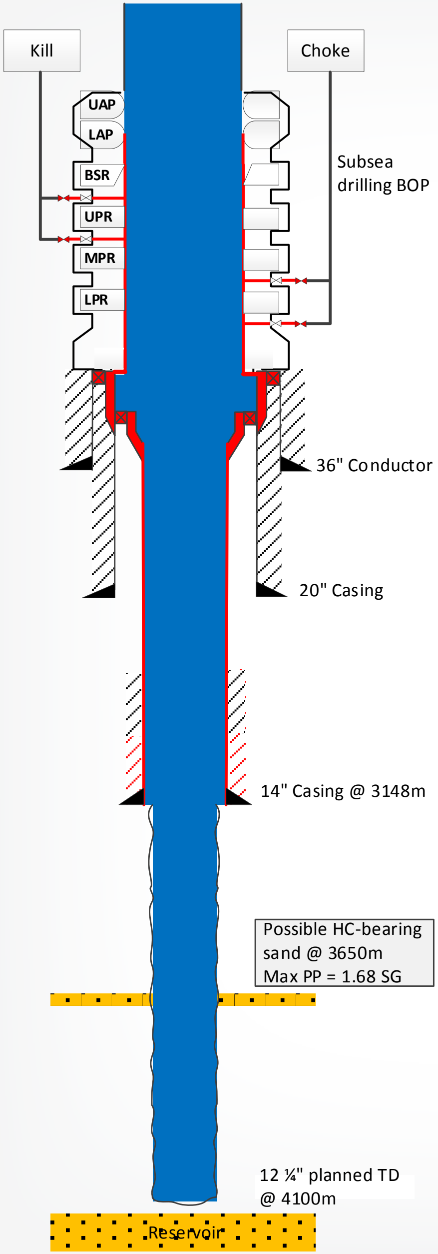
Norsk olje & gass

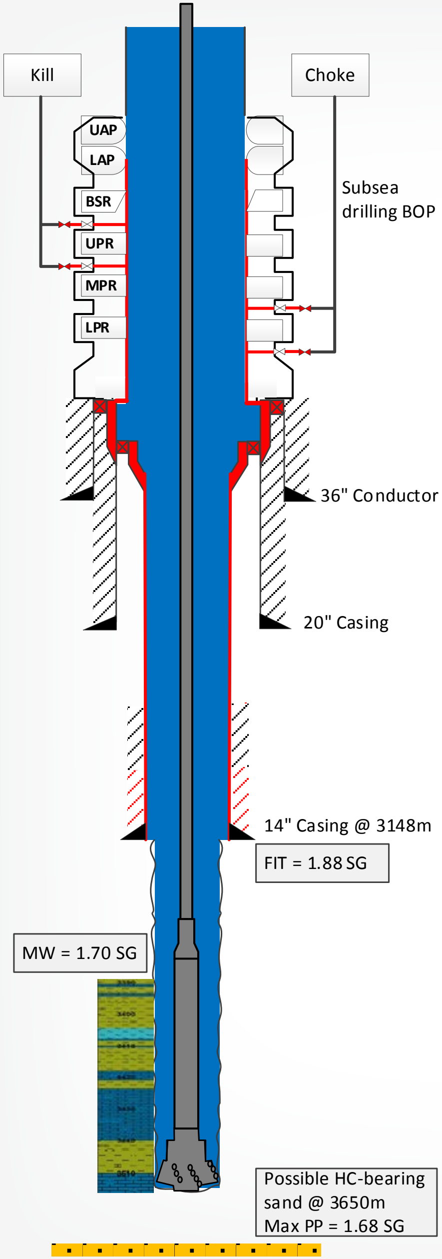
"Sharing To Be Better“

No 19
Serious (yellow) well control incident:
Influx in overburden section of (HPHT) exploration well – MAASP at shoe significantly exceeded



Well status - Exploration well

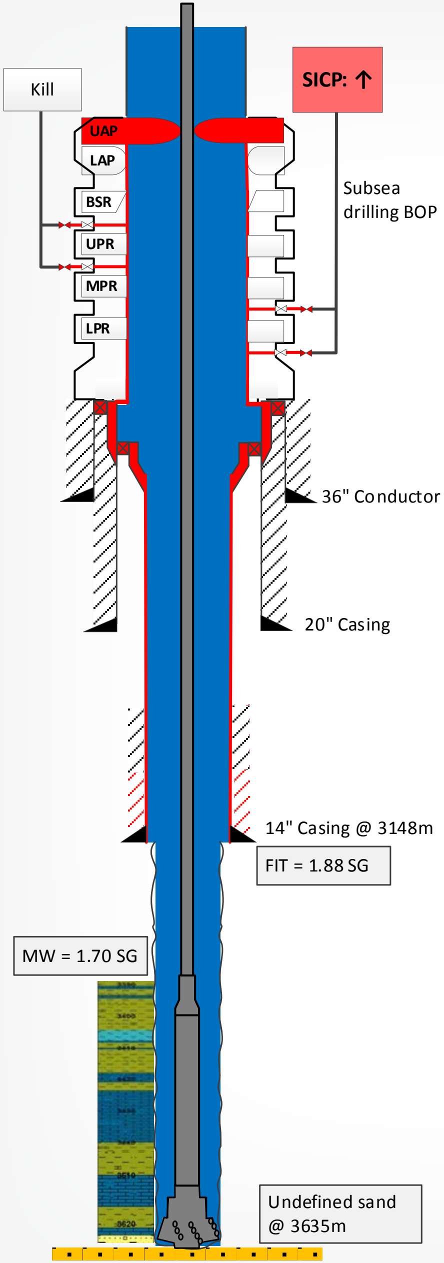
- 12 ¼" section of vertical HPHT exploration well
  - Semi-submersible rig, winter operation, water depth = 92 m
  - 14" shoe set in competent shale @ 3148m MD/TVD
  - Planned 12 ¼" section TD @ 4100m MD/TVD in pressure build-up ramp above HPHT reservoir
- Risk in 12 ¼" section: HC-bearing sand @ 3650m MD/TVD
  - Low probability of sand with flow potential
  - Maximum pore pressure estimated to 1.68 SG
  - Geological uncertainty = ± 50m TVD
- 14" shoe set deep in competent shale. Criteria:
  - Kick margin towards possible HC-bearing sand
  - Kick margin towards pressure build-up in lower part of section
  - Single relief well kill capability (if blowout from possible HC-bearing sand)



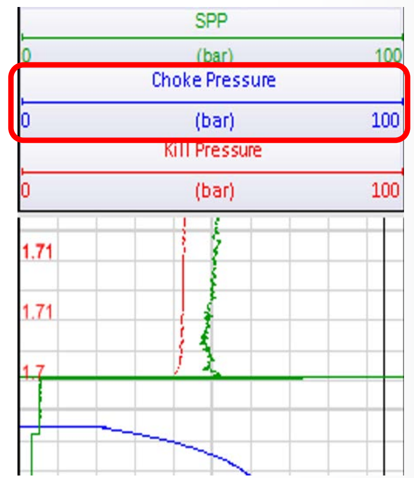
Drilling 12 ¼” section

- FIT @ 14” shoe = 1.88 SG (prognosed formation fracture gradient = 1.89 SG)
- Drilling ahead 12 ¼” section with 1.70 SG oil based mud
  - 0.02 SG above maximum prognosed pore pressure in possible HC-sand
- Selected HPHT drills and procedures implemented from start of 12 ¼” section, as training ahead of full HPHT mode in 8 ½” section
  - Pit drill, kick drill, choke drill
  - Fingerprinting connection flowback volume
  - Instrumentation synchronisation
  - Flowcheck drill breaks (30 minutes)
- Stringers and tight hole experienced while drilling. MWD failure at 3616m. Circulated hole clean and performed round trip to change MWD.
- Question 1: What is the main risk when continuing drilling?

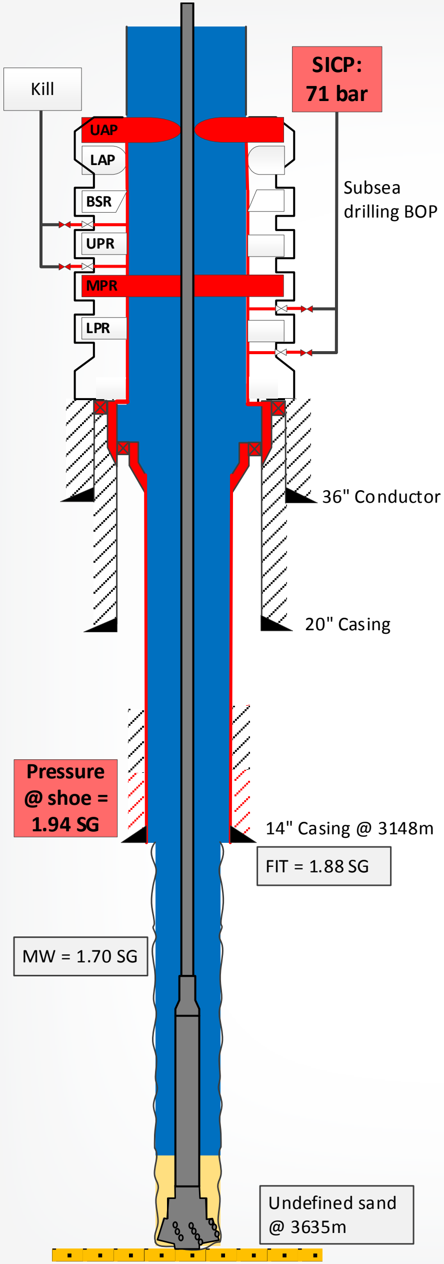
Drill break @ 3635m



- Continued drilling from 3616m, experienced drill break @ 3635m
  - Large increase in ROP and torque
- Pulled off bottom and initiated flow check
  - **1000 l gain observed**
- Shut in well on UAP
- Question 2: What is the theoretical MAASP? (ESD of 1.70 SG mud at bottom hole conditions is ~1.71 SG)
- 5 minutes after shut-in, choke pressure reaches MAASP and continues increasing (see chart >)

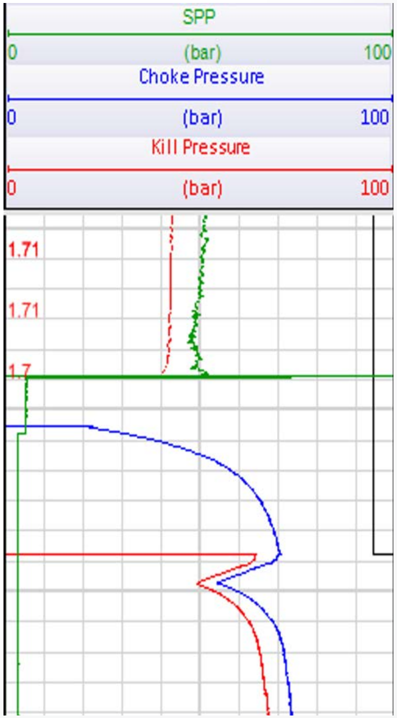


- Question 3: What would you do in this situation? When would you bleed off?

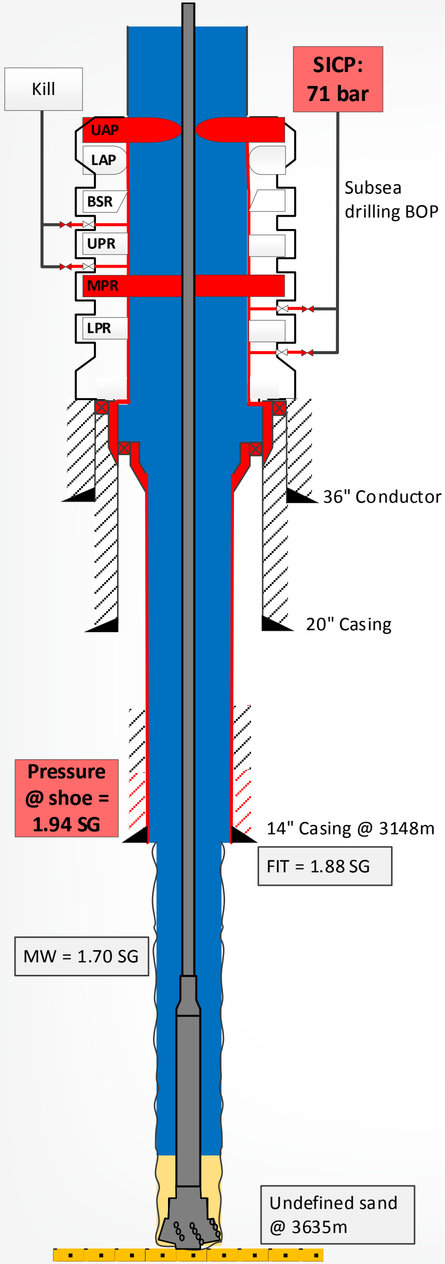


Shut in with SICP >> MAASP

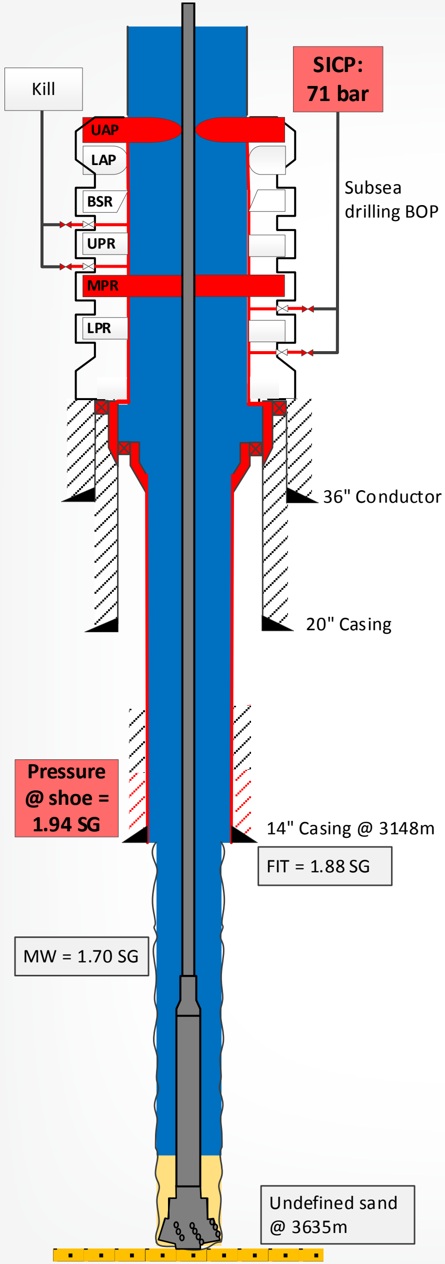
- SICP significantly exceeding theoretical MAASP of 52 bar
  - No explanation of the high pressure, major concern about the casing shoe
- Decided to bleed off to below theoretical MAASP.
  > Bled off 400 l and reduced SICP to 52 bar
  - Pressure rapidly comes back
  - Eventually SICP levels out at <u>71 bar</u>
  - Pumped open floats: SIDPP = 67 bar
  - Pressure at 14" shoe is now <u>1.94 SG</u> (0.05 SG higher than theoretical fracture gradient)
- Question 4: What do your well control procedures say about bleeding off after shut in?
- Spaced out string and closed MPR (fixed ram)
  - As per well control manual to facilitate hang-off and emergency shear if disconnect is required
- Question 5: Any thoughts about BOP configuration?



Evaluation

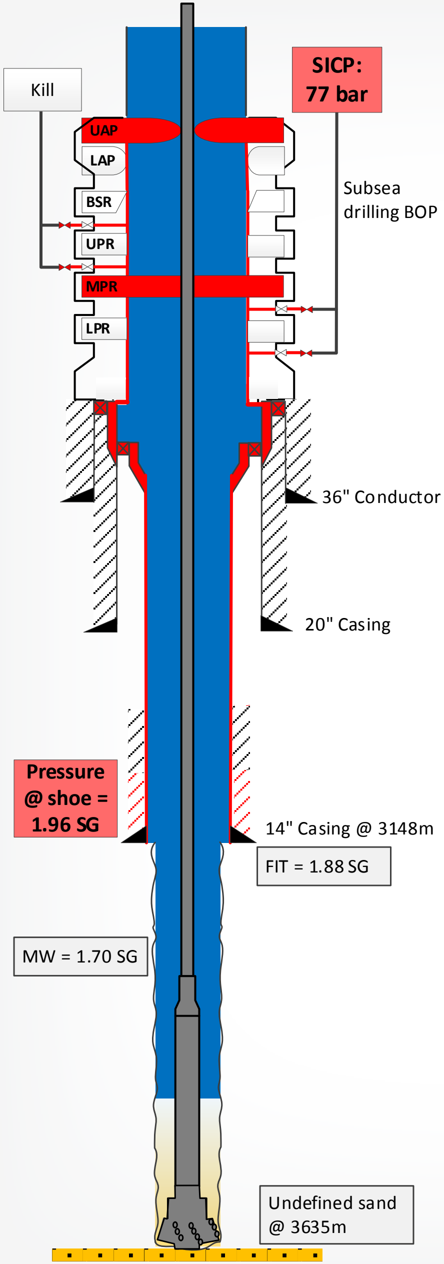


- Based on shut-in readings, pore pressure in the sand is estimated to <u>1.90 SG</u> (0.22 SG higher than maximum estimated pore pressure)
- Total gain = 1400 l
- Question 6: Using the readings of SIDPP and SICP, total gain volume, and 8” drill collars in 12 ¼” hole, which type of influx fluid are we dealing with?
- SICP stable at 71 bar during first 6 hours, no pressure fluctuation observed, indications that 14” shoe is holding pressure
- Question 7: What do you think about the influx behaviour? What are the available well control methods in this situation? What about the risks involved?
- Info: Choke line friction = 1 - 2 bar at 20 spm



Well control – alternatives

- Driller's method / Wait & Weight method
  - Evaluated to require additional 8 bar surface pressure, taking into account a safety margin and expected variation during choke operation
  - $V_{drillstring} > V_{open\ hole}$; Wait & Weight method does not offer advantage of reduced pressure at casing shoe
  - Risk of breaking down formation and initiating cross-flow
  - Handling of potentially large hydrocarbon volumes at surface conditions
- Bullheading
  - Potential for achieving injectivity without breaking down formation?
  - Keep the influx at bottom in case of fracture at shoe
  - 12 ¼" hole size – uncertainty about required rate for bullheading
- Dual gradient / sandwich kill (contingency)
  - Bullheading two different fluid weights; last resort if underground blowout
  - Heavy fluid down drillstring into open hole, light fluid down annulus
- Question 8: Any other thoughts about the proposed alternatives? In your opinion, which alternative should be chosen?

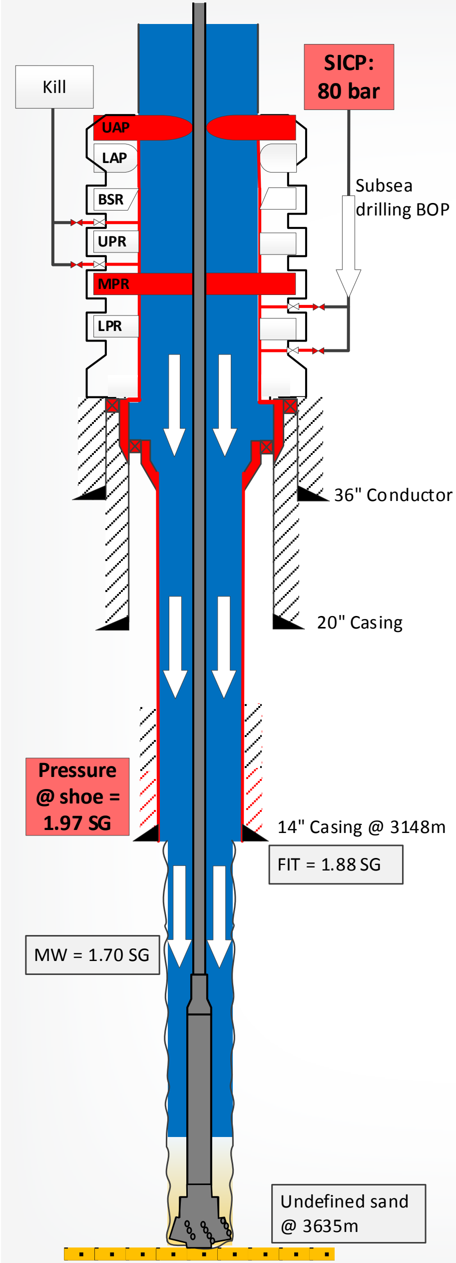


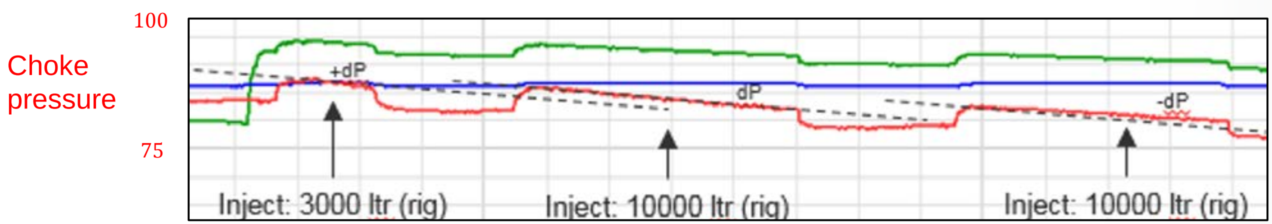
Hours are passing by…

- While risk assessing alternatives and preparing contingency plans:
  - SICP slowly increases to 77 bar, indicating kick is migrating up annulus
  - Geologist: updated fracture gradient at 14” shoe could be as high as 2.00 SG
- Based on updated fracture gradient, Driller’s Method is chosen for well control action. Decided to confirm 10 bar margin for this method. However, increased SICP has reduced the available margin.
- Decided to bleed off choke pressure to initial SICP of 71 bar
  - Concern with kick migrating without being allowed to expand, causing fracture of 14” shoe
  - Bleed-off to a predetermined *pressure* is not according to Volumetric Method (predetermined *volume* to allow gas to expand)
  - After bleed-off, the pressure increased rapidly back to 77 bar and continued gradually towards 80 bar
- Question 9: What happens downhole when the choke pressure is bled off?

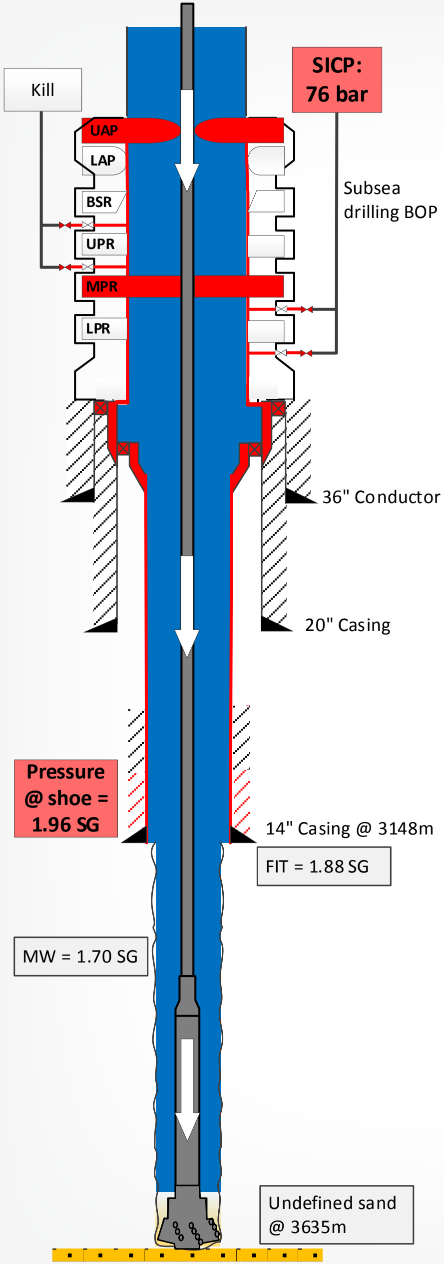
Well control action

- Decision to perform Open Hole FIT
  - Verify margins for well control circulation, or
  - Verify injectivity back into the formation
- Pumped down choke line at 5 spm, observed injectivity in the well
- Decided to continue bullheading down choke line at 10 spm
  - Pumped a total of 23 m3 in three sequences, observing reduction in choke pressure after each step, from 83 bar at start of bullheading, to 76 bar after final step





- Question 10: What does the reduction in choke pressure suggest? Would you continue bullheading at this point?



Well control action contd.

- Pumped down drill pipe to establish circulation / communication aiming to initiate Driller's Method
  - Pumped with 300 lpm and observed ~80% returns

- Question 11: Do you see any risks with continuing Driller's Method at this point?

- Question 12: Does the BOP configuration with closed MPR facilitate an optimal initiation of Driller's Method? (hint: position of K/C line outlets)

Normalization

- Succeeded circulating 1.90 SG kill mud into the well using Driller's Method, with manageable losses throughout (70-80% returns)
  - Decided to change over from MPR to UPR, to allow monitoring on static kill line
  - Mud samples from bottom showed reduced oil/water ratio, with 8.5 % gas at bottoms up; indications that the influx primarily contained water with some associated gas (later investigation of available data found that total kick volume was likely twice the initially assumed 1.4 m3, indicating water influx)

- Cross-circulated through BOP prior to opening well
  - The contractor's procedure called for closing a pipe ram during cross-circulation, however the concern was that seepage losses in a closed well could result in a new underbalance situation. Hence, the well was monitored via the lower choke inlet during cross-circulation, to maintain contact with the well and assure overbalance.

- Opened BOP and flowchecked static well. Ramped up pumps carefully up to 2300 lpm and circulated bottoms up, observing only 0.1 % gas.

- Plugged back well with cement

Learning and recommendations

- Influx volume likely higher than initially estimated. Recommended to invest more time in analysing flowback data prior to concluding the influx volume.

- Bleeding off pressure during build-up of SICP is not described in well control manuals and procedures. For a well in underbalance, bleeding off pressure only introduces additional influx volume into the well.

- The situation with SICP > MAASP is not part of compulsory well control training. Careful evaluation of risk, possible outcomes and contingency plans is required in order to avoid an escalation. More time should be invested during training to discuss unconventional kill methods (i.e. sandwich kill).

- Bullheading at low rate proved successful also in 12 ¼" hole (with water influx).

- The BOP configuration should be verified with respect to the well control contingency plans.

- Contractor's procedures for cross-circulation of BOP should be addressed in case of seepage losses in the well and risk of losing overbalance, due to loss of hydrostatic head from surface to BOP when isolating the well.