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ECD management in high-angle and complex wells.

MODULE 9

Questionary for ECD management in high-angle and complex wells.

Question 1.

- While drilling a 12 ¼" hole section the stand pipe pressure limit (maximum pressure that the rig can deliver) is approached. A decision is made to pull out of hole due to an MWD tool failure, but there is still 3,300 ft to drill. For the next run to TD which of the options below would be feasible options for reducing the stand pipe pressure, without adding significant risk for the rest of the section?

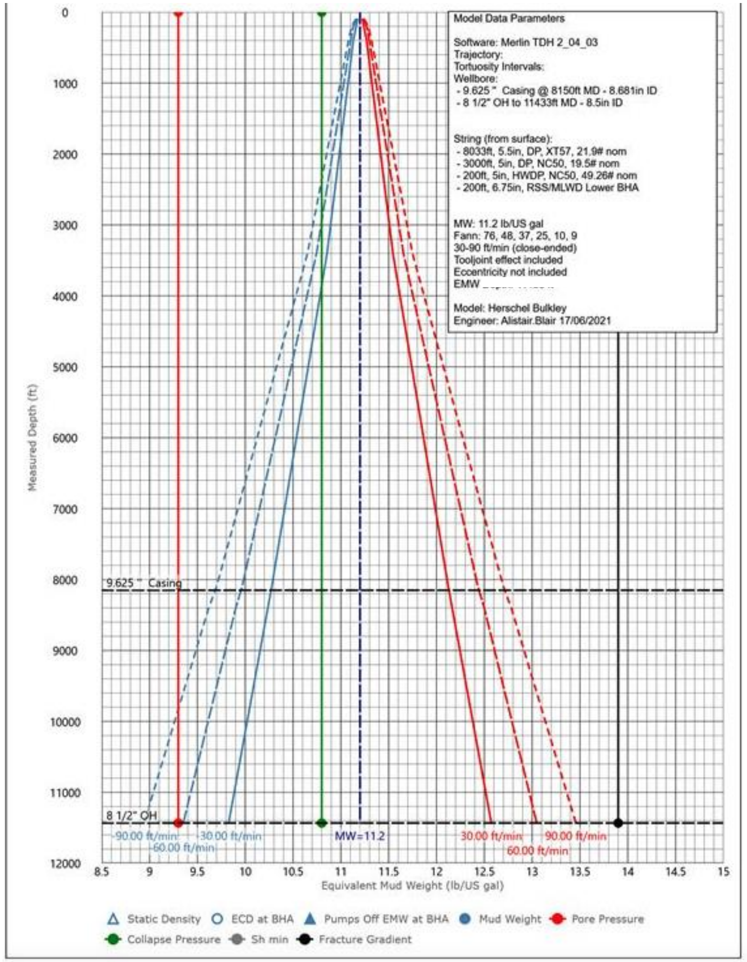
- Reduce high shear mud rheology.
- Reduce flow rate to 640 gpm.
- Remove some heavy-weight drill pipe and/or drill collars.
- Change mud pumps pop-off settings.
- Increase bit nozzle size / TFA.

Question 2.

What effects ECD:

- Length of the annulus or well.
- Annular clearances (drill-pipe / casing sizes).
- Mud properties.
- Flowrate.
- Rotation.
- Backpressure through surface return lines.
- ROP.
- Pipe movement (surge and swab pressures).
- All of the above.

Question 3.



You have just finished drilling an 8 ½” high-angle reservoir section, which is known to have intervals that are susceptible to weak bedding-plane failure.

A full clean-up cycle has been performed, but residual cuttings/caving’s beds are known to exist, with several over-gauge zones.

The next operation will be to run a 7” liner to TD.

Based on the data shown on the fixed-depth (TD) swab/surge model, which of the following tripping options would be safest overall?

Assume a pulling speed of 3 minutes per stand (range 2 drill pipe), except where otherwise stated.

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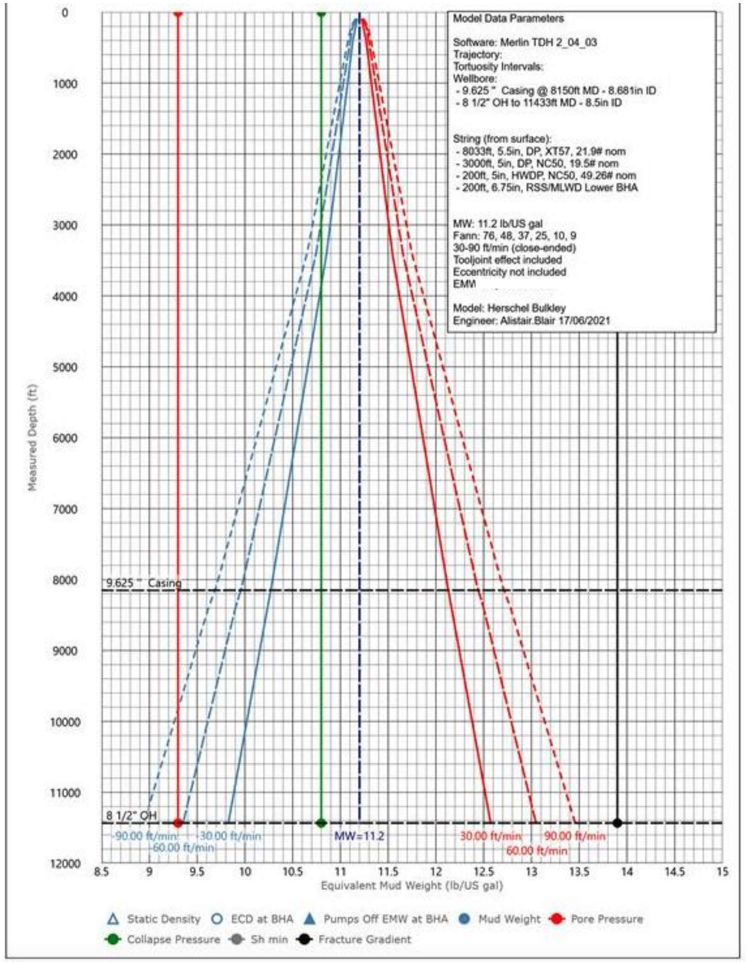
Question 3.



a. Pull on elevators at 1 minute per stand.
b. Pump out (no rotation) with 450 gpm.
c. Pull on elevators at 3 minutes per stand in open hole, increasing speed in cased hole.
d. Pump out (no rotation) with 50 gpm.
e. Back-ream out of open hole with parameters used to drill (450 gpm, 100rpm).
f. Pump out (no rotation) at 100 gpm and 10 minutes per stand.

Question 4.

- Which of the following are indicators of borehole instability?

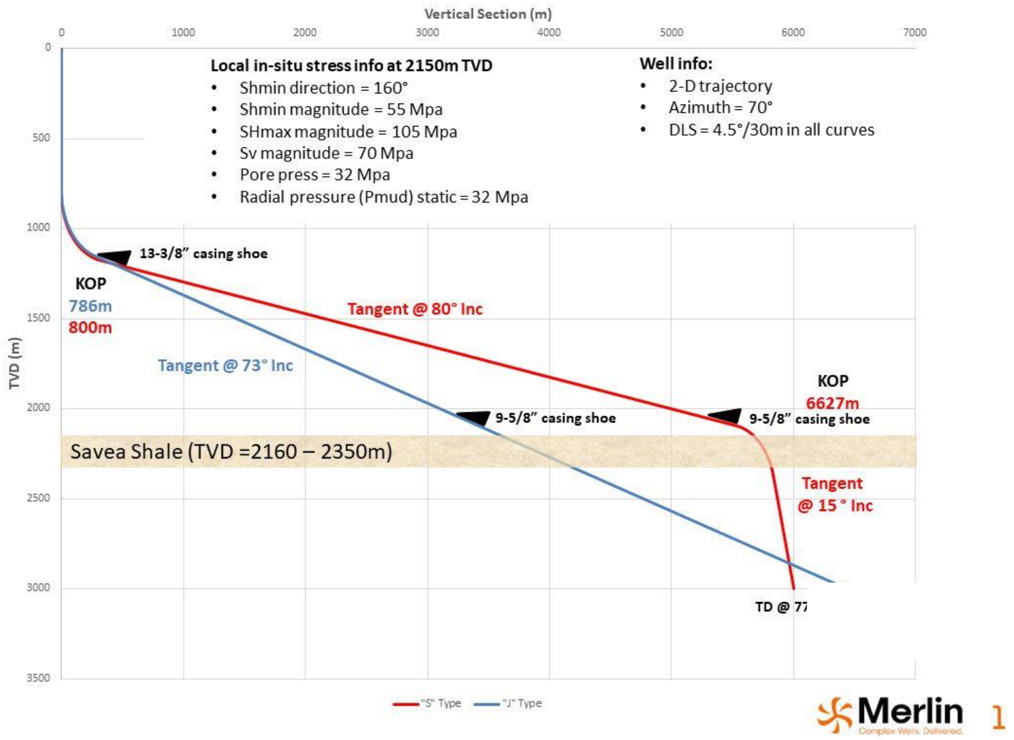
- Divergence of LWD logs from the drilling pass.
- Fill on bottom after trips.
- Seepage losses.
- ECD lower than predicted (model).
- Caving's on the shakers.

Question 5.

- An 8 ½” hole section is drilled in an ERD well (33,000 ft MD; 82° inclination) with 5 ½” drill pipe and a short, light BHA (~200ft) and oil based mud. What would you expect to contribute the most to surge and swab pressures?

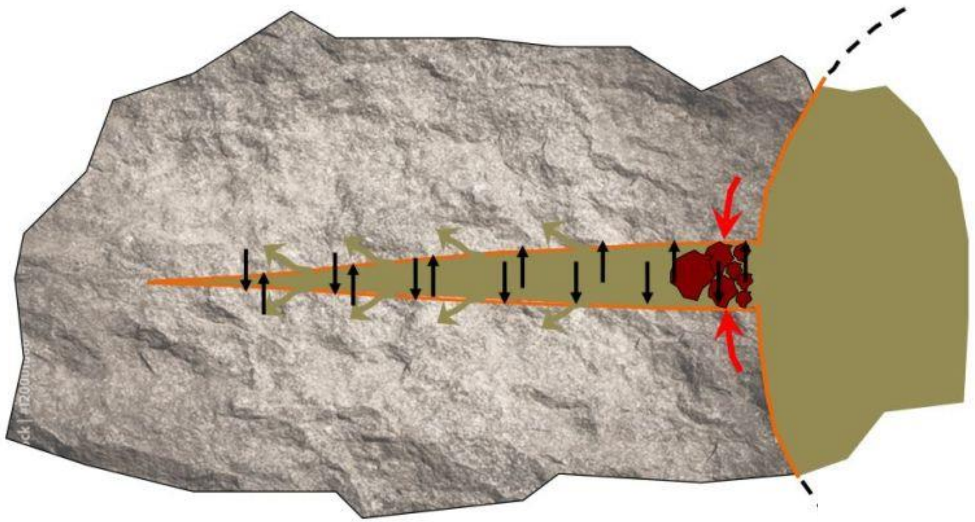
- Drill pipe.
- Bottom hole assembly.
- Inclination.
- Mud weight.
- Oil / Water ratio.

Question 6.



- The red and blue wells below differ only in trajectory. Which well will require higher SBP when drilling with MPD through the Savea shale to maintain a stable wellbore?

Question 7.



- What technique for addressing lost returns is shown in the diagram?

a. Pumping LCM.

b. Wellbore strengthening.

c. Using EC-drill controlled mud level.

d. Lower mud weight.

Question 8.

While drilling a 16” hole in a potentially pre-fractured formation at over 60 degrees inclination, a high amount of the returns (>50%) contained caving’s as shown in picture #1.

The MW was increased by 1.0ppg but the amount of caving’s increased and now look like those shown in picture #2.

Question 8.

What should be the next course of action?

a. Decrease mud weight.

b. Increase mud weight again.

c. Add a broad range of bridging material to the mud.

d. Set casing here.

e. Make up the TDS and go medieval on the hole by back-reaming to clean-out all the caving's.

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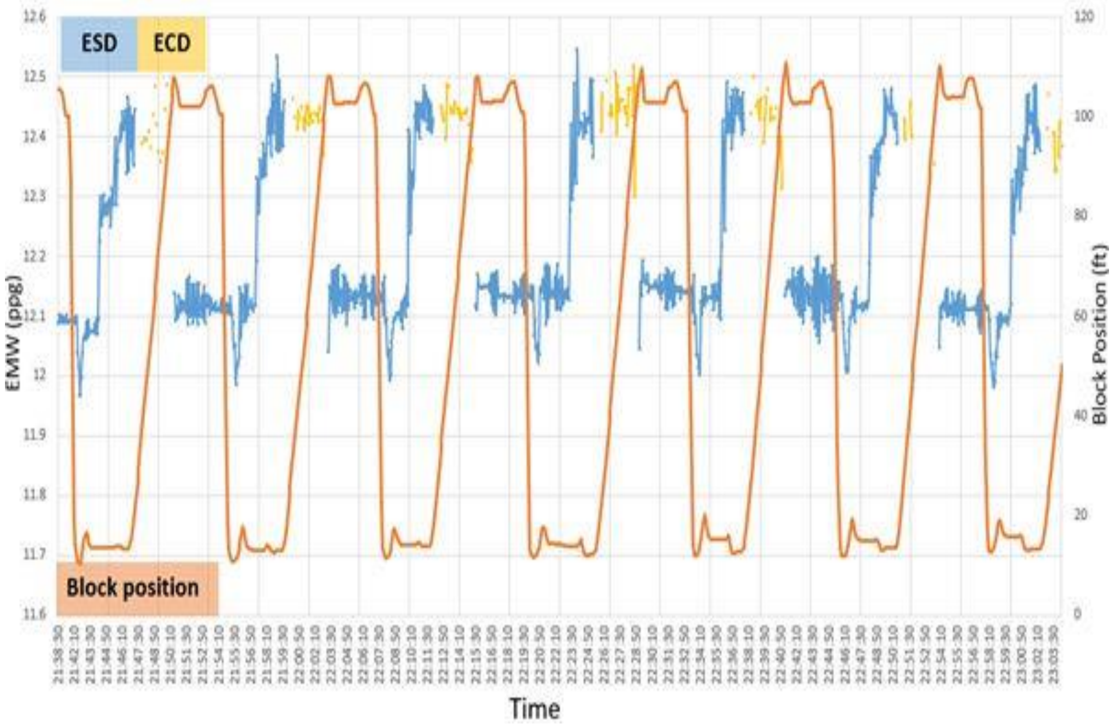
Question 9.



- In a high angle 8 ½" hole section what open hole drilling activity is shown on the chart?

a. Back reaming.

b. Tripping out of hole.

c. Connection.

- Is there any cause for concern?

a. No.

b. Swabbing.

c. Surge.

Question 10.

- The leak off test shown on the chart was taken below the 13 ⅜" casing shoe.
  The DSV is ready to make some hole, the geologist has his concerns because the minimum stress is lower than expected. The minimum required leak off is an absolute minimum for well control. Who is correct?

a. Geologist.

b. DSV.

c. Cook.

Bonus question.

- While drilling a high angle 6” section with 4” drill pipe at 20,000 ft, using optimal parameters for hole cleaning, a crew change takes place and the AD takes over at stand down for the drillers to handover. The keen AD begins reaming the stand up and down before making the connection. When beginning reaming down, partial losses occur, even though there is no change in formation over the stand just drilled. The same parameters are used and average pipe movement speeds remain as per the previous stands.

What could have caused the losses?

a. RPM increase.

b. Near bit stabiliser balling.

c. Packing off.

d. Tripping surge.

e. Cuttings bed.

f. Whiplash surge.

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MODULE 8

Case study: ECD design exercise.

ECD design exercise.

- Norway ERD well.
  - Example where 8 ½” ECDs affect the entire well design.

  - Rig equipment.
    - TDS4H Top Drive (43 k ft-lbs in low gear).
    - 3 x Continental Emsco FB1600 (1,600hp) pumps.
    - 5,000 psi system, practical limit of 4,500 psi.

  - Drill string
    - 5 ½” 21.9# S135 with DSTJ connections (40 k ft-lbs).

ECD design exercise.

- Norway ERD well.
  - Example where 8 ½” ECDs affect the entire well design.

  - Base case well design.
    - 13 ⅜” casing set at EoB at 4,000’ (1,200m) MD
    - 9 ⅝” casing at heel point 24,500’ (7,500m) MD
    - 6 ⅝” screens at TD 27,500’ (8,400m) MD

ECD design exercise.

- Norway ERD well.
  - Example where 8 ½” ECDs affect the entire well design.

  - Fluids.
    - Dispersive WBM is planned for the 17 ½”.
    - 12.5 ppg OBM is planned for 12 ¼”.
    - 11.2 ppg “clean” drill-in OBM will be used in 8 ½”.

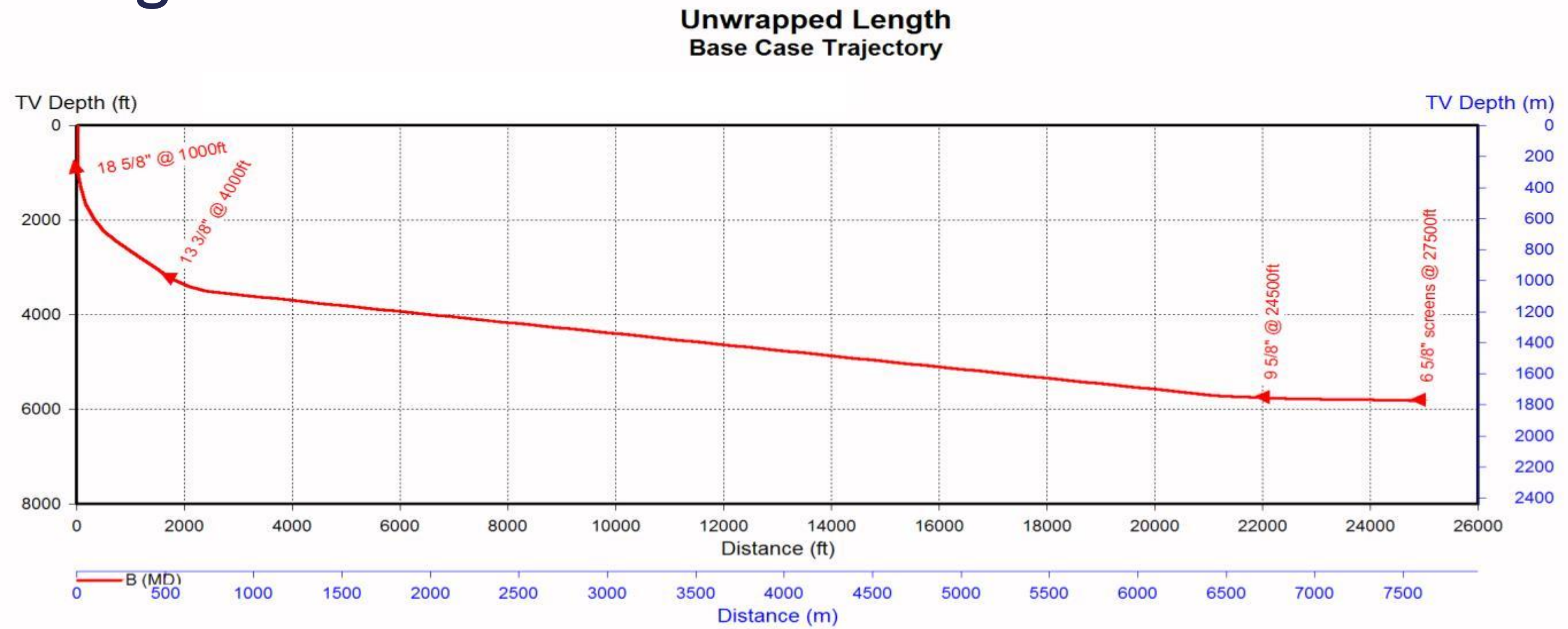
  - Reservoir conditions.
    - 10.9 ppg (1.31 sg) pore pressure.
    - 13.1 ppg (1.58 sg) fracture gradient.

ECD design exercise.

- Norway ERD well.
  - Example where 8 ½” ECDs affect the entire well design.

  - Overburden information.
    - Difficult (but possible) to build angle in 17 ½” interval.
    - Unstable shales from 1,500 – 3,000’ TVD, requiring high mud weight at > 60^{o}
    - 12.5 ppg (1.50 sg) is needed for stability in the 12 ¼” at 83^{o}
    - Fracture gradient in the 12 ¼” is 13.1 ppg.
    - Wellbore stability will not be an issue in the reservoir section.

ECD design exercise.



Base case well design.

- 13 ⅜” casing at 4,000’ (EoB).
- 9 ⅝” casing at 24,500’ (heel point).

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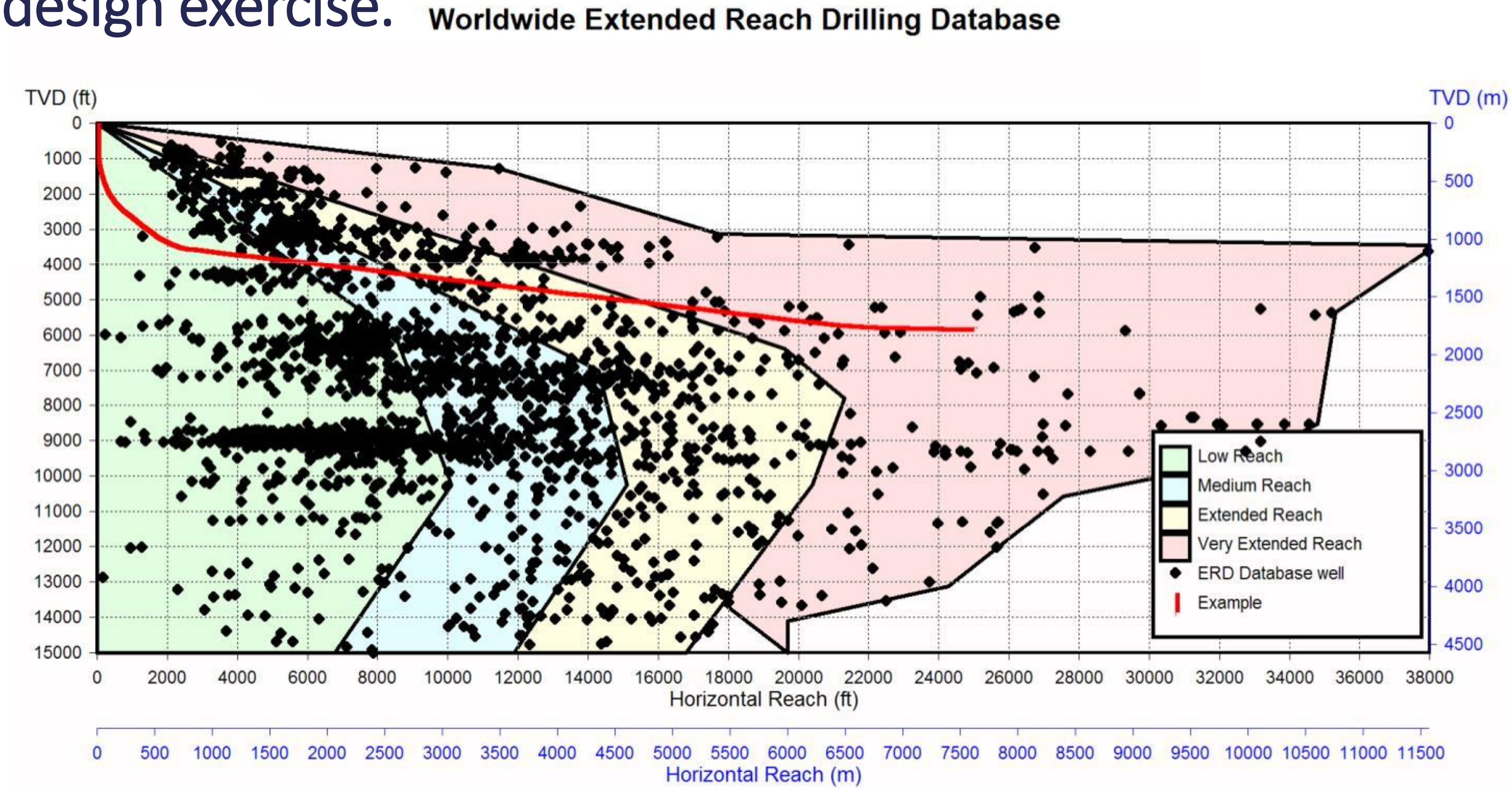
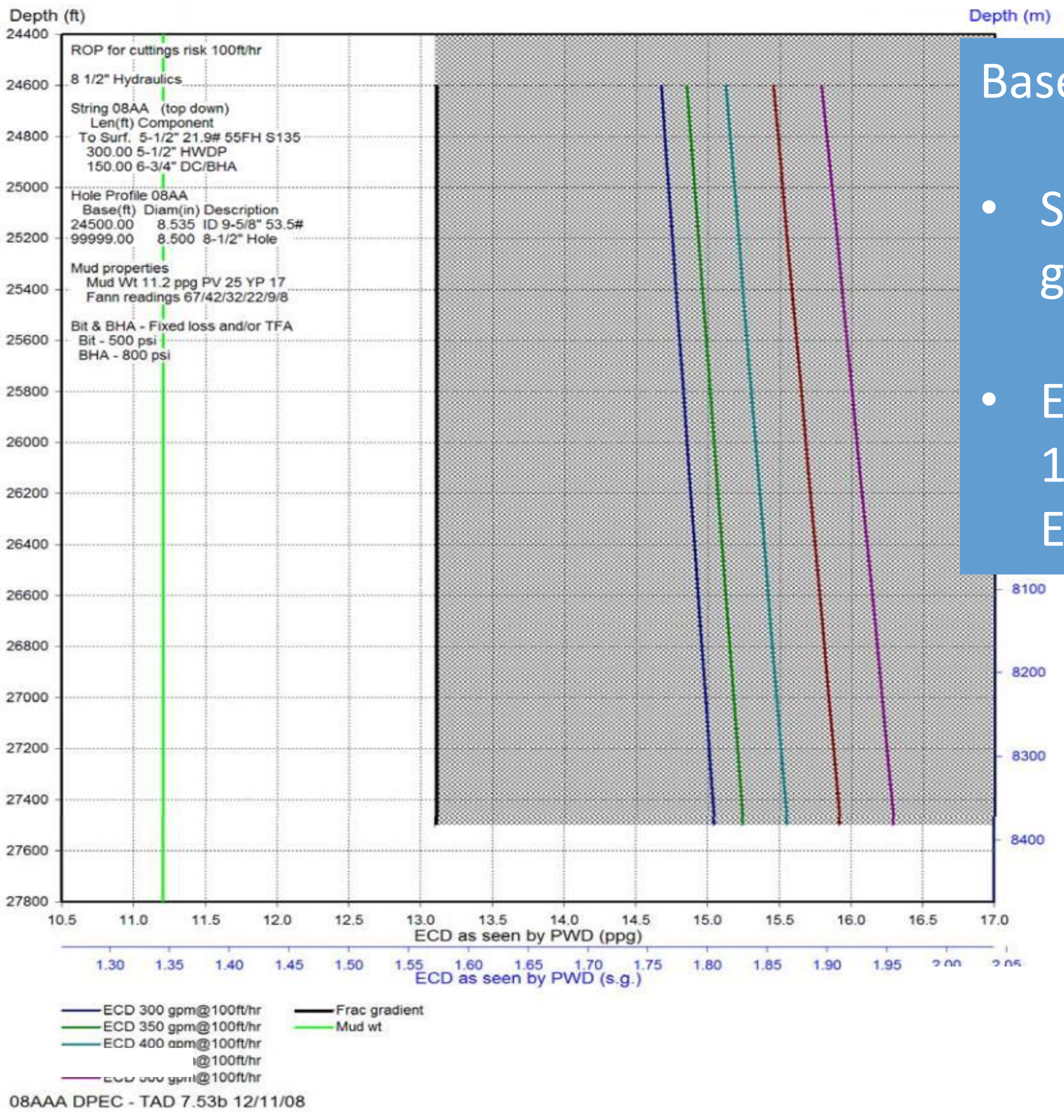
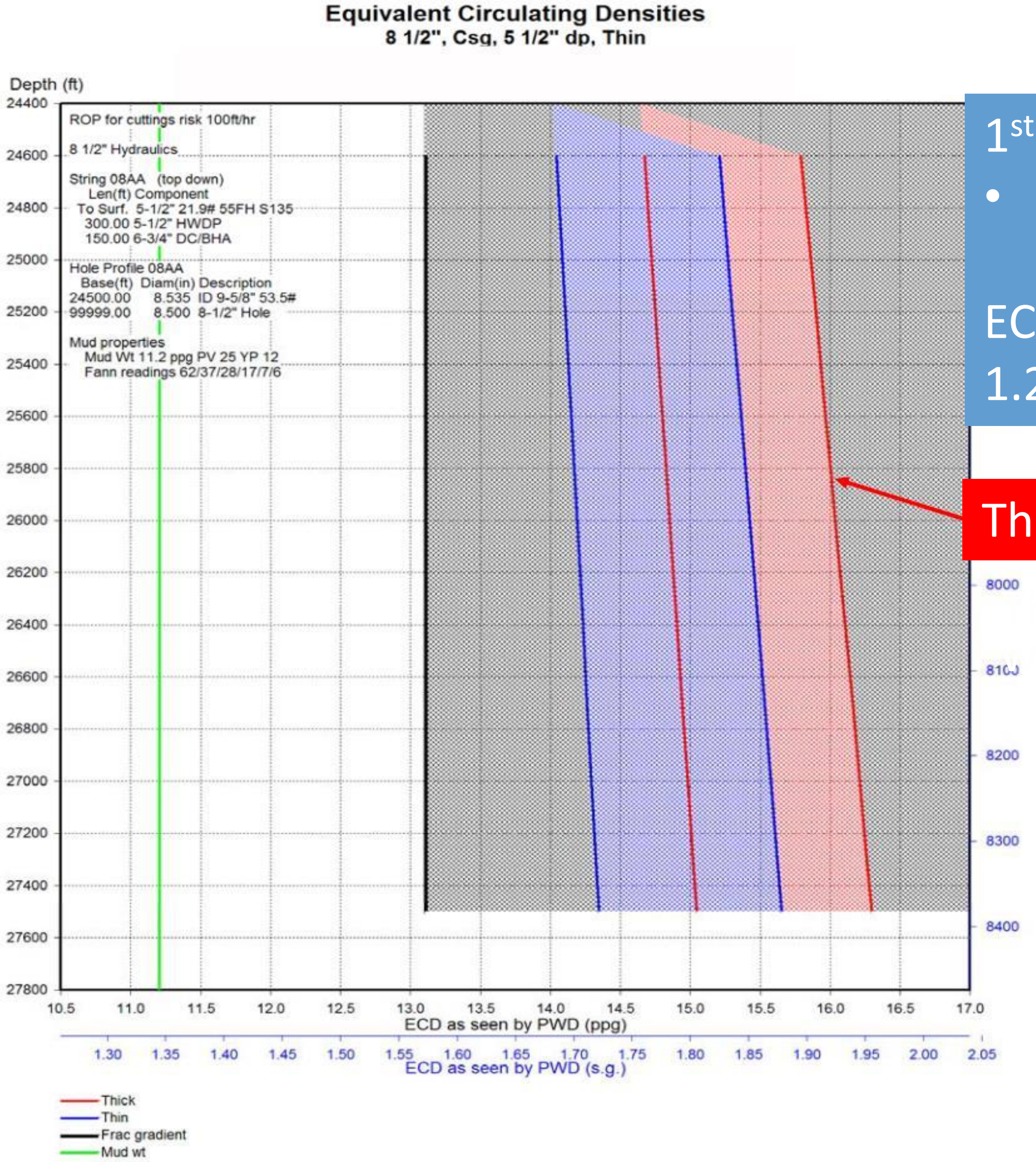
ECD design exercise.





Base case scenario:

- Sensitivity analysis for 300-500 gpm (1,100-1,900 lpm) flowrate.
- ECD's exceed FG by 1.9 – 3.2 ppg (0.22 – 0.38 sg) EMW.



1[st] Attempt to reduce ECD.

- Thinner low-end rheology's.
  6/3 reading = 7/6 vs 9/8.

ECD now exceed FG by
1.2 – 2.5 ppg (0.14-0.30 sg). EMW.

This is what the previous scenario was.

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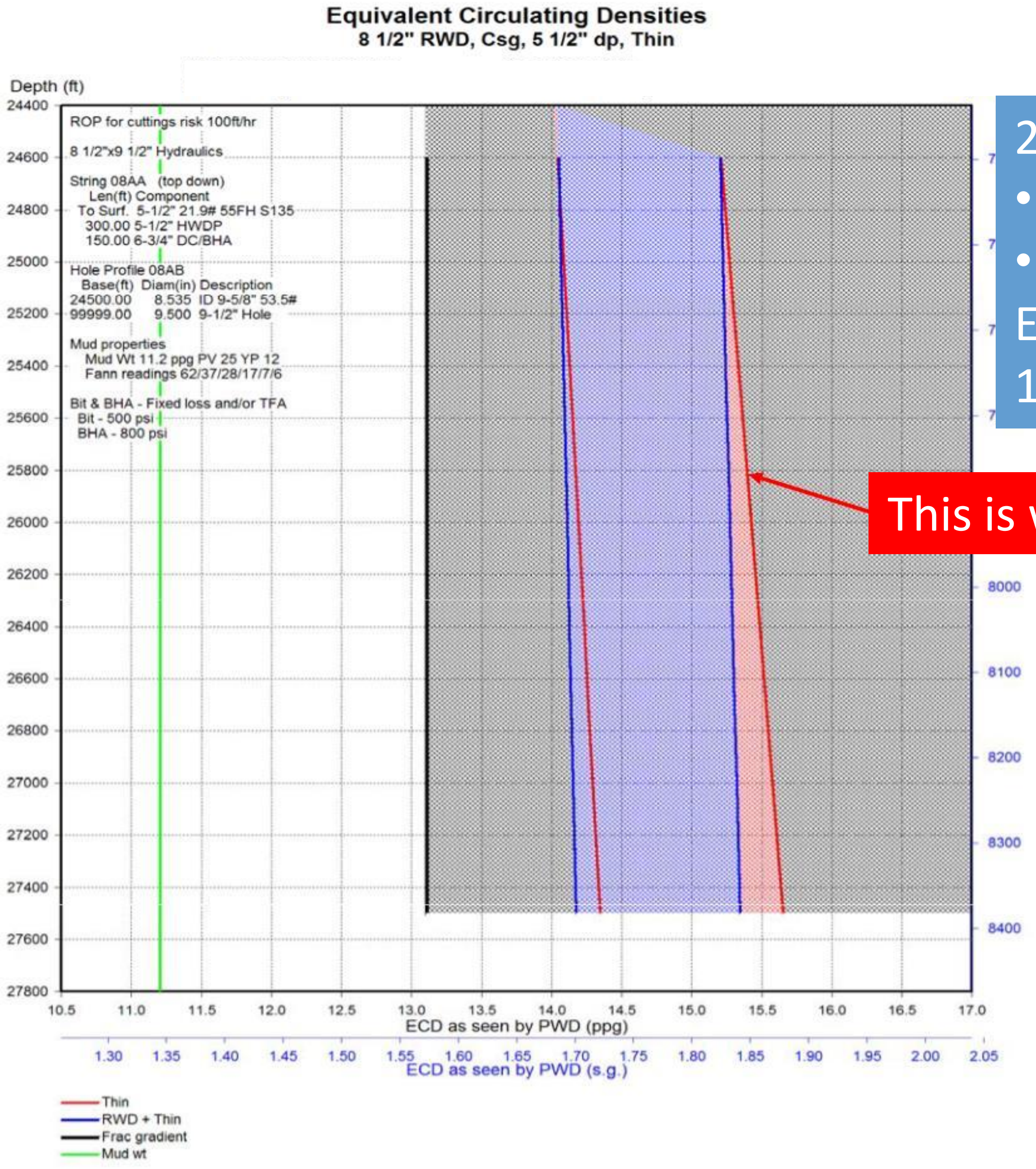
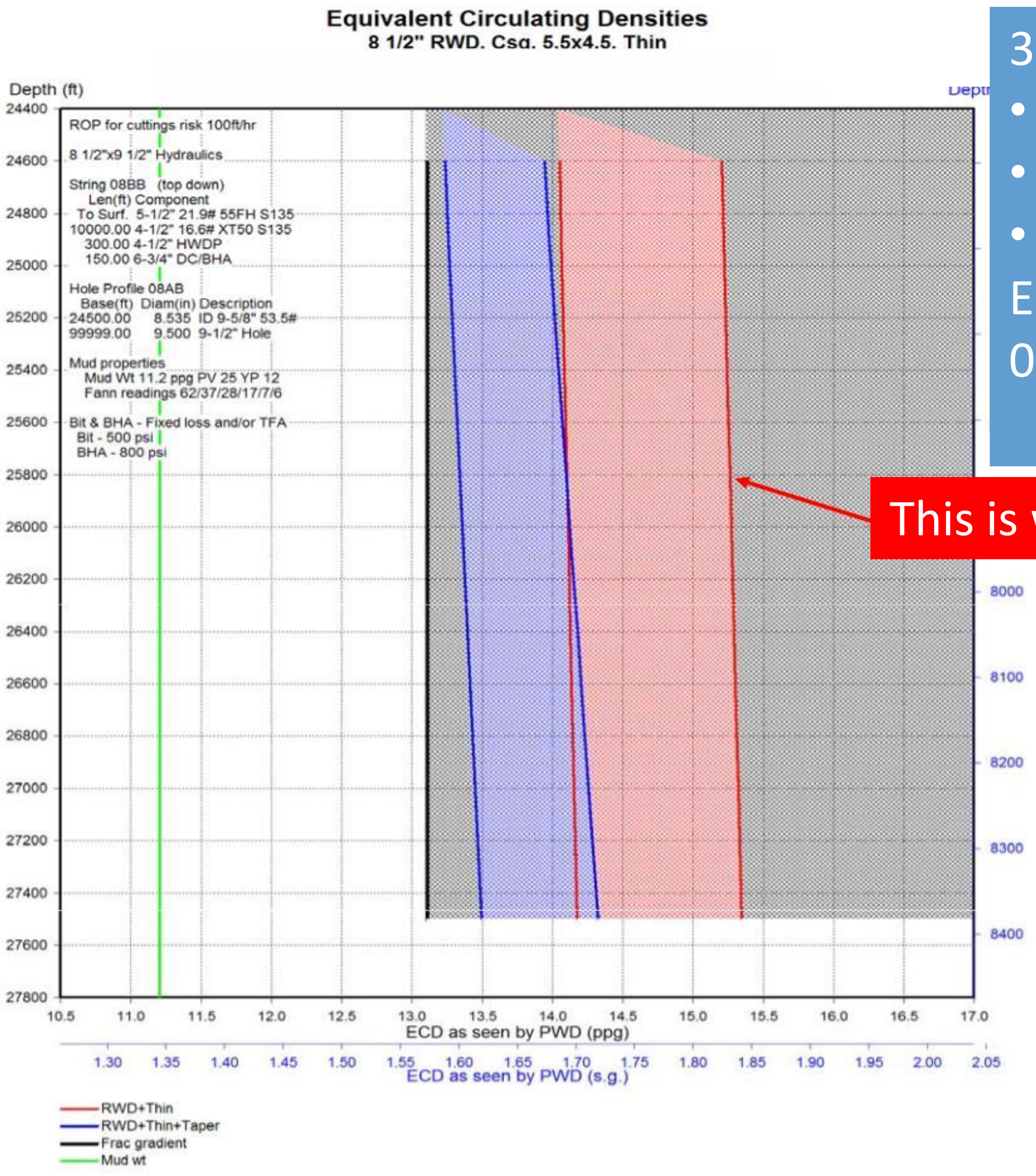


2^{nd} Attempt to reduce ECD.

- Thinner mud.
- Drilling over-sized hole.

ECD now exceed FG by
1.0 – 2.2 ppg (0.12-0.26 sg). EMW.

This is what the previous scenario was.

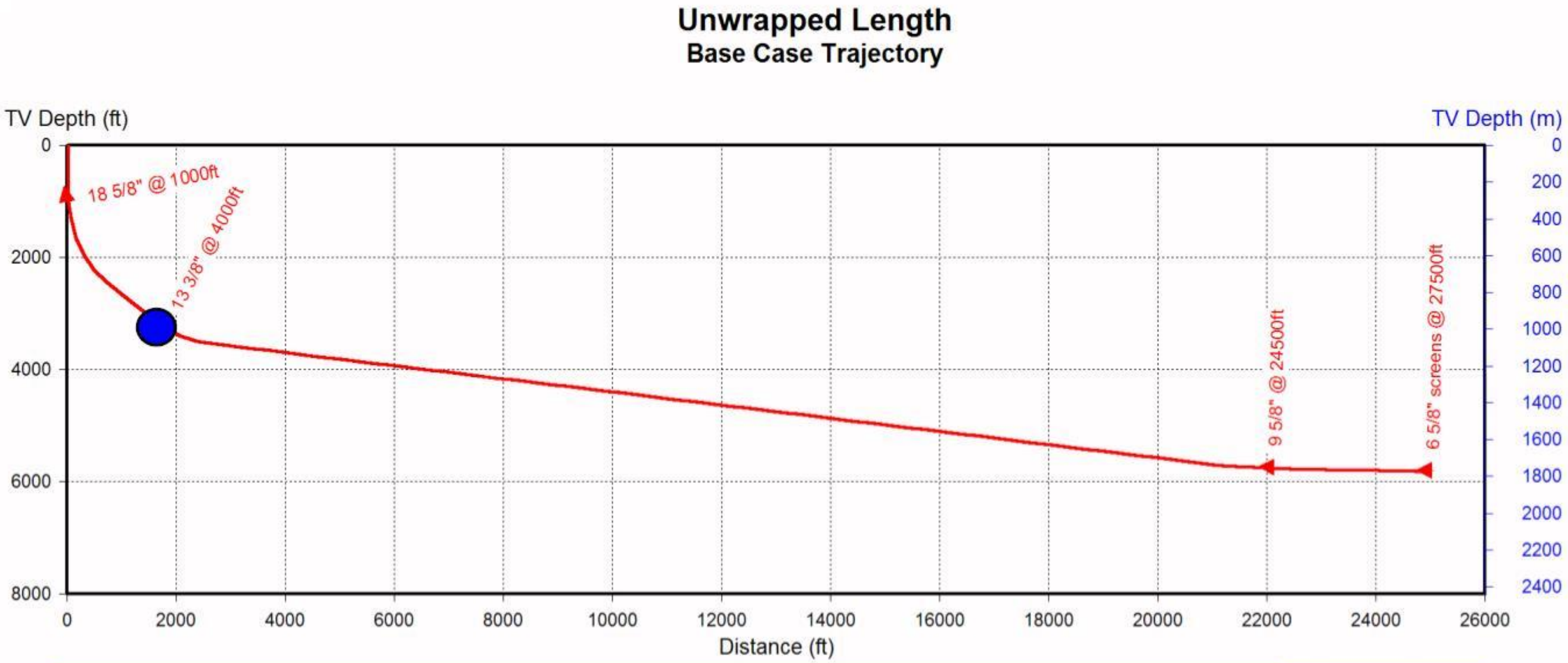


3rd Attempt to reduce ECD.

- Thinner mud.
- Oversized hole.
- Slim tapered drill-pipe (10,000').

ECD now exceed FG by
0.5 – 1.2 ppg (0.06-0.14 sg). EMW.

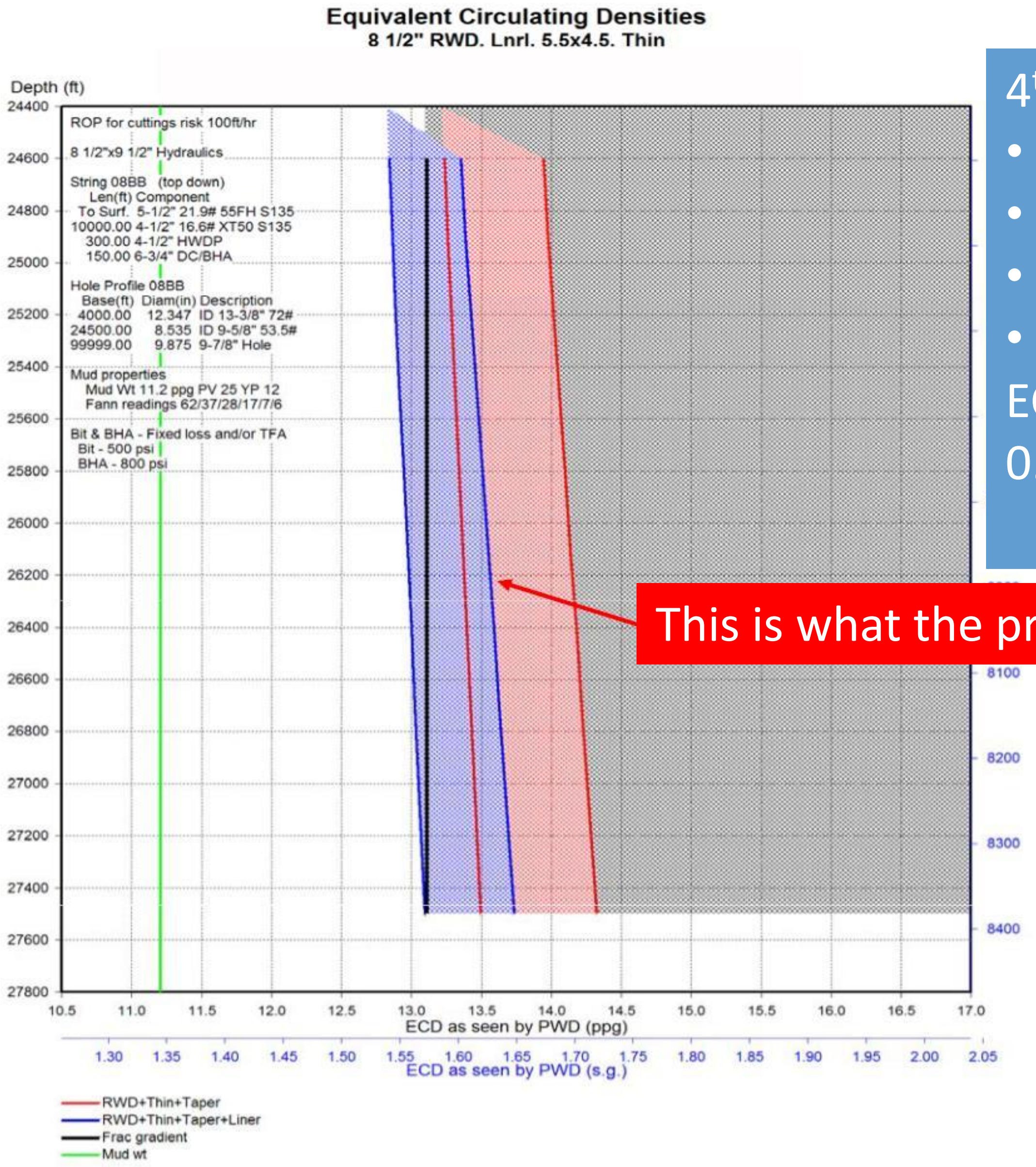
This is what the previous scenario was.



This is the Base-case well design.

We have done everything that can be done without changing the well design.

- To further reduce ECD's it's necessary to set the 9 ⅝" casing as a liner.
- The 1st logical point for the 9 ⅝" liner top is with the current 13 ⅜" casing point.



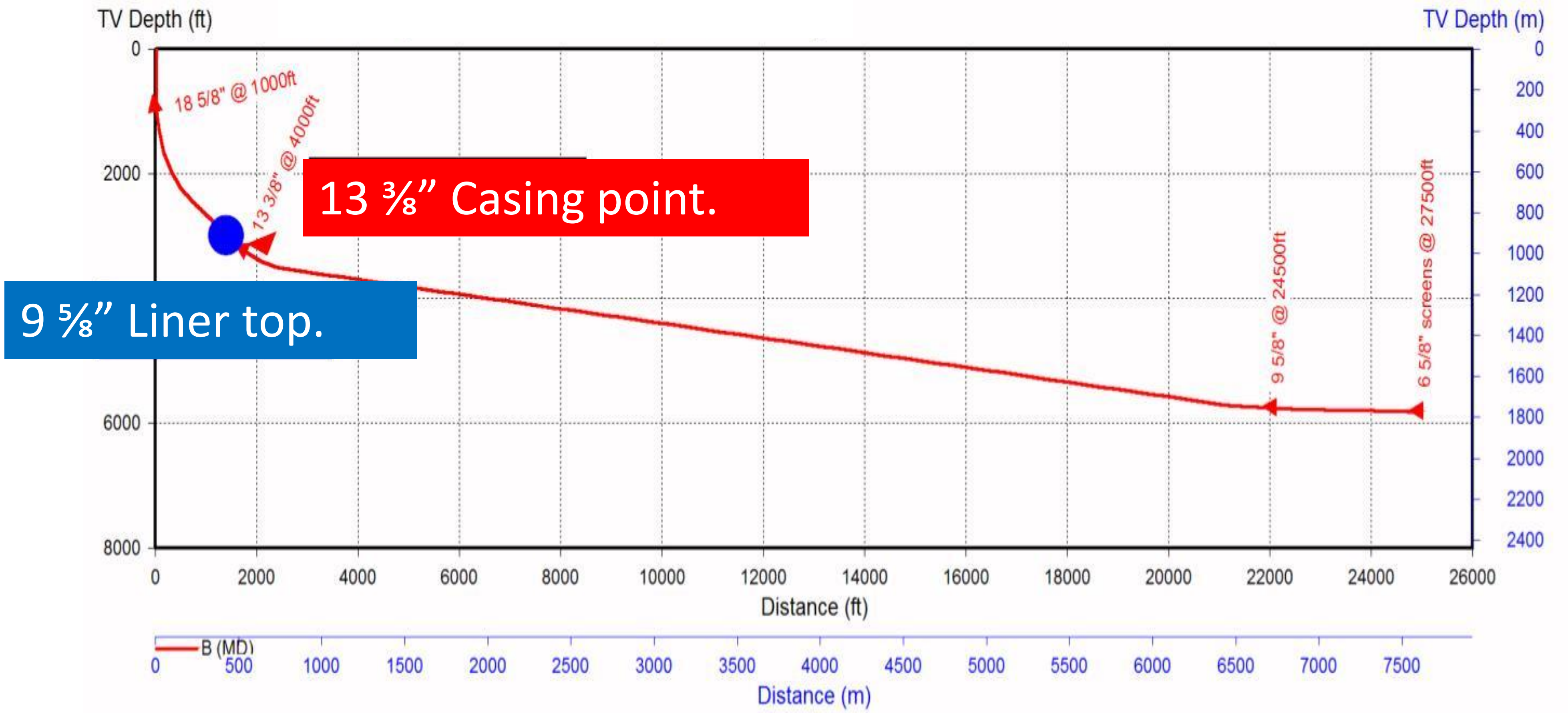
4[th]Attempt to reduce ECD.

- Thinner mud.
- Oversized hole.
- Slim tapered drill-pipe.
- 9 ⅝” run as a liner (TOL = 4,000’)

ECD now exceed FG by
0.0 – 0.6 ppg (0.06-0.07 sg). EMW.

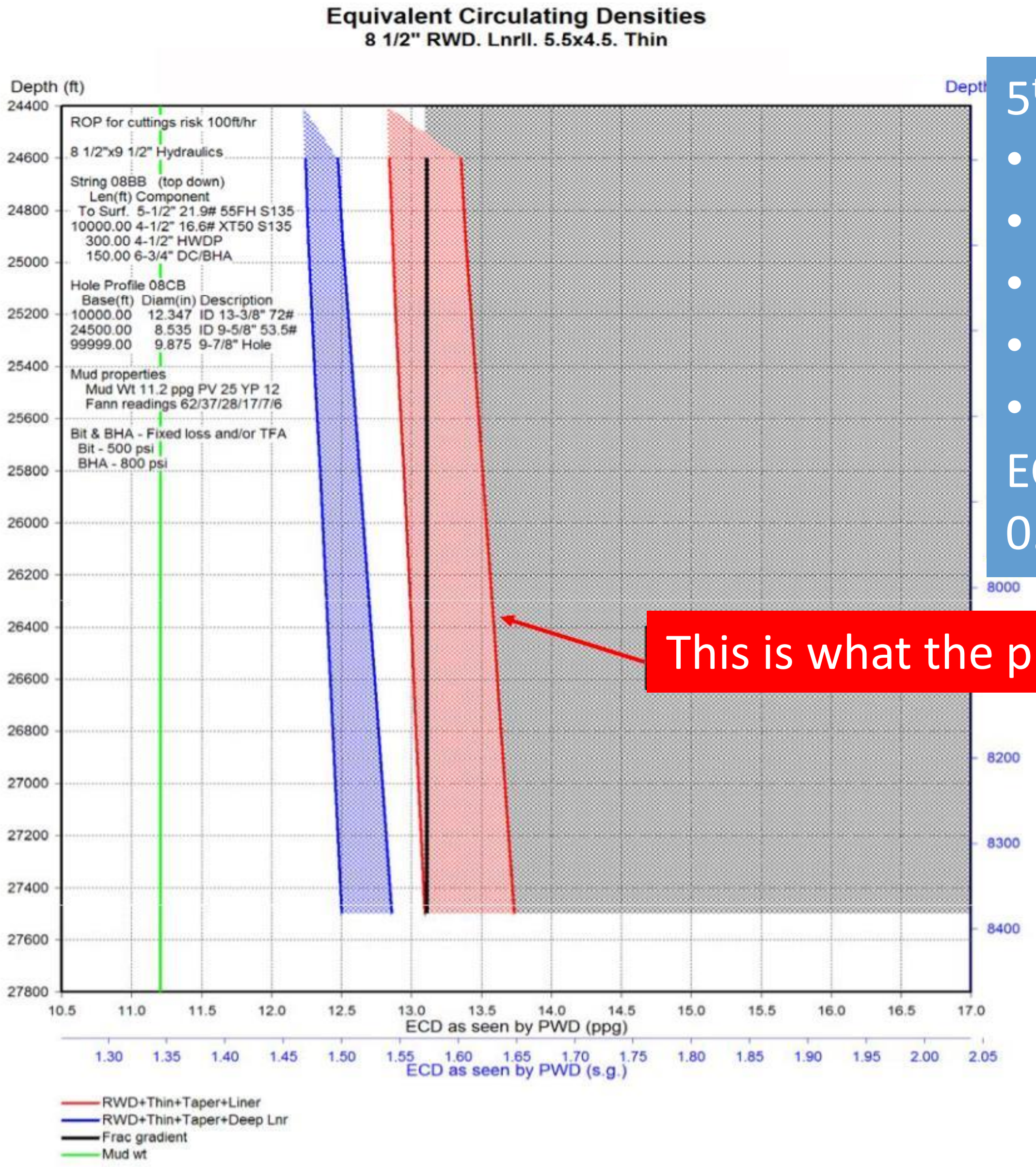
This is what the previous scenario was.

Unwrapped Length
Base Case Trajectory



So far we've tried (unsuccessfully) to manage ECD's within the existing casing design.

- But we need to drive then 9 ⅝” liner top deeper. Let's try 10,000' (3,000m).

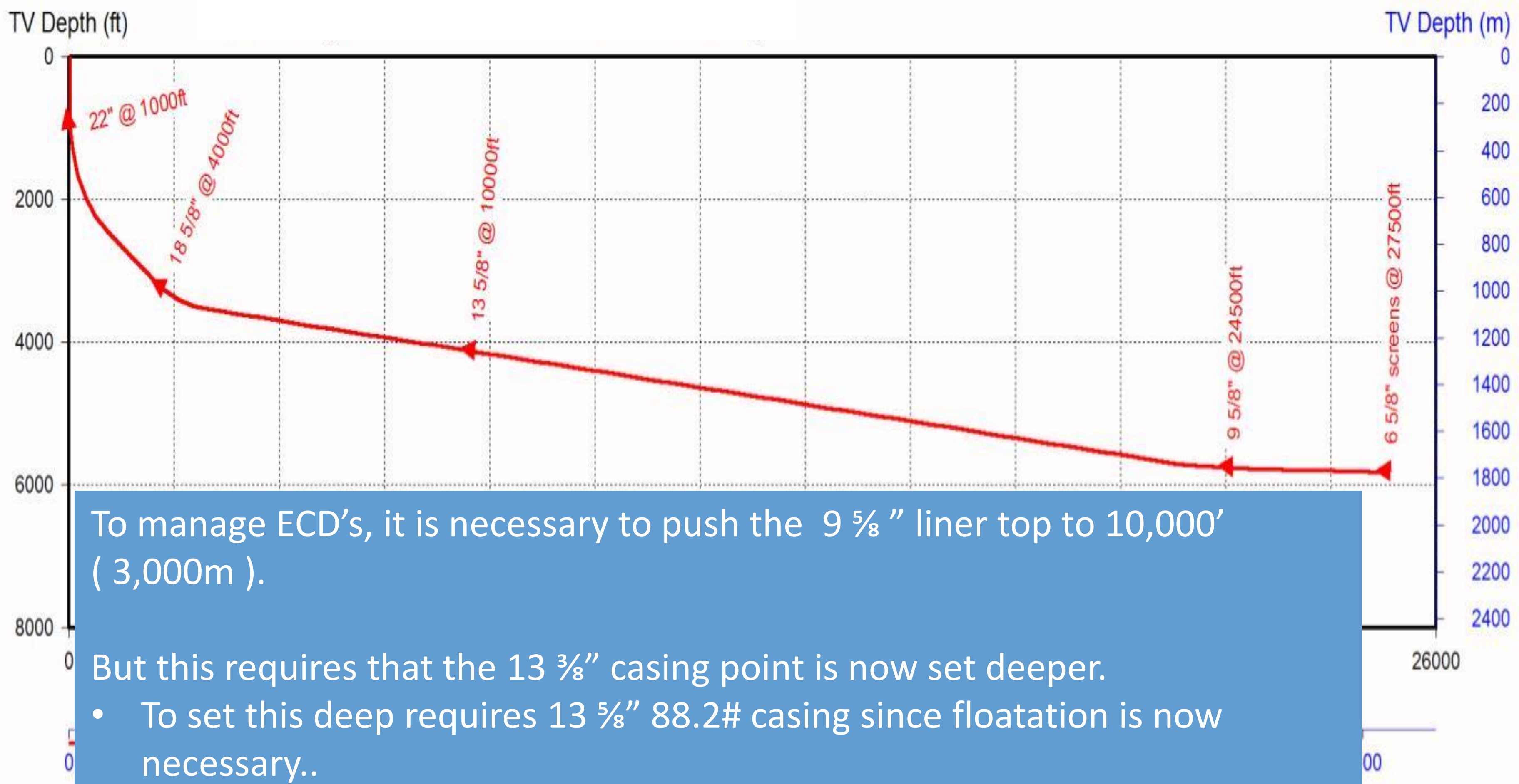


5th Attempt to reduce ECD.
- Thinner mud.
- Oversized hole.
- Slim tapered drill-pipe.
- 9 ⅝” run as a liner.
- Deep liner top (10,000’).

ECD margin at TD
0.3 – 0.6 ppg (0.03-0.07 sg) EMW.

This is what the previous scenario was.

Unwrapped Length
Revised Well Design for ECD Management



To manage ECD's, it is necessary to push the 9 ⅝ " liner top to 10,000' (3,000m).

But this requires that the 13 ⅜" casing point is now set deeper.

- To set this deep requires 13 ⅝" 88.2# casing since floatation is now necessary..

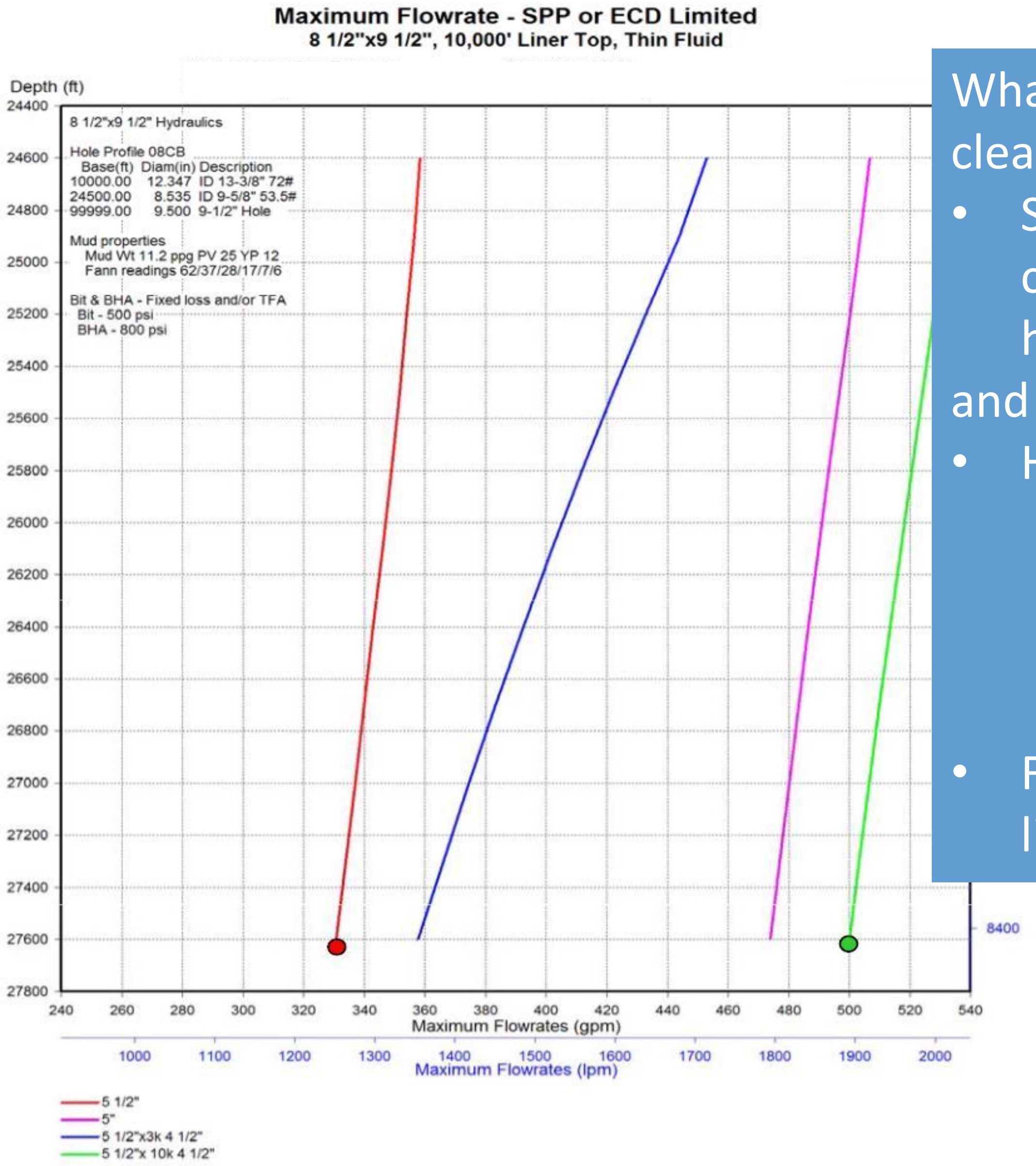
This drives the need for setting 18 ⅝" casing deep (and adding 22" casing).

ECD design exercise.

- To manage ECDs:
  - Fluid rheology affected.
  - Bit & Directional equipment affected
  - Drill-string design affected.
    - Need >10,000’ of 4 ½” drill-pipe

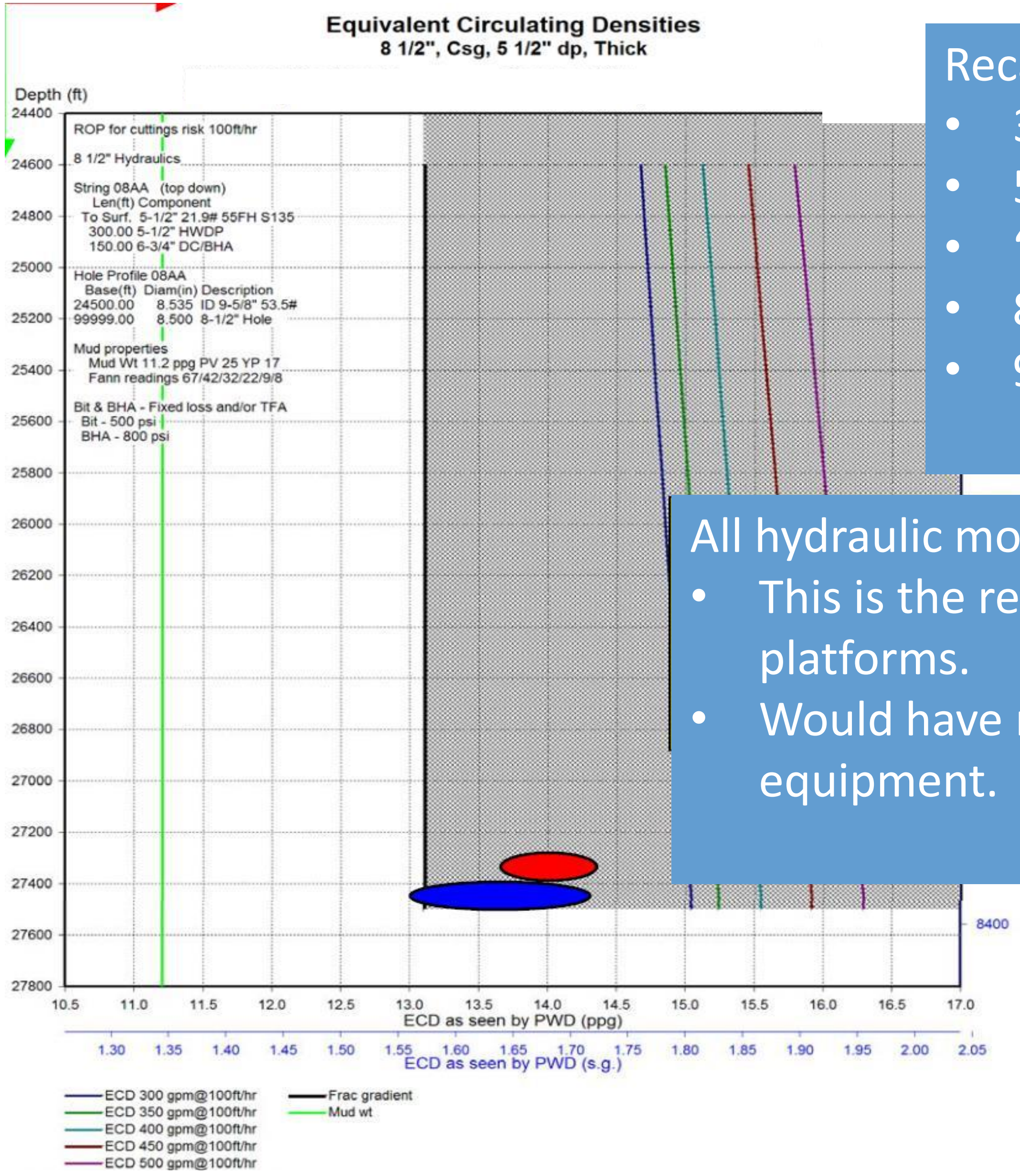
ECD design exercise.

- To manage ECDs:
  - Casing design affected.
    - 9 ⅝” liner top at >10,000’.
    - In turn requires 13 ⅜” casing set at 10,000’.
      - To run this deep, need flotation, which requires 13 ⅝” casing instead.
      - In turn requires additional 18 ⅝” casing at EoB.
  - Wellhead equipment affected.
    - Bigger size, more string (since 9 ⅝” will be tied back).



What are the implications on hole cleaning?

- Some would argue 4 ½” drill-pipe compromises hole cleaning due to lower flowrates and AV’s.
- Hydraulics shows the opposite.
  - 330 gpm max with 5 ½” = 135 ft/min
  - 500 gpm max 5 ½” x 4 ½” = 175 ft/min
- Flowrates are ECD limited, not SPP limited.



Recall, this was the ECD for the original scenario.

- 300 – 500 gpm (1,100 – 1,900 lpm) flowrate.
- 5 ½” drill-pipe.
- “Thick” mud.
- 8 ½” hole section.
- 9 ⅝” casing.

All hydraulic models are not created equal.

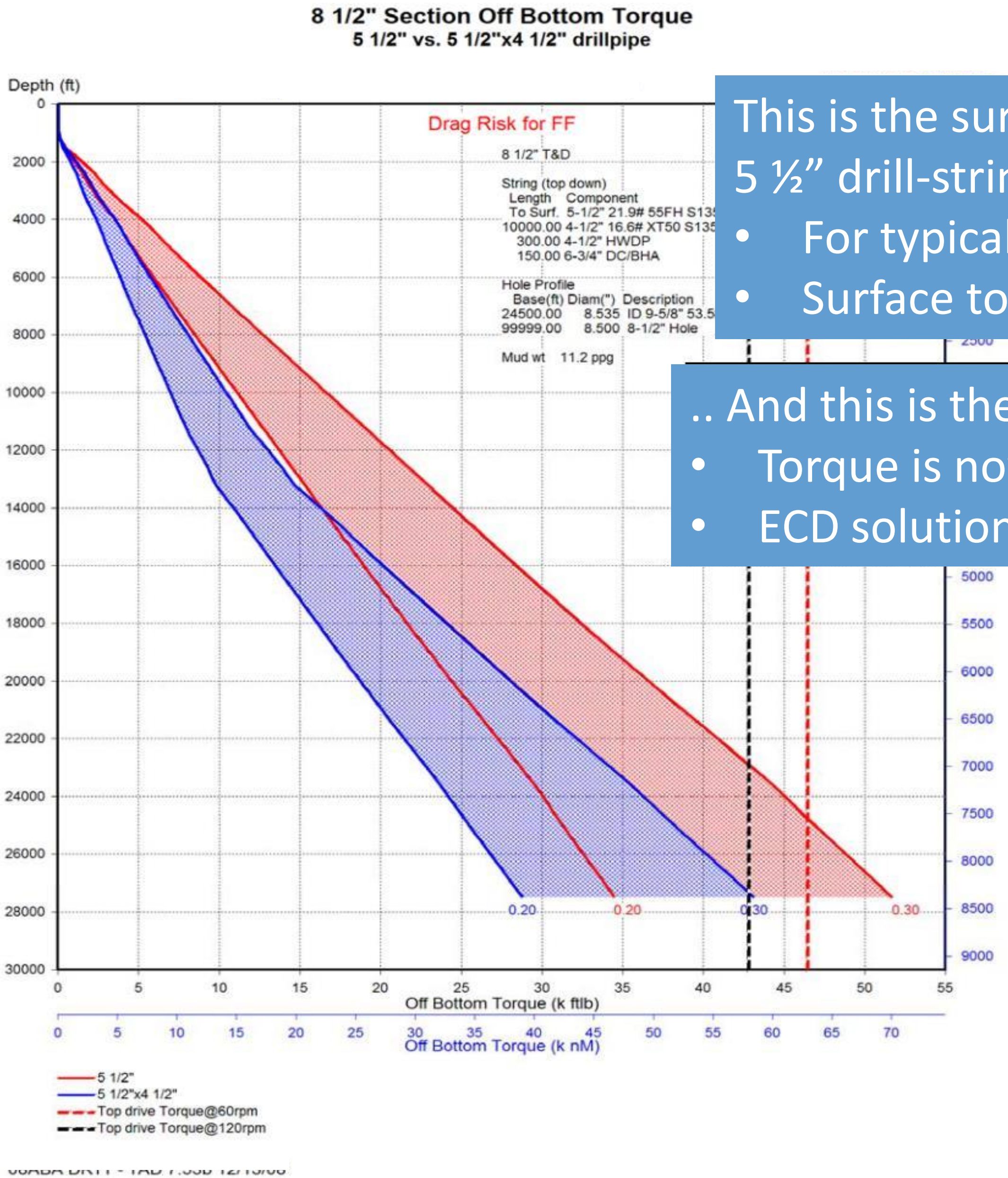
- This is the result from two other software platforms.
- Would have resulted in ordering the wrong equipment.

Failure by design.

ECD design exercise.

- Can’t the string be tripped in and out be rotated.
  - After all, we do need to rotate to drill!.
  - RSS are planned, means we don’t need the ability to slide.

- Let’s compare “base case” to the solution we evolved for the ECD solution to see where the trade-off exists...

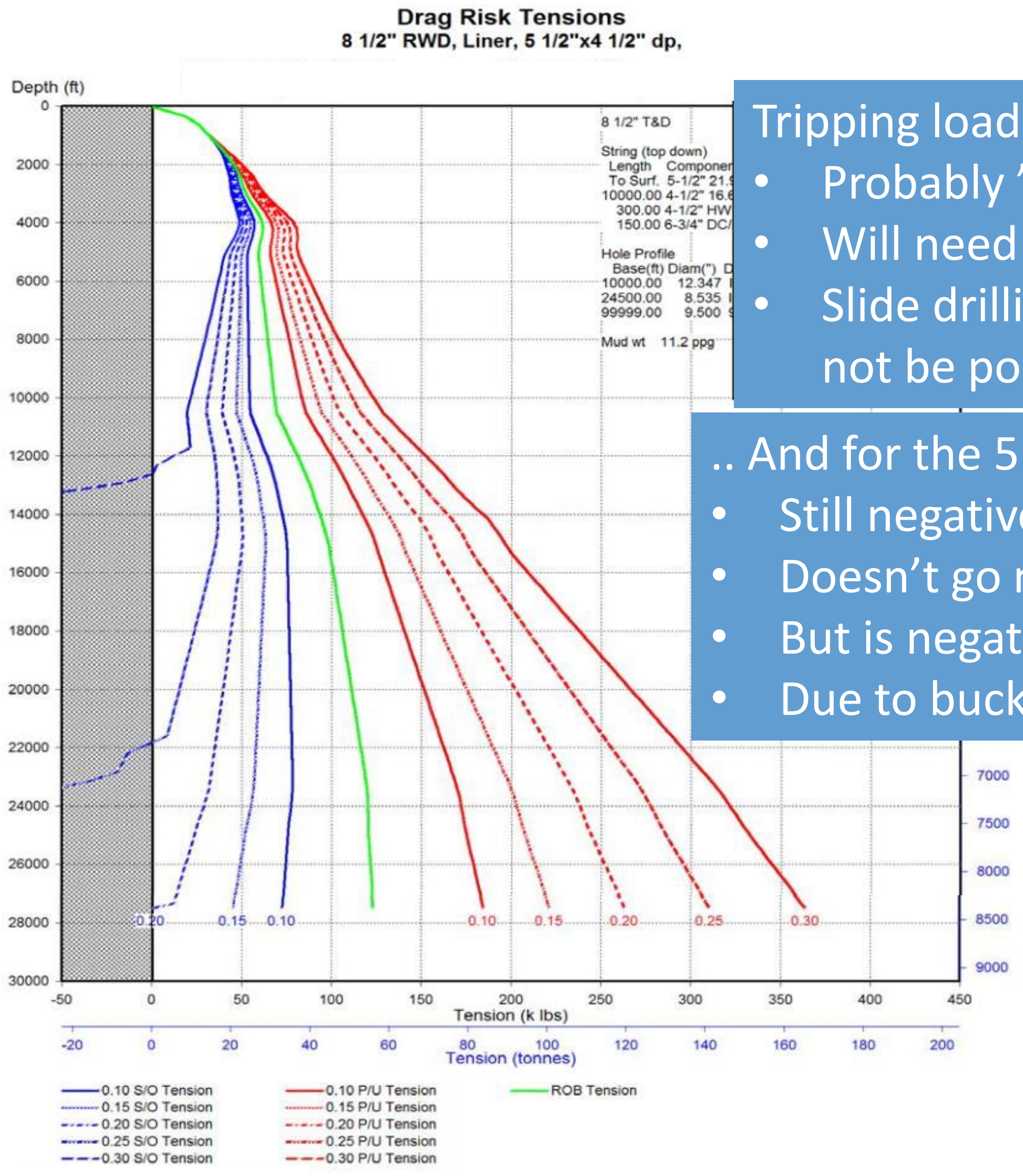


This is the surface torque vs depth for the "base case" 5 ½" drill-string.

- For typical OBM FF range in the area (0.20-0.30).
- Surface torque will likely exceed top drive limits.

.. And this is the torque for 5 ½" x 4 ½".

- Torque is now manageable.
- ECD solution also became the Torque solution.



Tripping loads for "base case".

- Probably "negative weight" below 15,000 – 20,000' MD.
- Will need rotation to move downwards from here on.
- Slide drilling and "setting weight" on downhole tools will not be possible beyond this depth.

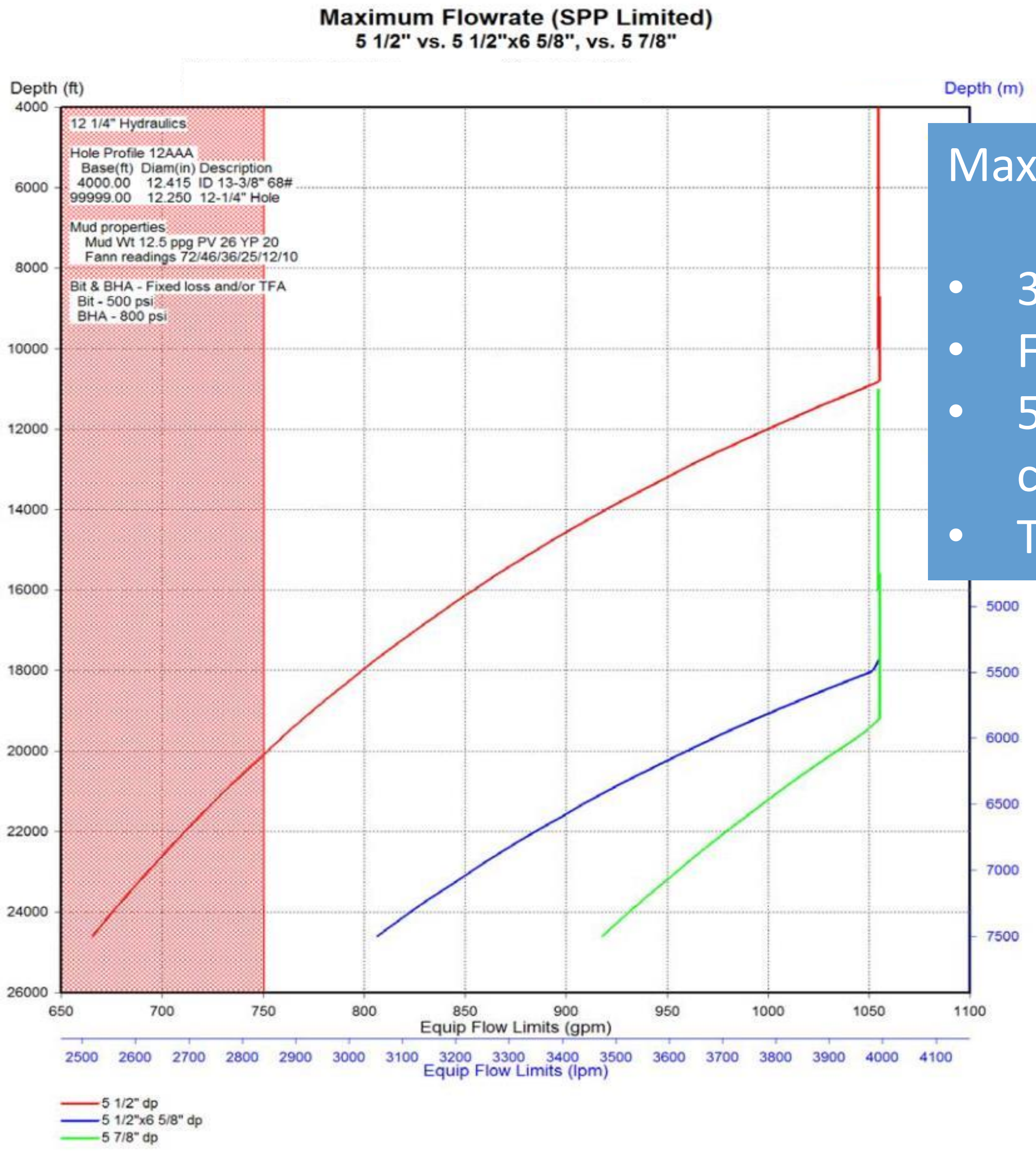
.. And for the 5 ½" x 4 ½", deep liner, RWD.

- Still negative weight.
- Doesn't go negative until 22,000' for a 0.25 FF.
- But is negative at 13,000' for 0.30 FF.
- Due to buckling.

ECD design exercise.

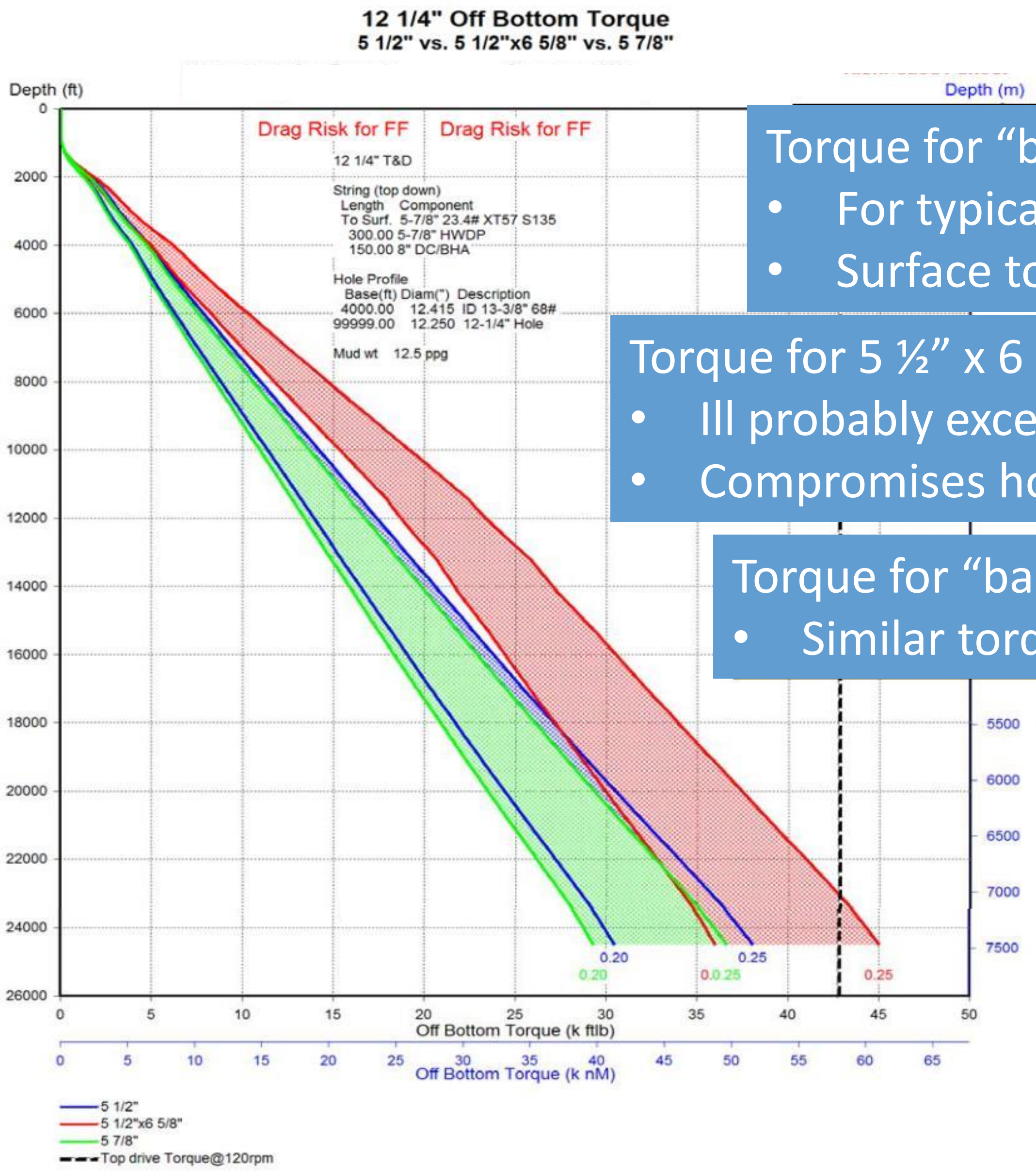
- We know we’re going to need some skinny drill-pipe in the 8 ½” interval.

- What drill-pipe is necessary in 12 ¼”?
  - Driven by hydraulics.
  - Has consequence/impact on torque as well.



Max flowrate profile.

- 3 Pumps online (5 ½” liners).
- For various drill string options.
- 5 ½” drill-pipe is inadequate for hole cleaning.
- Tapered 5 ½” x 6 ⅝” or 5 ⅞” is required.



Torque for "base case" 5 ½" drill string.

- For typical OBM FF range in this area (0.20-0.25).
- Surface torque within limits.

Torque for 5 ½" x 6 ⅝" drill-string.

- Ill probably exceed TDS limits near TD..
- Compromises hole cleaning by limiting RPM to < 120.

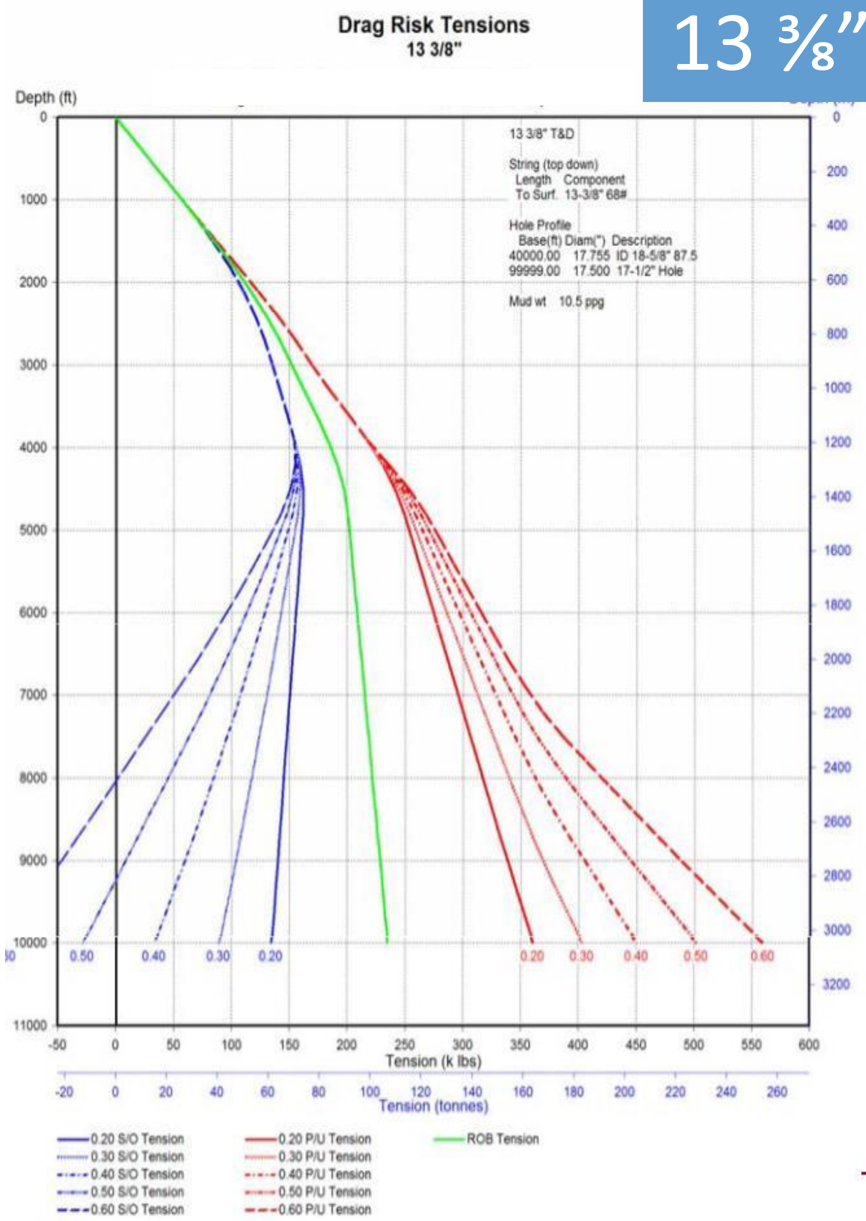
Torque for "base case" 5 ⅞" drill string.

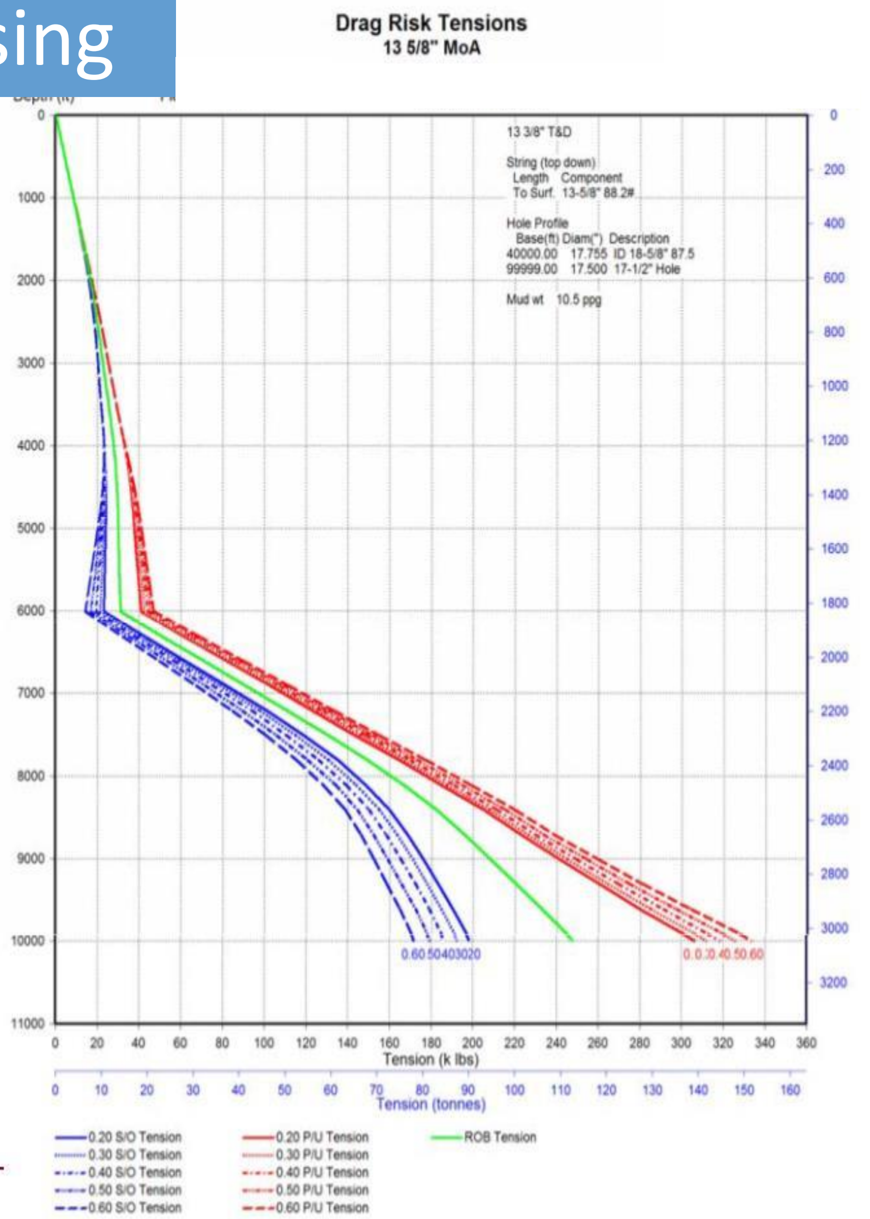
- Similar torque as 5 ½" drill-pipe.

ECD design exercise.

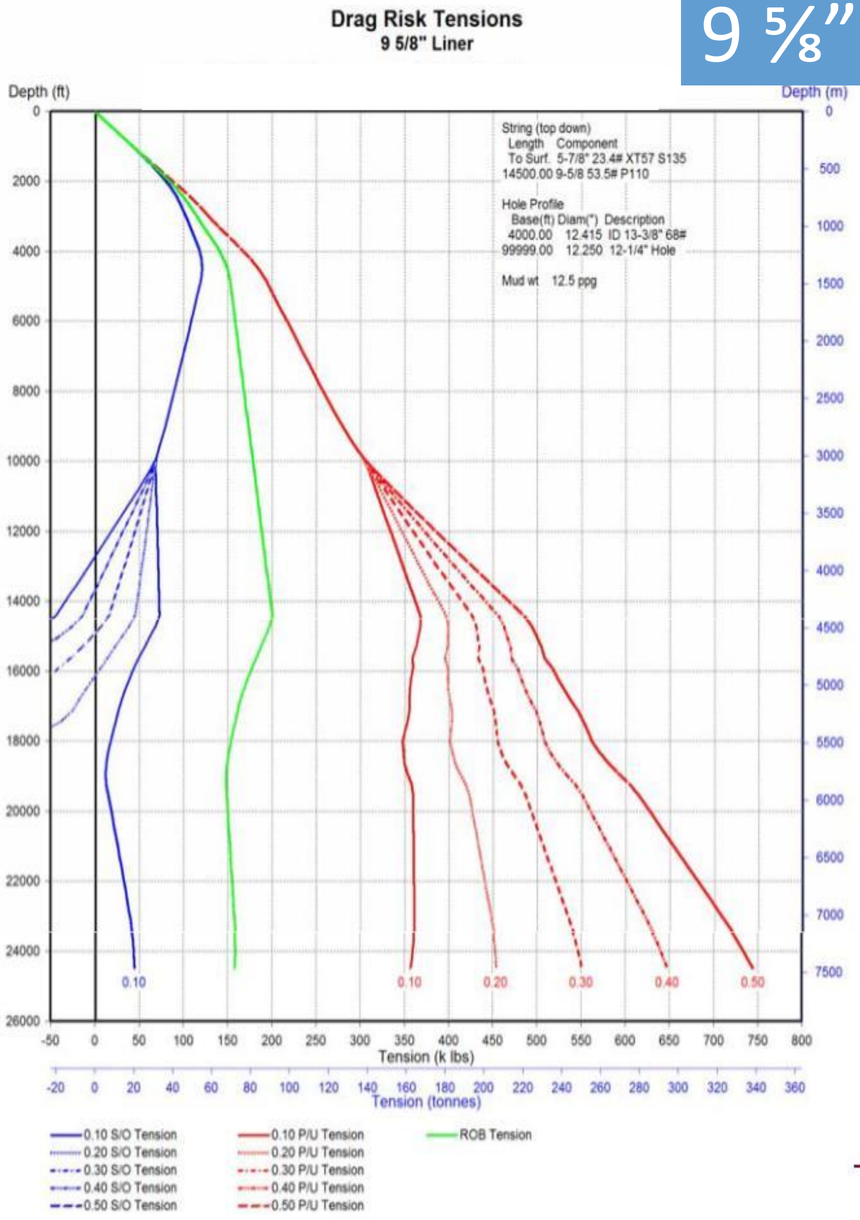
- 13 ⅜” must be floated to overcome drag.
  - But it collapses.
  - Requires 13 ⅝” for collapse strength and buoyancy.
- 9 ⅝” liner must be floated to overcome drag/buckling.
  - 40# casing is positively buoyant, and collapses.
  - Need 53.5# ≥P110 with premium connections.
- 6 ⅝” screens require HWDP, rollers on running string or swivel.
  - The hole geometry and drill-string complicates the screen run.

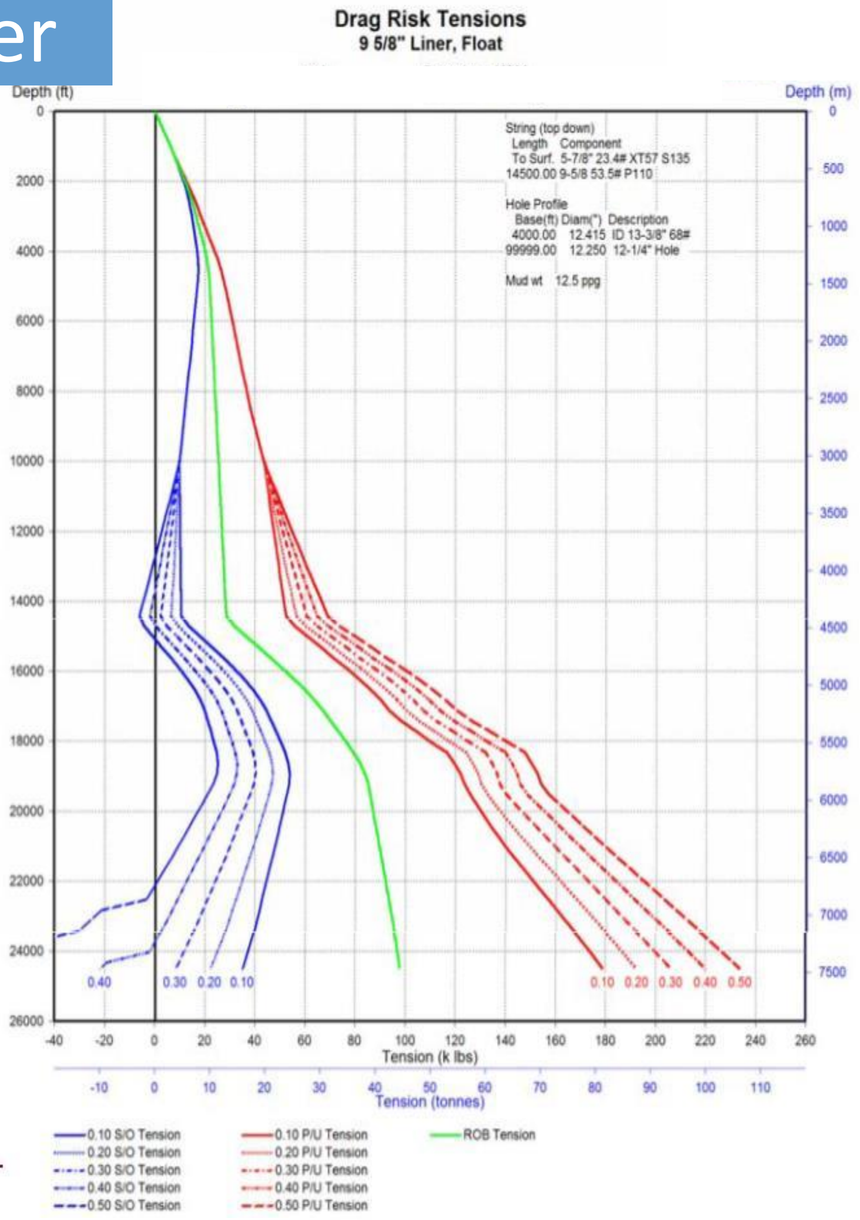
13 ⅜” Casing


Drag Risk Tensions
13 3/8"
Depth (ft)
13 3/8" T&D
String (top down)
Length Component
To Surf. 13-3/8" 68#
Hole Profile
Base(ft) Diam(") Description
40000.00 17.755 ID 18-5/8" 87.5
99999.00 17.500 17-1/2" Hole
Mud wt 10.5 ppg
Tension (k lbs)
Tension (tonnes)
0.20 S/O Tension
0.30 S/O Tension
0.40 S/O Tension
0.50 S/O Tension
0.60 S/O Tension
0.20 P/U Tension
0.30 P/U Tension
0.40 P/U Tension
0.50 P/U Tension
0.60 P/U Tension
ROB Tension

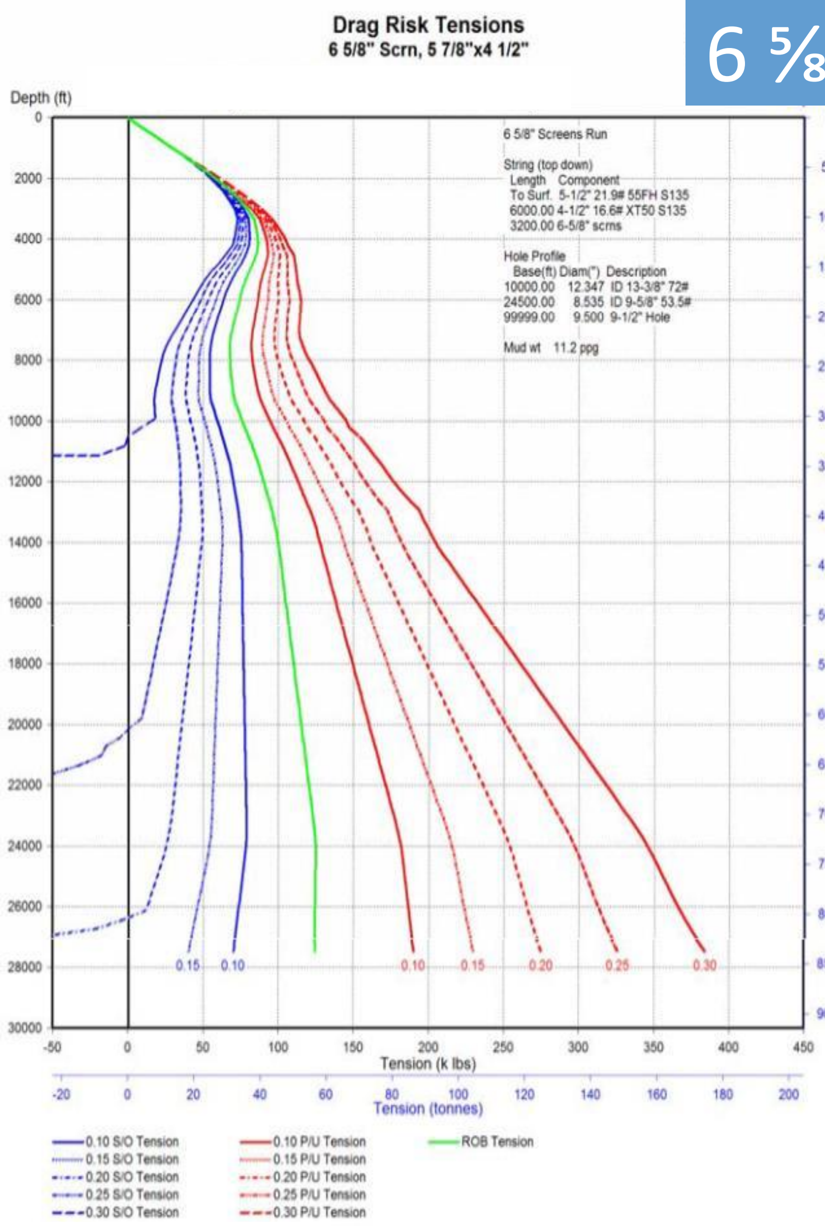

Drag Risk Tensions
13 5/8" MoA
13 3/8" T&D
String (top down)
Length Component
To Surf. 13-5/8" 88.2#
Hole Profile
Base(ft) Diam(") Description
40000.00 17.755 ID 18-5/8" 87.5
99999.00 17.500 17-1/2" Hole
Mud wt 10.5 ppg
Tension (k lbs)
Tension (tonnes)
0.20 S/O Tension
0.30 S/O Tension
0.40 S/O Tension
0.50 S/O Tension
0.60 S/O Tension
0.20 P/U Tension
0.30 P/U Tension
0.40 P/U Tension
0.50 P/U Tension
0.60 P/U Tension
ROB Tension

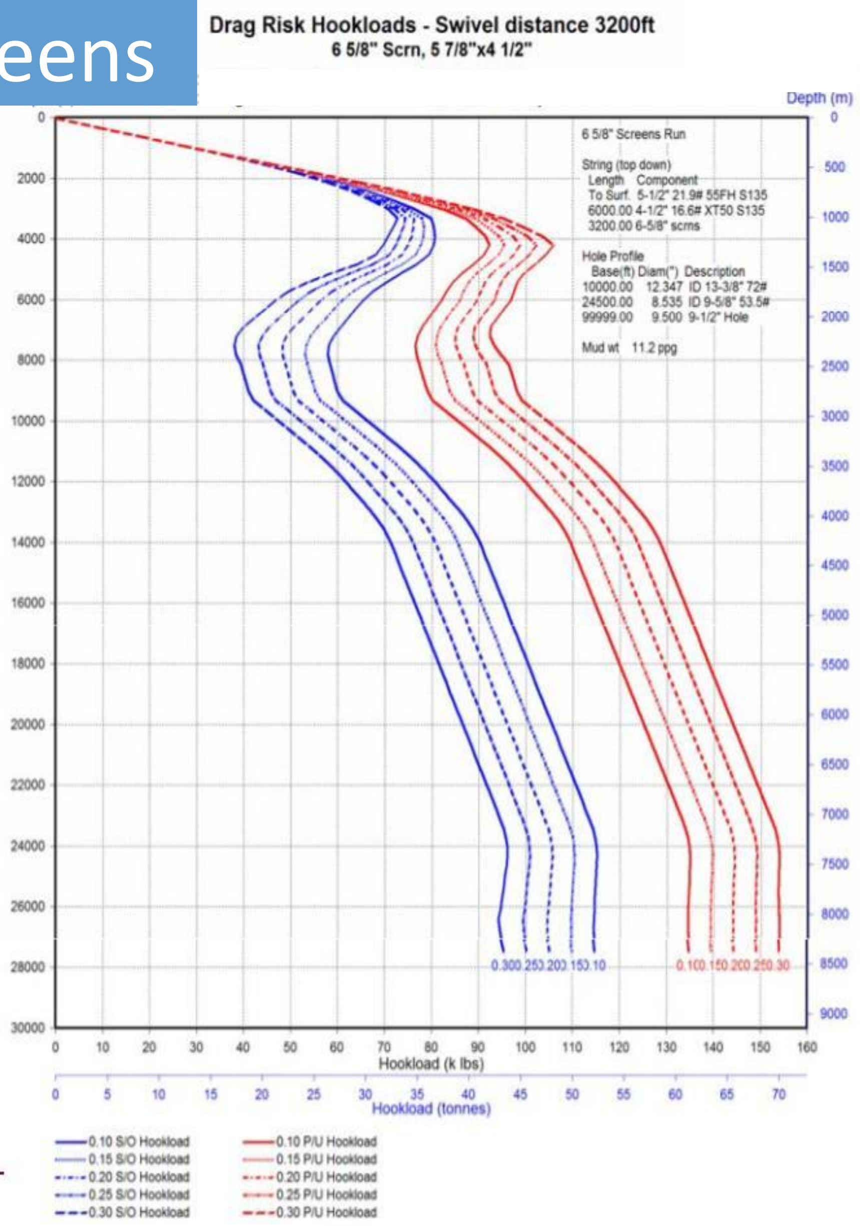
9 ⅝” Liner


Drag Risk Tensions
9 5/8" Liner
Depth (ft)
Depth (m)
String (top down)
Length Component
To Surf. 5-7/8" 23.4# XT57 S135
14500.00 9-5/8 53.5# P110
Hole Profile
Base(ft) Diam(") Description
4000.00 12.415 ID 13-3/8" 68#
99999.00 12.250 12-1/4" Hole
Mud wt 12.5 ppg
Tension (k lbs)
Tension (tonnes)
0.10 S/O Tension
0.20 S/O Tension
0.30 S/O Tension
0.40 S/O Tension
0.50 S/O Tension
0.10 P/U Tension
0.20 P/U Tension
0.30 P/U Tension
0.40 P/U Tension
0.50 P/U Tension
ROB Tension


Drag Risk Tensions
9 5/8" Liner, Float
Depth (ft)
Depth (m)
String (top down)
Length Component
To Surf. 5-7/8" 23.4# XT57 S135
14500.00 9-5/8 53.5# P110
Hole Profile
Base(ft) Diam(") Description
4000.00 12.415 ID 13-3/8" 68#
99999.00 12.250 12-1/4" Hole
Mud wt 12.5 ppg
Tension (k lbs)
Tension (tonnes)
0.10 S/O Tension
0.20 S/O Tension
0.30 S/O Tension
0.40 S/O Tension
0.50 S/O Tension
0.10 P/U Tension
0.20 P/U Tension
0.30 P/U Tension
0.40 P/U Tension
0.50 P/U Tension
ROB Tension

6 ⅝" Screens


Drag Risk Tensions
6 5/8" Scrn, 5 7/8"x4 1/2"
Depth (ft)
6 5/8" Screens Run
String (top down)
Length Component
To Surf. 5-1/2" 21.9# 55FH S135
6000.00 4-1/2" 16.6# XT50 S135
3200.00 6-5/8" scrns
Hole Profile
Base(ft) Diam(") Description
10000.00 12.347 ID 13-3/8" 72#
24500.00 8.535 ID 9-5/8" 53.5#
99999.00 9.500 9-1/2" Hole
Mud wt 11.2 ppg
Tension (k lbs)
Tension (tonnes)
0.10 S/O Tension
0.15 S/O Tension
0.20 S/O Tension
0.25 S/O Tension
0.30 S/O Tension
0.10 P/U Tension
0.15 P/U Tension
0.20 P/U Tension
0.25 P/U Tension
0.30 P/U Tension
ROB Tension


Drag Risk Hookloads - Swivel distance 3200ft
6 5/8" Scrn, 5 7/8"x4 1/2"
Depth (m)
6 5/8" Screens Run
String (top down)
Length Component
To Surf. 5-1/2" 21.9# 55FH S135
6000.00 4-1/2" 16.6# XT50 S135
3200.00 6-5/8" scrns
Hole Profile
Base(ft) Diam(") Description
10000.00 12.347 ID 13-3/8" 72#
24500.00 8.535 ID 9-5/8" 53.5#
99999.00 9.500 9-1/2" Hole
Mud wt 11.2 ppg
Hookload (k lbs)
Hookload (tonnes)
0.10 S/O Hookload
0.15 S/O Hookload
0.20 S/O Hookload
0.25 S/O Hookload
0.30 S/O Hookload
0.10 P/U Hookload
0.15 P/U Hookload
0.20 P/U Hookload
0.25 P/U Hookload
0.30 P/U Hookload

ECD design exercise.

- Everything is connected!.
  - Can’t change one aspect without affecting several others.
  - The trick is to prioritize things properly.
    - Logistical convenience or “low cost” approach would cripple this well.
    - Every well will have different issues, so the right solutions will vary.
- It’s all about the architecture!
  - Notice how much impact the hole / string geometry had on overall risk and problems.
  - “Assuming” all was ok would have lead to inappropriate equipment and an invalid design.

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MODULE 7

Inside the well.

How does the inside of the well looks like.

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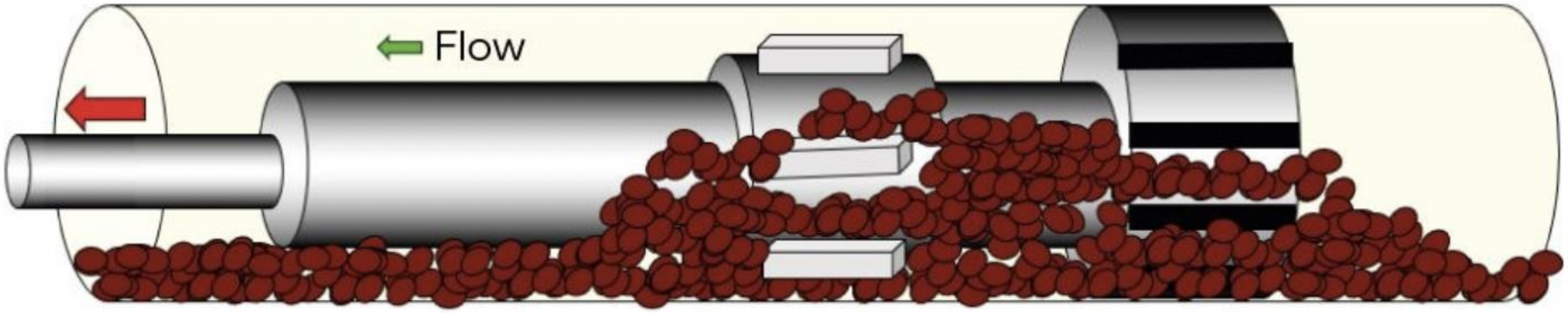
MODULE 6

Pumping out of hole.

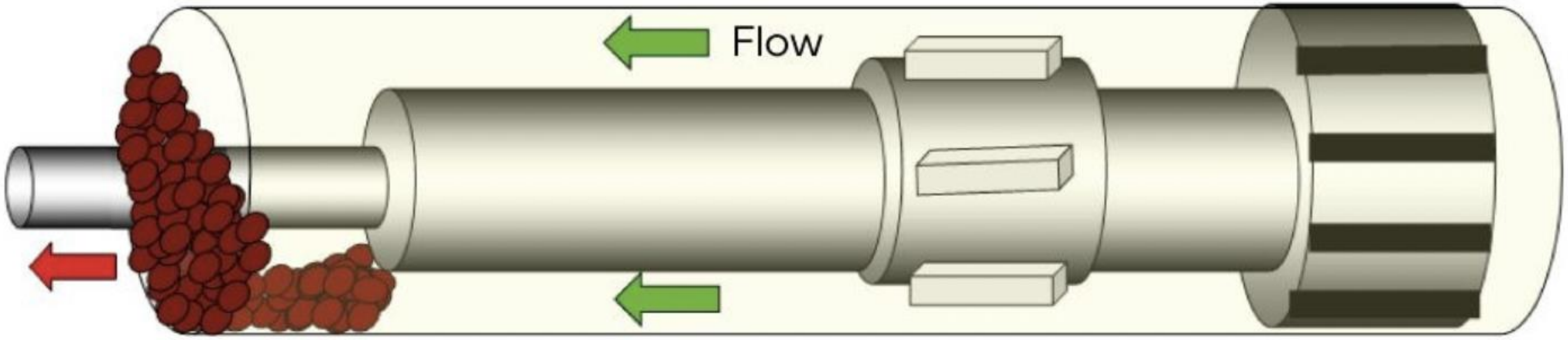
Pumping out of hole.

- What is it?



Pumping out of hole.

- What is it not?



Pumping out of hole.

How do we pump out of hole as safe as possible?

1. In the planning phase, if swab is identified as a risk, ensure that the risk is captured in an overall well specific risk assessment and that procedures are discussed in advance with the engineering and operations team to ensure that all are aware.

2. Make sure we are aware of our limits and loads – how fast can we pull at any given depth with the fluid properties we have in the well so we understand the conditions that will lead to swabbing or hole collapse (if this is a factor).

Pumping out of hole.

3. The hole should be as clean as it needs to be before starting the trip as we will not be cleaning it with the flow rates used to control swab or balance string displacement.

4. Minimise the flow rates in use. Higher flow rates increase AV which will clear more cuttings from around the BHA – meaning that the cuttings mound ahead will build up more quickly and in greater volume, meaning getting free is likely to be more of a challenge should we get stuck.

5. Have a road map for the trip, taking pick up data and using it to compare against the model. It is also important to select and impose overpull limits which are appropriate to the situation and that the team are going to stick to should divergence occur.

Pumping out of hole.

Lubricating or pumping out of hole can be managed safely provided that risks are identified and mitigated. Keeping AVs as low as possible, whilst managing swab or metal displacement is necessary to ensure that cuttings build up ahead of the BHA is minimised, which in turn minimises the chances of stuck pipe events in this part of the trip.

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MODULE 5

Surge and swab engineering.

Surge and swab basics.

Surging or swabbing pressures in drilling describe pressure changes in the annulus resulting from pipe movement. The swabbing occurs when the drill-pipe is pulled from the well, forcing mud to flow down the annulus to fill the void left by the pipe. However, the surging occurs when the drill-pipe is lowered into the well. Then the mud is forced out of the flow line.

Pressure changes caused by lowering the pipe into the well are called surge pressures and are generally considered to be added to the hydrostatic pressure. This module will cover the swab and surge in drilling risks and calculations.

Surge and swab basics.

Understanding surge and swab.

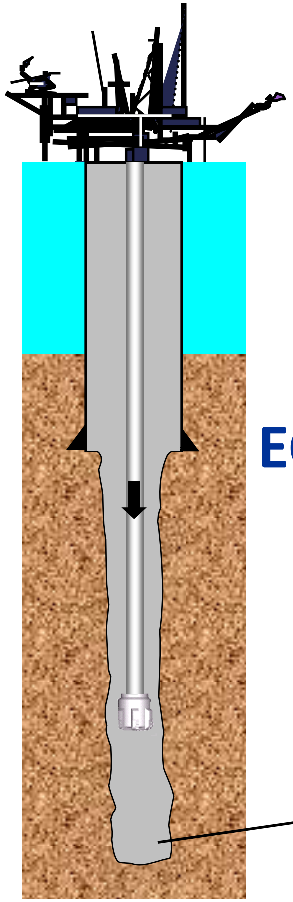
- Magnitude of ECD fluctuations.
- Causes.
- Effects.

Options to reduce surge and swab.

- Planning stage, implementation stage.
- Special equipment.

Surge and swab basics.

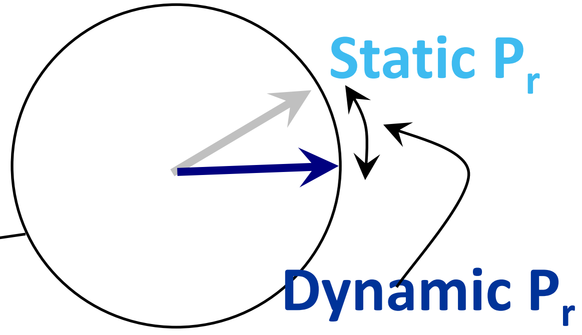
(With Pumps OFF)

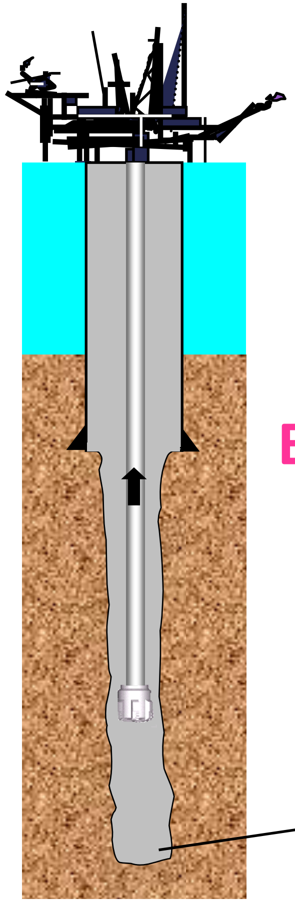


Surge:

Results from ***downward*** pipe movement.

$$ECD = ESD + \frac{Dynamic\ P_r}{g \times TVD}$$

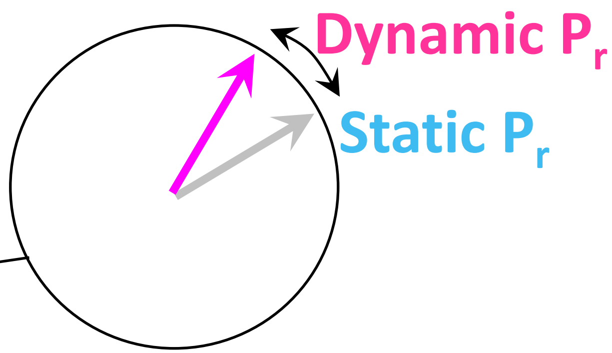




Swab:

Results from ***upward*** pipe movement.

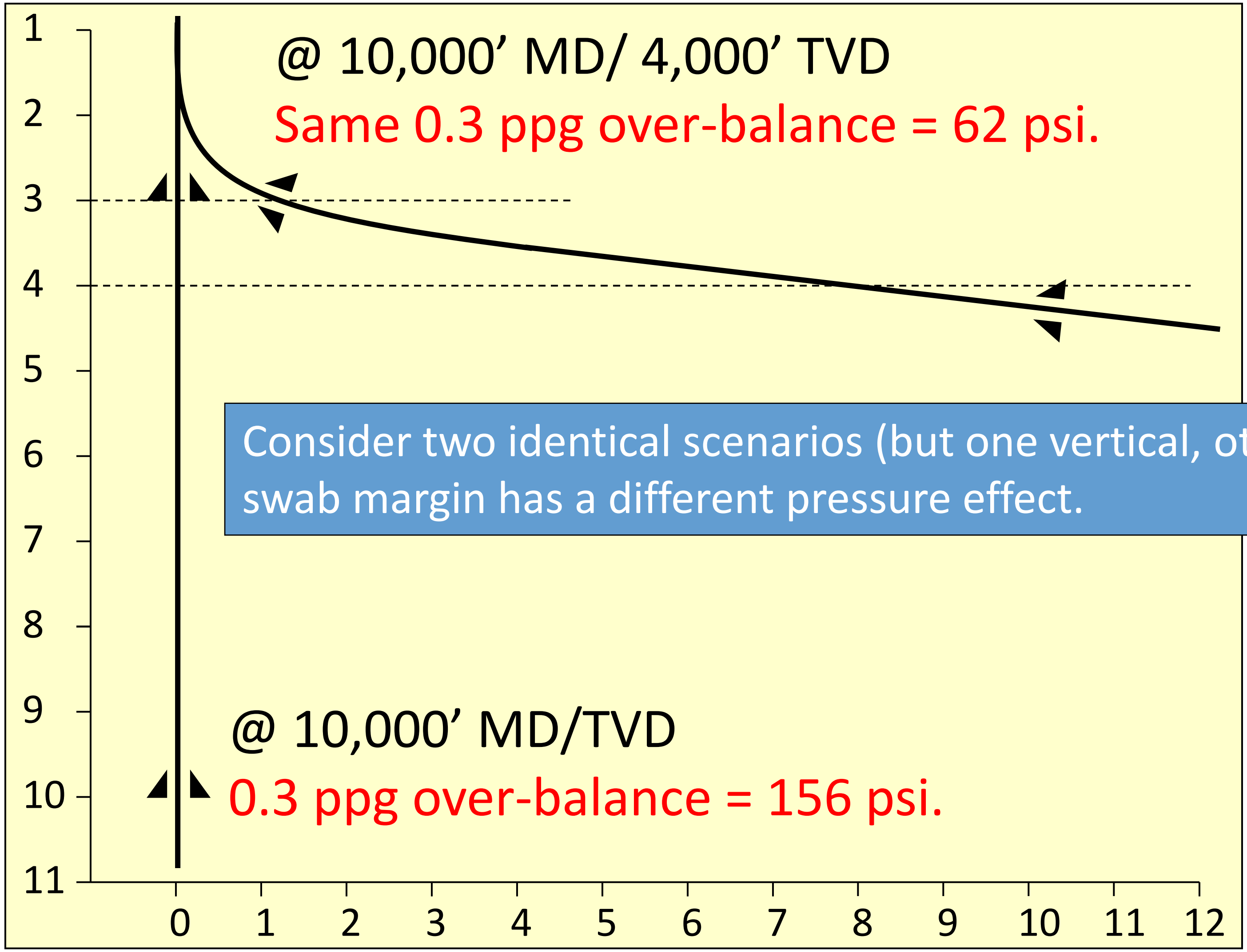
$$ECD = ESD - \frac{Dynamic\ P_r}{g \times TVD}$$



Why is surge and swab a particular concern for ERD?

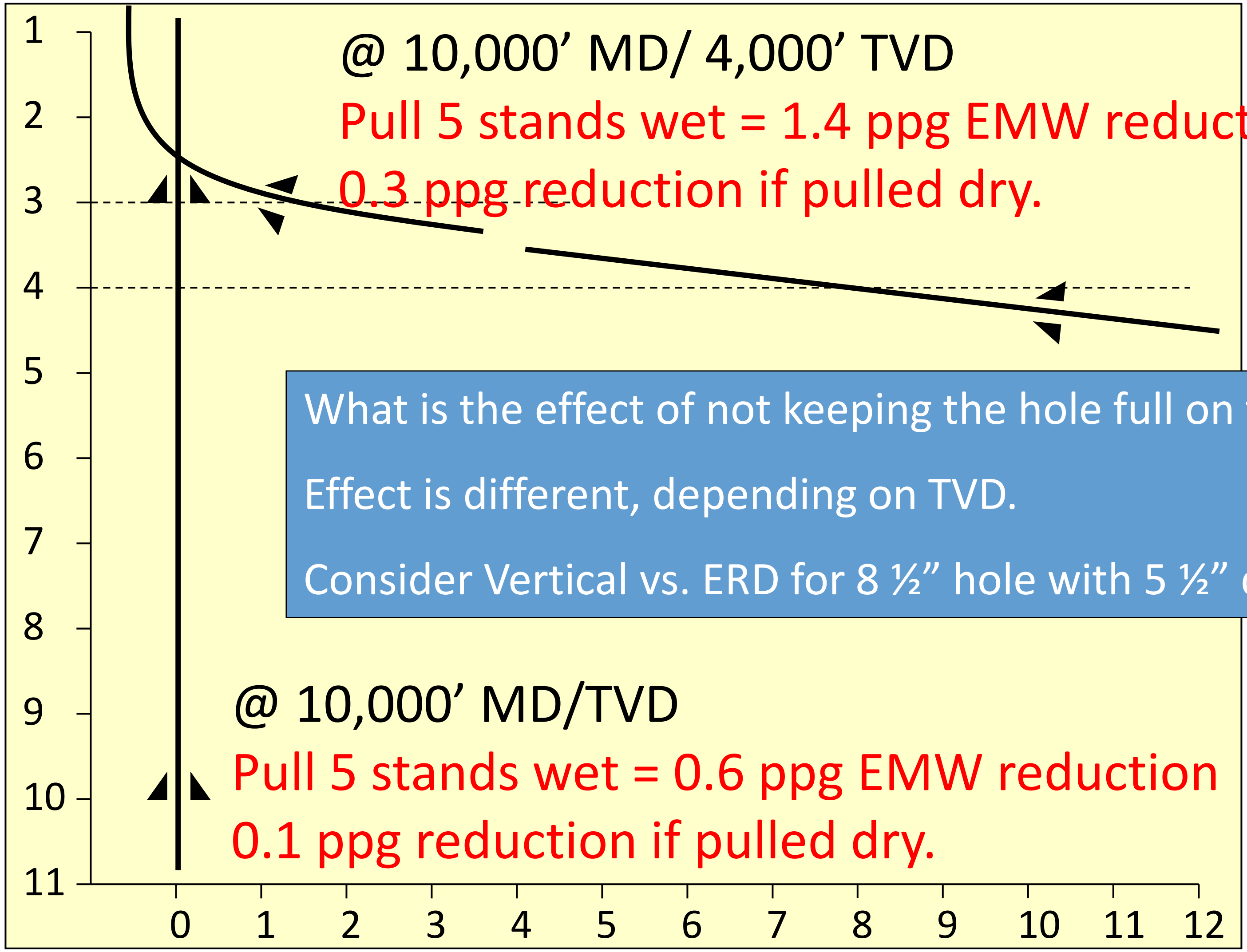
- ERD wells have much higher surge & swab ECD fluctuations.
  - For same reasons ECDs are higher.
- ERD wells require more swab margin for normal tripping.

Surge and swab basics.



Consider two identical scenarios (but one vertical, other ERD) The same swab margin has a different pressure effect.

Keeping the hole full.



What is the effect of not keeping the hole full on trips?

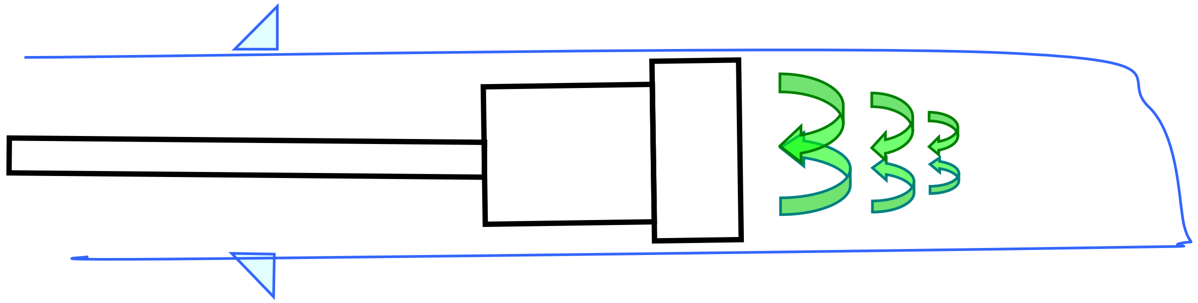
Effect is different, depending on TVD.

Consider Vertical vs. ERD for 8 ½" hole with 5 ½" drill-pipe.

Surge and swab basics.

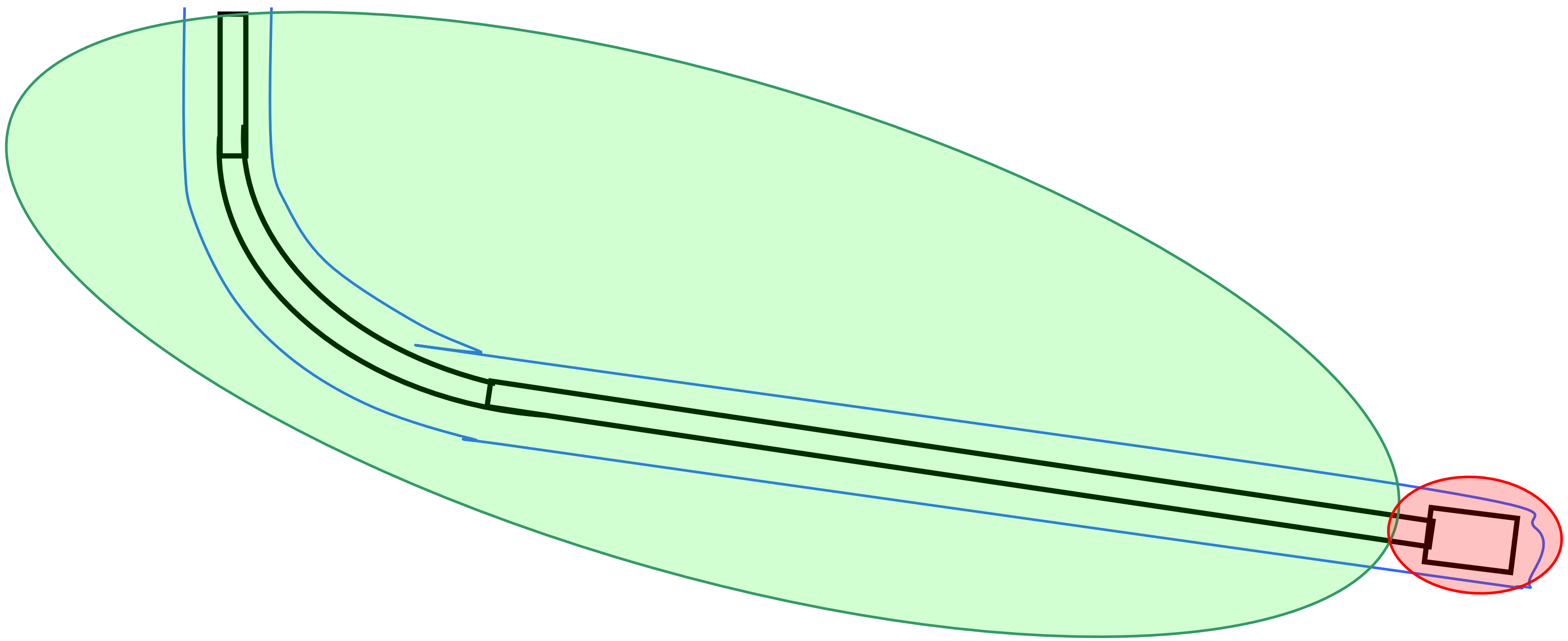
The typical *perception* of “what causes swab” is the following …

1. That the bit creates most of the swab (piston effect)
2. That the swab suction is not felt all the way to TD (i.e. it is local to just below the bit)



Surge and swab ECDs are made up of 2 components.

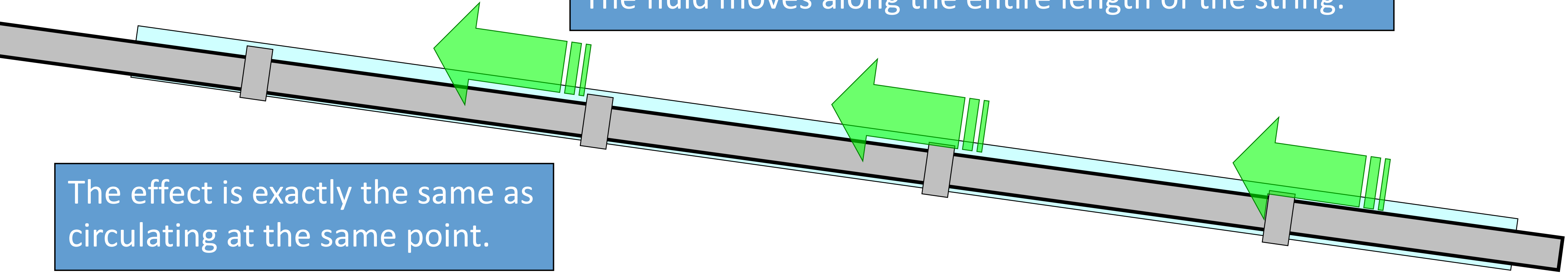
1. Bit creates a piston / plunger effect
   - This is what we normally think of for the surge & swab
2. But there are also overall drill-string effects. (more critical).



The drill-string pump.

When drill-pipe moves down, fluid moves up

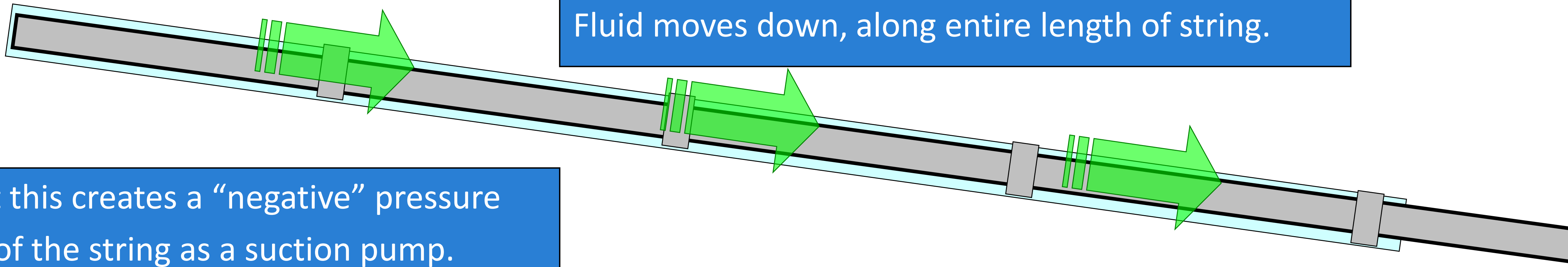
The fluid moves along the entire length of the string.



The effect is exactly the same as circulating at the same point.

The same applies to swab, when tripping out

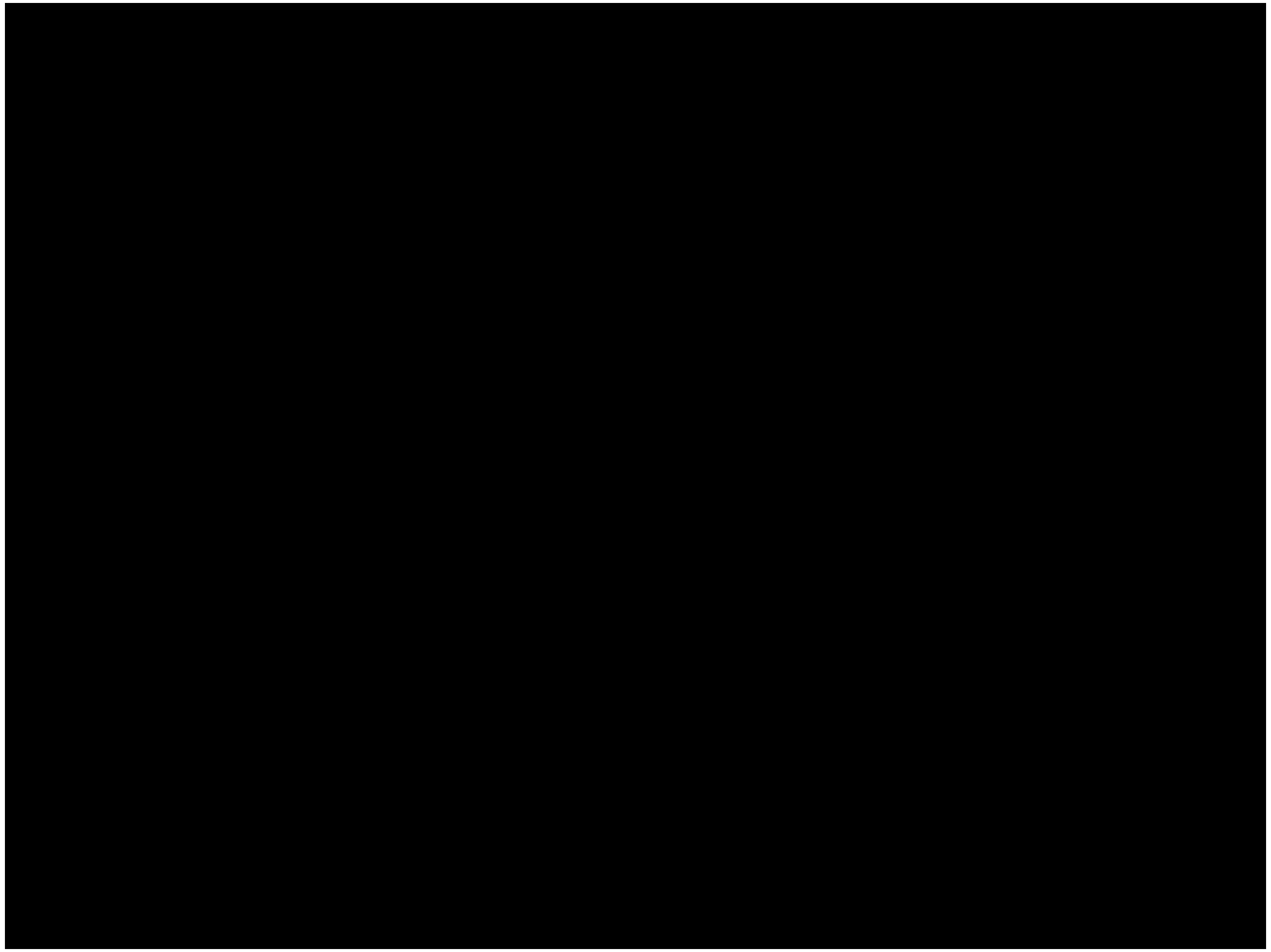
Fluid moves down, along entire length of string.



Except this creates a "negative" pressure

Think of the string as a suction pump.

Surge and swab basics.



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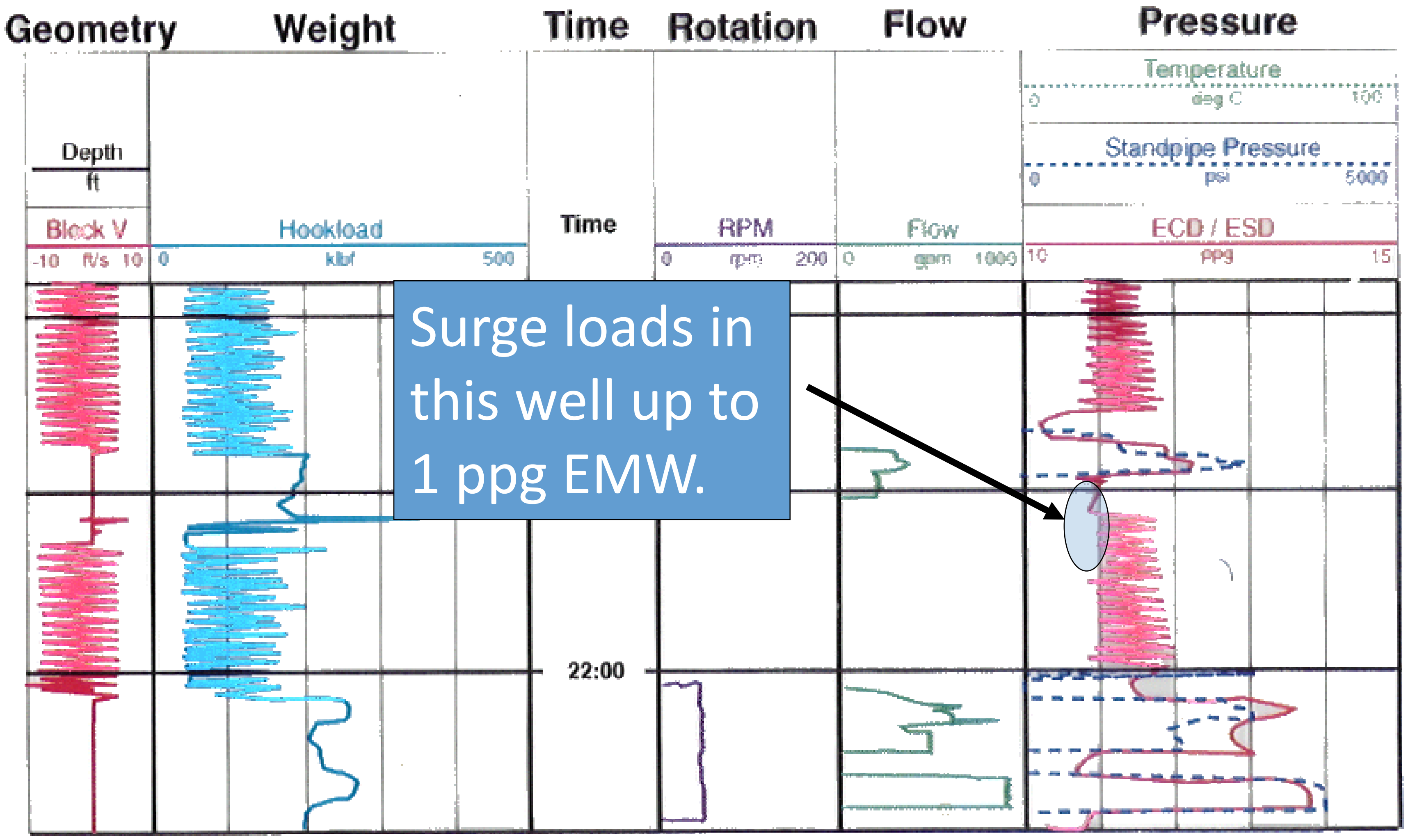
The drill-string pump.

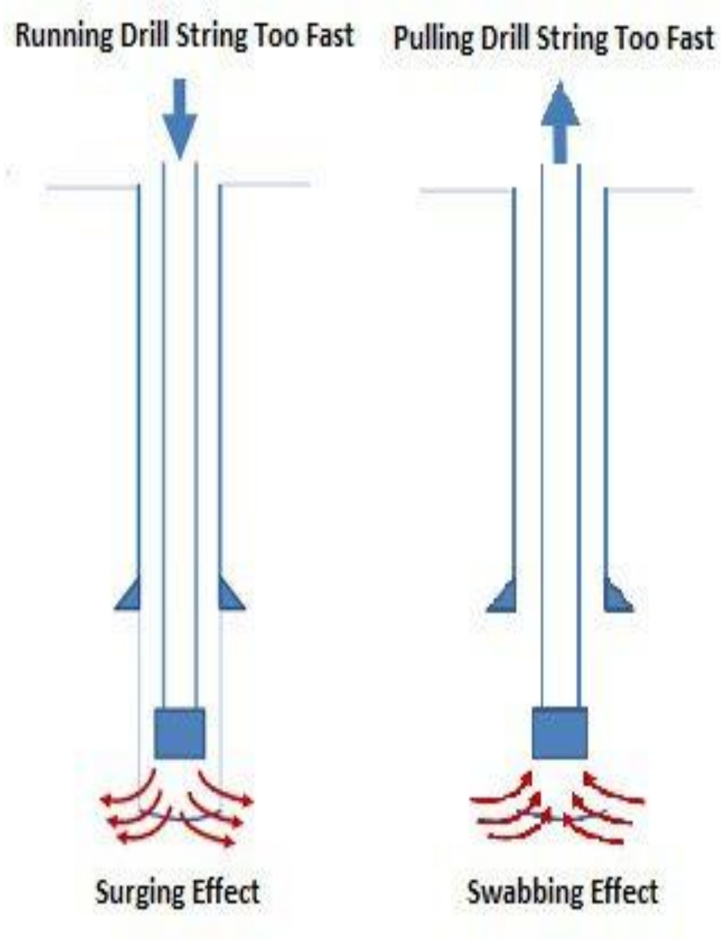


Surge and swab engineering.

SURGE AND SWAB CALCULATIONS.

Surge and swab calculations.

Nowadays we all use software to create all our calculations, but in this section I will show you how to calculate surge and swab by hand just incase you ever need it.



Surge and swab calculations.

- Removing the drill pipe from the well creates swab pressures, which are harmful, resulting in a net lowering of pressure in the well. Many problems are caused by the surge and swab pressures.

- Removing the drill pipe at rates that create considerable swab pressures can induce well kicks by lowering the wellbore pressure below formation pressure, leading to a well control issue.

- Surge pressures increase the total wellbore pressure and can cause formation fracturing and lost circulation.

Surge and swab calculations.

Calculating the surge and swab pressures in drilling is difficult because the fluid flows as the pipe moves in the well.

However, since the annulus is a fixed volume and the mud is considered incompressible, some drilling fluids must flow out of the annulus.

The mechanics are different from pumping since the fluid flow is considered only one direction.

Surge and swab calculations.

- The flow rate of a closed drill string into the well is:

$$Q = V_{pc}\left(\frac{-\pi c\ d_p^2}{4}\right)$$

- Where:
- Q = flow rate, gal/min
- Vpc = pipe velocity, ft/sec

Surge and swab calculations.

- In swab and surge, the velocity in the annulus is the quotient of flow rate and area:

$$V = \frac{Q}{A} = c\left[V_p\left(\frac{\pi\, d_p^2}{4}\right)\right] \Big/ \pi\left(\frac{d_H^2 - d_p^2}{4}\right)$$

$$= c\,\frac{-d_p^2\, V_p}{(d_H^2 - d_p^2)}$$

- If the pipe is open-ended, the flow velocity is solved in a similar manner:

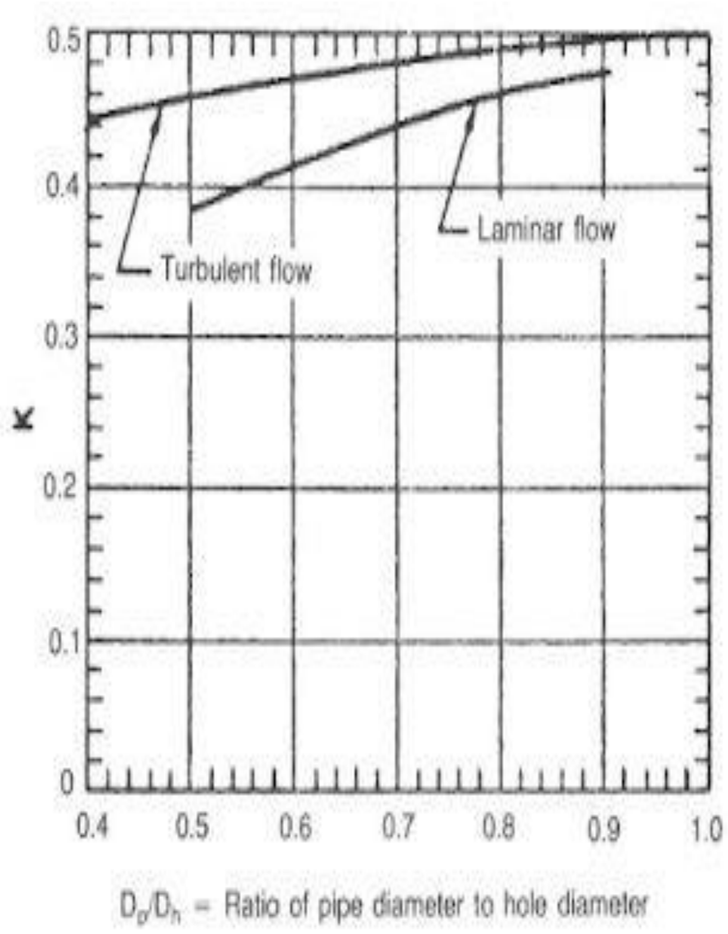
$$V = -V_p\,\frac{4\, d_p^2\, (d_H - d_p)^2 - 3d_p^4}{4\,(d_H - d_p)^2\,(d_H^2 - d_p^2) + 6d_p^4}$$

Surge and swab calculations.

- Applying the clinging constant, k, the effective annular velocity (Vc) is as follows:

$$Vc = V - kVp$$

- The clinging constant is applied to yield an effective velocity based on the complex flow patterns in the annulus. The surging or swabbing pressures in drilling are computed by substituting the effective velocity into any of the previously defined friction pressure equations. It is reasonable to use laminar flow equations since normal pipe velocities seldom cause greater than critical velocities.



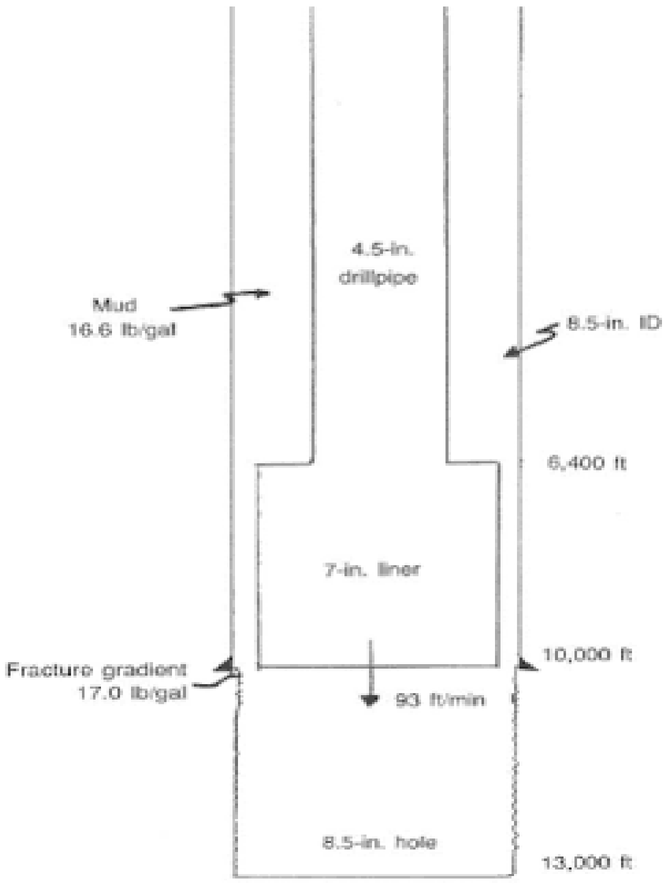
Surge and swab calculations example.

If a 7” liner is RIH at a maximum rate of 93 ft/min, will the surge pressures exceed the fracture gradient?

- Use the Bingham model and assume laminar annular flow.
- Assume the peak pipe velocity is the same as the average value.
- Assume the liner has a closed end from a float shoe.
- casing depth = 10,000 ft, casing ID = 8.5 in.
- open hole depth = 13,000 ft, open hole OD = 8.5 in.
- liner size = 7 in. (flush joint), liner length = 3,600 ft, drill-pipe = 4.5 in.
- mud = 16.6 Ib/gal, 38 cp (PV), 15 Ib/l00fe (YP)
- fracture gradient = 17.0 Ib/gal
- pipe velocity = 93 ft/min = 1.55 ft/sec

Surge and swab calculations example.

1. The maximum surge pressures in drilling occur when the bottom of the liner reaches the casing seat.



Surge and swab calculations example.

2. The mud flow rate leaving the well when the liner shoe reaches the casing seat is:

- V = Q / 2.448 (d^2)
- Q = 2.448 V (d^2) = 2.448 (1.55 ft/sec) (4.5 in.)^2
- Q = 76.8 gal/min

Surge and swab calculations example.

3. The annular velocities around the drill pipe (Vap) and the liner (Val)

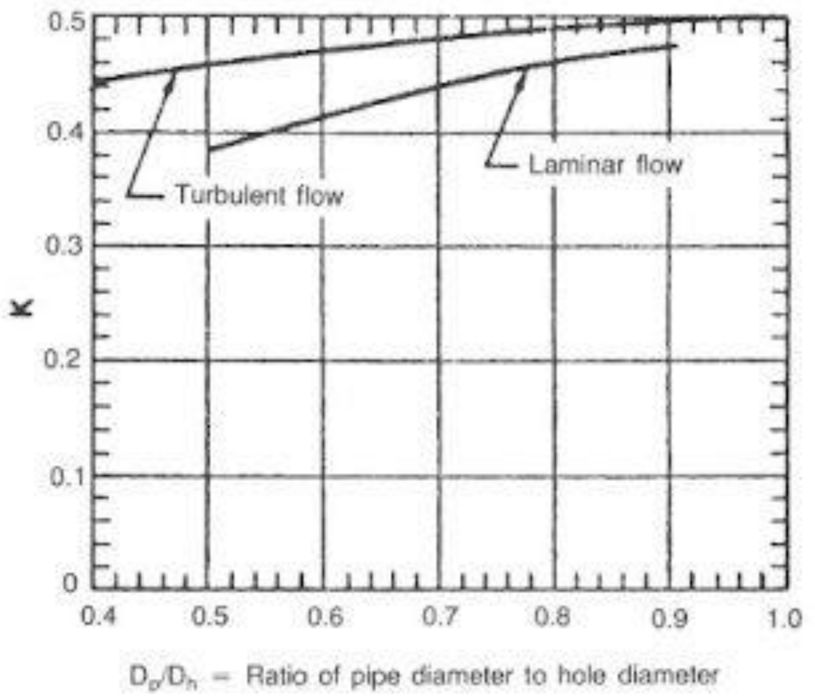
- Vap = Q / 2.448 (dH^2- dP^2) = 76.8/ 2.448 (8.5^2- 4.5^2) = 0.603 ft/sec = 36 ft/min
- Val= Q / 2.448 (dH^2- dP^2) = 76.8/ 2.448 (8.5^2- 7^2)= 1.349 ft/sec = 80.9 ft/min

Surge and swab calculations example.

4. To calculate surge and swab, determine the clinging constant, k, for the pipe and liner

- pipe – ratio = 4.5/8.5 = 0.529
  k ≃0.38

- liner – ratio = 7/8.5 = 0.823
  k ≃0.45



Surge and swab calculations example.

5. The effective annular velocities around the pipe (Vpe) and the liner (Vle) are:

- Vpe = V – 0.38 Vp = (0.603) – (0.38) x (– 1.55) = 1.192 ft/sec
- Vle = V – 0.45 Vp = (1.349 ft/sec) – (0.45) x(– 1.55) = 2.046 ft/sec

Surge and swab calculations example.

6. The pressure surge caused by the drill pipe using Bingham model for Laminar flow is as follows:

$$P_p = \frac{PVLV_{pa}}{1{,}500\,(d_H^2 - d_p^2)} + \frac{YPL}{225\,(d_H - d_p)}$$

- Pp = {(38)(6,400)(1.192) / 1,500 (8.5^2 – 4.5^2)} + {(15)(6,400) / 225 (8.5-4.5)}
- Pp = 3.716 psi + 106 psi = 110 psi

Surge and swab calculations example.

7. The pressure surge caused by the liner is:

- Pl = {(38)(3,600)(2.046) / 1,500 (8.5^2 – 7^2)} + {(15)(3,600) / 225 (8.5-7)}
- Pl =8.0 psi + 160 psi = 168 psi

Surge and swab calculations example.

8. The total pressure surge and equivalent mud weight is:

- 110 psi + 168 psi = 278 psi
- EMW = pressure x 19.323 / depth + mud weight
- EMW = 278 psi x 19.23 / 10000 ft + 16.6 lb/gal = 17.13 lb/gal

9. Therefore, the fracture gradient of 17.0 lb/gal would be exceeded (17.1 lb/gal) at a pipe velocity of 93 ft/min.

Surge and swab engineering.

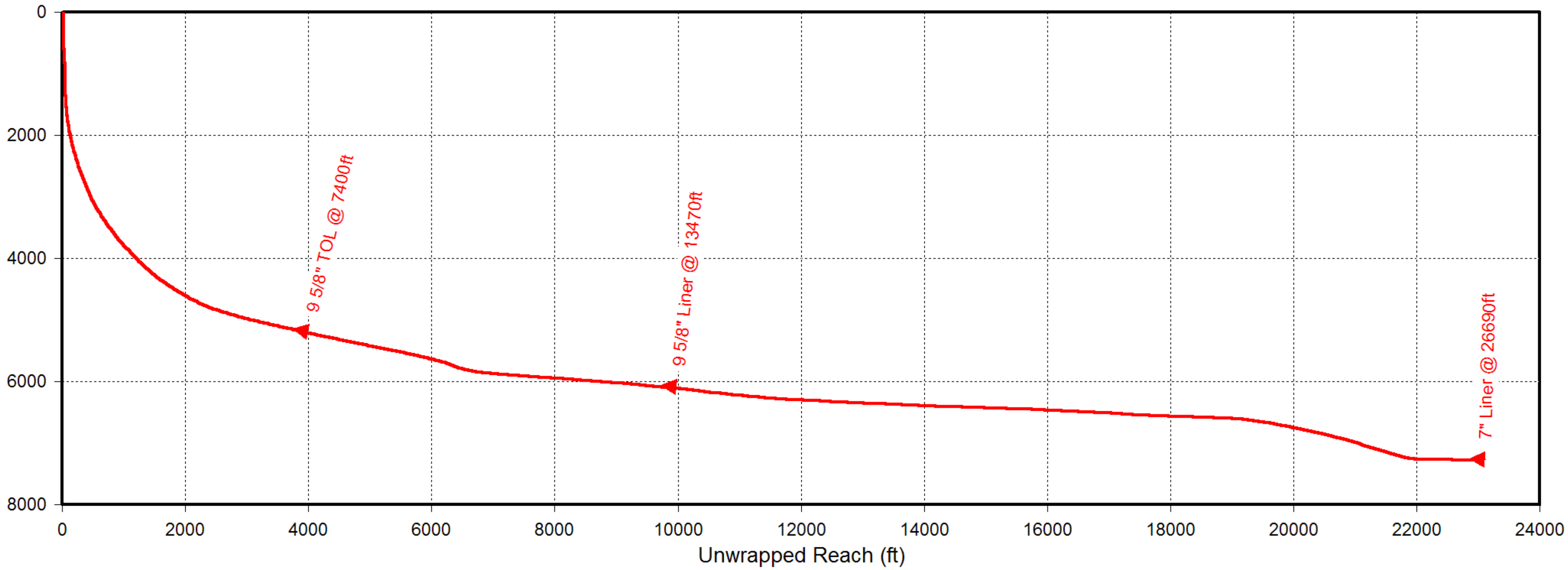
SURGE AND SWAB CASE STUDY.

Surge and swab basics.

- Swabbing is related to ECDs.
- Many of the same issues apply.
    - TVD amplification of swabbing magnitudes.
    - Most problems are predictable.
        - If you know what normal looks like.
- But there are misconceptions.
    - Is the swab mostly due to the bit / BHA?
    - Or the drill string?

Surge and swab case study.

- Consider this well.

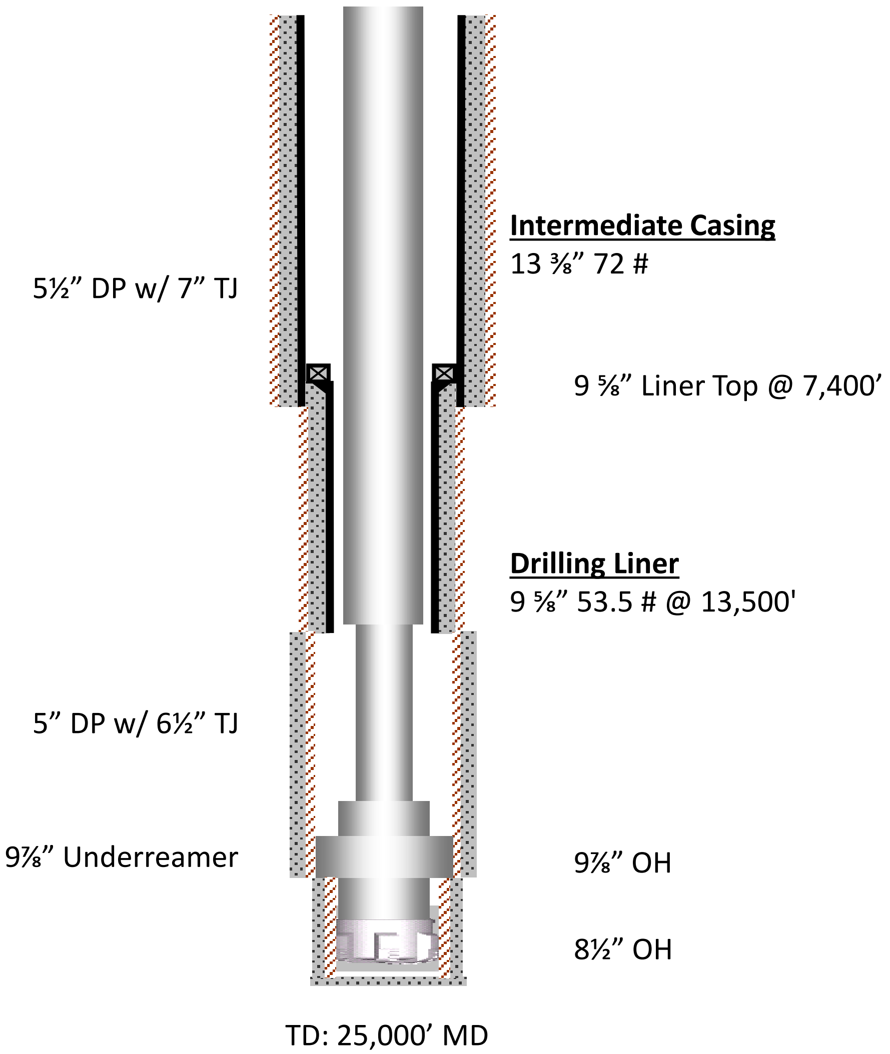


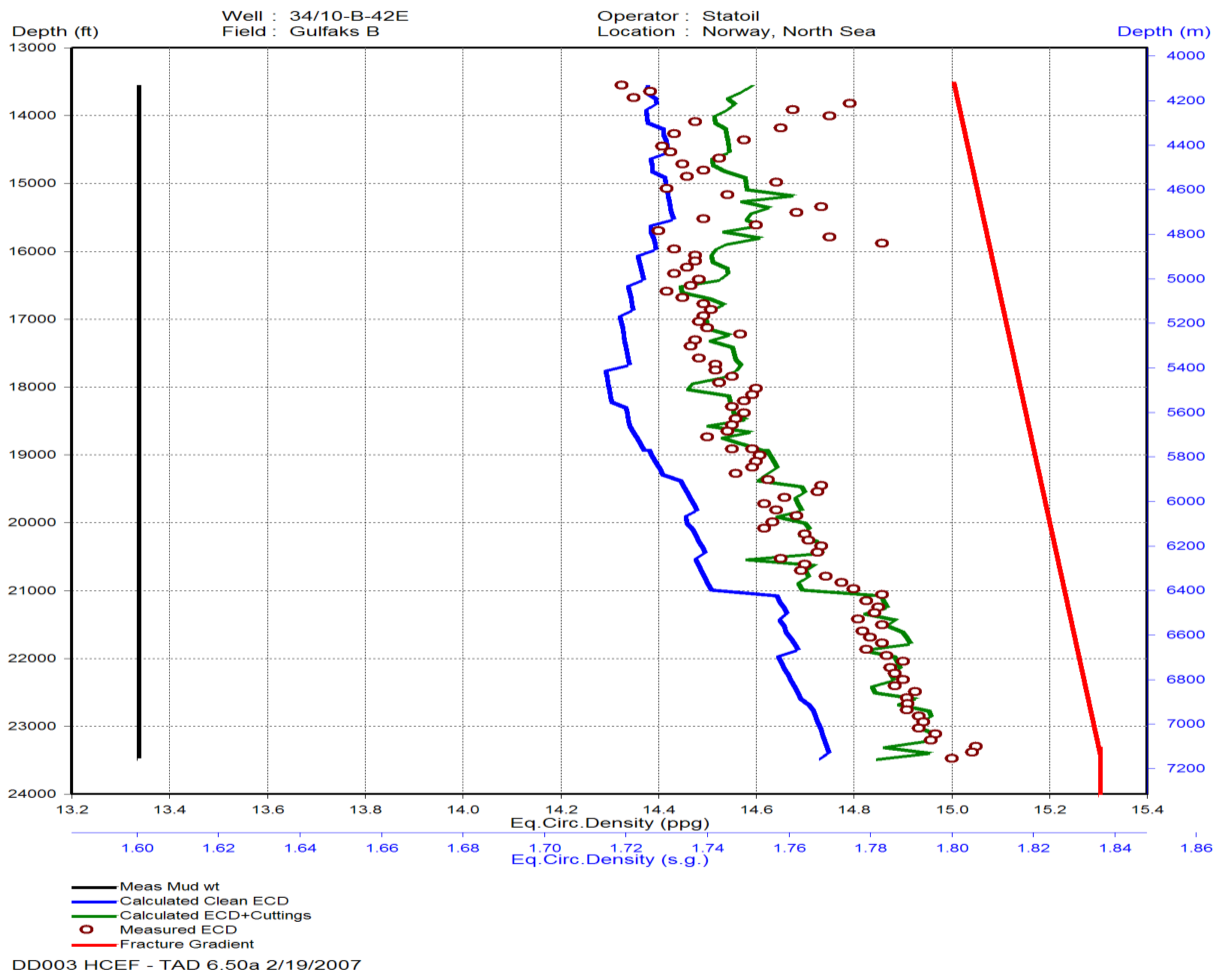
Surge and swab case study.

- Drilling 9 ⅞” hole, with 8 ½” BHA.

- Following facts:
  - 13.3 ppg mud, with 13.1 sg pore pressure.
  - Could not trip conventionally until above liner top.
  - Had to pump out +/- 16,000 ft.
  - No tight hole.
  - Mud weight is limited, because of ECD limitations.

Well schematic.

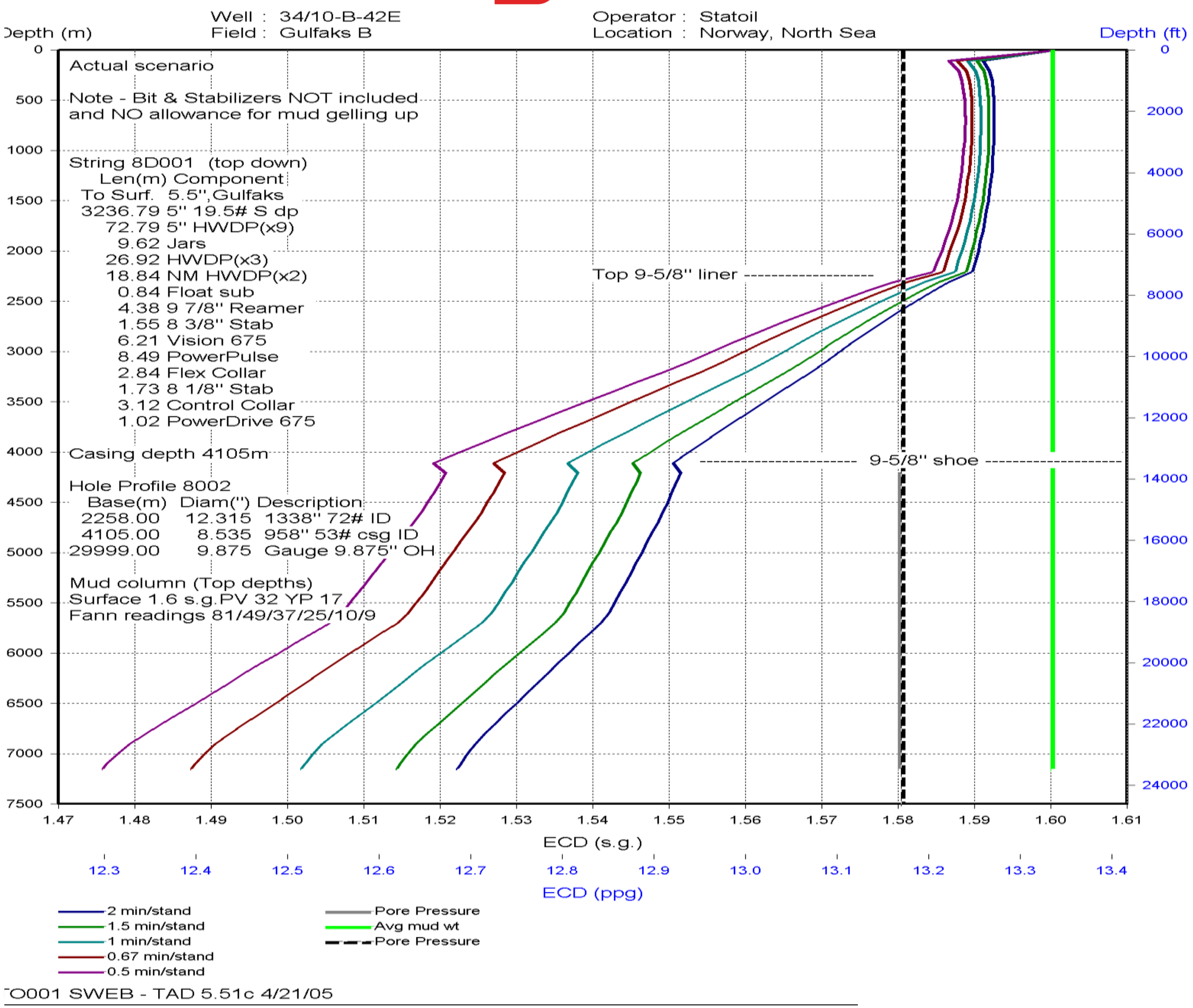




This shows the drilling ECDs.

Good calibration of the hydraulics model.

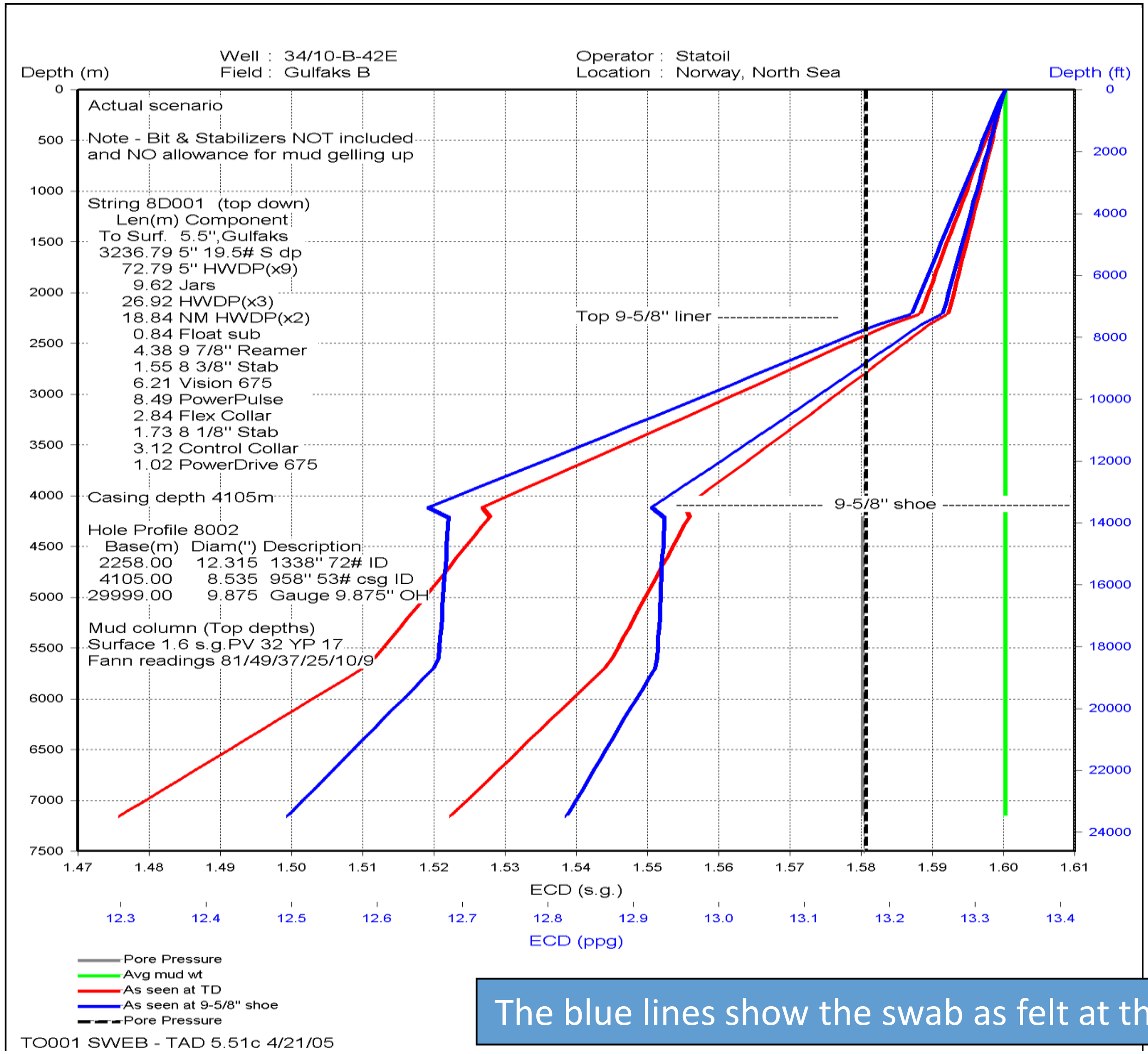
Shows that ECDs right up against the limit … mud weight is therefore limited to 13.3 ppg.



This is the predicted swab that the PWD would show on the time-log for the trip out.

With NO allowance for the bit, stabilizers or mud gelling up.

But is this swab felt at TD?



The red line now shows what TD feels, as the bit comes out.

In this case, swabbing is still occurring at TD when the bit is a LONG way off bottom.

Swabbing a kick in when a long way off bottom is a real risk.

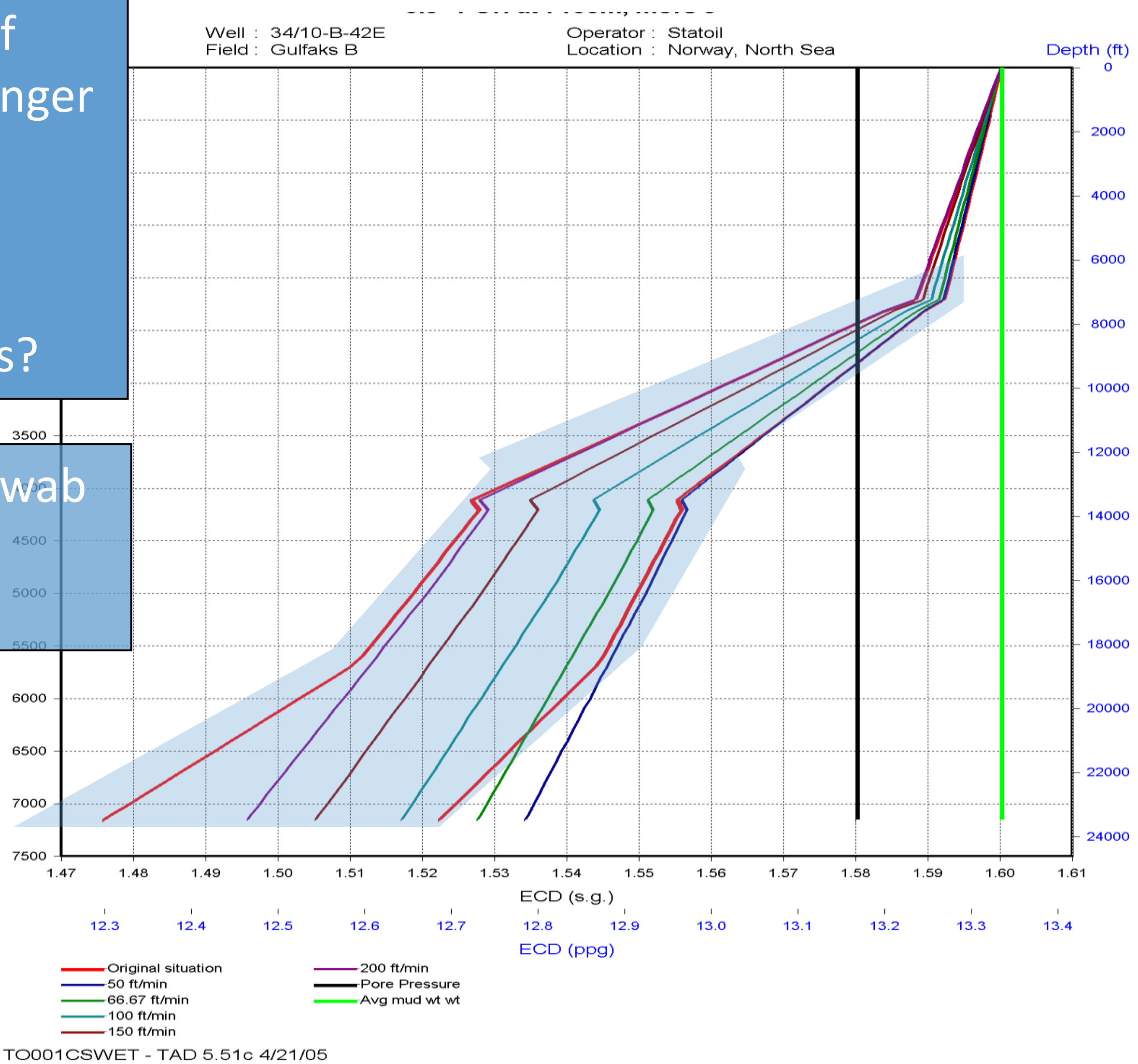
And remember, we still have not even allowed for the bit or stabilizer swab.

The blue lines show the swab as felt at the shoe.

So, if the swab at TD is more a function of ECD than "the plunger effect".

How does a more aggressive ECD solution affect this?

The shaded area is the swab load for the original situation.



In this case, how would drill-string optimization have helped?

If more 5" drill-pipe was run, initial swab is somewhat less

This is due to the smaller pipe within the 9 ⅝" casing.

But it still swabs to the same final point.

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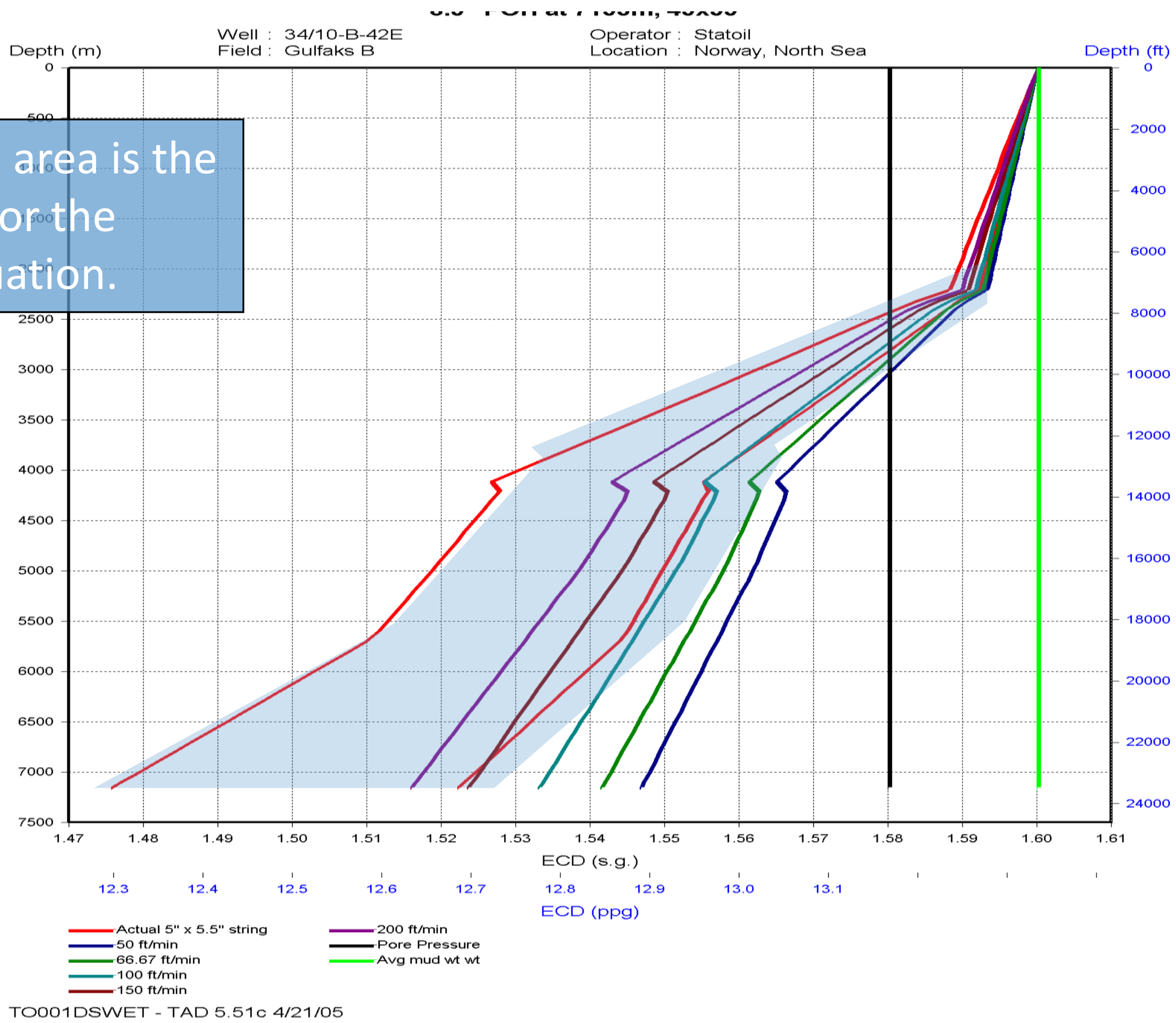
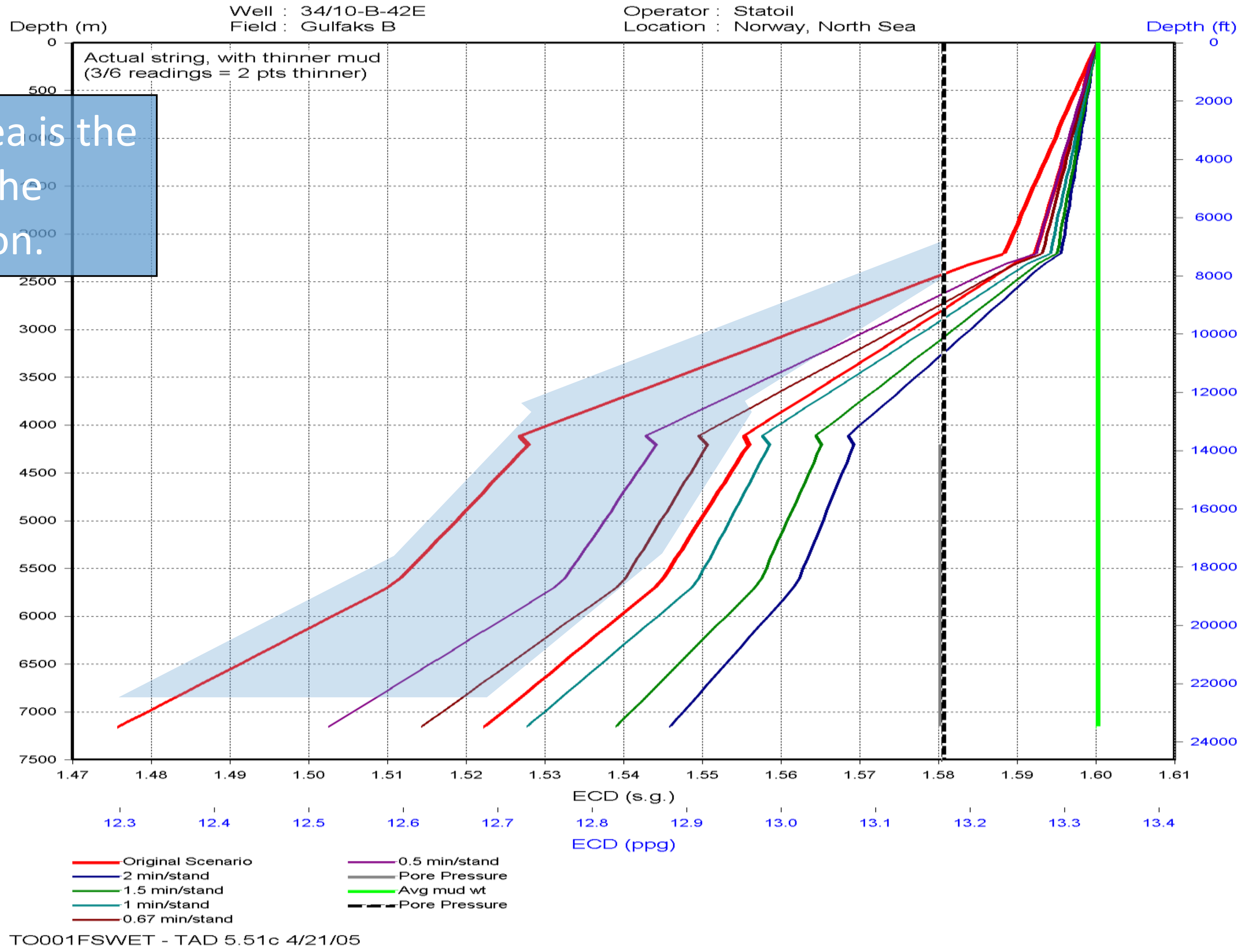


The shaded area is the swab load for the original situation.

If 4 ½” drill-pipe was used
instead of 5”, initial swab is somewhat less…

Significantly less swab initially, but again essentially similar end result.

The shaded area is the swab load for the original situation.



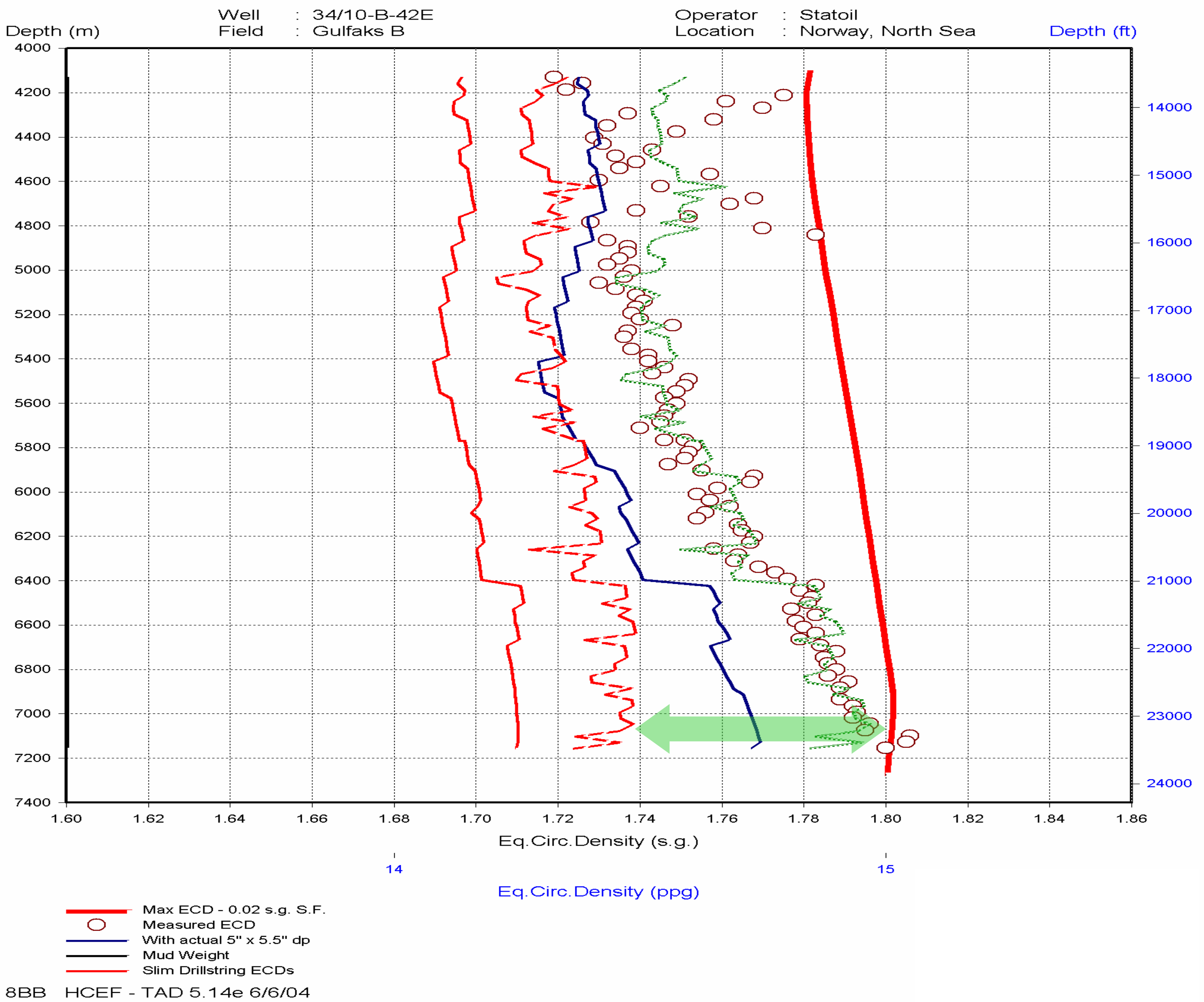
What if thinner mud was used?

Again, significantly less swab initially, but again essentially similar end result.

So the swab is because of ECD reasons, but the ECD solutions don't make much difference!

What's the point then?

Are we doomed to pump out?



ECD solutions must be designed to aggressively reduce ECDs, to solve this problem.

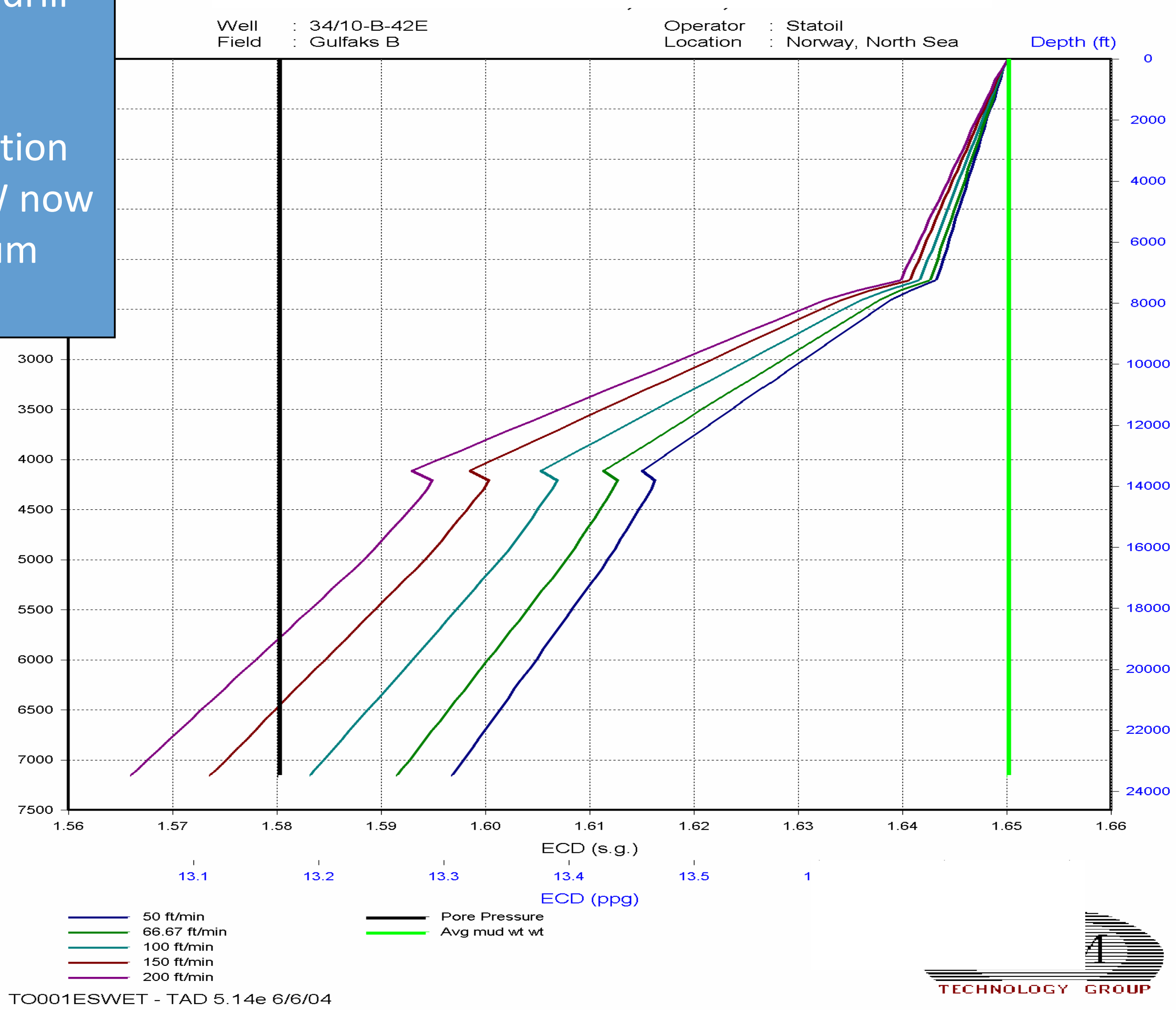
Because reducing ECDs buys you mud weight

In this case:

Can accommodate more MW when drilling (0.5 ppg) Need less MW to prevent swabbing.

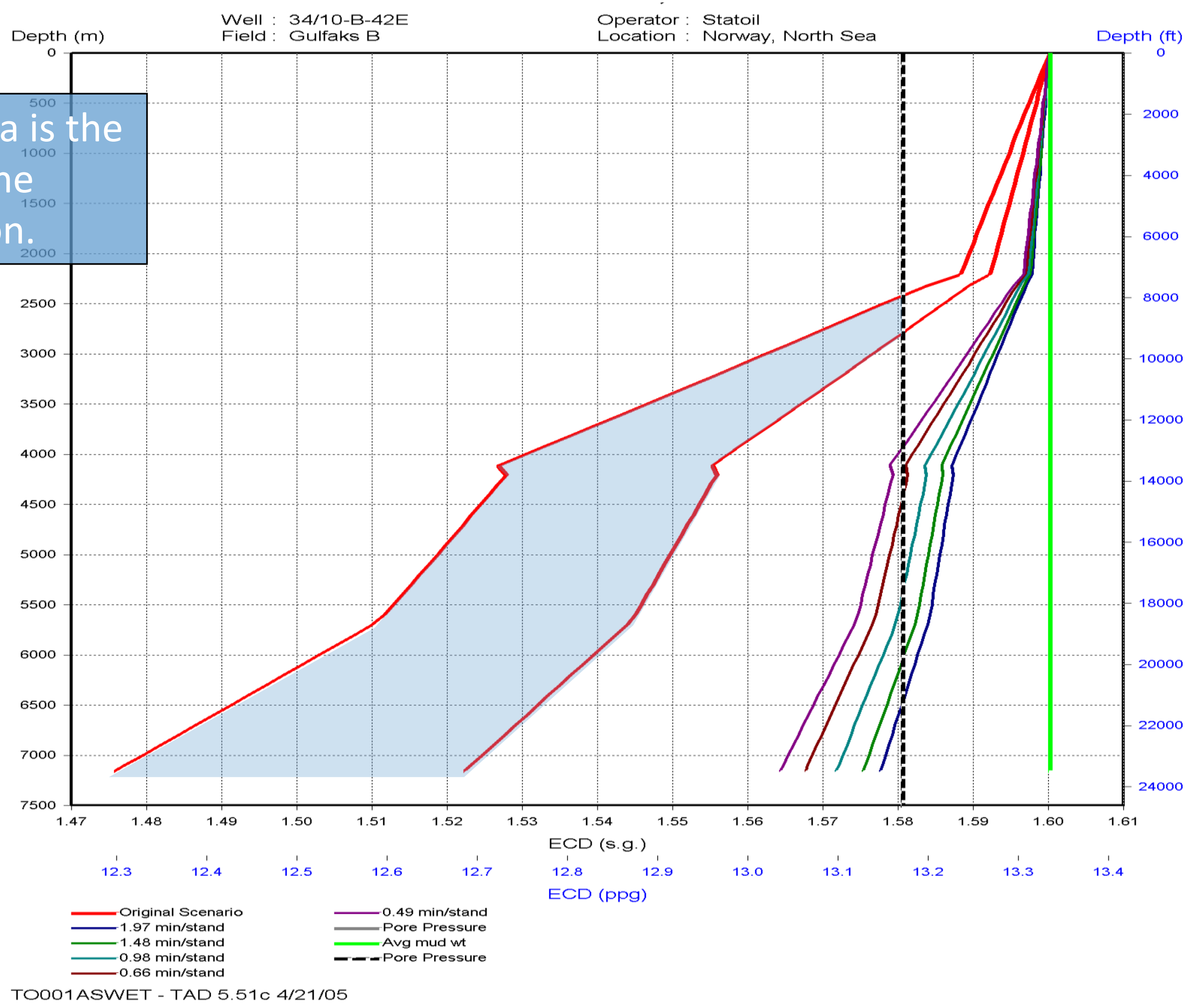
So how does a slimmer drill string help?

Shows the tripping situation with the increased MW now possible with a minimum ECD design.



Surge and swab case study.

- So, swab is all about ECDs.
- And ECDs are all about the well path.
    - Shallower & longer wells have higher ECDs.
- A side-effect of this is more MW margin is necessary to prevent swabbing (compared to vertical wells).
    - Shallower & longer wells require more MW margin.
- And the swab is felt all the way to TD.



The shaded area is the swab load for the original situation.

Like normal ECDs, swabbing is exaggerated in ER wells.

Tripping margin requires more over-balance MW than for a vertical well.

End result is that swab margins MUST be calculated for a well, and NOT assumed.

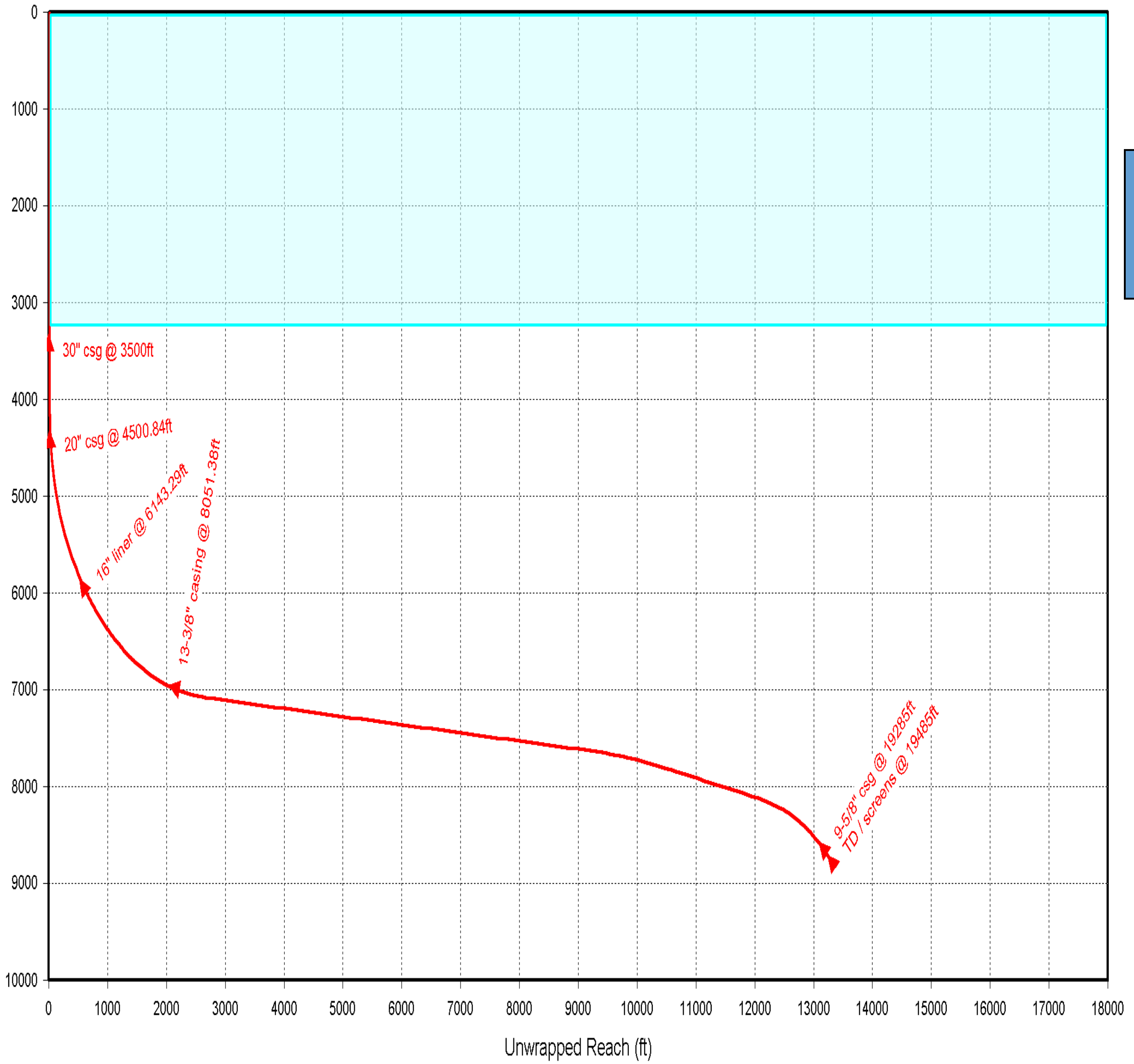
Surge and swab engineering.

SURGE AND SWAB AND WELLBORE INSTABILITY CASE STUDY.

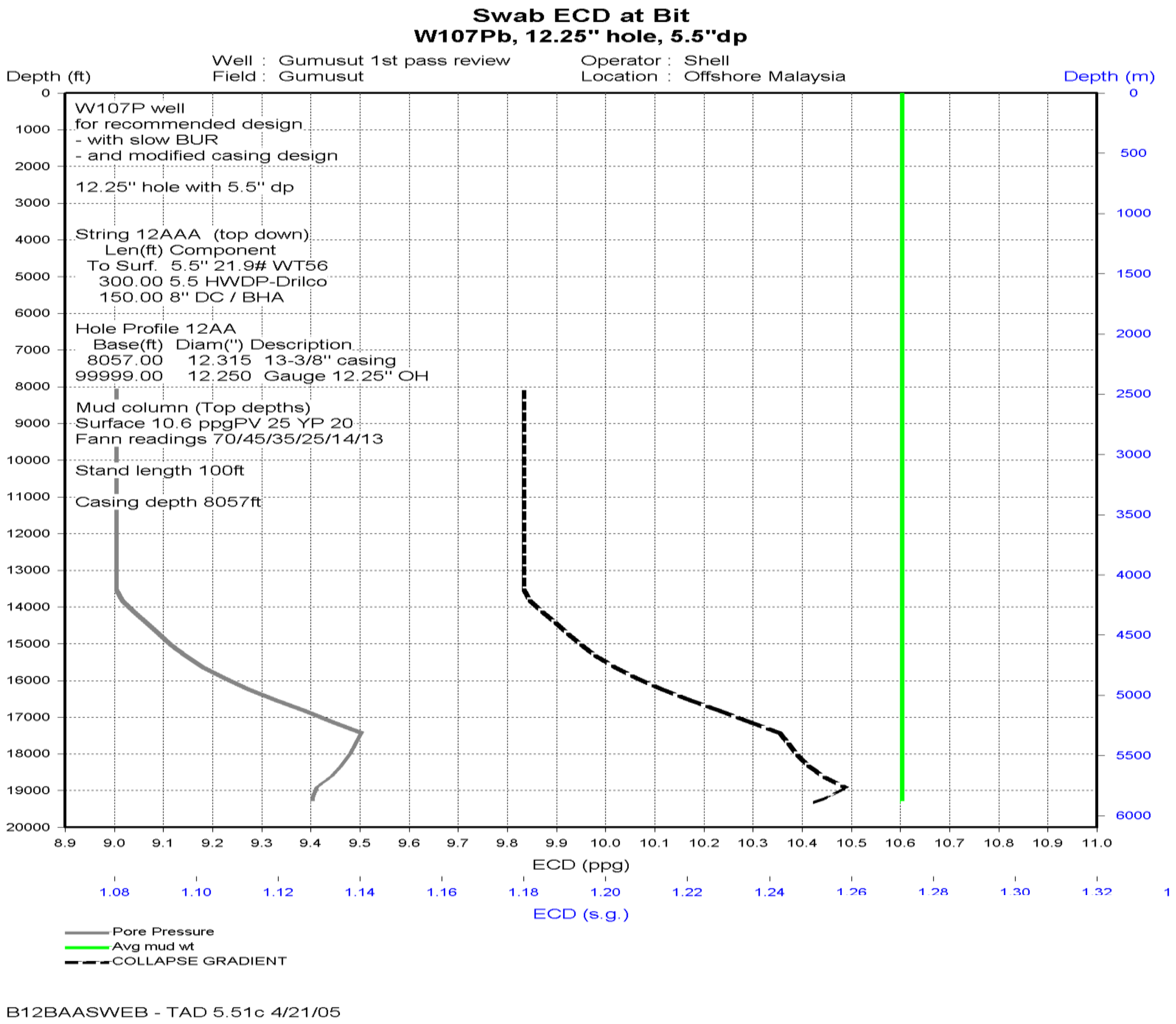
Surge and swab case study.

Swab ECDs also affect wellbore instability.

- Remember, this “drill string ECD” effect is felt throughout the wellbore.
- The effect on wellbore instability is exactly the same as if the mud engineer reduced the mud weight by this amount for the length of time of pulling.

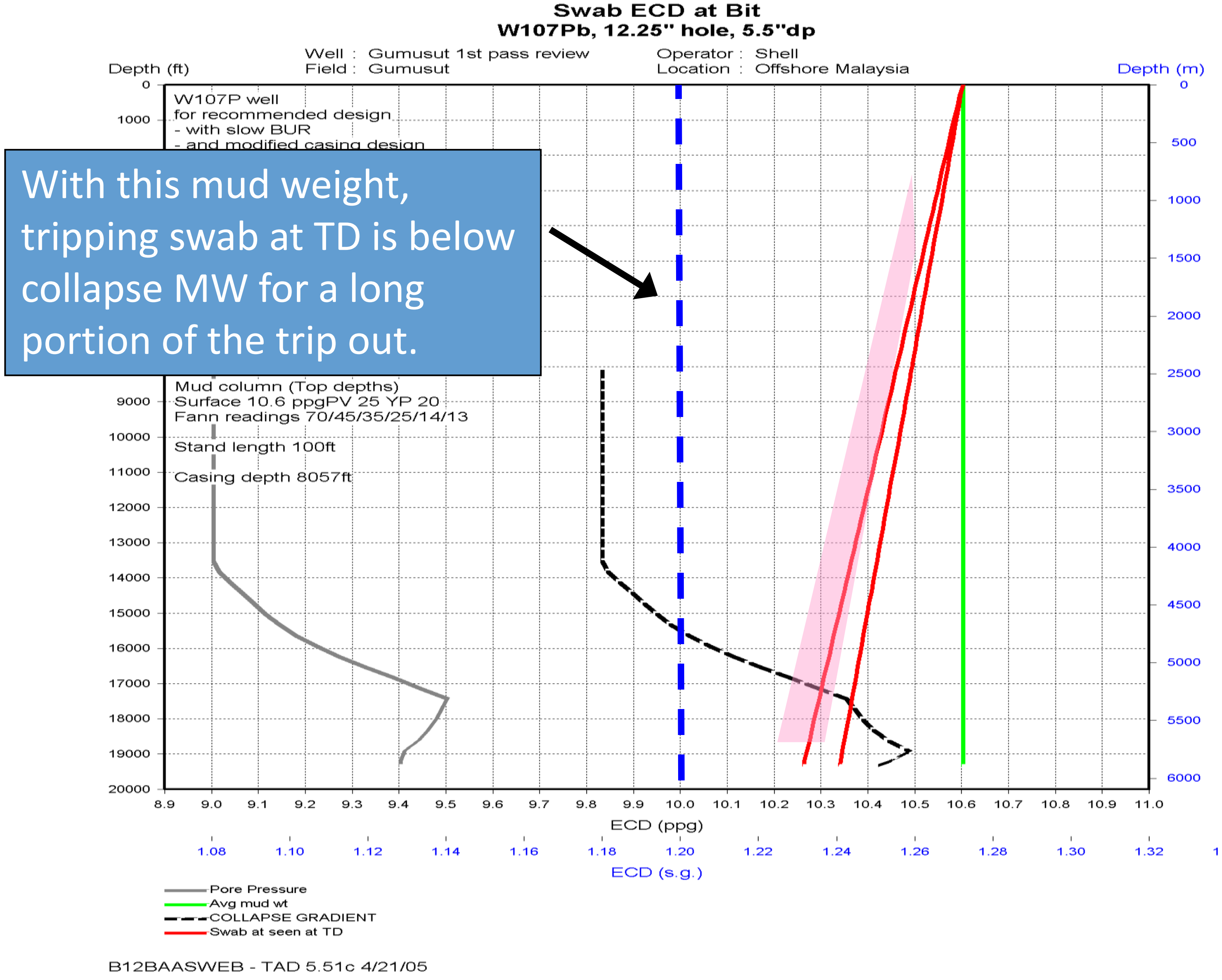


Consider the 12 ¼” section of this deep water ER well.



Like most ER wells, the mud weight is driven by wellbore stability reasons.

Mud weight for stability is > 1.1 ppg EMW over-balance to pore pressure.

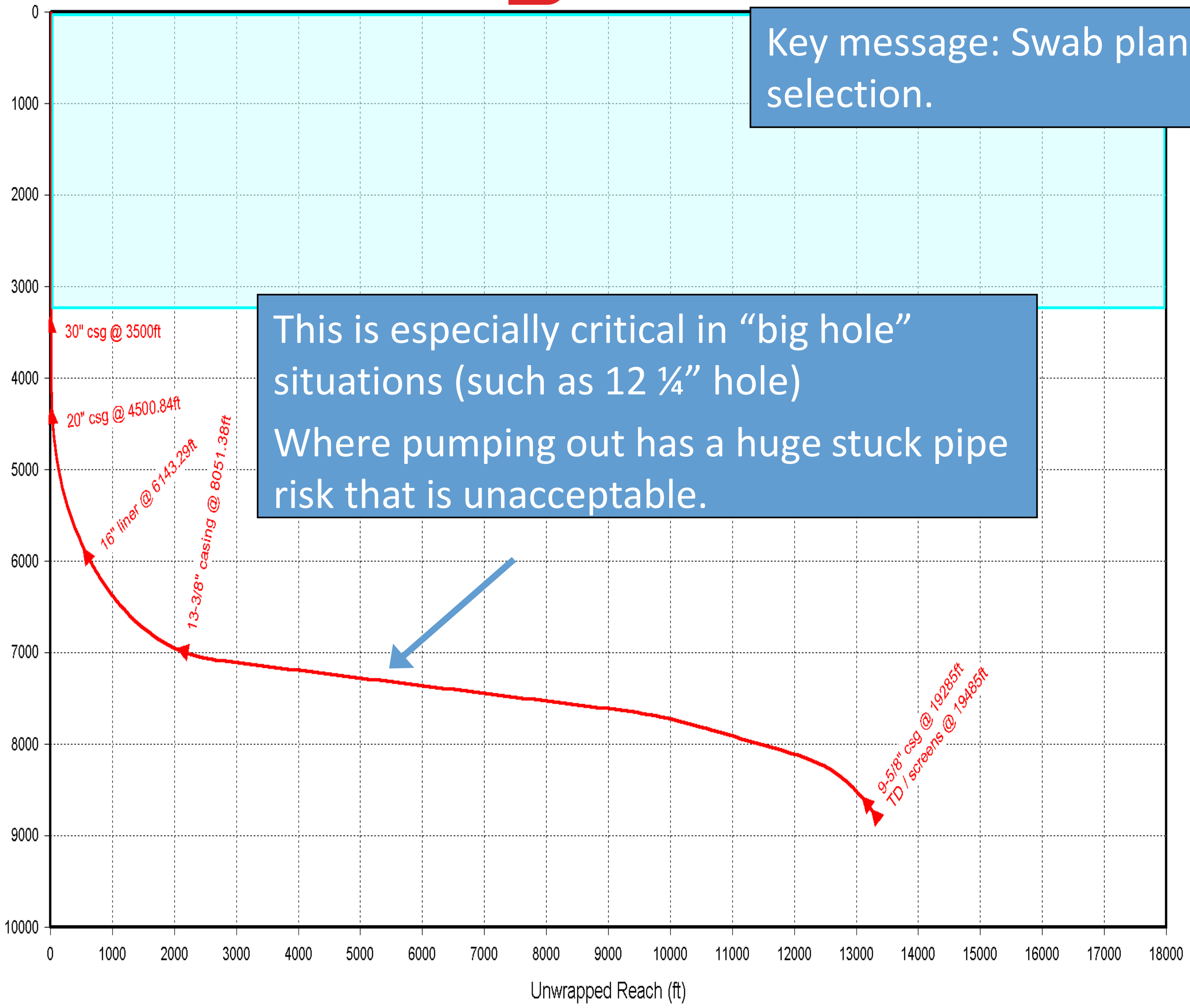


With this mud weight, swabbing an influx is not a concern.

But the swab ECD at TD is below the collapse MW for long time while pulling out More MW is necessary (11 ppg minimum).

Have you ever noticed caving's after a trip, but not while drilling & cleaning before the trip?

Key message: Swab planning is critical to MW selection.



This is especially critical in "big hole" situations (such as 12 ¼" hole)

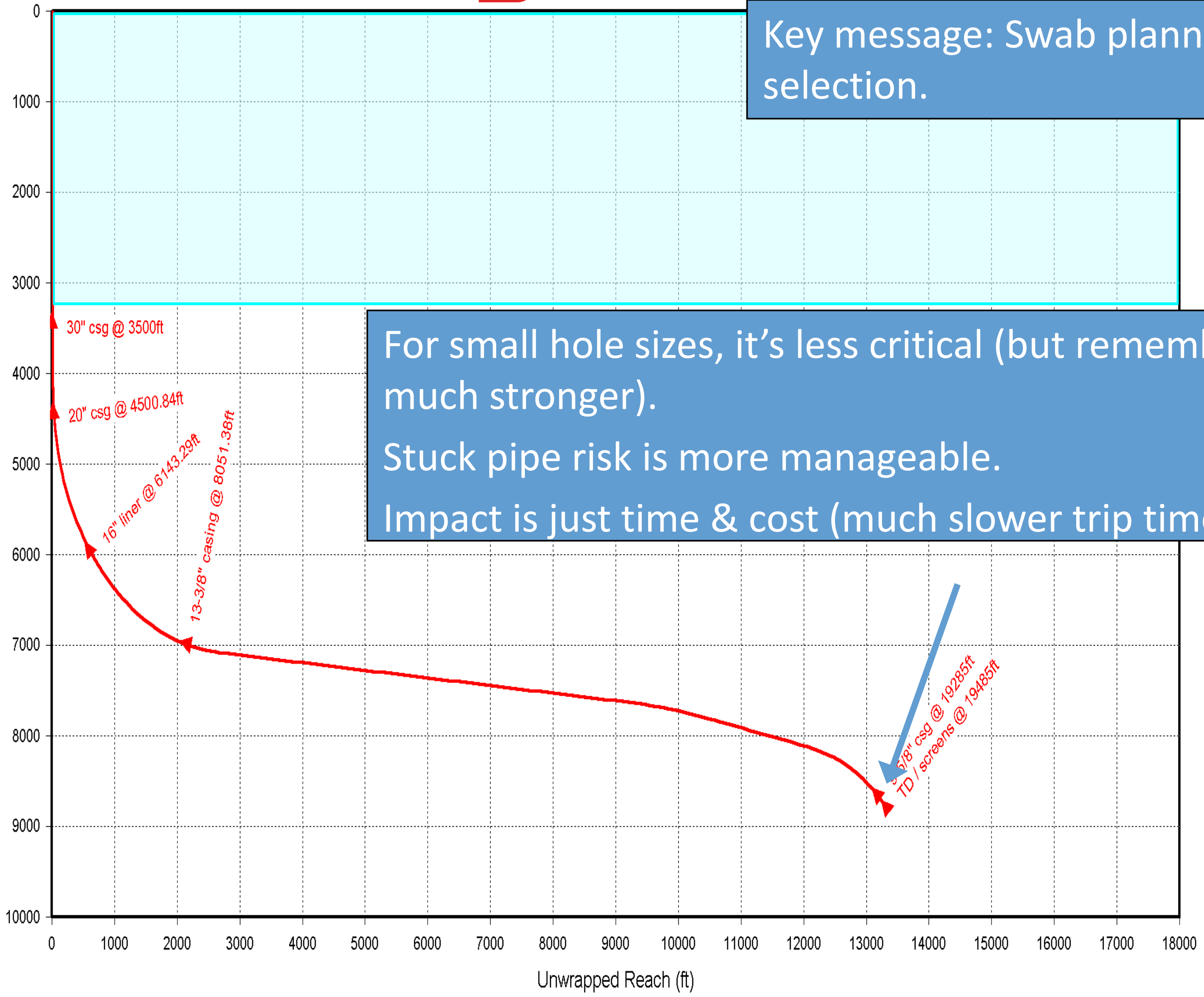
Where pumping out has a huge stuck pipe risk that is unacceptable.

Key message: Swab planning is critical to MW selection.

For small hole sizes, it’s less critical (but remember the swab ECDs are much stronger).

Stuck pipe risk is more manageable.

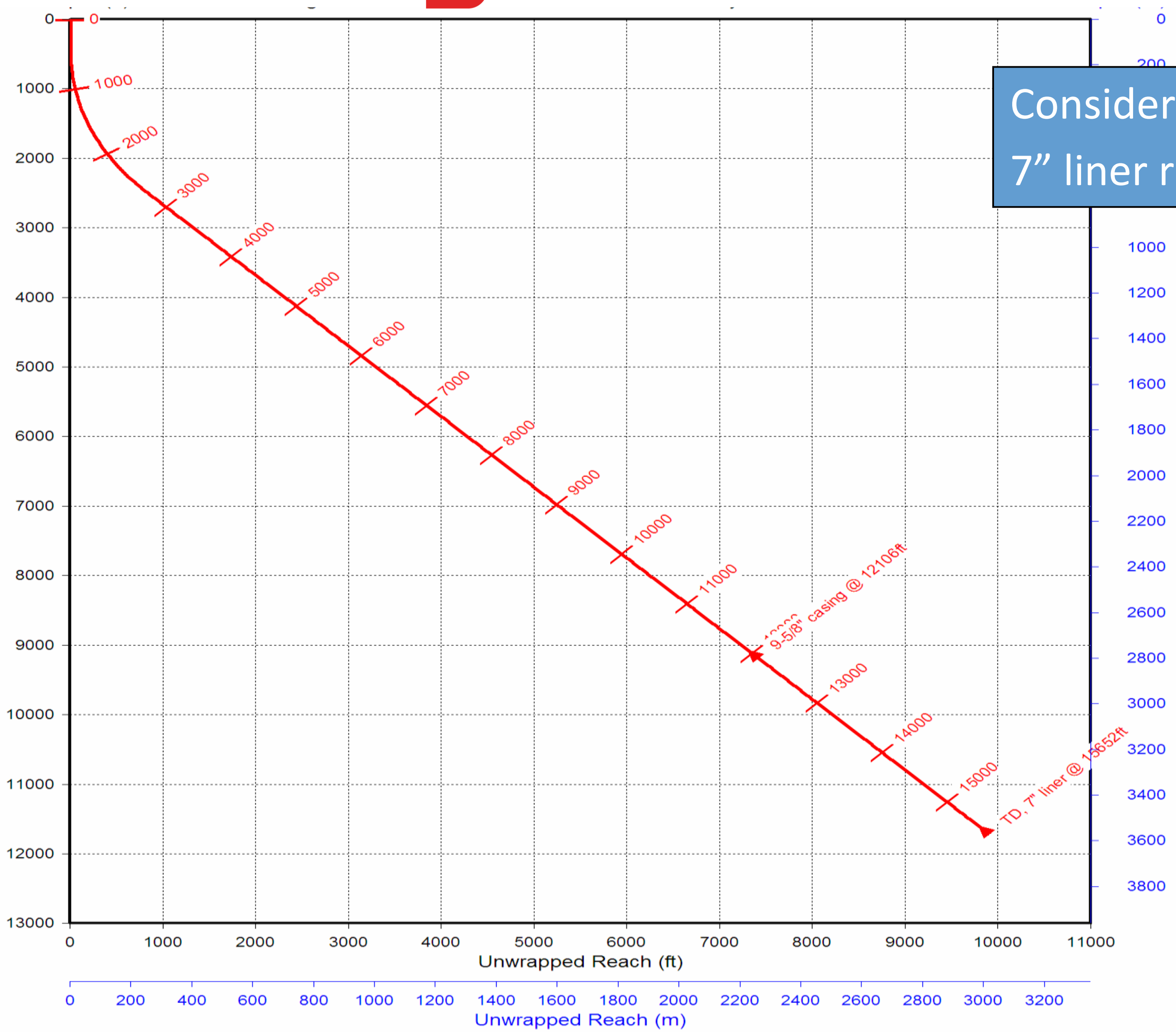
Impact is just time & cost (much slower trip times).



Surge and swab case study.

Swab ECDs also affect wellbore instability.

- Perhaps the most destructive form of swab is when picking up a casing string or a liner.
- Swab is particularly strong, picking up a 7” liner in 8 ½” hole.
- This should be considered when:
  - When working pipe
  - Picking up to break static friction.
  - Or pulling the string out.

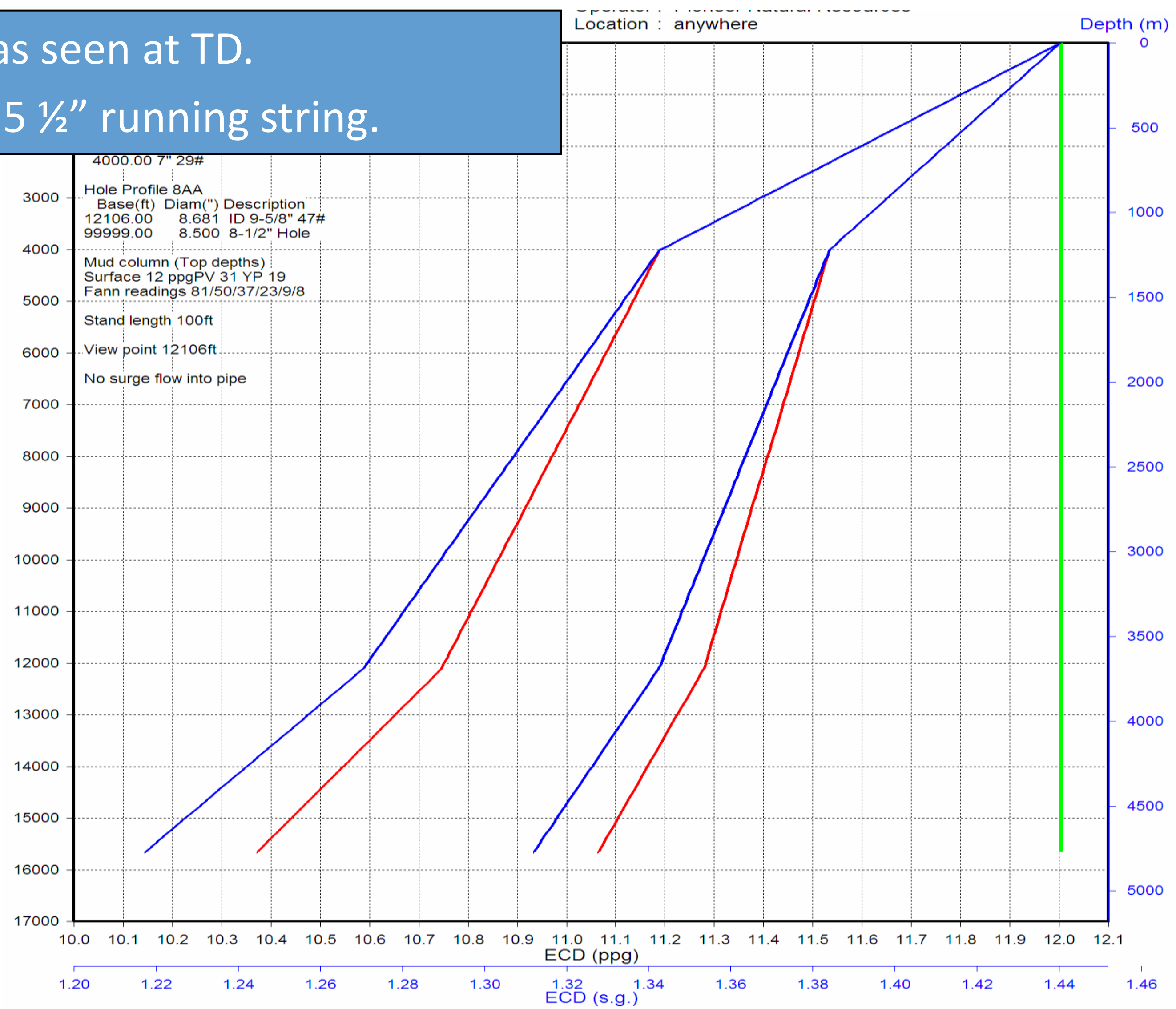


Consider this well …

7” liner run (4,000’ long).

And this is the swab as seen at TD.

Picking up with 5” or 5 ½” running string.



Swab at TD is ≥ 1.0 ppg EMW EMW

Each time that string is picked up at connections.

Even if just to take a “pick up load” measurement.

And this is a “normal “ well …

It’s much worse if it’s an ERD well.

Recommendations:

1. Don’t pick up unless necessary.
2. If necessary to pick up casing or liner, do so with slow circulation.

Surge and swab engineering.

SURGE AND SWAB AND WELLBORE INSTABILITY.

Swab implications.

1. Swab is felt by the wellbore, even when BHA is below that zone.
    - When picking up at each connections.
    - When tripping out.
2. Swab is felt by the wellbore, even when BHA is long above that zone.
    - Even when inside casing.
3. As far as the rock is concerned …
   … It's exactly the same as if the mud weight had been reduced.

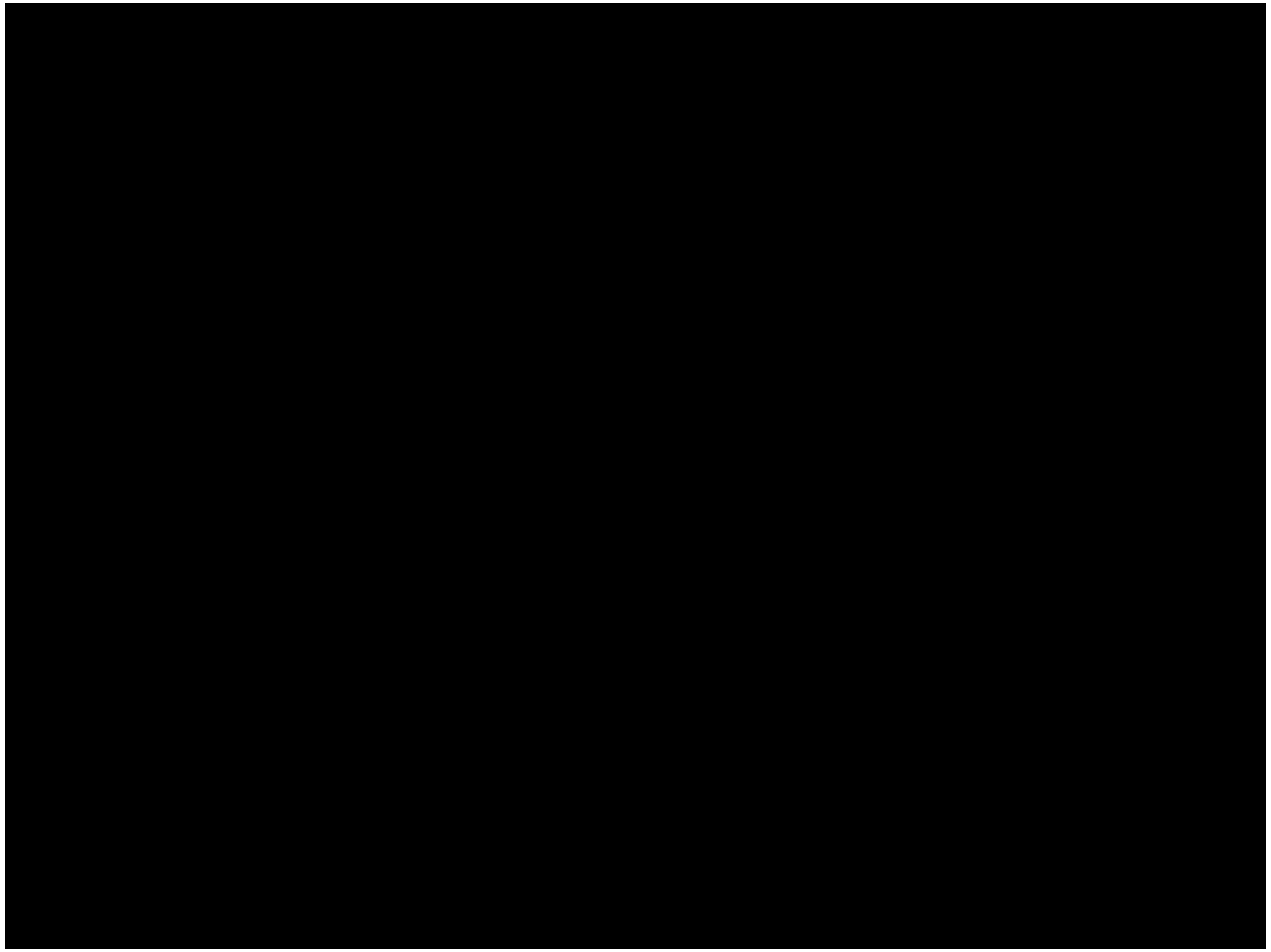
Dealing with instability.

1. Optimize operational practices – focus on hole cleaning for additional caving's and enlarged hole.
2. Tripping practices.
    - Avoid wiper trips unless added value outweighs the "cost".
    - Minimize the surge and swab pressures.
        - Control the tripping speeds.
        - Bit and BHA design for adequate bypass area.
        - Mud rheology and gel strengths.

Dealing with instability.

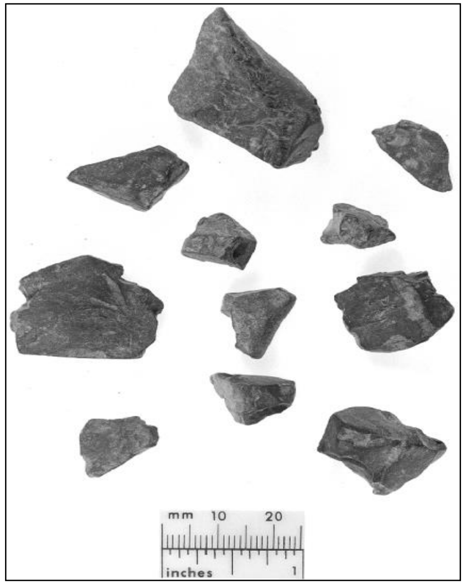
3. Avoid back-reaming / pumping out if possible.
   - If caving's start to "unload", be patient.
   - Cleaning out the "wings" is a process that must take its course without rushing (or risk disaster).
   - If a pre-planned back-reaming run is necessary, use an under-sized BHA.
   - Minimize hydraulic hammer and risk of stuck pipe.
   - Reduce the financial exposure to loss of an expensive BHA.

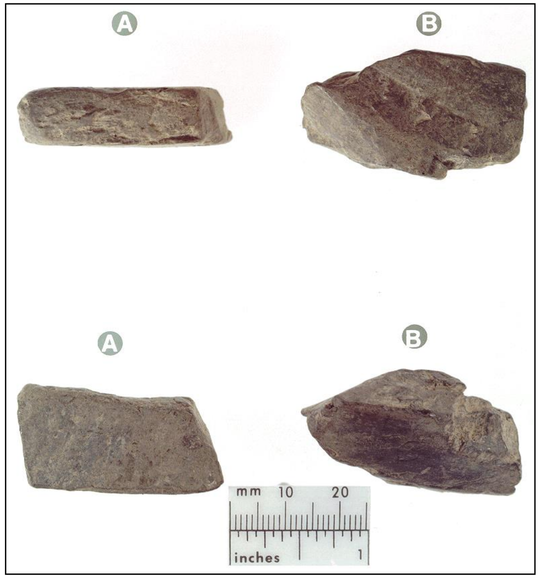
Wellbore shear failure.



Caving's vs cuttings.

Cuttings.





Caving´s

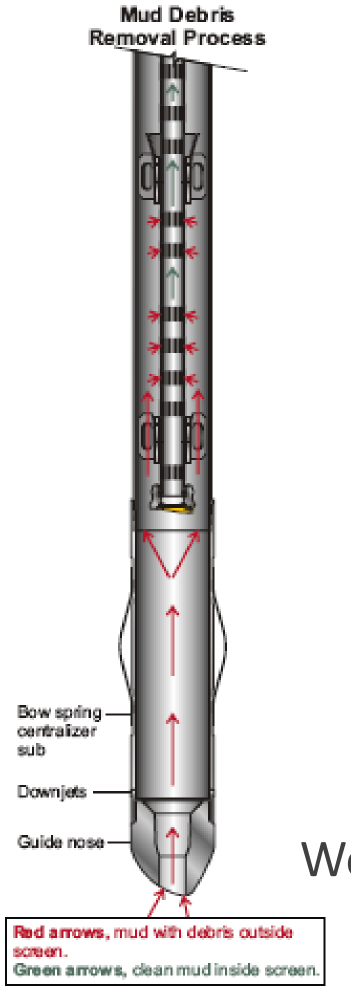
Caving's vs cuttings.

- What are we looking for in caving's analysis?
  - What type?
    - Angular
    - Tubular
    - Splintered
- When do they appear?
  - During drilling and circulating.
  - After tripping.
  - After back-reaming.

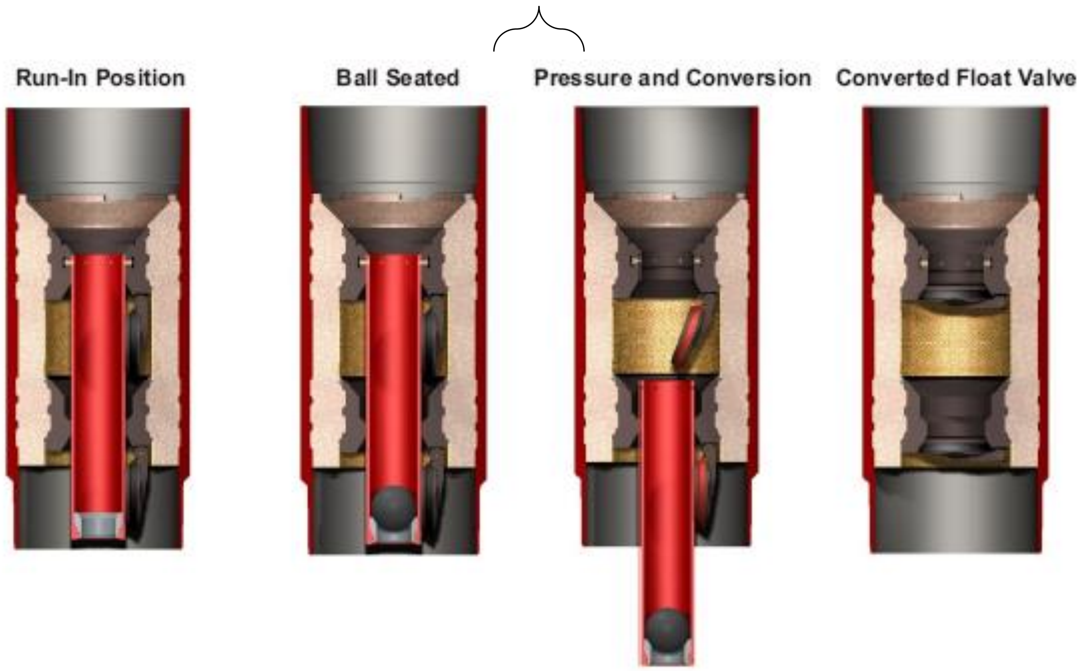
Surge and swab engineering.

SURGE AND SWAB AUTO FILL.

Surge and swab basics.



Weatherford Autofill Float Equipment

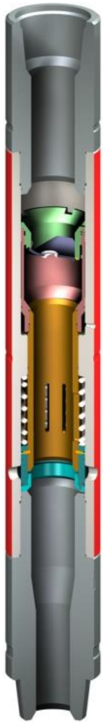


Weatherford Mud-master Filter

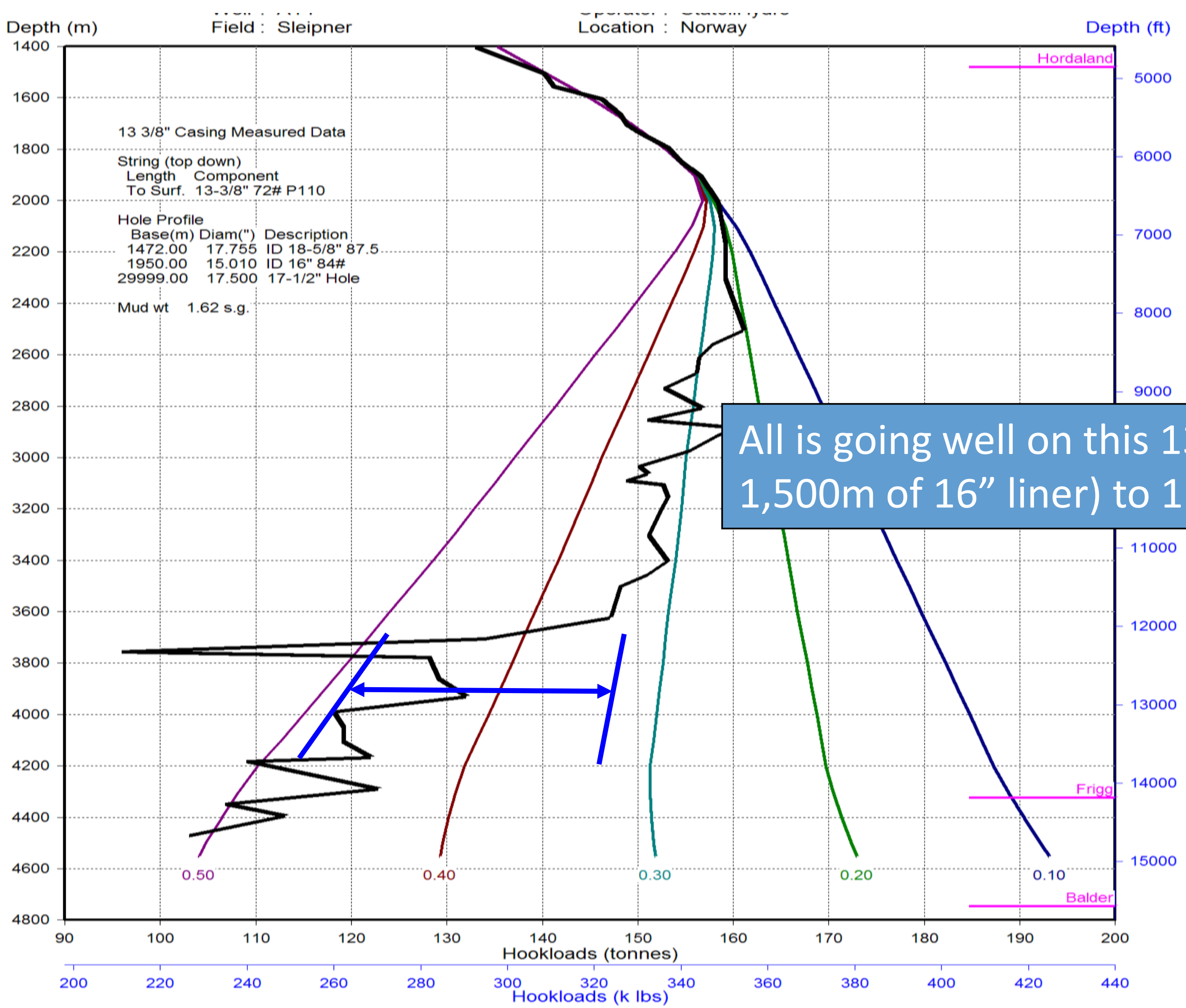
Surge and swab basics.

Allamon ATC Diverter Sub

Baker Hyflo Valve



Weatherford SurgeMasterII



Autofill equipment greatly reduces surge.

It also reduces drag, due to reduction in "piston force". Unfortunately, this benefit is lost as soon as the floats plug with cuttings or debris.

All is going well on this 13 ⅜" casing run (through 1,500m of 16" liner) to 11,800' MD.

Until the floats plug.

FF's jump from 0.30 to 0.45+.

This is only 500m of "tight clearance" geometry.

220 psi = 30 kips piston force.

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ECD management in high-angle and complex wells.

MODULE 4

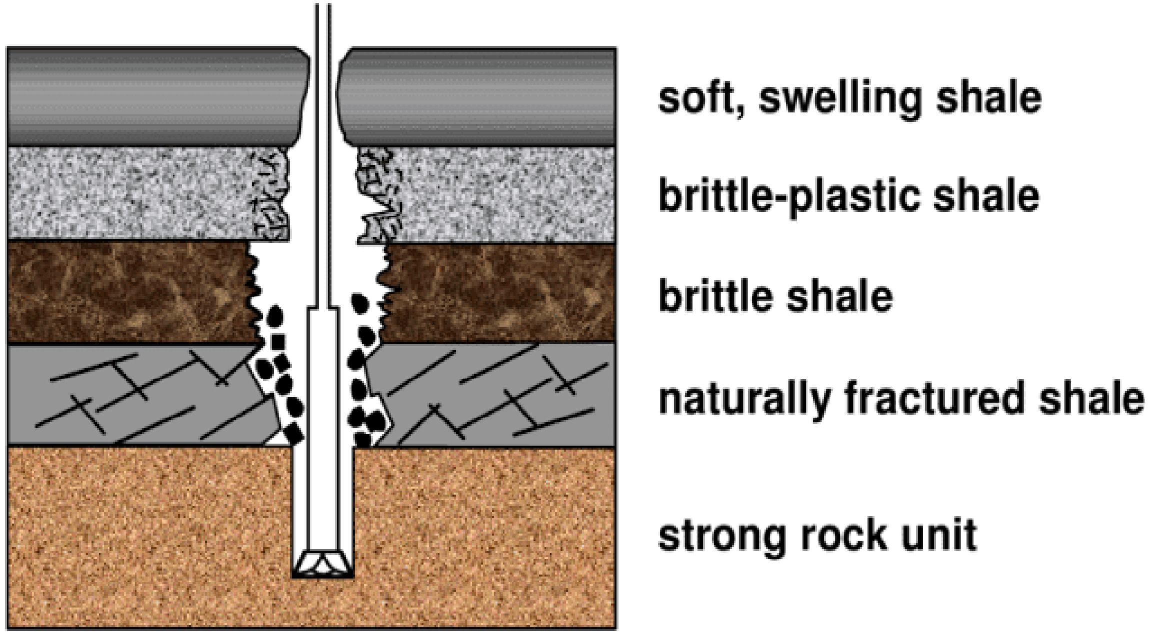
Basics of wellbore instability.

Basics of wellbore instability.

- In some cases, high angle wells require more MW for stability, than a vertical well in the same formations?
- Some directions are easier to drill than other directions?
- WBM may require more MW for stability, than SBM/OBM in the same circumstances?
- A lot of problems in the rat-hole below a casing shoe, especially when casing set off bottom.
- Caving's appear after trips, even if none are seen while drilling & circulating?

Basics of wellbore instability.

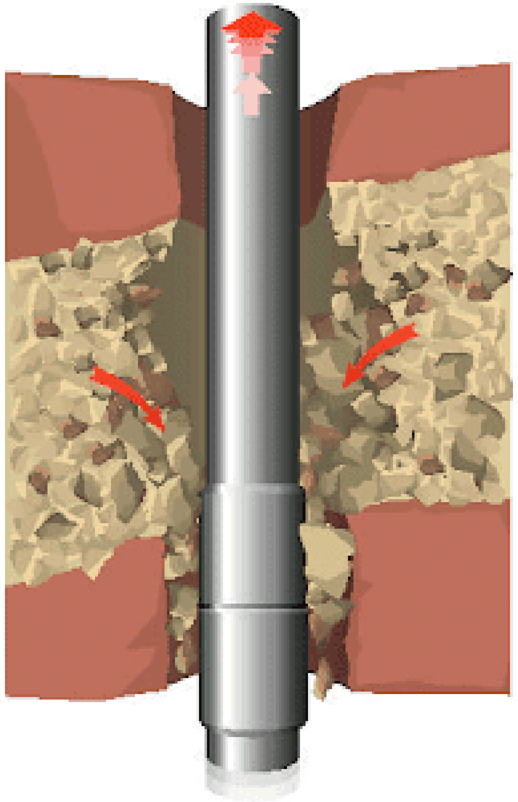
Wellbore or borehole instability is the undesirable condition of an open hole interval that does not maintain its gauge size and shape and/or its structural integrity.



The main course of wellbore instability.

1. Unconsolidated formation
2. Overburden stress / mobile formations
3. Fractured formation
4. Naturally over pressured shale
5. Induced over pressured shale
6. Reactive shale
7. Tectonic stress

How unconsolidated formations cause wellbore instability.

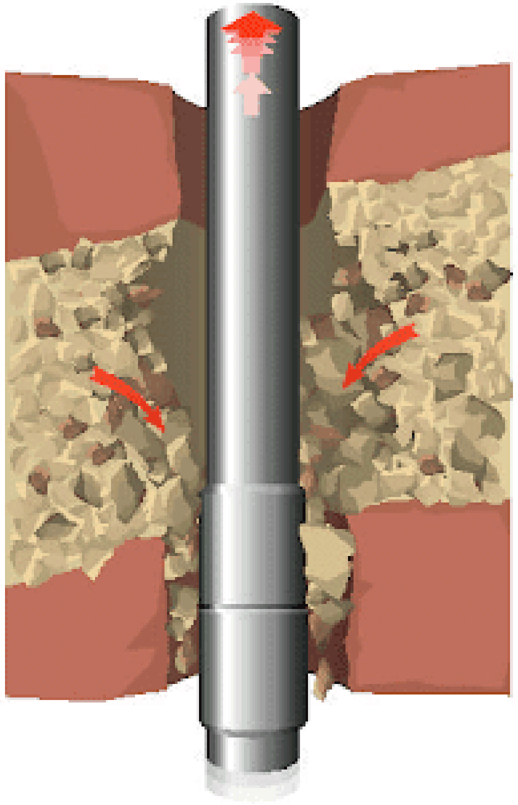


Wellbore or borehole instability is the undesirable condition of an open hole interval that does not maintain its gauge size and shape and/or its structural integrity.

How unconsolidated formations cause wellbore instability.

The collapse of the formation is caused by removing the supporting rock as the well is drilled. This is very similar to digging a hole in the sand on the beach, the faster you dig the faster the hole collapses.

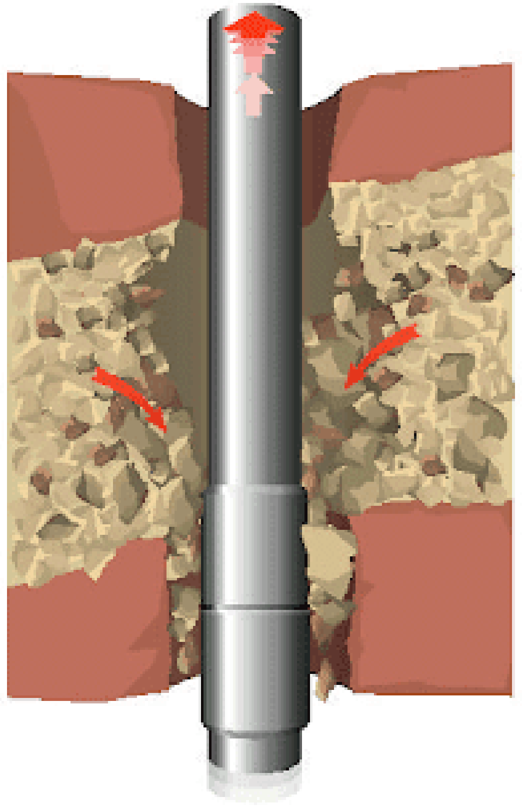
It happens in a wellbore when little or no filter cake is present. The un-bonded formation (sand, gravel, small river bed boulders, etc.) cannot be supported by hydrostatic overbalance as the fluid simply flows into the formation. Sand or gravel then falls into the hole and causes pack-off around the drill string. The effect can be a gradual increase in drag over a number of meters or can be sudden.



How unconsolidated formations cause wellbore instability.

This mechanism is normally associated with shallow formations. Examples are shallow river bed structures at about 500m in the central North Sea and in surface hole sections of land wells.

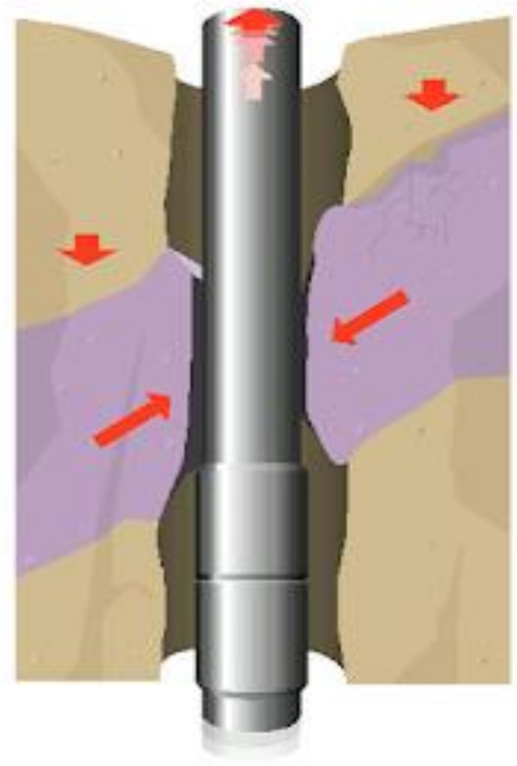
This type of wellbore instability normally occurs while drilling shallow unconsolidated formations.



How unstable mobile formations cause wellbore instability.

The mobile formation squeezes into the wellbore because it is being compressed by the overburden forces. Mobile formations behave in a plastic manner, deforming under pressure. The deformation results in a decrease in the wellbore size, causing problems running Bottom Hole Assembly BHA's, logging tools, and casing.

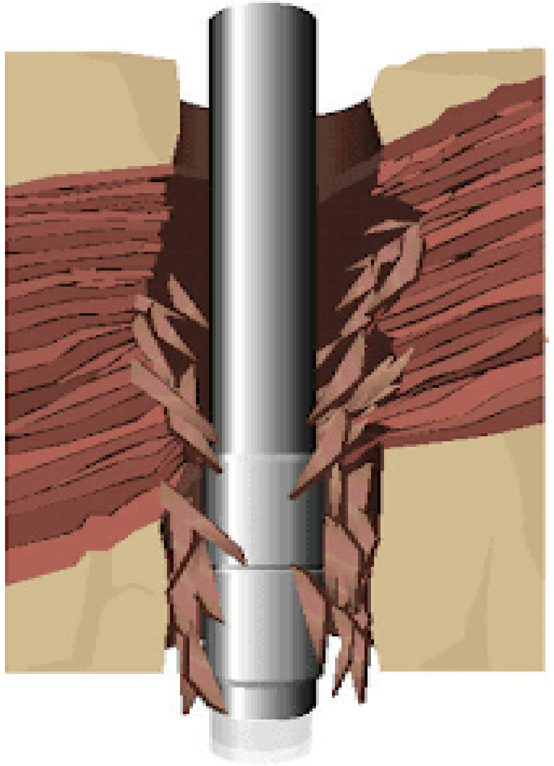
A deformation occurs because the mud weight is not sufficient to prevent the formation from squeezing into the wellbore. This kind of wellbore or borehole instability normally occurs while drilling salt.



How unstable fractured formations cause wellbore instability.

A natural fracture system in the rock can often be found near faults. Rock near faults can be broken into large or small pieces. If they are loose they can fall into the wellbore and jam the string in the hole. Even if the pieces are bonded together, impacts from the BHA due to drill string vibration can cause the formation to fall into the wellbore.

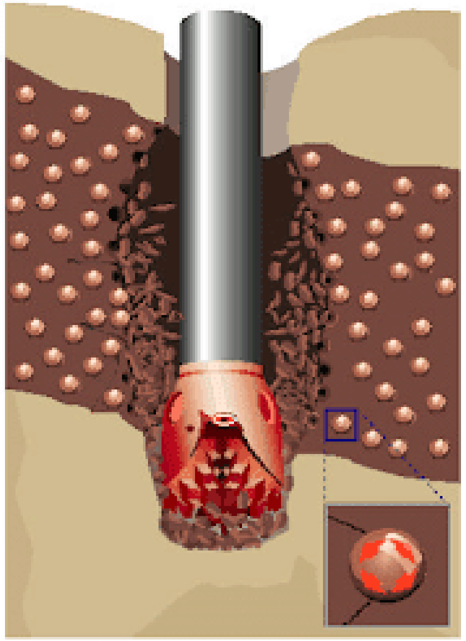
There is a risk of sticking in fractured/faulted formation when drilling through a fault and when drilling through fractured limestone formations.



How naturally over-pressured shale cause wellbore instability.

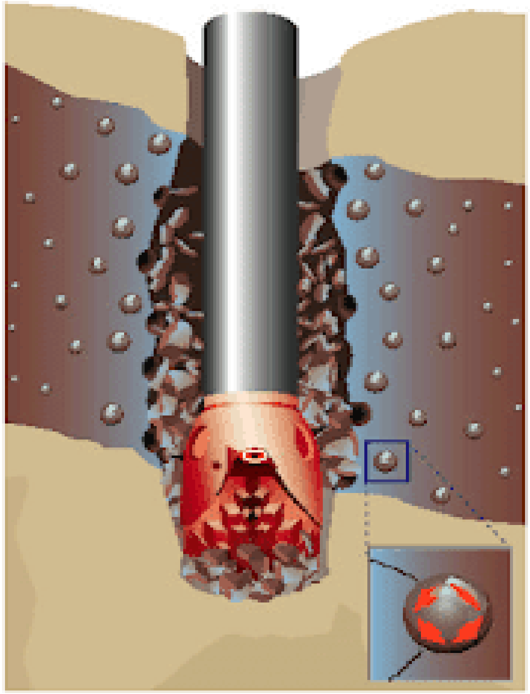
A naturally over-pressured shale is one with a natural pore pressure greater than the normal hydrostatic pressure gradient.

Naturally over-pressured shales are most commonly caused by geological phenomena such as under-compaction, naturally removed overburden (i.e. weathering), and uplift. Using insufficient mud weight in these formations will cause the hole to become unstable and collapse, that’s why it is a wellbore or borehole instability source.



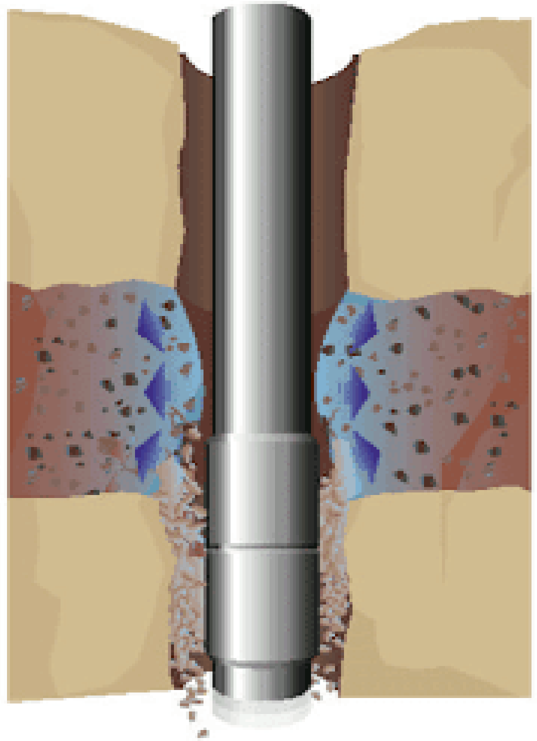
How induced over-pressured shale cause wellbore instability.

Induced over-pressure shale occurs when the shale assumes the hydrostatic pressure of the wellbore fluids after a number of days of exposure to that pressure. When this is followed by no increase or a reduction in hydrostatic pressure in the wellbore, the shale, which now has a higher internal pressure than the wellbore, collapses in a similar manner to naturally over-pressured shale and off course cause a wellbore instability problem.



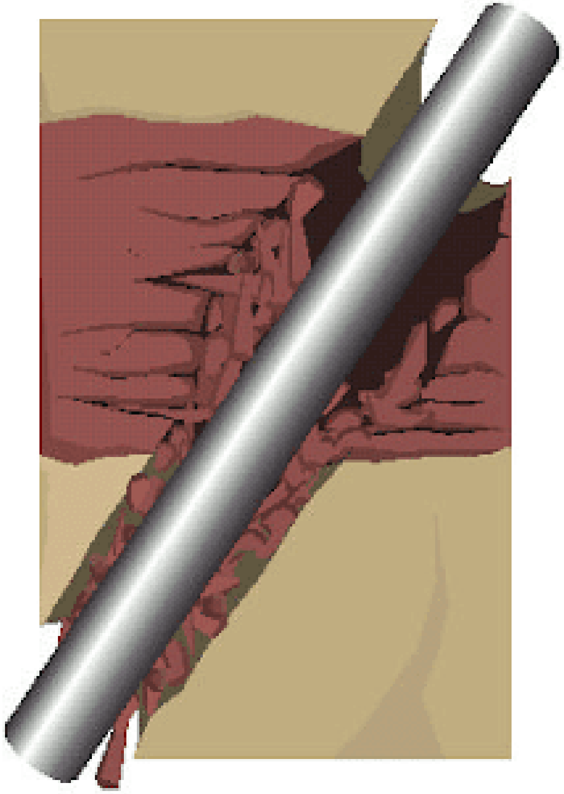
How reactive formations cause wellbore instability.

An unstable water-sensitive shale is drilled with less inhibition than is required. The shale absorbs the water and swells into the wellbore. The reaction is ‘time dependent’, as the chemical reaction takes time to occur. However, the time can range from hours to days.



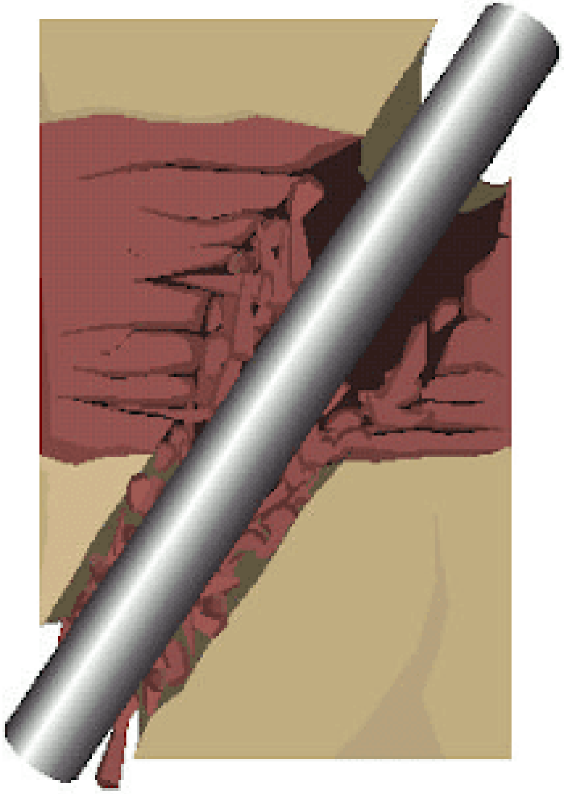
How tectonic stresses cause wellbore instability.

Wellbore instability is caused when highly stressed formations are drilled and there exists a significant difference between the near-wellbore stress and the restraining pressure provided by the drilling fluid density.



How tectonic stresses cause wellbore instability.

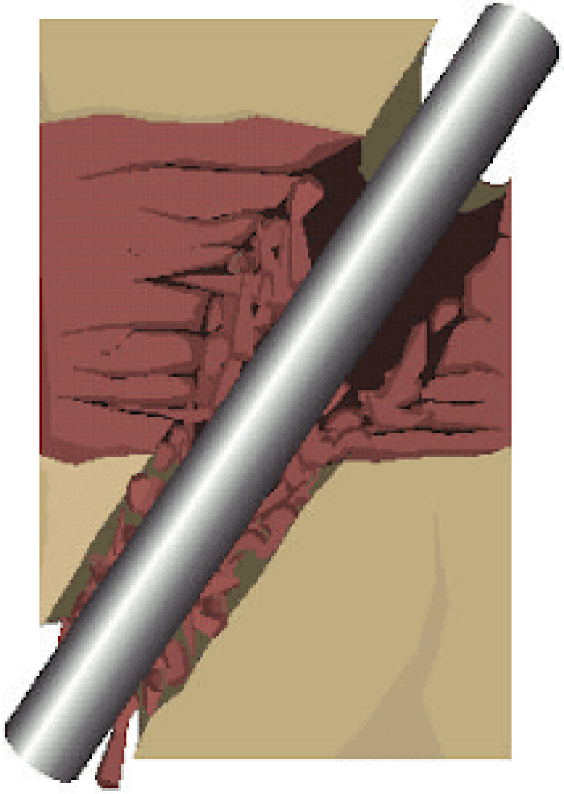
Tectonic stresses as a cause of wellbore instability, build up in areas where rock is being compressed or stretched due to movement of the earth's crust. The rock in these areas is being buckled by the pressure of moving tectonic plates. When a hole is drilled in an area of high tectonic stresses the rock around the wellbore will collapse into the wellbore and produce splintery caving's similar to those produced by over-pressured shale.



How tectonic stresses cause wellbore instability.

In the tectonic stress case, the hydrostatic pressure required to stabilize the wellbore may be much higher than the fracture pressure of the other exposed formations.

This mechanism usually happens in or near mountainous regions.



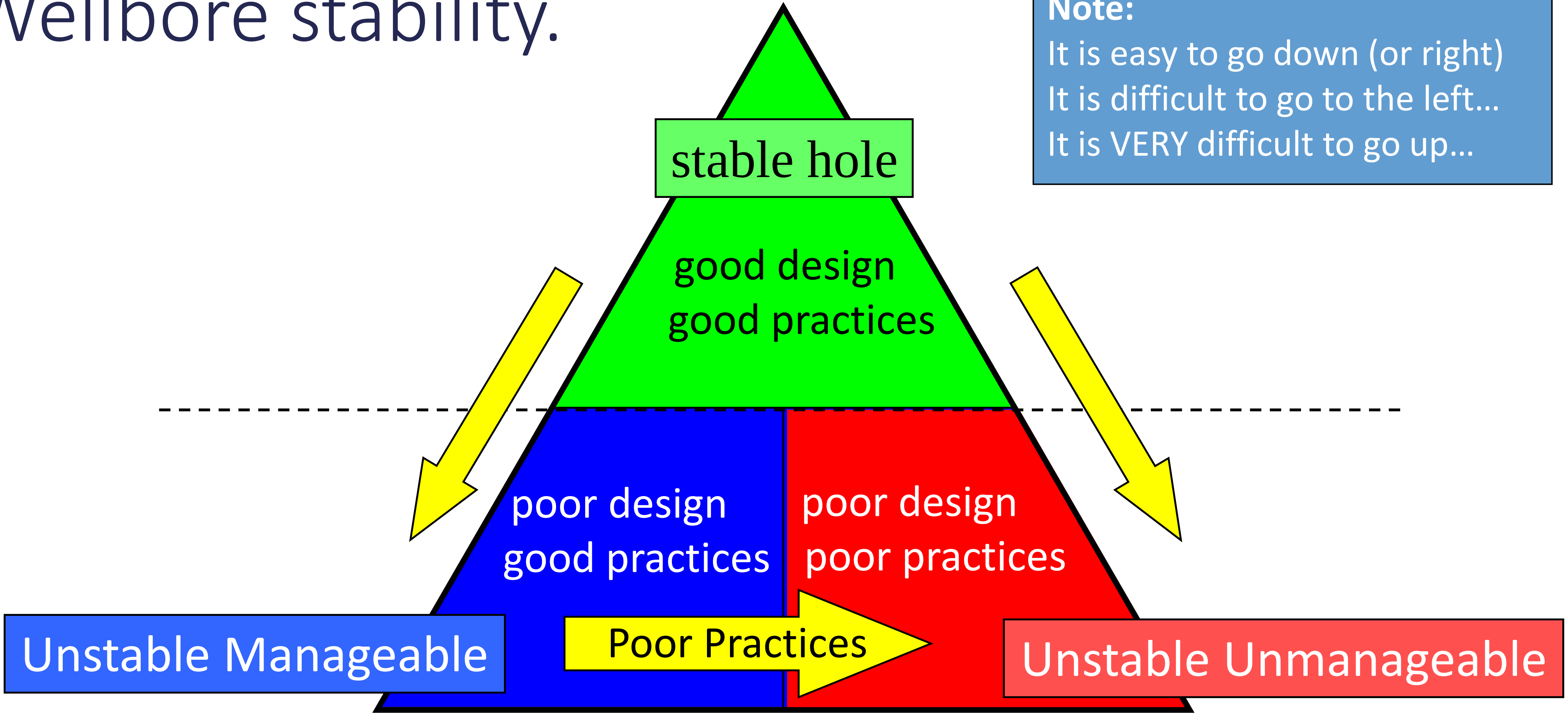
Wellbore stability key messages.

- Everything we do is based on the assumption that the bore hole we are creating is stable.
- Keeping the bore hole stable is not an optional extra.
- Good hole cleaning is a separate issue.
  - You most have good hole cleaning to identify and manage bore-hole failure.
  - Efficient rock removal doesn't stop the bore-hole from failing.

Wellbore instability from a to z.

Wellbore stability.

Note:
It is easy to go down (or right)
It is difficult to go to the left…
It is VERY difficult to go up…

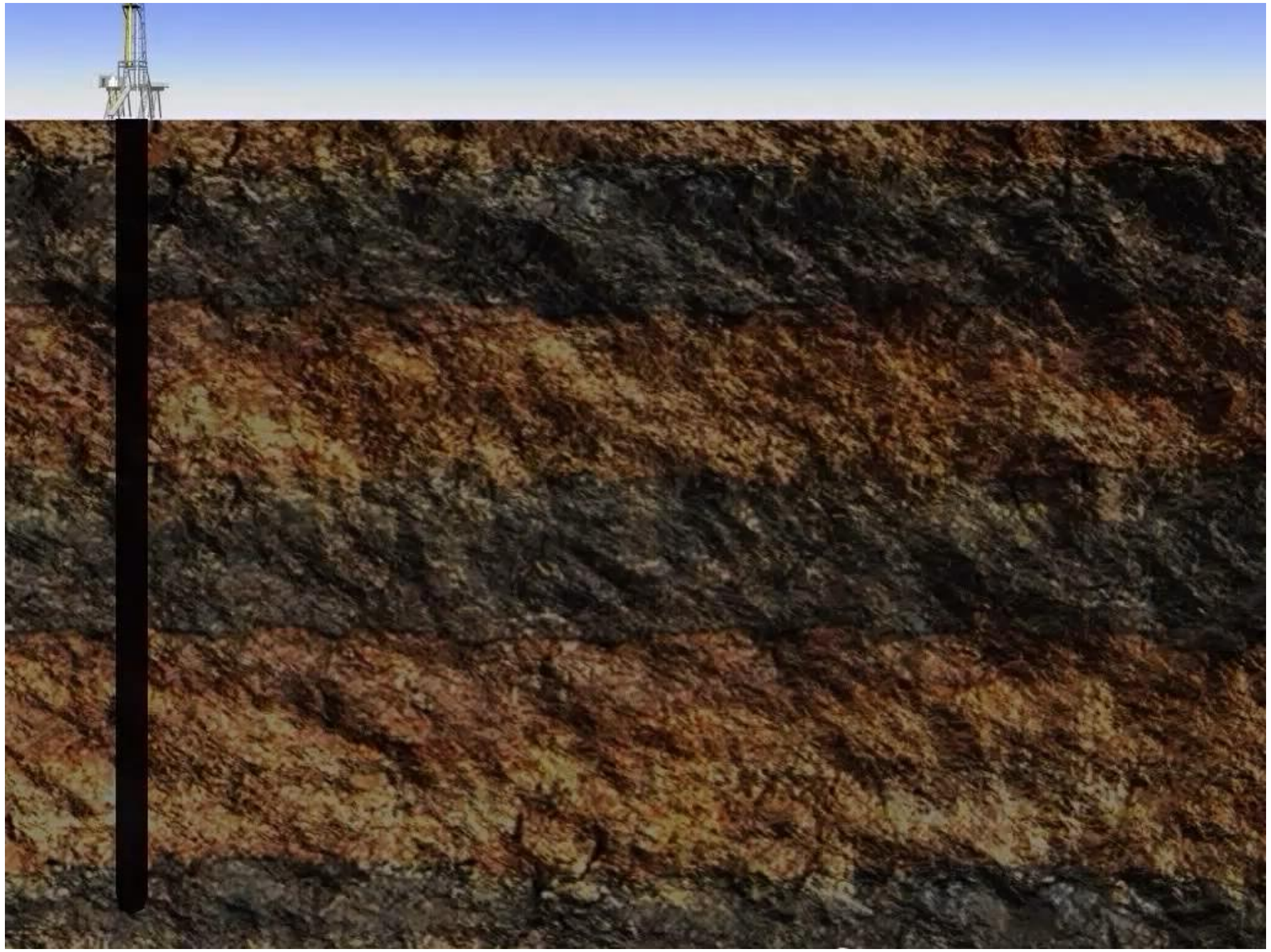


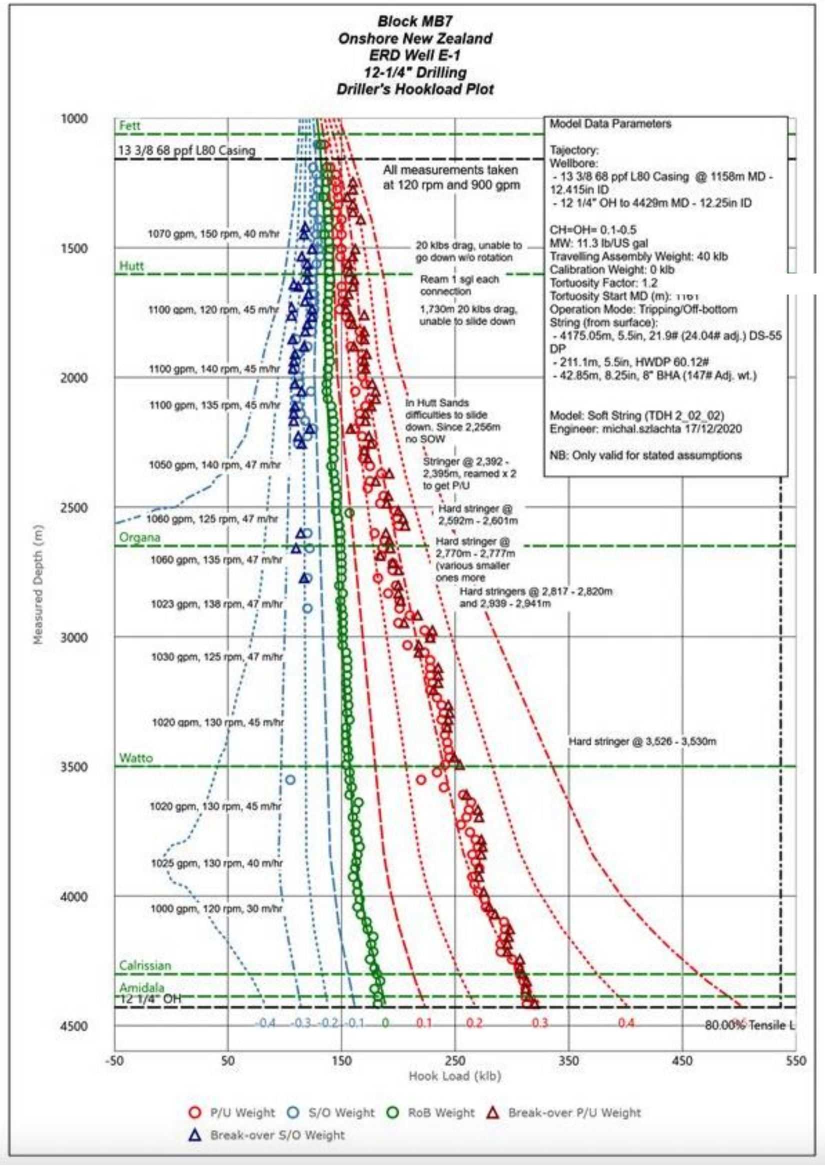
General observations.

1. Many wells are doomed from the start
    - Well path and casing points don't allow necessary mud weight.
    - ECD's are not aggressively designed-down, to allow necessary mud weight to prevent fatiguing the formation.

2. Instability can be self-induced in high-angle wells if appropriate practices are not used.
    - Hydraulic hammer during trips or pumping / back-reaming.
    - Swabbing on trips (including wiper trips).

Depths vs mud weight.

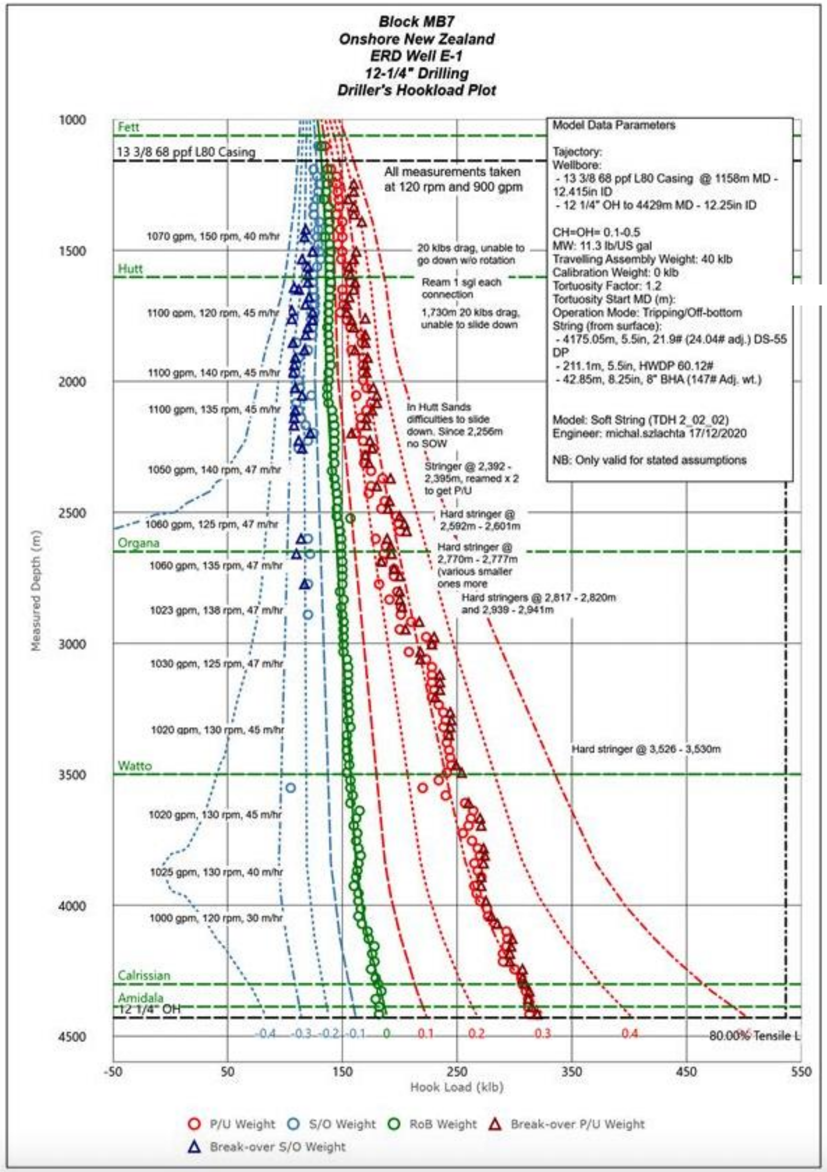




The 12 ¼" hole section has just been drilled to TD (4,429m MD) after the top of the sandstone reservoir was picked using LWD resistivity.

The driller picked up off bottom and shut down rotation and circulation to do a flow check, while picking up to 310 k-lbs and slacking off to 150 k-lbs to keep the string moving.

After the flow check the pipe is stuck, although full unrestricted circulation is possible and the bit is one single off bottom.



What happened and what should the driller do next?

a. Pull to the maximum allowable overpull.
b. Torque and slump.
c. Handover the brake to the AD and pretend nothing is wrong
d. Shut down circulation and pull to the maximum allowable overpull and slump, pick up to max allowable, torque and slump.


Coffee
Time!

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MODULE 3

Drilling parameters effect on ECD and SPP.

TORNADO GRAPH.

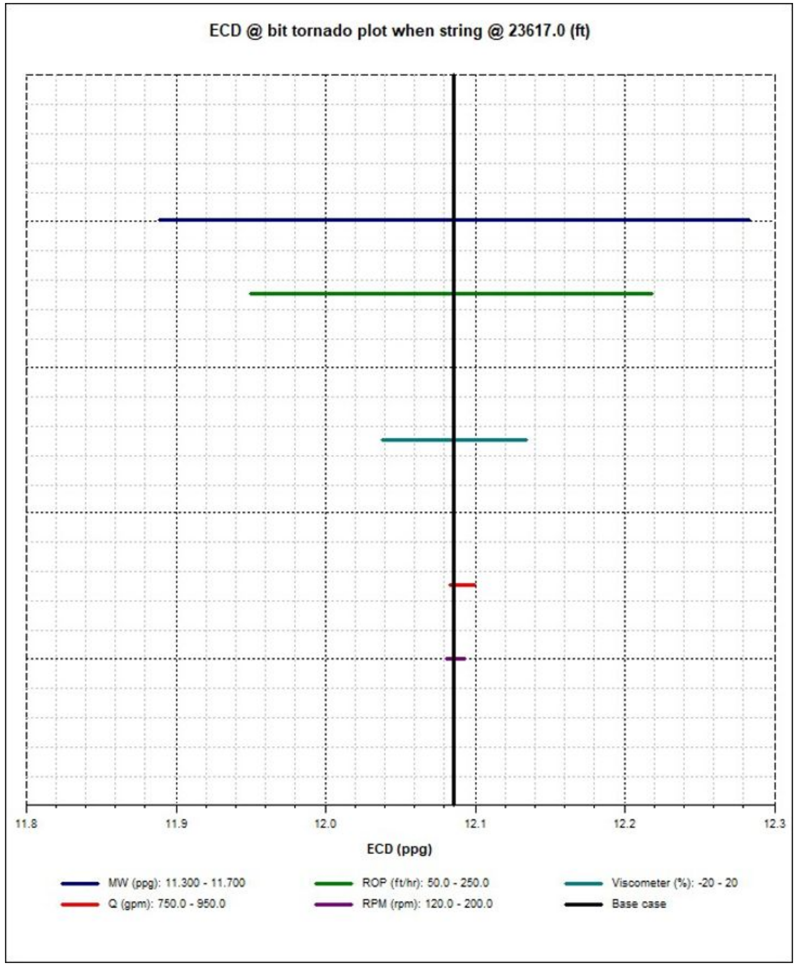
Drilling parameters effecting ECD and SPP.

- While drilling a 12 ¼” HS , which parameters effects the ECD and SPP the most.

Starting from the greatest to the smallest

a. ROP
b. Flowrate
c. MW
d. Viscosity
e. RPM

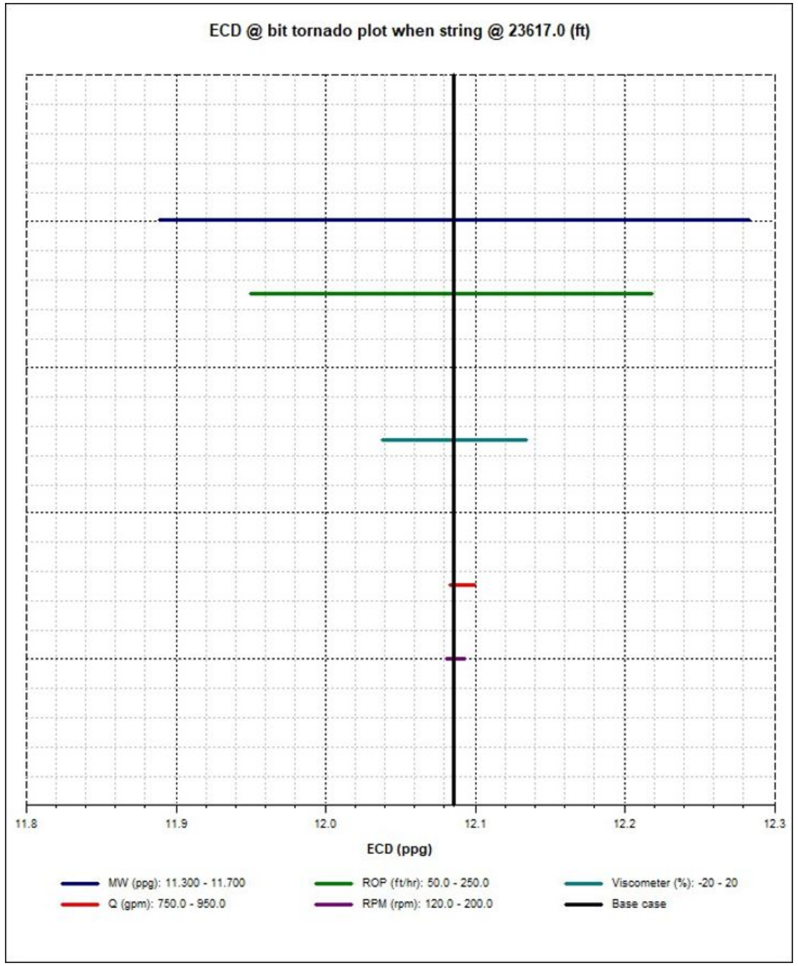
Case study.



The graph to the left is commonly called a Tornado Graph, and it shows the effect drilling parameters can have on ECD.

In this example, we'll look at how drilling parameters affect both ECD and SPP and explain how, depending on what your aims are, "dropping the flow rate" doesn't always have the desired affect you are looking for.

Case study.

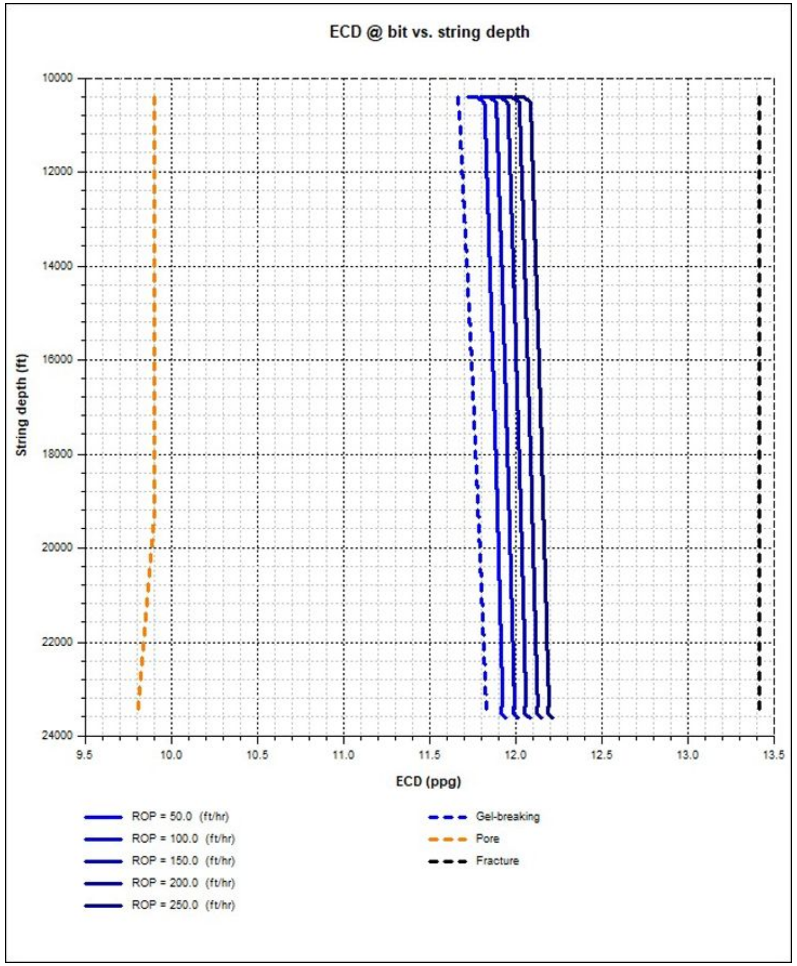


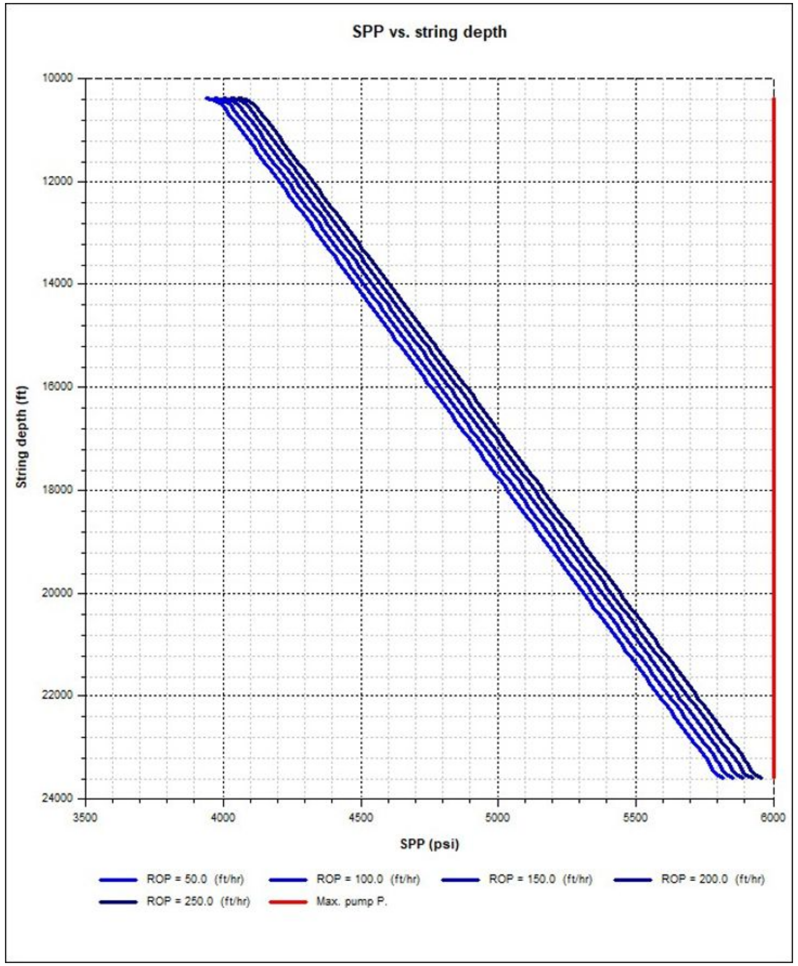
In 12 ¼” hole, the affects from greatest to smallest are:

a. MW
b. ROP
c. Viscosity
d. Flow Rate
e. RPM

ROP, this range of 50 – 250 fph, has about a 0.3 ppg effect on ECD .

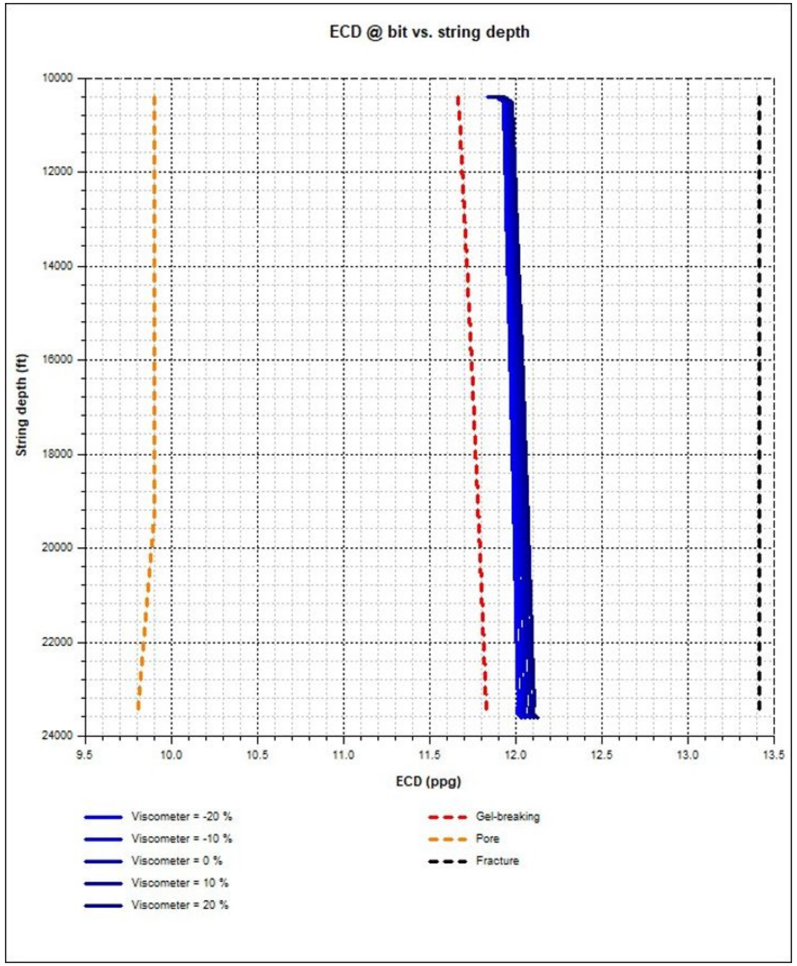
There is about a 150 psi SPP affect.

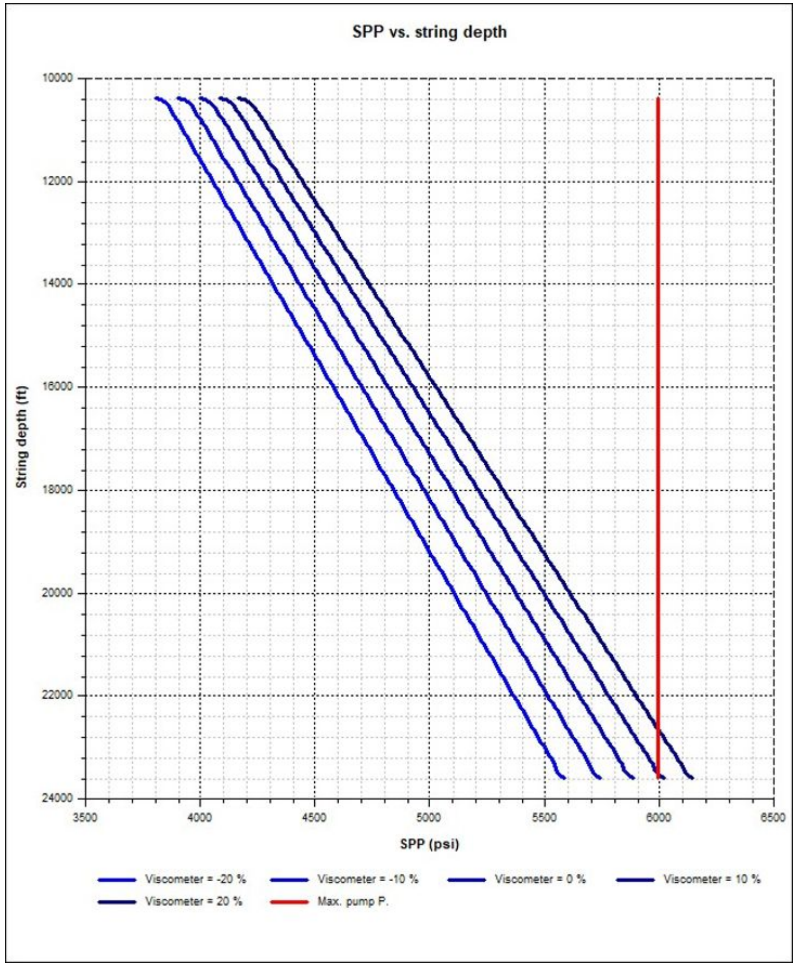




Viscosity, in this case a +/- 20% range, has about a .15 ppg affect on ECD.

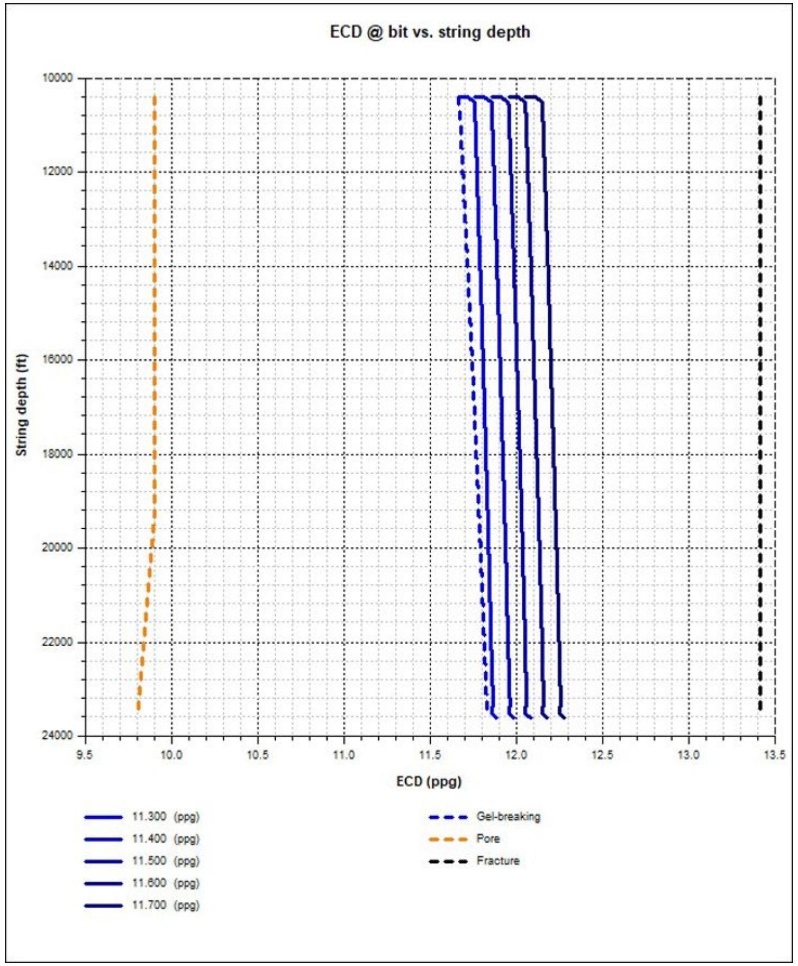
SPP, however, can be affected more significantly, with the same vis range having a 550 psi SPP affect. SPP can be heavily affected by Fann readings.

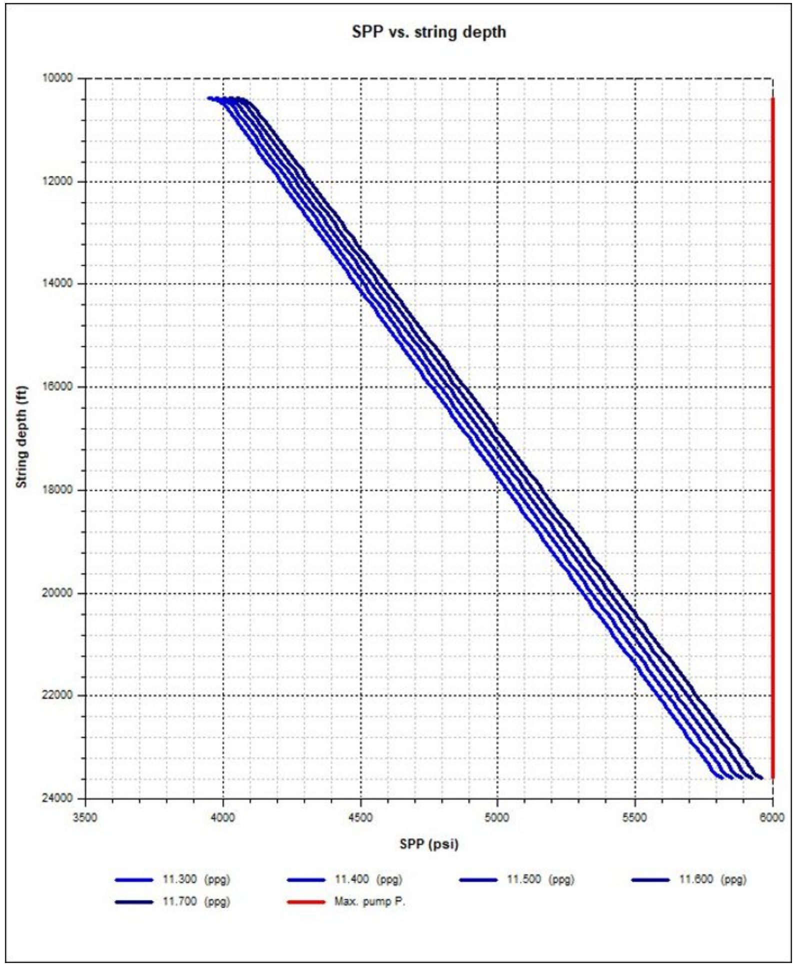




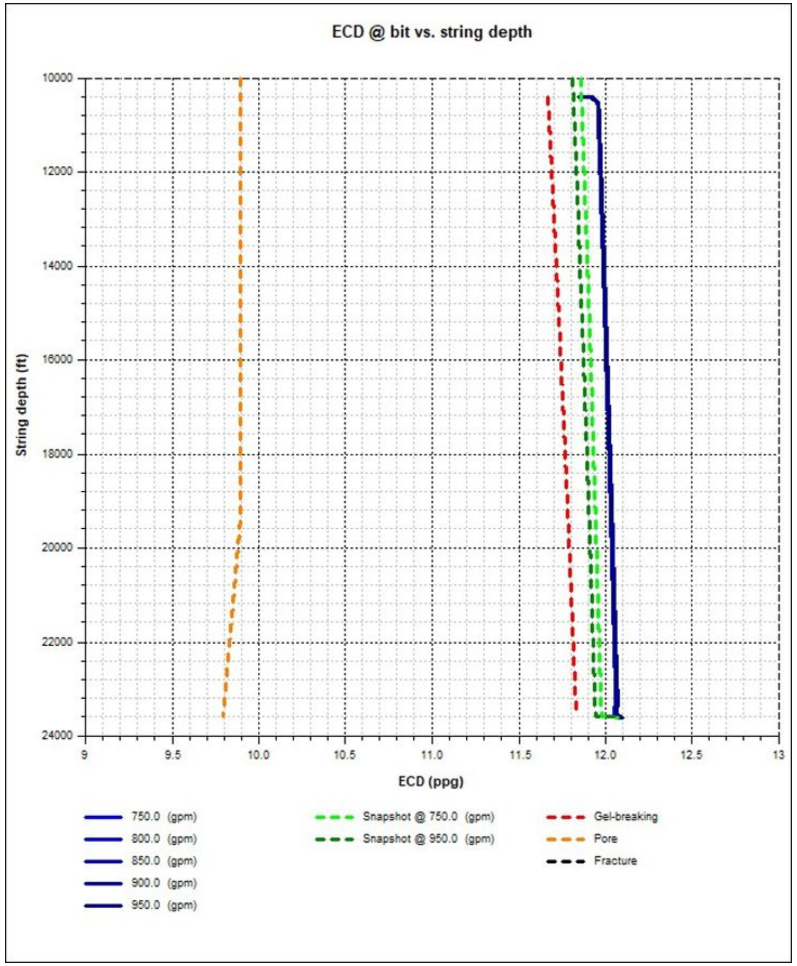
The affect of Mud Weight tends to be pretty linear on ECD.

SPP is only affected by about 200 psi in the 11.3 – 11.7 ppg range being looked at here.

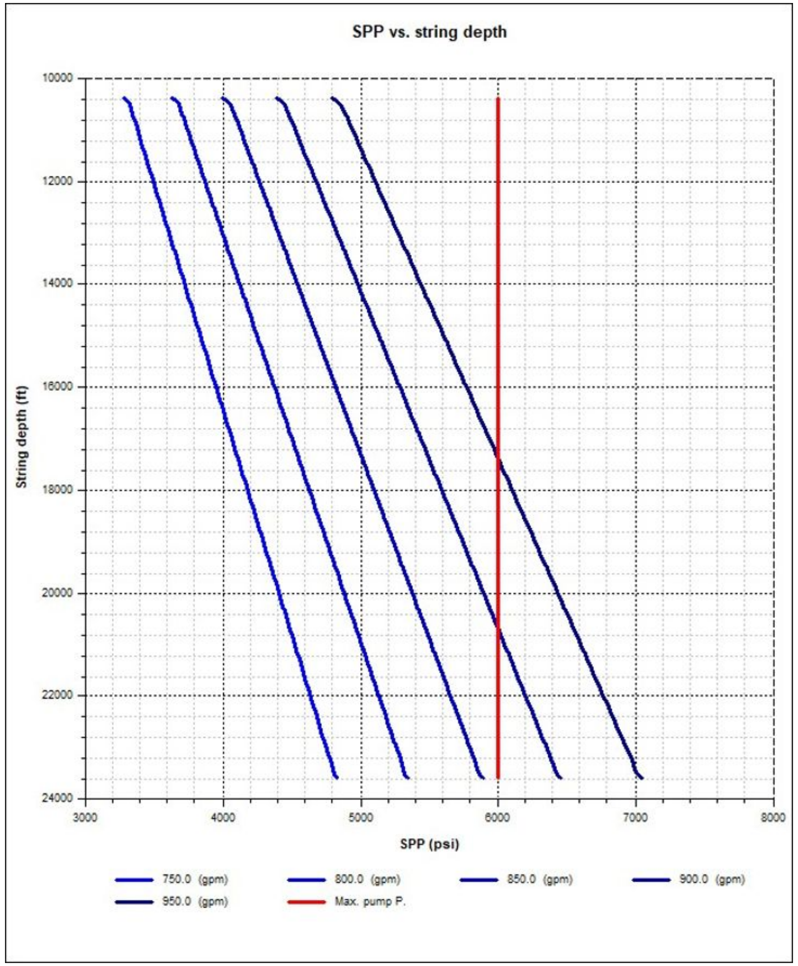




This is the most common ECD graph that people look at – a Flow Rate-based ECD graph. As you can see, how much you pump doesn't really affect ECD much.

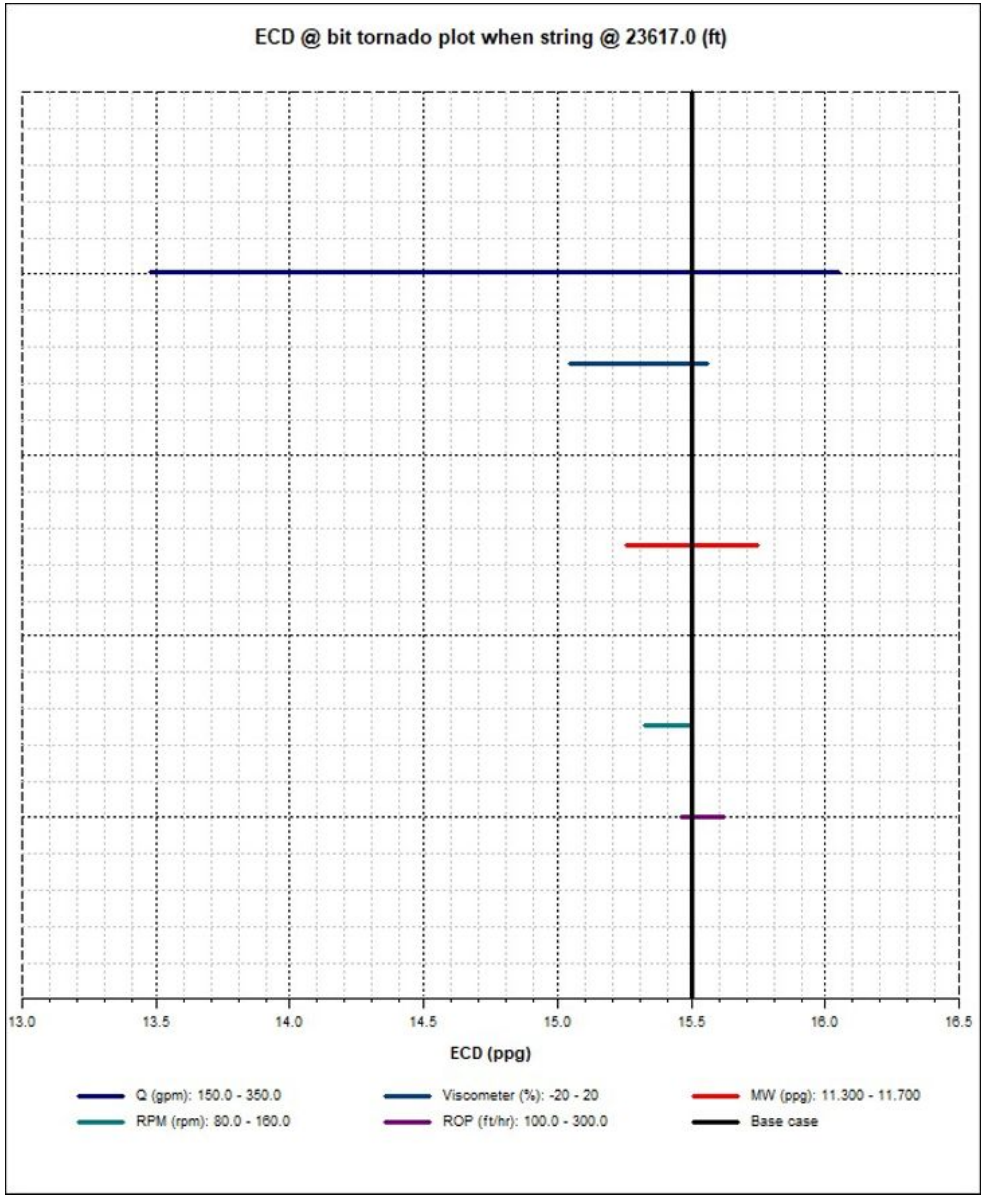


But as we all know, Flow Rate has a huge affect on SPP.



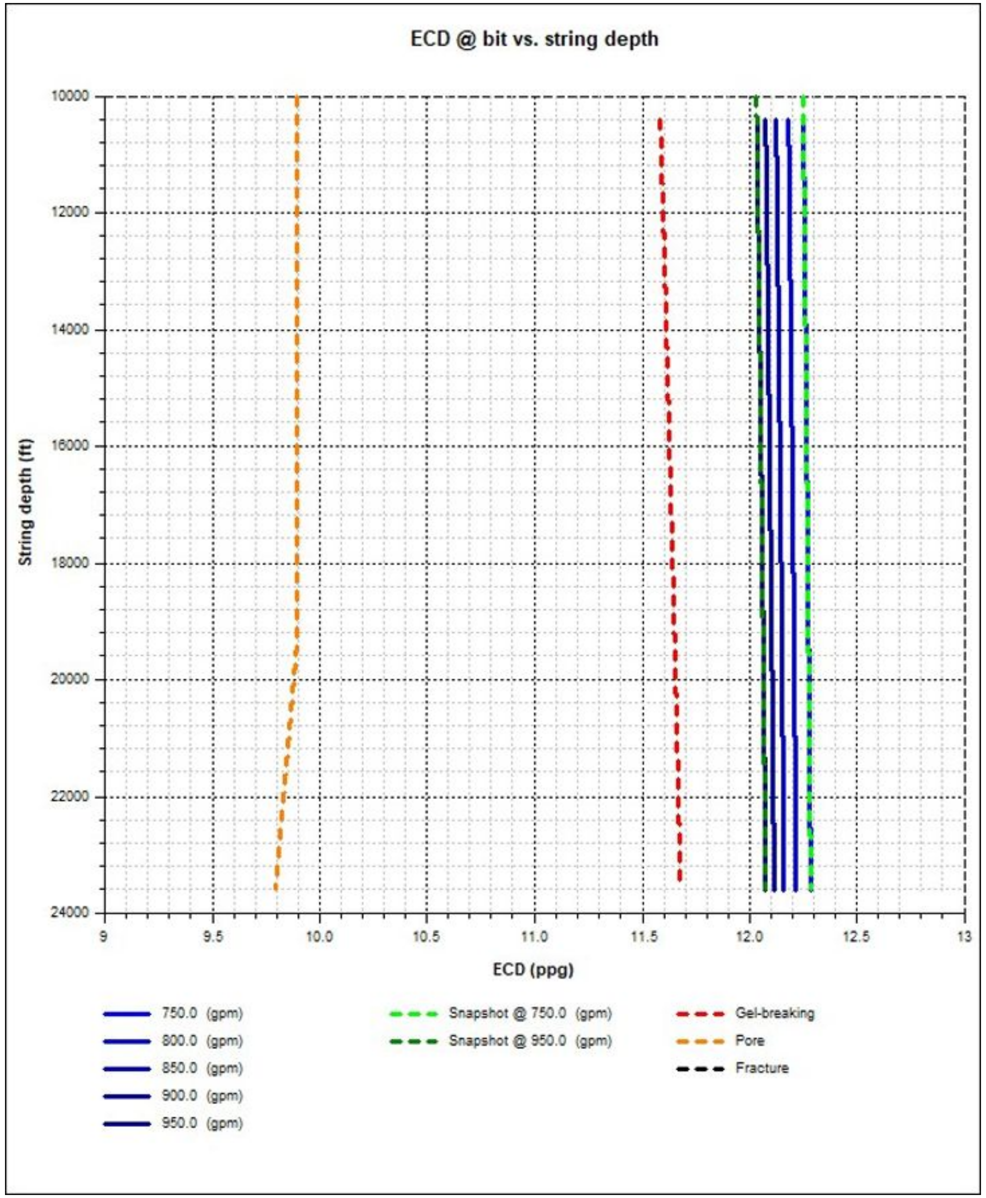
Hole size effecting ECD and SPP.

- While drilling a 6” HS, which parameters effects the ECD and SPP the most.
  - Starting from the greatest to the smallest
  - ROP
  - Flowrate
  - MW
  - Viscosity
  - RPM



For example, in 6” hole, the affects from greatest to smallest are:

a. Flow Rate
b. Viscosity
c. MW
d. RPM
e. ROP



WHAT IF I TOLD YOU…

- That turning your flow rate up will DECREASE ECD?
- It does – in larger hole.
- Here is the scenario in 17 ½”. Note that 950 gpm is 12.1 ppg ECD; 750 gpm is 12.3 ppg ECD. This affect is highly variable in regard to ROP, and becomes more acute as hole size increases.

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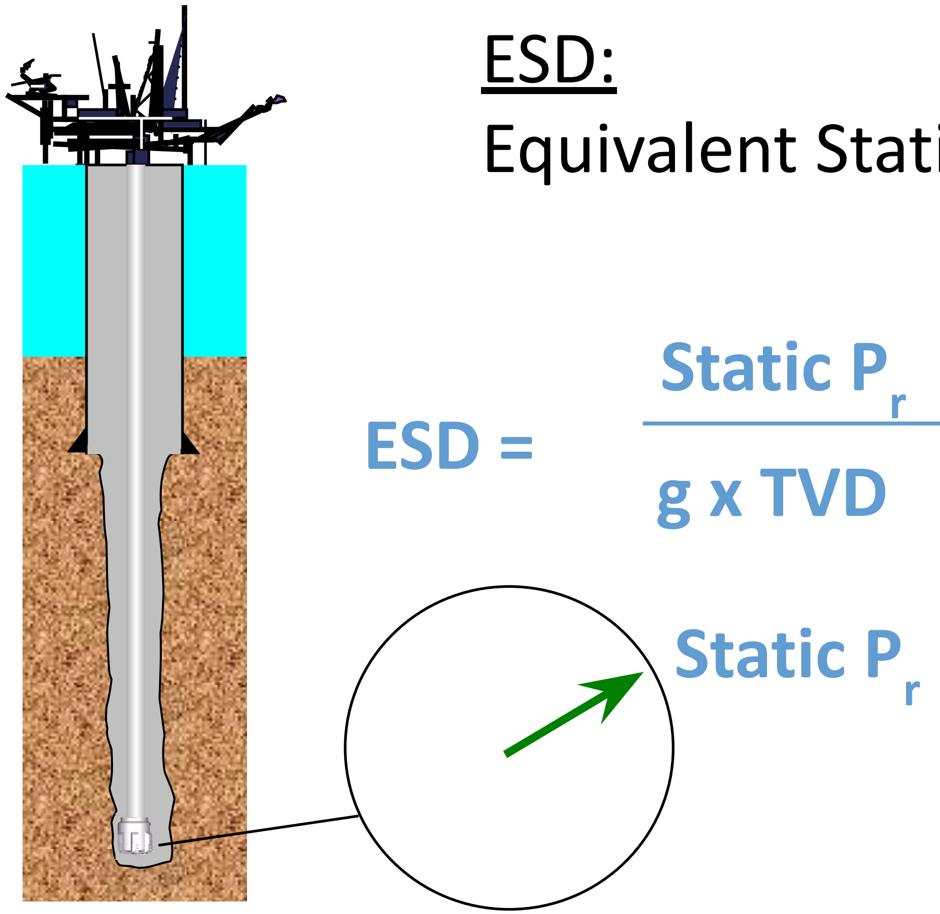
MODULE 2

ECD management.

What is ESD?



<u>ESD:</u>

Equivalent Static Density (***pumps OFF***)

$$ESD = \frac{\text{Static } P_r}{g \times TVD}$$

ECD management.

Static pressure is the pressure exerted by a stationary fluid of a given density at a vertical depth. It also includes any drilled solids suspended in the mud column. It is measured in pounds of force per square inch (psi).

We can calculate this pressure from the mud density using the formula:

- Pressure (psi) = mud gradient (psi/ft) * depth
  - psi/ft = pounds-force per square inch per foot

ECD management.

- Mud density can also be expressed in terms of psi/1000ft. This is denoted as pptf = pounds-force per thousand feet.
- pptf shows the pressure generated by the mud for each interval of 1000ft TVD (Note: TVD, not MD). To convert a pressure gradient of psi/ft to pptf, just multiply by 1000.
  - i.e. 0.5 psi/ft * 1000 = 500 pptf
- ECD is expressed in the same units as mud weight, i.e., pptf, ppg, psi/ft, SG

ECD management.

For an example of static mud pressure (hydrostatic pressure) calculation.

A 500 pptf mud exerts the following pressure at 6000 ft TVD:

- ***Pressure (psi) = 500 (pptf) * 6 (thousand ft) = 3000 psi***

Similarly, a 0.5 psi/ft mud exerts the following at 6000 ft TVD:

- ***Pressure (psi) = 0.5 (psi/ft) * 6000 (ft) = 3000 psi***

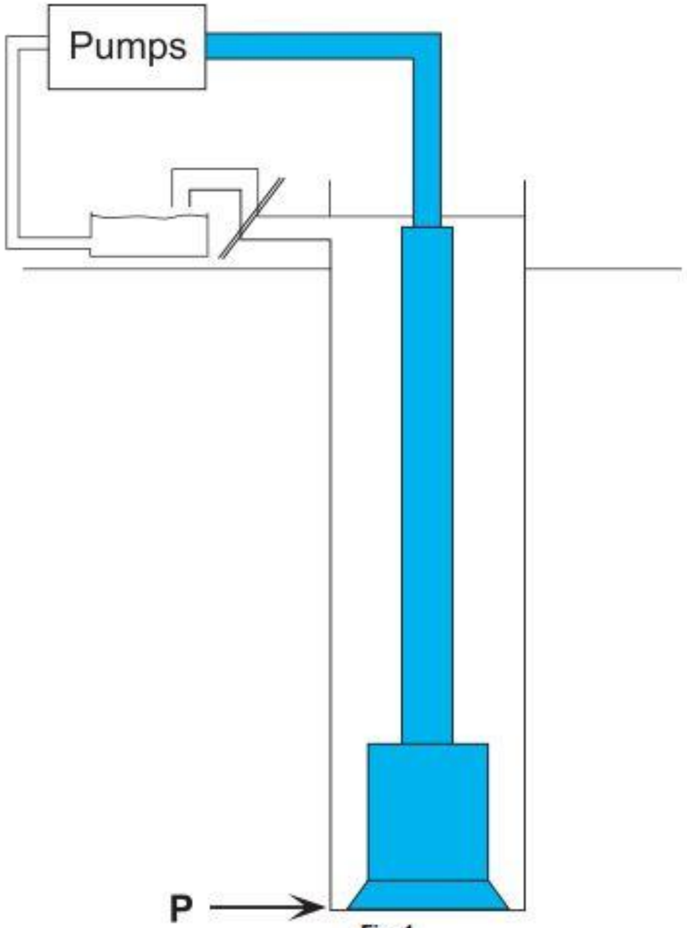


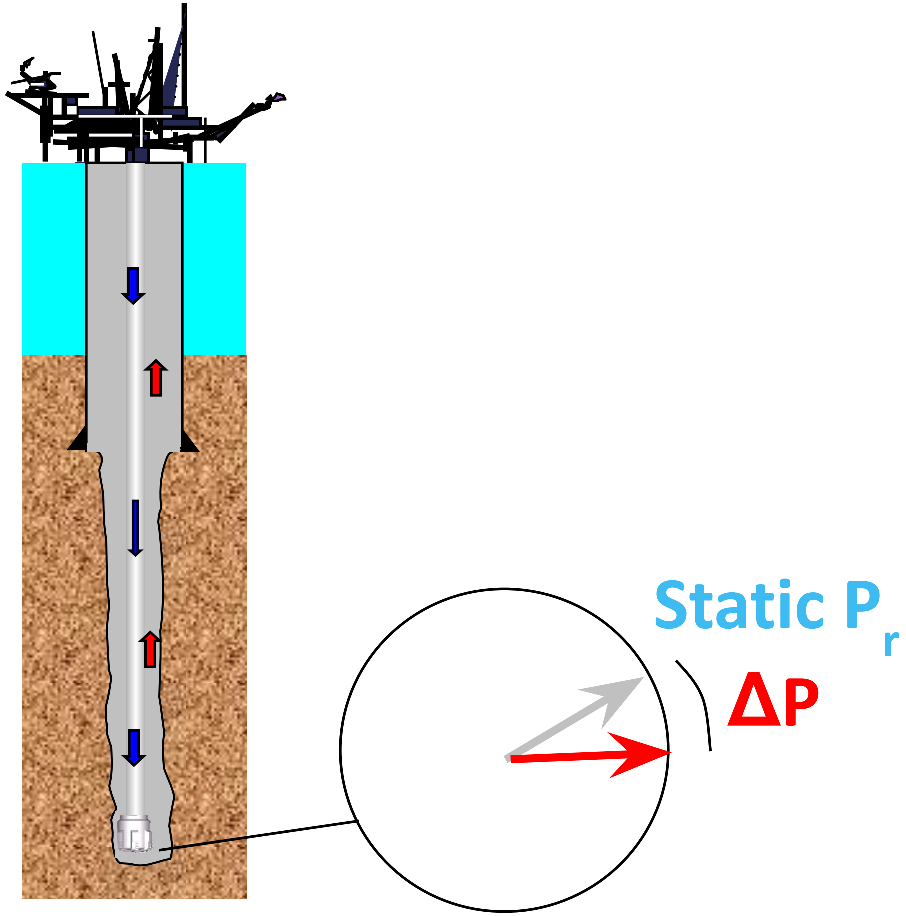
Fig. 1

What is ECD?

<u>ECD:</u>

Equivalent Circulating Density (***pumps ON***)

$$ECD = ESD + \frac{\Delta P}{g \times TVD}$$



ECD basics.

ΔP, the additional mud weight seen by the hole, due to the circulating pressure loss of the fluid in the annulus, and/or surge pressures.

ECD management.

ECD = MW + (APL/TVD)

Where:

- MW = mud gradient in pptf
- APL = annular pressure loss in psi
- TVD = True Vertical depth in ft

ECD basics.

The APL (and therefore ECD) is effected by the following:

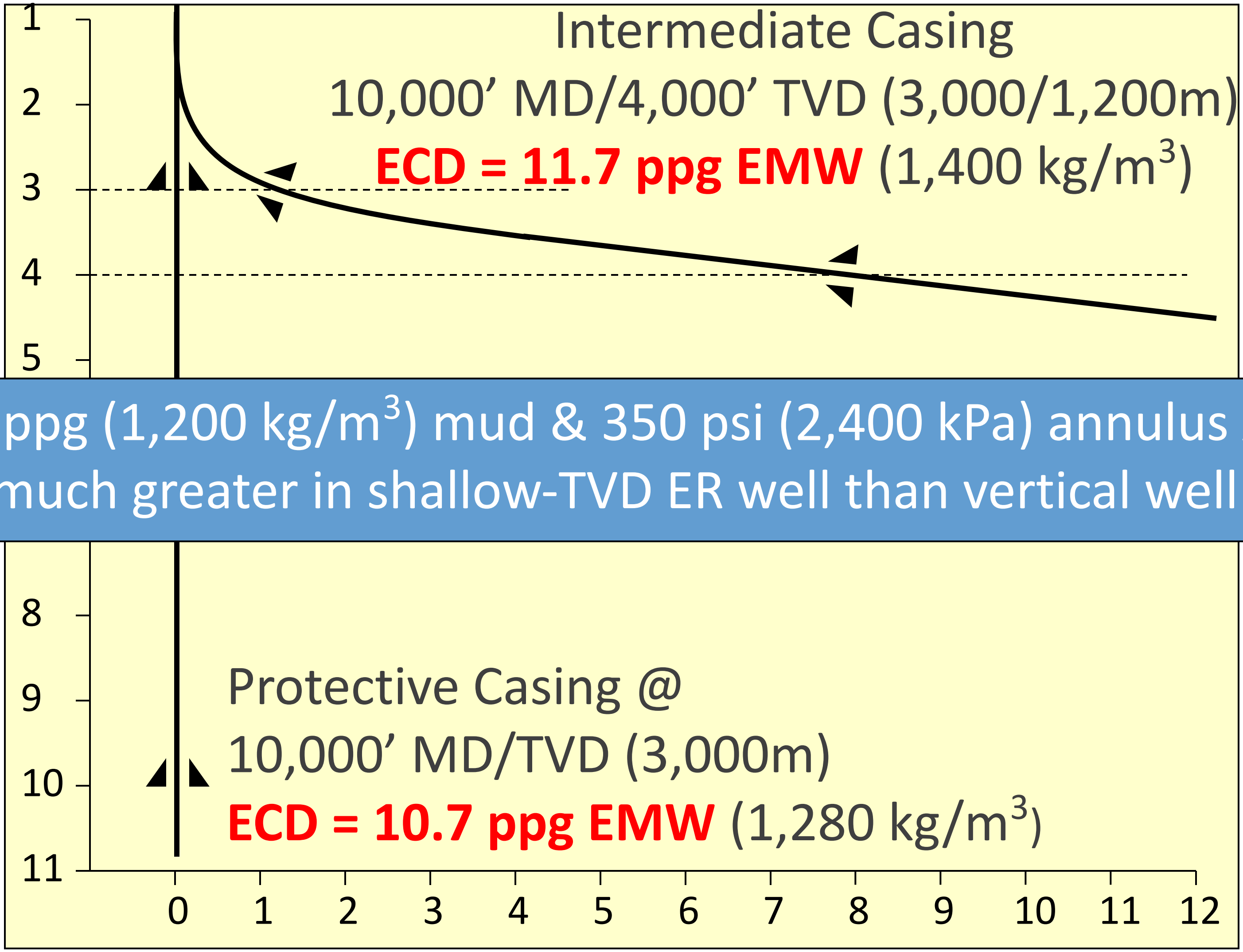
- Length of the annulus or well.
- Annular clearances (drill-pipe / casing sizes).
- Mud properties.
- Flowrate.
- Rotation.
- Backpressure through surface return lines.
- ROP.
- Pipe movement (surge and swab pressures).

Why are ECDs a particular concern for ERD?

1. ERD wells have much higher ECD fluctuations.
    - MD to TVD ratio is more significant.
    - Shallow ERD wells have little formation integrity.
    - Drill-pipe is often larger.
    - More aggressive parameters used for hole cleaning.
    - Mud properties.

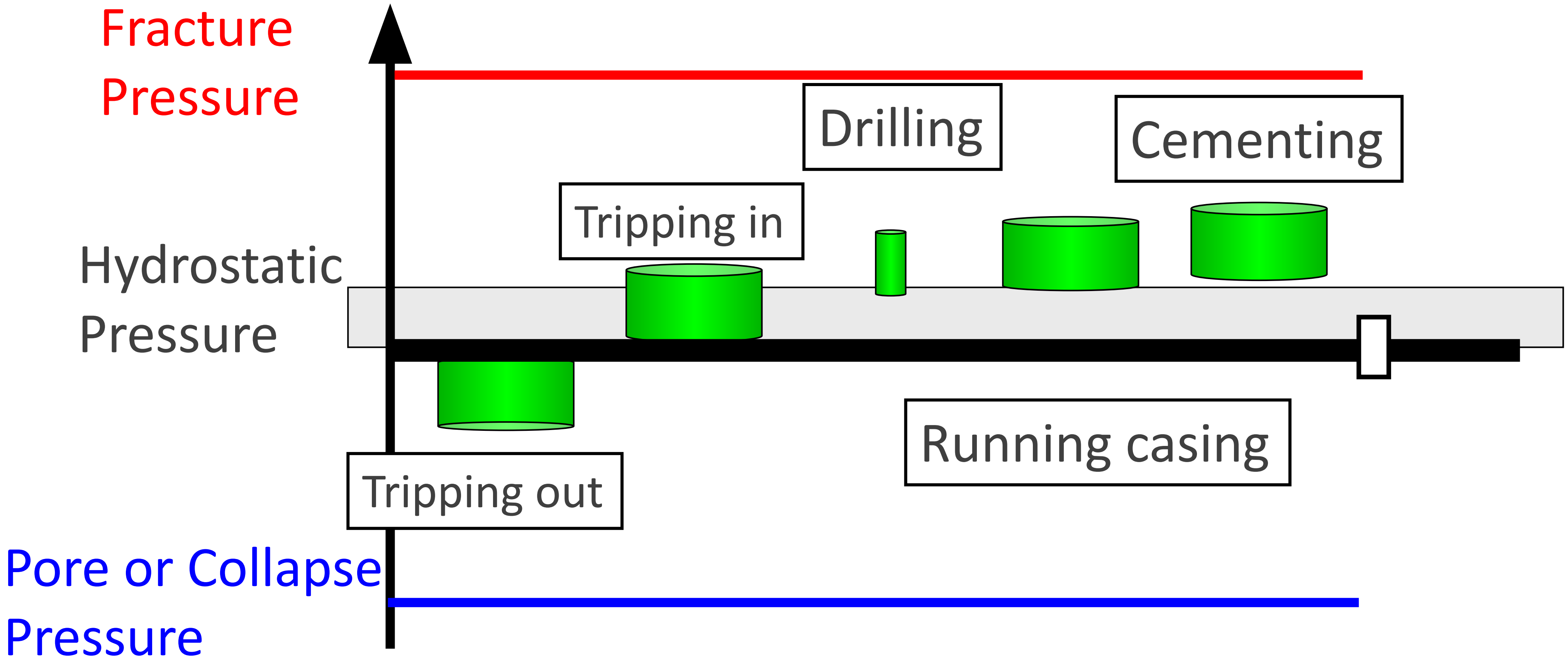
2. Understanding ECD effects is essential for ERD.
    - Numerous ER wells have been lost due to ECD.
    - Difficulties are sometimes wrongly blamed on other factors.

ECD basics.



Same 10.0 ppg (1,200 kg/m^3) mud & 350 psi (2,400 kPa) annulus ΔP in both wells.
ECD is much greater in shallow-TVD ER well than vertical well at same MD.

ECD basics.


Fracture Pressure
Drilling
Cementing
Tripping in
Hydrostatic Pressure
Running casing
Tripping out
Pore or Collapse Pressure

ECD basics.

ECD directly creates the following problems.

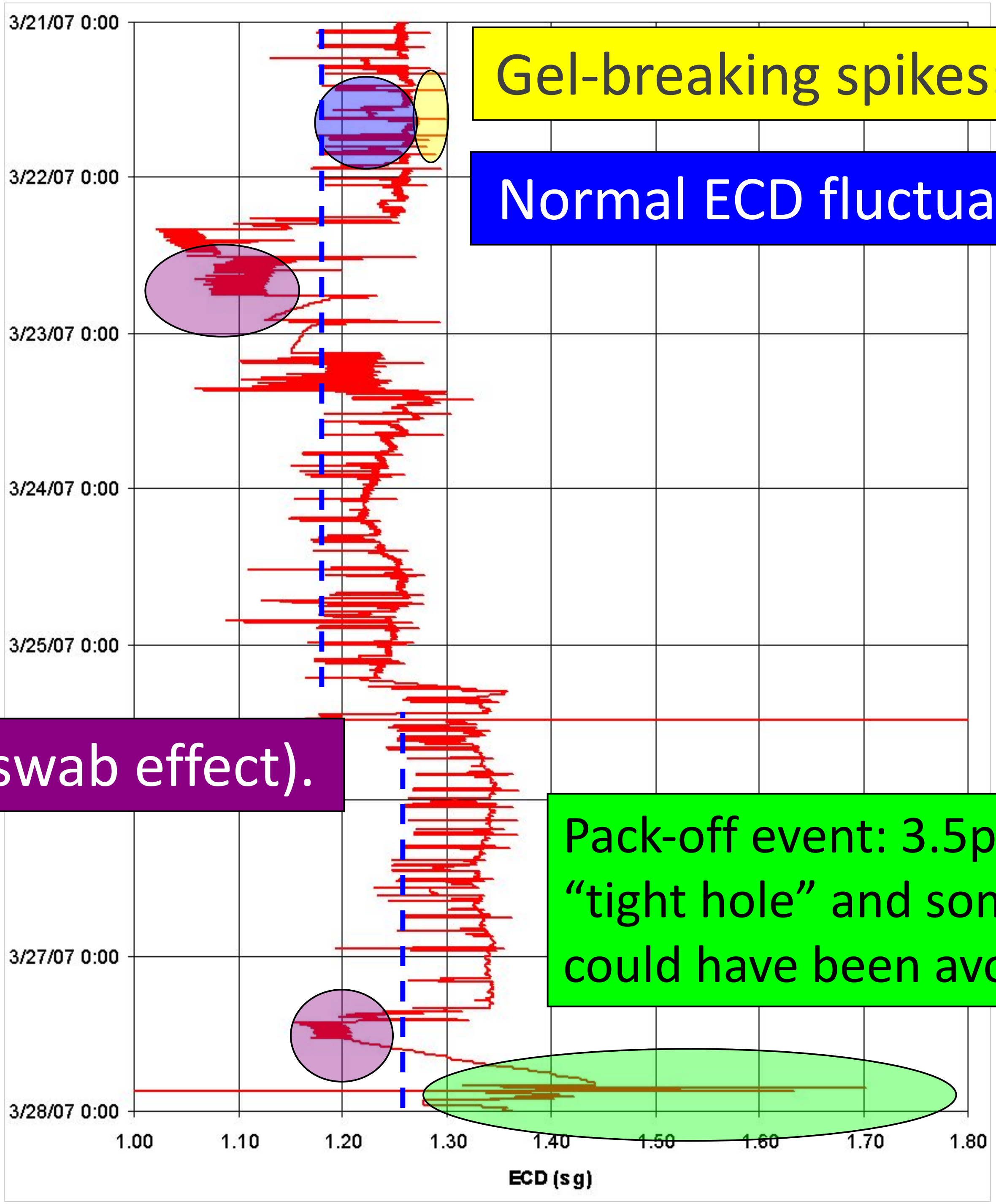
- Lost circulation:
  - When bottom hole pressure exceeds fracture gradient.
  - Usually most damage is done when off bottom.
- Often at connections.

ECD basics.

But ECDs also create other problems.

- Wellbore instability:
  - Hydraulic hammer (shock type ECDs).
  - Fatigue failure, think of a paper clip being bent back & forth.

- If the mud engineer was to have deliberately changed the MW by 2 – 3 ppg, would you expect problems? This is often mistaken for “time dependency”, when fatigue cycles are combined at a set rate (# connections per day).



Gel-breaking spikes: 0.3 ppg / 110 psi.

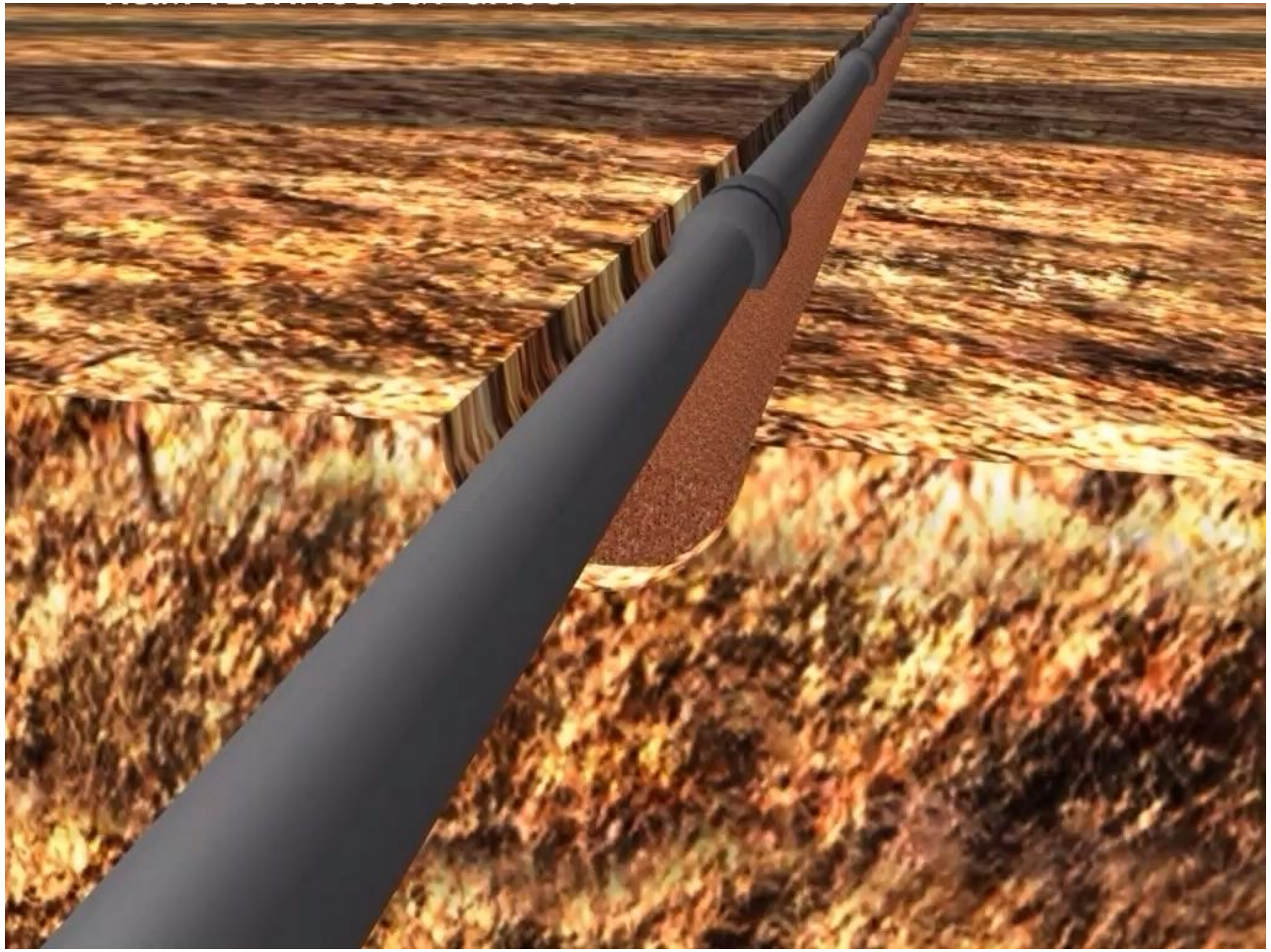
Normal ECD fluctuation: 0.8 ppg / 300 psi.

ER Well Example
- 11 ¾” @ 16,500’ MD
- Drilling to 23,000’ MD
- 10 ⅝” x 12 ¼” hole
- 5 ⅞”x 5” dp
- 9.7-10.5 ppg OBM
- 6rpm = 13-15

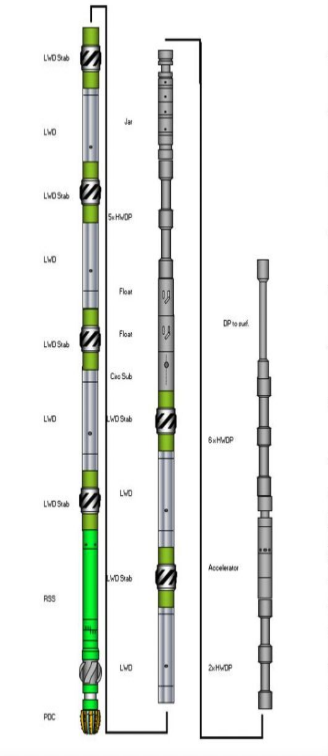
POOH (swab effect).

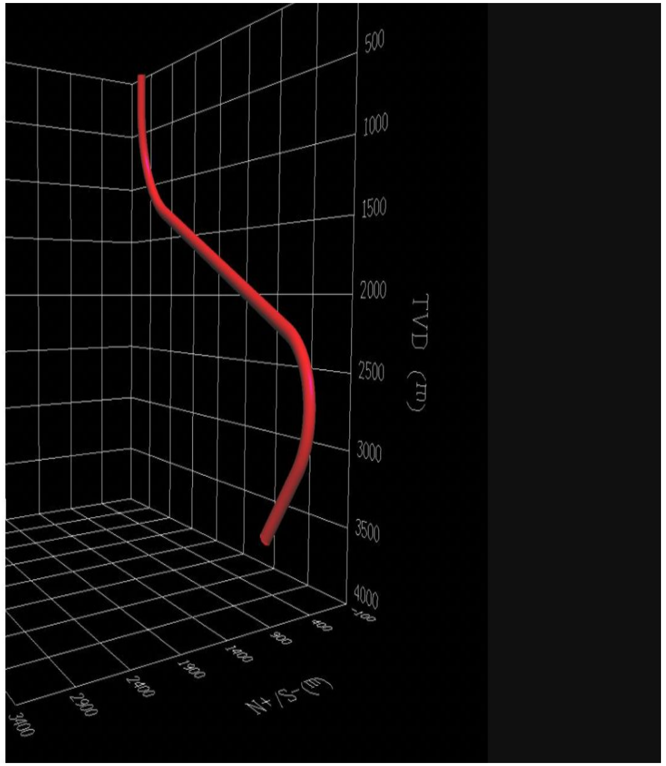
Pack-off event: 3.5ppg / 1,300 psi. The driller pulled into “tight hole” and someone turned the pumps on… this could have been avoided if procedure had been followed!

POOH with pack-off.



ECD S-shaped well





- While drilling a 6" hole section on an S-shaped well, the ECD reading from the PWD tool is seen to gradually increase above the expected trend (pre-drill modelling). Which of the following could qualify as a possible explanation?

a. ROP increase.

b. RPM increase.

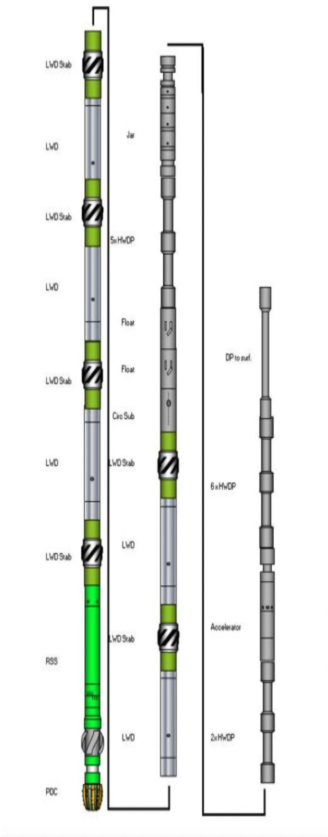
c. Near bit stabiliser balling.

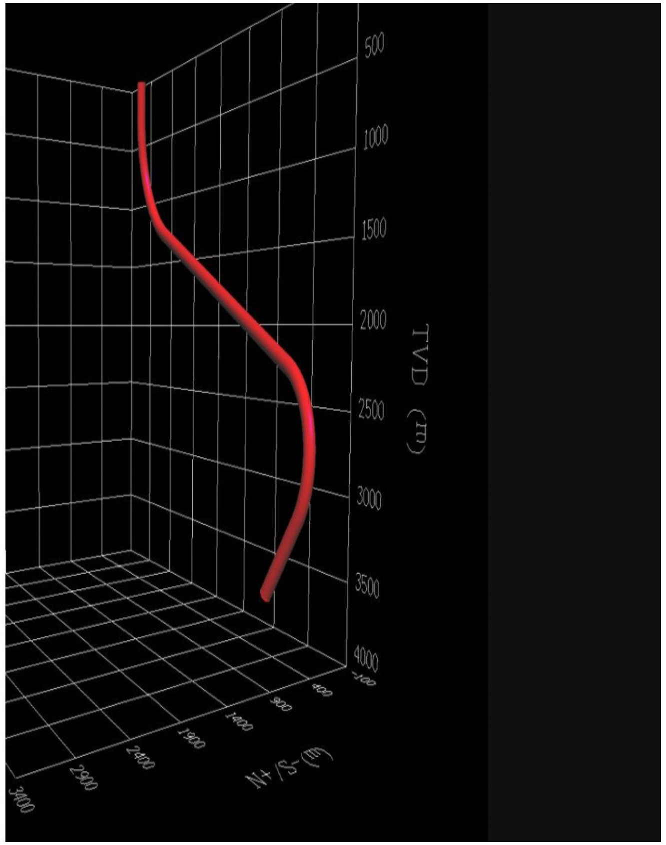
d. Drilling fluid YP increase.

e. Increased rate of drop-off in the trajectory.


Coffee
Time!

ECD S-shaped well





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b. RPM increase.

c. Near bit stabiliser balling.

d. Drilling fluid YP increase.

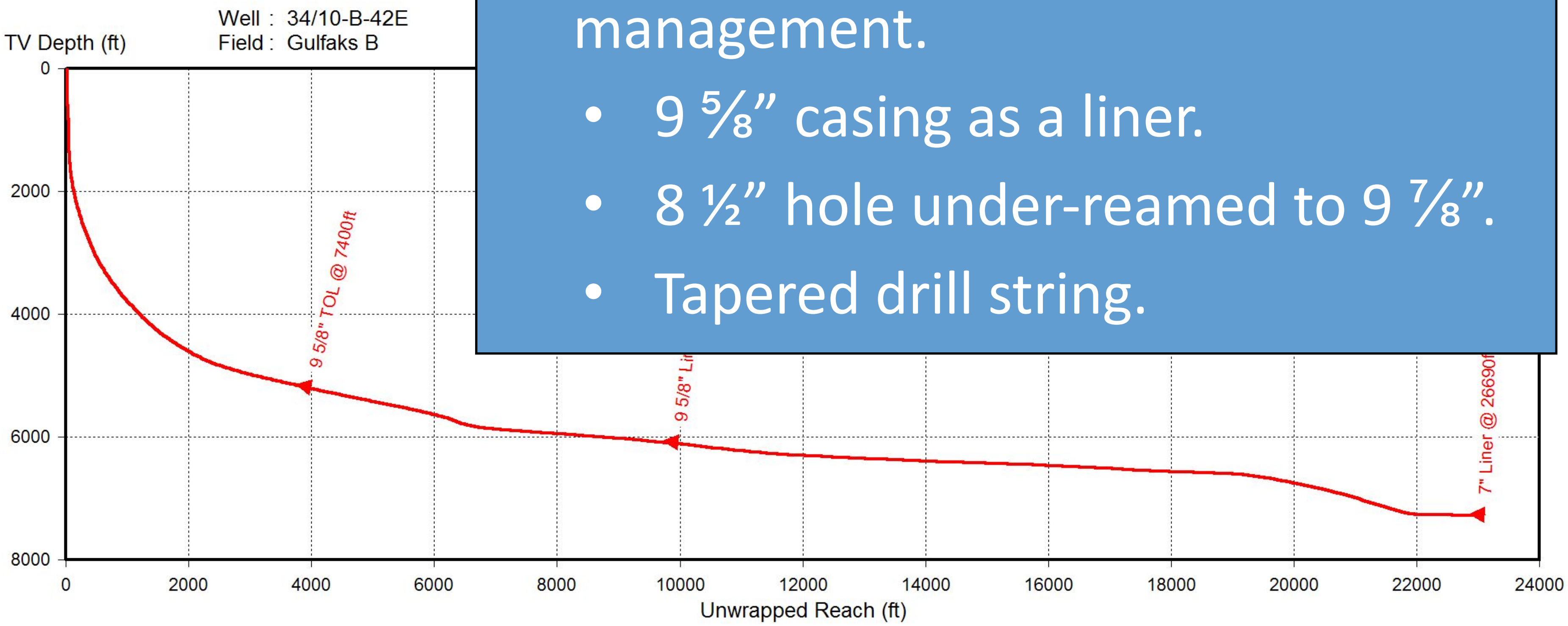
e. Increased rate of drop-off in the trajectory.

PWD roadmap concept.

- By itself, PWD is of limited value.
- Unless you know what "normal" looks like.
- PWD can tell you things you never thought of, if you know, how to listen to what it is saying.

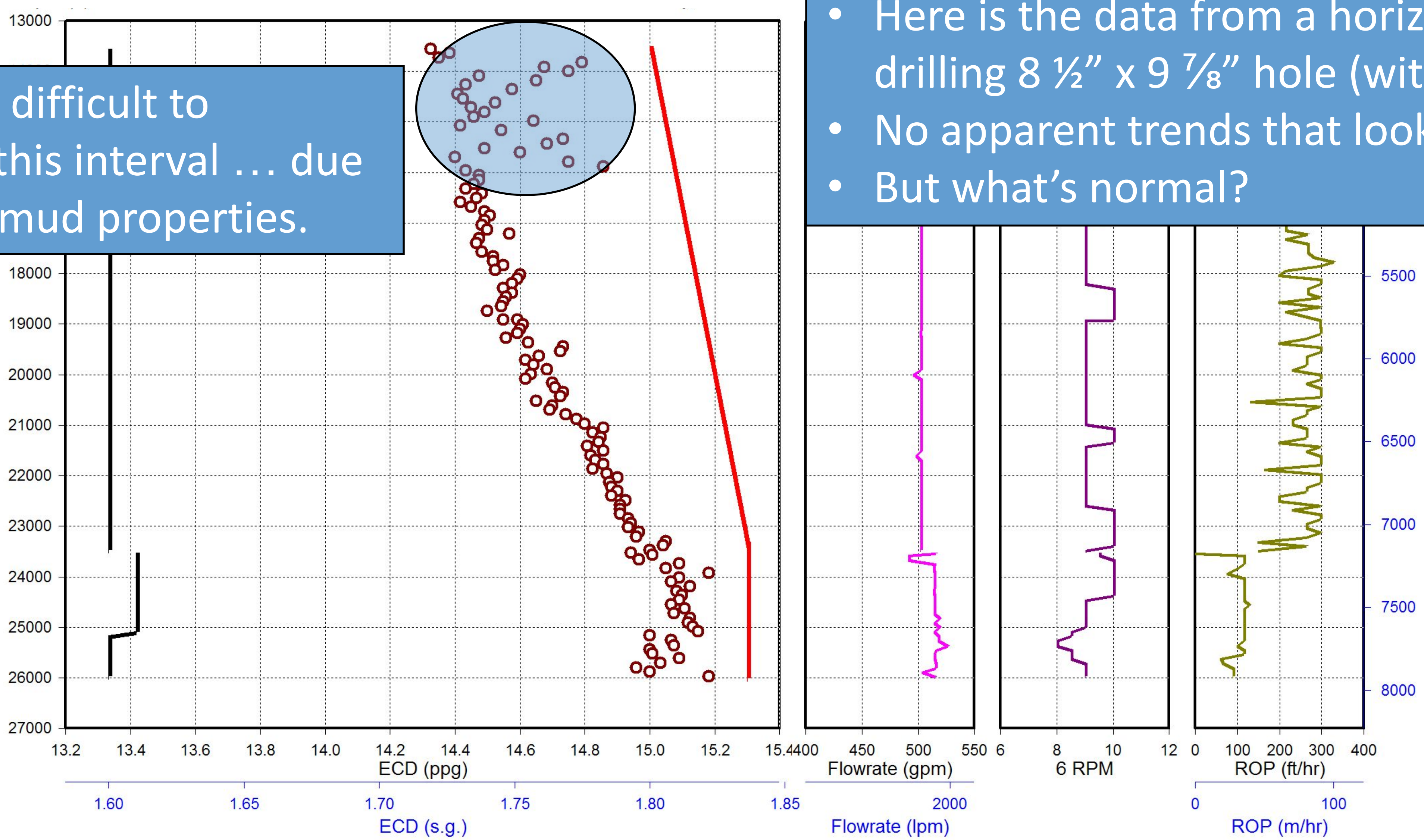
PWD roadmap example.

- Norwegian ER Well.
- Significant effort put into ECD management.
  - 9 ⅝” casing as a liner.
  - 8 ½” hole under-reamed to 9 ⅞”.
  - Tapered drill string.



- PWD data, by itself, doesn’t mean much.
- Here is the data from a horizontal well, drilling 8 ½” x 9 ⅞” hole (with RWD).
- No apparent trends that look unusual.
- But what’s normal?

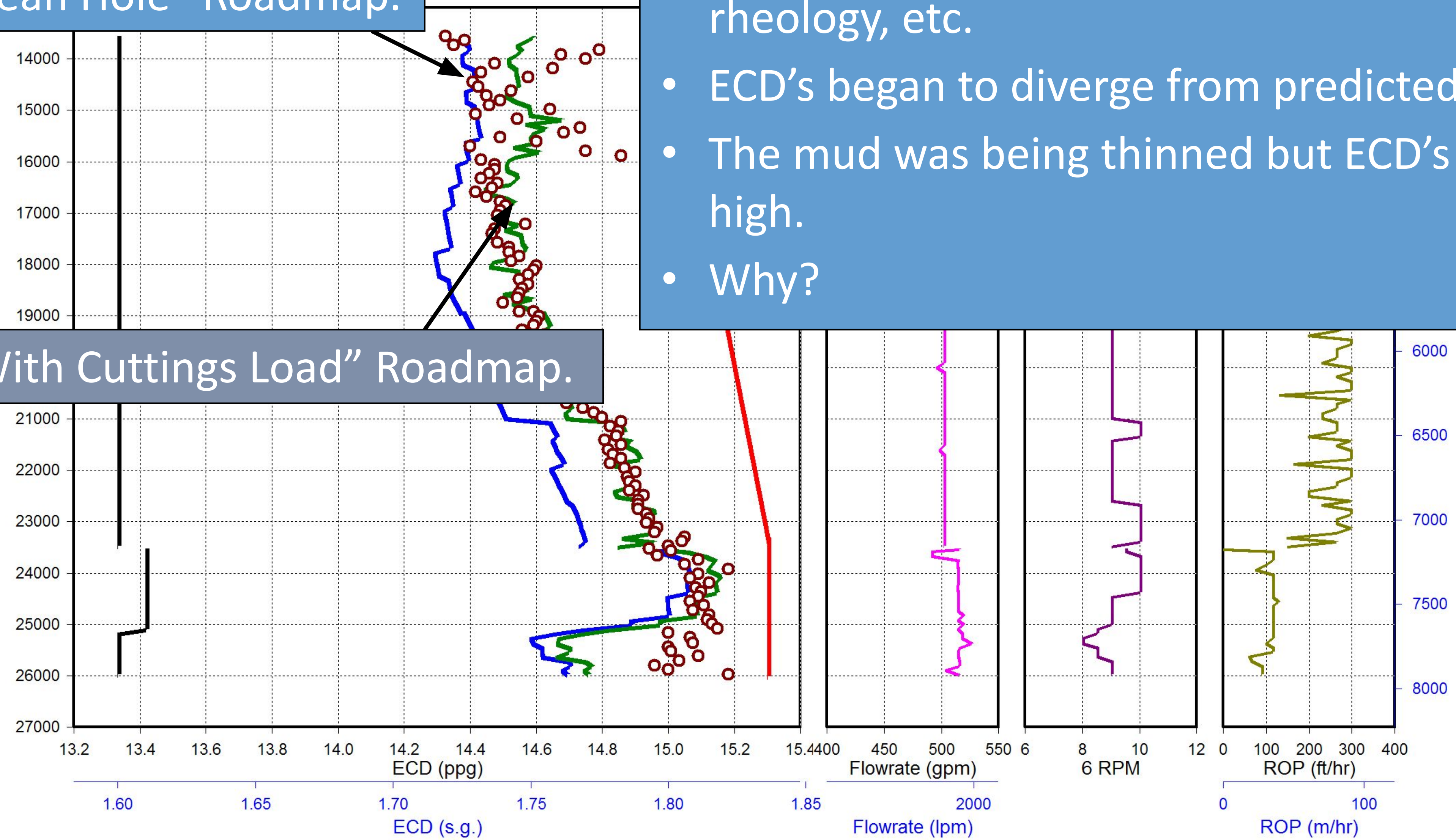
Note how difficult to interpret this interval … due to erratic mud properties.



- With roadmap view.
- Adjusted for changes to flowrate, rotary speed, rheology, etc.
- ECD's began to diverge from predicted values.
- The mud was being thinned but ECD's remained high.
- Why?

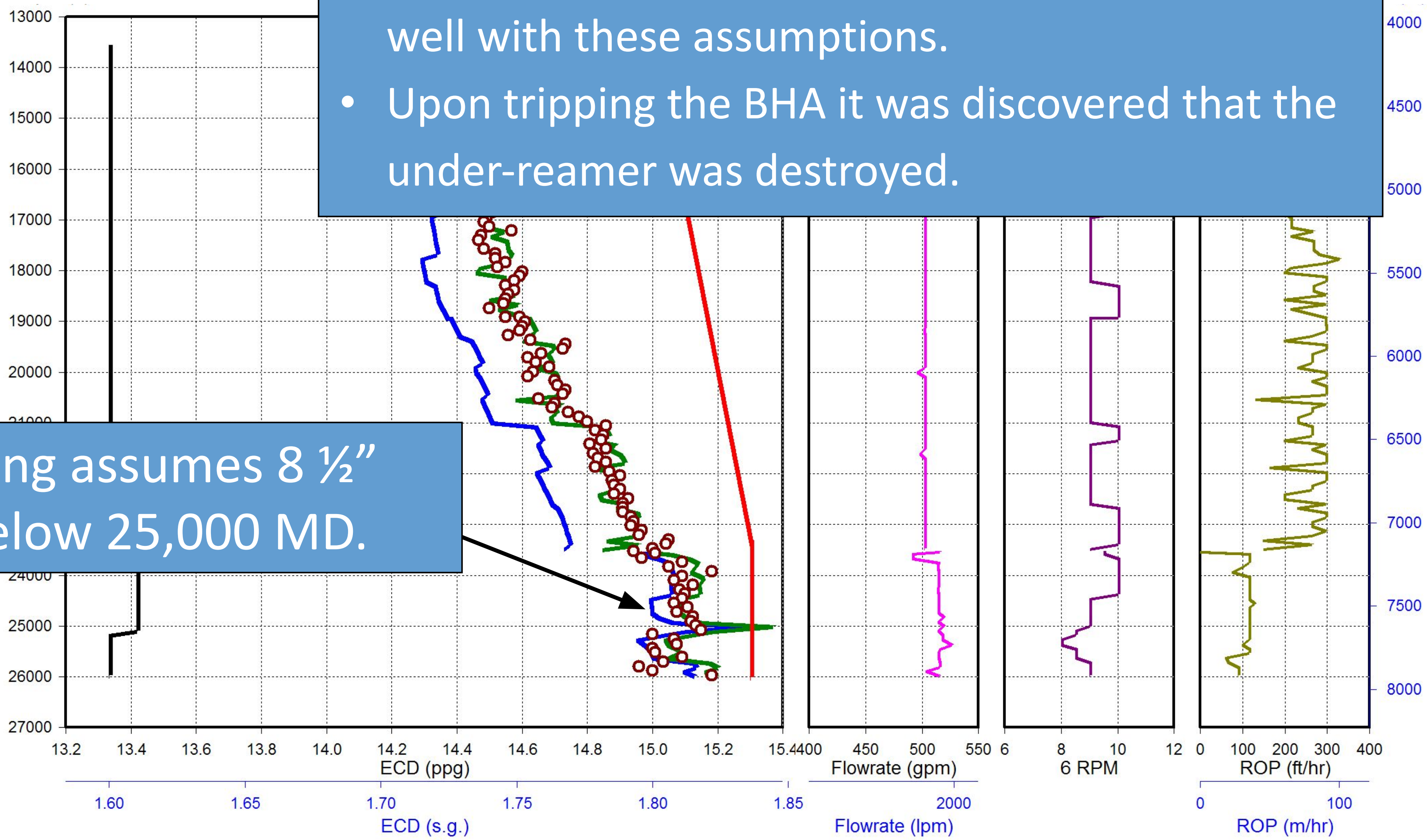
Blue: "Clean Hole" Roadmap.

Green: "With Cuttings Load" Roadmap.



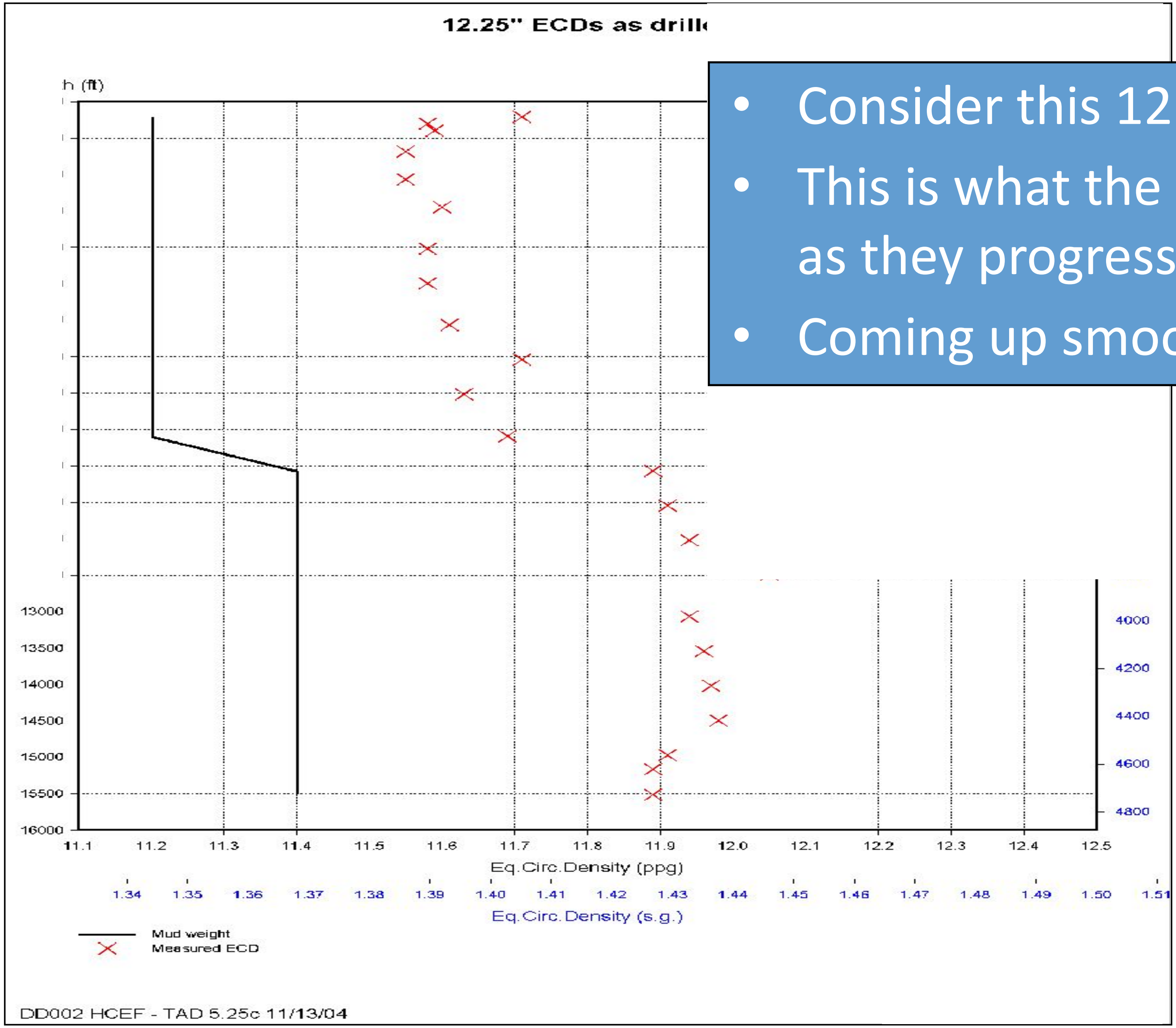
- Re-modeled for RWD failure.
- Assumes 8 ½" hole below 25,000'. Model matched well with these assumptions.
- Upon tripping the BHA it was discovered that the under-reamer was destroyed.

Modeling assumes 8 ½" hole below 25,000 MD.

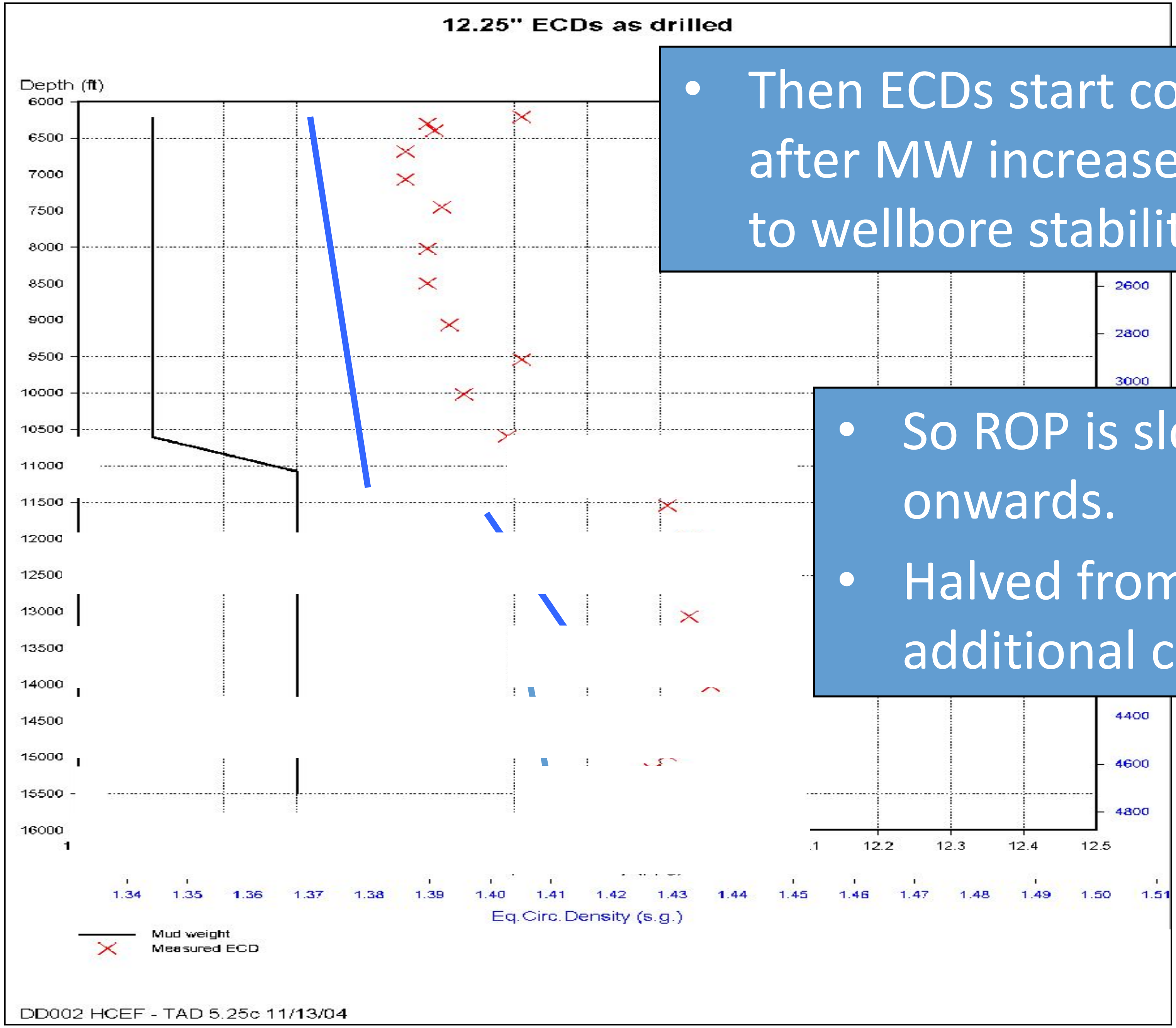


PWD roadmaps.

- Firstly, need to know geometry effect on the roadmap.
- Also need daily (or more often) variations in rheology accounted for.
- Fluid rheology's affect ECDs more than anything else (especially in the larger hole sizes).

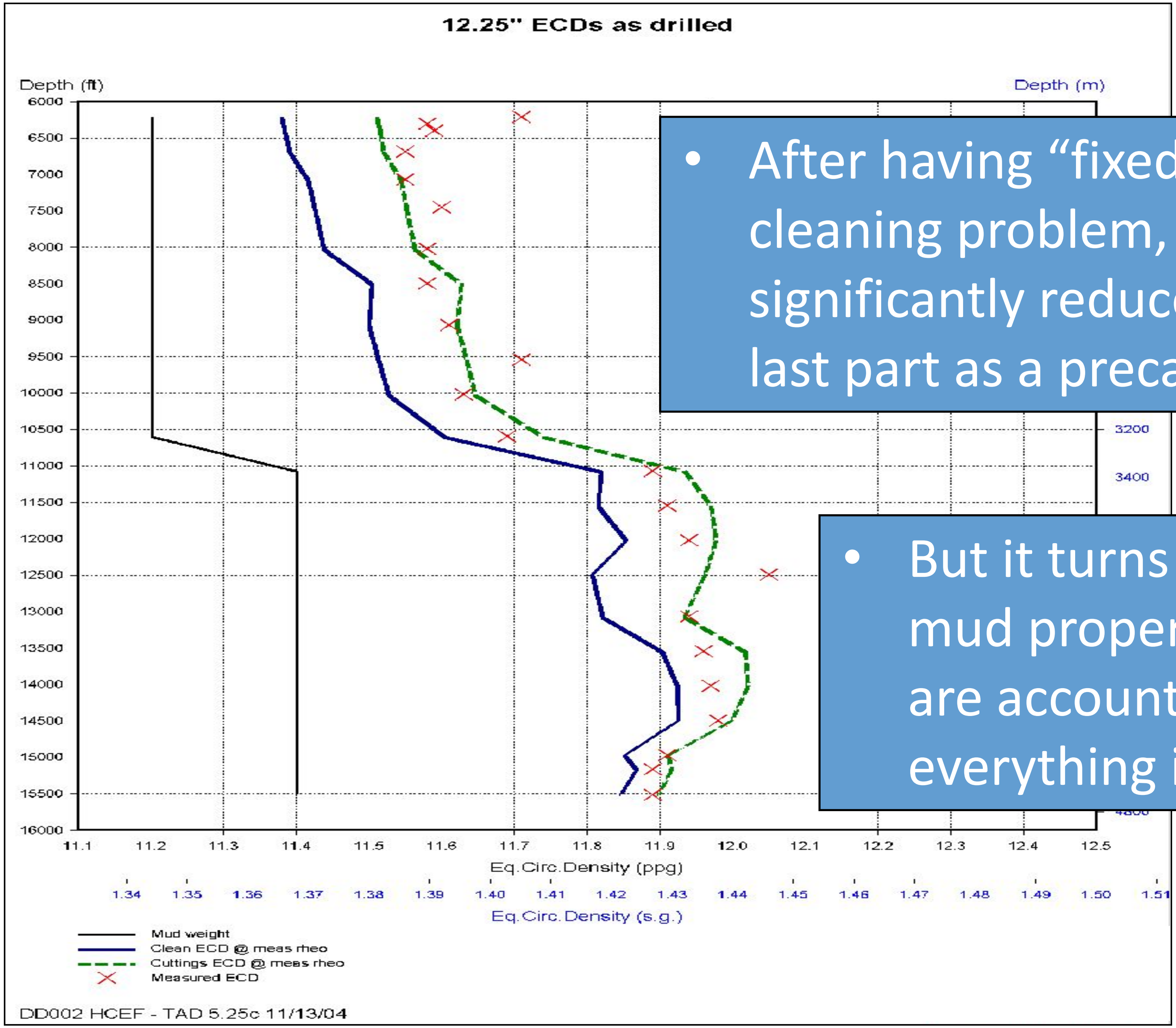


- Consider this 12 ¼” high angle section.
- This is what the drilling operation sees as they progress ECDs continuously.
- Coming up smoothly (OK).



- Then ECDs start coming up faster after MW increase (which was due to wellbore stability concerns).

- So ROP is slowed from 13,000’ onwards.
- Halved from 150 – 200’/hr, and additional circulating.

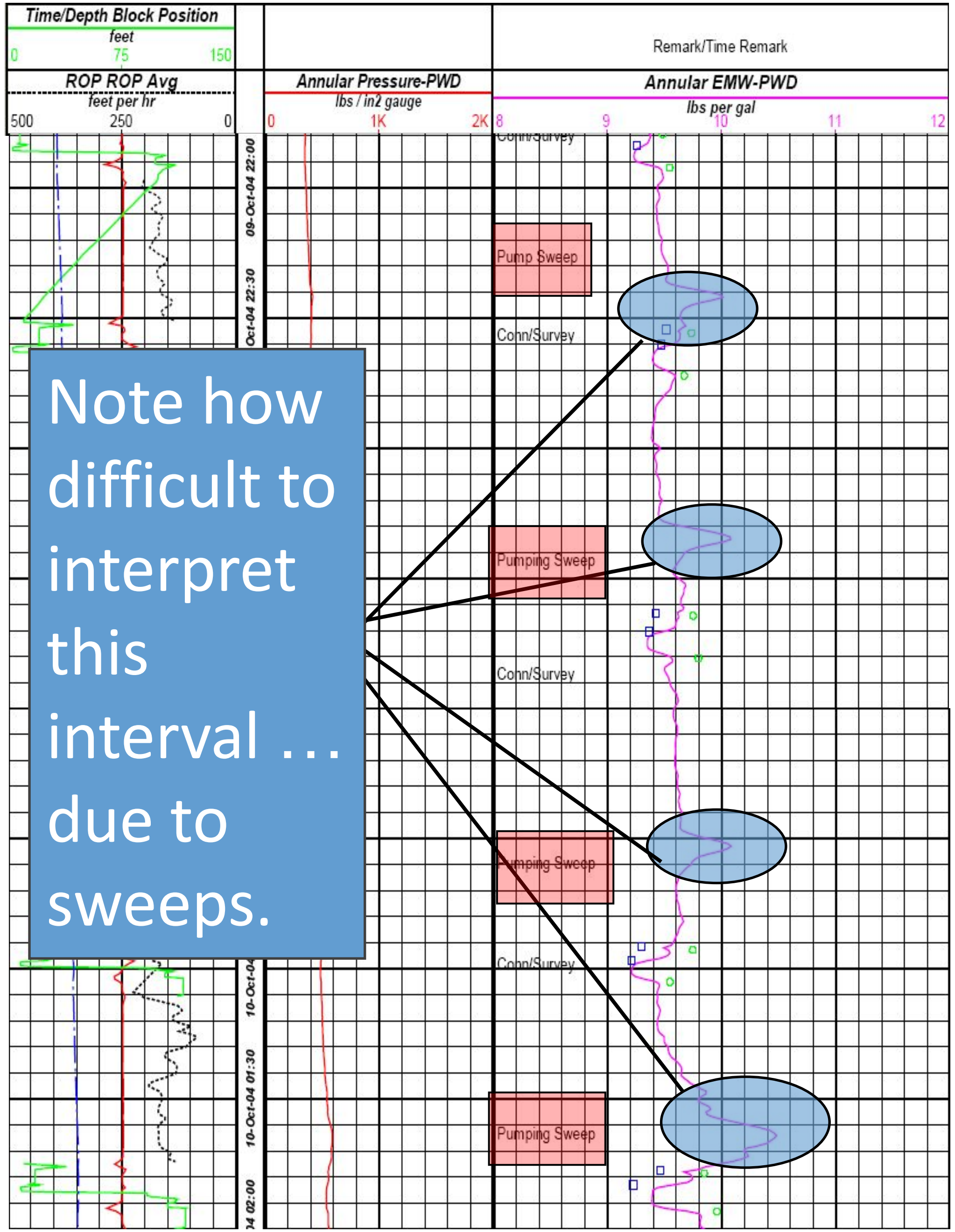


- After having "fixed" this hole cleaning problem, ROP is again significantly reduced for the last part as a precaution.

- But it turns out that when mud properties and ROP are accounted for, everything is "normal".

Sweeps effect ECD.

- Concentrated cuttings load in vertical hole can result in ECD spikes.
- Very sensitive to weighted, high-vis sweeps.
- Makes PWD hard to interpret.



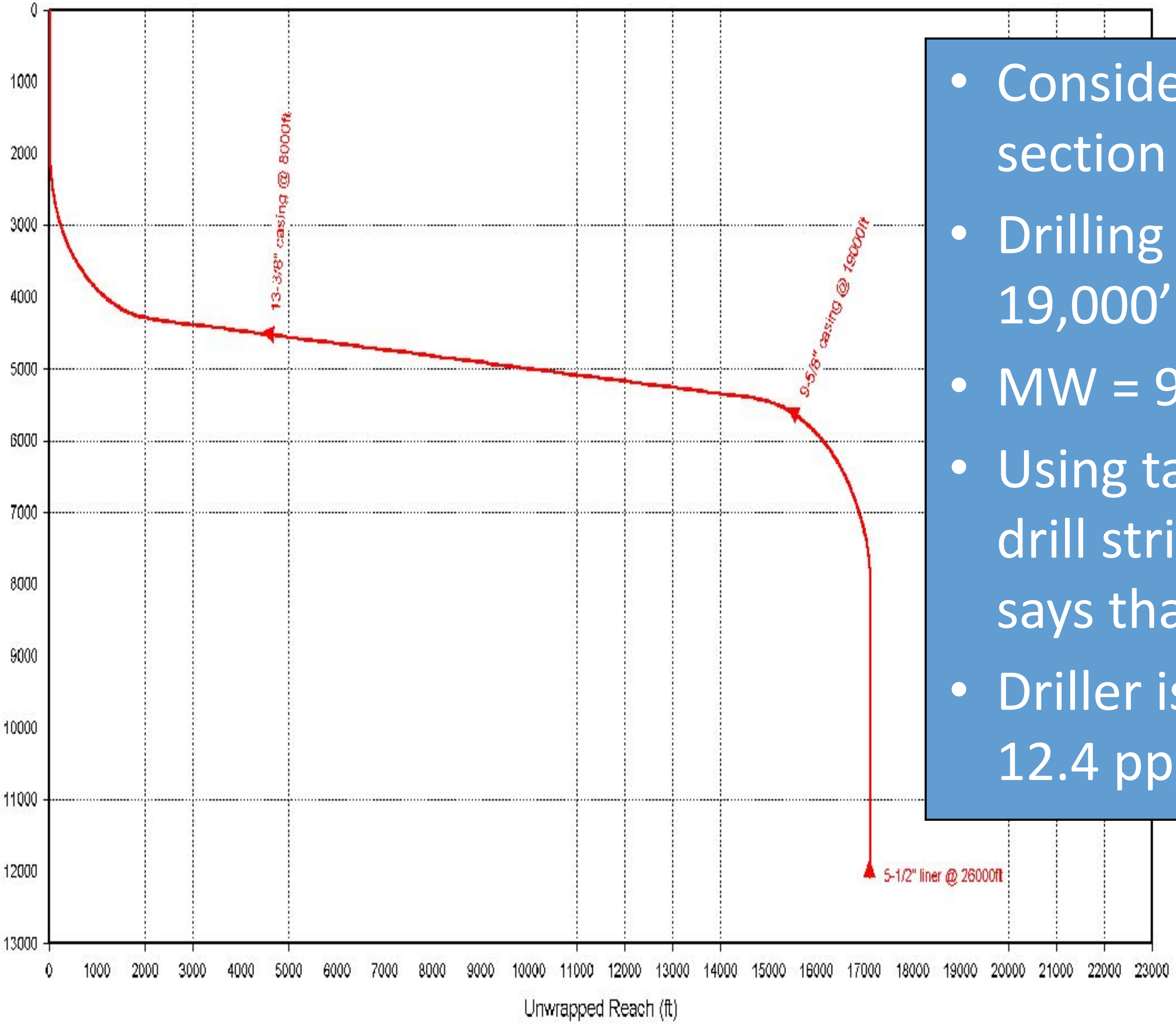
ECD management.

UNDERSTANDING THE PRESSURE WHILE DRILLING TOOL.

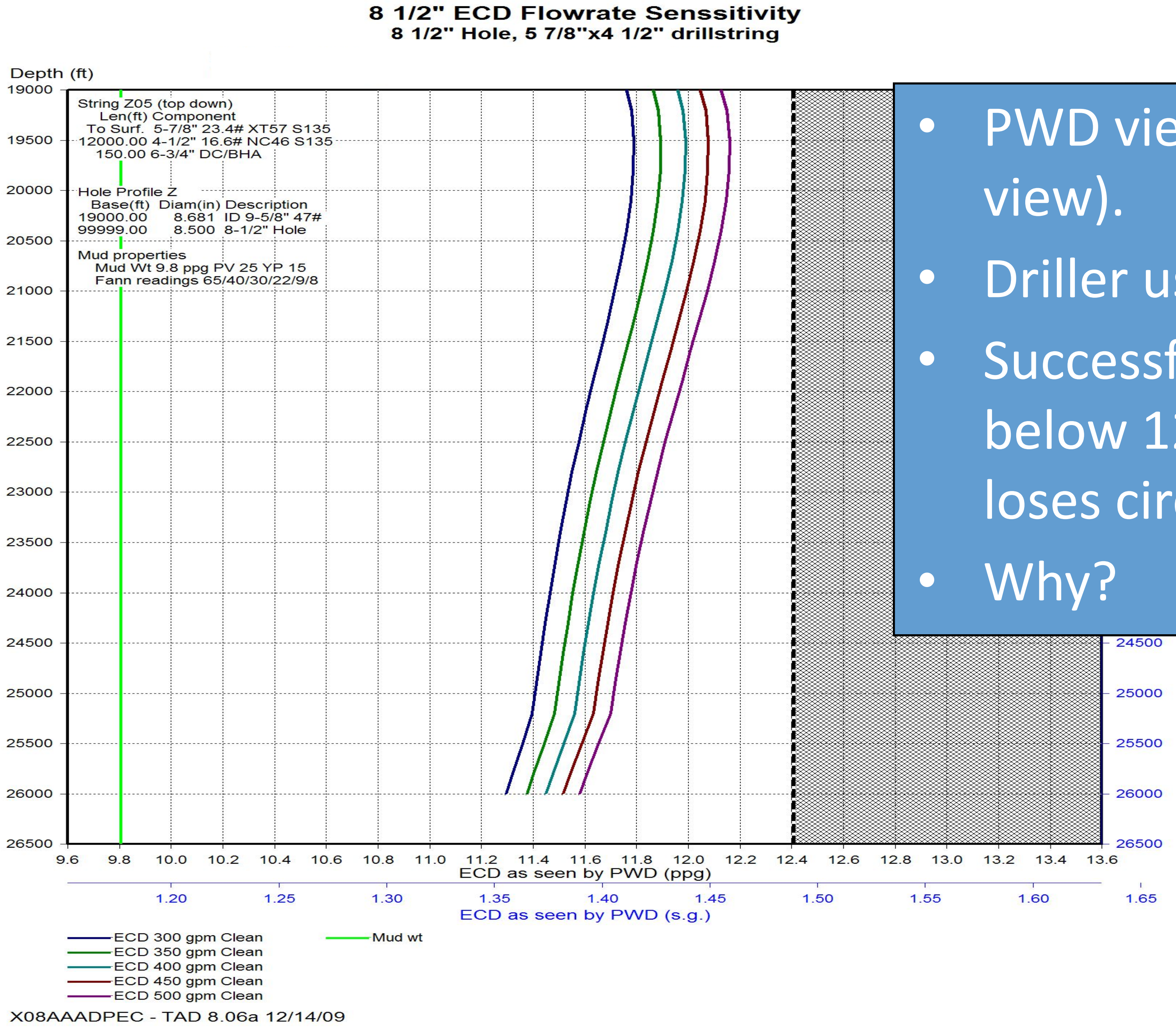
Understanding PWD.

- PWD doesn’t always see the “worst case load”

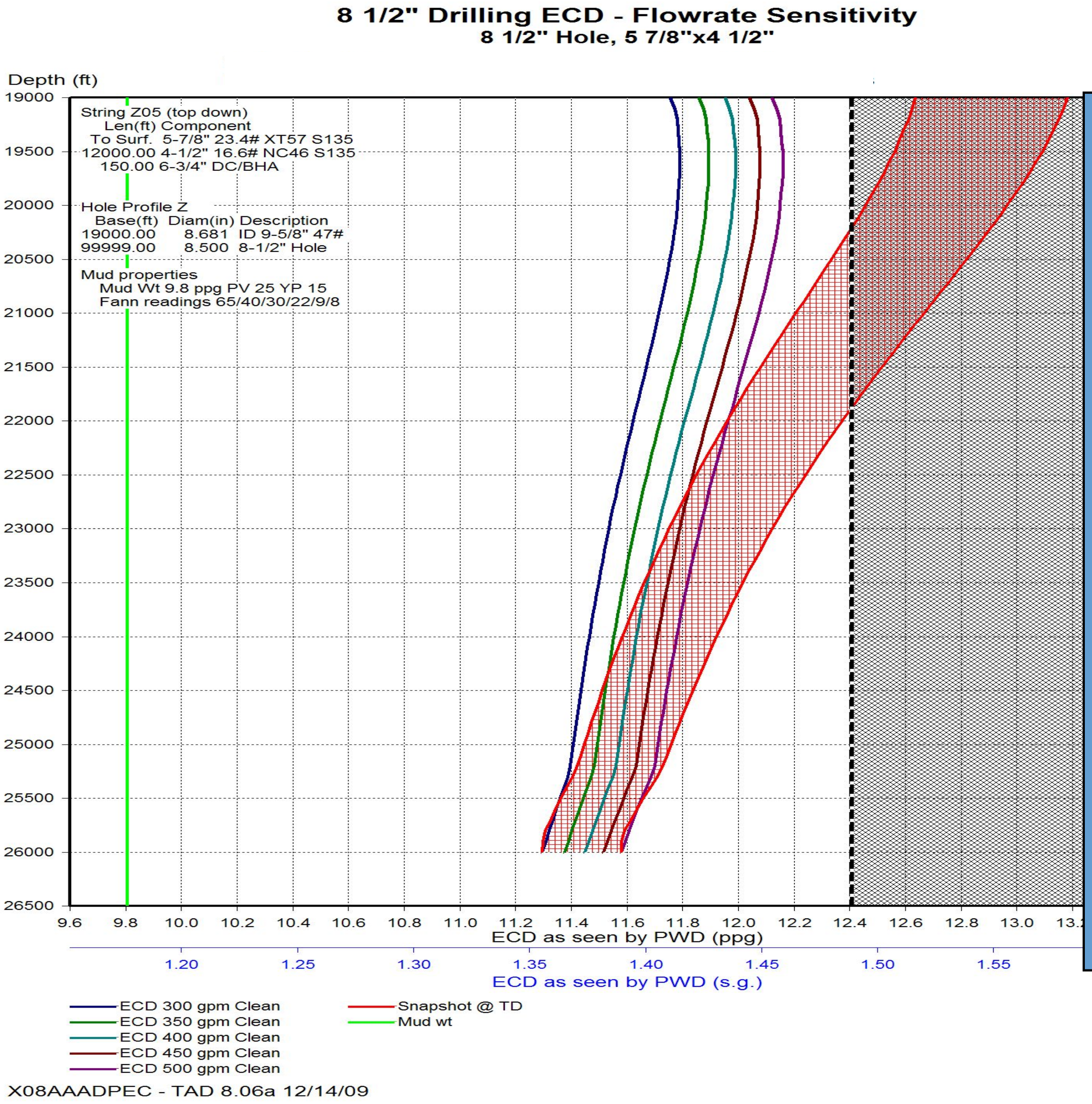
  a. S- type wells.
  b. Tapered drill strings.
  c. Varying mud properties.
  d. BHA restrictions.



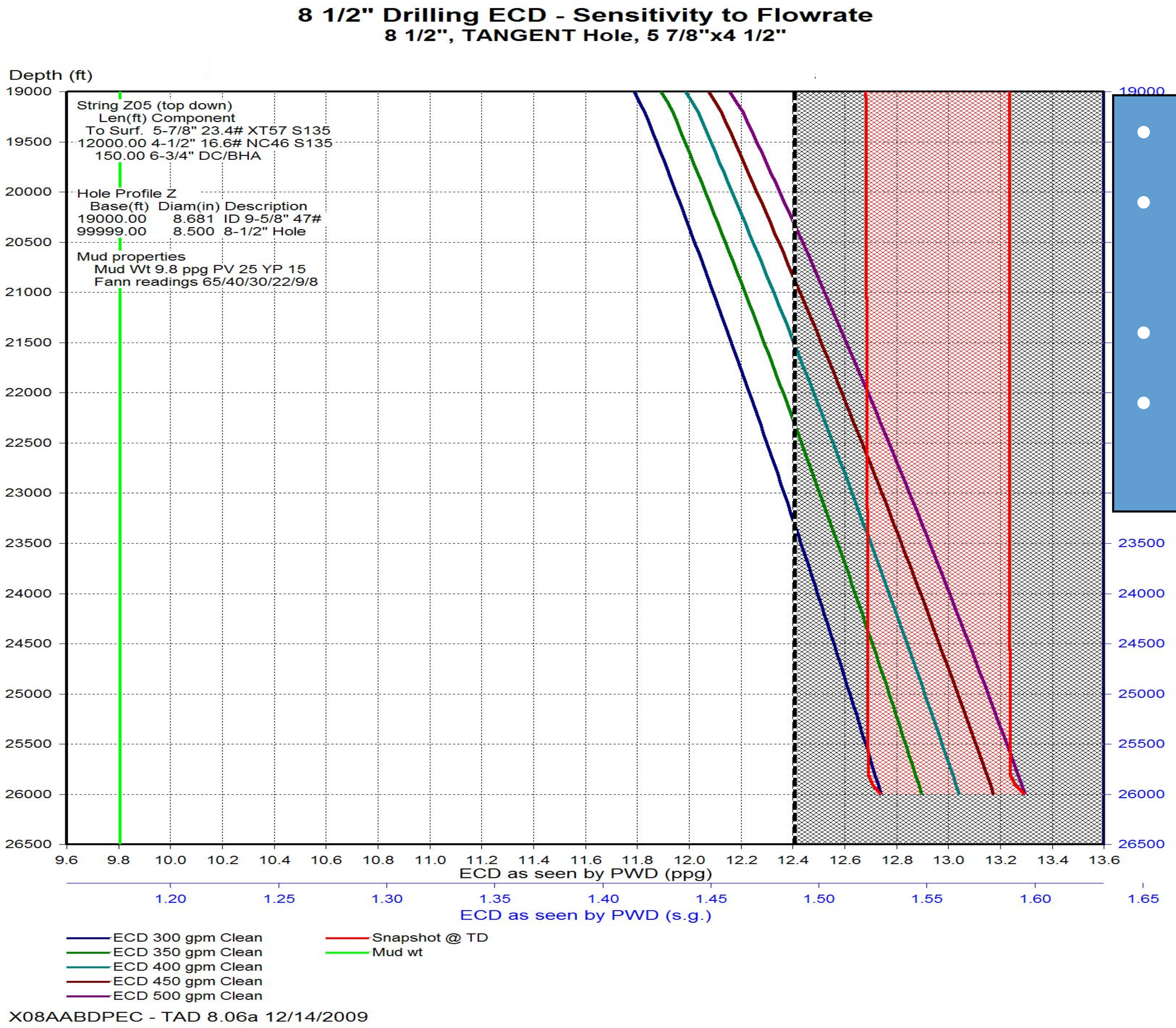
- Consider ECDs for 8 ½" section of S-path well.
- Drilling 8 ½" hole from 19,000' to TD.
- MW = 9.8 ppg
- Using tapered 4 ½" x 5 ⅞" drill string, since modeling says that this is OK at TD.
- Driller is told to keep below 12.4 ppg fracture gradient.



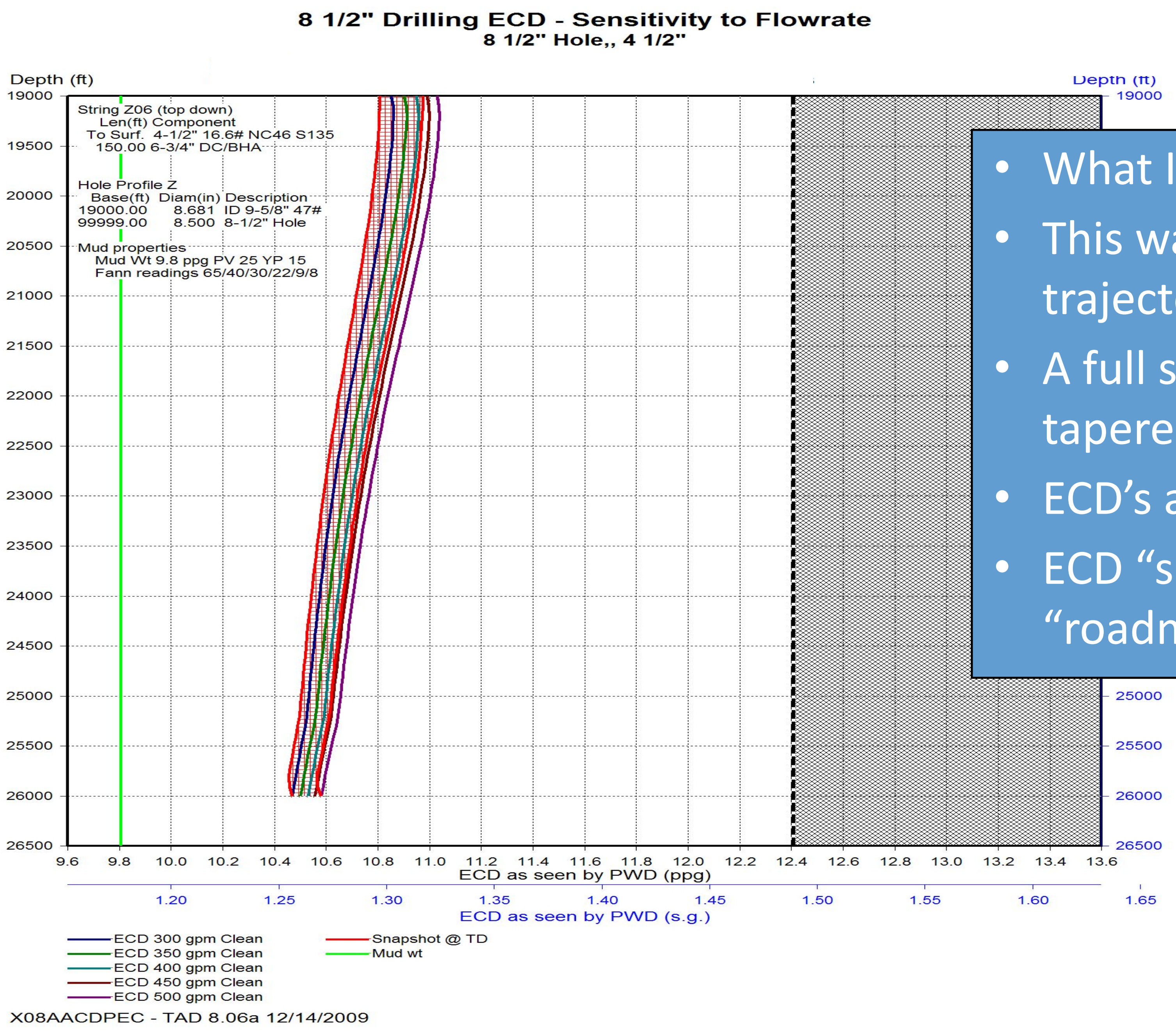
- PWD view of ECDs (roadmap view).
- Driller uses PWD.
- Successfully keeps ECDs below 12.4 ppg, but still loses circulation.
- Why?



- SNAPSHOT view of ECDs when at TD.
- ECDs at TD are OK, but …
- ECDs have grown at the shoe (unseen to PWD).
  - Was only 12.2 ppg when the bit was at the shoe, but has now grown to > 13.0 ppg
- Why?
  - S-path well masks ECDs
  - Tapered drill string masks ECD growth.



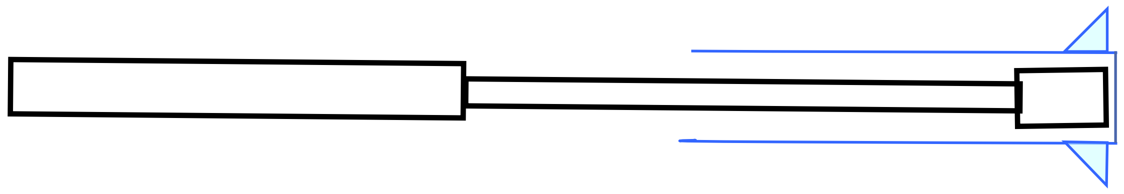
- What If…
- This had been a B&H well-path?
- Continual ECD growth.
- ECD “felt” at TD = ECD “felt” at shoe.



- What If…
- This was still a S-Path trajectory, but…
- A full string of 4 ½” (rather than tapered).
- ECD’s are dramatically lower.
- ECD “snapshot” mimics the “roadmap.”

Understanding PWD.

- This is how most operations design the drill string for 8 ½” or smaller hole…
  - Typically, a tapered drill string is used (say 5”x 5 ½”).
    - With the amount of small pipe = open hole length.
    - Which means this scenario is quite common.



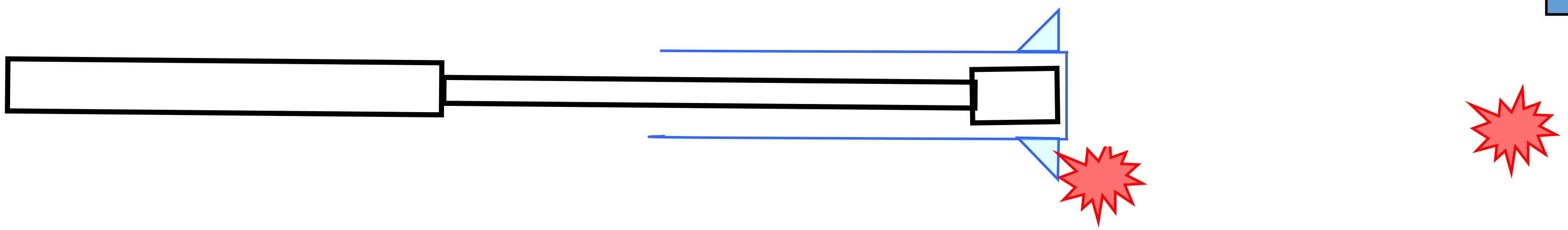
Understanding PWD.

1. Initial situation while drilling: no losses at shoe. (say, ECD = 12.0 ppg).

2. When drilling later on, losses occur (say PWD shows ECD = 12.4 ppg. LCM is spotted at bit.

but LCM is ineffective. As expected in hindsight if losses are at shoe (say, which has increased ECD to 12.7 ppg).

3. Snapshot view is necessary to understand where to spot LCM.

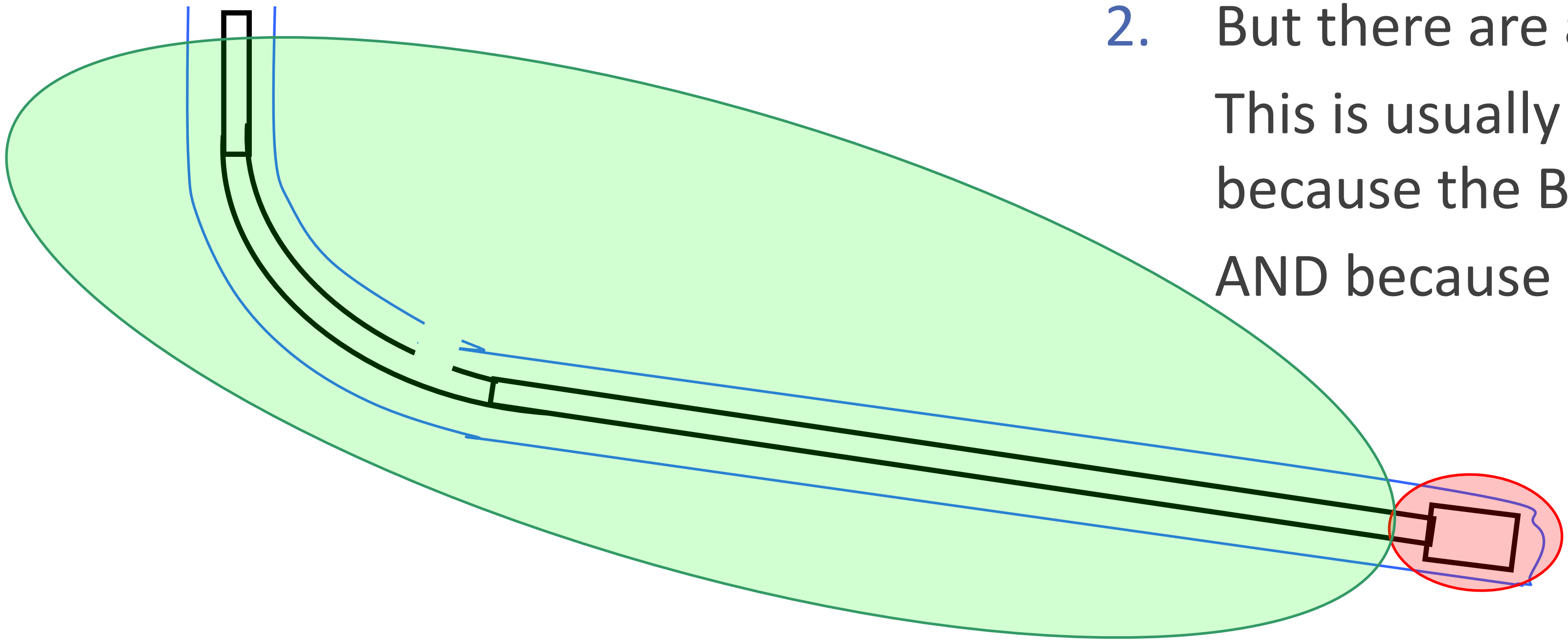


Understanding PWD.

- PWD measured ECDs are made up of 2 components

1. Overall annulus (around drill-pipe, etc.)

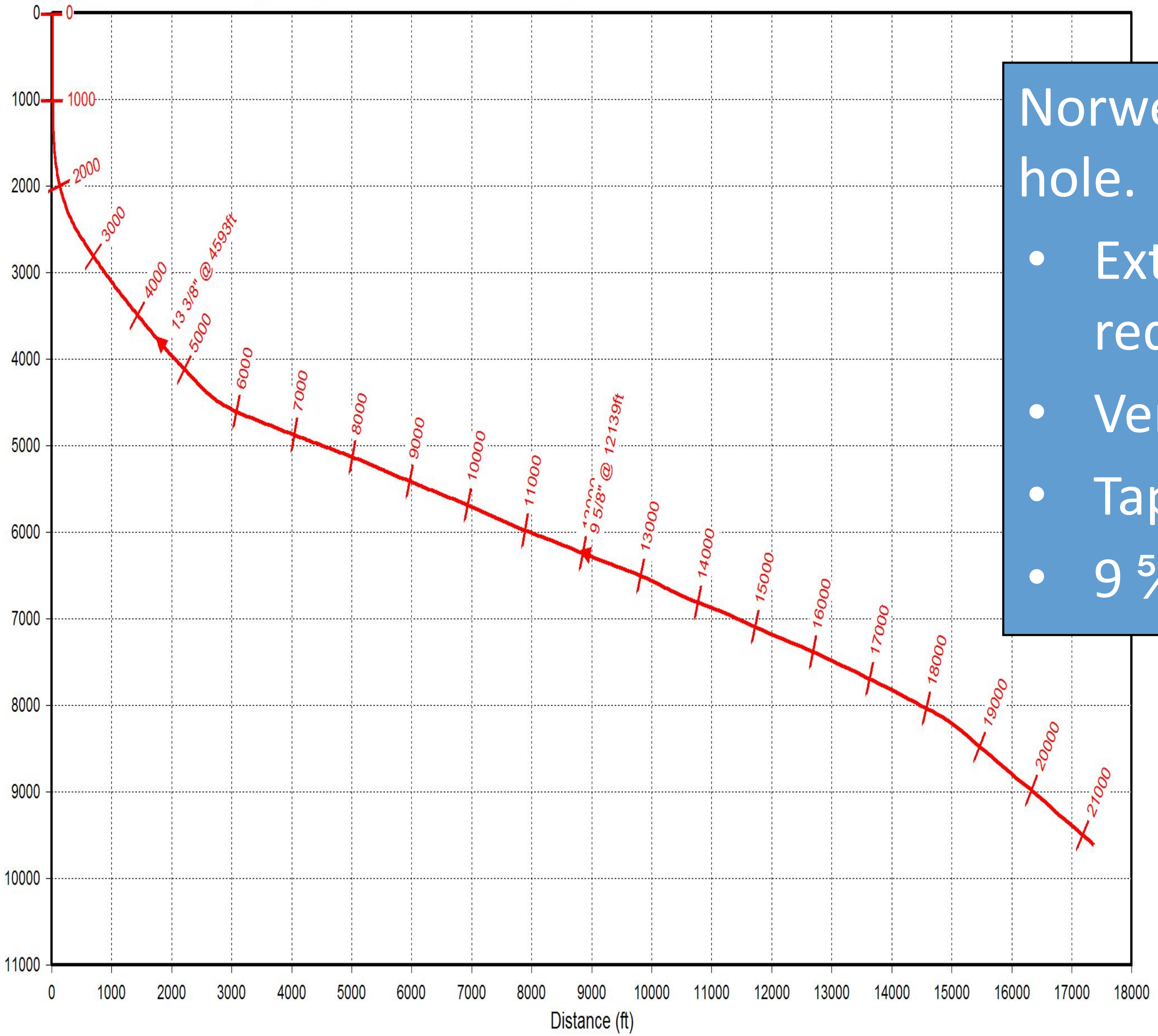
   This is what we normally think of for the ECDs



2. But there are also **Near BHA effects**

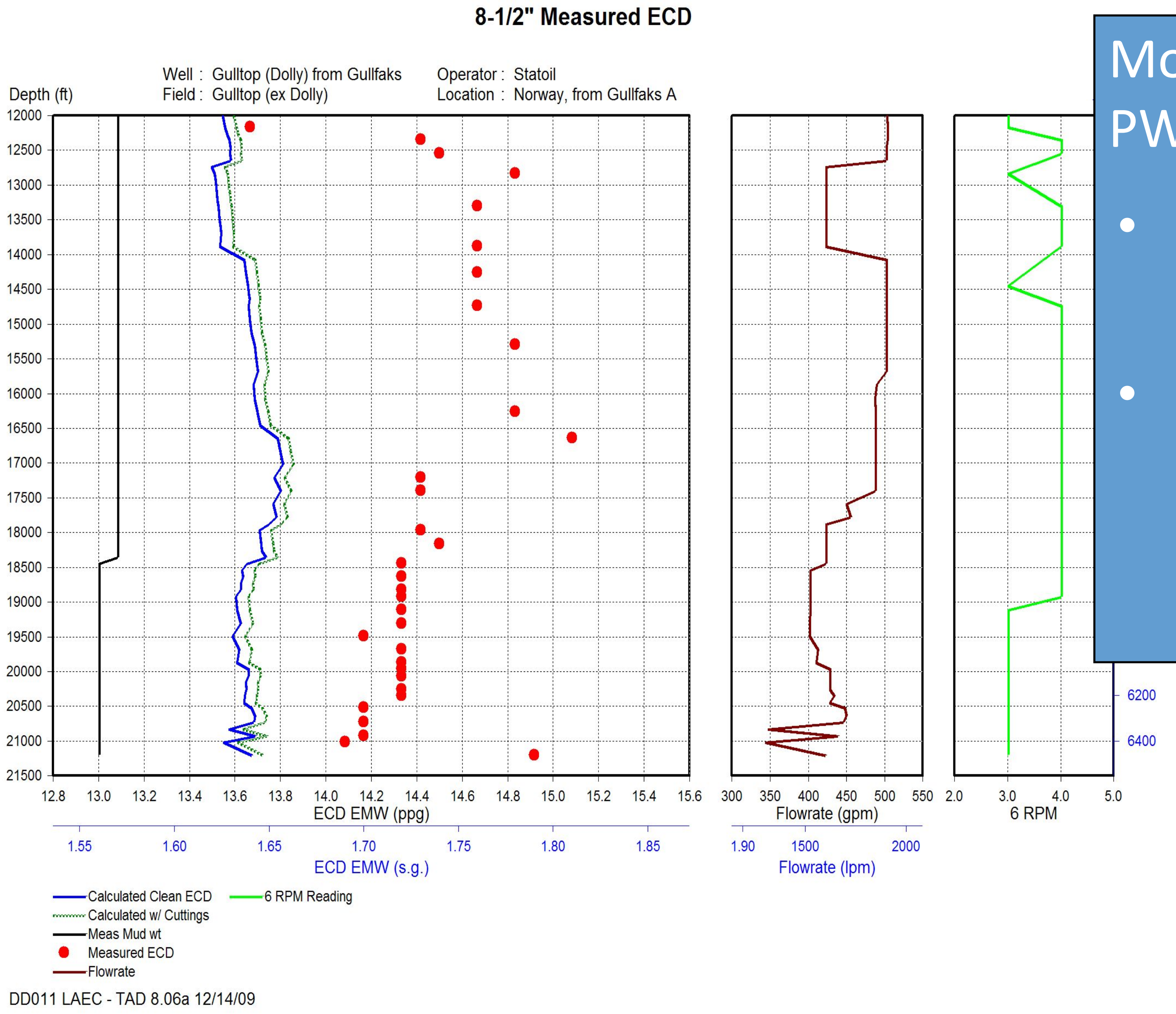
   This is usually assumed negligible because the BHA is so short

   AND because PWD rarely sees this



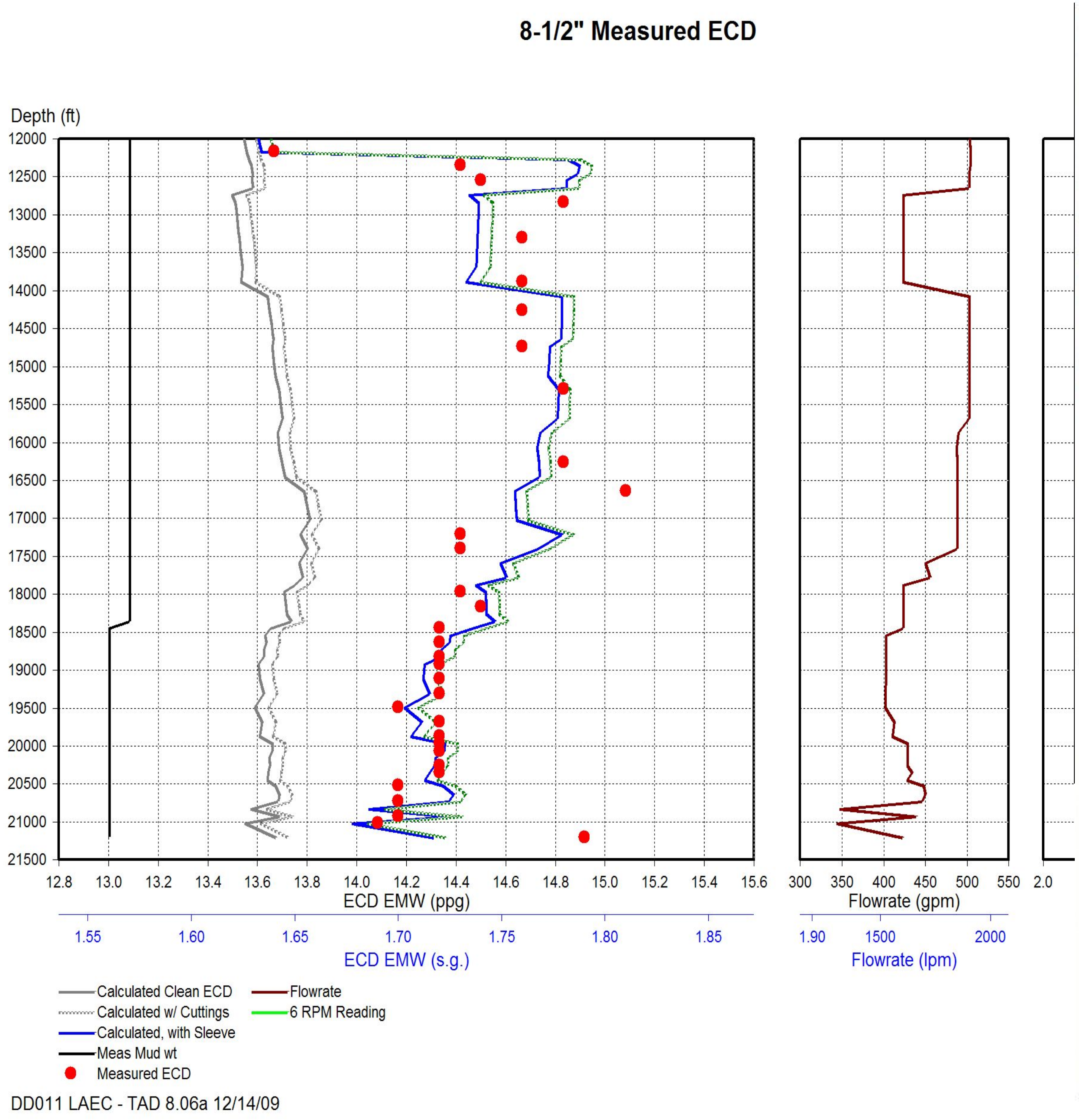
Norwegian well, drilling 8 ½" hole.

- Extreme efforts made to reduce ECDs.
- Very thin mud.
- Tapered drill string.
- 9 ⅝" casing run as a liner.

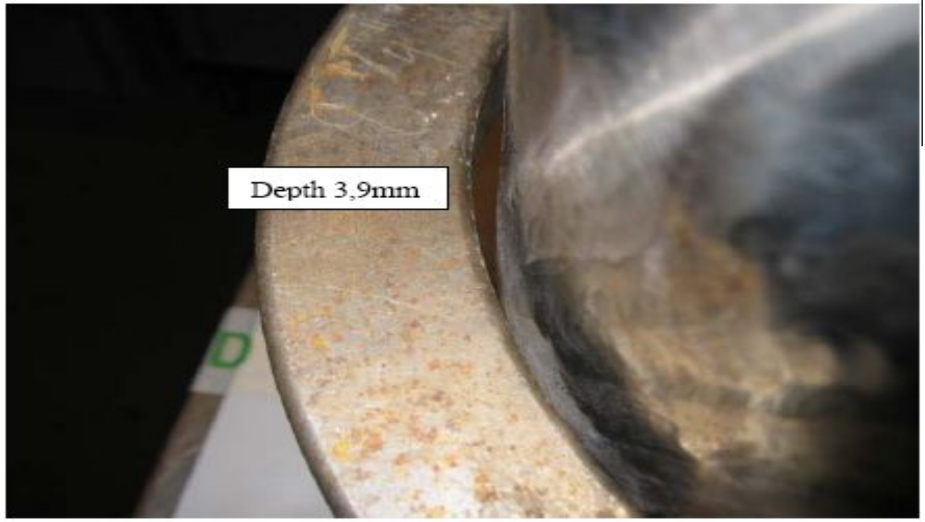


Model doesn't follow PWD readings.

- Error is 1.3 ppg falling to 0.8 ppg EMW.
- Even gross changes in mud properties cannot explain the results.


8-1/2" Measured ECD
Depth (ft)
ECD EMW (ppg)
ECD EMW (s.g.)
Flowrate (gpm)
Flowrate (lpm)
Calculated Clean ECD
Calculated w/ Cuttings
Calculated, with Sleeve
Meas Mud wt
Measured ECD
Flowrate
6 RPM Reading
DD011 LAEC - TAD 8.06a 12/14/09


3 pcs blades


Depth 3,9mm


TORQ


TOR-TORQ

Which of the following statements about drilling ECD (PWD tool data) is incorrect?

a. ECD will always be highest at TD in any hole section (assume no use of MPD).
b. YP (as recorded by the mud engineer on the DMR) will not have a significant influence on ECD.
c. Bit balling will not have any effect on ECD.
d. Rotary speed will influence ECD, especially in smaller hole sizes.
e. An increase in ECD could indicate hole cleaning has improved.
f. Reducing the D50 of the barite weighting aged will increase ECD.


Coffee
Time!

Which of the following statements about drilling ECD (PWD tool data) is incorrect?

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e. An increase in ECD could indicate hole cleaning has improved.

f. Reducing the D50 of the barite weighting agent will increase ECD.

ECD management.

ROTATION EFFECT ON ECD.

Critical hole sizes for drilling ECD.

- 8 ½” and smaller sizes are very sensitive to ECD.
- Larger hole sizes are much less affected.
- Most hydraulics models under-estimate ECD.
  - Tool-joints.
  - Torque reduction tools (if used, e.g. NRDPPs).
  - Pipe rotation / spiraling effect.

Rotation effect on ECD.

- So far, we've discussed the need for rotation.
  - It is the only way to clean the hole …
  - But have you noticed that ECDs go up when the RPM is increased when drilling 6" or 8 ½" hole ?
  - It may actually have more effect on ECDs than changing the flowrate.

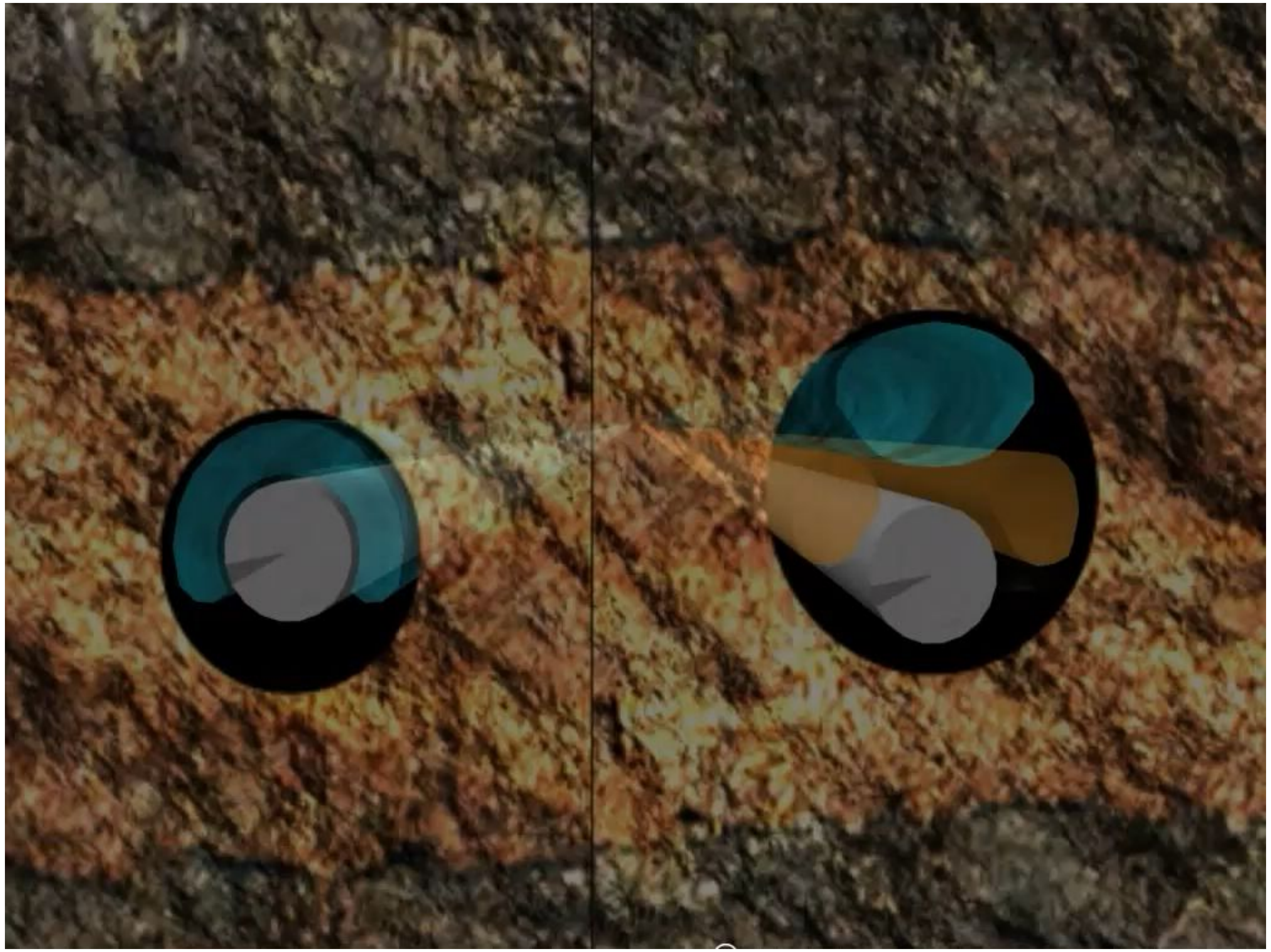
  - High speed rotation in small hole may be very bad.

Rotation effect on ECD.

- How does pipe rotation increase ECD?
  - This is not due to lifting or suspending cuttings …
    - How do we know ?
    - This effect is seen before drilling out the shoe.
    - And effect is as strong as the start, as at the end of the run.
  - What is happening ?

  - High speed rotation causes the fluid to spiral.

Spiral effect on ECD.



Rotation effect on ECD.

- Rotation effect depends on hole & drill-pipe size.
  - Rotation ECD is only a concern in “small hole with big pipe”.
  - ECD is quite insensitive to rotation when hole is big compared to drill-pipe.
  - To dominate ECD, the rotation effect requires a “small hole, big pipe” environment.

Rotation effect on ECD.

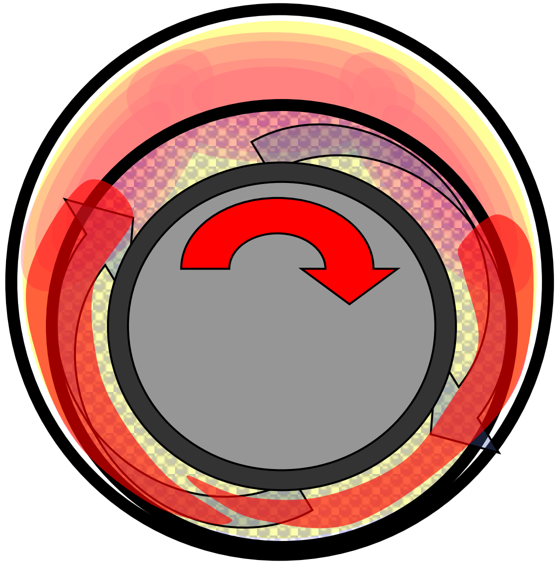
- What drives impact of rotation on ecd.
  - A "small hole, big pipe" situation is needed.
    - RPM is a non-issue in 12 ¼" hole, 9 ½" hole, etc.
    - But ≤ 8 ½" sees a step change in behavior … depending on the DP size.
      - 5 ⅞" DP and 5 ½" DP are VERY SENSITIVE.
      - 5" DP is quite sensitive.
      - 4 ½" DP and 4" DP is insensitive.

Rotation effect on ECD.

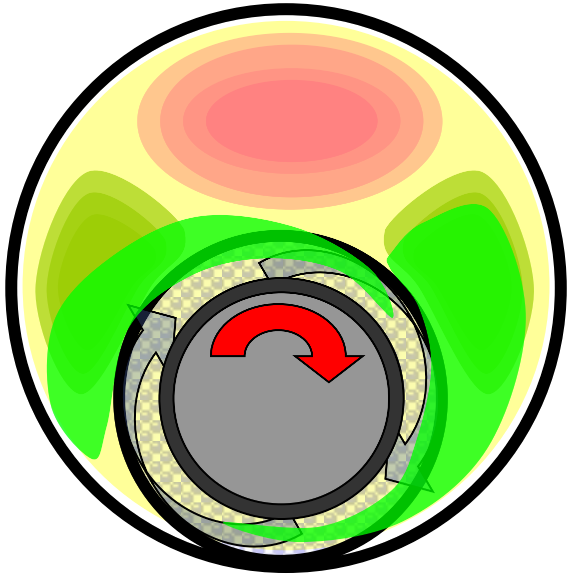
- What drives impact of rotation on ECD.
  - Mud rheology also drives RPM effect on ECDs.
  - Thicker mud increases rotation effect.
  - Thinner mud decreases rotation effect.
  - Low end rheology is important … not YP.

- Small hole , with a big drill-pipe.
- Very good hole cleaning, but high ECD while rotating.
- So can’t (or shouldn’t) rotate fast.

- But if we solve the ECD problem.
- We can now rotate fast without an ECD problem, but now we have a hole cleaning challenge.



This is scale for 5 ½” DP inside 8 ½” hole.



This is scale for 4 ½” DP inside 8 ½” hole.

Rotation effect on ECD.

- So which compromise do we choose?
  - Easy hole cleaning, but an ECD challenge?

OR

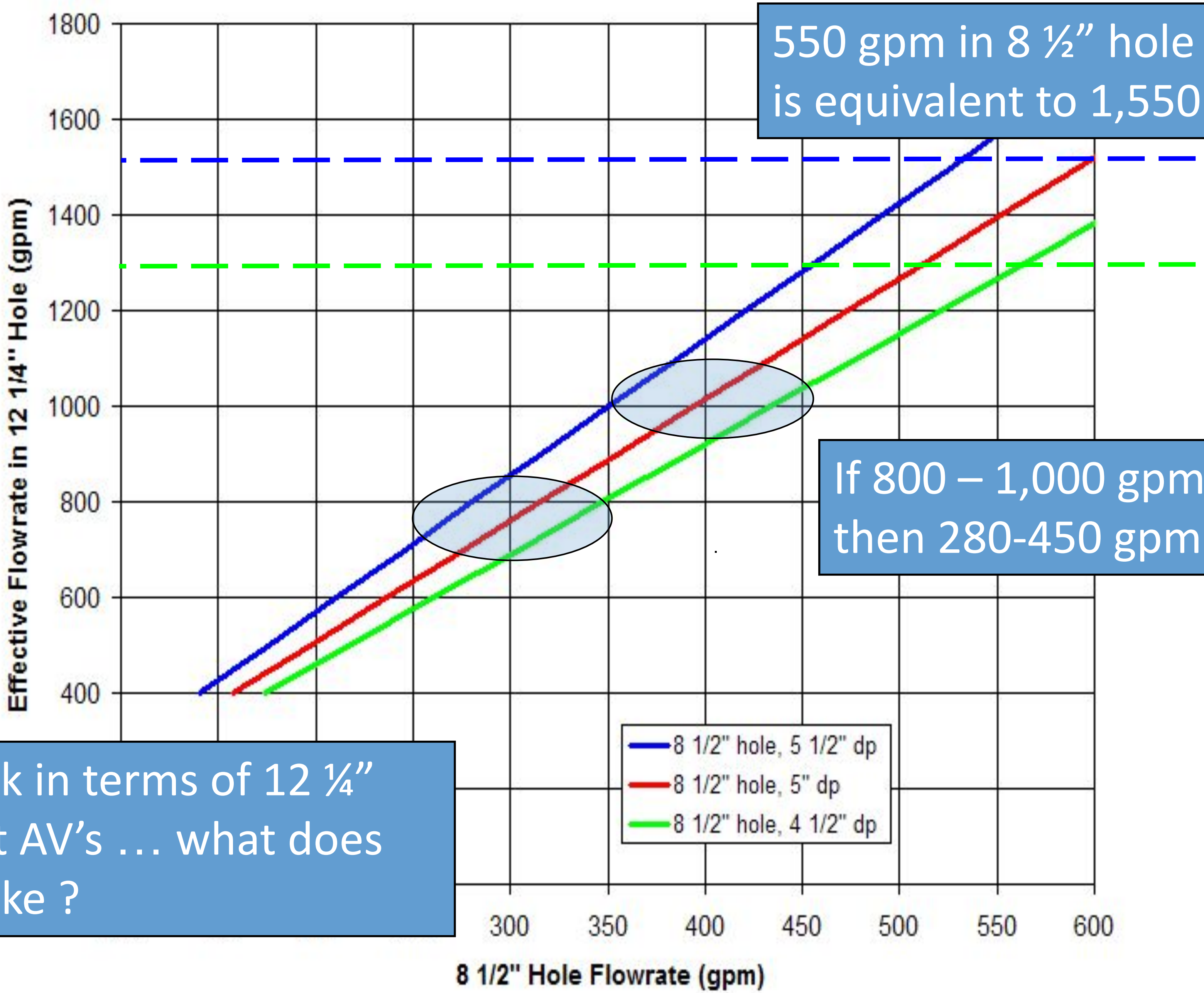
  - Acceptable ECDs, but a hole cleaning challenge?
  - If ECDs are NOT a limitation, prioritize on hole cleaning efficiency.
  - But if ECDs are the primary issue, ALWAYS solve ECDs.
    - ECDs are a design problem and solution.
    - Hole cleaning is easy. All you need is high RPM and patience.

ECD drivers.

- A common thought in drilling planning is that flowrates will be unacceptable if smaller pipe is used.

  - For example, in 8 ½” hole.
    - Maybe only able to pump at 350 – 450 gpm instead of 600 gpm.
  - The flowrates our industry uses in 8 ½” hole are nuclear drilling
    - If you aren’t willing to consider drilling at lower flowrate in 8 ½” hole, how can you justify drilling 12 ¼” hole … see next plot.

550 gpm in 8 ½” hole with 5 ½” drill-pipe is equivalent to 1,550 gpm in 12 ¼” hole!

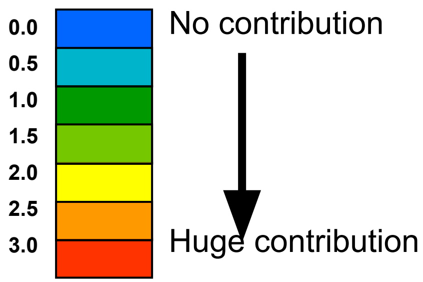


If 800 – 1,000 gpm is acceptable in 12 ¼”, then 280-450 gpm is acceptable in 8 ½”

If you think in terms of 12 ¼” equivalent AV’s … what does this look like ?

ECD drivers.

Hole Size	Drill Pipe	Tool Joint	Flowrate	Rotation	Rheology	ROP
17½”	Any					
12¼”	Any					
8½”	≥5 ½”					
8½”	5”					
8½”	4 ½”					
6½”	4”					
6½”	3 ½”					



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ECD management in high-angle and complex wells.

MODULE 1

ECD management in high-angle wells vs vertical wells.

WHAT IS DIFFERENT.

ECD management.

ECD is the term given to the total pressure acting on the wellbore. Drilling professionals generally use it to indicate when circulating increases pressure and when pipe movement (surge and swab pressures) causes an increase or decrease in pressure.

It is expressed as a density in the same units as the mud weight.

ECD management.

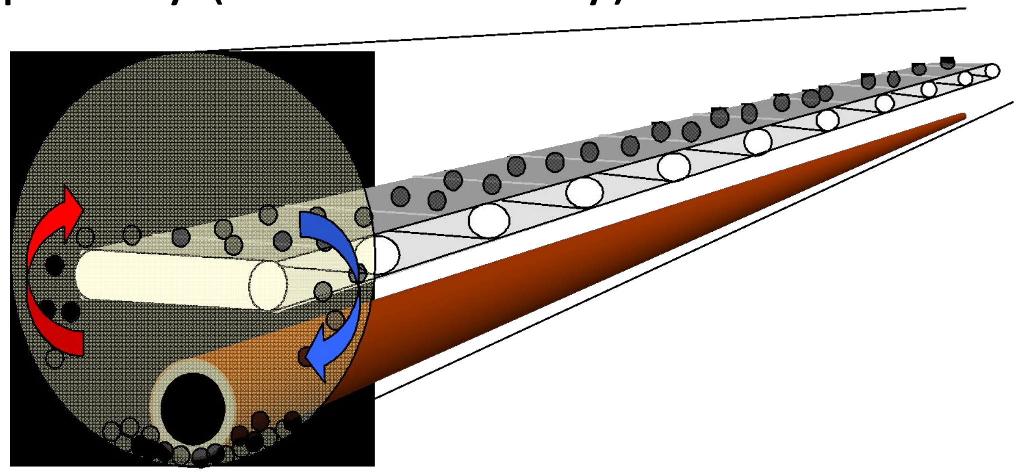
In this module we discuss the following.

1. Understanding ECD.
   - Why high-angle wells have higher ECDs.
   - Magnitude of ECD fluctuations.
   - What problems ECDs cause.
   - What PWD can and cannot tell you.

2. Options to reduce ECD.
   - Planning stage.
   - Implementation stage.

What is different.

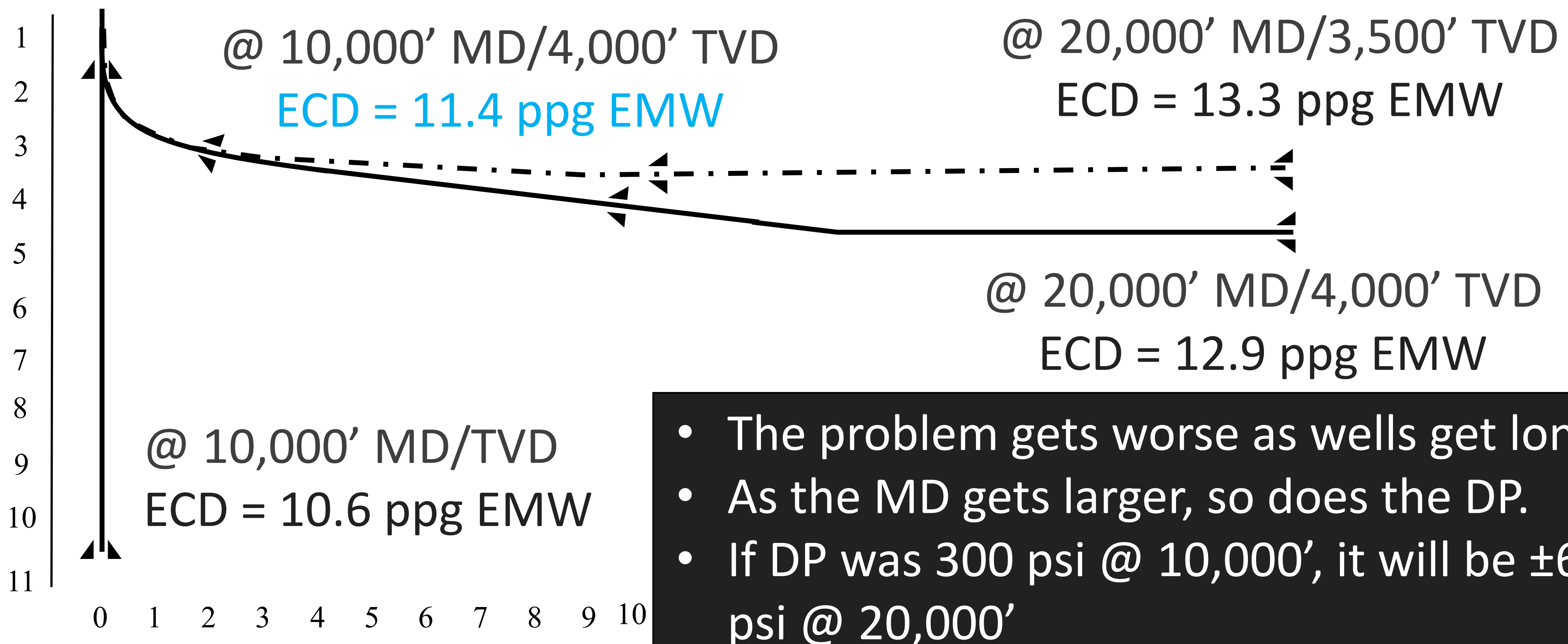
1. Hole cleaning.
    - Cuttings behavior is very different.
    - What works at low-angle doesn't work at high-angle.
    - In low-angle wells, hole cleaning is important, but is relatively easy.
    - In high-angle wells, hole cleaning is the #1 priority (and is not easy).
    - "Clean" Hole is actually a myth…



What is different.

2. ECD management.
   - Well example.
     - 2 wells with the same MW, 10 ppg and annular pressure loss at 10,000 ft MD.
     - One well is vertical the other a shallow - TVD extended reach well.
     - ECD is much greater in the shallow – TVD extended reach well.

…AND a slight decrease in TVD has a large effect on EMW.



- The problem gets worse as wells get longer!
- As the MD gets larger, so does the DP.
- If DP was 300 psi @ 10,000’, it will be ±600 psi @ 20,000’

What is different.

3. Tripping / Wiper tripping.

   - Tripping practices are critical in horizontal wells.
   - Stuck pipe practices must be different in horizontal wells.
   - Value and meaning of wiper trip is different.

     - They don’t clean the hole.
     - May induce shale instability problems due to cyclical fatigue.
     - There are better ways to monitor hole conditions.

Tripping in a high-angle well.

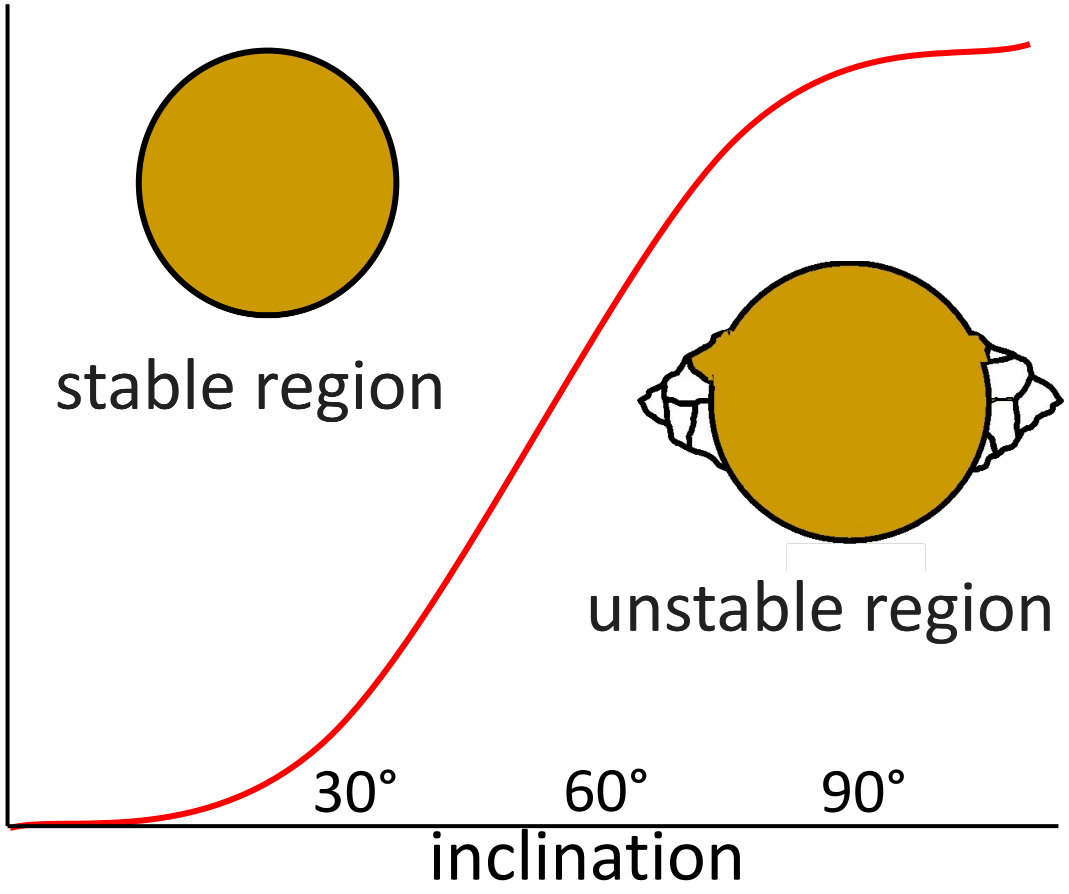
What is different.

4. Wellbore instability.

   - Time sensitive is often perceived to be a problem.
   - High-angle wells usually requires more mud weight for stability.
   - More likely to be exposed to “un-conventional” instability.
     - Fatigue, hydraulic hammer, bedding plane.

What is different.

5. Wellbore instability.



What is different.

6. Mud properties.
   - Good vertical hole rheology, is not good in a horizontal well.
     - But both high-angle and vertical sections must be cleaned.
   - Barite sag can become a problem.
   - ECD behavior is much more sensitive to mud properties.
   - Inhibition is critical in shale / clays.
   - Lubricity is especially important when “conventional” drilling techniques are being used.

What is different.

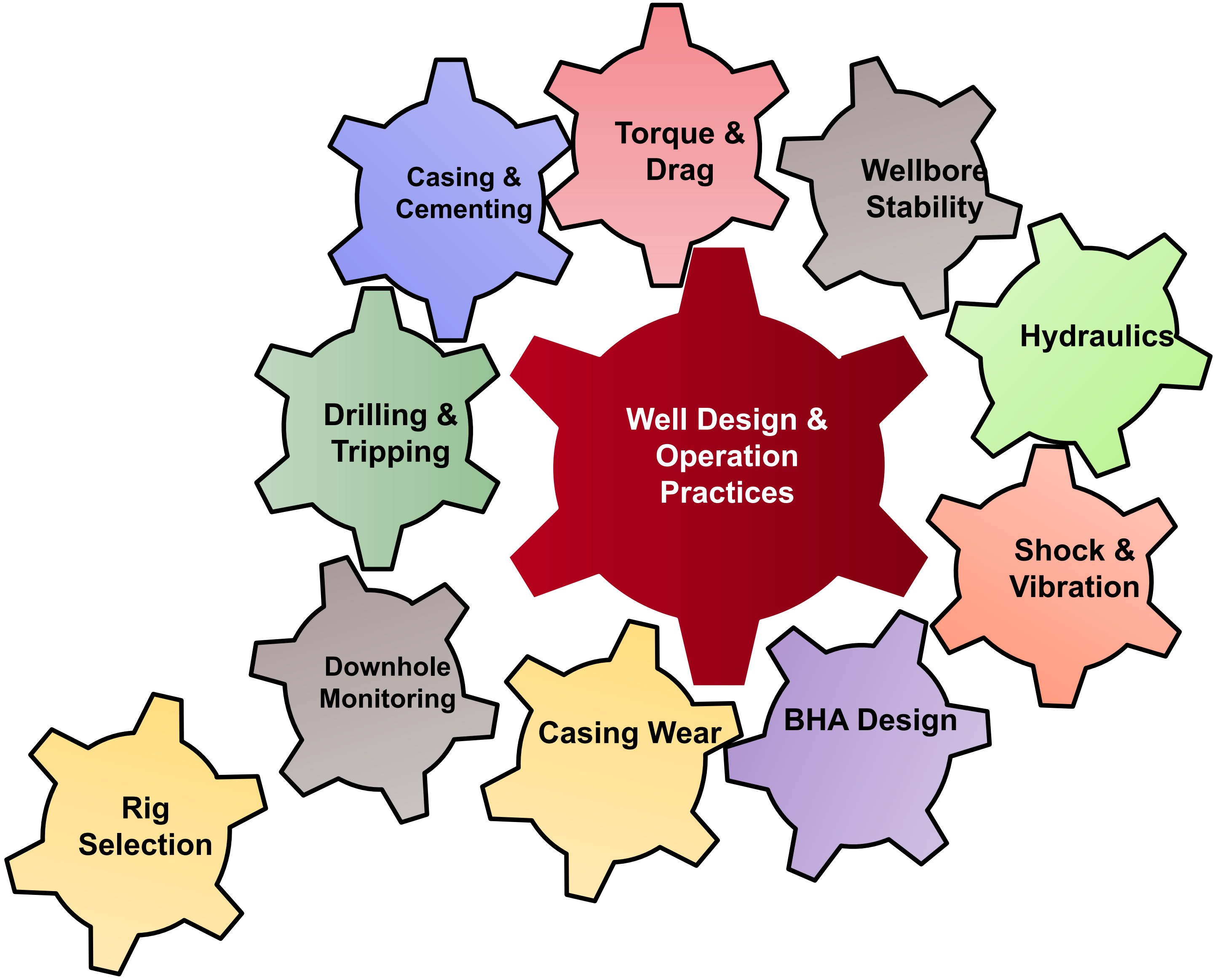
7. Hole condition monitoring.
   - The important data is quite different.
   - Torque and ECD are both of little value for hole cleaning.
   - Slack-off and Pick-up loads are the most critical.
   - The interpretation of trends is different.
   - Data by itself is less useful than on a vertical well.

ECD management in high-angle wells vs vertical wells.

HOLE CLEANING, ONE BIG ENGINE.

One big engine.

- Each element will have an impact on the entire operation.
- No design or practice can be treated in isolation.
- Hole cleaning needs to be the focal point.


Torque &
Drag
Casing &
Cementing
Wellbore
Stability
Hydraulics
Drilling &
Tripping
Well Design &
Operation
Practices
Shock &
Vibration
Downhole
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ECD management in high-angle and complex wells.

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About the Instructor

Cees Stapel

- ERD / complex wells specialist in engineering, supervision, training and coaching.
- 35 years industry experience.
    - BSc in drilling engineering at the oil and gas university “Noorderhaaks” in the Netherlands.
    - 20 years Baker Hughes as drilling supervisor and senior directional driller.
    - 15 years ERD / complex well specialist. Working worldwide for K&M, Shell, Merlin, GDP and Well Academy.

INTRODUCTION

Avoiding this…

Avoiding this…

Disaster prevention.

What causes most of the train wrecks?

- Mud?
- Iron?
- Lack of data?
- Or is it… people?

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