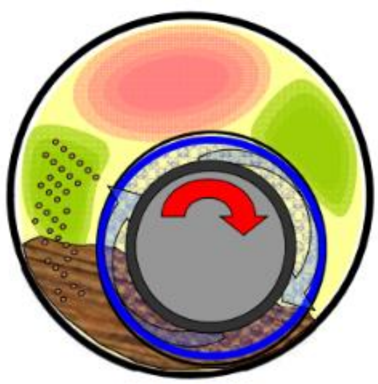

Figure 18 (Courtesy K&M): At medium RPM [2]

At 120 rpm [2]

- ❖ Pipe walks further up the hole
- ❖ Viscous coupling film thickness reaches height of tool joint upset
- ❖ Fluid now unable to pass through the gap in laminar flow
- ❖ Vortices (turbulence) break off, stirring the bed
- ❖ flow at bottom of the hole

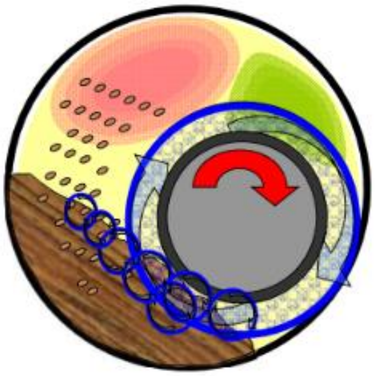

Figure 19 (Courtesy K&M): At 120 RPM [2]

6.5.3 RPM Selection

According to K&M Technology Group [2] here are some guidelines on RPM selection:

- ❖ High Speed RPM is the key to operation of the conveyor belt
- ❖ For "Big Hole" (Conveyor belt is "on" at > 120 RPM, Conveyor belt is "off" at < 120 RPM)
- ❖ For "Small Hole" (Conveyor belt is in "high gear" at > 120 RPM, Conveyor belt is in "low gear" at < 120 RPM)
- ❖ Rotation turns the conveyor belt on and off

6.5.4 Implications for Steerable Motors

According to K&M Technology Group [2] here are some implications on using motors:

i. The manufacturer determines the stress in the motor for a given bend setting
ii. They then determine how many times (cycles / revolutions) the motor can be flexed at that stress before it breaks (i.e. fatigue)
iii. The directional drilling (DD) company then determines how many hours any given motor needs to operate in order to pay for the motor, expenses, and a profit margin.
iv. Therefore, in order to rotate fast consider the following;
   - ❖ Reduce the bend setting (<1.15 °)
   - ❖ Purchase a new motor (to "zero" the service history)

❖ Be willing to pay more for accelerated wear and tear

6.5.5 PHAR Factor [2]

An easy Rule of Thumb to calculate which environment you are in is the "Pipe-Hole Area Ratio" (P-HAR). It gives you a feel for how "far" the top of the pipe is from the top of the hole. "Big hole" rules apply, no matter what drillpipe size. PHAR = Rh2 ÷ Rp2 > 3.25 = "Big Hole" Rules & if < 3.25 = "Small Hole" Rules [2].

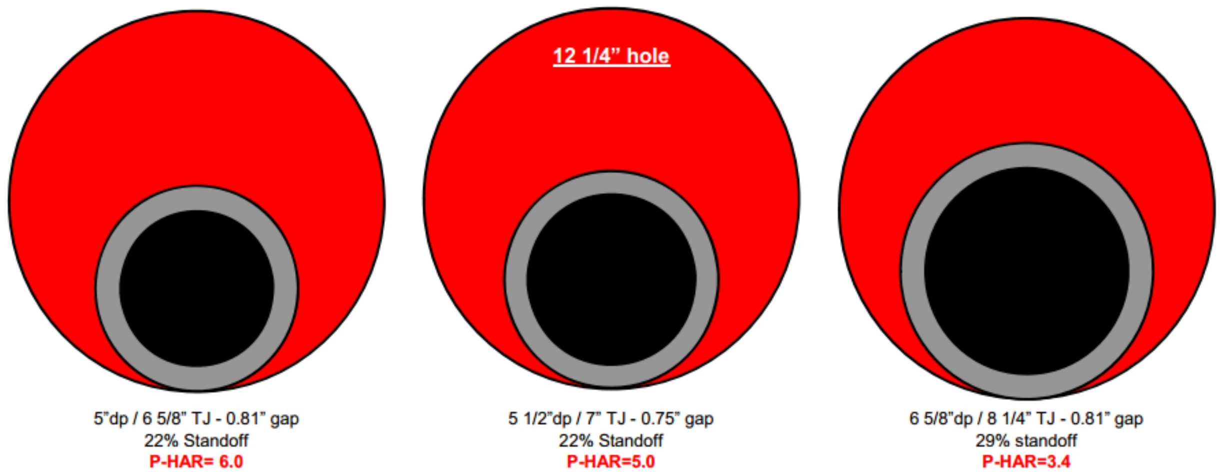

Figure 20 (Courtesy K&M): Big hole PHAR factor [2]

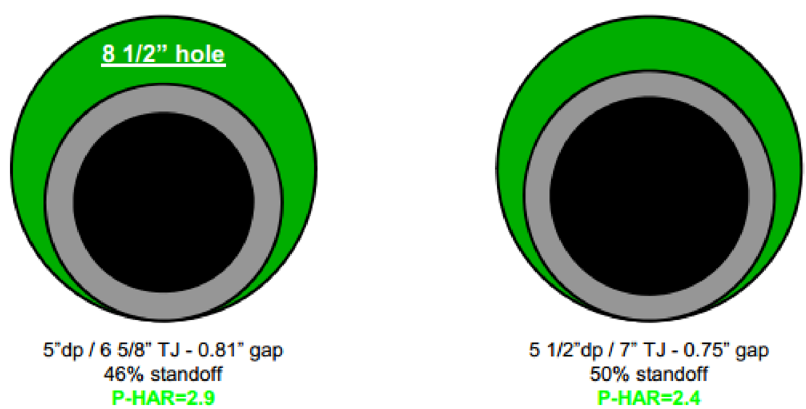

Figure 21 (Courtesy K&M): Small hole PHAR factor [2]

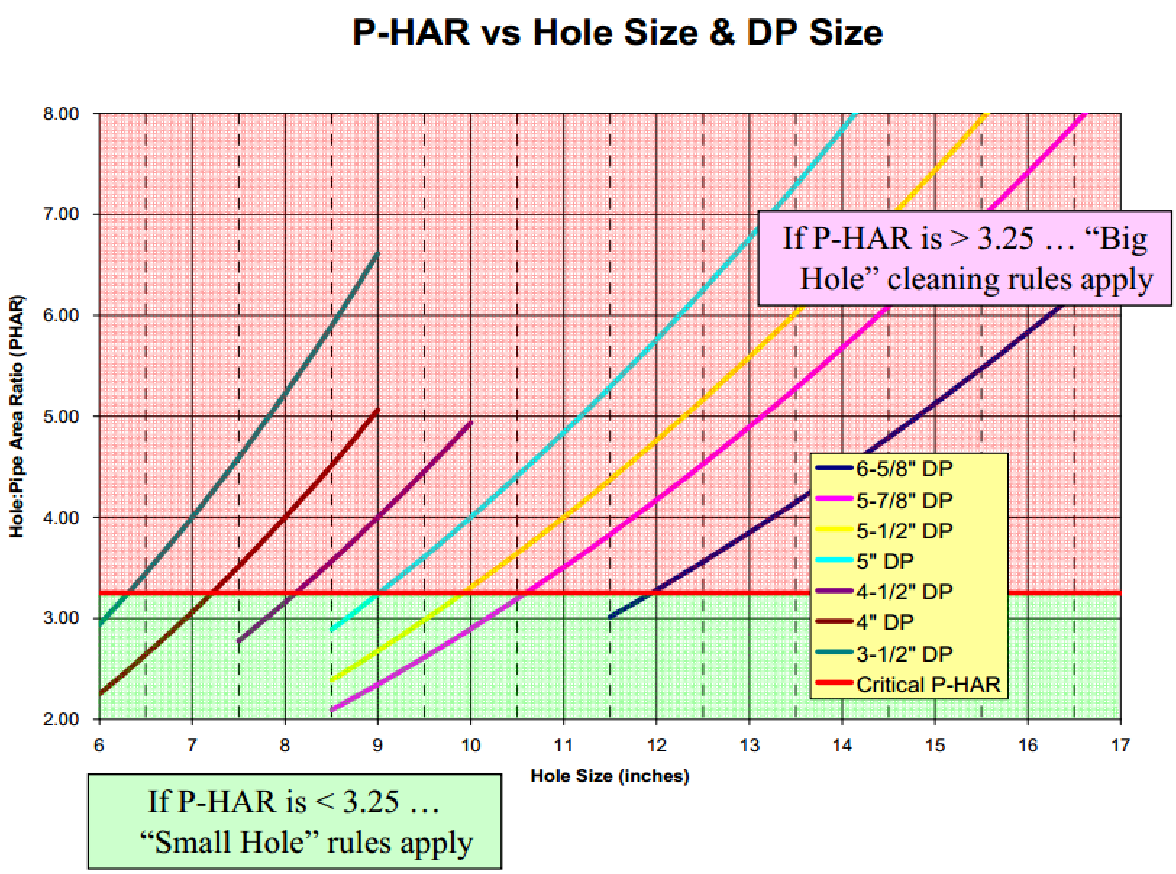

Figure 22 (Courtesy K&M): PHAR factor versus hole size & DP size [2]

Here Rh stands for hole radius & Rp satnds for pipe radius.

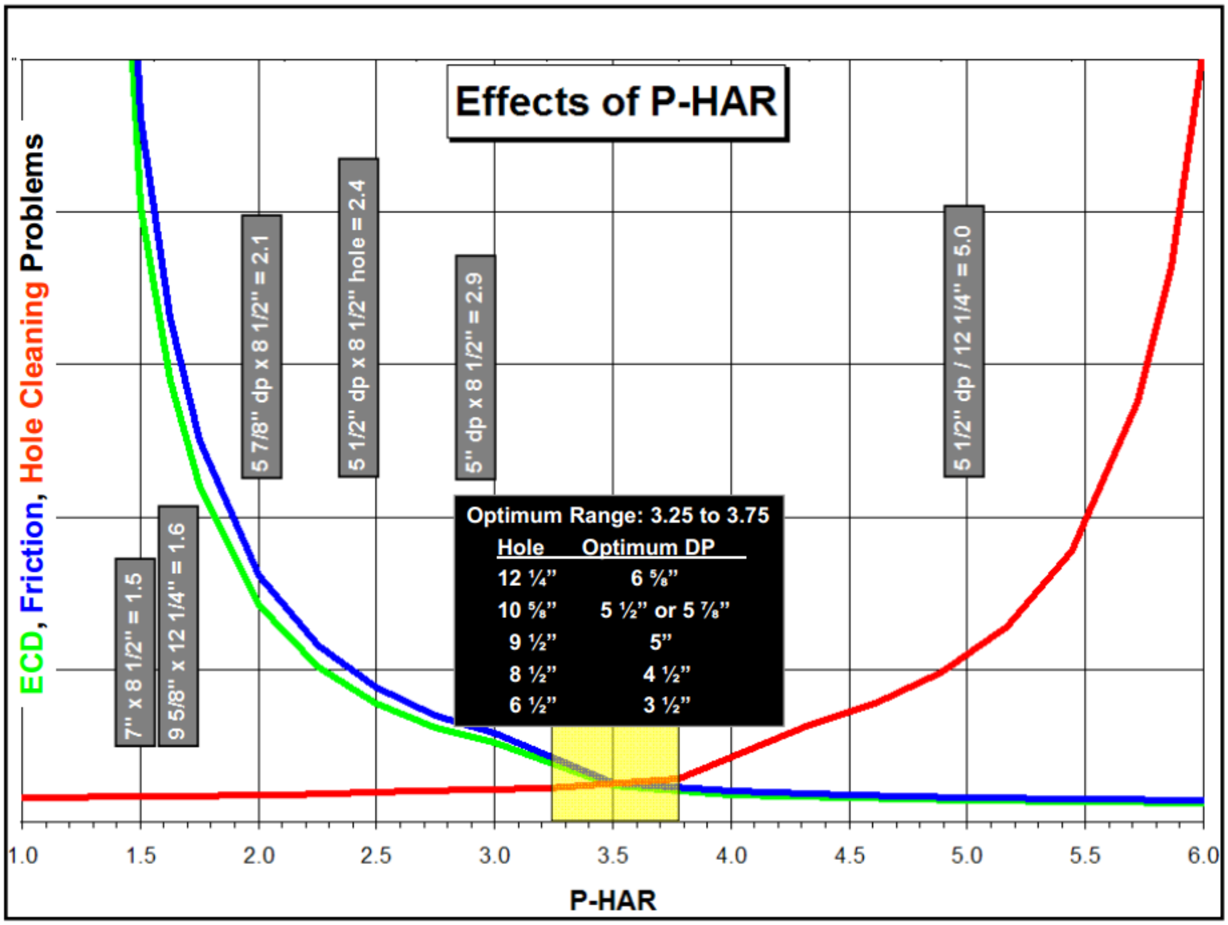

Figure 23 (Courtesy K&M): Effects of PHAR factor [2]

6.5.6 Rules of Thumb

According to K&M Technology Group [2] here are some rules of thumb:

i. Rotary Speed (independent of hole size)
   - PHAR > 6.50 – >120 minimum, 180 RPM ideal
   - PHAR 3.25 – 6.50 – >120 RPM minimum
   - PHAR < 3.25 – 60-70 rpm minimum, 120 RPM ideal

ii. Annular Velocity
   - 200 ft/min (1.00 m/sec) – **Ideal**
   - 150 ft/min (0.75 m/sec) – **Minimum** (for efficient hole cleaning)
   - 100 ft/min (0.50 m/sec) – **Poor Cleaning + Barite Sag Problems**

iii. Flow Rate (High angle)
   - 17½" hole: 1,200 – 1,500 GPM

- 12¼” hole: 750 – 1,000 GPM
- 9⅞” hole: 450 - 650 GPM
- 8½” hole: 350 - 500 GPM
- 6⅛” hole: 150 – 200 GPM

6.6 Mud Rheology

Mud Rheology depends on the hole size. For 17½” & 12¼” sections hole cleaning is the top priority & for 8½” ECD is most important. If mud is too thick it tunnels up the high side of the hole & dead zone (a zone where cuttings are accumulating & no effect of viscous coupling) becomes impenetrable for cuttings thrown up. If mud is too thin there is no “viscous coupling” to lift cuttings into the flow [2].

6.6.1 Thick Mud Rheology

If mud is too thick viscous coupling is good, but dead zone becomes impenetrable, while conveyor belt zone shrinks [2].

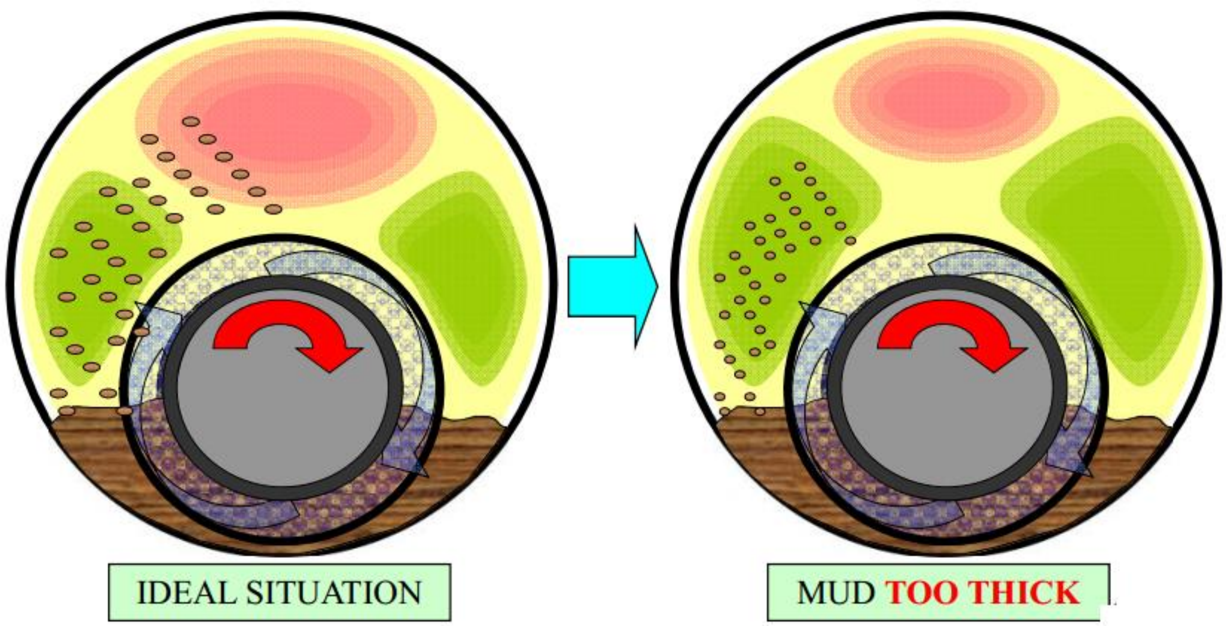

Figure 24 (Courtesy K&M): Mud rheology too thick [2]

6.6.2 Thin Mud Rheology

If mud is too thin, one will experience lower ECD, but less effective coupling (harder to turn the conveyor belt on). There are also difficulties in cleaning “vertical” hole portion [2].

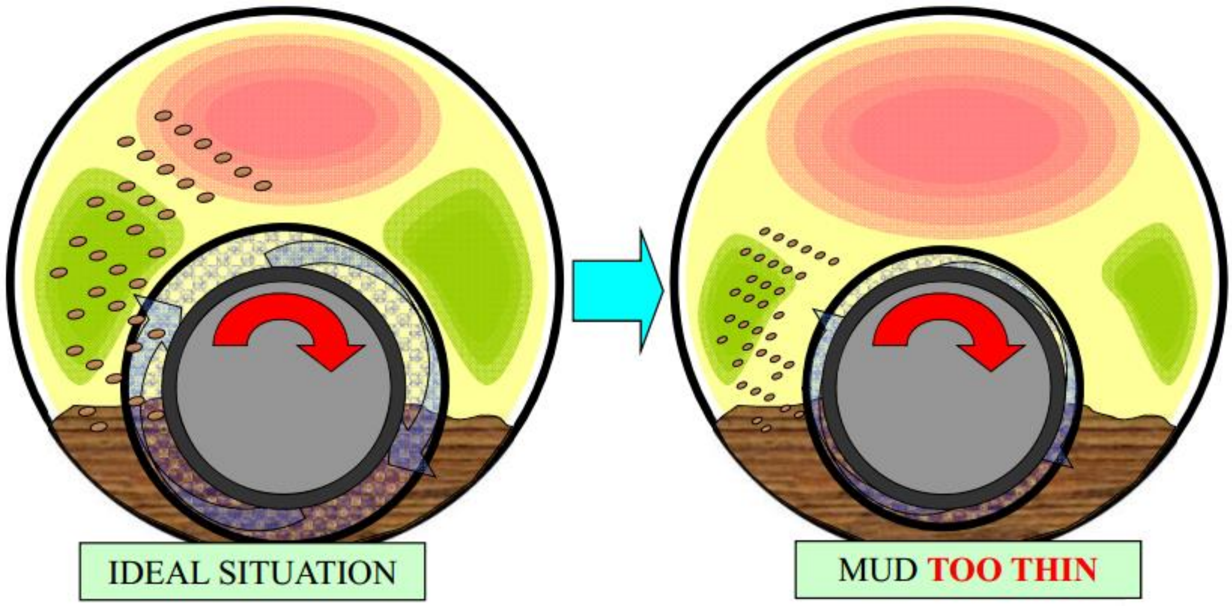

Figure 25 (Courtesy K&M): Mud rheology too thin [2]

6.6.3 What is meaning of Mud Rheology?

According to K&M Technology Group [2] considering the mud measurements (Fann readings), Mud engineer takes "resistance" readings at 600, 300, 200, 100, 6, and 3 RPM.

- Inside the drillpipe – 600 & 300 RPM represent this mud
- Around the drill collars, – 300, 200 RPM represent this mud
- In the annulus – 6 & 3 RPM represent this mud
- Thru the bit nozzles – 600 RPM represents this mud
- Hole cleaning & ECDs sensitive to 3 & 6 RPM
- What is yield point (YP)? YP = 2 x (300) – 600 (or 300 – PV), where PV is plastic viscosity
- YP has absolutely nothing to do with hole cleaning or ECDs, with modern mud systems

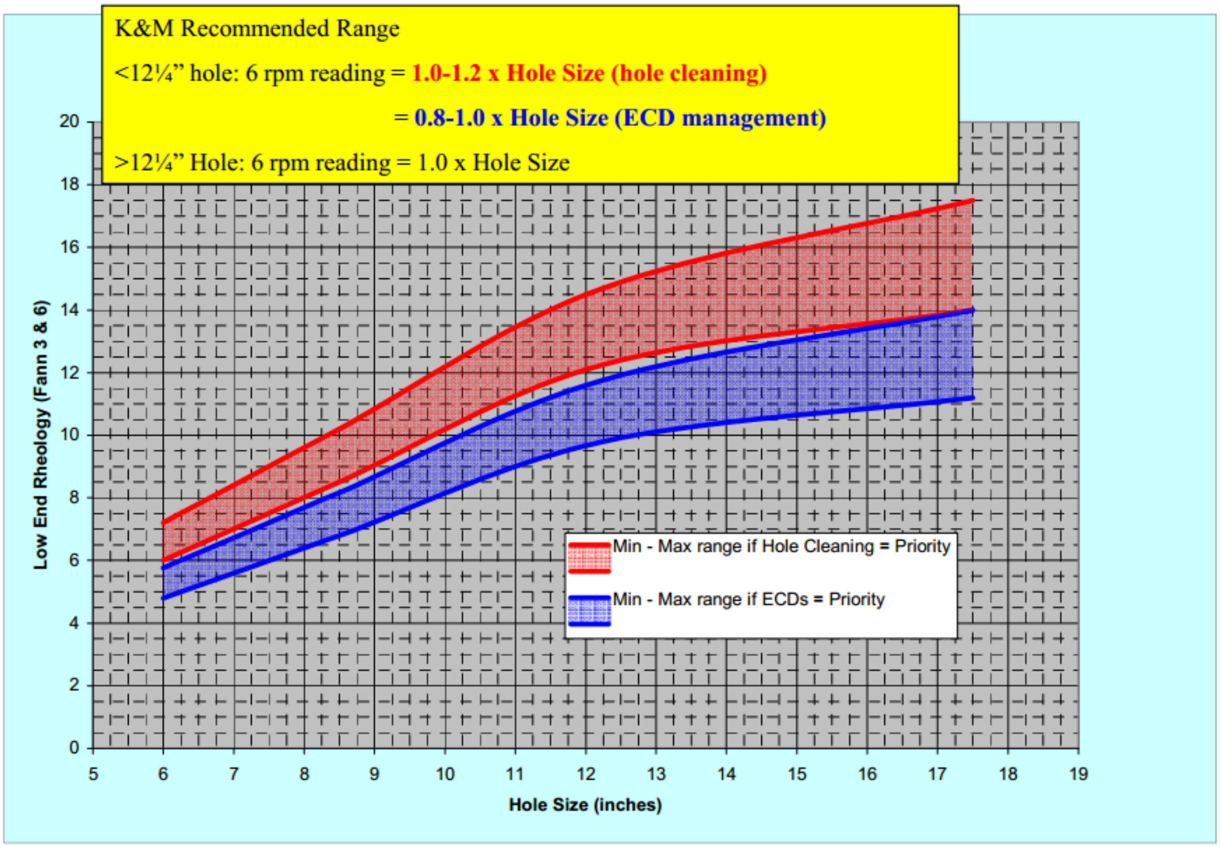

Figure 26 (Courtesy K&M): K&M recommendations on hole cleaning & ECD [2]

6.7 Sweeps in ERD Wells (K&M recommendations)

Usually the team assumes that the extra cuttings came from the bit. K&M [2] would argue that it most likely came from the "low angle portion" that was probably cleaning OK already. Sweeps are ineffective in the directional portion & cannot carry cuttings very far, no matter what type of sweep. Furthermore, sweeps cause problems:

- ❖ ECDs, and risk of packing off around BHA
- ❖ Harder to interpret PWD
- ❖ Dangerous message sent to the crew when sweeps are empty as it is assumed that hole is clean
- ❖ Circulation sweeps affect ECD i.e. concentrated cuttings load in vertical hole can result in ECD spikes. This also makes PWD hard to interpret.

7 Tripping and Backreaming

7.1 General Observations

Back-reaming or pumping out should be avoided when possible in high-angle wells. The ability to trip out without pumping or backreaming is a risk reduction measure. Choosing any practice or equipment that forces you to back ream significantly increases risk. Back-reaming and/or pumping out are the single-most dangerous operations in an ERD well. This poses maximum risk of stuck pipe, destabilizing the wellbore, time consuming, and destructive on BHA equipment. However, there is a time and a place for backreaming and it can be done safely with the proper equipment, practices, and patience [2].

7.2 What is happening downhole?

When tripping in a deviated well always assume that the hole is NOT 100% clean even with a thorough clean-up & with Rotary Steerable system (RSS). The BHA does NOT pull cuttings up the hole. Cuttings flow around the BHA, until they become too compressed. BHA design is critical to "flow around" ability and pose significant implications for how to manage tight hole. When pulling out, the BHA pulls up through the dirt. For a trouble-free trip, the dirt must flow around the BHA as the BHA moves through the bed [2].

7.3 Backreaming

With standard trip there is no rotation or circulation & harmless cuttings bed by-passed. With backreaming rotation and circulation is required while POOH & cuttings bed expected to be fully removed from the bottom of the hole [2].

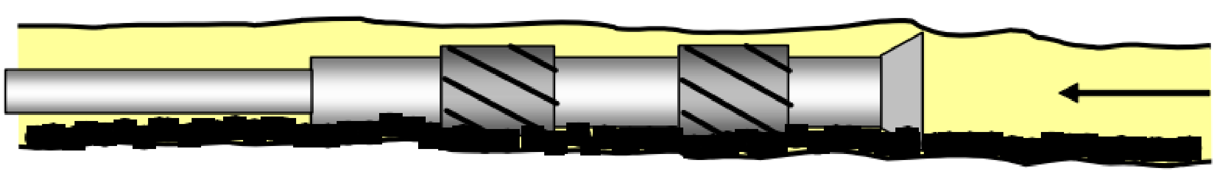

Figure 27 (Courtesy K&M): Standard tripping [2]

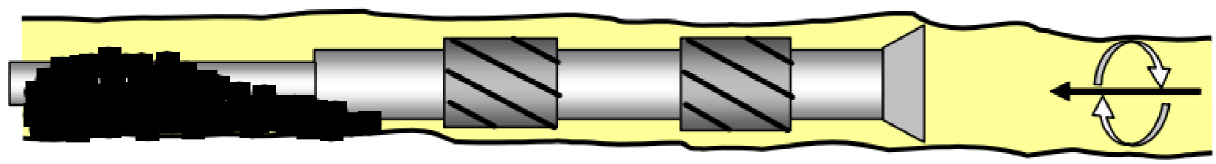

Figure 28 (Courtesy K&M): Backreaming [2]

7.3.1 Backreaming Practices

What are the downsides/risks associated with backreaming according to K&M Technology Group [2]?

- Stuck pipe
- BHA equipment failures due to vibration
- Key seating
- Lost returns (if packoffs exceed fracture gradient)
- Self-inflicted wellbore stability problems

Backreaming itself doesn't damage the wellbore rather, it is the Hydraulic hammer effect that causes all the problems. This hammer effect is triggered by pack off around BHA/string due to cuttings accumulation. This results in sudden large ECD pressure shock below pack-off which are often too large for APWD to measure & pressure spikes are often off the scale. When we see a pack-off at surface, we only see what's left after dampening thru the bit, BHA & drillstring [2].

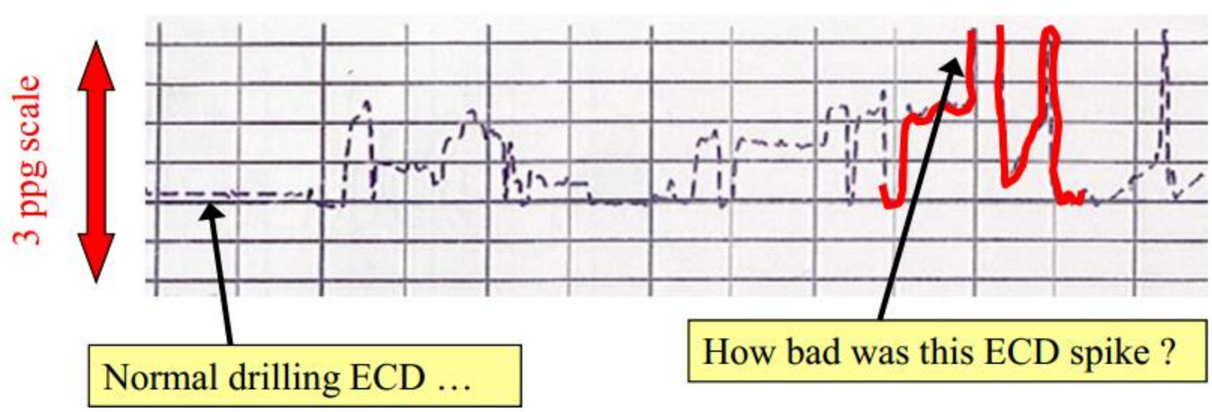

Figure 29 (Courtesy K&M): Hydraulic hammer effect [2]

Interpretation of "wellbore stability" problems change entirely if the wellbore has been "hammered". Often, the presence of cavings after packoffs is perceived as the very cause of the packoffs. K&M [2] contend that it is more likely the packoffs created the cavings due to the hammer effect. Evidence of this is “wellbore stability” problems often go away when tripping practices are modified (due to avoidance of packoffs).

Many operators say “don’t back-ream unless you have to. But experienced ERD people “know” that no-matter what the procedures say, that’s the only way they can get out of the hole. How clean must the hole be for tripping, it depends on the bit & BHA [2].

- ❖ Junk slot area affects how thick a safe cuttings bed can be. Junk slot area is the water ways area across which cuttings flow takes place after being drilled.
- ❖ Lower Junk slot area requires cleaner hole to trip safely.
- ❖ Alternatively, larger junk slot area tools can be tripped through a “dirtier” hole.

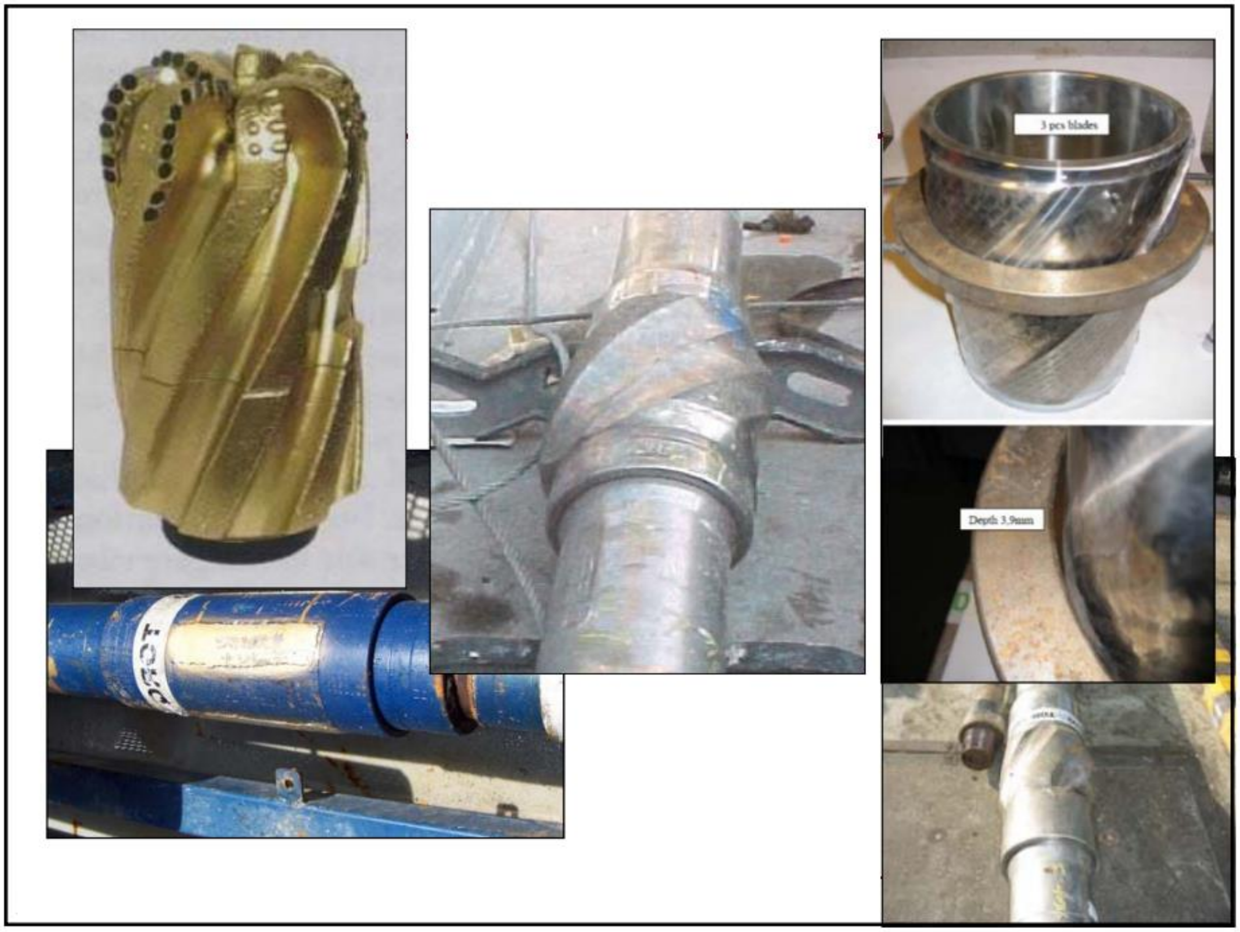

Figure 30 (Courtesy K&M): BHA Junk Slot area [2]

7.3.2 Un-Trippable BHA

According to K&M Technology Group [2] unless the BHA components are addressed as a high priority, conventional tripping may be impossible despite best practices. It only takes one component to make a BHA un-trippable. Junk-slot-area & junk-slot-tortuosity are key BHA Design priorities.

i. Remove sleeve stabilizers on big-OD collars
   - ❖ Classic 9½” tools for 12¼”, 6¾” tools for 8½” hole
   - ❖ Especially on RSS, motors and MWD-LWD tools
   - ❖ Shoot for a minimum of 25-30% open area

ii. Or downsize to smaller collars
   - ❖ Example: 8” tools instead of 9⅝” for 12¼” hole

iii. Replace sleeve stabilizers with integral blade stabilizers

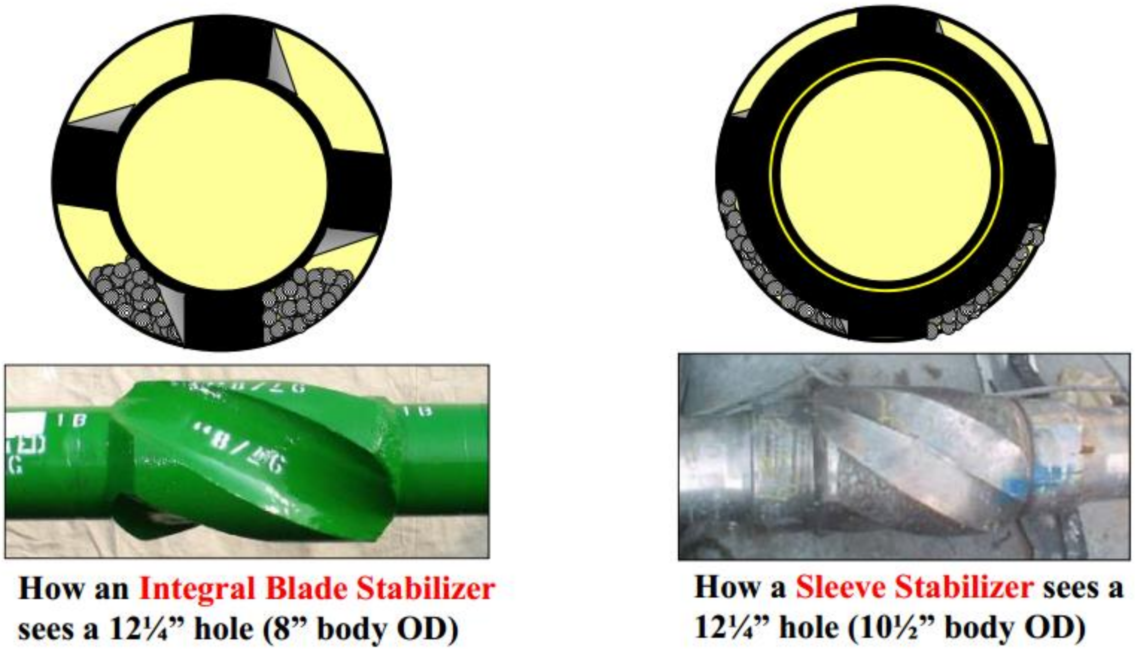

Figure 31 (Courtesy K&M): Sleeve VS Integral Blade Stabilizer [2]

7.4 Hole Cleanup Techniques

The hole must be cleaned prior to tripping. To achieve this, Conveyor belt must be turned on (>120 RPM). Sufficient circulation is required i.e. multiple bottoms up circulations are required at >120 RPM & always look for at least 2 waves of cuttings. It is common mistake that RPM is often slowed whenever circulating for off-bottom. Hence, hole cleaning system is shut-down, convincing the team that the hole is clean. Conveyor belt must be on when bit is off-bottom too. This is one of the most common mistakes done during drilling ERD well [2].

- Bottoms up (BU) is irrelevant for high angle wells
- Expect > 4 x BU for clean-up time
- This is very sensitive to angle above 70° & also very sensitive to hole size (large PHAR = longer clean-up)
- Patience is critical
- And only "conveyor belt ON" time counts i.e. Circulation time at < 120 RPM is irrelevant and wasteful

- ❖ The hole doesn't have to be completely clean, except for cases where there is poor junk slot area. Or if a tight-clearance casing/liner string is going to be run i.e. 10¾" in a 12¼" hole & 13⅜" in a 14¾" hole.

7.5 Tripping-out Procedures [2]

i. Pull out of hole without rotation or circulation
- ❖ Tripping speed is important, control speed of dirt flow through the stabilizers & bit
- ❖ Tighter BHAs require slower speeds

ii. Monitor P/Up weight while tripping out of hole
- ❖ Compare real-time to theoretical drag trends ("roadmaps")
- ❖ Must have a road-map to know what "normal" is

iii. If tight hole is encountered;
- ❖ Set over pull limits low: 30 Kilo pounds (kips) maximum

iv. Always assume the problem is cuttings
- ❖ Run in hole (RIH) 3 to 5 stands to get BHA away from tight spot
- ❖ If obstruction is dirt, you must un-pack the BHA before pumping
- ❖ If it took 5 stands to pack it, expect that many to un-pack it!
- ❖ Remember that cuttings can move down hole with BHA (in avalanche regime <65°±)

v. Circulate & rotate at > 120 RPM for 30 minutes
- ❖ Goal is to verify cuttings dune, so as not to waste time if otherwise
- ❖ Conveyor belt must be on, if cuttings are to be moved

vi. POOH carefully without rotation or circulation watching for the tight spot to recur
- ❖ If the tight spot has moved up hole, then obstruction was cuttings
- ❖ Continue cleaning the hole up, per standard clean-up procedures

vii. If the tight spot has NOT moved up hole;
- ❖ Then genuine tight hole is likely (key seat, ledge, etc.)
- ❖ Circulating or backreaming may be used with caution

- ❖ Must avoid pack-off while circulating or backreaming out of the hole (Risk of stuck pipe, Pressure damage to wellbore below pack-off, Don't want to lose returns)

7.6 Backreaming Procedures [2]

i. Sometimes backreaming is necessary
   - ❖ Tight hole on trips
   - ❖ Swabbing (can't trip conventionally)

ii. When removal of all cuttings is necessary
   - ❖ To clean up hole for extreme casing runs in ERD wells
   - ❖ Typical "trigger" is if casing run is so challenging as to require flotation
   - ❖ For production liner cement jobs, or running screens
   - ❖ For tight-clearance casing runs (10¾" or 11¾" in 12¼" hole)

iii. When back-reaming, K&M have noticed that;
   - ❖ Once you start back-reaming in a directional well, you can't stop …until you get to ±30°
   - ❖ We don't see cuttings while backreaming, until we get to about 30°. Then we get lots of cuttings suddenly.
   - ❖ Back-reaming was easier on lower angle wells
   - ❖ The faster you go, the more problems you have.

7.7 Backreaming Recommendations [2]

Firstly, let's define what back-reaming is: Tripping, while rotating & pumping; a means of fighting tight hole. Back-reaming is not working the pipe up (with rotation) during normal connections & not when racking back stands during the clean-up process [2].

i. What is K&M's opinion on backreaming?
   - ❖ Dangerous, with high risk of stuck pipe, packing off, and inducing wellbore failure. Only operation that has higher risk than backreaming is "pumping out".
   - ❖ Tough on MWD & BHAs (vibration)

ii. BUT can be done safely:

- ❖ But needs to be done slowly to be safe
- ❖ Needs adequate (high) flowrate and rotary speed
- ❖ Practices must vary according to angle
- ❖ Back-reaming is not faster than cleaning up thoroughly before tripping
- ❖ Torque is primary tool to monitor pulling speed
- ❖ Stand pipe pressure (SPP), Hook load, Return Flow, ECD, etc. "secondary" indicators

iii. Never commence back-reaming while in over pull or tight hole

- ❖ BHA is literally embedded in cuttings
- ❖ Consider pipe stretch: what direction does the BHA move if pipe is in tension and we start to rotate?
- ❖ Always drop down away from the tight spot before beginning to backream
- ❖ Backream "with the conveyor belt on", ≤ 3-4 stands per hour initially
- ❖ Perform full cleanup cycle "with conveyor belt on" prior to attempting to pull on elevators

iv. Clean up hole after finishing backreaming – Don't just pull out of the hole. This is one of the most common mistakes K&M has seen.

- ❖ Applies for cased hole as well as open hole
- ❖ This explains the industry's "typical" experience that once backreaming starts, it can't be stopped (in reality, all we need to do in order to return to tripping on elevators is erode the dune away from the top of the BHA)

v. Take special care coming into a casing shoe

- ❖ Large OD rathole/washout accumulates cuttings
- ❖ Consider extra circulation with rotation before proceeding

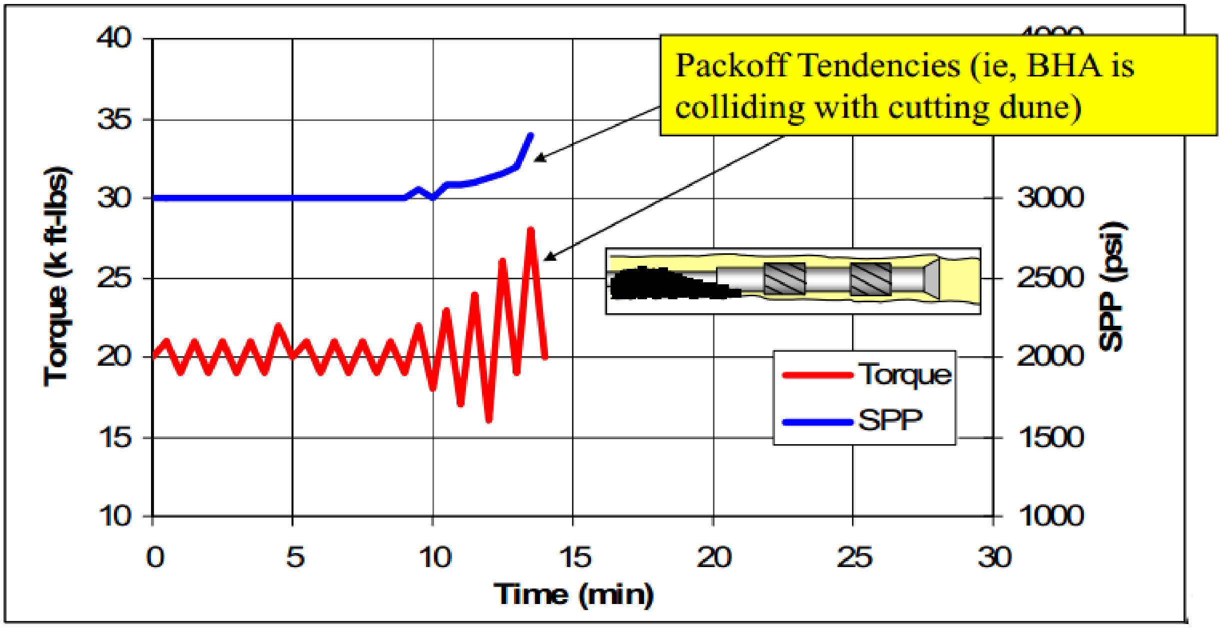

Figure 32 (Courtesy K&M): Backreaming Indicators [2]

8 Directional drilling technology and surveying

8.1 Standard Directional Drilling Profiles

Depending upon the application and objectives there are different directional drilling profiles being executed by the industry [4]:

- ❖ The simplest profile is vertical profile where well is drilled vertically without any deflection from vertical. These are mostly Land wells, no space restrictions & cheap low producers
- ❖ J-shape profile included kick off from vertical (build) and then tangent/hold towards total depth (TD). These are drilled mostly offshore when it's impossible to get directly over target. They increase reservoir exposure.
- ❖ S-shape profile is relatively complex profile where well is drilled with build-hold-drop profile. These are drilled to cope with reservoir issues.
- ❖ Horizontal profile is drilled with First build-hold-2nd build-horizontal section. They increase reservoir exposure & drilled into thin zones and into naturally fractured areas. ERD wells mostly include this profile.

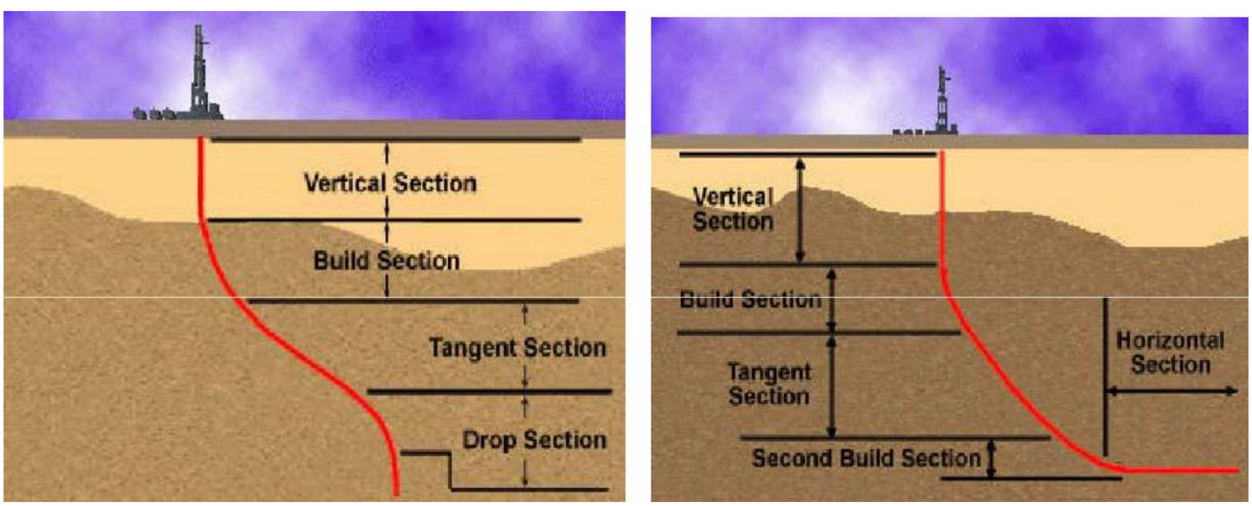

Figure 33: Directional Drilling Profiles [4]

8.2 Why Directional Drilling?

Directional drilling helps industry in different ways to exploit oil & gas reserves. Below are some of the applications of directional drilling [4].

- ❖ Sidetracking

- ❖ Reaching inaccessible locations
- ❖ Salt dome drilling
- ❖ Fault controlling
- ❖ Relief wells
- ❖ Platform drilling/reentry drilling
- ❖ Horizontal drilling
- ❖ Multilateral drilling

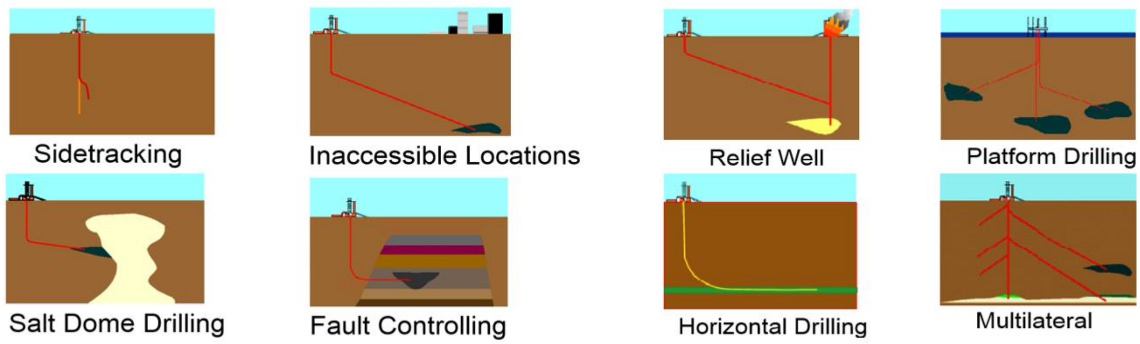

Figure 34: Applications of Directional Drilling [4]

8.3 Rotary Steerable System Technology

According to Schlumberger Internal documents [4] Rotary Steerable System (RSS) has introduced huge step change in directional drilling industry. The big upside of using RSS over motors is rotating all the time while steering and helping boost in hole cleaning & drilling efficiency. The major benefits of using RSS are listed below:

- ❖ Steering while rotating all the time
- ❖ Steady Deviation Control: Independent of bit torque & problems of controlling tool face through elastic drill string are reduced
- ❖ Cut AFE time: Drill faster while steering & reduces wiper trips
- ❖ Cleaner Hole: Continuous rotation, efficient casing/liner running & cementing
- ❖ Less Drag: Improves WOB control
- ❖ Workover is easy
- ❖ Less risk of stuck pipe
- ❖ Completion cost & risk is reduced

- ❖ Longer Horizontal Range: geosteering in reservoir
- ❖ Complex Well designs: 3D targets & uphill drilling
- ❖ Longer ERD: without excessive drag
- ❖ Field development Plans: Fewer Platforms to develop a field
- ❖ Well Downsizing: Fit for purpose wells
- ❖ Number of wells: Fewer Wells to exploit a reservoir
- ❖ Less cost per foot
- ❖ Better well placement & improved wellbore positioning

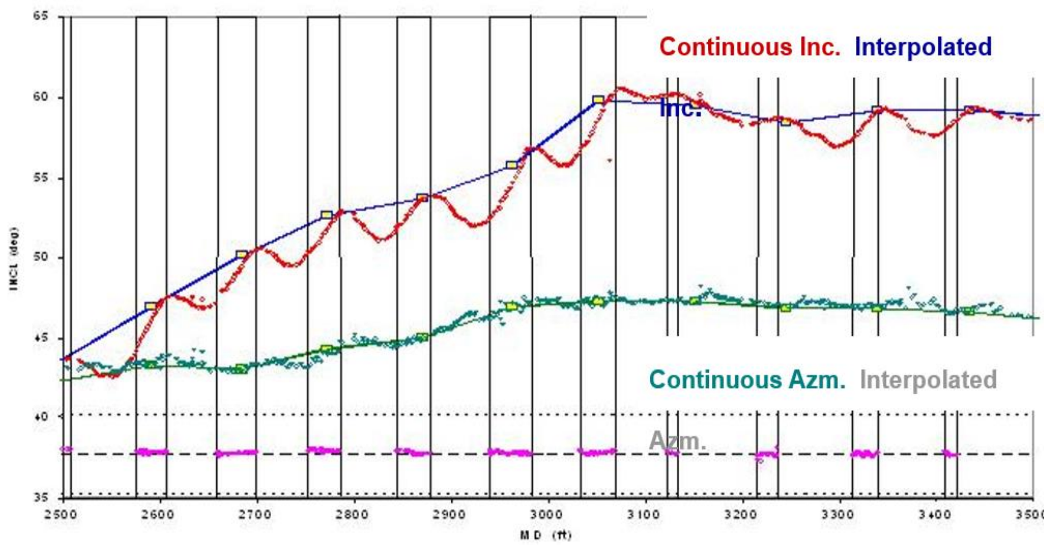

Figure 35: Profile with Motor (Slide/rotary) drilling [4]

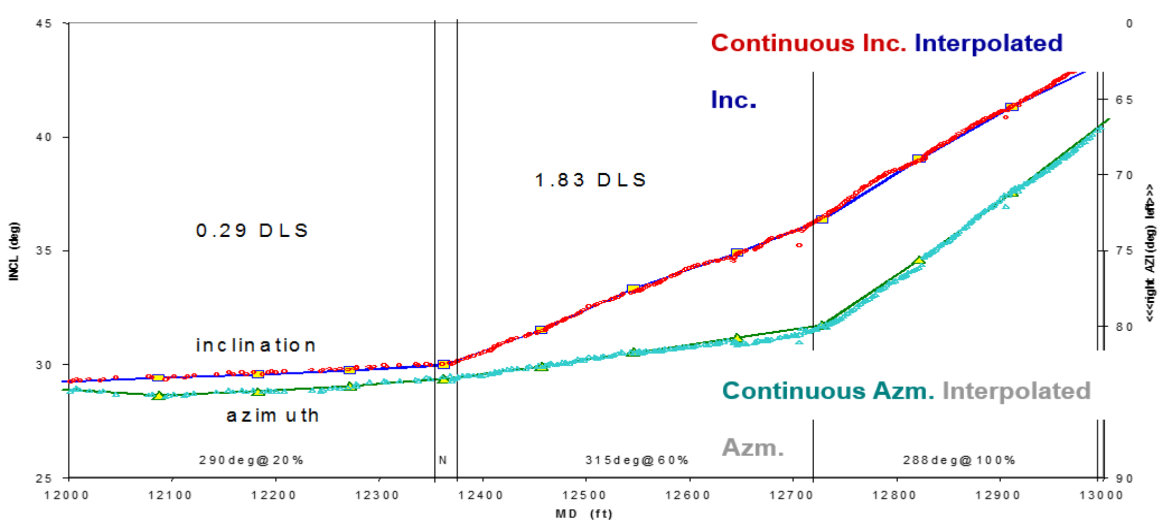

Figure 36: Profile with RSS drilling [4]

8.4 Types of RSS

Depending upon Service Provider there are different brands of RSS available in the industry. In this thesis only Schlumberger RSS technology will be included. According to Schlumberger RSS is a 3D fully steerable tool capable of changing both the inclination and azimuth of the well bore while maintaining continuous drill string rotation. In RSS all external components rotate with string RPM.

i. Push-the-bit RSS (PowerDrive X6 RSS)

In this type of RSS side force is applied to the bit to increase side cutting action. PowerDrive X6 (PDX6) is engineered to offer new level of reliability & performance in harsh drilling environment. It is designed to drill from casing shoe to TD in one run at maximum rate of penetration (ROP). PDX6 has wider & more robust flow ranges to minimize the effect of external drilling environment to handle aggressive & heavy muds & debris. The dual impeller control provides a wider operating envelope & impeller design increases available hydraulic torque to improve tool face control. Advanced coating materials resist wear and optimized flow profile reduce risk & erosion of components. A new bearing design & materials resist high temperature & aggressive mud. PDX6 electronics are chassis mounted for reliability & durability & can operate in downhole temperatures as high as 302 deg F. Control unit has been extensively upgraded & smarter electronic boards enable dual impeller control to improve resistance to stick slip and optimize real time communication.

An MWD type tri-axial sensor package close to the bit provides accurate azimuth & inclination directional information allowing fast, responsive directional control in either automatic or manual operation mode. Once a target formation has been penetrated, the trajectory can be locked in using the inclination hold. PDX6 gives the driller full directional control while rotating the drill string. An automatic inclination hold enables the driller to maintain directional control while drilling ahead-with minimal interaction. This provides smooth tangent sections & improved true vertical depth (TVD) accuracy in horizontal sections. Real time 360° gamma ray measurements & imaging of wellbore provide formation dip &

fault boundary information. Quick identification of bed boundaries enables drillers & geologists to optimize well placement & detect casing & coring points. As said earlier all external components of PDX6 rotate, eliminating the friction caused by stationery parts, it reduces drag, improves ROP, decreases risk of differential or mechanical sticking, and improve hole quality. Full rotation also enhances the flow of drilled cuttings, preventing creation of annular bottlenecks of wellbore. Working in combination with automatic hold, full rotation increases wellbore smoothness & decreases tortuosity. This reduces drilling torque, improves drilling efficiency & eliminates the need for unplanned wiper trips. PDX6 has drilled more than 1 million feet in 32000 operating hours and has improved reliability more than 25% in all hole sizes [4].

- ❖ Full back reaming capabilities
- ❖ Can Kick Off from Vertical
- ❖ Inclination, Azimuth and GR at Bit
- ❖ Better quality LWD measurements

ii. Point-the-bit RSS (PowerDrive Xceed Ruggedized RSS)

In this type of RSS an offset is introduced to the bit trajectory - analogous to steering with a bent motor. PD Xceed provides accurate steering & reliability in harsh, rugged environments & challenging drilling conditions. This extends the benefits of RSS drilling to difficult wells that exceed the performance limits of externally steered tools like PDX6. PD Xceed RSS points the bit using the rugged internal steering mechanism that is completely enclosed to significantly reduce wear & improve reliability. This mechanism has a bit shaft that pivots within the collar, tilting the bit in desired direction. A motor counter rotates at the same speed as drill string RPM to hold the bit-shaft tool face orientation geo-stationery. Internal components & seals are protected from wellbore temperature upto 302 deg F. The internal mechanism improves steering in soft & interbedded formations as there is no dependency on wellbore contact. That makes PD Xceed RSS ideal for open hole sidetracking in over-gauged or washed out holes & improves steering in hard, interbedded formations to keep the wellbore in target window. This point-the-bit RSS does not restrict bit nuzzling or hydraulics, and bit nozzles can be optimized without using a flow restrictor, allowing steering response in soft formations to be maximized. Increasing total flow area improves steering response by reducing wash out at the bit. This type of RSS can be used with Bi-center bits to increase hole gauge. It is combined with MWD telemetry to provide real time inclination & azimuth, at the bit, to guide steering decisions. A closed-loop inclination hold mode follows the desired trajectory-automatically correcting any deviations in inclination & azimuth & allowing the driller to focus on drilling optimization and maximizing ROP. Like other RSS, all external components of PD Xceed rotate, eliminating the friction caused by stationery parts, it reduces drag, improves ROP, decreases risk of differential or mechanical sticking, and improve hole quality. The full rotation also delivers a smooth, high quality wellbore that makes casing running & cementing easier. PD Xceed RSS gives superior ° of steering accuracy & reliability in harsh environments & soft formations. This RSS continues to successfully operate when externally steered mechanisms have reached their performance limits [4].

- 7– 8°/30m dogleg
- Vortex Applications (350 RPM)
- Open hole side-tracking capability
- Real time, near bit inclination and azimuth information
- Downhole hold inclination and azimuth control
- Bi-Center bit
- Soft Formations
- Hard formations
- Flexible Hydraulics requirement

8.5 Tortuosity

Tortuosity is the excess curvature in a wellbore. It is usually expressed as a value per unit length e.g. 0.4deg/30m. It is very important when trying to predict torque and drag for a particular profile.

Rotary steerable assembly should significantly reduce tortuosity compared with steerable motors.

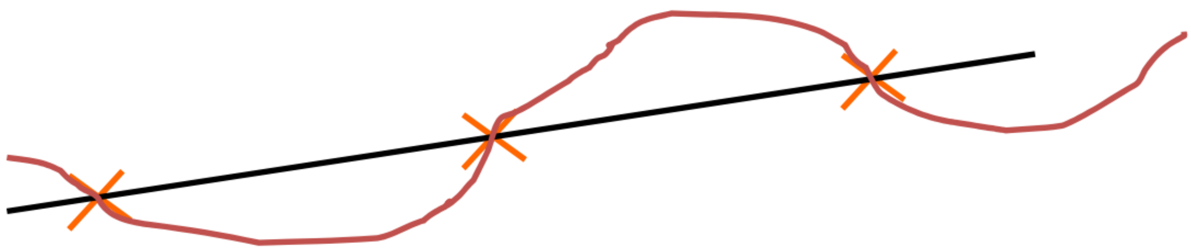

Figure 37: Wellbore Tortuosity [4]

8.6 Surveying

Surveying is extremely critical for target sizing, wellbore positioning, collision avoidance, good log data, reserves estimates, legal requirements & relief wells. For better reservoir exposure & exploitation it is very important that well is placed with enough certainty. In this section we will only discuss magnetic surveying & gyro surveying techniques as they are the most useful surveying techniques being used in the industry. In magnetic surveying only measurement while drilling (MWD) tool will be discussed briefly [4].

8.6.1 MWD

It is most widely used surveying tool in the industry today. Main features of this tool are [4]:

- Magnetic tool
- Uses a system of magnetometers and accelerometers to measure the earth's magnetic field and gravity
- Powered by batteries or turbine and transmit the survey data through mud pulse or electromagnetic waves
- Can be "collar mounted" or "retrievable"

8.6.2 Gyro

Two most common types of gyros are drop gyro/pumped down gyro/wire line gyro & Gyro while drilling (GWD). Continuous north seeking gyro is the most accurate gyro to reduce size of error of ellipse (EOU). GWD is the latest surveying technique being used today. GWD40 is used upto 40° inclination, GWD70 is used upto 70° inclination & GWD90 is used upto 90° inclination. GWD90 is the latest tool [4].

9 C-16A ERD Well Introduction & Background

9.1 Well/Slot History

According to Statoil Activity Program for C-16A well [5], The 33/9-C-16 well was drilled and completed as an oil producer in 1986. The 20” casing was cemented according to plan. 17 ½” section was drilled, cased of with 13 ⅜” casing and cemented without any issues. The 12 ¼” section was drilled straight into the reservoir, cased off and cemented without any issues. A 7.00” tubing was run inside the 9 ⅝” casing after which the well was perforated from 2860mMD to 2821m MD. Re-completed and re-perforated in 1993. The arrival status on this well is shown in figure below:

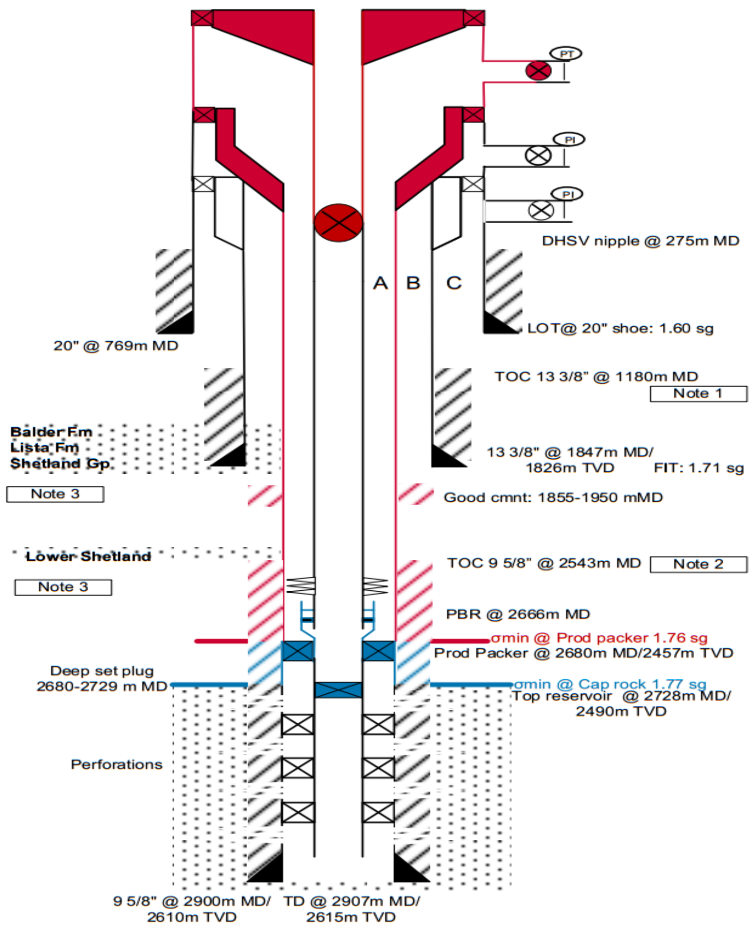

Figure 38: C-16A arrival status [5]

9.2 Summary of Planned Operations

Sequence & Summary of Operations planned on C-16A ERD well were [5]:

- Pull tubing and logging 9 ⅝" casing.
- P&A reservoir by setting a double cement plug in 9 ⅝" casing.
- Remove 9 ⅝" casing to be able to log cement behind the 13 ⅜" casing. The Rogaland group was planned to be P&A inside the 13 ⅜" casing with a double cement plug.
- Set 13 ⅜" EZSV before initiating removal of the 13 ⅜" casing down to minimum 50m below the 20" casing shoe.
- Side-track well by setting a cement plug into open hole with the 13 ⅜" EZSV as base.
- Kick off (on cement plug) and drill 17 ½" section in one run with same BHA. The
- Case off below the hydrocarbon zone in permeable Lista formation
- Cement the 13 ⅜" casing & temporarily P&A well by setting a shallow V0-rated plug in the 20" casing to access the well later for drilling 12 ¼" section when weather is quiet in North Sea (May 2016).
- Return back to C-16 A & prepare for drilling a 6000m long 12 ¼" section by building drillpipe stands and logging the 13 ⅜" casing cement.
- Drill 12 ¼" section in two runs. The objective of the first drilling run was to drill with 5 7/8" DP-stands until the derrick is empty and then perform a QC survey, with drop keeper gyro while POOH to change BHA. On the second drilling run it was planned to pick up 6 ⅝" singles before starting to drill with 5 7/8" stands. Clean hole by continuous back reaming from TD to the avalanche section inside 13 ⅜" casing. A 9 ⅝" liner was planned to be floated (evacuated liner with a mud over air concept) down to TD and cement.
- Drill 8 ½" section with a rotary BHA and clean hole at TD.
- Handover operation to completion.

9.3 Estimated Collision Probability Simulations

Statfjord field has significant well collision risks due to mature asset and many re-entry wells drilled. Estimated collision probability simulations showed below results [5]:

Interference well	Depth in well [m MD]	Centre/centre distance [m]	Separation Factor	Estimated collision probability [%]	Comments
33/9 K-1 H/AH	6870	43	0,78	0.02 (0.07**)	Plugged and abandon
33/9 L-2 H	7423	46	0,36	0.32	Shut in producer
33/9 L-1 H	7590	66	0,58	0.16	Shut in producer
33/9 L-3 H	7610	92	0,71	0.07 (0.09**)	Plugged and abandon

**) Positional errors assumed to follow a Student's t-distribution (considered to be more realistic than normal distribution for low probabilities).

Table 1: Well Collision probability simulations [5]

9.4 Well Objectives

Well 33/9-C-16A was planned to be drilled to the Statfjord Øst field from the Statfjord C platform, targeting Lower Brent reservoir. The target formations were the Etive Fm. and Ness Fm. The well was expected to increase reserves and secures future production from Statfjord Øst [5].

9.5 Well path Description

The well path started with kick off from 1° inclination towards the target at 147° azimuth. After kick off plan was to gradually build towards 87.2° with an increasing dogleg severity (DLS) from 1° to 2.2° inclination at end of build. The 87.2° tangent was planned to be drilled for approximately 5400m before dropping with a 2.8 DLS towards 37° inclination. The reservoir section planned to be drilled as a 37° tangent. The well path was planned without any turns in 17 ½" & 12 ¼" sections [5].

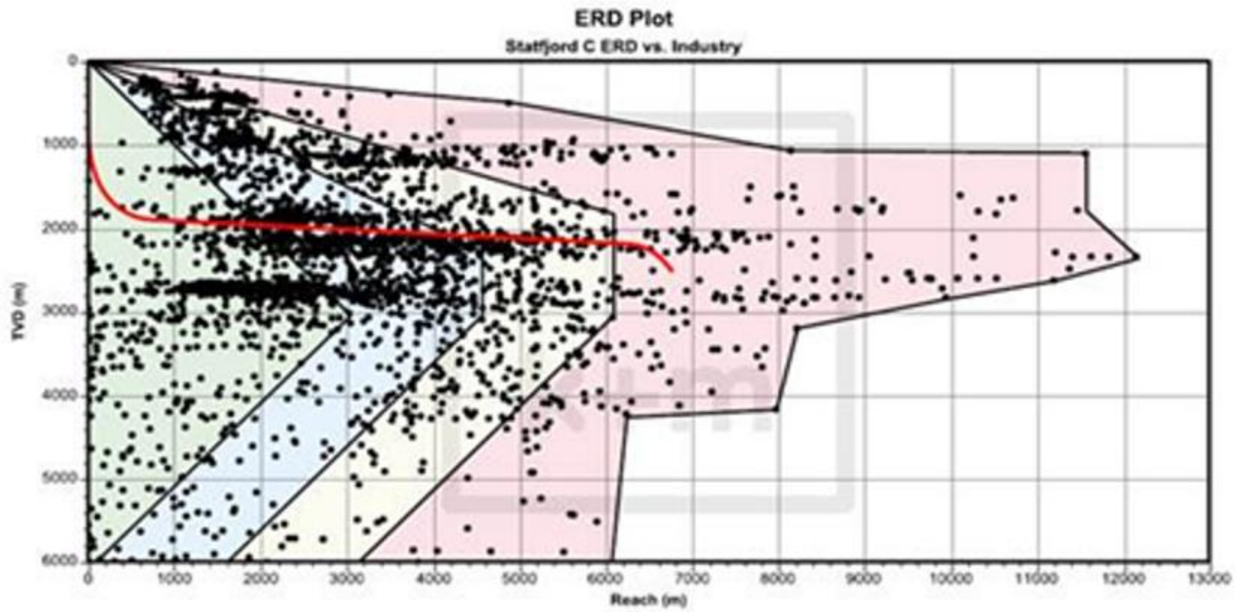

Figure 39: Complexity of well (red) [5]

The ERD parameters for this well were as follows:

- ❖ Along hole departure (AHD) = 6665m
- ❖ ERD Ratio (AHD/TVD) = 2.663
- ❖ Tortuosity = 144.50°
- ❖ Directional difficulty index = 7.02 (> 6.8 indicates long, tortuous well paths with a high ° of difficulty)

9.6 TD Criteria

17 ½" section TD was planned to be set on depth at 2215m MD/1885m TVD RKB / 1807m TVD MSL in Lista Fm. 12 ¼" section TD was planned to be set in lower part of Shetland by combined depth and geological uncertainty distance from top of reservoir. This was to assure reservoir is not entered in this section. TD planned to be set on depth at 8223m MD/2417m TVD RKB/2339m TVD MSL. Similarly 8 ½" section TD planned to be set as distance from top Etive Fm., with length for 3 screens and a rat hole, to 40m MD after top Etive Fm. Prognosed TD was 8333m MD/2505m TVD RKB [5].

10 17 ½” Section-Planning

10.1 Planned Objectives

The planned section objectives were [6]:

- ❖ Kickoff from open hole cement plug through 50m narrow window between 20” casing shoe and 13 3/8” casing stump, around 770m TVD in Nordland Group
- ❖ Perform FIT up to 1.52 SG
- ❖ Drill section to 2215m MD @ 79° inclination (1445m section length), 1 – 12° inclination through Utsira, 12 – 47° through Hordaland and 47 – 79° through Rogaland Group. Planned TD was in Lista Sand, at the deepest estimated spill point, at 1885 mTVD RKB
- ❖ Mud weight was planned to be gradually increased from 1.30 to 1.48 S.G at TD
- ❖ There was no experience with that long 17 ½” section with such a shallow kick off and TD below Lista Sand and 79° inclination.

10.2 Drilling Challenges

The main drilling challenges included open hole cement plug kick off, high angle & hole cleaning and instability in utsira formation.

10.2.1 Kick Off from vertical

Historically on statfjord field re-entry wells have been drilled by kicking off through whipstock window. DLS across whipstock window ranges from 7-9 °/30m. Therefore whipstock window kick off on this ERD well could pose huge risk of high side forces & casing wear while drilling 6000m long 12 ¼” section due to high DLS in shallow part of the well. To avoid this risk plan was made to kick off from open hole cement plug between 20” casing shoe & 13 3/8” casing stump. Based on Hussain et al. (2016), lesson learned were implemented and 50m window was planned for kick off. This technique of kick off was planned to give DLS of 2.5 °/30 thereby reducing the risk of high T&D and casing wear. The maximum limit of DLS was set to be 4.00 for safe drilling of 12 ¼” section. A decision tree was developed to identify different risks related to window length & respective tools selection [1].

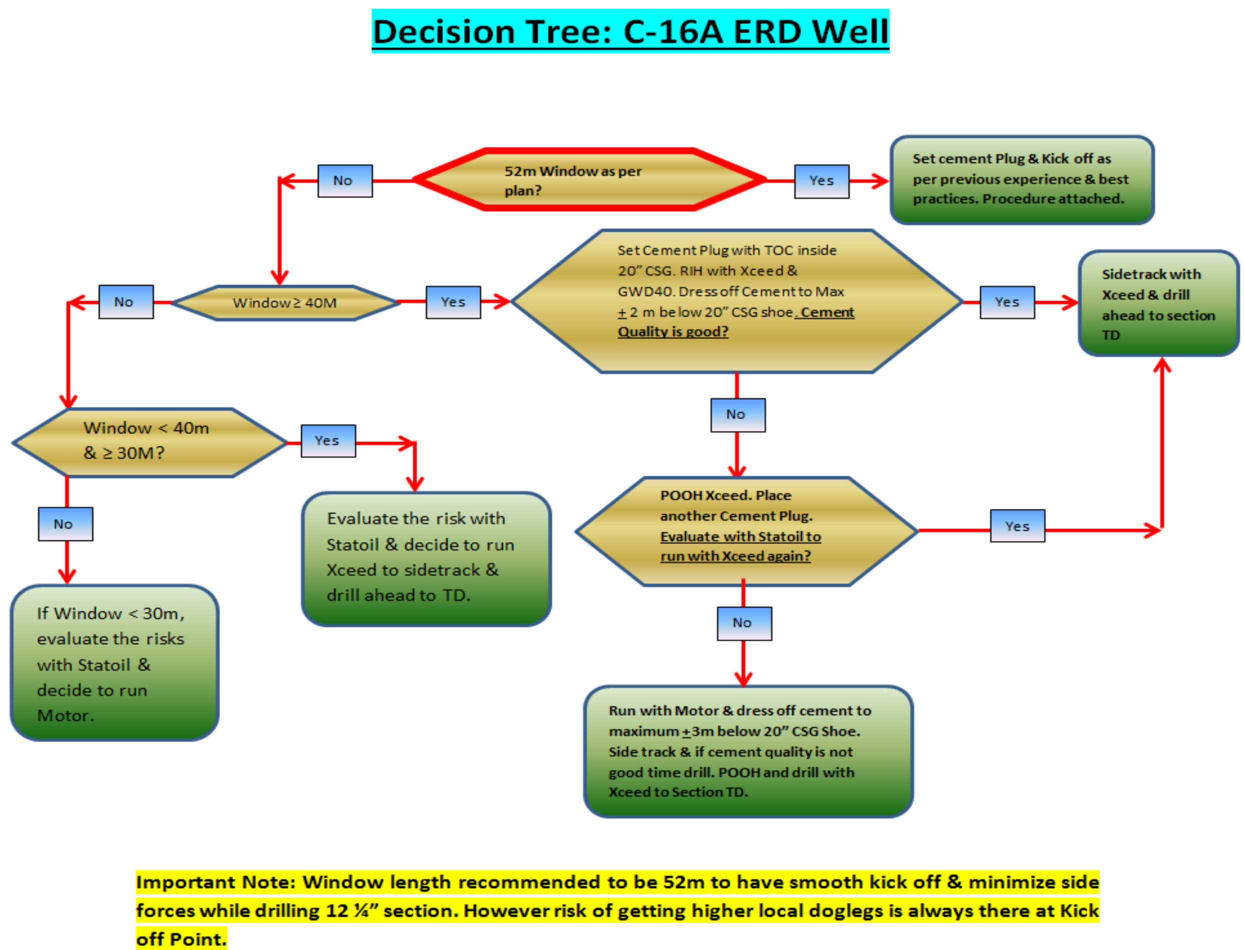

Figure 40: Open hole cement plug kick off decision tree

10.2.2 High Possible DLS creating a kink at Kick off Point (KOP)

Historically in North Sea similar open hole kick offs have been performed by Motor BHA followed by RSS BHA to drill to TD. Motor kick off have been performed to secure the kick off success & avoid colliding offset wells due to risk of high magnetic interference from nearby casings especially at shallow depths. Kicking off with motor is such an environment could lead to high DLS creating a kink in the well which may lead to high T&D & casing wear especially in ERD wells. Therefore it was planned to kick off with PowerDrive Xceed tool (Point-the-Bit RSS) to keep smooth DLS at KOP and drill 17 ½" section to TD in one run. Another benefit of Xceed was good tool face control in high magnetic interference environment leading to kick off in required direction & avoiding well collision with producers, Hussain et al. (2016) [1].

10.2.3 High Angle & Hole Cleaning

Historically no 17 ½" section has been drilled on Statfjord at such a high angle, therefore hole cleaning was a big risk. This high angle added a risk of instability in Rogaland group which induced the risk of hole cleaning. 1.48 S.G mud weight was selected to cope with wellbore instability risks. Hole cleaning was also of prime importance to avoid cuttings loading & hence losses at 20" casing shoe. Following measures were planned to improve hole cleaning in this section [5]:

- Use a range of high RPM (160-180) in high angle part of the section
- To devise hole cleaning strategy offset well analysis was performed for the wells drilled on Gulfaks, Statfjord & Brage
- Some of the offset wells reported cavings at high RPM due to drill string banging wellbore walls, but then it was established that these cavings were most probably caused by off bottom work & not by high RPM
- Avoid off bottom work
- Reduce connection time to minimize risk of cuttings settling. Since GWD was planned for kick off so it was decided reduce number of GWD surveys as much as possible to reduce connection time & improve hole cleaning (However close to operation GWD was dropped out of BHA based on collision risk assessment)
- Backreaming was also expected but was very less likely (However ended up in backreaming almost entire section, will be discussed later in execution phase)

10.2.4 Instability in Utsira Formation

Main challenges identified in drilling utsira formation were instability & poor directional control. Therefore only DLS of 1.00 was planned through utsira with maximum inclination of 10° [1].

Comments	MD (m)	Incl (°)	Azim Grid (°)	TVD (m)	VSEC (m)	NS (m)	EW (m)	Northing (m)	Easting (m)	DLS (°/30m)	GTF (°)	BR (°/30m)	TR (°/30m)	DeltaMD (m)
Marker Mud...	224.00	0.00	0.00	224.00	0.00	6.79	28.15	6796485....	441224.65	1.02	0.00	0.00	0.00	0.00
30" Conduct...	333.10	0.83	259.50	333.10	-0.24	6.96	27.71	6796485....	441224.21	1.39	-26.24	1.13	-73.95	9.10
Tie-In to Ac...	764.03	0.35	264.36	764.00	-3.60	4.74	25.19	6796483....	441221.69		50.21			
20" Casing	769.00	0.37	268.71	768.97	-3.62	4.74	25.16	6796483....	441221.66	0.22	45.86	0.15	26.28	4.97
Kick Off	770.00	0.38	269.52	769.97	-3.63	4.74	25.15	6796483....	441221.65	0.22	146.62	0.15	25.93	5.97
EOC	810.00	3.02	52.17	809.95	-2.68	5.38	25.85	6796484....	441222.35	2.50	0.00	1.98	106.99	40.00
Top of Intra...	858.16	4.63	52.17	858.00	0.53	7.35	28.39	6796486....	441224.89	1.00	0.00	1.00	0.00	48.16
Top Utsira	903.36	6.13	52.17	903.00	4.77	9.95	31.74	6796488....	441228.23	1.00	0.00	1.00	0.00	93.36
Top Hordala...	1055.14	11.20	52.17	1053.00	27.63	23.97	49.79	6796502....	441246.28	1.00	0.00	1.00	0.00	245.14
EOC	1120.01	13.36	52.17	1116.38	41.42	32.43	60.69	6796511....	441257.17	1.00	0.00	1.00	0.00	310.01
EOC	1420.01	25.36	52.17	1398.90	140.69	93.31	139.09	6796571....	441335.55	1.20	0.00	1.20	0.00	300.00
EOC	1720.02	42.56	52.17	1646.81	307.66	195.72	270.97	6796674....	441467.38	1.72	0.00	1.72	0.00	300.02
Top Balder	1801.74	48.55	52.17	1704.00	365.97	231.48	317.02	6796710....	441513.42	2.20	0.00	2.20	0.00	81.71
Top Sele	1863.48	53.08	52.17	1743.00	413.81	260.82	354.81	6796739....	441551.19	2.20	0.00	2.20	0.00	143.45
Top Lista	2006.49	63.57	52.17	1818.00	535.35	335.36	450.81	6796813....	441647.16	2.20	0.00	2.20	0.00	286.47
13 3/8" Pro...	2215.00	78.85	52.17	1884.96	732.16	456.06	606.26	6796934....	441802.55	2.20	0.00	2.20	0.00	494.98
EOC #1 (3D...	2328.81	87.20	52.17	1898.77	845.03	525.28	695.41	6797003....	441891.67	2.20	0.00	2.20	0.00	608.79
Base Lista S...	2394.89	87.20	52.17	1902.00	911.03	565.76	747.55	6797044....	441943.79	0.00	0.00	0.00	0.00	66.08
Top Vaale	2599.49	87.20	52.17	1912.00	1115.38	691.08	908.96	6797169....	442105.14	0.00	0.00	0.00	0.00	270.68
Top Shetlan...	2804.08	87.20	52.17	1922.00	1319.73	816.40	1070.37	6797294....	442266.50	0.00	0.00	0.00	0.00	475.27
Intra Shetla...	7427.92	87.20	52.17	2148.00	5938.04	3648.67	4718.25	6800126....	445913.07	0.00	0.00	0.00	0.00	5099.11
KOP #2	7668.52	87.20	52.17	2159.76	6178.35	3796.04	4908.07	6800273....	446102.82	0.00	-180.00	0.00	0.00	5339.71
9 5/8" Prod...	8170.00	40.39	52.17	2375.09	6615.89	4064.38	5253.66	6800541....	446448.29	2.80	-180.00	-2.80	0.00	501.48
EOC #2 (3D...	8206.37	37.00	52.17	2403.47	6638.62	4078.32	5271.62	6800555....	446466.24	2.80	0.00	-2.80	0.00	537.85
Base Lower...	8224.56	37.00	52.17	2418.00	6649.57	4085.04	5280.27	6800562....	446474.89	0.00	0.00	0.00	0.00	18.20
Top Mime	8247.10	37.00	52.17	2436.00	6663.14	4093.36	5290.98	6800570....	446485.60	0.00	0.00	0.00	0.00	40.73
BCU/Top Ne...	8253.36	37.00	52.17	2441.00	6666.91	4095.67	5293.96	6800572....	446488.57	0.00	0.00	0.00	0.00	46.99
Main Field C...	8256.37	37.00	52.17	2443.40	6668.71	4096.78	5295.39	6800574....	446490.00	0.00	0.00	0.00	0.00	50.00
Top Ness 1	8257.12	37.00	52.17	2444.00	6669.17	4097.05	5295.74	6800574....	446490.36	0.00	0.00	0.00	0.00	0.75
Top Etive 2	8293.43	37.00	52.17	2473.00	6691.02	4110.46	5313.00	6800587....	446507.61	0.00	0.00	0.00	0.00	37.06
Top Etive 1	8307.20	37.00	52.17	2484.00	6699.31	4115.54	5319.55	6800592....	446514.16	0.00	0.00	0.00	0.00	50.84
Proposed TD	8356.37	37.00	52.17	2523.26	6728.90	4133.69	5342.92	6800610....	446537.52	0.00		0.00	0.00	100.00

Figure 41: Planned trajectory [1]

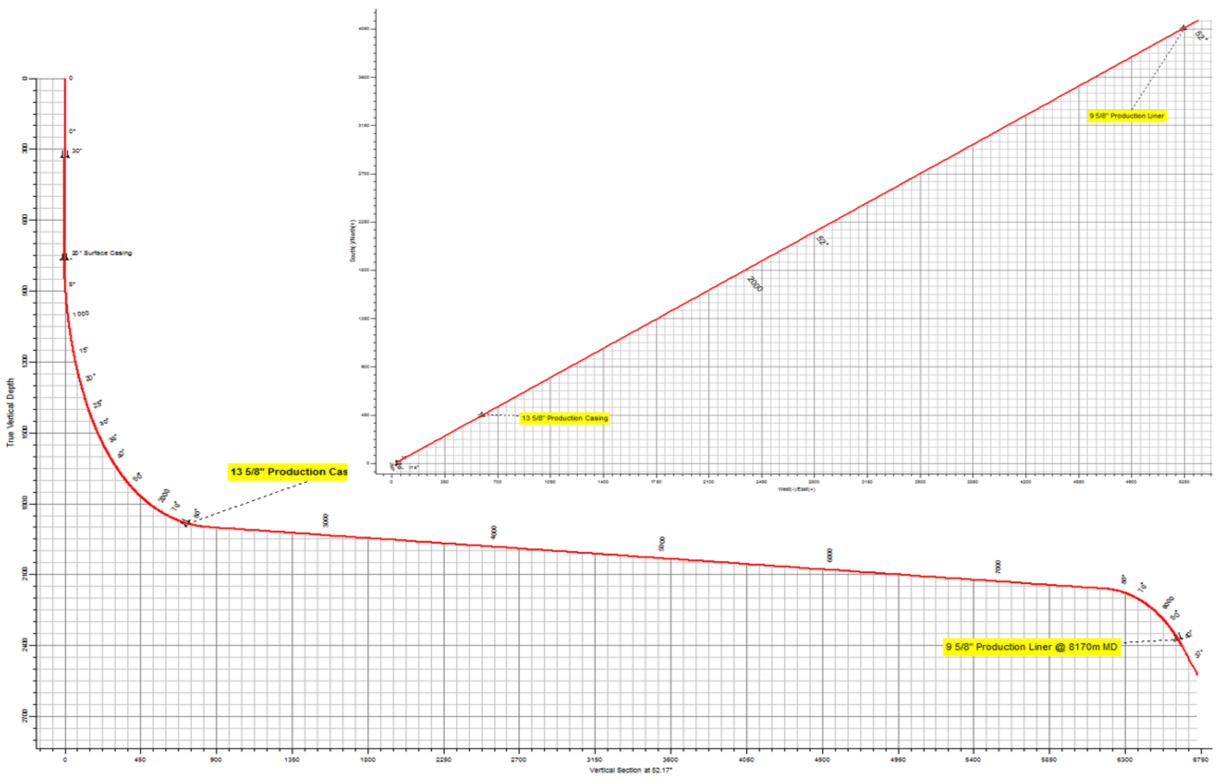

Figure 42: Planned trajectory [1]

10.3 Survey Program

In this section the most important element of survey program was to avoid or minimize blind zone and hence minimize the risk of collision with offset wells. Blind zone is measured depth interval within which MWD surveys are affected by magnetic interference from casings in offset wells. The planned/expected blind zone was 150m MD from kick off point which means MWD surveys were expected to be bad due to magnetic interference from offset wells. Therefore GWD40 tool was planned to be used in 17 ½” section to help kick off in desired direction & minimize risk of collision with offset wells. Remember GWD is not affected by magnetic interference. The planned Survey program was as follows:

- GWD40 was planned to be used in BHA to cover 150m blind zone (760m MD to 910m MD)
- Drill from 910m MD to a point where inclination is 20 ° at 1190m MD. Drill this part of the section with “SLB_MWD+DEC+SAG” error model in Dox (Drilling Office Software) (Schlumberger) & “Magnetic, IFR, non-mag, reduced QC” error model in Compass Software (Statoil).
- Drill from 1190m MD to section TD at 2215m MD using “SLB_DUAL-INC+SAG+DEC” error model in Dox & “Magn, IFR, non-mag, reduced QC, MSA Dual inc” error model in Compass. This were the error models used while drilling. It was first time that Schlumberger Multi-station analysis & Dual inclination processing was applied with Statoil. The main reason of using dual inclination error model was to optimize TVD.

Figure below is showing a snapshot of Definitive survey in 17 ½” section.

Survey Program By Parts_C-16A ERD Well								
Parts	MD From (m)	MD To (m)	Survey Frequency	Tool Error Code - DOX	Tool Error Code - Compass	Survey Tool Description	Hole Size	Comments
1	224	764.03	30	SLB_RIGS	RIGS, cont	RIGS	30" & 26"	Legacy Motherbore surveys
	764.03	899	30	SLB_MWD-INC_ONLY_FILLER	Magn, interpolated azimuth	MWD	17 1/2"	Already drilled. Dual inclination processing was done at TD.
	899	1187	30	SLB_MWD+DEC+SAG	Magnetic, IFR, non-mag, reduced QC	MWD IFR	17 1/2"	
	1187	2215	30	SLB_DUAL-INC+SAG+DEC	Magn, IFR, non-mag, dual inclination	MWD IFR	17 1/2"	
	2215	6219	30	SLB_DUAL-INC+SAG+DEC	Magn, IFR, non-mag, reduced QC, MSA Dual inc	MWD IFR, MSA & Dual Inclination processing	12 1/4"	MSA & Dual inclination processing in RT (02 time/24 hrs). GWD90 is in the BHA & OBM will be used for MWD verification all the way to 764.03m. GWD90 survey can also be taken as a contingency while drilling if any signs of issues with MWD (Dual inc & MSA to verify). No MWD Clustershots are required.
2	764.03	899	30	SLB_NSG+BATTERY	Wellbore surveyor, stat	GWD90 OBM	17 1/2"	GWD90 OBM for MWD verification
	899	1187	30	SLB_MWD+DEC+SAG	Magnetic, IFR, non-mag	MWD IFR	17 1/2"	GWD90 OBM for MWD verification
	1187	2215	30	SLB_DUAL-INC+SAG+DEC	Magn, IFR, non-mag, dual inclination	MWD IFR	17 1/2"	No change in tool code
	2215	6219	30	SLB_DUAL-INC+SAG+DEC	Magn, IFR, non-mag, dual inclination	MWD IFR, MSA & Dual Inclination processing, GWD90 OBM	12 1/4"	MWD verification using GWD90 OBM. Tool code will be changed after GWD90 OBM survey data is received from Gyrodata.
	6219	8223	30	SLB_DUAL-INC+SAG+DEC	Magn, IFR, non-mag, reduced QC, MSA Dual inc	MWD IFR, MSA & Dual Inclination processing	12 1/4"	In 2nd run no GWD90 in the BHA. No verification of MWD. MSA & Dual inclination processing will be run in RT 02 times/24 hrs. No MWD Clustershots required.
	8223	8356	30	SLB_MWD+DEC+SAG	Magnetic, IFR, non-mag	MWD IFR	8 1/2"	Reservoir section

Figure 43: Survey Program [1]

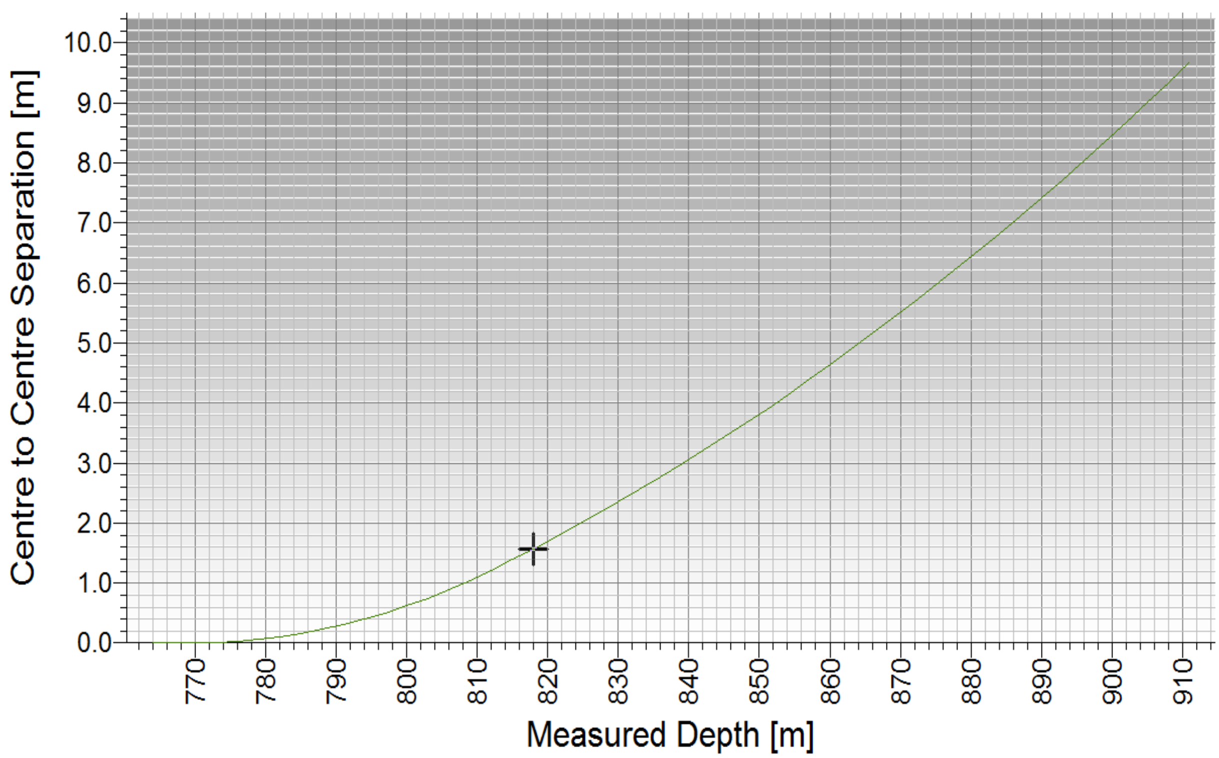

Figure 44: Expected Blind Zone at 10m center to center distance (Compass)

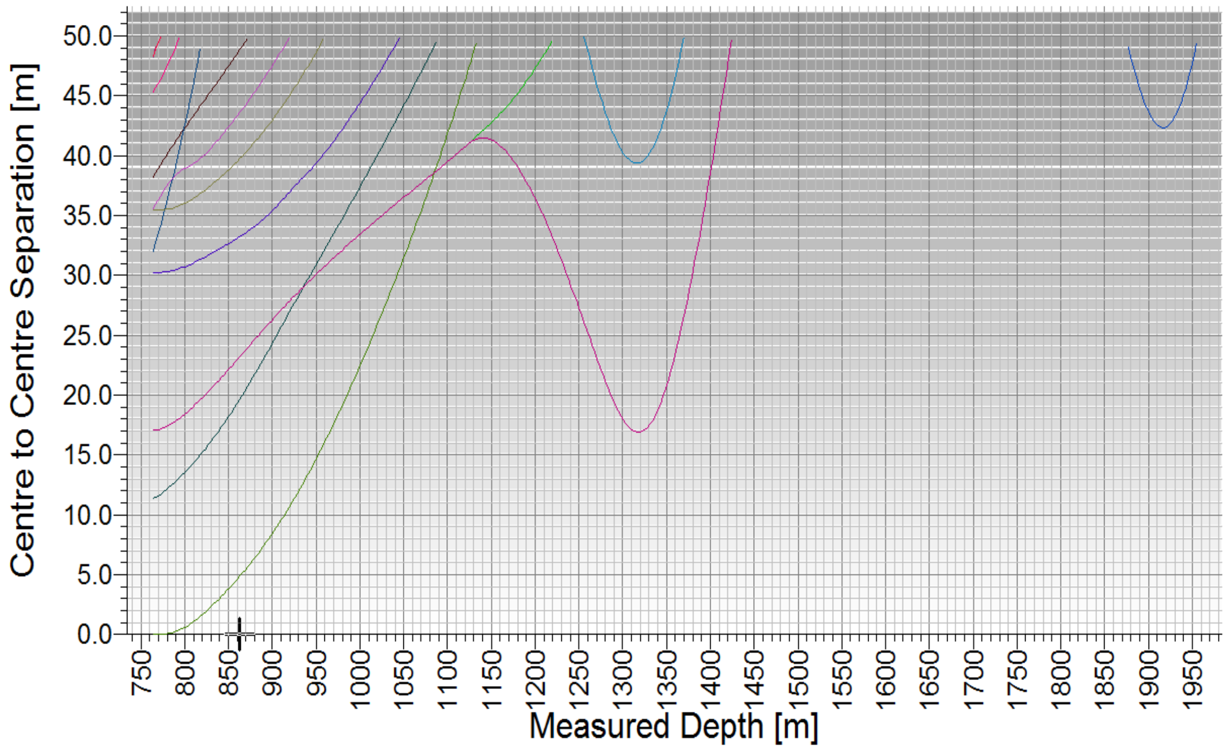

Figure 45: Ladder Plot showing center to center distances (Compass)

10.4 Risk Register-Kick off from Cement Plug

The main risks related to kick off from open hole cement plug were identified as follows:

#	Hazard Description and Worst Case Consequences with no Prevention or Mitigation Measures in Place	Hazard Category	Population Affected	Loss Category	Potential Risk	Prevention Measures	Mitigation Measures	Residual Risk
1	Cement Integrity & Kick off Issues	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- 1. Follow Decision Tree agreed with Statoil. - 2. Use Offset data for reference.	- 1. Decision Tree agreed with Statoil - 2. Statoil is aware of the risks. - 3. Another Cement Plug in worst case - 4. Refer to Kick off Procedure - 5. Previous experience shows good quality cement - 6. Use Xceed near Bit inclination to establish Kick off (Cuttings are not reliable, same colour as cement). - 7. Give enough setting time to cement to achieve maximum compressive strength. - 8. Make sure one complete stand before initiating kick off to avoid	Medium
2	Not enough window & Collision with Stump	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- 1. Follow Decision Tree agreed with Statoil.	- 1. Follow Decision Tree agreed with Statoil. - 2. Agree with Statoil on maximum cement dress off before we stop due to poor cement quality, evaluate the situation and/or another cement plug. - 3. Compare subject wellbore inclination (Xceed Near Bit Inclination) with motherbore inclination. Motherbore is almost vertical upto 1144m MD. - 4. Ensure minimum 1.5-2.00 DLS while kicking off. - 5. Refer to Kick Off Procedure. - 6. Previous experience shows that upto 40m window is enough to sidetrack.	Medium
3	Magnetic Interference from nearby offset wells (C-24, C-27 A/B/BT2 & 13 3/8" Casing Stump)	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	High	- 1. GWD 40 - 2. Good experience with Xceed in similar environment.	- 1. GWD40 - 2. Good experienec on Statfjord in similar environment. - 3. Refer to Kick Off Procedure for collision risks & mitigation.	Medium
4	High Doglegs at kick off Point with Xceed900 resulting in high side forces/casing wear while drilling 12 1/4" ERD section	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- 1. Refer to Kick Off Procedure. - 2. Minimum 50m window between 20" Casing shoe & 13 3/8" casing stump	- 1. Refer to Kick Off Procedure. - 2. Start with Controlled Power Setting, 100% in first 5m & then reduce to 70%. - 3. Project ahead & keep track for crossing the stump. - 4. Minimum 1.5-2.00 DLS is enough to cross stump without collision. - 5. Ream high DLS interval.	Medium

Figure 46: Risk Register, Open Hole Cement Plug kick off

10.5 Risk Register-Drilling 17 ½" section

The main risks related to drilling 17 ½" section were identified as follows:

#	Hazard Description and Worst Case Consequences with no Prevention or Mitigation Measures in Place	Hazard Category	Population Affected	Loss Category	Potential Risk	Prevention Measures	Mitigation Measures	Residual Risk
1	Instability in Rogaland Gp., Inclination 85 degree requiring high Mud weight (1.48 SG) resulting losses at 20" Casing shoe	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- Focus on good hole cleaning & mud properties in Spec - Statoil is aware of the risk.	- Optimize flow rate - Optimized Mud weight	Medium
2	Shock and vibrations while drilling leading to tool failure particularly at hard stringers	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Schlumberger	High	- 1, Vary drilling parameters to eliminate / minimize shock and vibrations. - 2, DD & MWD closely monitoring shock and vibration - 3, Evaluate to run a dedicated BHA to drill through the hard Stringers. - 4, Drill through the sand with low flow in order not to wash the sand, thereby creating lateral motion around the bit.	- 1. Vary drilling parameters to eliminate / minimize shock and vibrations - 2. OSC to help in monitoring and managing S&V closely - 3. Follow SLB procedure.	Medium
3	Instability in Utsira, unable to achieve directional control, dropping angle	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- 1. Well planned with 1.00 DLS in Utsira. Previous expereince shows that upto 2.5-3 DLS has been achieved with Xceed. - 2. Mobilize DDs with good Xceed experience	- 1. Well planned with 1.00 DLS in Utsira. Previous expereince shows that upto 2.5 -3 DLS has been achieved with Xceed. - 2. DD to project ahead and verify required build after Utsira to compensate for drop.	Low

4	Accummulation of casing swarfs in the wellbore thereby jamming/blocking tools leading to tool failures	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- 1. Ditch magnet to be cleaned at regular intervals at least once a shift during drilling and every 2-3 hours at the beginning of the section - 2. Disuss with client during DOP meeting - 3. Document the swarf recovery	- 1. Ditch magnet to be cleaned and checked at a regular interval - 2. Circulate hole clean until level of swarf recovered on magnets is as expected after milling a hole	Low
5	Poor Hole cleaning	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- 1. Keep flow and RPM as high as allowable in order to achieve the 'conveyor belt' effect. - 2. Monitor drag and hookload ie follow T&D with driller's road map	- 1. Circulate until hole is clean with high as allowable flow and RPM at section TD. - 2. Monitor drag, hookload and pressure. Use the roadmap - 3. Pump Max flow limited by Stand pipe pressure	Medium
6	Lost circulation.	Machinery/Equipment/Hand Tools	Schlumberger, statoil	Non-Productive Time-->Client	Medium	- 1. Follow trip in procedure as stated by the client. - 2. Treat mud with LCM at intervals.	- 1. Evaluate the extent of losses in order to determine if the hole can still be salvaged by running casing.	Low
7	Collision risks at KOP	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- 1. Monitor AC on TC Plots provided & respect hard lines. - 2. Drill first 50m with controlled parameters & track BHA tendancy. - 3. Please refer to AC review for detailed risks & mitigation measures.	- 1. Exemption in Place (Please refer to TC Plots & AC review). - 2. Refer to detailed AC review & exemption document. - 3. Statoil is aware of the collision risks. - 4. OSC on 24 hrs watch. - 5. Refer to Kick Off Procedure. - 6. Deatiled review & meeting with DD To discuss risks & mitigation.	Medium
8	High sand contenets leading to tool failure	Machinery/Equipment/Hand Tools	Schlumberget, Statoil	Non-Productive Time-->Client	Medium	- 1. Reduce ROP & circulate to reduce sand contents in the system. - 2. Stop drilling if required & circulate.	- 1. Optimize shaker screens. - 2.DD/MWD to get CNS signed by Statoil. - 3. Statoil is aware of this known risk.	Low
9	Tool failure & slow drilling progress due to hard stringers	Machinery/Equipment/Hand Tools	Schlumberger, Statoil	Non-Productive Time-->Client	Medium	- 1. Optimize drilling parameters thru stringers. - 2. use Statoil best paractices.	- 1. Run dedicated assembly if needed. - 2. Reduce flow rate & keep the ROP tominimize washot effects. - 3. Statoil is aware of the risks.	Low

Figure 47: Risk Register, drilling 17 ½” section

10.6 Kick Off Procedure

Kick off from open hole cement plug is always a risky operation. This risk gets multiplied when kick off is from vertical (less than 10.00 ° inclination). Therefore detailed planning was made to make sure successful kick off is performed in first attempt.

10.6.1 Background

Open hole cement plug kick off from vertical with Xceed900 in 17 ½” section, building from vertical to 79°, on 52° azimuth. Window length planned be 52m between 20” casing shoe & 13 3/8” casing stump. 20” Casing shoe was at 769m & 13 3/8” casing stump at 820m MD.

DLS control was important in the shallow sections to minimize T&D and side forces. It was extremely important to drill as close to the planned DLS as possible, while still kicking-off and achieving clearance to the 13 3/8" casing stump. Anti-collision risks were moderate at KOP. Kick-off was planned with max DLS of 2.5 but could go up to 3.00 (preferred not more). The DLS was planned to be 1 – 1.2 after passing the casing stump then increases to 2.00 again. BHA planned included Xceed900, Telescope (MWD) & GWD40.

10.6.2 Offset wells Analysis

Similar kick-offs from cement plugs have been made before with window lengths from 37m to 80m. These kick-offs were from +/-10 inclination rather than vertical. A ~50m window is good, previous experience shows this should be long enough to kick-off and gain sufficient separation. The cement plug was planned to be set against a solid barrier in the 13 3/8" casing and historically have been good quality requiring 5-10 ton to drill with 60-80 RPM. This is harder than the formation and is a good basis for a successful side-track. The plug will extend to ~30m inside the 20" casing.

The primary objective was to make side-track on first attempt, but this could not be at the expense of dog leg severity – the objective was to kick off with a 2.5 deg/30m DLS. It was undesirable to see a DLS over 3deg/30m. The minimum required DLS to pass the 13 3/8" casing stump with 0.5m wall-wall separation was 1.5deg/30m.

10.6.3 Guidelines for Directional Drillers (DD's)

Guidelines for DD's were as follows:

- The kick off will be on magnetic tool face (MTF) so there is the possibility of magnetic interference affecting the accuracy of MTF due to the proximity of nearby wells. The mother well C-16 is the only well within 10m of the planned well path. The mother well is < 1.00 ° inclination but on a 270 deg azimuth so C-16A kicking off at 52 ° azimuth will separate as quickly as it is possible to do so. A kick-off azimuth of 90 ° would be optimum but add unnecessary tortuosity.
- Since the kick-off is on MTF a relatively clean magnetic field is required. This means that the Xceed survey package needs to be outside the casing

shoe at kick-off point. This also means that the magnetometers will be able to measure string RPM. It is not anticipated that there is a need for the added complexity of the Gyro Xceed for RPM measurement. The well path does not enter the zone of exclusion.

- MTF will switch to GTF in the Xceed at 4° inclination when building. The advantage of GTF is that with accelerometer control mode it is not affected by the potential magnetic interference affecting the accuracy of MTF. When the casing stump is passed most likely MTF will still be in use and some error in steering could be expected. Looking at offset data from Statfjord and Balder 17 ½" Xceed runs, an offset in toolface 10-15deg right/clockwise is anticipated so set kick off toolface to 36/42MTF, anticipating +/-52 azimuth. This does not account for any magnetic interference due to adjacent C-16 casing strings.
- Dress cement 2-3m outside 20" casing shoe before starting kick-off. The magnetometers need to be outside the 20" shoe before kicking off. Surveys will not be good but would expect MTF to give the correct quadrant initially. The GWD will not help with the MTF apart from confirming the Kickoff direction when the survey point is deep enough.
- Use 100% SR to initiate kick-off and until build on near bit inclination is seen, then reduce accordingly (Using cuttings as indication of kick off should be avoided because of the similarity between Nordland formation and Cement). 60-70 % SR has yielded 2-2.5 DLS. Minimum of 1.5 DLS is required to pass casing stump. When the stump is passed the DLS reduces to 1-1.2deg/30 or 20-40 % steering ratio. Monitor near bit inclination closely to control build rate. In the past it has been found that 3deg/30m is the maximum achievable, this will increase with inclination and depth.
- Space out for full stand at kick-off.
- Building consistently with low DLS through Utsira could be difficult. Previous wells have shown that the maximum DLS achievable was

approximately 3.5 so the build rate will not be 'out of control' even with 100% steer ratio. Offsets show that 20-40% can yield 1-1.5 DLS.

- ❖ Xceed flow range is anticipated as 600-1200 GPM / 2200-4500 LPM. For effective steering the flow needs to be above 2200 LPM.
- ❖ Utsira - will probably be drilled with low weights 1-2MT / high ROP 40-70m/hr, 100-120 RPM, stick slip can be higher and the higher RPM can mitigate this. Flow rate will likely need to be reduced in the Utsira sands due to blinding the shakers. Previously 3100 LPM has been ok. When out of the Utsira increase flow to 3500-4000 LPM.
- ❖ No wells within 10m Ct-Ct except for C-16. C-16 >10m at 914m MD. Anticipate interference from C-16 until 914m but at approximately 850m inclination > 4deg so GTF will be used and mode switched to accelerometer mode. There is an advantage to building more quickly to reach GTF mode earlier, but that is at the expense of a higher DLS which is undesirable.

10.6.4 PROCEDURE & PARAMETERS

Following procedure & parameters were planned for this challenging kick off with smooth exit:

- ❖ Wash down, tag top cement plug with 1000 LPM, no rotation. Set weight down and establish cement compressive strength. Would hope to be able to set down 5 – 10 ton, no rotation.
- ❖ Drill/dress cement to 3m outside 20" casing shoe, 3000-3500 LPM, 60-80 RPM, 5-10 ton weight on bit (WOB). Assess the compressive strength of the cement while drilling.
- ❖ Space out string to have a full stand prior to initiating the kick-off.
- ❖ When 3m outside 20" casing shoe, at 772m, set Xceed to 42 ° MTF/100% to initiate kick-off. Parameters 3000 LPM / 60-80 RPM / 3-5 ton WOB or +/-5-10m/hr ROP.
- ❖ Maintain 100% steer ratio until change in near bit inclination is seen (and/or 5-10m), then reduce the steering ratio to ~70% and continue the

kick-off with the planned DLS. A minimum DLS of 1.5 is required to pass the 13 3/8" casing stump.

- As kick-off is confirmed and the casing stump is passed increase flow rate from 3000 – 4000 LPM and rotation 80 – 120 RPM. Through the Utsira sands expect to increase ROP to 30-50 m/hr to maintain 1-3 ton WOB. 120 RPM to help torque/stick slip. Anticipate the sand blinding the shakers and consequently flow being reduced to 3000 LPM. After passing the Utsira increase flow rate to 3000-4000 LPM & 120-140 RPM. It may be necessary to control ROP until shakers have cleaned up after drilling the Utsira.
- Utilize GWD surveys until MWD survey is >10m distance from adjacent wells.

10.6.5 Collision risks with Offset Wells

Offset wells C-24 & C-21 are above and C-27 (the last well that crosses C-16A) is below. In order to get too close to C-24 and C-21 the C-16A well need to be building too fast continuously or kick-off too aggressively and with no control of the build rate. In practical terms the build rate would have to be so far ahead of plan for C-24 and C-21 to be a problem which is unlikely to happen. More likely is that dogleg is under achieved and C-16A falls behind/below plan and C-27 becomes a larger risk since it crosses C-16A at a deeper measured depth. Below figure shows travelling cylinder plot which is used for collision monitoring purposes.

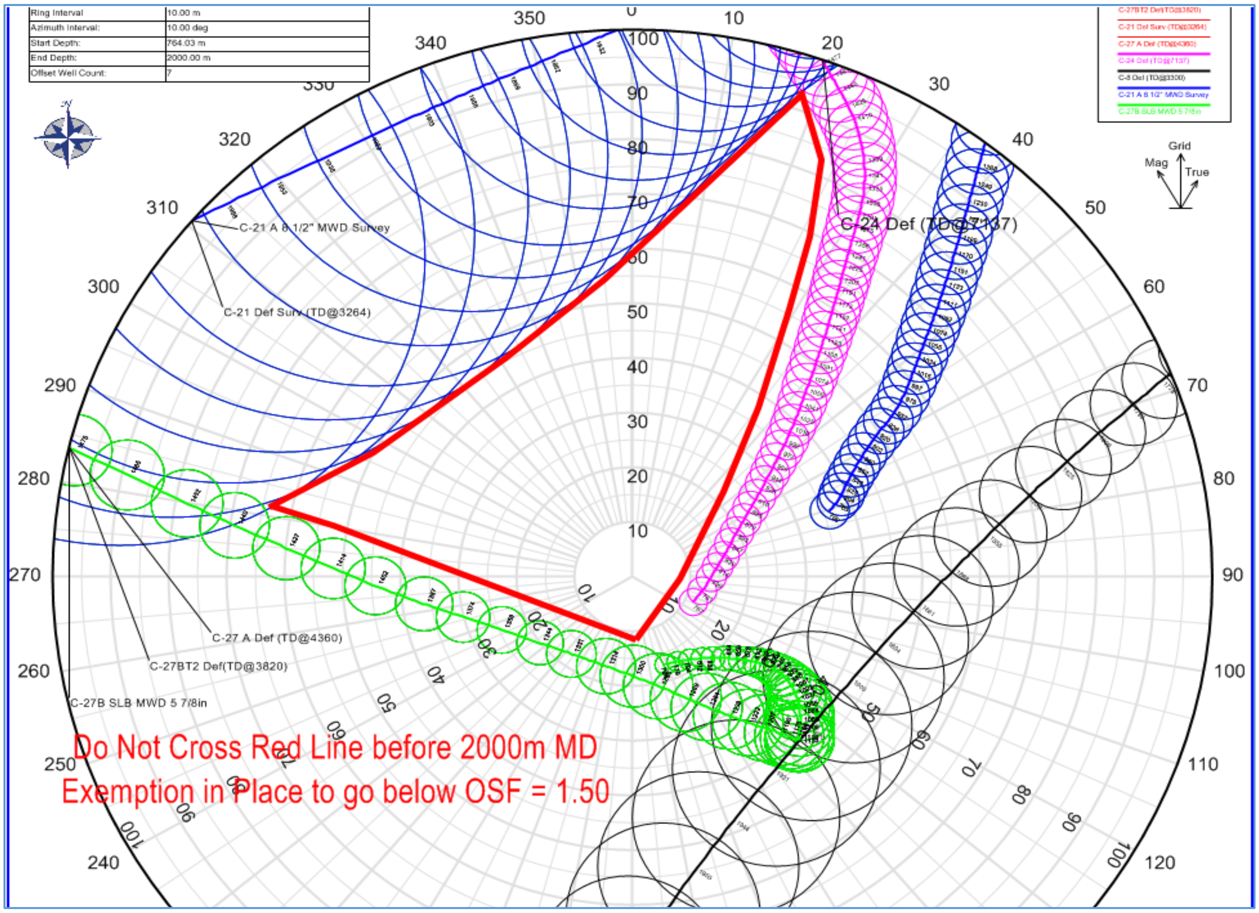

Figure 48: Travelling Cylinder Plot for collision monitoring with offset wells

10.7 BHA Design

The main objective of the BHA was to kick off, drill and able to back ream out of hole with stabilization such that it poses no restriction & risk to hole cleaning. Sting blade PDC bit was selected to drill the section and expected stringers more effectively. Xceed was selected as RSS to help in kick off from vertical through 50m window in high magnetic interference environment. MWD & GWD were planned for surveying & tracking wellbore trajectory all the time. Enough drill collars were planned below Jar to have sufficient available WOB for drilling. Jar & accelerator were included in the BHA to mitigate risks of stuck pipe mainly due to high angle at TD. Below figure shows the planned BHA.

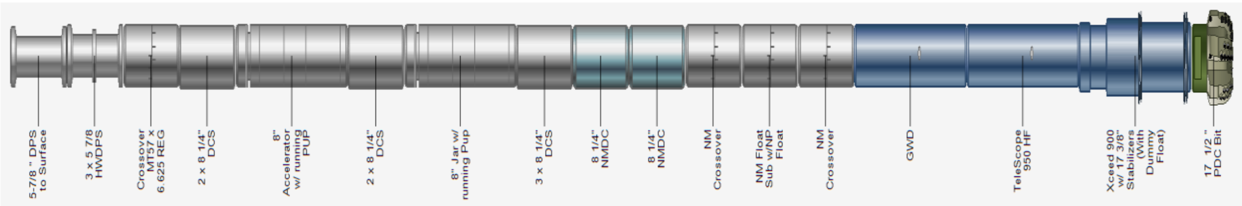

Figure 49: Planned 17 1/2" BHA

10.8 Bit Design

Sting Blade PDC bit was planned to drill this section mainly because of expected hard stringers and long 17 ½" section which is not common on Statfjord. This bit has exceptional performance in 17 ½" section drilled on Statfjord as well as North Sea.

StingBlade
17 1/2 in Z616

SMITH BITS
A Schlumberger Company

(444.5 mm) ID:66272B0001
ER:26522

StingBlade bits, with Stinger conical diamond elements across the bit face, are designed to significantly increase footage and ROP in tough-to-drill formations, drill with better steerability in directional applications, mitigate shocks and vibrations through greater bit stability, and create larger cuttings for improved surface formation evaluation.

Specifications

Total Cutters	78
Cutter Size	16mm (5/8 in)
Face Cutters	(46) 16mm
Gauge Cutters	(6) 16mm
Cone Cutters	(20) 16mm
Back-Up Cutters	(6) 16mm
Total Stinger Element Count	55
Stinger Element Size	9/16 in
Blade Count	6
Nozzles	9 Standard Series 60N
Bit Connection	7 5/8 Reg
Junk Slot Area, in2	70.352
Gauge	Length: 3" Protection: Options Available
Length	Make-Up: 13.306 in Overall: 18.494 in
Fishing Neck	Diameter: 9.38 in Length: 3.461 in

Operating Parameters

Bit Speed	140 To 300 RPM
Weight-on-Bit	15,000 To 60,000 (lbf) 6,818 To 27,270 (daN) 7 To 27 (Tonnes)
Flow Rate galUs/min	700 To 1450
Hydraulic Horsepower, HSI	1 To 6
Recommended Make-up Torque	61,850 To 79,800 ft/lbs

FEATURES

- Bit design and performance have been certified through the validation process prescribed by IDEAS simulation technology.
- The Stinger's unique conical geometry delivers high point loading to fracture tough-to-drill formations more efficiently.
- Placed on the blade, Stinger conical diamond elements offer improved impact resistance when drilling through inter-bedded formations or when hard inclusions such as chert or conglomerates are encountered.
- The center location of the Stinger conical diamond in the bit enhances its stability to mitigate whirl and other artifacts that waste energy and reduce ROP. The Stinger element also provides an efficient mechanism to drill the very center of the borehole.
- Bit design is available with RockStorm PDC technology. These all-in-one cutters break the paradigm and provide ultimate wear resistance and ultimate impact resistance in the same PDC cutter. As a result, faster drilling rates are delivered while increasing overall run length.

Figure 50: Selected 17 1/2" Bit Design

10.9 Hydraulics

Hydraulics was extremely critical for this section for hole cleaning & was one of the most important element which decides successful casing running. The maximum planned mud weight was 1.48 S.G at section TD so hydraulics simulation were performed at maximum mud weight as bit pressure drop was not critical for this section. Main highlights of hydraulics simulations were:

- Hydraulic simulations were performed at following fann readings:
  - Fann 3: 10.0 lbf/100ft2
  - Fann 6: 13.0 lbf/100ft2
  - Fann 100: 34.0 lbf/100ft2
  - Fann 200: 55.0 lbf/100ft2
  - Fann 300: 68.0 lbf/100ft2
  - Fann 600: 100.0 lbf/100ft2
- Expected flow rate was 3000-4200 LPM and there was no limitation seen on hydraulic system.
- Bit TFA selected was 1.553 in2 (9 x 15/32" nozzles0
- Section was planned to be drilled using 7" pump liner (4500 LPM & 220 Bar stand pipe pressure limit)
- Figure 51 below shows pressure drops & ECD's at different flow rates.
- Figure 52 shows ECD at different ROP's & flow rates.
- Figure 53 shows Hole Cleaning Index (HCI).

Pump Flowrate:	4000.0	3000.0	3120.0	3240.0	3360.0	3480.0	3600.0	3720.0	3840.0	3960.0	4080.0	4200.0	L/min
Reamer flowrate(Total):													L/min
Motor Pwr Section Flow:	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	L/min
Motor Bearing Flow:													L/min
Bit Flowrate:	4000.0	3000.0	3120.0	3240.0	3360.0	3480.0	3600.0	3720.0	3840.0	3960.0	4080.0	4200.0	L/min
Pressure Drop:													
Surf. Eqpt:	16	10	10	11	12	12	13	14	15	15	16	17	bar
Inside Drillstring:	83	52	56	59	63	66	70	74	78	82	86	90	bar
MWD/LWD:	43	25	27	29	31	33	35	37	40	42	45	47	bar
Motor/RSS/Turbine:	10	5	6	6	7	7	8	8	9	9	10	10	bar
Flow Restrictor:	0	0	0	0	0	0	0	0	0	0	0	0	bar
Bit Nozzles:	34	19	21	22	24	26	28	29	31	33	36	38	bar
Annulus:	6	7	6	6	6	6	6	6	6	6	6	6	bar
Chokeline:	0	0	0	0	0	0	0	0	0	0	0	0	bar
Hydrostatic Imbalance:	0	0	0	0	0	0	0	0	0	0	0	0	bar
TOTAL:	191	118	126	134	142	151	160	169	178	188	198	208	bar
RSS Pads:													bar
ECD:													
ECD at Bit:	1.5104	1.5152	1.5145	1.5138	1.5131	1.5125	1.5120	1.5115	1.5110	1.5105	1.5102	1.5098	g/cm3
ECD at Shoe:	1.5068	1.5119	1.5112	1.5104	1.5097	1.5091	1.5085	1.5079	1.5074	1.5069	1.5065	1.5061	g/cm3
ECD at 2215 m:	1.5104	1.5152	1.5145	1.5138	1.5131	1.5125	1.5120	1.5115	1.5110	1.5105	1.5102	1.5098	g/cm3

Figure 51: Pressure drops & ECD's at different flow rates

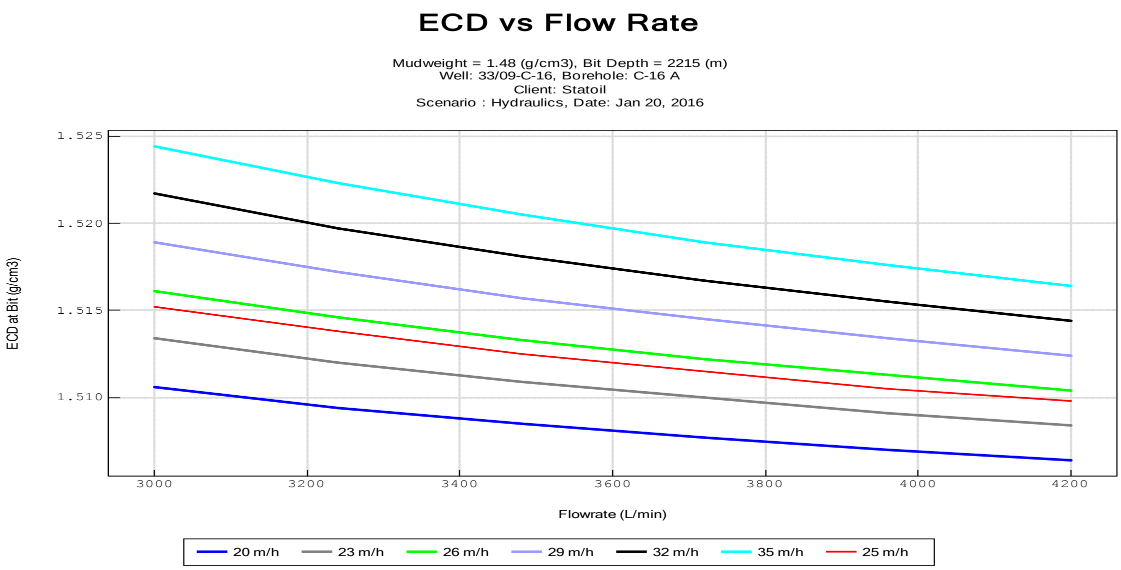

Figure 52: ECD at different flow rates

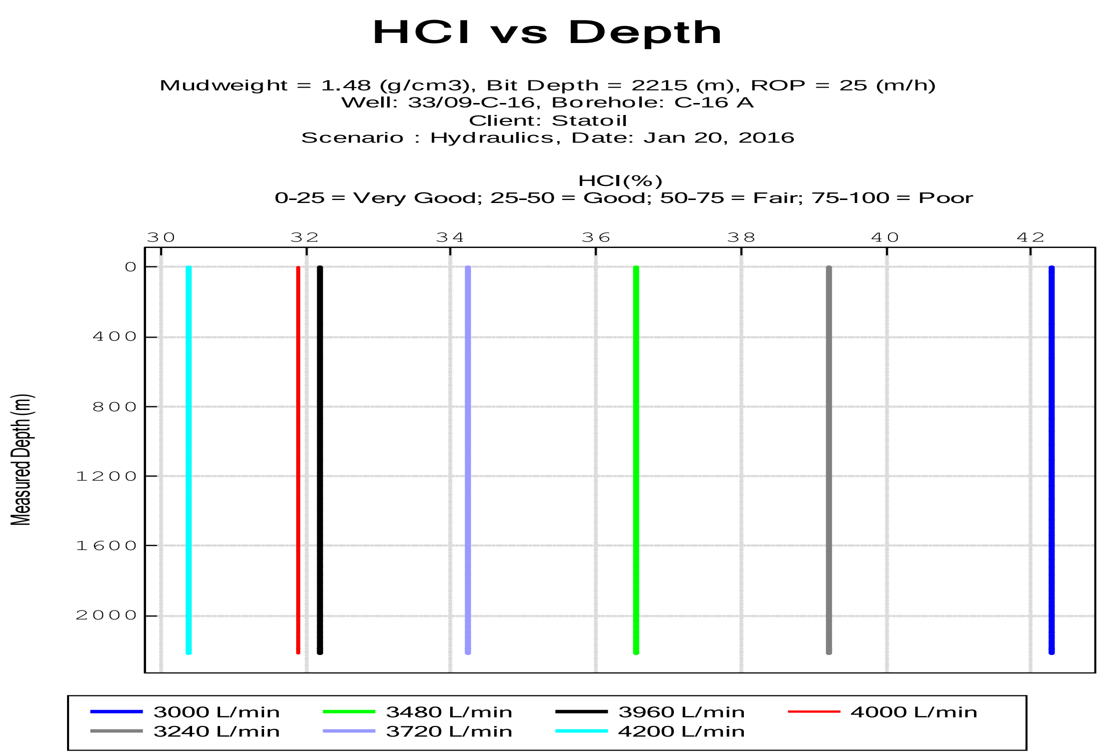

Figure 53: Hole cleaning Index

Hole Cleaning Index in figure 53 clearly shows that hole cleaning was good upto 25 m/hr ROP. At 3000 LPM HCI was ~43% which still provides good hole cleaning. Typically following criteria is used to assess hole cleaning using HCI.

- ❖ 0-25%; Very good hole cleaning
- ❖ 25-50%; good hole cleaning
- ❖ 50-75%; satisfactory hole cleaning
- ❖ 75-100%; Poor hole cleaning

10.10 T&D

T&D simulations are hear & soul of an ERD well and define the rig limitations. On C-16A ERD well T&D simulations showed no rig limitations at TD in 17 ½" section. Below are the parameters used for running T&D analysis:

- ❖ Open & cased hole friction factors used: 0.20
- ❖ Hook load: 40 tonnes
- ❖ WOB: 10 tonnes
- ❖ Torque: 5.00 KN.m
- ❖ Over pull: 20 tonnes
- ❖ BHA: As already shown

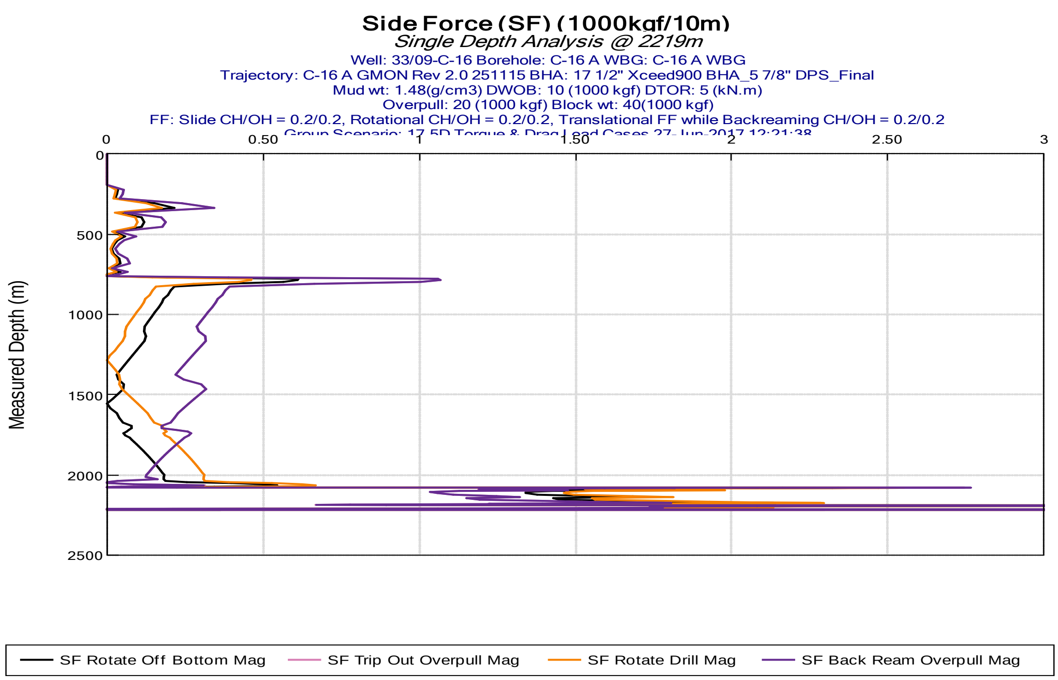

Figure 54: Side forces

Side forces plot is shown above in Figure 54 where it is clear that no abnormal side forces were expected in this section. Side forces are considered as normal as long as it is below 2 KN/Joint.

Below in figure 55 Von Mises stresses are shown which are well below 60% yield stress of pipes even while backreaming.

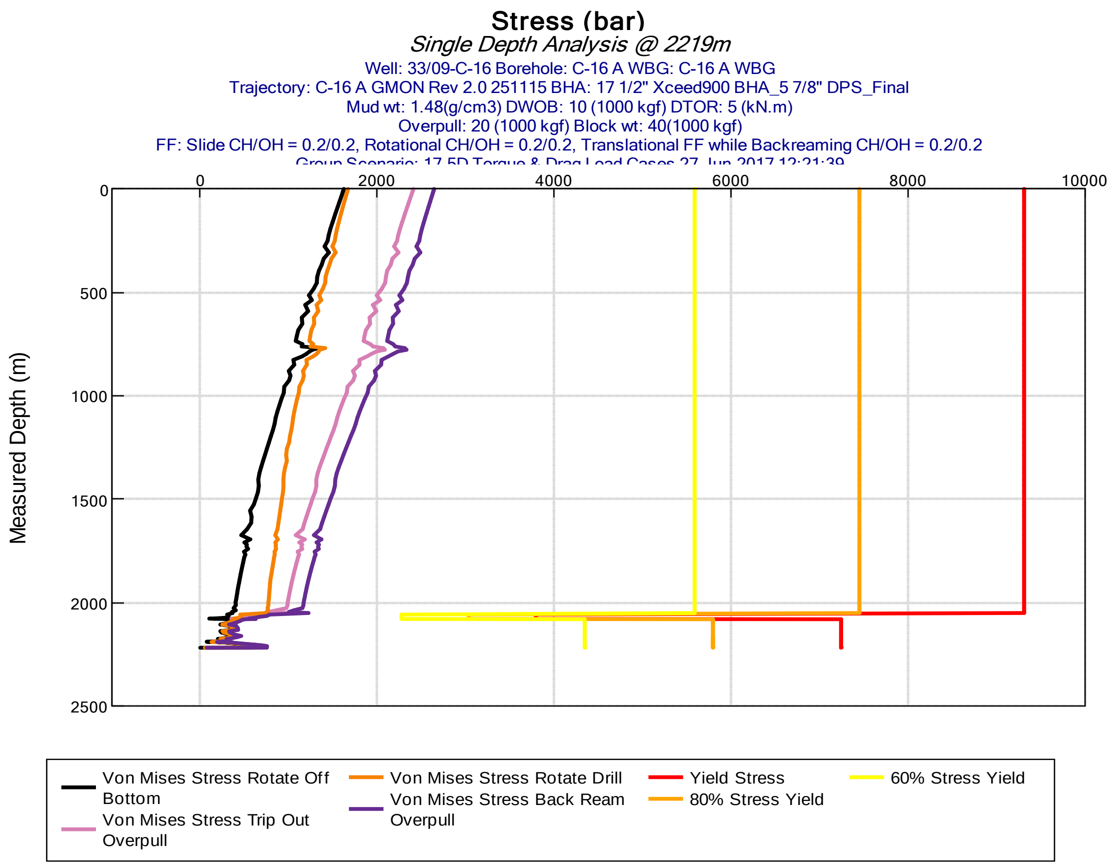

Figure 55: Von Mises Stresses

Below Figures 56 & 57 show tripping road map and off-bottom surface torque respectively. Both surface torque & hook load are well within rig specifications.

Figure 58 showing buckling margins, no risk of buckling & sufficient margins available.

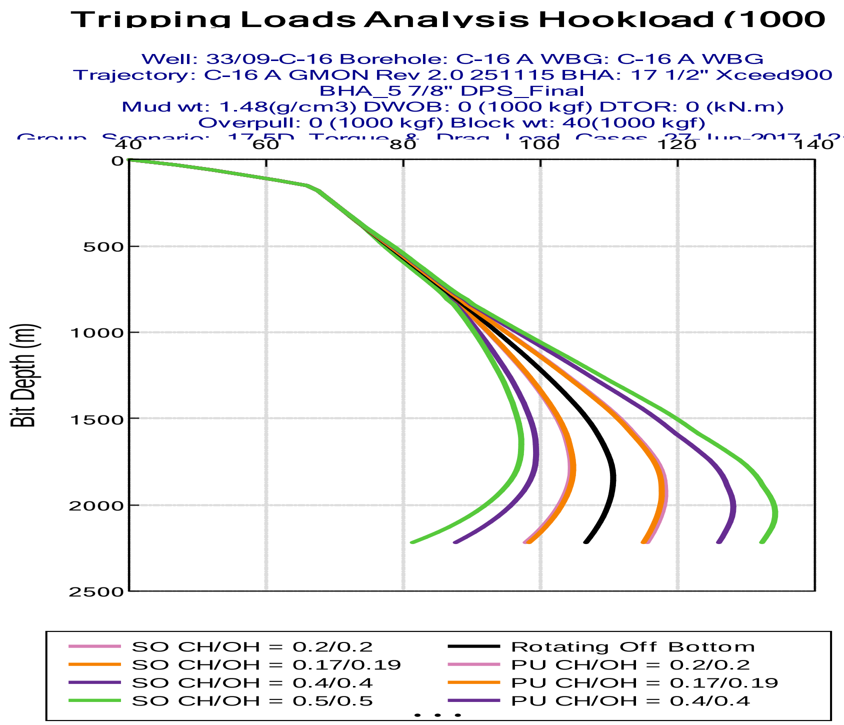

Figure 56: Tripping Road Map

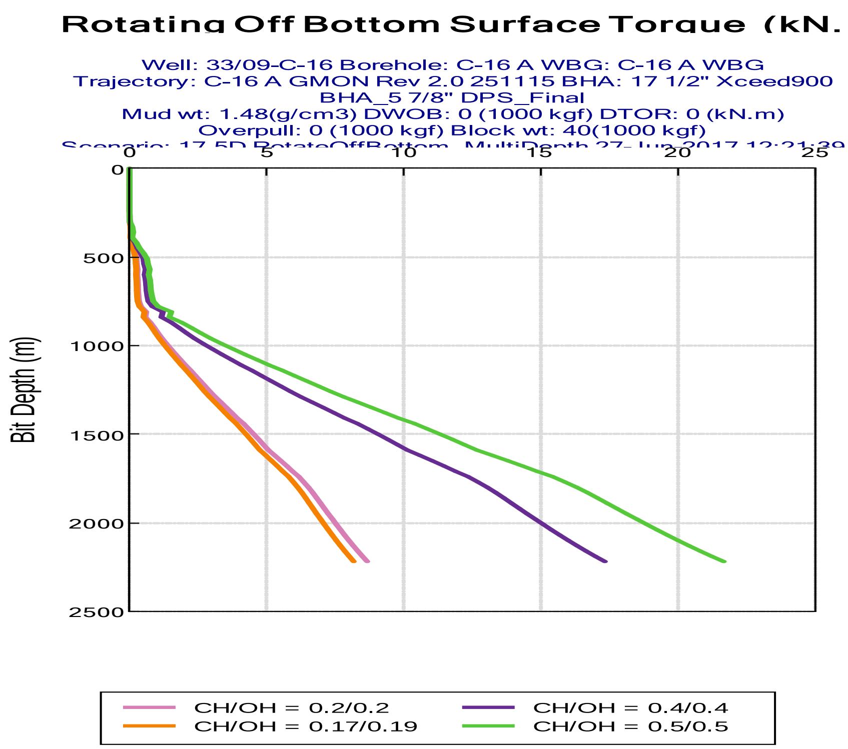

Figure 57: Rotating off bottom surface torque

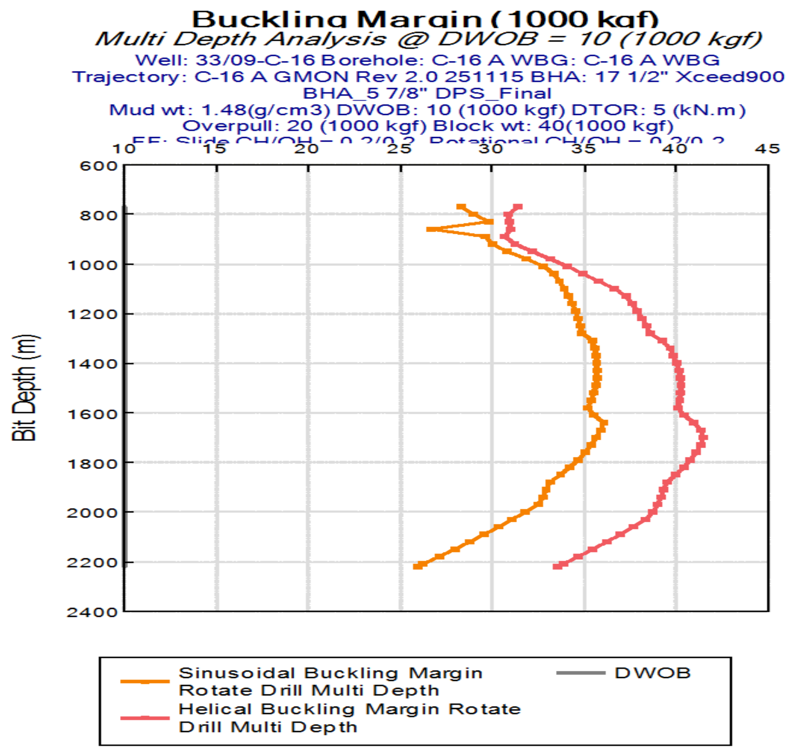

Figure 58: Buckling margins

11 17 ½" Section-Execution

11.1 Drilling Operations Sequence

Main highlights & sequence of drilling operations conducted as follows [1] & [6]:

- ❖ The 40m of cement was drilled out inside 20" casing using 60-80 RPM, 3000-3200 LPM fluid flow, 5-10 tonnes WOB and 10 m/hr ROP.
- ❖ Initiated Kickoff 2m below the 20" casing shoe based on offset experience. The WOB decreased intermittently, indicating patches of soft cement. After drilling down one stand, a checkshot survey was made, which showed that the bit followed the mother well due to bad cement quality resulting in not able to Kickoff.
- ❖ Before tripping out, the hole was circulated clean with 4400 LPM to prepare for a new cement plug. In the second run, the cement was found to be soft and it was decided to wait 5 hours to obtain harder cement for a successful kick-off. The well kicked off successfully with 2700 LPM, 60 RPM, and 10 tonnes WOB as planned. Figure 59 & 60 show divergence from mother well in first & second run respectively.
- ❖ The initial parameters used when drilling were 25-32 m/hr ROP, 4150 LPM and 120-140 RPM. In the shallow low angle part of the well (At < 1500m TVD and inclination < 30^0) drilling was performed with 4150 LPM and 140 RPM. After 1500m TVD the flow rate was reduced to 4000 LPM, due to problems with mud pump pop-off (releasing 30 bar lower than specification), and RPM was increased to 160. Figure 61 shows possible wash outs in the sand area with low ROP.
- ❖ At 2015m MD/1824m TVD, when inclination was above 65^0, the RPM was increased to 180. ROP was held between 15-20 m/hr mainly limited by cuttings reinjection (CRI), and then reduced to 10 m/hr the last stand.
- ❖ At TD the hole was cleaned with maximum flow (limited by pop-off) and rotation. Circulated well clean with 180 RPM/5-6 KN.m torque, 4000 LPM/194 bar SPP while reciprocating string. Amount of cuttings decreased significantly after first BU. Minor amounts of cavings observed

initially, then increasing percentage of small, blocky cavings as the well was cleaning up. Total circulated volume: 1350 m3 (4.2 x BU). The RPM was then reduced to 120.

❖ Reduced to 120 RPM after four BU due to an impression that these cavings were produced due to heavy rotation during the attempt to circulate the well clean, the well was observed cleaning up to an acceptable level after approximately 5.2 x BU. At this stage no noticeable change was observed when continuing to circulate until a total of 5.6 x BU (7hrs 30 min of pumping and rotating). Very little to zero shock and vibration was recorded from the downhole tools during circulating clean.

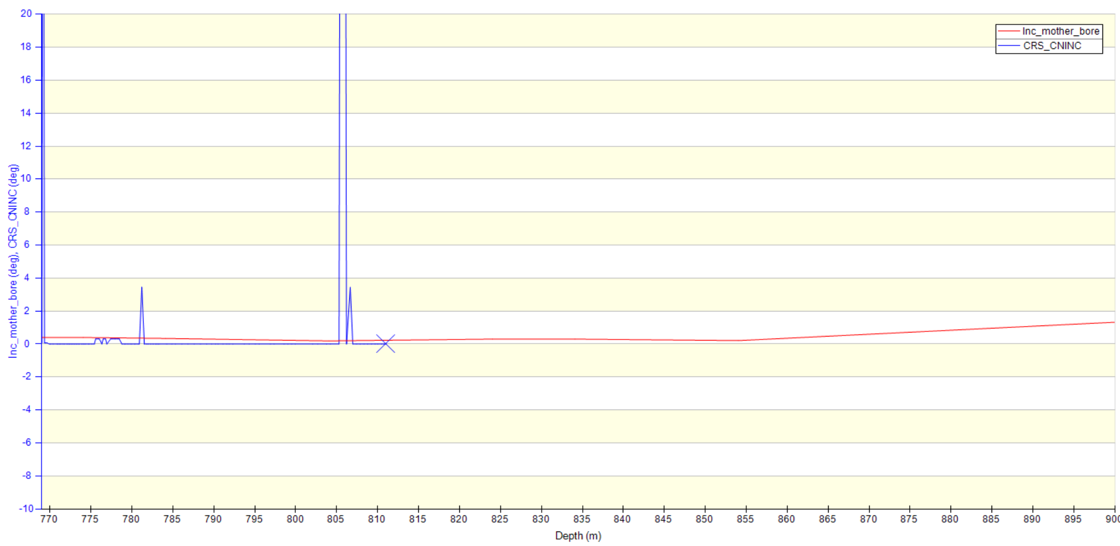

Figure 59: Divergence from mother well, first run

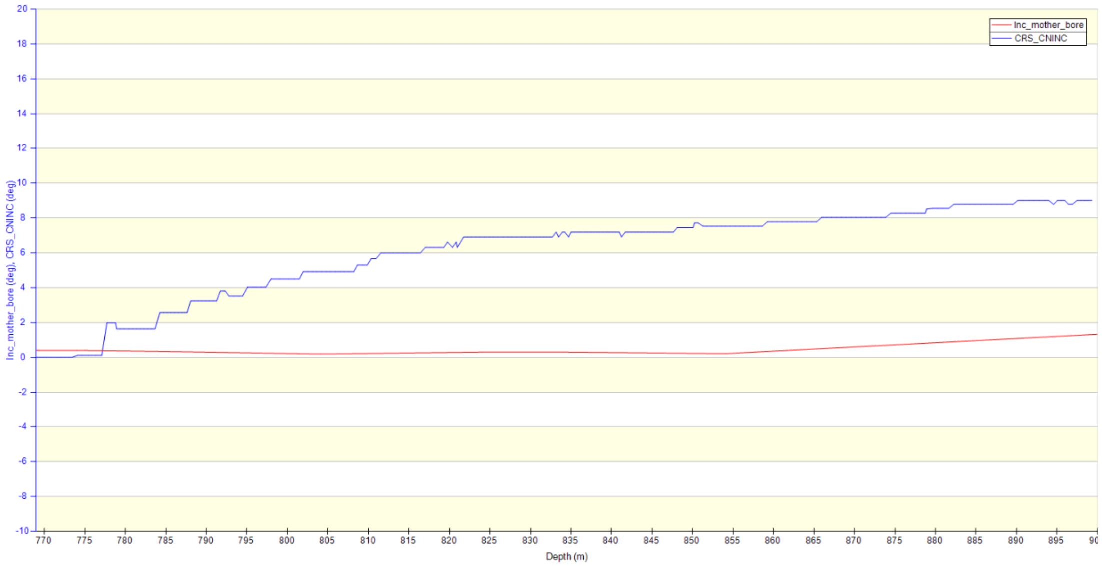

Figure 60: Divergence from mother well, second run [1]

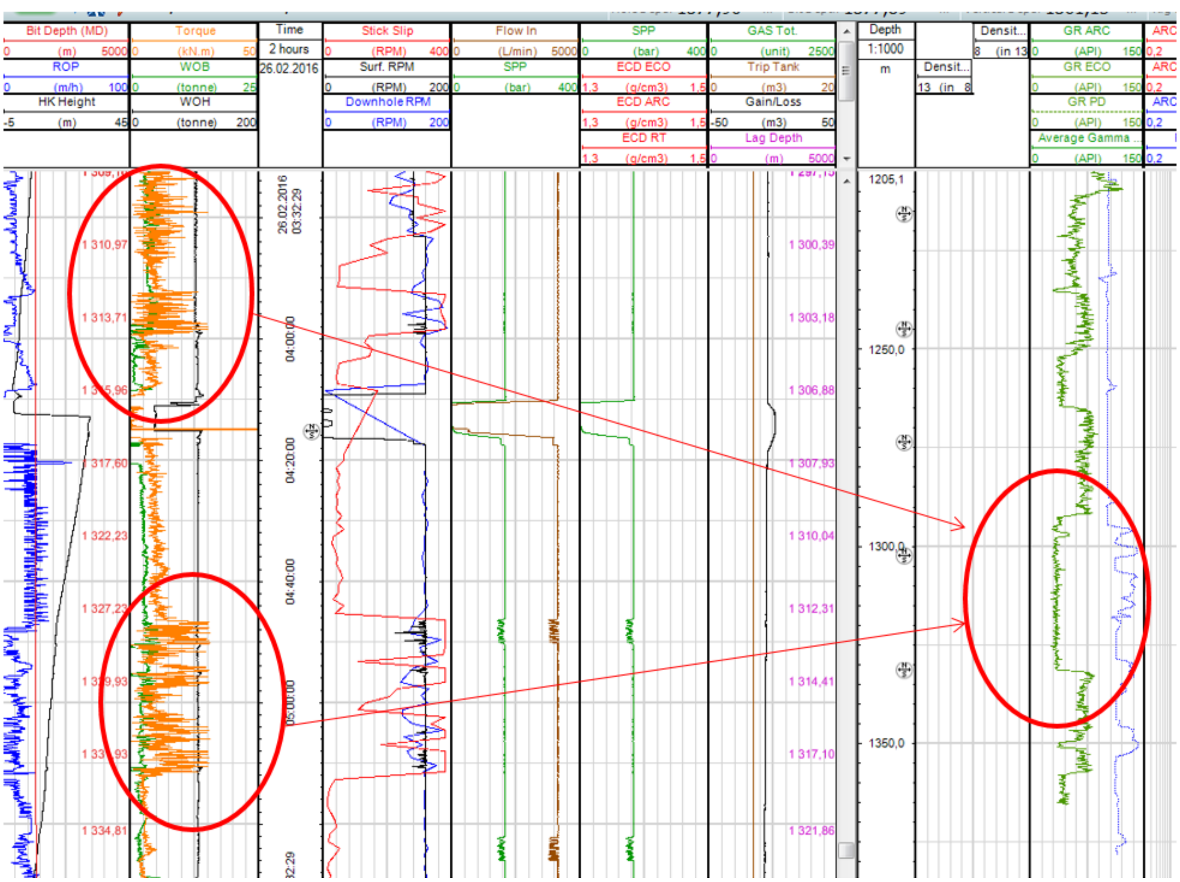

Figure 61: Possible wash outs in the sand area with low ROP [6]

11.2 Tripping out of hole

Main highlights & tripping sequence was as follows [6]:

- When attempting to POOH (after 15 BU) the string took 20 tonne Overpull. It was decided to continue circulation with 4000 LPM and 160 RPM while reciprocating between 2200-2184m MD before it was decided to backream out of hole (BROOH) to 1830mMD (50° well inclination). BROOH was not planned upto 30° well inclination due to high amount of stringers from 1800m MD and upto Hordaland sands.
- Backreaming parameters were selected as per Statoil best practice. BROOH was performed without any pack-offs or losses but a lot of cavings from all formations was seen when backreaming. After reaching 1830m MD backreaming was stopped, and 2.5 BU was circulated with 160 RPM and 3980 LPM while reciprocating.
- Still a significant amount of mechanical cavings were coming over the shakers. The RPM was then reduced to 120 for 1.5 BU. The similar amount of cavings was seen when reducing the RPM. Tried to POOH three times, but took 20-25 tonnes overpull.
- It was then decided to backream up to 20” casing shoe without any stops to circulate hole clean. Due to the steady amount of cavings, and the low inclination at this depth (less than 40° inclination), the RPM was reduced to 60-100.
- Continued backreaming until 1150m MD from where straight POOH on elevator was possible. At this depth two BU was circulated with 4350 LPM and 80 RPM while reciprocating. Significant amount of larger cavings was seen during circulation. String was pulled to surface.
- No shocks or stick slip were observed on the tools while backreaming the hole. When the BHA was on the surface, the tools and bit were found to be in good condition and the hard facing on the stabilizers were intact [1].

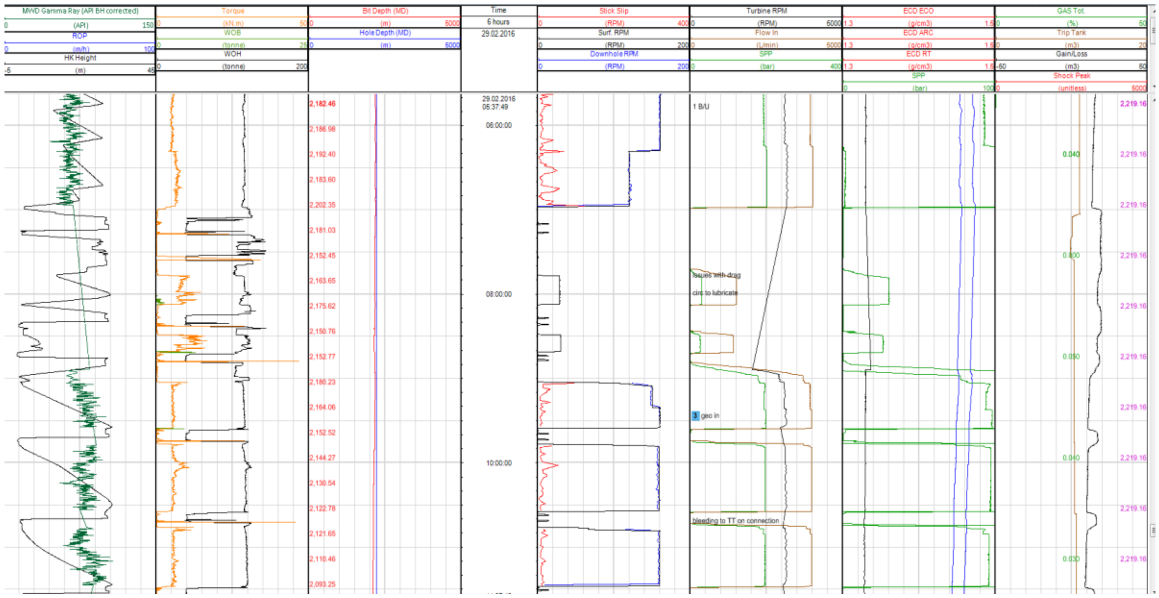

Figure 62: String stalled out while backreaming @ 2038m MD as entering stringer with top stab [6]

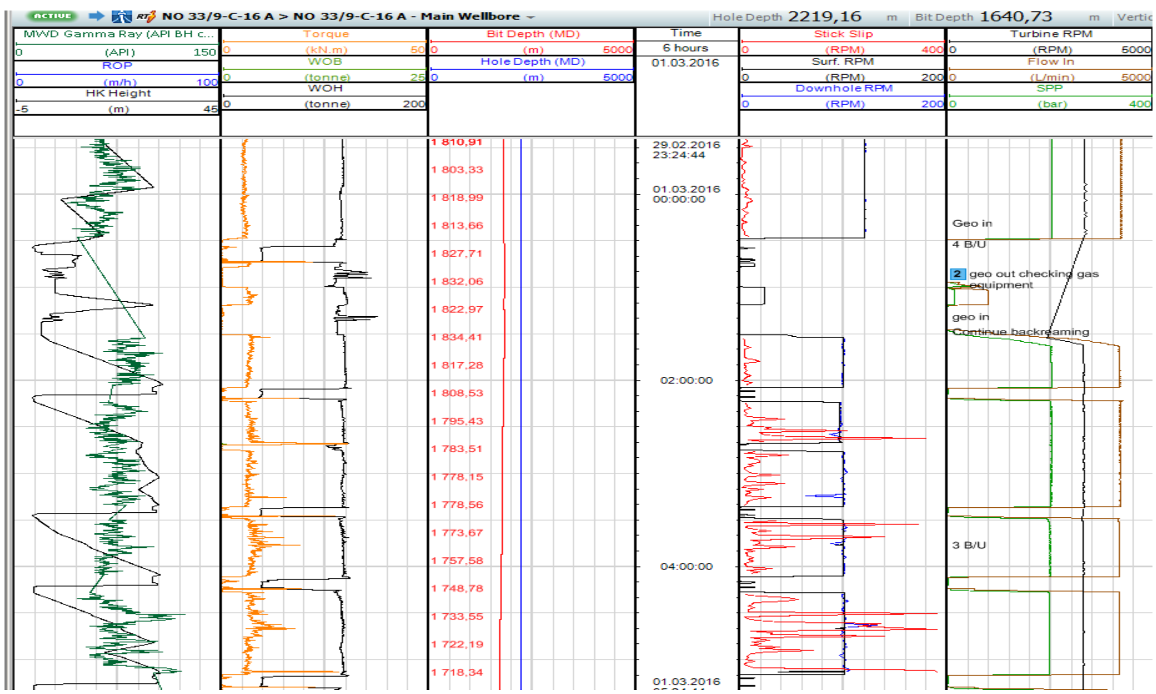

Figure 63: RIH to 1816m MD and attempted three times to pull with no rotation/circulation - no go. Taking weight @ 1798 & 1796m MD experiencing 20-25 tons overpull [6]

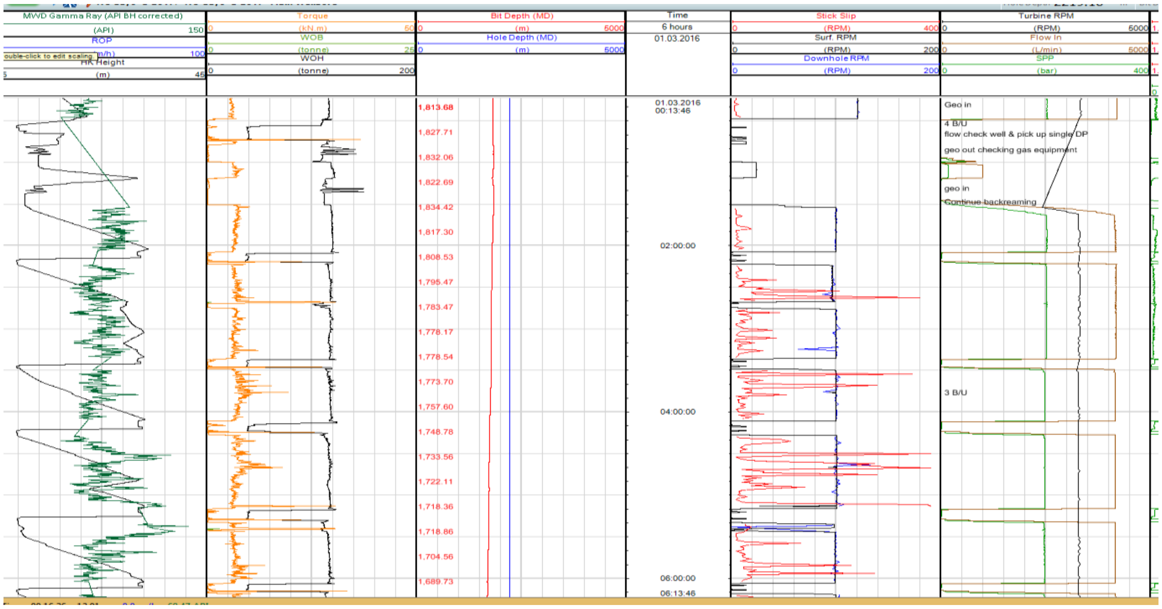

Figure 64: Stringers at 1778, 1732 &1691m MD. Backreamed - worked over stringer area two times [6]

Figure 65: Bit condition after POOH

Figure 66: Stabilizer condition after POOH

11.3 Casing Running

Main highlights of casing running were as follows [6]:

- ❖ The casing consisted of 200m 13 ⅜" casing at bottom with a standard tapered nose and then 1500m of 13 ⅝" casing crossed back to 13 ⅜" casing. Centralizers program consisted of 400m with double centralizers on each joint.
- ❖ No problems RIH with casing until 1825mMD/1722mTVD (50° inclination), where first restriction was met. The problem area corresponded with the first circulation depth during backream. After almost 24 hrs of working casing with 2500 LPM and +/-100 tonnes, the casing passed the problem zone. The restriction is believed to come from a combination of cuttings/cavings bed and a ledge created when reciprocating across the area.
- ❖ After passing 1850mMD the casing was steadily washed down with ~1500 LPM until 2050m MD where a new restriction was met. Due to increasing

SPP the flow had to be reduced to 700 LPM to avoid the risk of fracturing the formation. Continued washing down casing until 2150m MD/1870m TVD (75° inclination) where pack-off was experienced. From this point the casing had to be worked and lubricated down to TD with 200 LPM and up to 130 tonnes down weight. The casing was continuously pulled up to make sure casing was free. High up weights (300 tonnes) and several pack-offs were experienced when working casing down towards TD.

❖ Once at TD the long process of establishing flow was initiated. At first only 700 LPM was established before pack-offs was experienced. Decided to land the casing and establish flow in much slower steps, about 20-25 LPM/20min steps until able to establish 1100 LPM before the hole packed-off again. Cement job was carried out with not much success.

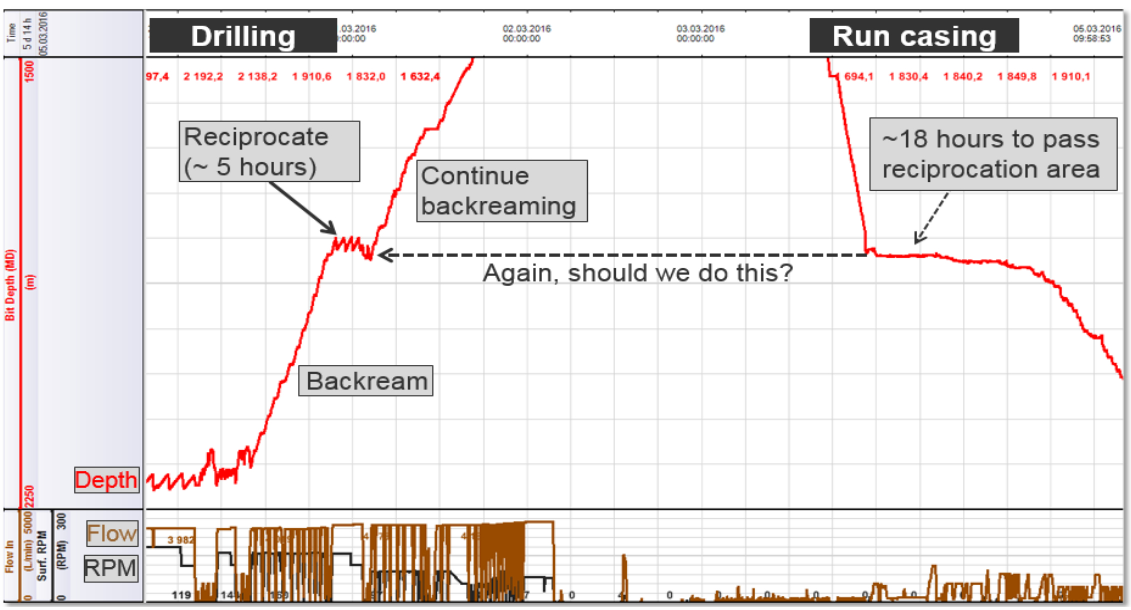

Figure 67: Drilling & casing running [6]

11.4 Actual BHA used

Based on risk assessment GWD40 was dropped from the BHA prior to operation to save cost and minimize connection time. Figure 68 shows actual BHA used in this section. This changed the survey program as per Figure 43.

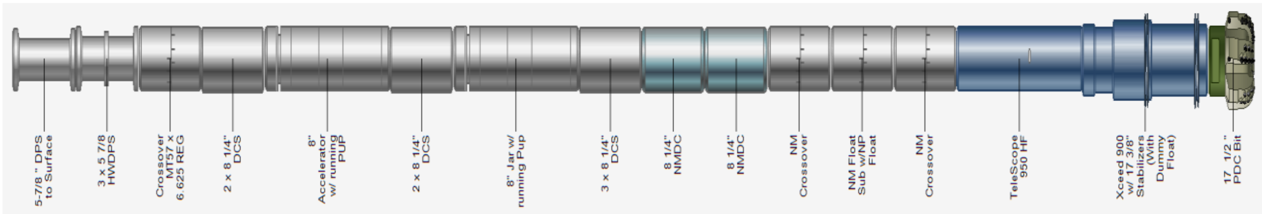

Figure 68: 17 ½" section actual BHA used

11.5 Lesson Learned

Following lessons were learnt in 17 ½" section:

- ❖ Renting an additional pump was very useful in this well. The downside was mainly that it could not be used continuously while drilling and backreaming. This was due to overheating of the pump, and that the driller could not control the pump in case of pack offs where the flow needs to be adjusted down quickly. For any future ERD wells it is recommended to rent a pump that can be used continuously without overheating and it should be possible for the driller to control it or at least have an emergency stop.
- ❖ Regarding RPM, it is well known that higher RPM gives better hole cleaning but sometimes this comes with the cost of mechanical cavings. In the 17 ½" section the average ID was calculated to be 19.2" after seeing a lot of mechanical cavings when backreaming with 180 RPM. The cavings means that more cleaning is necessary to get these outs. But more importantly the increased ID means that the annular velocity goes down and the hole cleaning becomes worst. The experience from this well is that 180 RPM should be used only while drilling. Once the bit is at rest, or pulled of bottom, the RPM should be reduced to maximum 140. For Statfjord the only exception is Shetland (not including Våle formation), which showed to handle high RPM. Although on this well the backreaming in Shetland was mainly performed with 160, not 180 RPM.
- ❖ BHA design proved very successful for hole cleaning, directional control & cuttings removal.

- Cement plug Kickoff was unsuccessful in first attempt due to poor cement quality. One of the possible cause was no cleanout trip prior to cement plug placement. Therefore it is rrecommended to have dedicated cleanout trip before cement plug with enough weight on cement (WOC).
- Extended WOC really helped in second Kickoff attempt. Always use highest possible WOB, 60-80 RPM and minimum possible flow rate (stable RSS tool face is very important). PowerDrive Xceed proved the most successful tool in kicking off from narrow window cement plugs.
- Xceed helped to provide smooth DLS at KOP which helped to minimize side forces & casing wear.

12 12 ¼" Section-Planning

12.1 Planned Objectives

The planned objectives for 12 ¼" section were [6]:

- ❖ This was a long nearly horizontal section through remaining Lista and Shetland, approximately 6000m MD long. Inclination will build to 87° from beginning and hold until Middle Shetland, then dropping the angle to 37 deg at TD. Mud weight (MW) used will be 1.58 S.G.
- ❖ 12 ¼" Section was planned to be drilled in two runs, which could result in top Shetland open for more than 2 weeks. Shetland is a tight claystone and expected to be stable.
- ❖ Hole cleaning will be the main challenge and main focus in this section.
- ❖ TD was planned to be set on depth in the lower part of Shetland group, before reaching the thin Mime formation. It is important to set TD before entering the reservoir. Losses are almost certain with too high mud weight for the depleted reservoir if penetrated accidently.
- ❖ Fault in Lista formation was prognosed between 2315-2395m MD is and planned to be drilled perpendicular to the fault plane, which was a less unstable direction than along the fault plane. Drilling practice was planned to be optimized in the zone of interest.
- ❖ Long floated liner will be run after the section is drilled. Excessive mechanical work needs to be avoided.
- ❖ Refer to Figure 41, 42 & 43 for well trajectory & survey program.

12.2 Drilling Challenges

The 12 ¼" was 6000m long, where majority of it was at 87° inclinations, and was regarded to be the most challenging part of the well. Several meetings and discussions were held to identify potential risks, and accommodate for them by either reducing, eliminating or balancing the risk [6].

The key risks identified were:

- ❖ Hole cleaning

Hole cleaning presented the greatest risk in the 6000m long 12 ¼" section while keeping limitations in mind, including pump liners and maximum pop-off pressure. The 6 ½" pump liner was to be used in the first run with maximum flow capacity of 3700 LPM and pop-off pressure of 275 bar. The 6 ¼" pump liner was to be used in the second run with a maximum flow capacity of 3400 LPM and pop-off pressure rating of 300 bar. To cope with the hole cleaning challenges, point-the-bit RSS (Xceed), 2100m of 6 5/8" drill pipes in the second run and mud rheology readings were of prime importance. The plan called for drilling the first part of the 12 ¼" section with 3300-3600 LPM flow rate and the second part with 3300-3400 LPM flow rate. BROOH was planned for the second run to help float the 9 5/8" liner [1]. As a risk reducing measure an HT400 pump was planned to be installed on the deck to boost flow in shorter time periods when necessary. The pump would also help with cutting re-injection system, which is normally a bottleneck for fast drilling on Statfjord [6].

❖ High torque & drag

Torque and drag is one of the main challenge on ERD wells. On Well C-16A, road maps were developed with different friction factors. Monitoring torque and drag trends on each connection and the use of lubricants were the main control measures. Torque and drag simulations were performed with different levels of tortuosity in the wellbore and worst case scenarios were established in the planning stage. Based on offset well experience, the average expected friction factor was 0.2-0.25 in both the open and cased hole. Drillpipe buckling was another concern, especially rotating with buckled pipes. The planned torque and drag results were found to be within rig capabilities [1].

❖ Backreaming

Backreaming is a debatable topic in ERD wells but has been proven successful in that it helps in floating liner and casing. It has almost become industry practice that backreaming is considered as being required for casing and liner floatation. The well plan called for backreaming the entire 6000m section to ease liner floatation. Backreaming poses various risks to wellbore quality and downhole tools. Close monitoring of tool shocks and vibrations and formation cavings on shakers help to optimize backreaming parameters and speed the drilling operation. The plan for this well was to backream at full drilling parameters unless any issues were encountered [1].

- Tortuosity

  Tortuosity in long laterals can induce abnormal torque and drag and issues in running and floating liners. Tortuosity can also result in an increase in pickup weights, a reduction in buckling margins, and an increase in side forces. To establish worst-case scenarios, tortuosity of 0.75°/30 m in tangent and vertical sections and 1.5°/30 m in build and drop sections was added in the planning phase. The Xceed hold inclination and azimuth (HIA) mode, which allows for automatic downhole control for both inclination and azimuth to minimize tortuosity, was planned for use in the long lateral with a setting control at 50% of the maximum steering force for smooth recovery if the formation deflected the BHA from the desired trajectory.

  High-Resolution continuous surveys methodology was also run in parallel to evaluate any additional signs of tortuosity. Defining the well path with just one station per stand is often not enough to capture the real characterization of the well, leading, in some scenarios, to well engineering simulations misinterpretation due to the unseen extra tortuosity not applied in the torque and drag analysis. The processing uses a software designed to merge the static MWD or RSS data with the continuous single-axis data to provide a more refined definition of well path with the stations defined every 3m (10ft). The continuous data is filtered out by noise or telemetry bandwidth issues and finally checks that the new High-Resolution inclination agrees with the static inclination at the same depth stations [1].

- Unable to drill to TD

In the planning phase, it was identified that there is a possibility of not being able to drill the 12 ¼" section to TD, either due to rig limitations (top drive), high torque and drag, or hole instability. Studies from ERD contractors and experience transfer from partners helped to establish guidelines and road maps for drilling the section to TD. The BHA was simplified and optimized, and the wellpath was expected to have minimized torque and drag [1].

- Well surveying

  To satisfy operator's surveying technical requirements, fulfill the critical survey program for target sizing as well as be able to capture any unintended gross error in the surveying measurements it was planned to:

  - Verify first run MWD surveys with GWD with sufficient overlap.
  - Verify the second run MWD surveys with first run MWD surveys by taking 10 MWD surveys in second run.
  - Drop gyro as contingency.
  - Perform Multi-station analysis (MSA) in both runs to ensure that sensors' scale factors and biases were within the specifications.
  - Perform Dual Inclination processing. This analysis requires the comparison of both continuous inclination from the MWD and RSS tools as well the MWD's static inclination; the analysis passes if 95 % of the delta inclination between the RSS and MWD measurements are within +/- 0.18 deg inclination [Berger, P.E. et al. (1998)]. In both runs the processing passed the criteria and the Dual Inclination error model was applied on Statfjord for the first time which helped in TVD assurance.

  Additionally to reduce any Non Productive Time (NPT), an additional stand pipe pressure transducer (SPT) was installed to improve signal strength and ensure that the MWD data will be well transmitted to surface [1].

- Barite sagging

  Sagging refers to when weighing material in mud, which is added to give it the required density (referred to as mud weight), settles at the bottom of the wellbore causing the mud weight to drop. This can result in wellbore instability or hole collapse. Sagging had however not been a significant problem on the shorter wells drilled on Statfjord, but it was known that this risk becomes larger in the longer sections. To mitigate this risk it was planned to change from standard Versatec mud to the newly developed Rheguard mud that was less prone to sagging. The main reason for the change was the wider spectre the Rheguard mud had, meaning that the properties of the mud could always be manipulated to that of Versatec. Simulations from the two external companies MI-Swaco and IRIS also showed that the hole cleaning would not be affected by the Rheguard planned lower rheology [6].

❖ Liner collapse & negative weight when floating

  Negative weight refers to the scenario when the sliding friction becomes larger than the available slack off weight, rotation then needs to be applied to the assemblies to break the sliding friction and get the assemblies down. Due to this, the heavy weight components in the BHA (Drill collars and heavy weight drillpipe) works against, since they are laying on the low side preventing rotation. In a floating operation however, negative weight could also occur when the buoyancy force is larger than the available slack off weight, in this case rotation will not help [6].

❖ Accidently drilling into reservoir

  Accidentally drilling into the reservoir on Statfjord would result in an immediate lost circulation scenario, and might cause loss of section. The survey uncertainties at 8200m MD, as well as the increased geological uncertainty at a less familiar area of the field, increased the probability of this risk. To limit this risk, TD was set shallower than what is normal on Statfjord, and a high focus was put on the surveying [6].

❖ Tubular Logistics

  Since 12 ¼” section was planned to be drilled in two runs therefore racking capacity was used to set the TD of the first run. A two run strategy would also make it possible to take learnings from the first run and apply the appropriate measures into the second run. Therefore, two sets of drill pipes were reserved and inspected to the highest level (DS-1 cat 5). One set consisted of a continuous string of 5 ⅞" drill pipes, and the other was a reversed tapered string with 3000m of 6 ⅝" drill pipes at bottom and 5 ⅞" to surface. If hole cleaning was the main problem, the 6 ⅝" drill pipe would allow for higher flow rate and annular velocity. Should torque be the main issue, the smaller 5 ⅞" drill pipe would be the preferred choice [6].

- ❖ Drilling Hard Stringers

  Another challenge that was expected in 12 ¼" section were possible hard stringers. Therefore bit choice was very critical. The formations on Statfjord are known for being easy to drill, with the exception of the limestone stringers. They are unpredictable, sometimes large in numbers, and can at worse take a day to drill through. With a 6000m section at 87° inclination it could turn into a nightmare. This led to the change from the standard MDi616 bit type that is usually used, to the Z616 (sting blade) that is designed to drill stringers more efficiently. Although the sting blade bit had been used before, the MDi616 have the longest track record on Statfjord [6].

12.3 Survey Program

Survey program is defined in figure 43. GWD90 was planned to be run in first run BHA to verify MWD and check any gross errors, however GWD90 surveys were not planned to be used as definitive surveys since this tool was not approved by Statoil (for definitive surveys) by then. So it was planned to drill this first part of 12 ¼" section (~4000m) using "SLB_DUAL-INC+SAG+DEC" error model in Dox & "Magn, IFR, non-mag, reduced QC, MSA Dual inc" in compass. After verification with GWD90 error model in compass planned to be replaced by "Magn, IFR, non-mag, dual inclination" getting rid of reduce QC. It was also planned to switch GWD90 to out run battery mode (OBM) at TD of first run to get static surveys for longer overlap with MWD. While drilling it was also planned to run MSA (multi-station analysis) & dual inclination processing to implement dual inclination error model and also to avoid MWD Cluster shots.

Similarly in second run MWD was planned to verify with first run MWD surveys by taking 10 overlapping surveys while tripping in hole. After running QC checks and MSA & dual inclination processing “Magn, IFR, non-mag, dual inclination” error model will be used as definitive. The main reason & benefit of using dual inclination processing & error model was to optimize TVD and evaluate wellbore tortuosity. This will be further explained in execution part of this section.

12.4 Risk Register

The main risks & mitigations for 12 ¼” section are as under [7]:

	HAZARD		POTENTIAL RISK			CONTROL MEASURES		RESIDUAL RISK		
	Hazard Description and Worst Case Consequences with no Prevention or Mitigation Measures in Place	Loss Category/ Population Affected				List all Current and Planned Control Measures, taking into Account all Contributing and Escalating Factors				
Activity Steps			Likelihood	Severity	Risk Level	Current and Planned Prevention Measures to reduce Likelihood	Current and Planned Mitigation Measures to reduce Severity	Likelihood	Severity	Risk Level
1. 12 1/4" Section Drilling			H (4)	M (-3)	M (-12)			M (3)	M(-3)	M (-9)
1.1. Poor Hole Cleaning (6000m section, 310 bar Stand pipe pressure limitation)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	S (-2)	M (-6)	- 1. Follow road maps. - 2. Adjust ROP and Optimize RPM & Flow rate as per ERD recommendations - 3. Rheguard mud to be used to minimize pressure drop & to be able to pump more	- 1. Make sure Mud propoerties in Spec. - 2. Xceed to maximize flow rate at TD - 3. ~2000m of 6 5/8ï¿½ï¿½ DPS in 2nd run - 4. Maximum flow rate 3350 LPM at TD of both first & 2nd run as per simulations - 5. 6 1/4" pump liner in 2nd run to have more room at stand pipe pressure to be able to pump more (3400 LPM)	M (3)	S (-2)	M (-6)
1.2. Shock and Vibration (hard stringers)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Schlumberger Schlumberger, Statoil	M (3)	M (-3)	M (-9)	- 1. Optimize & adjust drilling parameters	- 1. Follow SLB shock and Vibration mitigation procedure. - 2. Idrill simulations show stable BHA - 3. Stinger Bit	M (3)	S (-2)	M (-6)
1.3. Hard Stringers	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	M (-3)	M (-9)	- 1. Follow Stringers drilling procedure at the end of this HARC.	- 1. Follow Stringers drilling procedure at the end of this HARC. - 2. central stinger Bit - 3. Idrill Simulations performed	M (3)	S (-2)	M (-6)
1.4. Potential magnetic debris/Foreign material accumulated (casing wear)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	S (-2)	M (-6)	- 1. Ditch magnet to be cleaned in regular intervals (every 06 hrs minimum), material retrieved to be weighted and recorded at regular intervals. Include procedure in DOP - 2. Optimize ditch magnet placement in shaker Box.	- 1. Ditch magnet to be cleaned in regular intervals (every 06 hrs), material retrieved to be weighted and recorded at regular intervals. Include procedure in DOP - 2. Optimize ditch magnet placement in shaker Box. - 3. Wellpath is catenray profile to minimize casing wear.	L (2)	S (-2)	L (-4)
1.5. Pack off around BHA resulting in bellows burst in Xceed	Machinery/Equipment/Hand Tools	Non-Productive Time-->Schlumberger Schlumberger, Statoil	M (3)	M (-3)	M (-9)	- 1. If cement debris or cuttings pack round the Xceed tool, reduce the flow rate and work the pipe until the pressure has stabilized and the pack off is cleared. - 2. DD to discuss this with Driller and ask him to react quickly to reduce flow in case pack off is encountered.	- 1. If cement debris or cuttings pack round the Xceed tool, reduce the flow rate and work the pipe until the pressure has stabilized and the pack off is cleared. - 2. DD to discuss this with Driller and ask him to react quickly to reduce flow in case pack off is encountered. - 3. Differential pressure to burst bellows is 2500 psi. - 4. Include in the DOP.	L (2)	M (-3)	M (-6)
1.6. Abnormal Torque & Drag	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	M (-8)	- 1. Follow road maps. - 1. Statoil Roadmap 2. Use Broomstick chart to track T&D 3. Geoservices to report any deviations on Broomstick chart - 2. Monitor T&D at each connection.	- 1. TDS Torque limits included in QHARC Presentation. - 2. T&D Simulations are within Rig specification with 0.2 friction factor in cased & open hole. - 3. Consider using Lubrucants to reduce friction - 4. Optimize drilling parameters & BHA to minimize sideforces. - 5. Wellpath is Catenary profile to minimize T&D. - 6. Perfform Torque no load test of TDS.	M (3)	S (-2)	M (-6)

1.7. Unable to pump planned flow due to high stand pipe pressure/ECD	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	S (-2)	**M (-6)**	- 1. Follow road maps. - 2. Monitor ECS/ESD with ARC/RT APPO - 3. Rheguard mud to be used to minimize pressure drop & to be able to pump more	- 1. Follow road maps. - 2. Monitor ECS/ESD with ARC/RT APPO - 3. Hydraulics Simulations show normal trend (Refer to attached QHARC presentation for detailed simulations) - 4. Use 6 1/4" Pump liner in 2nd run. - 5. Optimize Mud specs to minimize ECD & stand pipe pressure. - 6. Optimize BHA ID - 7. Xceed tool to optimize flow & minimize bit pressure drop. - 8. Optimize Hydraulics simulations & callibrate during first run.	M (3)	M (-3)	**M (-9)**
1.8. First Run: Unable to POOH on elevators resulting in Back reaming (Tool failure)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. Use Back reaming procedure - 2. Statoil is aware of the risk.	- 1. Use Back reaming procedure - 2. Statoil is aware of the risks. - 3. Backreaming parameters, 2-3 stands/hr, 100-120RPM & full flow has been suggested to Statoil.	M (3)	S (-2)	**M (-6)**
1.9. Hole Collpase resulting in Pack offs & Stuck pipe	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. Follow Road Map & monitor hole cleaning. - 2. Monitor ESD from RT APPO	- 1. Follow Road Map & monitor hole cleaning. - 2. Monitor ESD from RT APPO	M (3)	S (-2)	**M (-6)**
1.10. High side forces & 13 3/8" Casing w ear	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. Well Trajectory-Catenary profile - 2. Max 3.93 DLS in 17 ½" section @ 813m (KOP).	- 1. Well Trajectory-Catenary profile - 2. Max 3.93 DLS in 17 ½" section @ 813m (KOP). - 3. Casing wear simulations attached.	M (3)	S (-2)	**M (-6)**
1.11. Tortuosity in the Well path resulting abnormal T&D	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. Use HIA mode on Xceed - 2. Simulations with Tortuosity has been run & discussed with Statoil for casing & completions running	- 1. P/UP weight increases by ~5 ton at TD, Torque increases by 2-3 KN.m and buckling margin reduces by 2-3 ton. More side forces. - 2. Do NOT run the Xceed above 50% SR in IAH/IAT (Technical Alert) - 3. Added Tortuosity Tangent/Vertical: 0.75 deg/30m Build/Drop: 1.5 deg/30m - 4. Tortuoisty numbers: a) Tangent/Vertical: 0.75 deg/30m b) Build/Drop: 1.5 deg/30m have been added for simulations.	M (3)	S (-2)	**M (-6)**
1.12. 2nd Run: Deteriorating Hole conditions & tool failure due to Back reaming	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. Bit design to assist back reaming - 2. 12 1/8ï¿½ string stabilizer as per Exxon recommendations & Sakhalin experience	- 1. DL Xceed to 100% high side to assist back reaming (Good experience in QATAR) - 2. Statoil recommended procedure (SSC) - 3. Back reaming parameters: 100-120 RPM Full flow 2-3 stands/hr - 4. 6. Reduce RPM when Backreaming inside 13 3/8ï¿½ï¿½ casing - 5. Use HIA mode to minimize tortuosity	M (3)	S (-2)	**M (-6)**
1.13. 2nd Run: Unable to drill section to planned TD at ~8223m MD due to Rig limitations (T&D and hydraulics) and/or hole instability resulting in additional section to reach top of reservoir	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	S (-2)	**M (-6)**	- 1. Well path has been designed to minimize torque and drag. - 2. Feasibility study by K&M & experience transfer from Exxon.	- 1. Well path has been designed to minimize torque and drag. - 2. Feasibility study by K&M/Merlin & experience transfer from Exxon. - 3. Optimized BHA configuration & accurate ID's/OD's - 4. Simulations show no rig limitations - 5. Check surface system/sensors is propoerly callibrated & are in good condition.	L (2)	S (-2)	**L (-4)**
1.14. Sw abbing resulting in hole collapse	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	M (-3)	**M (-9)**	- 1. Update Swab calculations with actual mud rehologies before POOH. - 2. Evaluate the use of actual swab EMW from ARC to callibrate tripping Speed. - 3. GSS Swab calculations	- 1. Update Swab calculations with actual mud rehologies before POOH. - 2. Evaluate the use of actual swab EMW from ARC to callibrate tripping Speed. - 3. GSS Swab calculations	M (3)	S (-2)	**M (-6)**
1.15. Loosing the section and/or poor hole quality due to long section and stopping drilling because of WOW/Boat/Logistics	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. BHA tools mobilization as per Weather conditions - 2. PM in close contact with Statoil Logistics	- 1. Section will start drilling in July. - 2. 6ï¿½ï¿½ Contingency Section.	M (3)	S (-2)	**M (-6)**
1.16. 2nd Run: Setting section TD too shallow (above mime) due to geological & survey uncertainty leaving long overburden section exposed to reduced MW w hile drilling 8 ½" section (1.25 – 1.30 SG)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	S (-2)	**M (-6)**	- 1. Section TD on depth - 2. Ops Geologist on board. - 3. MWD surveys verification & Dual inclination	- 1. Section TD on depth - 2. Ops Geologist on board. - 3. MWD surveys verification & Dual inclination - 4. Darcy Screens	L (2)	S (-2)	**L (-4)**
1.17. 2nd Run: Hole collapse due to long exposure time (P/UP & L/D pipes)-Not able to rack back 6 5/8" DPS (Max racking capacity is 5800m of 5 7/8" DPS)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	S (-2)	**M (-6)**	- 1. Shetland is stable formation - 2. 1.60 SG Mud weight (Rheguard mud)	- 1. Shetland is stable formation - 2. 1.60 SG Mud weight (Rheaguard mud system)	L (2)	S (-2)	**L (-4)**
1.18. Unable to run 9 5/8ï¿½ï¿½ Liner to TD due to high friction in long horizontal section- stuck liner adding additional 8 ï¿½ï¿½ section to reach top of reservoir	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. Liner is floated to reduce drag - 2. Ultralube II(e) upto 3% in the system, Statoil plan is to add this lubricant if any issues seen or at end of first run (but lubricants disturb mud properties)	- 1. Liner is floated to reduce drag - 2. Ultralube II(e) upto 3% in the system, Statoil plan is to add this lubricant if any issues seen or at end of first run (but lubricants disturb mud properties)	M (3)	S (-2)	**M (-6)**
1.19. First Run: Unable to verify MWD due to GWD90 failure w hile drilling/OBM failed after POOH	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. It was proposed to drop SDI ADK gyro regardless	- 1. Follow Gyrodata procedures - 2. SDI ADK Drop gyro on board as a backup - 3. Totco in the BHA (both runs) to accommodate drop gyro - 4. Option of verification in 2nd run as well	M (3)	S (-2)	**M (-6)**
1.20. Surveying & use of SDI ADK Drop gyro for the first time	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	M (-3)	**M (-9)**	- 1. SDI ADK drop gyro in the first run-Follow SDI running procedure.	- 1. SDI ADK drop gyro in the first run-Follow SDI running procedure. - 2. MWD in 2nd run to be verified with first run surveys (agreed with Statoil)	M (3)	S (-2)	**M (-6)**
1.21. Tool failure (long section)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Schlumberger Schlumberger, Statoil	H (4)	S (-2)	**M (-8)**	- 1. Test tools at first filling of pipes (~1000m) in the first run - 2. Test tools in the 2nd run at first filling (~1000m) - 3. After POOH in first run, send one set of fresh backup of tools.	- 1. Meeting has been conducted with R&M emphasing on criticality of the section. Actions items are being worked on to ensure high SQ in the section. - 2. Dedicated Drillout run to cleanout cement/floats inside 13 3/8ï¿½ï¿½ casing	M (3)	S (-2)	**M (-6)**
1.22. Weak MWD signals	Machinery/Equipment/Hand Tools	Non-Productive Time-->Schlumberger Schlumberger, Statoil	M (3)	S (-2)	**M (-6)**	- 1. Identify and avoid noisy pump strokes - 2. Adjust pump strokes - 3. Switch to the lower bit rate	- 1. Signal strength prediction performed by FSM looks good at given conditions - 2. 3rd SPT is being installed - 3. Toggle delayed surveys - 4. OSC to assist if necessary - 5. Consider having smaller gap TeleScope as 2nd backup	L (2)	S (-2)	**L (-4)**

1.23. Problems during downlink to Xceed	Machinery/Equipment/Hand Tools	Non-Productive Time-->Schlumberger Schlumberger, Statoil	M (3)	S (-2)	M (-6)	- 1. MWD engineer and DD to work closely to ensure decent MWD signal prior to perform D/L to the tool - 2. Use a back up FSL for lower bit rate	- 1. 36 sec downlink bit period was very successful, no downlink was missed (Sakhalin experience) - 2. Use a back up FSL for lower bit rate - 3. Reduce flow-rate change to 10 % - 4. Make sure tool accepts commands	L (2)	S (-2)	L (-4)
1.24. Landing well @ wrong TVD/missing a target/accidently drilling into reservoir due to survey uncertainty (TVD)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	M (-3)	M (-9)	- 1. Driller target is 23 x 31m. - 2. Perform Survey QC on daily basis	- 1. Dual inclination & MSA processing in RT (Twice/day) by survey specialist - 2. Use HIA mode in Xceed - 3. DD to start projecting ahead 500m prior to landing on top of reservoir - 4. DD to Escalate to Statoil ASAP in case risk of missing the driller target.	L (2)	M (-3)	M (-6)
1.25. Collision risks with L-1H, L-2H, L-3H, K-1H & K-1AH	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	M (-8)	- 1. Monitor AC on TC Plots provided & respect hard lines. - 2. Controlled drilling parameters in close proximity interval.	- 1. Monitor AC on TC Plots provided & respect hard lines. - 2. Controlled drilling parameters in close proximity interval. - 3. Refer to AC review for this well. - 4. Exemption in place.	M (3)	S (-2)	M (-6)
1.26. Accuracy/sensitivity of IFR value with respect of long tangent/Changing IFR values throughout the section	Machinery/Equipment/Hand Tools	Non-Productive Time-->Schlumberger Schlumberger, Statoil	M (3)	S (-2)	M (-6)	- 1. Checked with Survey Specialist & should not be a problem. - 2. Discuss procedure with SDM/MWD/DD	- 1. Checked with Survey Specialist & should not be a problem. - 2. Discuss procedure with SDM/MWD/DD	L (2)	S (-2)	L (-4)
1.27. MWD modulator jamming / erosion while pumping sweeps	Machinery/Equipment/Hand Tools	Non-Productive Time-->Schlumberger Schlumberger, Statoil	M (3)	S (-2)	M (-6)	- 1. Verify with driller number of strokes required to pump the sweep to the BHA and through BHA - 2. New MWD anti-erosion kit and increased modulator gap installed (If available)	- 1. Before sweep reaches BHA, reduce flow to flow rate below MWD switch threshold (below 600 gpm) and maintain this while sweep is going through BHA - 2. Gradually bring pumps up after pumping sweep through BHA - 3. Should jamming occurred, FE to perform MWD anti jamming procedure with a help from OSC	L (2)	S (-2)	L (-4)
1.28. Unexpectedly high friction factors leading to unable to drill/Rig limitations (mainly in 2nd run)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	H (4)	S (-2)	M (-8)	- 1. Ultralube II(e) upto 3% in the system, Statoil plan is to add this lubricant if any issues seen or at end of first run (but lubricants disturb mud properties)	- 1. Optimize 6 5/8ï¿½ length after first run based on actual FF seen. - 2. If high FF after first run, reduce 6 5/8ï¿½ DPS in 2nd run. - 3. Flow should still be high due to Rheguard mud.	M (3)	M (-3)	M (-9)
1.29. Loosing Xceed diagnostic data (important for Backreaming) due to Xceed memory becomes full)	Machinery/Equipment/Hand Tools	Non-Productive Time-->Schlumberger Schlumberger, Statoil	H (4)	S (-2)	M (-8)	- 1. Xceed logging parameters should be changed to allow more memory hours at the expense of slightly slower memory data frequency	- 1. Xceed logging parameters should be changed to allow more memory hours at the expense of slightly slower memory data frequency - 2. Discuss with R&M & management	M (3)	S (-2)	M (-6)
1.30. Stuck Pipe	Machinery/Equipment/Hand Tools	Non-Productive Time-->Client Schlumberger, Statoil	M (3)	S (-2)	M (-6)	- 1. Not common on Statfjord - 2. Shetland is very stable formation	- 1. 1.60 SG mud weight - 2. Accelerator (Sakhalin experience)	M (3)	S (-2)	M (-6)

Figure 69: Risk register [7]

12.5 Collision risks with offset wells

As usual on Statfjord there were collision risks with offset wells in Statfjord øst. Travelling cylinder plots were developed to monitor collision with offset wells in real time. Figure 70 shows analysis of all offset wells i.e. separation factors, center to center distances, allowable deviation from plan etc. along with well status. Figures 71 & 72 showing travelling cylinder plots including offset wells. DD's use these plots offshore for real time collision monitoring.

Anti-Collision analysis (12 ¼" section)

Offset Well	Min DOX OSF	AC Controlling Rule	Min ADP DOX	Min. Ct-Ct	Depth Interval of Close Approach	Comp SF	Comp ADP	Brief Comment
K-1H/K-1AH	0.62	OSF	Negative	45.98	6807-6972* 6830-6941	0.634	Negative	K-1H: P&A K-1AH: Injector
L-1H	0.32	OSF	Negative	62.50	7479-7740* 7511-7709	0.386	Negative	Shut in due to low reservoir pressure
L-2H	0.26	OSF	Negative	49.11	7287-7570* 7319-7523	0.273	Negative	Shut in due to low reservoir pressure
L-3H	0.45	OSF	Negative	88.97	7460-8356* 7502-7748	0.493	Negative	P&A
M-3H	**1.30**	**OSF**	**57.84 (major)**	**228**	**8166-8240***	**-**	**-**	**Shut in due to low reservoir pressure**

K, L & M: Statfjord øst
***Dox**

Figure 70: Anticollision analysis [7]

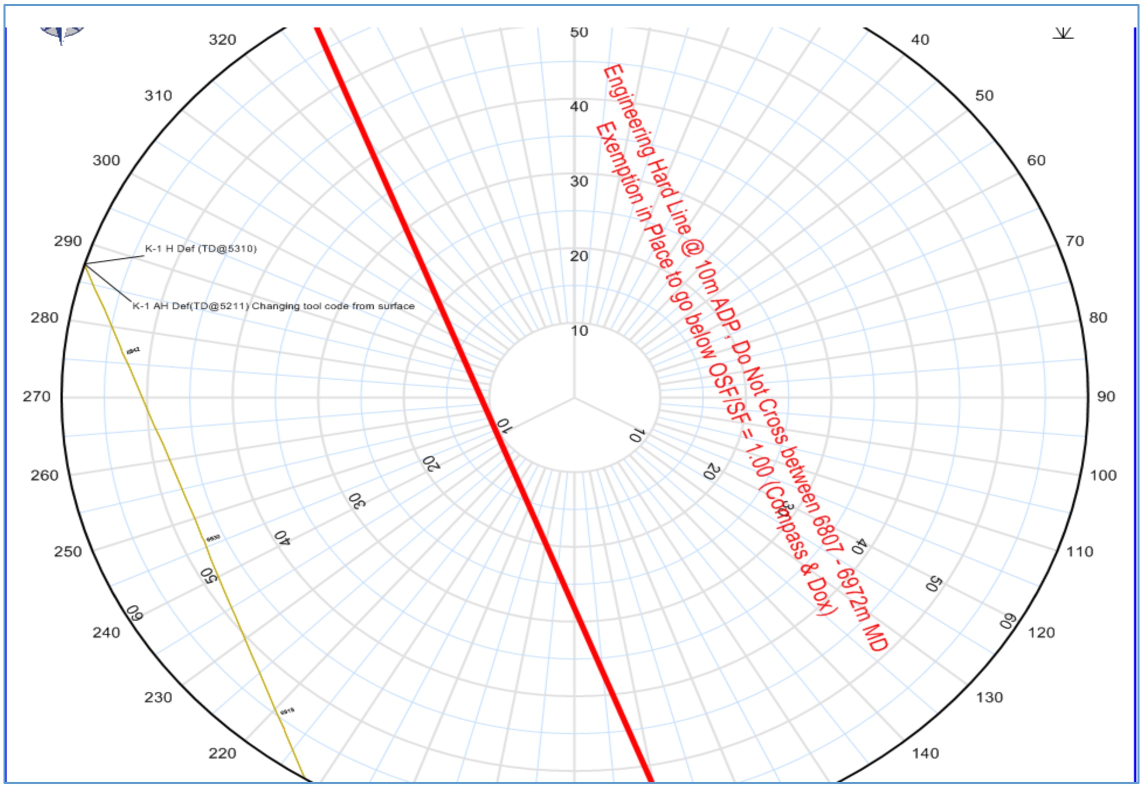

Figure 71: Travelling cylinder plot for K-1H & K-1AH wells [7]

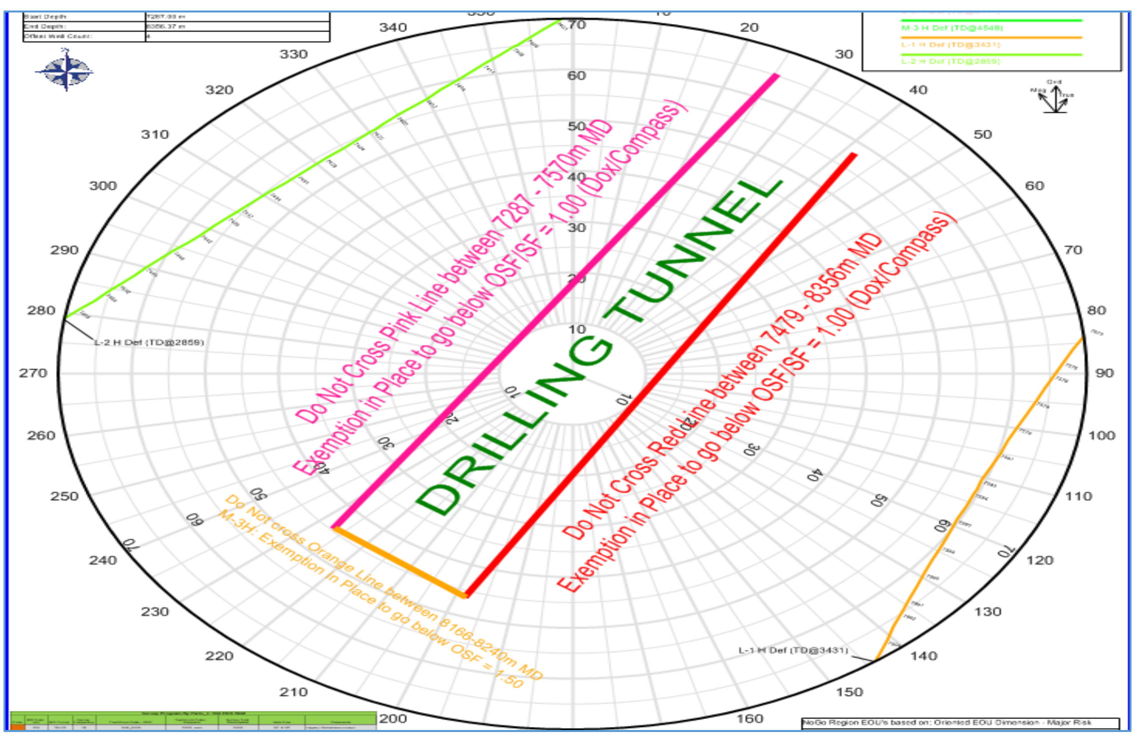

Figure 72: Travelling cylinder plot for L-1H/2H/3H & M-3H wells [7]

12.6 BHA Design

As shown in figure 73, Run-1 BHA design consists of PDC bit, Xceed RSS, Array Resistivity Compensated (ARC) tool for resistivity & ECD, Telescope (MWD) and GWD90. Based on experience from Sakhalin ERD wells a string stabilizer was added on top GWD90 to provide stability to tools and help in backreaming. Float sub was also added in the BHA which accommodates non-ported float valve to prevent any inflow through drill string. Two 6 5/8” HWDP joints were included both above & below the jar. One of the 6 5/8” HWDP below jar was non-mag to reduce estimated drill string interference (EDI). Totco ring was also placed in 6 5/8” HWDP above jar to accommodate drop/pumped down gyro as a contingency if GWD90 fails. 5 7/8” DPS were used to surface to drill first 4000m.

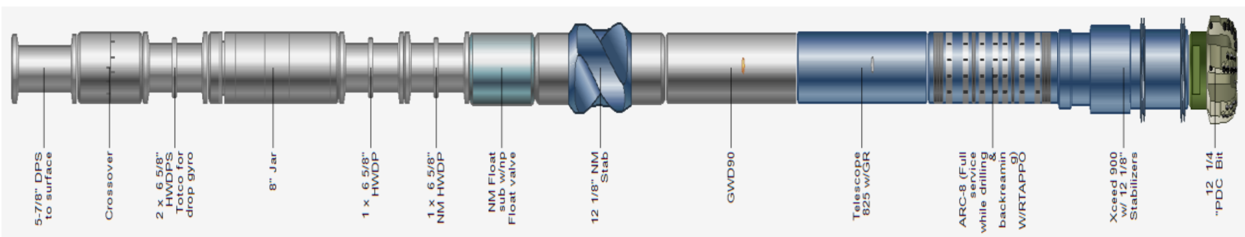

Figure 73 : BHA design, Run-1 [7]

Figure 74 shows Run-2 BHA design which consisted of PDC bit, Xceed RSS, MWD, ARC, string stabilizer & float sub with non-ported float. Three 6 5/8” HWDPS were added below jar out of which two were non-magnetic to minimize drill string interference. Two 6 5/8” HWDPS were added above jar for jar placement. As discussed earlier ~2100m of 6 5/8” DPS were planned in run-2 BHA for being able to pump more flow rate to clean the well. Rest was 5 7/8” DPS to surface.

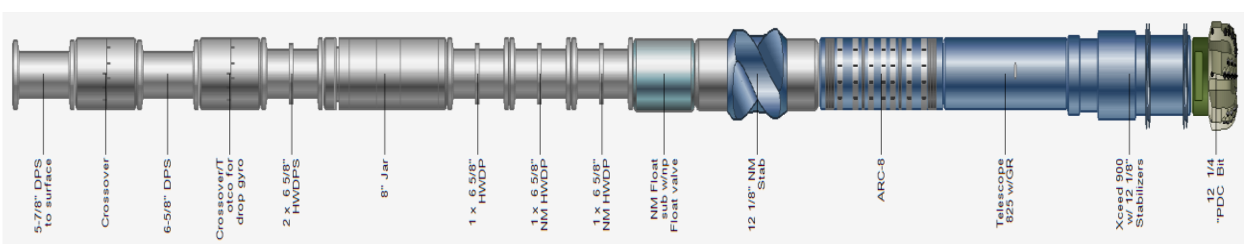

Figure 74: BHA design, Run-2 [7]

12.7 Bit Design

As shown in figure 75, sting blade PDC bit was selected to drill this section (both parts). This bit was selected for durability, performance, stability and ability to drill hard stringers.

StingBlade
12 1/4 in Z716

SMITH BITS
A Schlumberger Company

(311.15 mm) ID:66407A0002
ER:26649

StingBlade bits, with Stinger conical diamond elements across the bit face, are designed to significantly increase footage and ROP in tough-to-drill formations, drill with better steerability in directional applications, mitigate shocks and vibrations through greater bit stability, and create larger cuttings for improved surface formation evaluation.

Specifications

Total Cutters	70
Cutter Size	16mm (5/8 in)
Face Cutters	(36) 16mm
Gauge Cutters	(10) 16mm
Cone Cutters	(17) 16mm
Back-Up Cutters	(7) 16mm
Total Stinger Element Count	42
Stinger Element Size	9/16 in
Blade Count	7
Nozzles	7 Standard Series 60N
Bit Connection	6 5/8 Reg Box
Junk Slot Area, in2	27.257
Gauge	Length: 3" Protection: Options Available
Length	Make-Up: 11.315 in Overall: 16.253
Fishing Neck	Diameter: 8 in Length: 3.521 in

Operating Parameters

Bit Speed	140 To 300 RPM
Weight-on-Bit	6,000 To 45,000 (lbf) 2,727 To 20,452 (daN) 3 To 20 (Tonnes)
Flow Rate galUs/min	500 To 1200
Hydraulic Horsepower, HSI	1 To 6
Recommended Make-up Torque	47300 To 47800 ft/lbs

Operating parameters are typical ranges. Please contact your Smith Bits representative for recommendations for your individual well.

FEATURES

- Bit design and performance have been certified through the validation process prescribed by IDEAS simulation technology.
- The Stinger's unique conical geometry delivers high point loading to fracture tough-to-drill formations more efficiently.

- Placed on the blade, Stinger conical diamond elements offer improved impact resistance when drilling through inter-bedded formations or when hard inclusions such as chert or conglomerates are encountered.

- The center location of the Stinger conical diamond in the bit enhances its stability to mitigate whirl and other artifacts that waste energy and reduce ROP. The Stinger element also provides an efficient mechanism to drill the very center of the borehole.

- Bit design is available with RockStorm PDC technology. These all-in-one cutters break the paradigm and provide ultimate wear resistance and ultimate impact resistance in the same PDC cutter. As a result, faster drilling rates are delivered while increasing overall run length.

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Figure 75: Bit design [7]

12.8 Hydraulics

❖ Hydraulics Run-1

As shown in figure 76 below, at planned TD of run-1 maximum possible flow was 3360 LPM limited by SPP. Planned MW was 1.60 S.G and 6 ½" pump liner was planned to be used. Planned Fann readings for mud were as per figure 76. Figure 77 shows ECD variations with flow rate at different ROP's. It is clear from the figure that ROP upto 45 m/hr was achievable. Figure 78

& 79 are showing critical transport rate VS ROP & Hole cleaning Index VS depth at different flow rates. Both these figures are self-explanatory & can easily be interpreted.

Depth [mMD]	Flow [lpm]	ECD [sg]	Press [bar]	TFA [in²]	Pr. Loss @bit [bar]	HSI (3400 LPM)	MW [sg]
5200	3600	1.68	262	1.427	35	2.0	1.60
5600	3520	1.68	264	1.427	34	2.0	1.60
5900	3440	1.68	262	1.427	32	2.0	1.60
6219	3360	1.69	261	1.427	31	2.0	1.60

Pump Liner	Max Flow (LPM)	Pop Off (Bar)
6”	3150	310
6 ¼”	3400	300
6 ½”	3700	275

Fann data	
3	8
6	9
100	27
200	42
300	56
600	93

Figure 76: Planned hydraulics Run-1 [7]

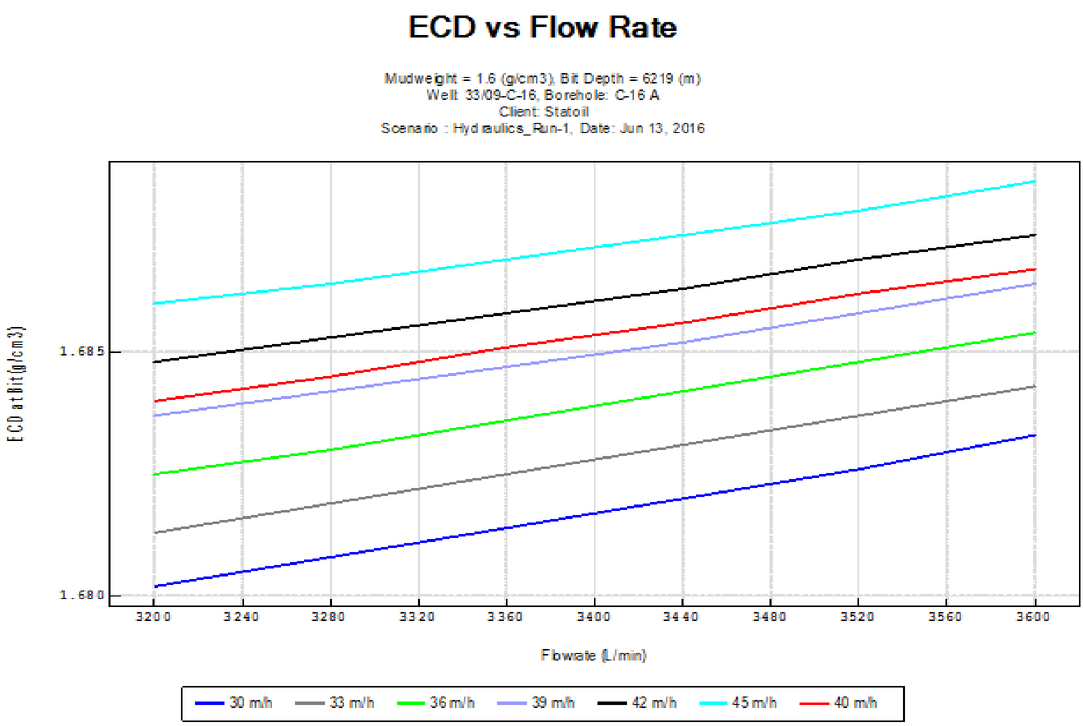


Figure 77: ECD VS Flow rate Run-1 [7]

Figure 76

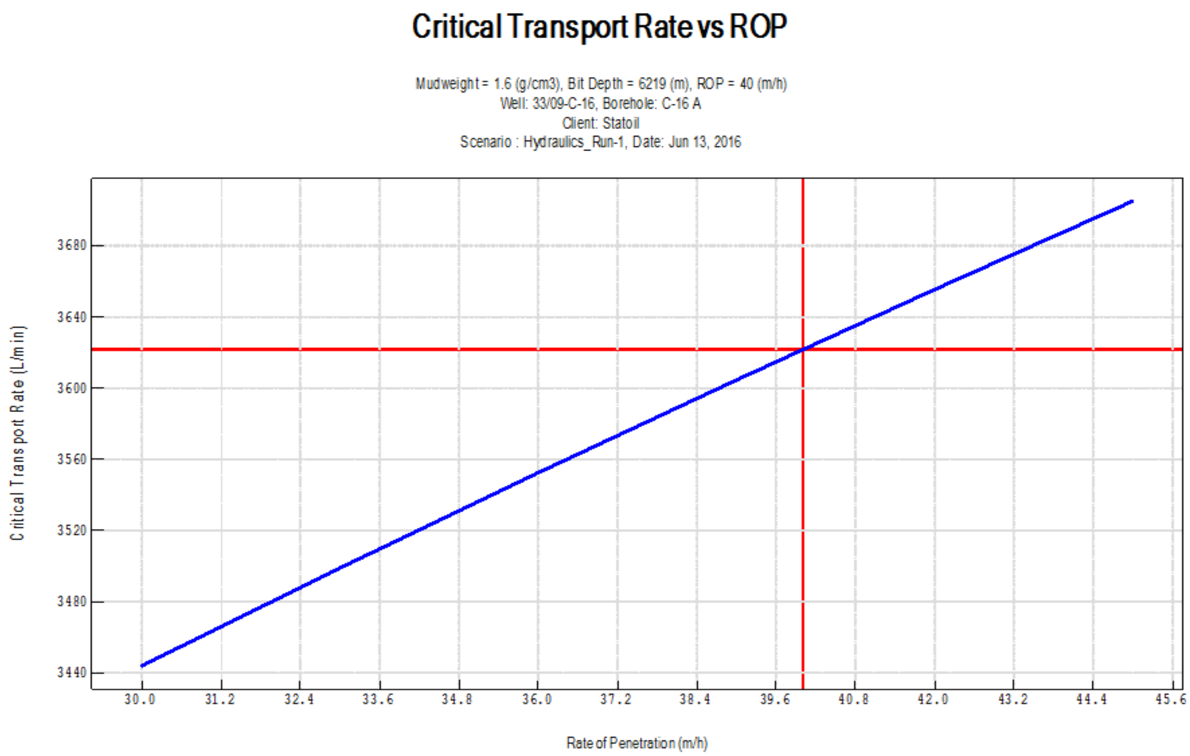


Figure 78: Critical transport rate VS ROP Run-1 [7]

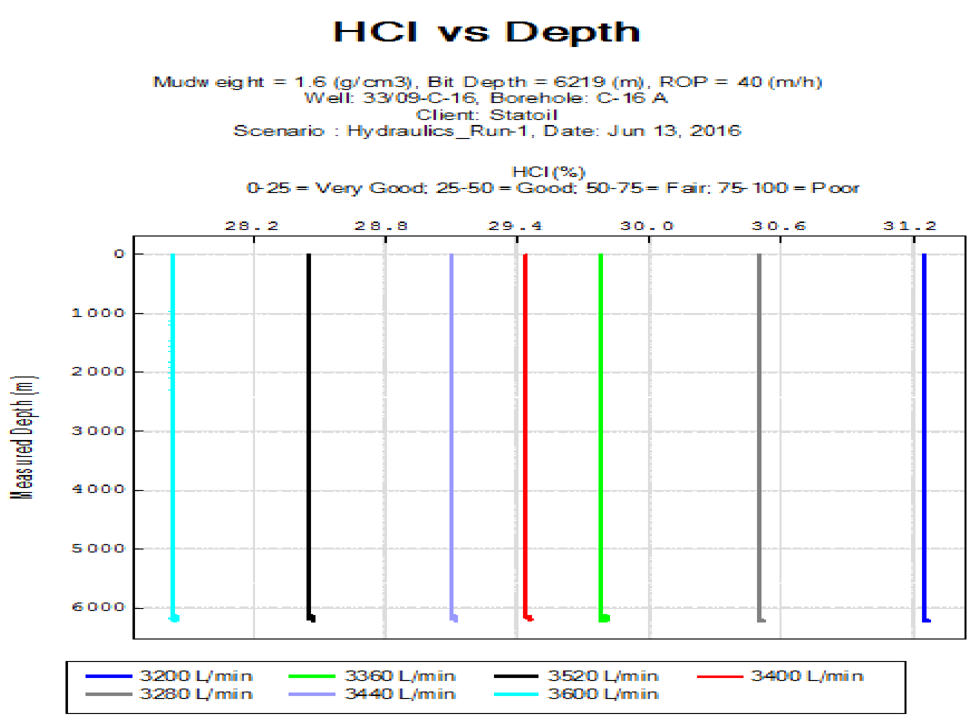


Figure 79: Hole cleaning Index VS depth at different flow rates Run-1 [7]

❖ Hydraulics Run-2

Figure 80, 81, 82 & 83 are showing planned hydraulics, ECD VS flow rate, critical transport arte VS ROP and hole cleaning index VS depth at different flow rates respectively which are self-explanatory. 6 ¼" pump liner was planned to be used in second run to achieve more SPP limit.

Hydraulics 12 ¼" Section (2nd Run)

Depth [mMD]	Flow [lpm]	ECD [sg]	Press [bar]	TFA [in^2]	Pr. Loss @bit [bar]	HSI (3200 LPM)	MW [sg]
8000	3400	1.69	284	1.552	25	1.4	1.60
8223	3320	1.68	280	1.552	26	1.4	1.60

Pump Liner	Max Flow (LPM)	Pop Off (Bar)
6"	3150	310
6 ¼"	3400	300
6 ½"	3700	275

Fann data	
3	8
6	9
100	27
200	42
300	56
600	93

Figure 80: Planned hydraulics Run-2 [7]

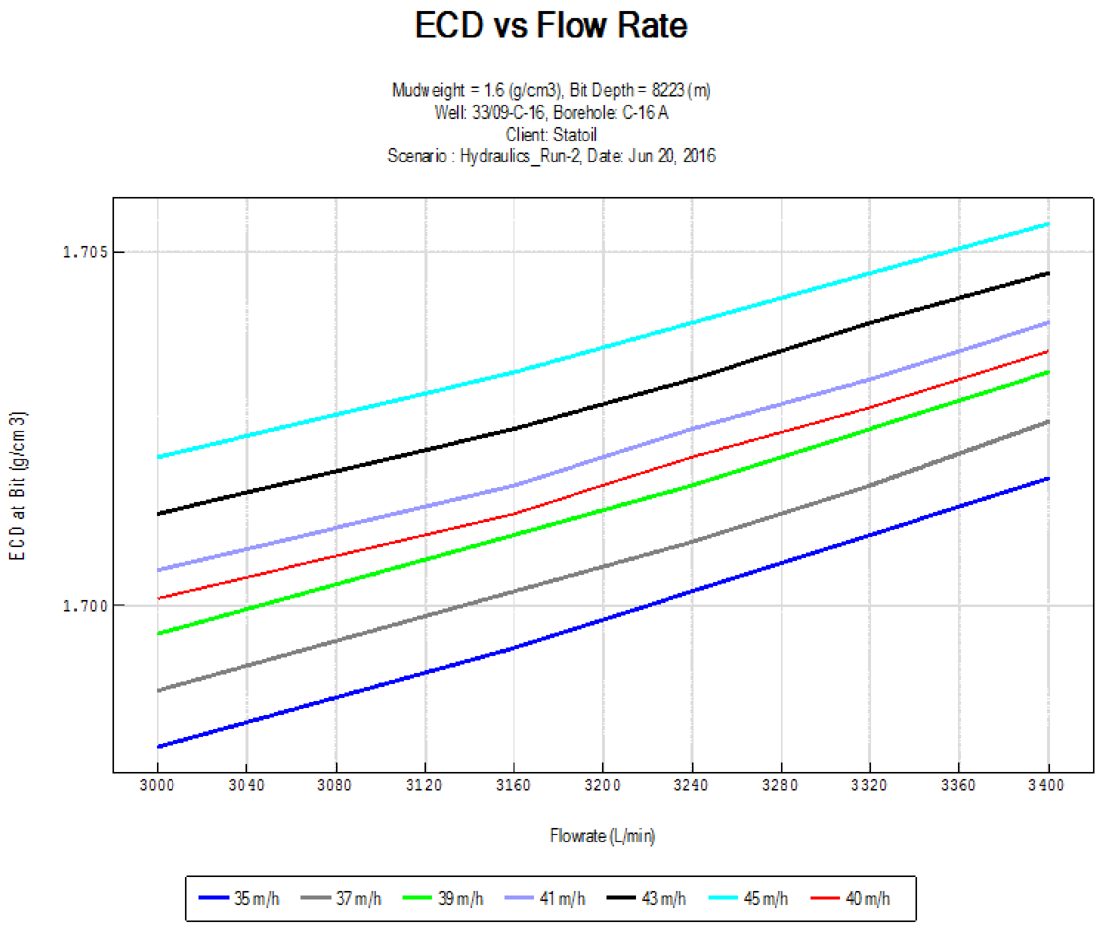


Figure 81: ECD VS Flow rate Run-2 [7]

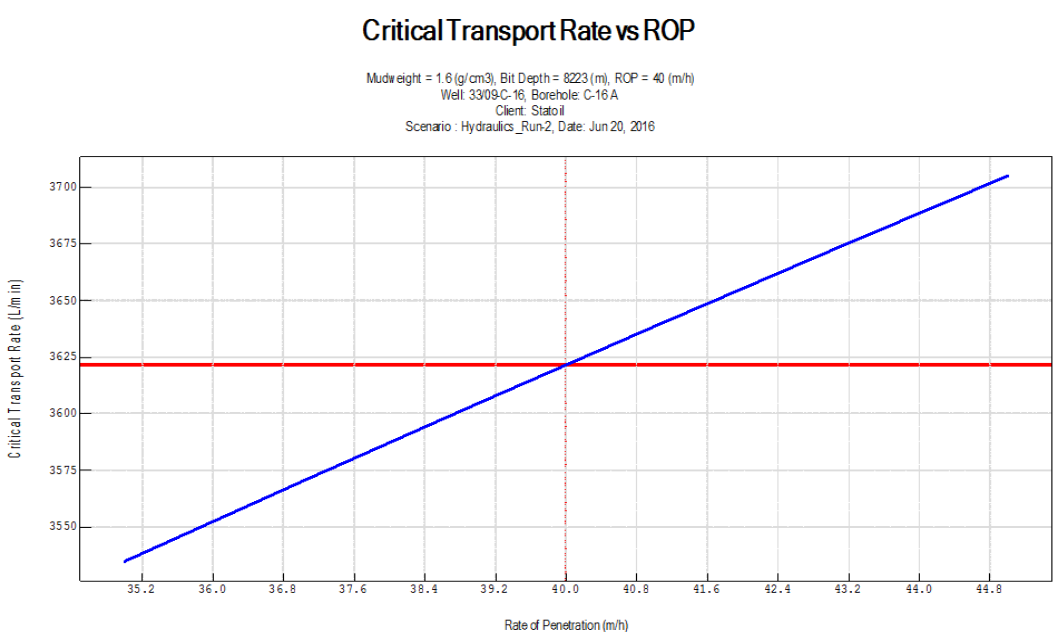


Figure 82: Critical transport rate VS ROP Run-2 [7]

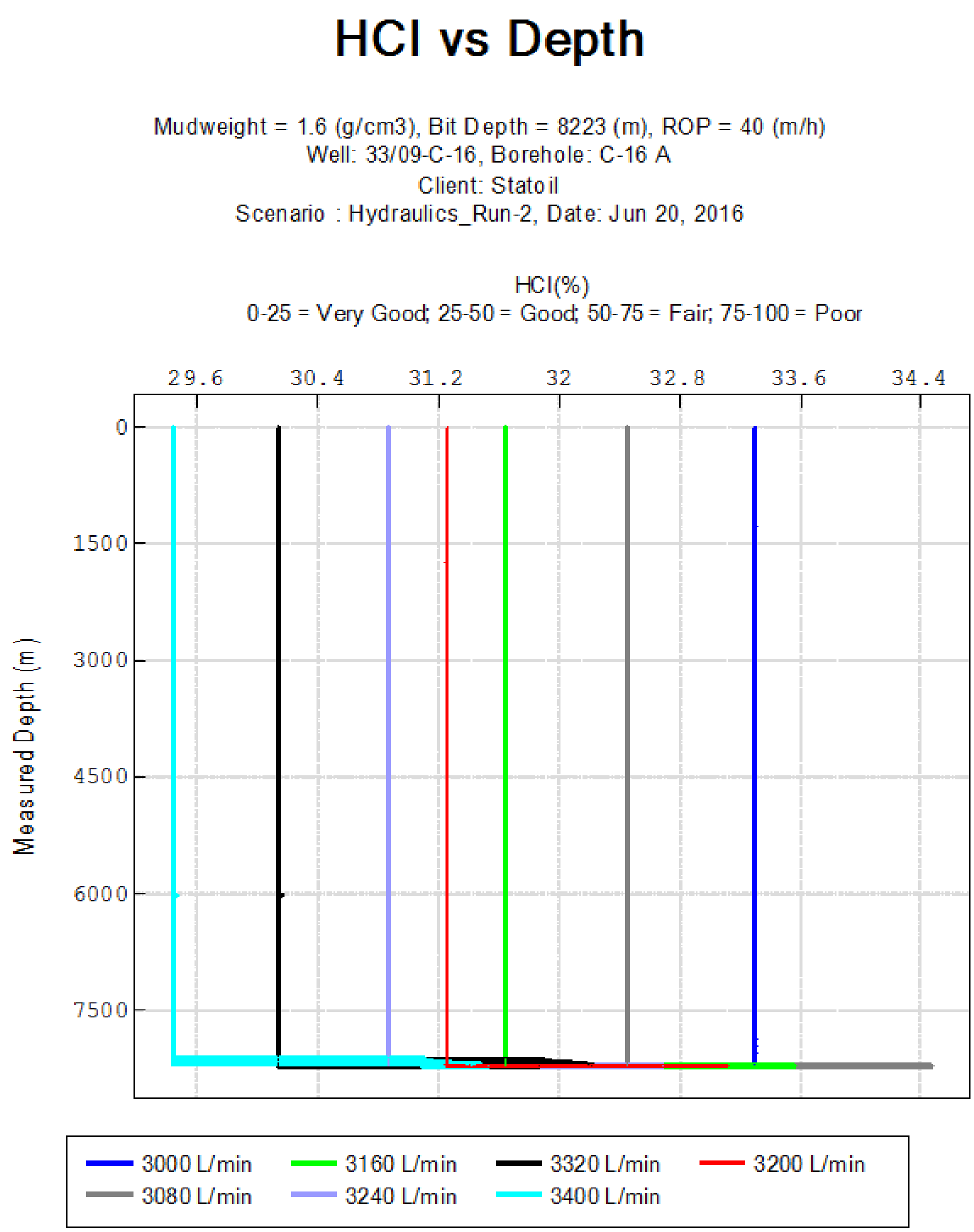


Figure 83: Hole cleaning Index VS depth at different flow rates Run-2 [7]

12.9 T&D

Figure 84 & 85 show summary of T&D simulations for both run-1 & run-2 clearly depicting that there is no rig limitations except Top drive system (TDS) might reach to torque limit and might get heated during long backreaming hours. This also show assumptions made for T&D simulations.

12 ¼" Section (First Run T&D)

MD (m)	3000	4000	5000	6219
Torque (kNm)	17	22	27	33
Off Bottom torque (kNm)	12	16	21	27
PU Weight (ton)	112	120	129	142
SO Weight (ton)	89	83	77	70
ROB Weight (ton)	101	103	104	106

1. **Simulations based on FF = 0.2, WOB = 10 Ton**
2. **Max WOB (Sinusoidal Buckling) = 30 Ton (20 ton margin at TD)**
3. **Max WOB (Helical Buckling) = 39 Ton (29 ton margin at TD)**
4. **Normal side forces**
5. **Consistent Tortuosity**

Figure 84: T&D simulations summary Run-1 [7]

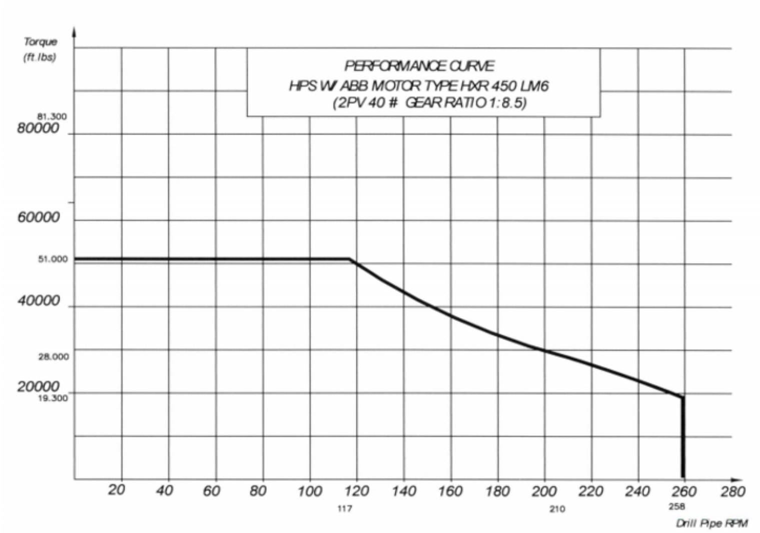
12 ¼" Section (2nd Run T&D)

MD (m)	6219	7000	7500	8223
Torque (kNm)	39	43	46	48
Off Bottom torque (kNm)	33	37	40	46
PU Weight (ton)	148	157	162	191
SO Weight (ton)	67	62	58	72
ROB Weight (ton)	107	108	109	124

1. **Simulations based on FF = 0.2, WOB = 10 Ton**
2. **Max WOB (Sinusoidal Buckling) = 30 Ton (20 ton margin at TD)**
3. **Max WOB (Helical Buckling) = 35 Ton (25 ton margin at TD)**
4. **Normal side forces**

Figure 85: T&D simulations summary Run-2 [7]

Figure 86 is TDS performance curve showing torque VS RPM. Block weight was 40 tons & hoisting capacity of 450 tons. Figure 87 is showing combined load curve for 5 7/8” DPS.



TDS Limits (SFC)	
kNm	RPM
69	115
60	140
55	150
50	160
45	170
Block Weight	40 Ton
Hoisting Capacity	450 Ton

Figure 86 (Courtesy Archerwell): TDS Performance curve [6]

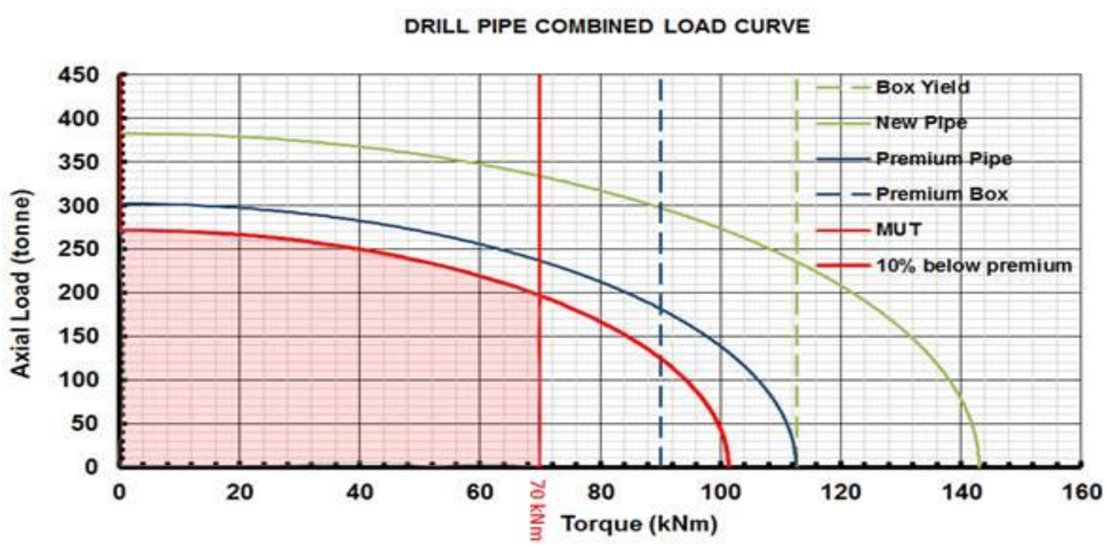


Figure 87 (Courtesy Archerwell): DP combined load curve [6]

Figure 88 to 95 show detailed T&D simulations for run-1. Figures on **right side** are with added tortuosity and figures on **left side** are without tortuosity. Added tortuosity for the sake of simulations & establish worst case scenarios is Build drop: 1.5°/30m & Vertical/tangent: 0.75°/30m.

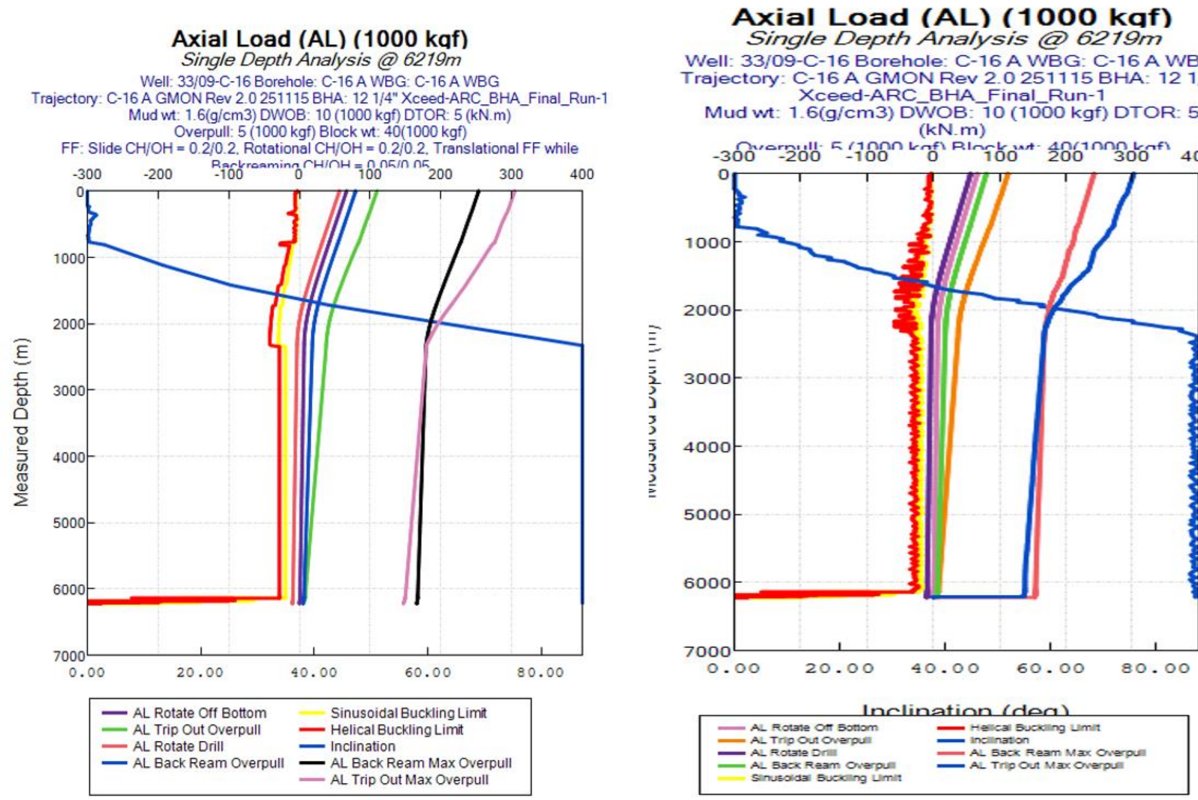


Figure 88: Axial Load curves Run-1 [7]

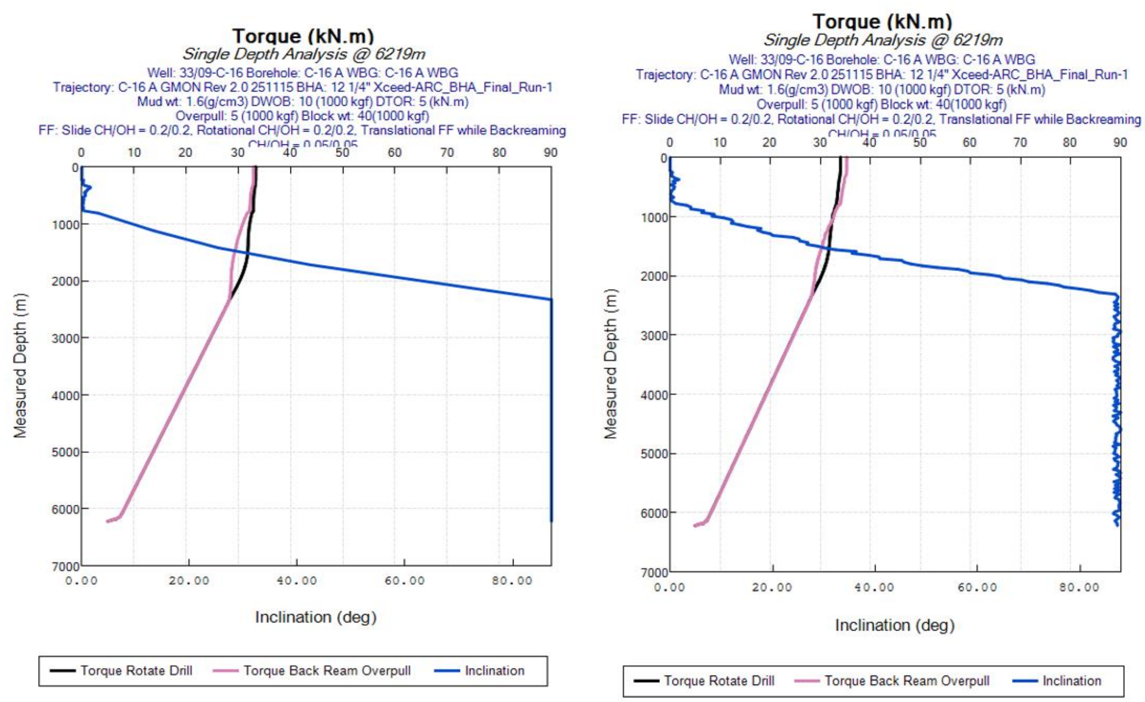


Figure 89: Simulated surface torque Run-1 [7]

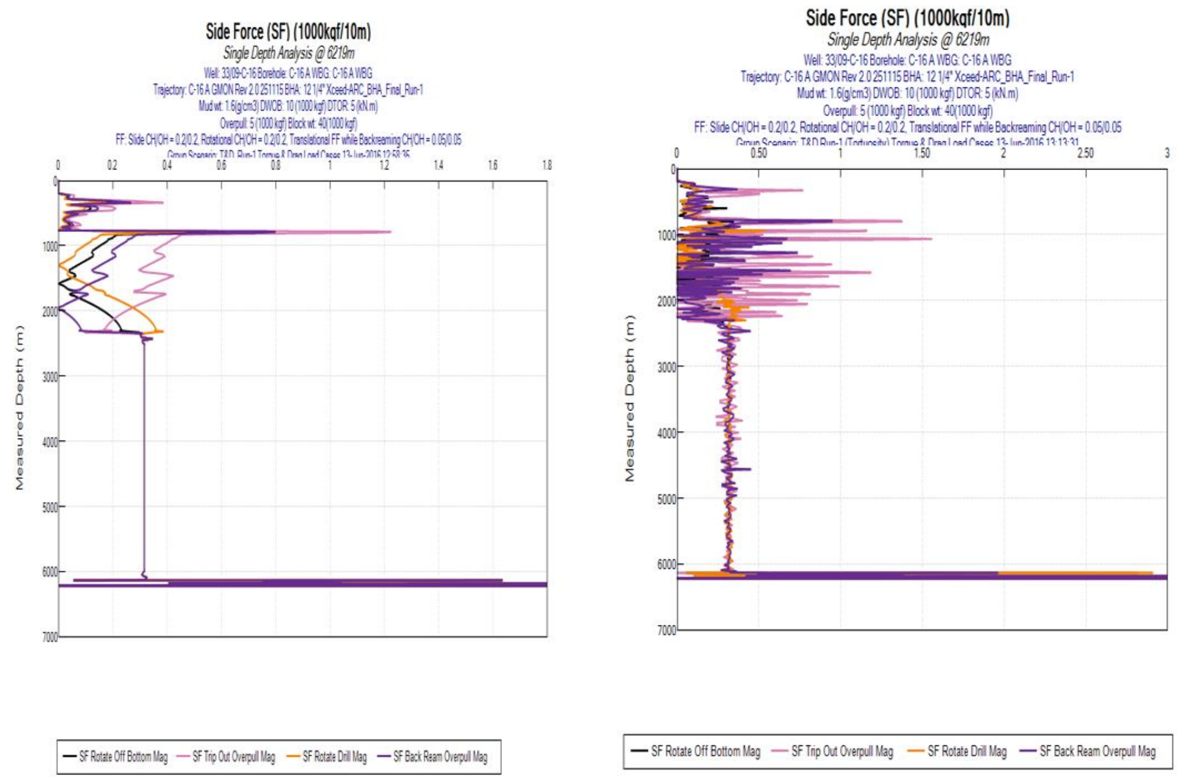


Figure 90: Sideforces Run-1 [7]

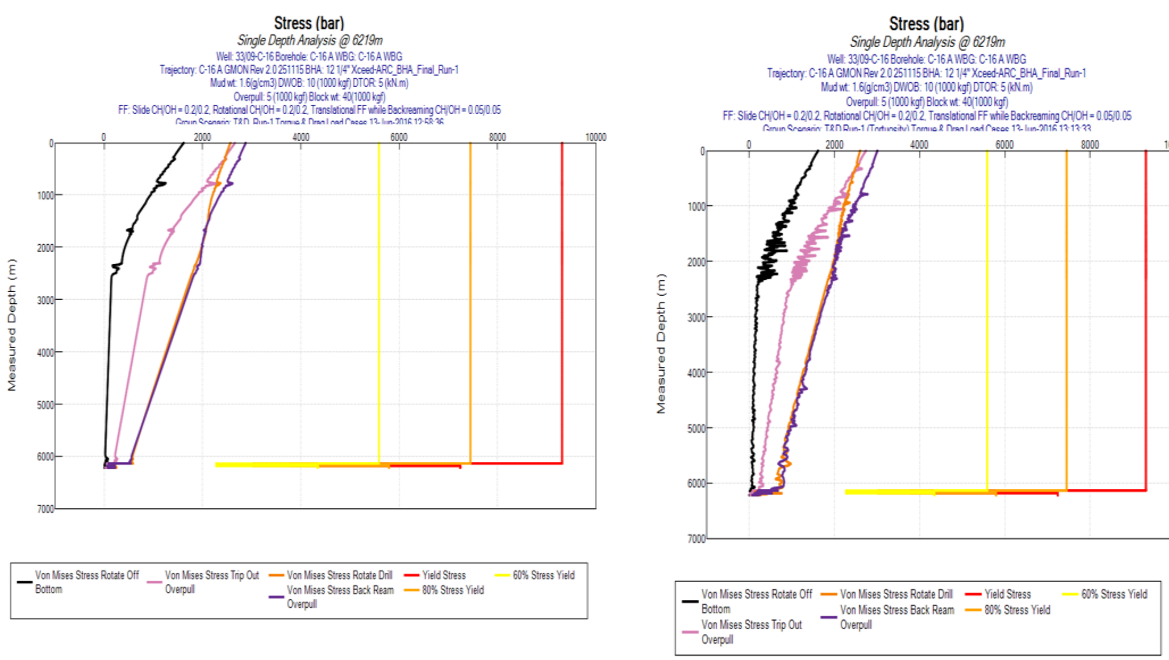


Figure 91: Von misses stresses Run-1 [7]

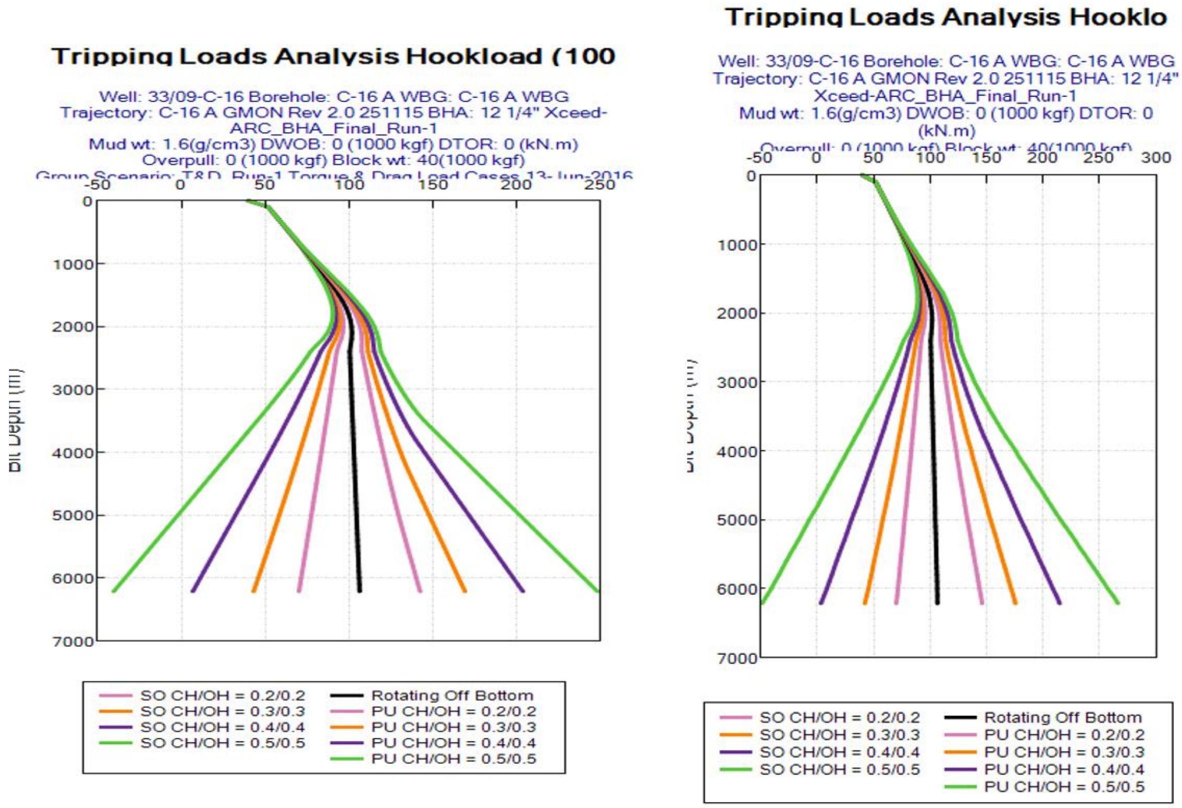


Figure 92: Tripping load analysis Run-1 [7]

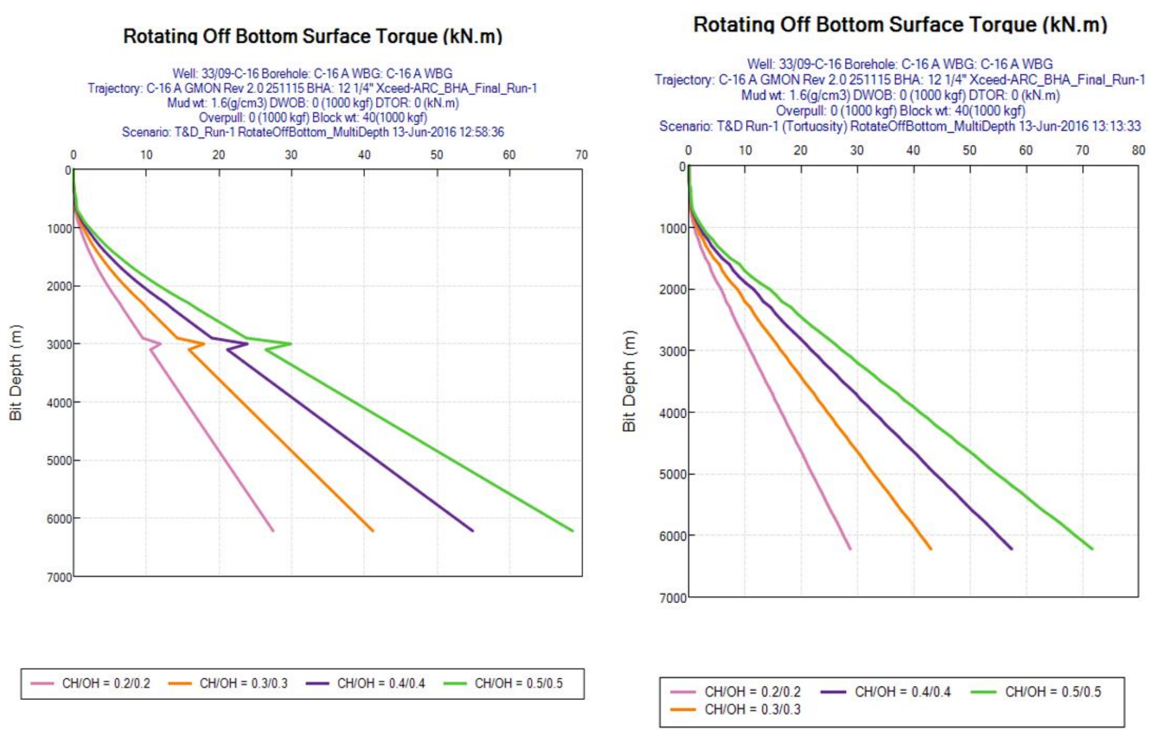


Figure 93: Rotating off bottom surface torque Run-1 [7]

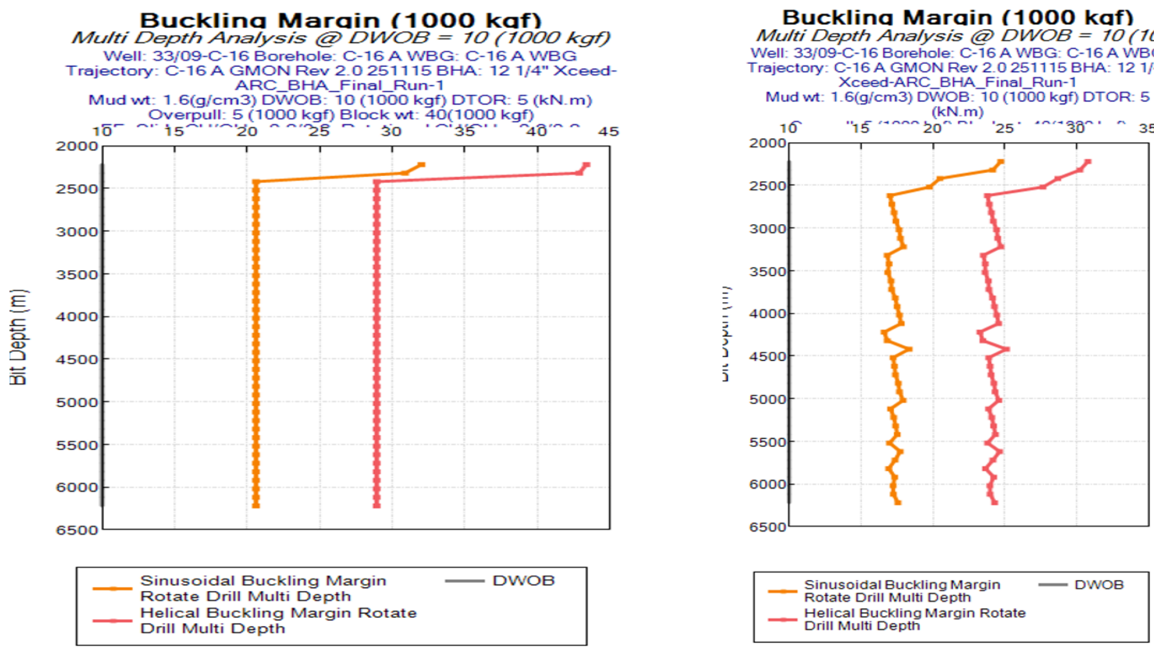


Figure 94: Buckling Margins Run-1 [7]

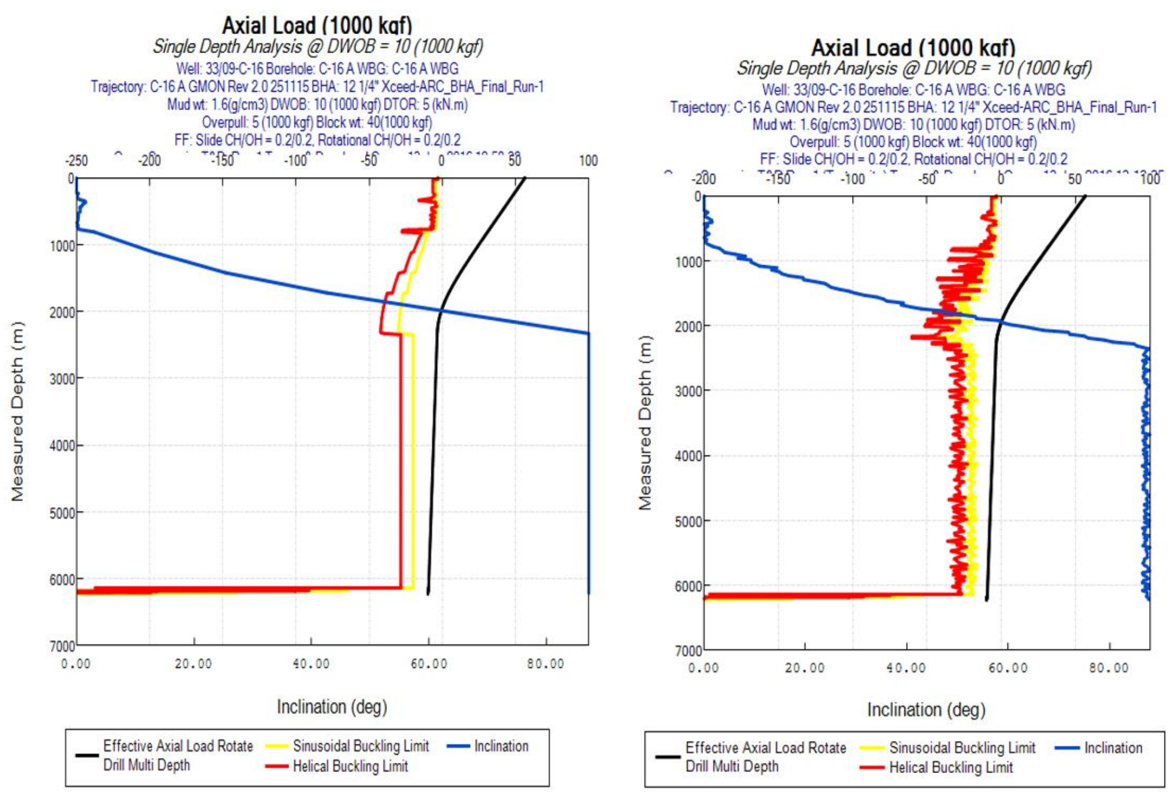


Figure 95: Buckling limits Run-1 [7]

Figure 96 to 103 show detailed T&D simulations for run-2. Figures on **right side** are with added tortuosity and figures on **left side** are without tortuosity. Added tortuosity for the sake of simulations & establish worst case scenarios is Build drop: 1.5°/30m & Vertical/tangent: 0.75°/30m.

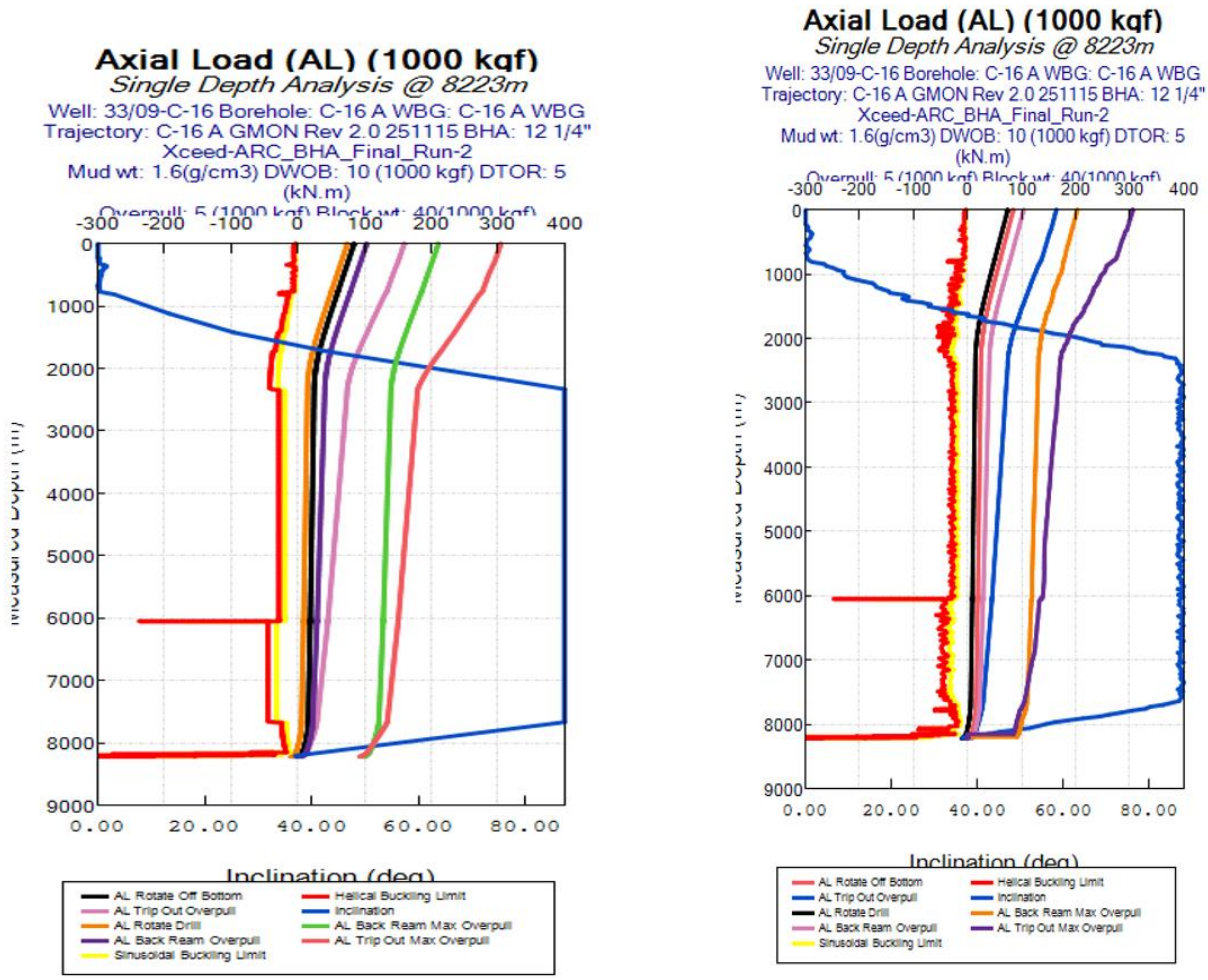


Figure 96: Axial Load curves Run-2 [7]

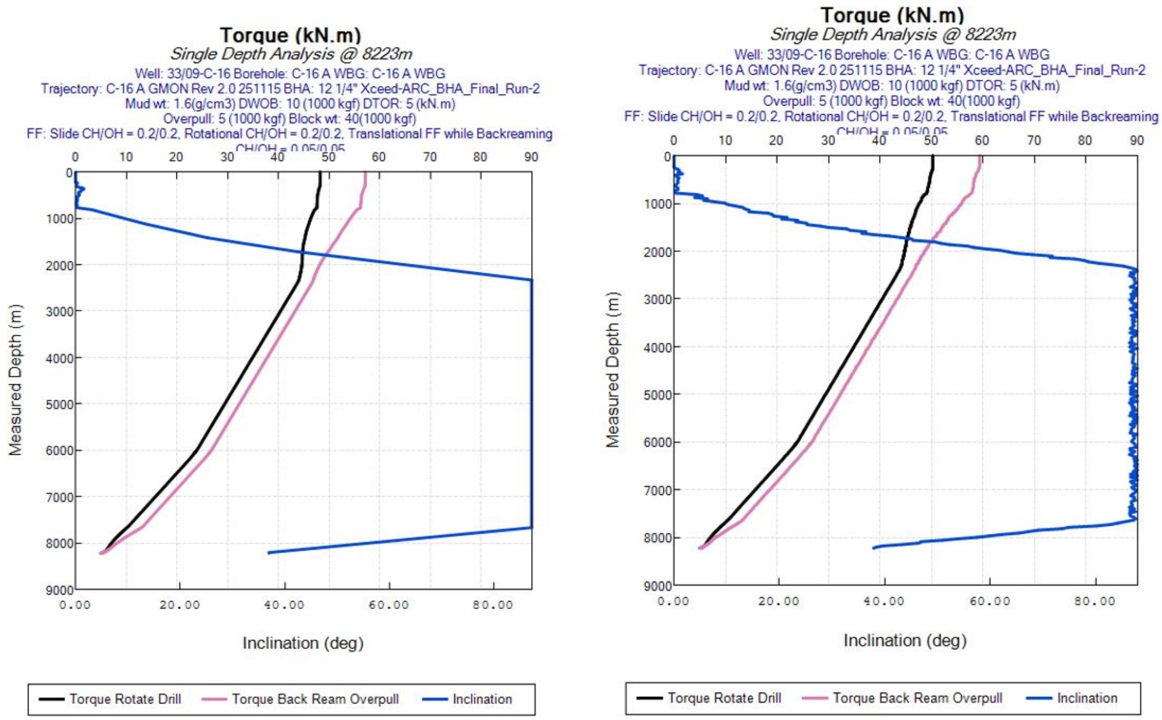


Figure 97: Simulated surface torque Run-2 [7]

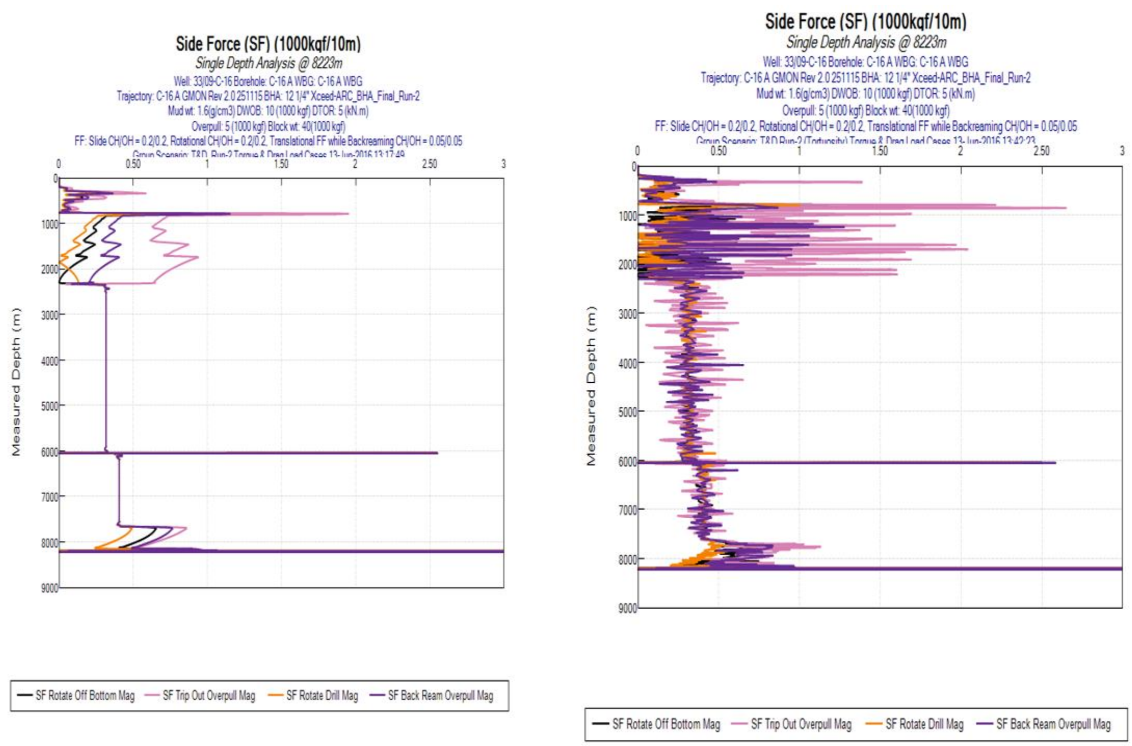


Figure 98: Sideforces Run-2 [7]

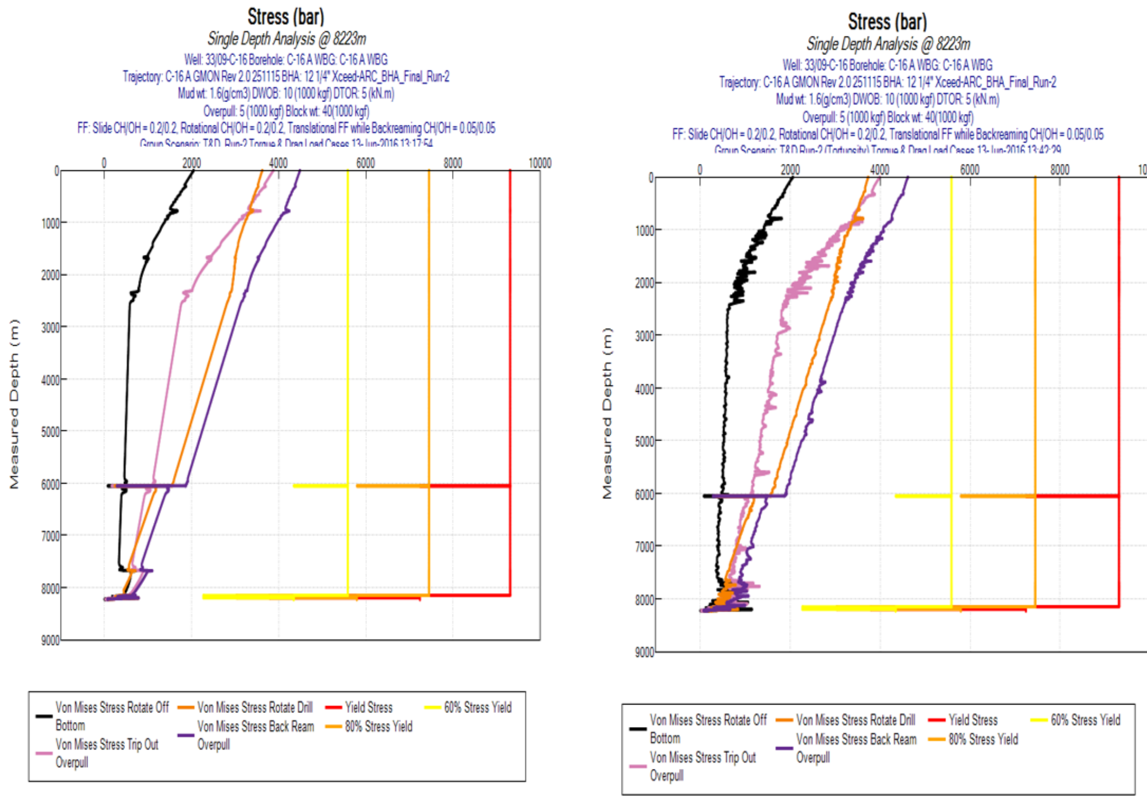


Figure 99: Von misses stresses Run-1 [7]

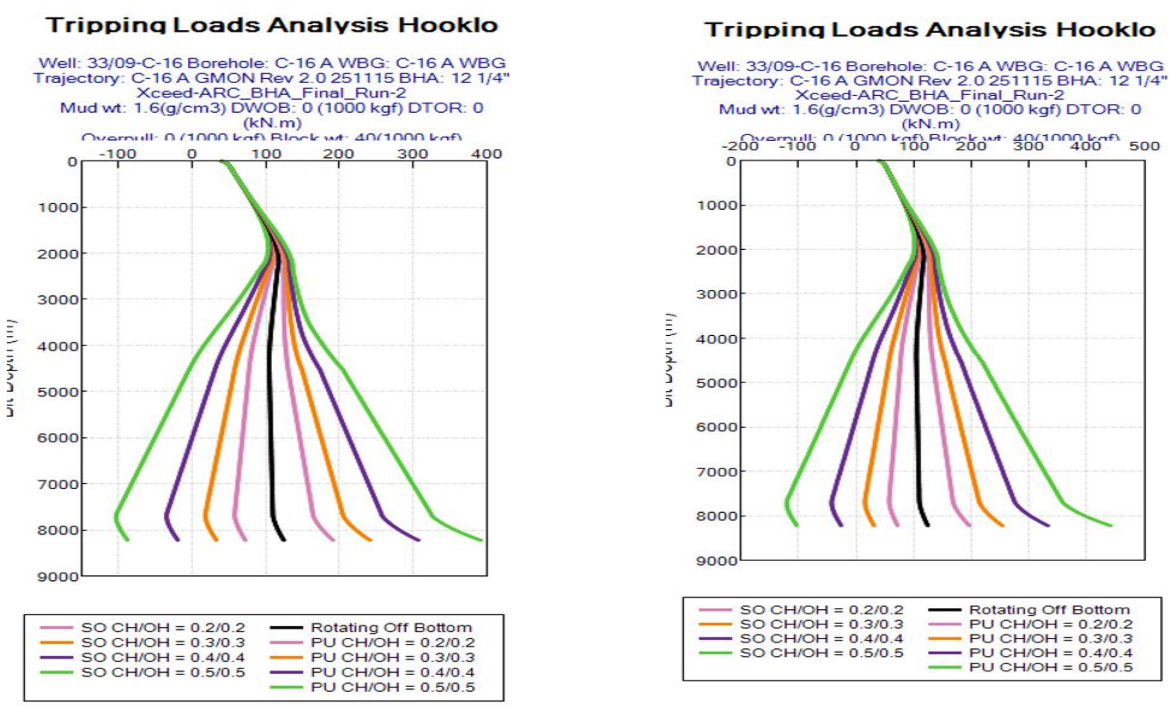


Figure 100: Tripping load analysis Run-2 [7]

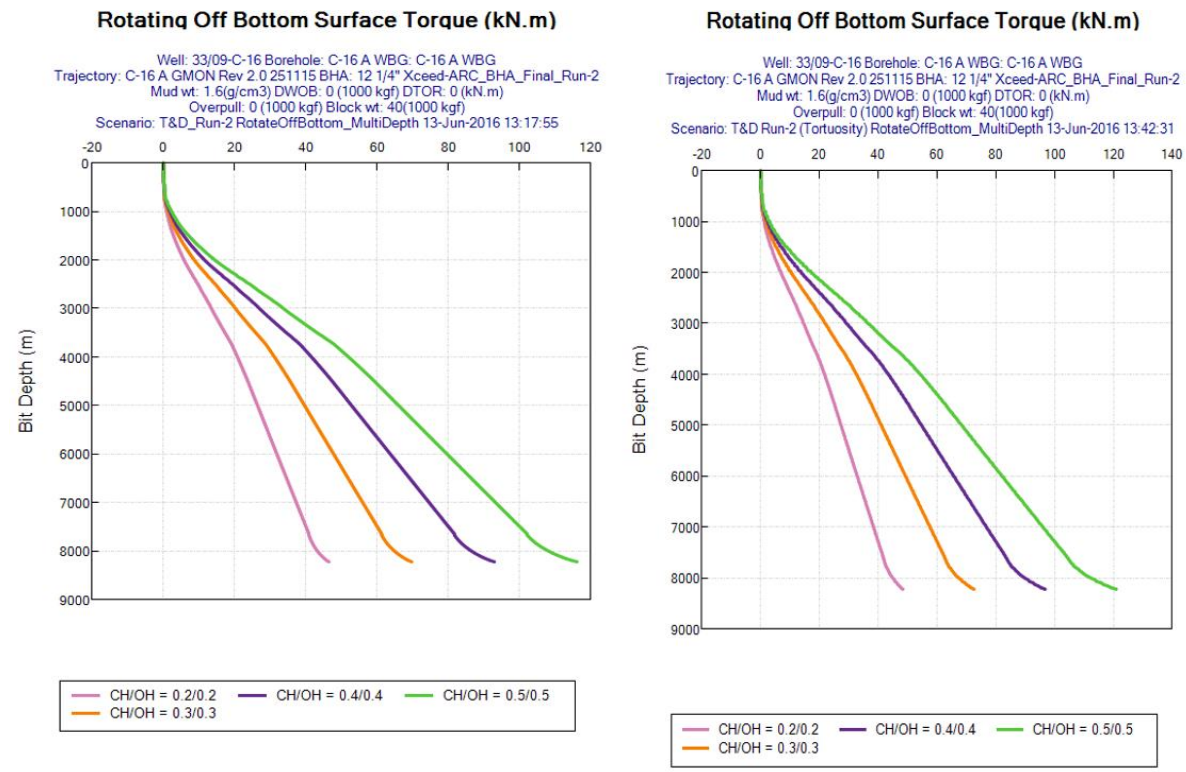


Figure 101: Rotating off bottom surface torque Run-2 [7]

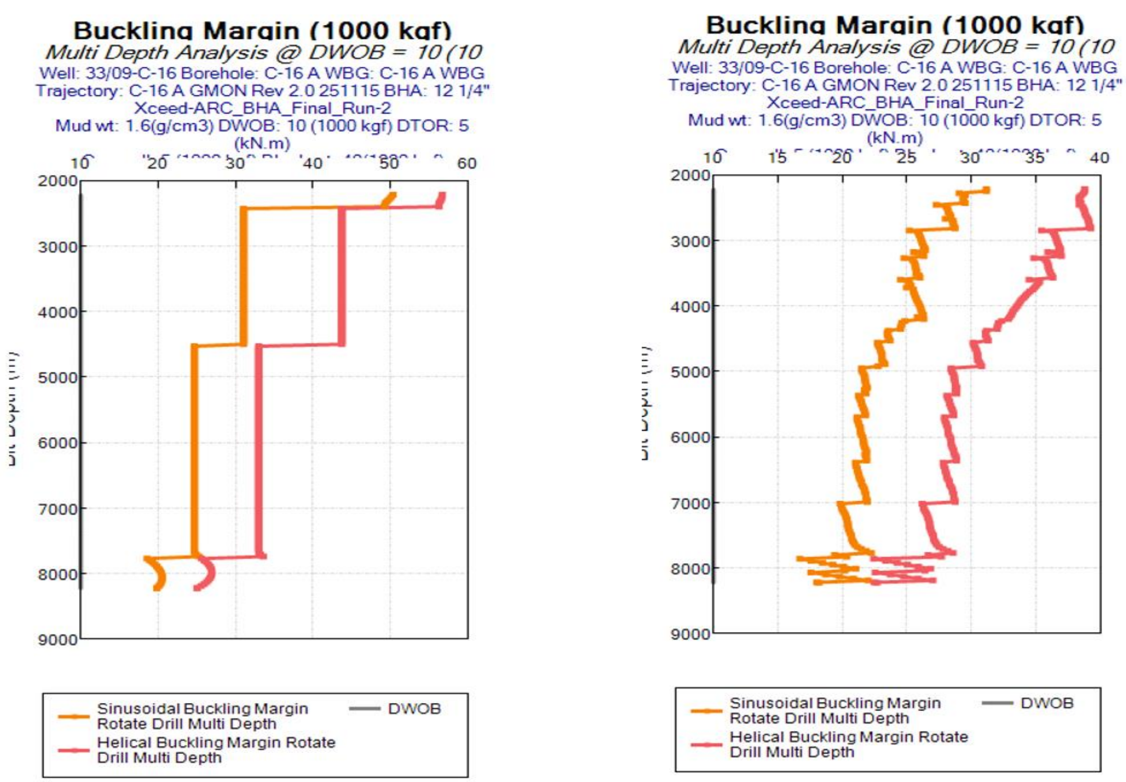


Figure 102: Buckling Margins Run-2 [7]

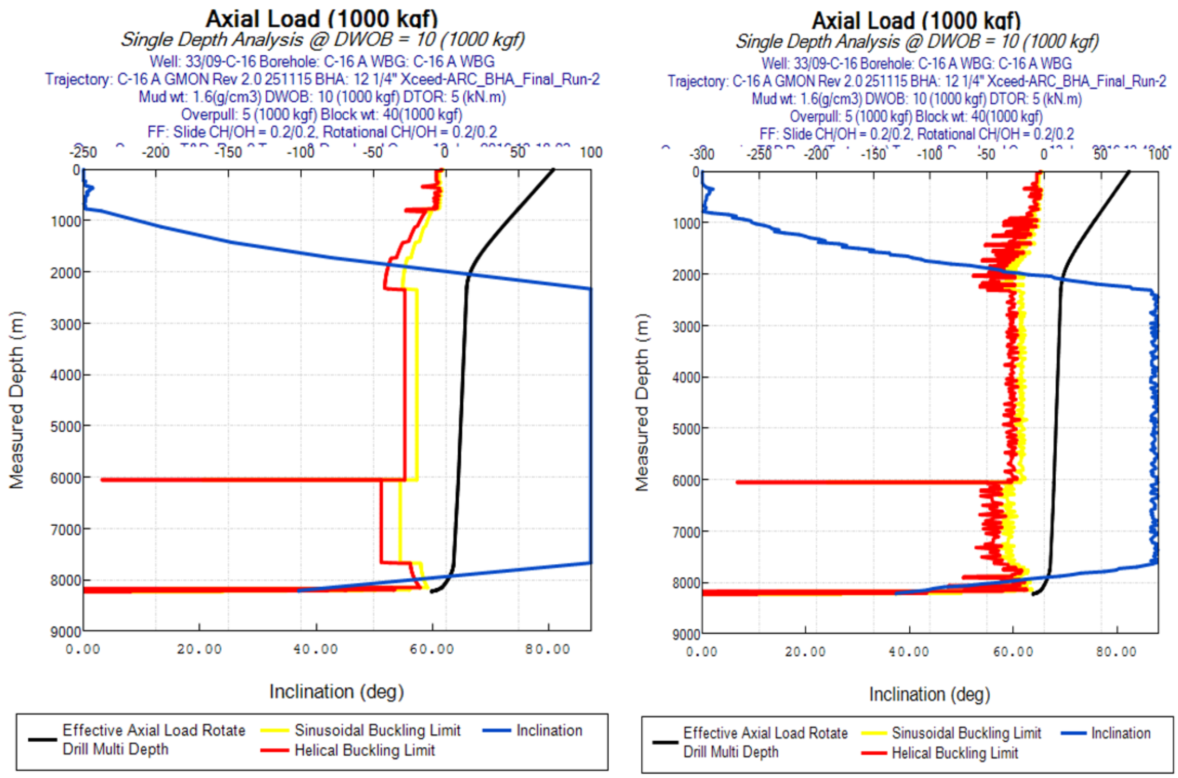


Figure 103: Buckling limits Run-2 [7]

13 12 ¼” Section-Execution

13.1 Drilling Operations Sequence [6]

Main highlights & sequence of drilling operations conducted as follows [1] & [6]:

- All DPS were inspected onshore & plan was to pick up & rack back in derrick due to the plan of drilling on stands. Therefore, a separate drill out run for the 13 ⅜” casing shoe was planned. Pickup of DPS & shoetrack drilling went according to plan.
- 12 ¼” section drilling **(run-1)** started with 3600 LPM (equal to an annular velocity of 1.00 m/s), 180 RPM and a gradual increase of net ROP from 15 to 45 m/hr over the first 2-3 stands.
- The first up/down weight indicated a FF of 0.25 and torque friction of 0.18, which was on the high side of what was expected. The drilling parameters were kept at 45 m/hr for 700m (2900mMD) until the friction started to increase towards 0.32 (torque FF remained steady at +/- 0.15). This was assumed to be due to poor hole cleaning, and the ROP was then reduced to 35 m/hr. The roadmap however (Figure 104), still showed an increase trend with FF upto 0.38 and the ROP was further reduced to 30 m/hr. A positive effect was then seen on the roadmap with the friction factor reducing towards 0.27.
- After digging more into possible causes of poor hole cleaning, it was then seen that the mud rheology was below than what was planned. The investigation report from Mud Company showed that the mud planned for this well had be sent to another field due to a loss situation there. A new mud was mixed for Statfjord, but rheology had not been treated to the planned specification. The mud rheology for 3/6/30/60/300/600 RPM at start of drilling was 4/5/10/14.5/43/76 lbs/100ft2 respectively.
- Due to the uncertainty around the hole cleaning & quality of the mud, ROP was further reduced to 25 m/hr, and then to 10 m/hr. The HT400 pump was also frequently used to boost the flow up from 3600 LPM to 3850 LPM. None of these measures had any effect on the FF’s. This

situation seemed to worsen as the FF increased upto 0.45 at around 3800m MD. At this depth a large amount of stringers were also encountered, which reduced the progress significantly. After spending quite few hours the WOB was increased to break through the stringers. This caused a slight increase in the inclination (Figure 105), which was corrected by subsequently steering down to planned inclination.

- It was also no longer possible to take down weights, so up weights were the only measurement for the drag forces. And it was clear that, if the trend continued, it would eventually be impossible to move the string downwards without rotation (the torque friction was still within the acceptable range of 0.15-0.20).
- To get a verification on the hole cleaning problem, a high density pill was pumped. When the pill reached the shakers a noticeable increase in cuttings. The observation lead to an increase focus on the mud rheology, and started treating the mud to a higher rheology. The hole cleaning parameters were now 3600 LPM, 160 RPM and an ROP of 15-20 m/hr at approximately 4300m MD. As a consequence of the mud treatment, the SPP increased from 240 bar to 250 bar, pumping with 3600 LPM.
- At this point a plan was set in motion to replace the mud system with fresh mud from shore. The mud had also picked up a lot more fines than expected causing an increase in low gravity solids (LGS).
- The mud rheology was treated up to 8/9/17/27/74/126 lbs/100ft2 respectively. The reluctance for increasing the rheology was because of the 126 lbs/100ft2 value which caused an increase pressure and consequently reduced flowrate. The reduced flowrate could then worsen the hole cleaning, and the LGS problem would increase the high end of the rheology even further. After the rheology was increased, a large drop in FF was experienced. This was however short lived as the friction again increased up to 0.4. Reaming of stands on connection was tried and had, as expected, an effect on the up weights. But the effect was limited, and not regarded as a sustainable solution to the drag problems.

- There were several options on how to proceed forward. The two main options were; to either stop the first drilling run at planned depth (~6000m MD) and then back ream the hole section, or stop earlier and pull out of hole. Eventually it was decided to stop early, pull out of hole and only backream the avalanche area from about 2200m MD to 1700mMD (500m into the 13 3/8" shoe). The road map from the first drilling run can be seen in Figure 104.
- At 4662m MD, TD of run-1 was set, 1000m earlier than initially planned. The hole was cleaned with 3600 LPM and 120 RPM while backreaming with 30 m/hr. A total of 3.5 BU was circulated before starting to POOH.
- The friction seen when POOH had now been reduced to 0.30. At 2600m MD a 20 tonnes over pull was observed, and backreaming was initiated slightly earlier than planned. Backreamed at 40-60 m/hr, 3600 LPM and 80-120 RPM with a torque of ±15 kNm. Thin flakes of mechanical cavings were observed on the shakers. Large amounts at first, but as the bottom BHA entered the casing the amount gradually reduced. At 1580m MD, backreaming was stopped and the hole was cleaned. The HT400 pump was used to boost the flow to 4100 LPM limited by the flowlines.
- After 1.5 BU the GWD was set in OBM to verify the surveys, and the string was pulled out of hole. No significant wear was seen on the bit and the other BHA components.
- In **run-2**, all the components in the BHA were changed with new ones. The bit was changed from the StingBalde to the standard bit type, MDi716. Reducing the size of the string stabilizer was considered, but disregarded due to uncertainty around the effect this would give. Since the torque had been at an acceptable levels in run-1, but hole cleaning was regarded as the main problem, the drill string was changed to include 219 joints of 6 ⅝" DPS at the bottom.
- When RIH the BHA failed the shallow hole test (communication problem) at 2200m and had to be replaced. The backup BHA was successfully

tested at 600m MD, and the BHA was RIH to 2208m MD where the logging tool (LWD) was activated to log potential washouts while RIH.

- ❖ RIH without rotation, broke circulation at 4400m MD to perform 10 MWD surveys that was verified against the MWD surveys from previous run. Figure 106.
- ❖ At 4622m MD a tight spot was experienced and the string had to be worked past with 90 RPM/20-30 kNm and 900 LPM/28 bar to 4660m MD. Started to displace to new mud while working the string down. It was a big struggle to reach the bottom of the hole and establishing drilling parameters. Specifically, transferring weight down to the bit was not easy. Several spikes in both torque and weight were seen. The string was worked up and down several times with varying parameters for 15 hours before drilling commenced. The varying parameters and response can be seen below Figure 107.
- ❖ Eventually 3 stands were backreamed, and then the string was reamed down with 100 RPM and 2500-3000 LPM before a new hole was drilled at 20 m/hr. Drilling parameters were established with 3300 LPM and 180 RPM. Although there was steady drilling progress, both torque & WOB were erratic. As can be seen in Figure 108 below, the torque and weight had a wave like response corresponding to each other. As the weight increased, so did the torque.
- ❖ The immediate thought was that the 6 ⅝" DPS was the cause of the varying torque. The theory was that the difference in size and stiffness between the two drillstring used in run-1 and run-2 somehow created a cyclic torque response. Although no severe stick slip or shocks was reported from the downhole measurements, there was still a difference between the two runs (Figure 109). Regardless of what was seen, the response was still within the rig limitations, so it was decided to continue drilling, both to get as much as possible out of the BHA in hole, and to see if the response would level out over time. Some actions were tried, like reaming stands on connection, without effect.

- Drilling continued without any significant changes in torque and weight response. What could be seen however, was that the forever increasing drag seen on run-1 had stopped. Instead the friction seemed to going down slowly from 0.4 towards 0.30-0.35.
- At 5800m MD drilling stopped due to a leak in the suction manifold in the mud pumps. This was the only major surface equipment failure experienced when drilling C-16 A, and took roughly 7 hours to fix. While fixing the problem flow was first reduced to between 1600-2200 LPM, until the flow had to be stopped completely. At this point the string was only frequently moved to check that it was free as a continuous low rotation could provoke sagging of mud. Once drilling commenced the torque pattern reappeared, but now with a slightly less frequency and amplitude (Figure 110).
- During drilling there was high focus to keep a high RPM at 180 for hole cleaning. But due the high torque the RPM had be reduced to 160 to prevent the top drive from overheating. The reduced RPM had no effect on the torque response, and there was no indication that the hole cleaning became worse (Figure 111).
- In the first drilling run the drag was the main concern. In the second run the drag was still high, but was less of a concern since simulations showed that it would remain within the rig limitations. Instead torque, or specifically the torque peaks, became the main issue as it was uncertain if it would be possible to backream the section as planned. This caused the team to look for all potential mitigating actions, even the ones that was expected to fail, like adding friction reducer to the mud which through experience had shown to mainly have an effect on metal to metal friction, not formation to metal. At 5700m MD, Ultralube up to 1% concentration was added to the mud. This was agreed to be a sufficient enough concentration to prove, or disprove, any effect. And as expected no improvement could be seen on the torque picture. Later addition of

graphite (G-seal fine) to the mud was also tried without any effect on the torque.

- Around 6800m MD, backreaming on connections was tried, both as an early warning to what could be experience later and to see if it improved the torque. This procedure had no effect, and the torque picture was observed to be the same when backreaming (Figure 112). It did however show that backreaming was possible, and the drilling continued.
- At 6900m MD, all of the 6 ⅝" DP had entered the hole created in the second drilling run. There was some hope that this would improve the torque picture, but no effect could be seen on either torque or the weight (Figure 113).
- At 7668m MD, the drop segment of the well path was initiated. Both experience and simulations indicated that an increase in torque would be expected at this point. And there was a concerns if the torque increase would get so high that a stuck situation could occur. Therefore, backreaming on entire stand on each connection was initiated with close monitoring of the parameters. And at 7778m MD, TD was set 445m earlier than the initial plan, which consequently meant an additional section was required to reach top reservoir. The reason for this was the increased torque seen while drilling when starting on the drop section of the wellpath (Figure 114).

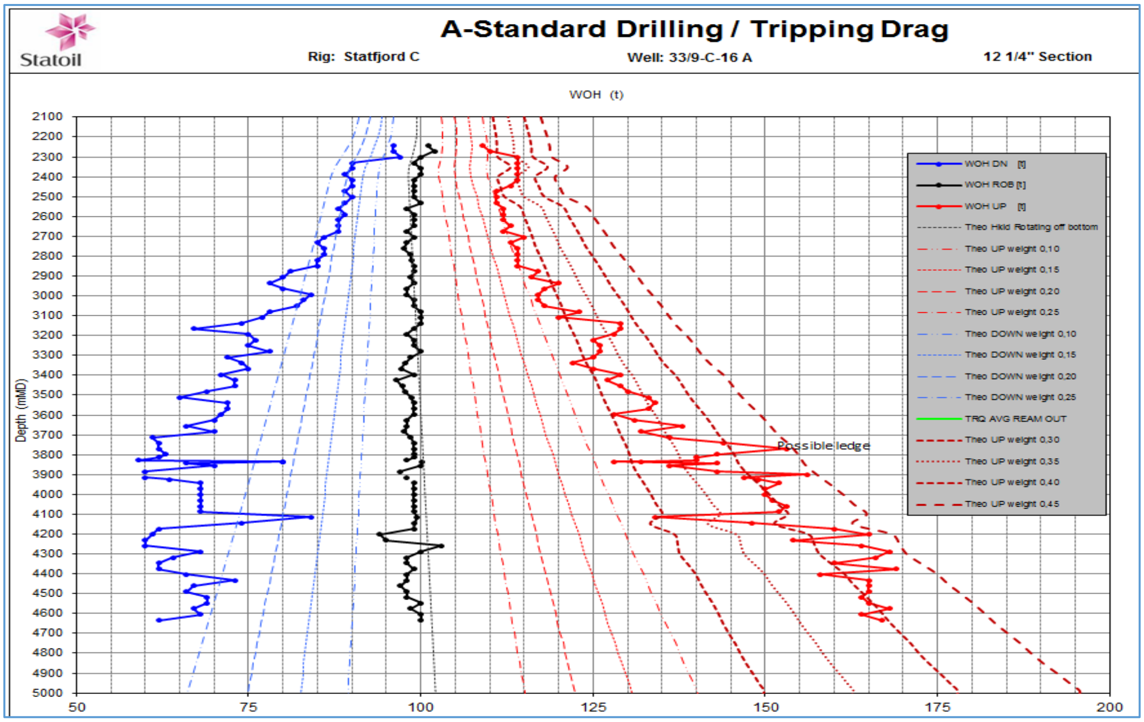


Figure 104: Roadmap of the first drilling run [6]

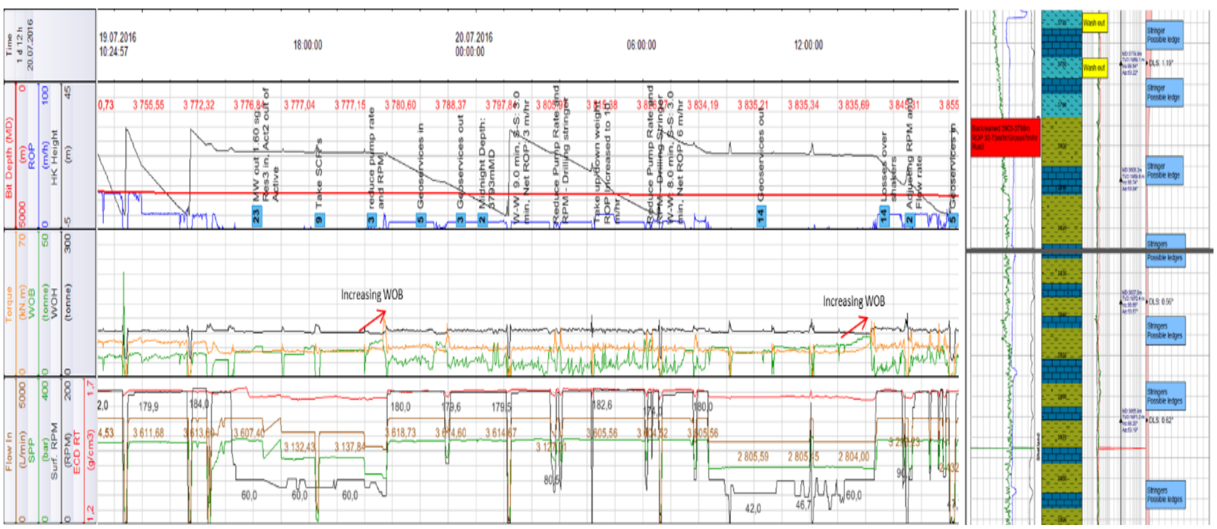


Figure 105: Parameters used when drilling stringers and the increase in inclination [6]

MWD Run-1			MWD Run-2			Gyro			Delta MWD Run-1 & MWD-Run-2			Delta MWD Run-2 & Gyro		
MD	INC	AZI	MD	INC	AZI				MD	INC	AZI	MD	INC	AZI
4314.16	**87.48**	**50.96**	4314.16	87.71	51.34	4314.16	87.25	51.8	0.00	0.23	0.38	0.00	-0.46	0.46
4336.76	**86.84**	**50.52**	4336.76	86.54	51.10	4336.76	86.61	51.65	0.00	-0.30	0.58	0.00	0.07	0.55
4394.64	**86.57**	**51.11**	4394.64	86.54	51.92	4394.64	86.24	51.69	0.00	-0.03	0.81	0.00	-0.30	-0.23
4421.71	**86.57**	**51.51**	4421.71	86.57	51.92	4421.71	86.28	51.89	0.00	0.00	0.41	0.00	-0.29	-0.03
4453.12	86.59	51.45	4453.12	86.54	52.09	4453.12	86.31	52.18	0.00	-0.05	0.64	0.00	-0.23	0.09
4479.23	**86.64**	**51.79**	4479.23	**86.74**	**51.87**	4479.23	86.38	52.13	0.00	0.10	0.08	0.00	-0.36	0.26
4506.94	**86.67**	**52.1**	4506.94	**86.68**	**52.22**	4506.94	86.43	52.29	0.00	0.01	0.12	0.00	-0.25	0.07
4537.09	**86.63**	**52.37**	4537.09	**86.68**	**52.79**	4537.09	86.43	53.03	0.00	0.05	0.42	0.00	-0.25	0.24
4597.13	**86.65**	**52.47**	4597.13	**86.71**	**52.68**	Gyro surevys not available			0.00	0.06	0.21			
4625.14	86.74	52.1	4625.14	**86.86**	**52.43**				0.00	0.12	0.33			

Figure 106: 12 1/4-in section, MWD surveys comparison [1]

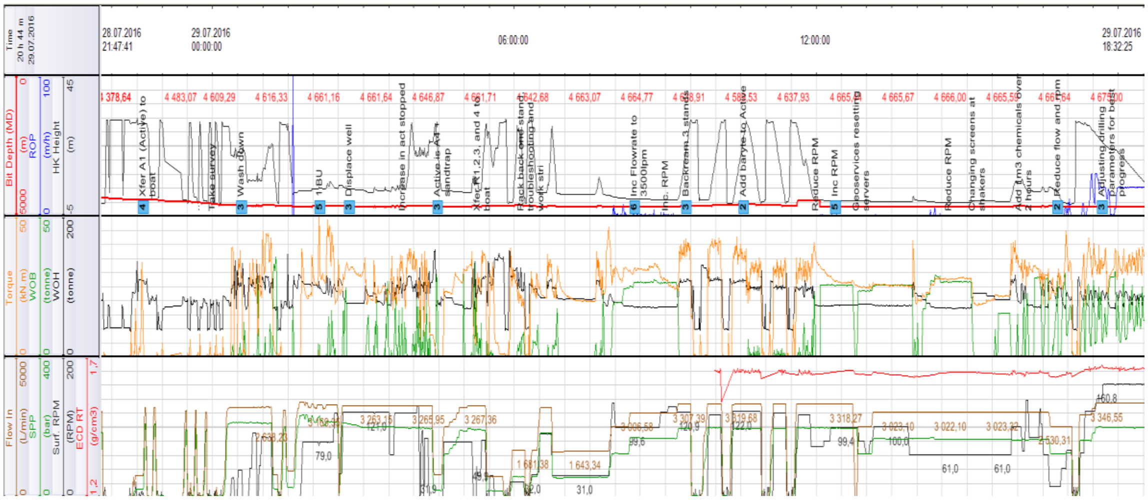


Figure 107: Parameters seen when trying to get down to start drilling on the second run [6]

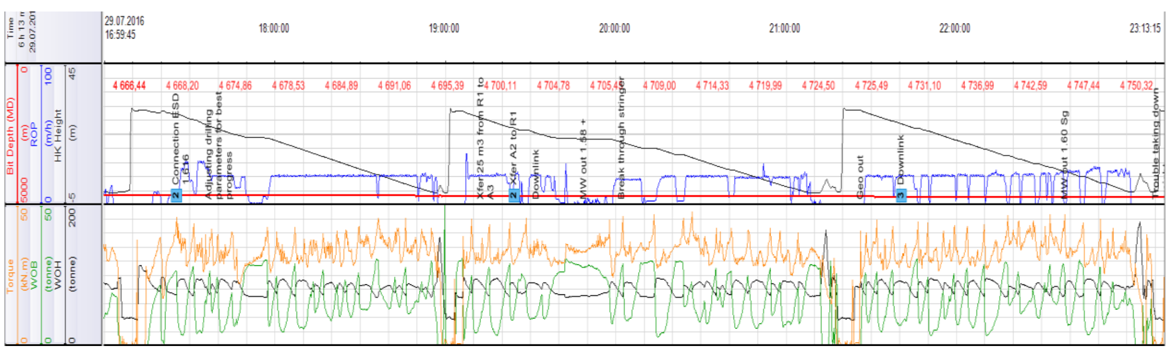


Figure 108: The varying torque and weight seen when starting drilling on the second run [6]

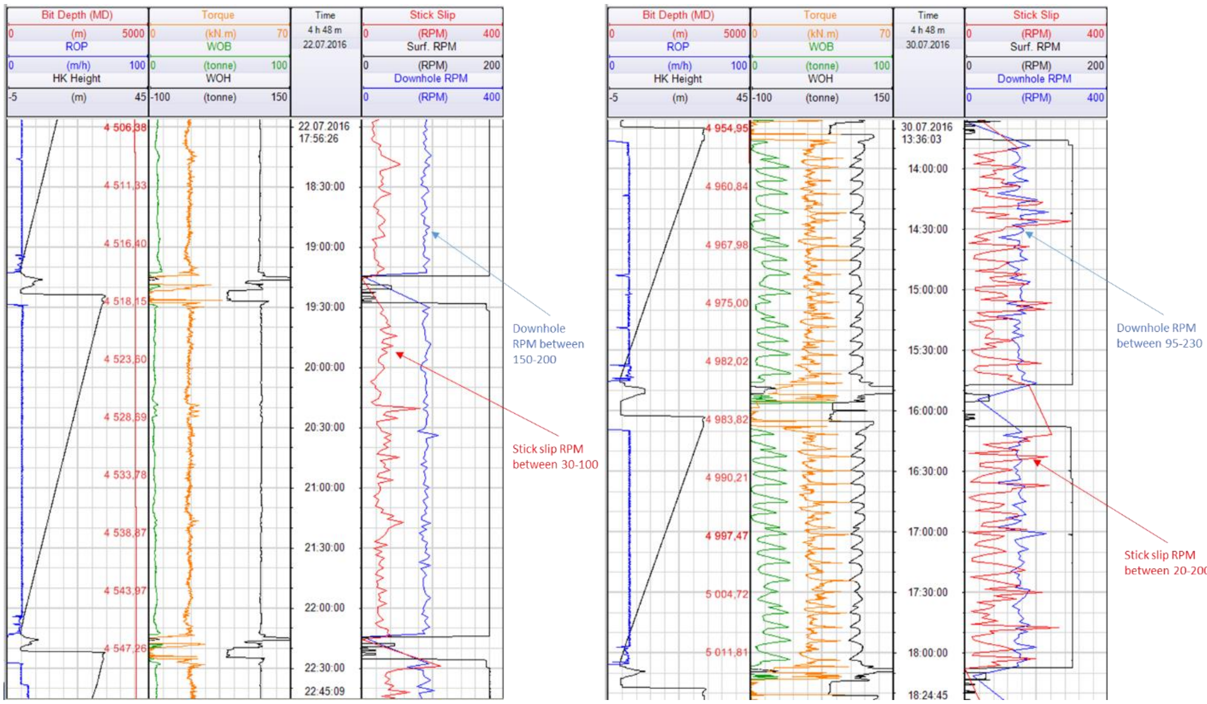


Figure 109: Difference in torque and stick slip between the two runs. The stick slip severity level was reported to be medium with mitigating reaction required [6]

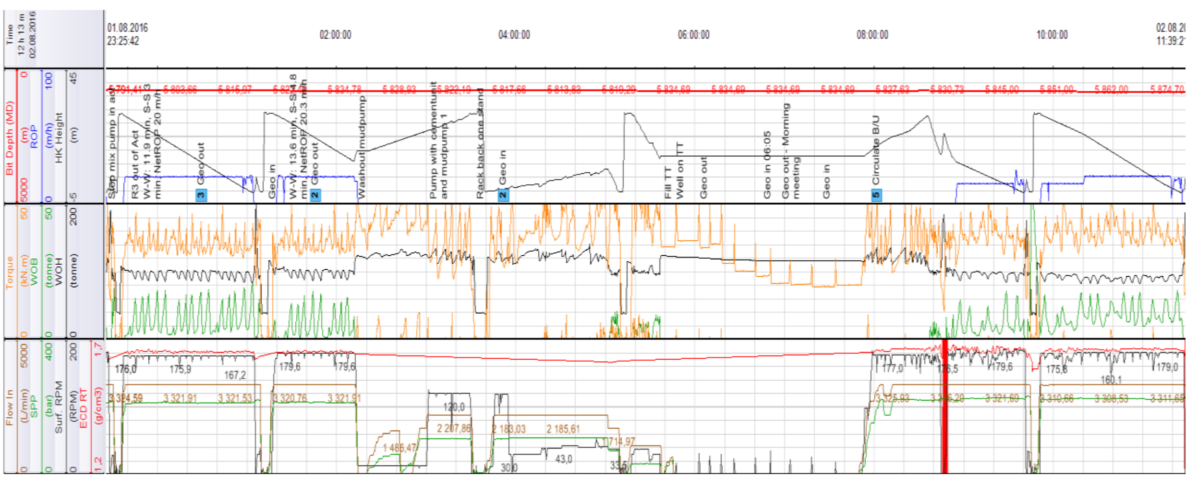


Figure 110: There was a small reduction in the torque frequency after longer stop [6]

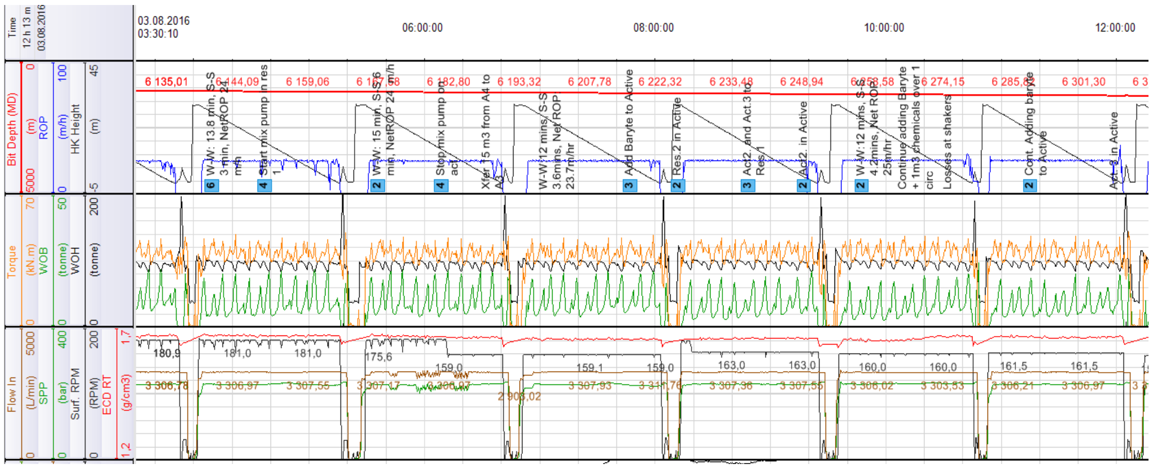


Figure 111: Picture showing no change in response when changing from 180 to 160 RPM [6]

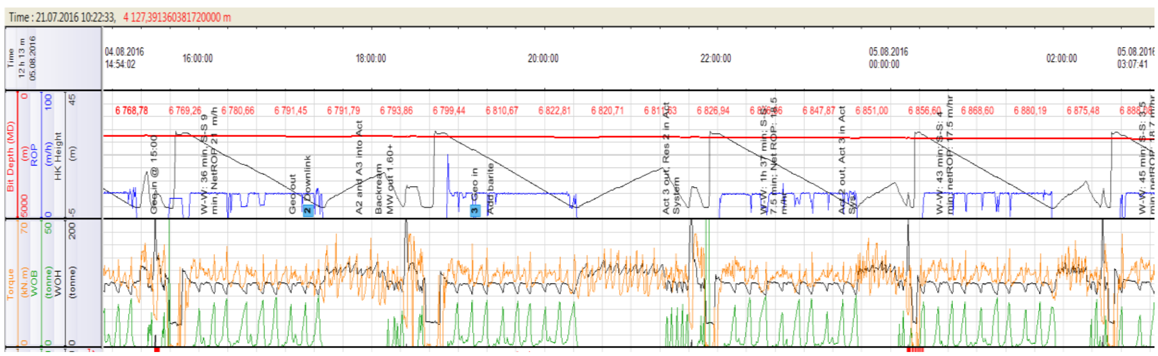


Figure 112: Parameters seen when trying to backream on connections [6]

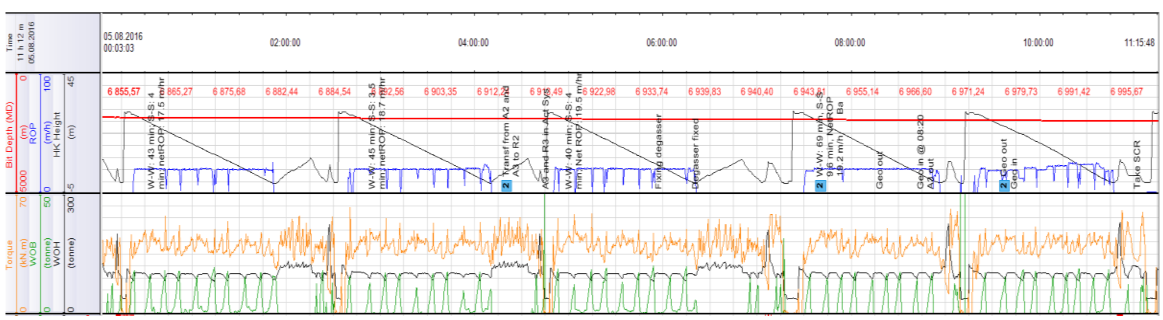


Figure 113: Torque response when the 6 5/8 DP had entered the hole drilled in run-2 [6]

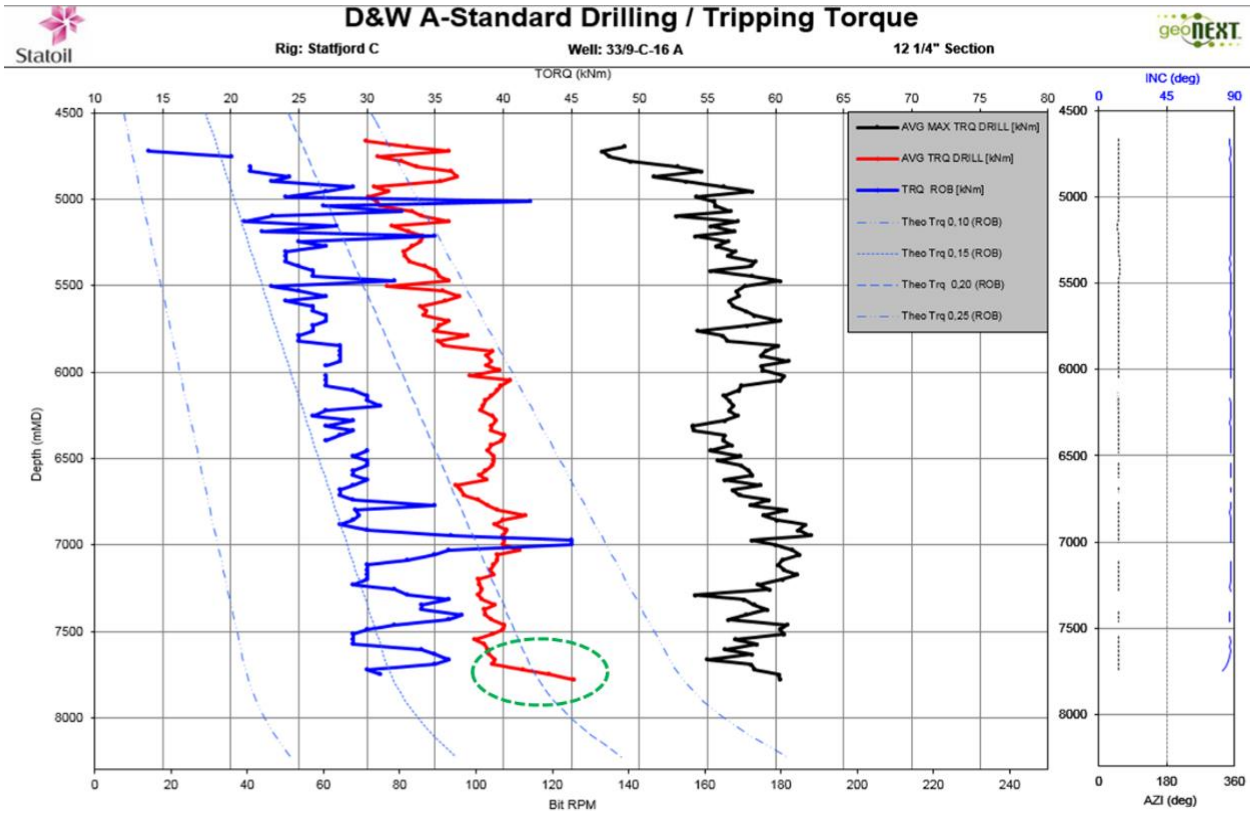


Figure 114: Torque roadmap of the second run. The torque increase causing the drilling TD to be set earlier is marked with green [6]

13.2 Tripping & Backreaming [6]

Main highlights & sequence of backreaming conducted as follows [6]:

- After reaching TD backreaming was initiated. The first stand was planned to be pulled slowly to clean the hole, and then the pulling speed was to gradually increase. But already on the first stand high over-pull and torque was seen, causing stall outs and uneven rotation. Almost eight hours were spent on backreaming the first stand. Due to this slow progress, halfway through the second stand the offshore crew tried to pump out of hole. But this soon led to increasing pump pressure and partial pack offs, so backreaming was again initiated. Backreaming speed was slow, about 2-3 m/hr, causing the crew to again try pumping out of hole. About 80m was pulled, over a 2-hour period, before pack-off tendencies was seen, and backreaming was continued. Backreamed with 180 RPM and 3600 LPM, and with a torque varying from 30-60 kNm.

- ❖ When reaching 7400mMD, on day 3 of backreaming, the cap seal and pulse dampener in the mud pumps had to be changed causing a stop in the backreaming operation. While fixing the mud pump, flow was maintained with the HT400 pump with 40 RPM on the string. Just before the pump failure, a small flattening trend on the torque and hookload could be seen, this trend became clearer when the backreaming continued again. It was now possible to maintain a backreaming speed of 10-15 m/hr. The rotation speed was also reduced from 180 to 160 RPM. As the parameters were flattening out, the backreaming speed was gradually increased to 30 m/hr at around 7000m MD. This speed was maintained until 6140m MD, where indications of pack-offs were seen by an increase in ECD and pressure, and the speed was reduced. The pack-off tendencies eventually disappeared, but at 6080m MD the erratic torque re-appeared. This also corresponded to the 6 5/8" DP entering the earlier mentioned area with several stringers.
- ❖ After only being able to backream 100m over 2.5 days, a decision was made to try and pump string across the assumed trouble area. The flow was reduced to 1000 LPM while trying to pull free with 232 tonnes hookload without success. Another attempt was tried, this time with 21 kNm torque and 206 tonnes hookload. When this did not work, it was decided to go back to backreaming. The surface torque was removed, and the hookload was reduced to free rotation weight (119 tonnes). 62 kNm was then applied to the string to attempt to establish rotation. The pump rate reduced from 1000 LPM/29 bar to 1000 LPM/4bar and the torque reduced to 2 kNm. The flow was increased to 3500 LPM, and the corresponding pressure showed that the string had backed off at approximately 1500m. The string was pulled out of hole, and it was confirmed that the connection at 1404m MD was unscrewed. Damage could be seen on the pin at the end of the last joint (Figure 115), which was removed, and a fresh joint was ran back in hole in an attempt to screw back on to the string.

- The joint was tagged at correct depth and flow was increased to 300 LPM while trying to screw in. An increased pressure was observed, confirming that pin end had entered the connection. Make up torque was then applied to the string, and the joint was successfully screwed back in. Circulation was established, and a total of 3.5 BU was pumped, before rotation was established with 160 RPM and backreaming continued. The incident did not affect the parameters, as they still corresponded to that before the incidents, including the erratic torque and slow backreaming speed.
- Due to the slow progress, it was discussed if the operation should be aborted, by cutting the string about 1000m below the 13 ⅜" casing shoe and leave the rest down hole. But since the cost of the string left in hole equalled to more than a week of operations, the cutting operation was put on hold to make sure all measured was tried to get the string out of the hole. As a result of this, the following list of measures were sent to rig crew to try before the operation of cutting the string was initiated:
    1. Add lube
    2. Add G-seal
    3. Try lubricating out (low flow and stepwise reduce RPM)
    4. Ream down minimum 30m, and then try to go up again.
    5. Pull string with 280 tonnes. In this case it was to make sure that the torque in the string is not more than 60kNm to avoid twist-off.
    6. Increase Mud Weight
    7. Increase Mud Rheology
- Both point 1 and 2 showed no effect (this had also been tried earlier without any significant effect). Lubricating out did not work, as it was impossible to maintain a low rotation due to high torque spikes and stall outs. It was then decided to go straight to point 5, which had been put further down the list due to the weak connection down hole.
- The torque was removed according to the procedure, and 230 tonne was applied to the string. Several attempts were tried, pulling out string by applying 230 tonnes followed by a rapid release down to 100 tonnes. On

the 11th attempt the hookload reduced to approximately 180 tonne, and the string could be POOH. First the string was pumped out of hole until the weak connection was pulled to surface, and then the rest was pulled straight out without pumping.

Figure 115: Damaged Pin-end [6]

Figure 116: High torque in backreaming [6]

13.3 Wiper Trip [6]

It was discussed whether to go with wiper trip prior to running liner or directly go with liner. Eventually it was decided to go in with a wiper trip due the large downside of an unsuccessful liner trip. If the liner had to be pulled out of hole, it could not be re-used (since it is necessary to break of the connection when pulling out with liner, the seal could not be guaranteed when making it up again. This would increase the risk of leakage on the liner, and could potentially cause a well control situation), and ordering a new liner would take 11 months. In worst case, a failed liner trip could cause loss of the well. The purpose of the trip was to both check the condition of the hole, to backream the areas that was not backreamed in the previous run & try to drill to planned TD if possible. Main highlights & sequence of wiper trip were conducted as follows [6]:

- The string weight was reduced to an absolute minimum, using only 5 ⅞" DPS, one non-mag HWDP and no Jar. Downhole drilling mechanics sub (Optidrill) was included in the BHA to understand downhole environment better. Figure 117 shows the BHA used.
- Tripped in at around 200 m/hr, but had to reduce the speed further down as more frequent filling was necessary due to less down weight caused by the drag. At 4400m MD the pipe had to be rotated down due to the friction, and the tripping speed was reduced to 100 m/hr. At 6000m MD it was decided to do a friction test and try backreaming to gather data and compare the response of the 5 ⅞" DP to the 6 ⅝" DP used in the previous run. The friction had gone down compared to the drilling run, but the torque response when backreaming remained the same. The torque seen when rotating down was fairly stable (Figure 118).
- While the operation continued by rotating the string down towards TD, there was a discussion if it was worth trying to drill the last 500m, but this was in the end declined due to risk of getting stuck because of the high torque. In Figure 119, one can see how the torque gradually increased as the string was rotated across the drop.
- TD was tagged with rotation, and hole was circulated clean. Three BU were circulated with 160 RPM and 3120 LPM (flow was limited due to the 5 ⅞" DP). Small amounts of cuttings was seen on the shakers while circulating. After circulation was finished, the string was pulled up to 5800m MD, about 100m above the depth where the string was pulled free on the last run. From there backreaming was again initiated, and this time a more

aggressive approach was used while backreaming. On the first stand the same erratic torque could be seen, but as the pulling speed was gradually increased the torque straighten out (Figure 120).

- ❖ From here on the backreaming went according to procedure, with a pulling speed between 30-90 m/hr, 160 RPM and 3350 LPM. Pack-off tendencies were almost non-existent, but the speed was reduced at potential pack-off areas noted in the trip risk log. The amounts of cuttings were also steadily low. At some occasions communication to the MWD and hence the ECD measurements were lost. Even though, the backreaming continued as no major pack-off tendencies had been seen and the risk of not getting the ECD measurements was regarded as minimal.
- ❖ At 2900m MD, backreaming was stopped due to entering of Våle formation. The cavings that had been seen on the previous run was identified from this formation, so it was not desirable to backream in this area. Instead the hole was circulated clean, and the string was pulled inside the 13 ⅜" casing shoe. Here the hole was again circulated clean, this time with the inclusion of the HT400 pump which got the flow up to 3900 LPM. Minor amount of fines and cuttings was seen on the circulation. The string was pulled out of hole, the BHA was laid down and preparations for running liner commenced.

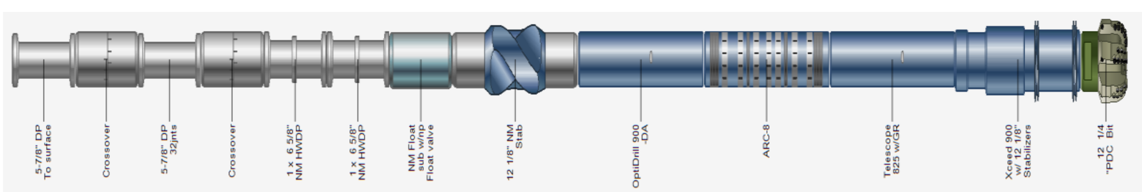


Figure 117: Wiper trip BHA [6]

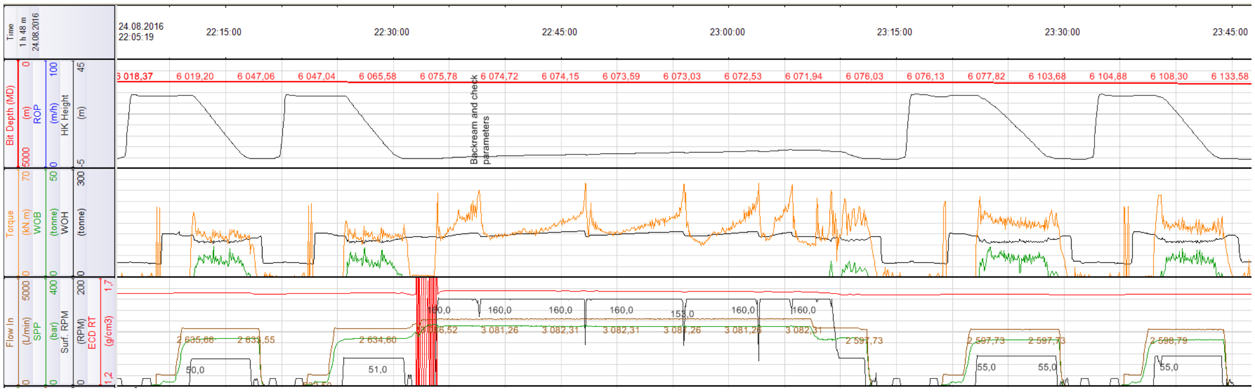


Figure 118: Parameters when running in hole compared to backreaming [6]

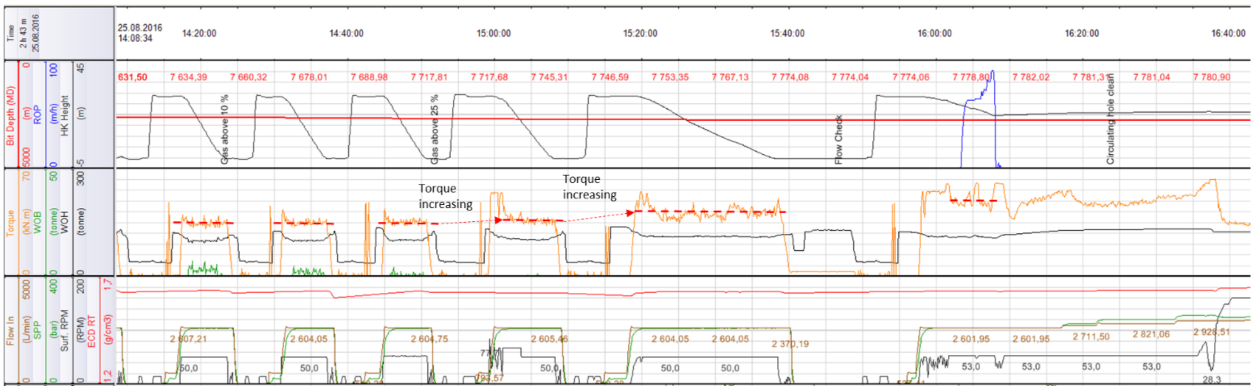


Figure 119: Parameters when running in hole. Torque increased as the BHA moved across the drop [6]

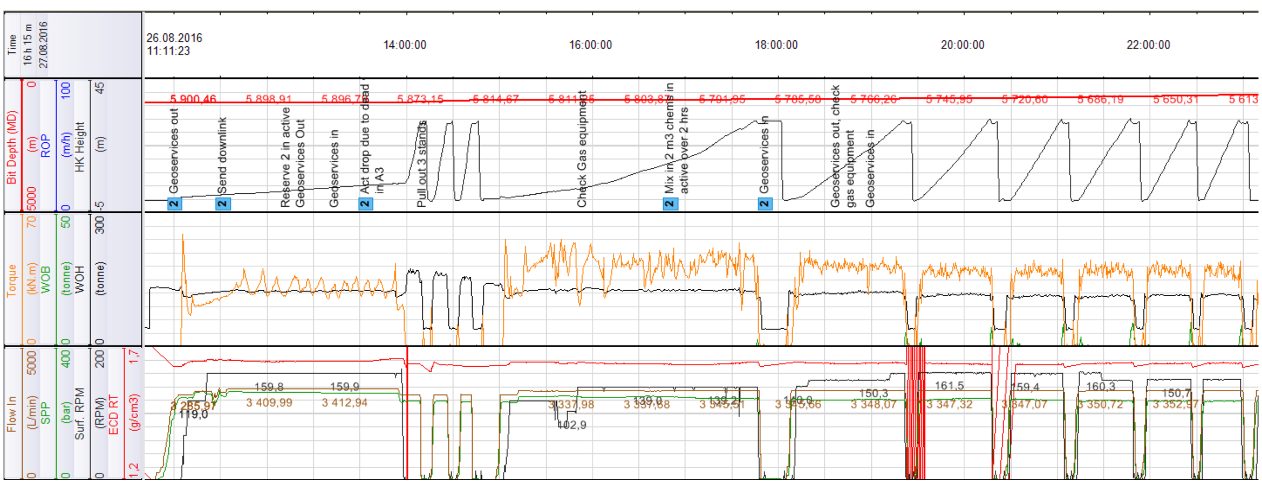


Figure 120: It shows how the pulling speed was gradually increased and the torque response became more stable. The string was also pulled across the area where the backreaming stopped on second run. [6]

13.4 Floating Liner [6]

9 5/8” liner was floated to TD successfully without issues but this will not be discussed in details in this thesis.

13.5 High Resolution Surveys [1]

Figure 121 shows the tortuosity evaluation of the drilled section in run-1 by the use of the High-resolution surveys. We can clearly notice the effect of the stringers and formation changes in the definition of the inclination. This figure also shows how the High-resolution surveys correlates very well with the raw continuous inclination from the RSS tool, this serves as a quality control that both independent sensors measurements –MWD and RSS- are correct and well within the tolerance limitations. This, in addition to the dual inclination analysis, allowed the application of the dual inclination error model in this interval.

Figure 122 shows the impact in the DLS once the High-Resolution inclination is taken into account to define the trajectory. Even though additional unseen DLS were revealed they were not significant enough to compromise the liner floating [1].

As per run-1 High-resolution continuous surveys were used to evaluate tortuosity (Figures 123), Dual Inclination processing also passed the QC criteria allowing the use of Dual Inclination tool code in this second run as well. In terms of DLS evaluation, there were intervals in which also the High-resolution DLS seems higher than the static one, but in overall the average of the High – Resolution DLS over the tangent interval was in the order of 0.65 deg/30 m correlating with the average Static DLS of around 0.45 deg/30 m indicating good wellbore quality (Figures 124) [1].

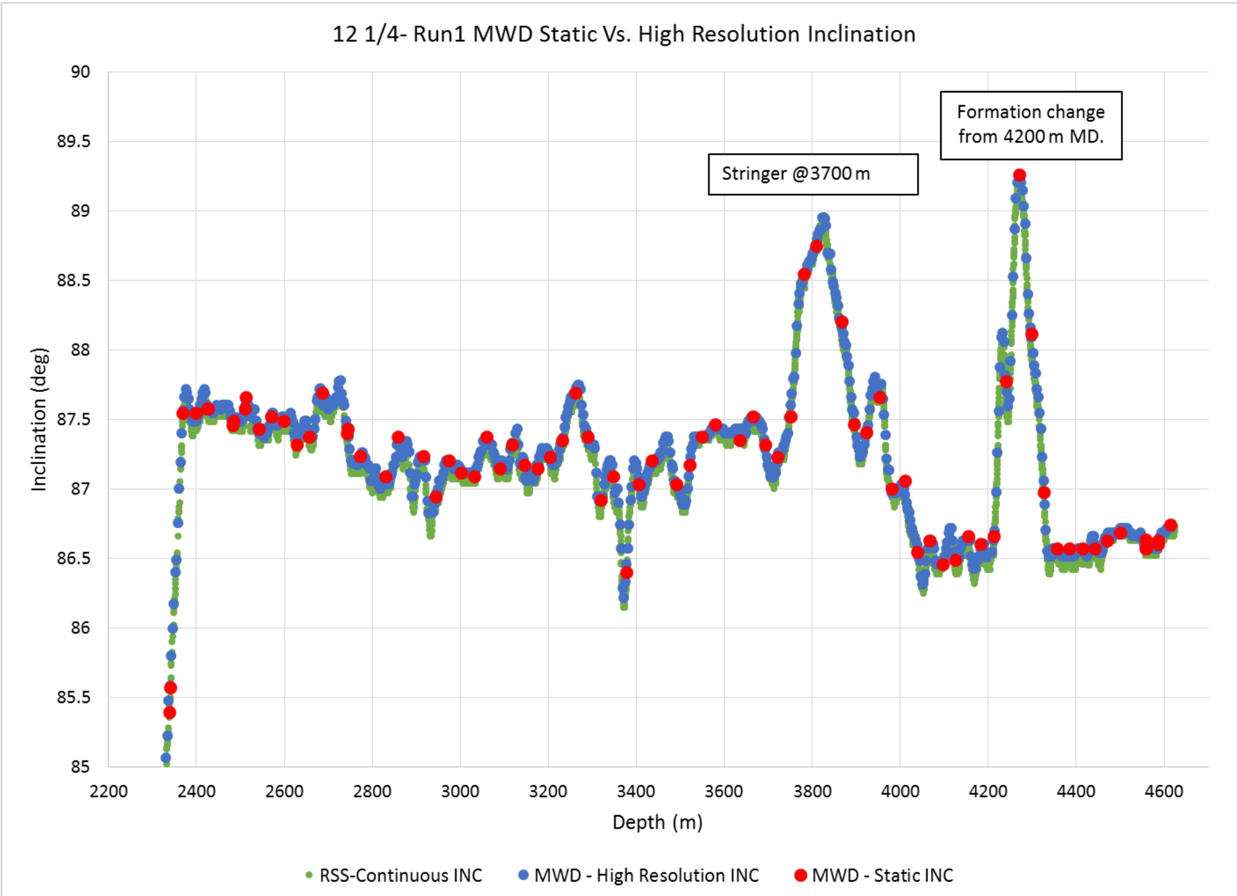


Figure 121: High- Resolution Continuous Inclination surveys vs RSS Continuous Inclination, Run-1 [1]

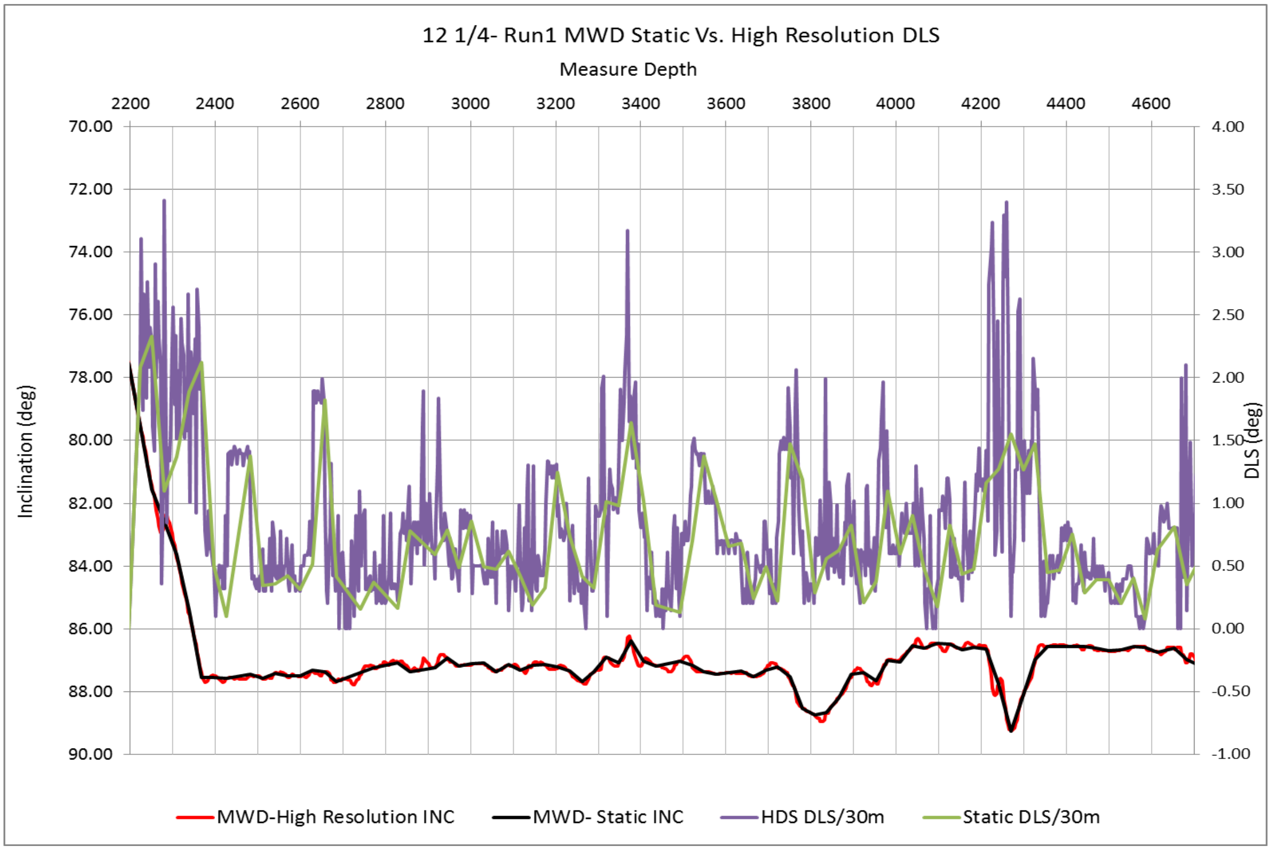


Figure 122: High- Resolution Continuous Inclination vs Static DLS, Run-1 [1]

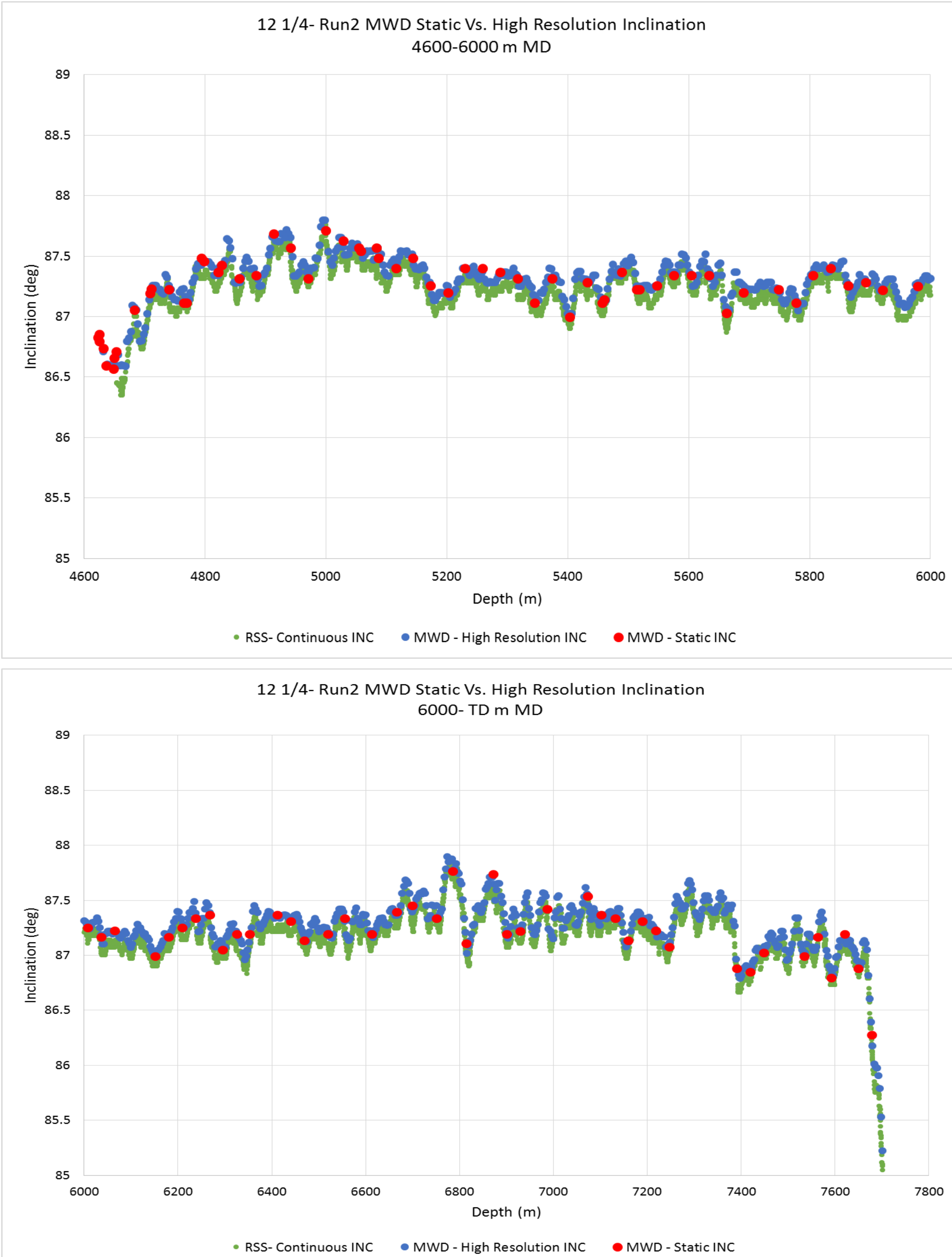


Figure 123: High- Resolution Continuous Inclination vs Static DLS, Run-1 [1]

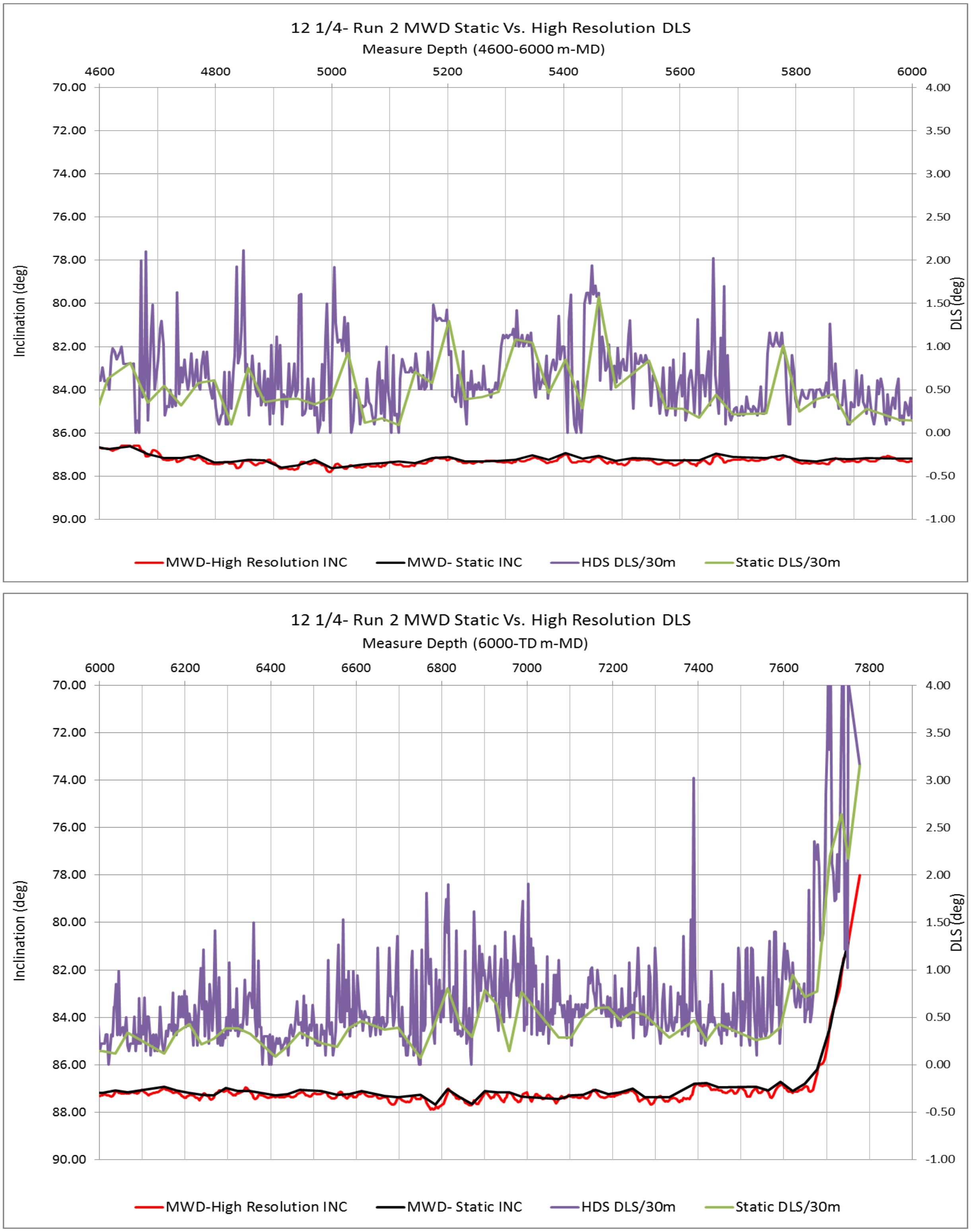


Figure 124: High- Resolution Continuous Inclination vs Static DLS, Run-2 [1]

13.6 Lesson Learned

Following lessons were learnt in 12 ¼” section:

- ❖ An increased bending moment was observed across the stringers in the wiper trip run with the downhole drilling mechanics sub [1].
- ❖ Although the final results from ongoing investigations have yet to be completed, the immediate reactions was that the problems encountered in the 12 ¼-in section were due to off-specification mud and fast ROP [1].
- ❖ The point-the-bit RSS proved to be an extremely robust tool and was still functioning normally after ~500 hrs downhole in the 12 ¼-in section [1].
- ❖ The HIA mode allowed the point-the-bit RSS tool to automatically control inclination and azimuth in long tangent section mitigating risks of hole spiralling and tortuosity. Evaluation of the tortuosity by the use of High-resolution continuous surveys shows good wellbore quality [1].
- ❖ Downhole drilling mechanics sub in the wiper trip proved very helpful in analysing drilling mechanics and weight transfer [1].
- ❖ The BHA showed exemplary performance in all sections and showed no damages to components. The same BHA strategy will be followed on future ERD wells [1].
- ❖ Lubricants did not show significant improvement.
- ❖ Hole cleaning was not optimal during drilling, cuttings stayed in the hole for a long time and was finely ground up [6].
- ❖ Overgauged Lista; mechanical cavings from this formation was observed throughout the backreaming and cleaning of the well [1].
- ❖ High drag when drilling the 1st part of the 12 ¼” section could be possibly due to: Stringer and uneven hole, hole cleaning, Spiral hole, Buckled 13 3/8” casing and 17 ½” rat hole or Formation creeping [6].
- ❖ Sinusoidal torque and hook load when drilling the 2nd part of the 12 ¼” section could be possibly due to: Inverted tapered drill pipe, TDS induced, two run drilling strategy, washouts in Lista formation after backreaming or a consequence of the high drag seen in first run [6].

- ❖ High torque and over pull when backreaming the 12 ¼” section could possibly due to: Key seating or consequence of high drag [6].
- ❖ Successful use of GWD90 for MWD verification. Agree on W2W time with Gyrodata on future wells (on this well it took up to 18 min).
- ❖ GWD90 battery was depleted while BROOH leaving 17½” section unverified especially in blind zone-Never plan to use GWD90 OBM surveys for MWD verification on ERD wells (most likely battery will be depleted). Plan for drop Gyro as a contingency and have it on rig.
- ❖ Unable to drill to planned depth in run-2 due to diverging trends on roadmap (this resulted in more problematic 2nd run drilling & tripping)-Use correct mud system & plan future sections in one run.
- ❖ Successful use of first run MWD surveys (10 surveys) to verify 2nd run MWD surveys-Similar strategy can be used on future ERD wells after Statoil approval. PowerDrive Xceed surveys can also be used to support the argument.
- ❖ Wellbore quality/wellbore spiralling/tortuosity-No significant tortuosity in wellbore, spiralling was not possible with this bit and BHA & 9 5/8” liner was run successfully.
- ❖ Inclination pushed up at stringers due to maximum 50% setting allowed in HIA mode-This required to disengage HIA and apply more settings in manual to bring inclination down. On future operations up to 70% setting will be allowed in HIA mode to bring the inclination down especially at stringers.
- ❖ 100% high side setting on PowerDrive Xceed really worked during BROOH-Same is recommended for future operations & can be shared globally.
- ❖ Higher friction than expected (up to 0.45 FF) compared to historical FF of 0.2-0.25 maximum-Use BHA as light as possible. Use of 3rd pump for better hole cleaning was a success. Avoid using 6 5/8” DPS.

14 8 ½" Section- Planning & Execution

14.1 Planning

This section was planned in reservoir with rotary BHA & no steering was required. Since 12 ¼" section TD was marked ~400m earlier than planned so 8 ½" section was planned as a contingent section to drill last 400m to top of reservoir with Xceed BHA.

The concept of an 8 ½" contingency section had been discussed in the pre-planning, but most of the detailed planning was done during operations phase. When length of the section was only 500m, the section was regarded to be less of a concern with the biggest risks being losses due to high ECD and potential problems running the 7" production liner. Drilling BHA (Figure 125) was planned with the same concept as in 12 ¼" section but with low flow rate limit tools. The 9 5/8" shoetrack was planned to be drilled in a separate run due to the poor cement job and the uncertainty around the wiper plug system (no indication of bumping). One of the advantage of including a new section was the use of Ultralube. Since more than 90% of the wellpath was now sealed off with casing, the effect of the Ultralube on the friction factor was expected to be significant and the problems seen in the previous section were expected to be disappeared. Another advantage of including a new section was the possibility of having a good cement job much deeper. This would make future P&A of the well less complicated and much cheaper [6].

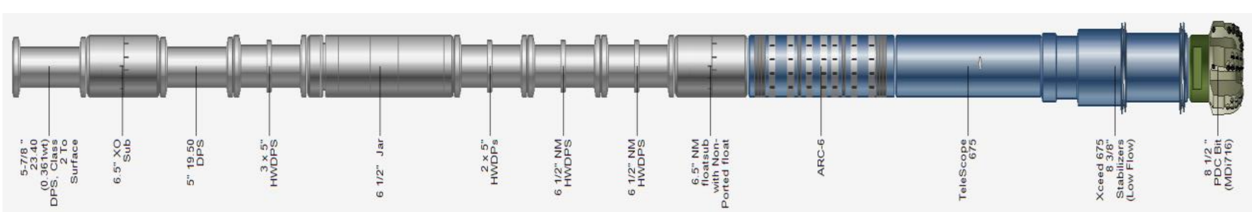


Figure 125: 8 ½" drilling BHA [1]

14.2 Execution [6]

This section was drilled in three runs i.e. drill out run, open ended drill pipe (OEDP) for cement squeeze & followed by drilling BHA run. Followings were the drilling sequence for this section.

- 8 ½” drill out BHA (consisting of a milled tooth bit and 4 stands 5” HWDP) was made up and RIH. At 3450m MD the string had to be worked through a restriction (with 30 tonne), probably related to pre-release of wiper plugs from the liner run. From 5800m MD the string had to be washed and rotated down to overcome the normal friction with 40 RPM and 500 LPM to get to TD. The float collar was tagged at 7756m MD, 2m shallower than expected, and drilling of the shoetrack was initiated while bleeding in Ultralube. After drilling about 3m, losses were experienced, confirming no cement. Once the pumps were stopped, the lost volume was regained (ballooning).
- While drilling shoetrack there were discussions to perform a squeeze cement job in the same run. But it was eventually decided to POOH. This was due to the uncertainty of getting a successful squeeze job at this depth with the current BHA & risk of BHA getting stuck.
- It was decided to perform a cement squeeze with OEDP (including a float sub). The string was RIH without rotation (the Ultralube had significantly reduced the friction), and a 20m3 of cement was successfully placed and squeezed. The squeeze pressure was held for 12.5 hours before circulating the well clean and POOH.
- The 8 ½” drilling BHA was made up and RIH with little resistance, but had to be rotated down from 7580m MD due to friction. The cement was drilled out without any indication of ballooning/losses. As an additional measure to the ballooning problems seen earlier, an LCM pill was placed, squeezed and washed out prior to taking FIT to 1.75 S.G. Drilling parameters was established with 160 RPM and 1400 LPM (limited by ECD). The ROP was set to maximum 20 m/hr. The drilling and steering went very smoothly with an average torque FF between 0.13-0.16 and drag FF between 0.21-0.23. Figure 126 shows road map for drilling 8 ½” section.
- The hole was circulated clean with 4 BU at 1800 LPM and 170 RPM, where the majority of the cuttings were seen on the first BU. The string was then pulled inside the 9 ⅝” shoe, where the liner was cleaned by pumping 1.5

liner volumes at 1800 LPM. The BHA was then pulled and laid down, before going in with 5 7/8" OEDP to top of 9 ⅝" liner to perform a last clean out of the 13 3/8" casing. The casing was cleaned with 3850 LPM and 150 RPM. Some flat cuttings were seen on the shakers, but after 1.2 BU the amount was insignificant and the circulation was stopped and the DP was pulled out of hole.

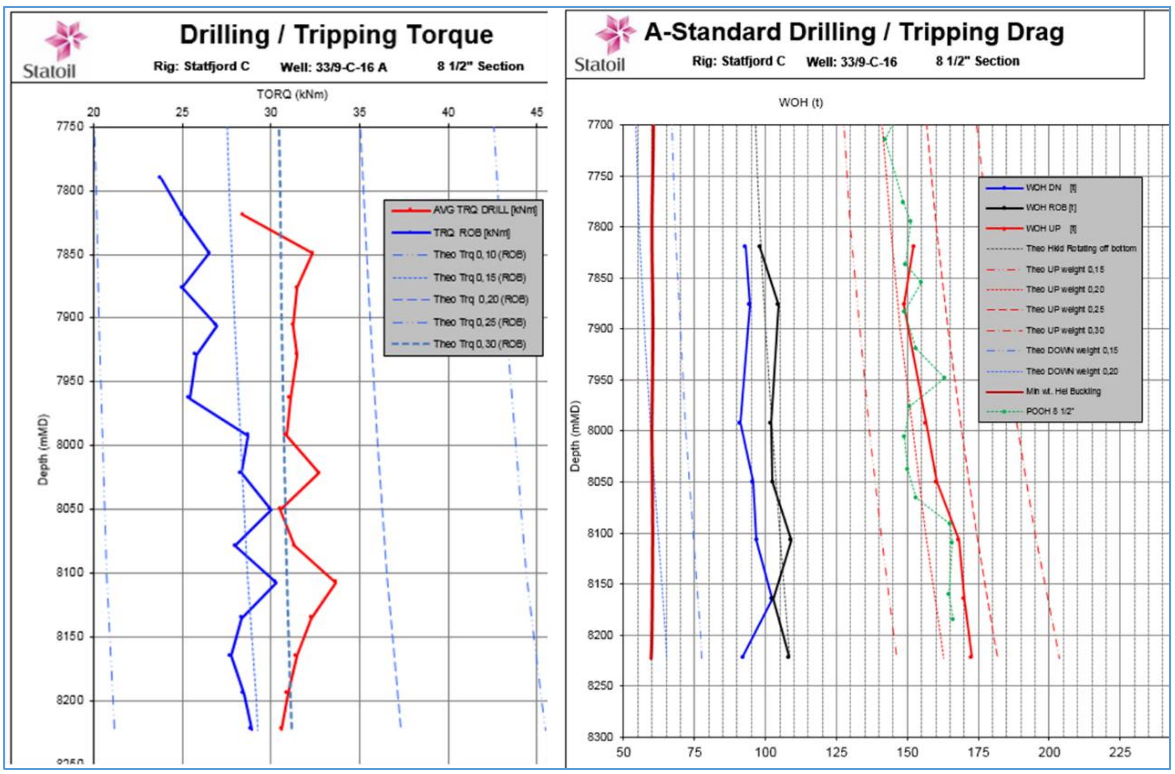


Figure 126: Roadmap for drilling 8 1/2" section [6]

14.3 Running Liner & Cementing

7" liner was successfully run to TD & cemented without any losses. This will not be discussed here.

14.4 Lesson Learned

Following lessons were learnt in 8 ½" section:

- ❖ Rheguard oil based mud provided good hole cleaning with limited flow rates [6]
- ❖ Increasing torque when displacing from Rheguard to WARP [6]
- ❖ Adding 3% lubricants helped to reduce friction in the cased hole [1]

- ❖ Drilling 9 5/8" liner shoe track in 5 hours using dedicated shoe track drilling procedure (utilizing Sakhalin experience)- Always use this shoe track drilling procedure for ERD & normal wells. It was faster than many normal wells on Statfjord. Use similar BHA's with 1 x string stabilizer.
- ❖ Drilled 8 ½" section as per plan without any aggressive DLS (drop was spot on plan) - Use controlled settings and offset experiences. Use similar BHA without string stab in similar environment.
- ❖ Friction factors whilst 8 ½" section drilling were not far from theoretical values (POOH: 0.2-0.25, down weight: 0.15-0.2, torque: 0.15-0.2 & rotating off bottom same as theoretical). RIH 8 ½" drilling BHA down to 7389m MD without rotation- Same BHA & drill string design on future ERD wells in 8 ½" section. 3% Ultra lube really helped to bring down friction (mostly cased hole).

15 6” Section- Planning & Execution

15.1 Planning

This was contingent reservoir section which was not planned earlier. Most of the planning was done during execution phase. Here the biggest concern was choice of DPS. Usually the 6” section on Statfjord is drilled with 3 ½” DPS inside the 7” liner. But due to the low make up torque on these pipes, and the higher torque expected at this depth, 4” DPS were planned to be used. The downside from the larger OD pipe, such as increased ECD and torque, were relatively low due to a short 7” liner.

Concerns around hole cleaning and debris from the shoetrack, which has caused problem on standard Statfjord wells earlier, resulted in the decisions to have a separate shoetrack drill out run. This enabled optimizing the BHA for flow, with larger nozzles on the bit and higher flow with a higher mud density. Normally roller cone bit is used in drilling shoetrack but here PDC bit was selected to minimize risk of losing the cone.

Placement of circulation subs and well cleaning strategy prior to running the completion equipment was analysed and discussed based on simulations. Here the goal was to get as high flow as possible at different parts of the well without fracturing the reservoir due to high ECD. Large parts of this had been agreed in the planning phase, but some adjustment had to be made to accommodate for the contingency 7” liner [6].

15.2 Execution [6]

This section was drilled in two runs i.e. drill out run, followed by drilling BHA run. Followings were the drilling sequence of operations in this section.

- ❖ The 6” drillout BHA was made up and RIH without meeting any restriction. The FF seen when RIH was between 0.15-0.19, and it was not necessary to rotate the string to get down. The shoetrack was drilled out in four hours with 1300 LPM and 70 RPM with a torque between 20-30 kNm.
- ❖ The well was then cleaned, first through the bit at the bottom of the rathole with 1300 LPM and 120 RPM. Then the bit was pulled to the top of 7” liner

where the 9 5/8” liner was cleaned with 1650 LPM and 120 RPM. Some fines and rubber pieces were seen on the shakers, which peaked between 1.5 and 2 BU. A total of eight 9 ⅝” liner volumes were pumped before the circulation sub (located 1800m below top 9 5/8” liner) was opened, and the 13 ⅜” casing was circulated clean with 3700 LPM and 80 RPM. After circulating about 1.5 volumes of 13 ⅜” casing, more rubber elements from the shoetrack were seen on the shakers. The final circulation was stopped after circulating 5 casing volumes. The circulation sub was closed, the BHA was ran back to TD, and the well was displaced to 1.30 S.G WARP mud. BHA was pulled out to surface.

- 6” reservoir drilling BHA (Figure 127) was made up and RIH. At the 7” liner shoe, the mud was conditioned and LCM (lost circulation material) was bled into the mud. The section was drilled to TD at 8330m MD using 740 LPM and 70 RPM. Figure 128 shows road map for drilling 6” section.
- Open hole was cleaned with 750 LPM and 100 RPM while pulling out slowly. At the end of the circulation, preparation to displace bottom part of well to completion fluid (LSOBM) started. The BHA was RIH to TD as LSOBM exited bit and displaced up to the near horizontal part of the well. The LCM from the WARP mud was screened over the shakers throughout the displacement. While screening the mud a pressure drop was experienced as MWD flow limit was exceeded. Attempts were made to adjust flow to wake it up again without success and the MWD remained inactive throughout the remaining operations.

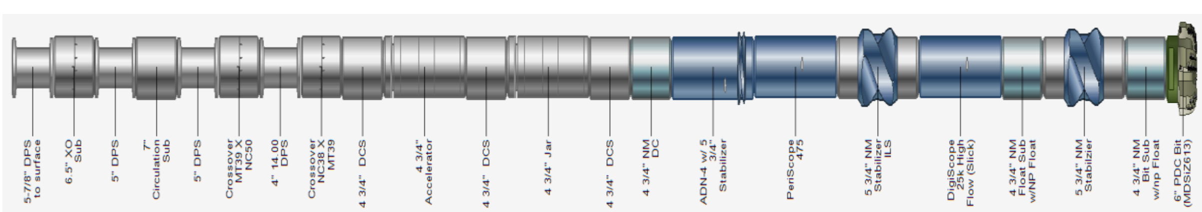


Figure 127: 6” section drilling BHA [1]

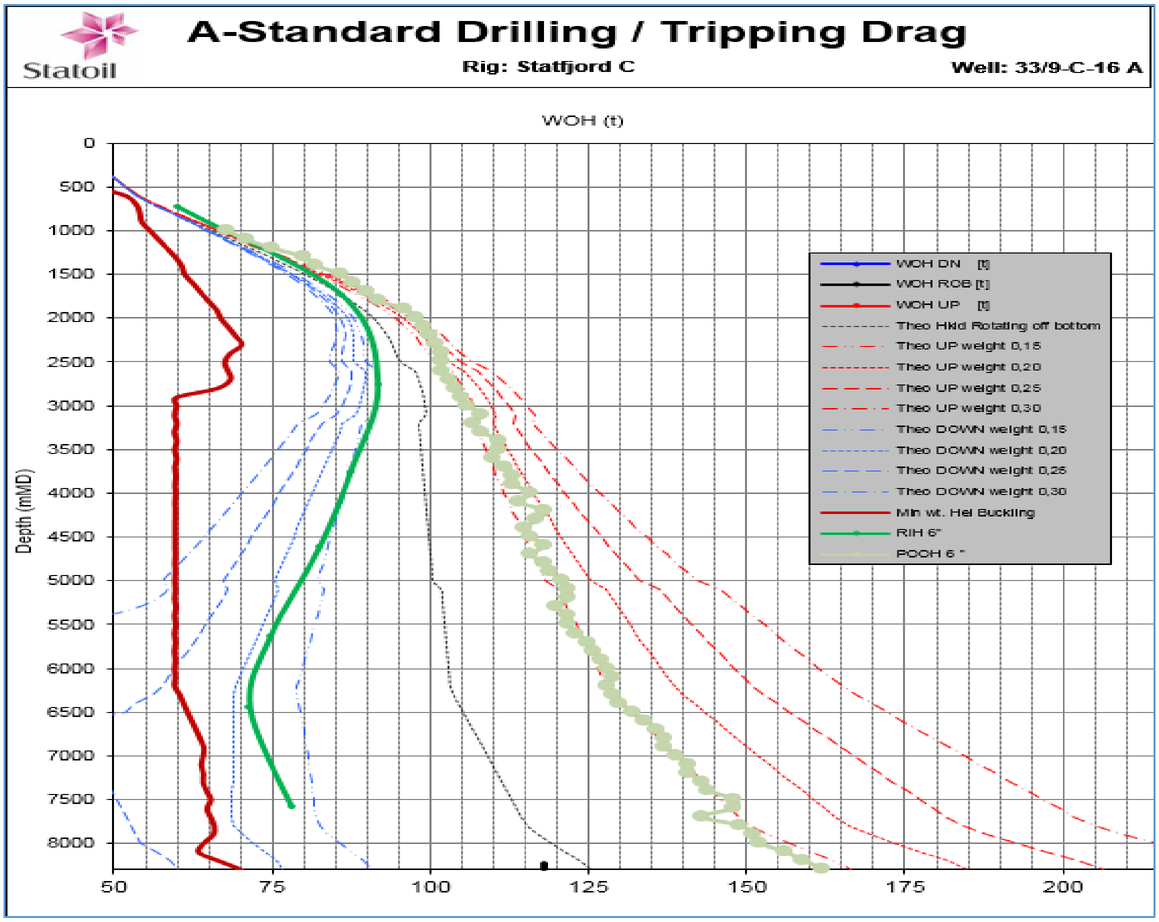


Figure 128: 6” section road map [6]

15.3 Lesson Learned

Following lessons were learnt in 6” section:

- New technology MWD (Digiscope) assured signal strength and provided high data transmission rates in deep ERD well [1]
- Friction factors whilst drilling 6” section were not far from theoretical values (POOH: 0.15, down weight: 0.15-0.2). RIH 6” drilling BHA down to float collar without rotation. Used two floats in BHA due to longer trips- Same BHA & drill string design on future ERD wells in 6” section. 3% Ultra lube really helped to bring down friction (mostly cased hole).
- Drilling flow close to lower limit of Digiscope due to ECD limitations (Digiscope flow kit: 750 – 1170 LPM) - Digiscope worked perfectly and was turned on at 700 LPM, section was drilled at 750 LPM.

- ❖ Digiscope was selected due to well depth & helped with good signals and it worked perfectly- Digiscope had to be switched to delayed surveys. Strongly recommended in similar operations. Third SPT was also a good help.
- ❖ Drilling 7” liner shoe track in 3.25 hours using dedicated shoe track drilling procedure (utilizing Sakhalin experience)- Always use this shoe track drilling procedure for ERD & normal wells. It was faster than many normal wells on Statfjord. Use similar BHA’s with 1 x string stabilizer.

16 Recommendations

I. Since ERD wells on Statfjord field are reentry wells, it is recommended not to exit using whipstock rather open hole cement plug kick off is absolute necessary to avoid kink in the well.

II. Since most of the time 12 ¼” section will be the longest, it is recommended to plan & drill it in one run instead of two runs.

III. It is highly recommended to use Xceed RSS & Optidrill (Downhole drilling mechanics sub) in 12 ¼” & 8 ½” BHA’s.

IV. Installing 3rd Stand pipe pressure transducer (SPT) is extremely important for adequate MWD signal assurance in ERD wells.

V. It is recommended to always keep a contingent 6” section in design & must be planned as normal while planning rest of the well.

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