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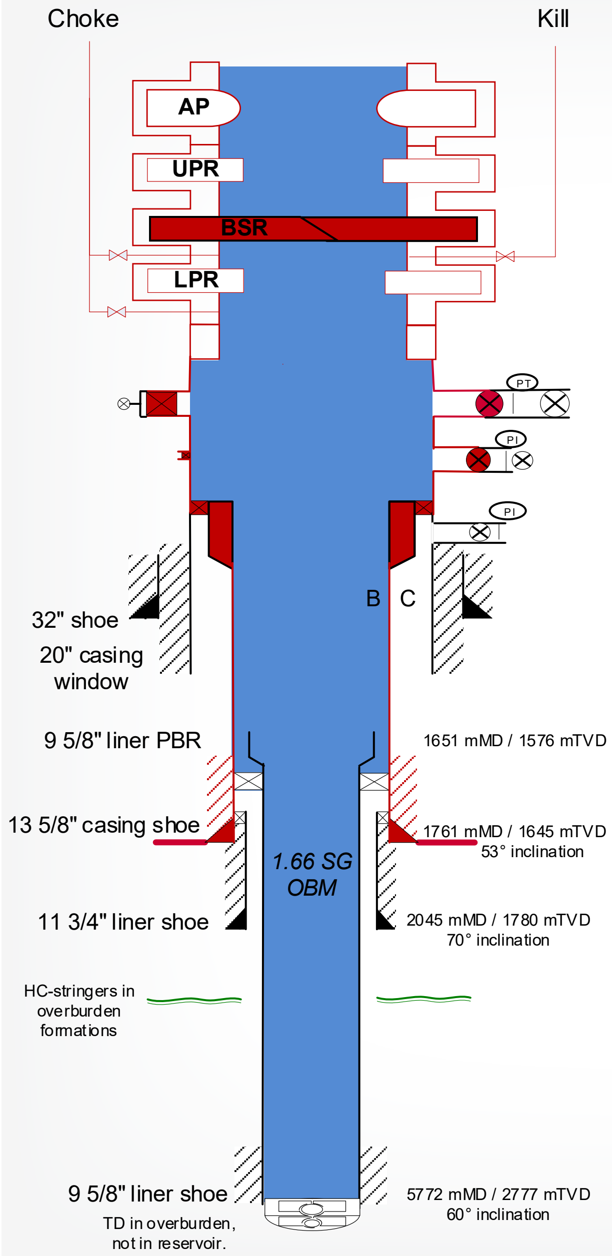
"Sharing To Be Better"

No 21

Well Control Incident: Failed downhole mechanical isolation barrier



Well Status – Platform production well

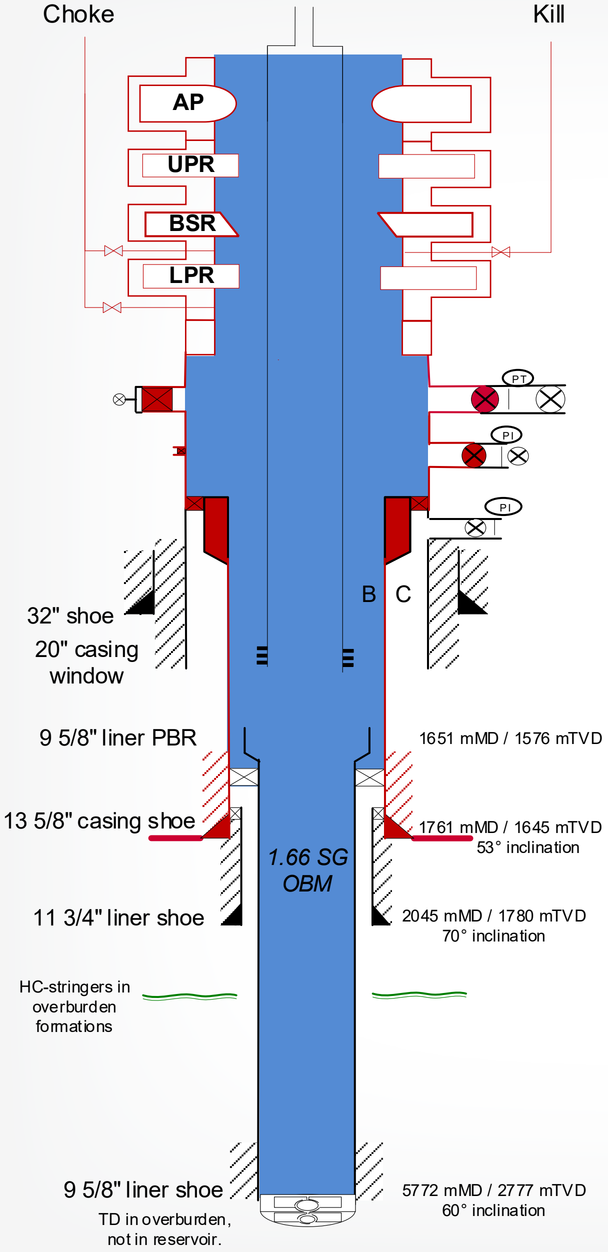
- Extended Reach (ERD) well on a mature field, targeting deep segment with higher reservoir pressure

- 13 5/8" intermediate casing
  - Set at depth with formation integrity towards 12 ¼" section TD

- 11 ¾" intermediate liner
  - Installed to isolate high pressure overburden formation

- 9 5/8" production liner
  - 4000m+, isolating the long 12 ¼" ERD section (max 85 deg inclination)
  - Increased gas levels observed while drilling stringers in upper part of 12 ¼" section with 1.66 SG OBM

- Cement jobs performed according to plan. Positive tests of casing, liners and liner hanger packers achieved as planned.
- Entire well tested to 290 bar surface pressure with 1.66 SG OBM



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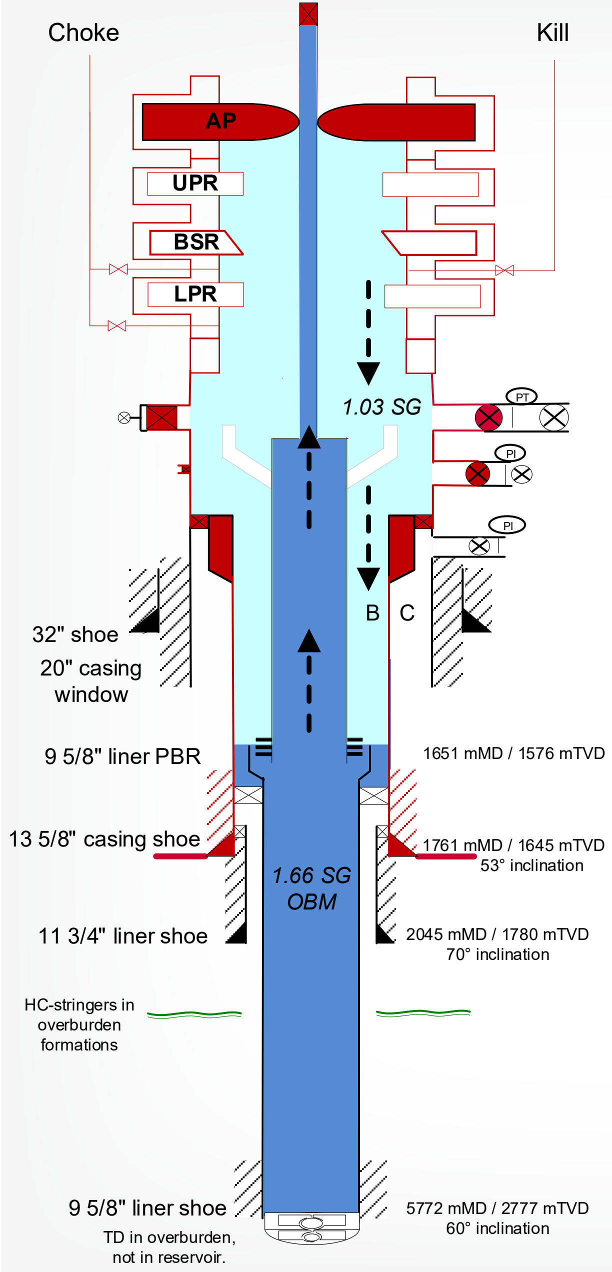
Plan – 10 ¾" tieback casing

- 10 ¾" tieback required for well design pressure
- Plan:
  - Run 10 ¾" tieback casing to above 9 5/8" liner PBR
    - Info: 10 ¾" casing is non-shearable
  - Displace 1.03 SG packer fluid into B-annulus prior to landing tieback in PBR
- Question 1: Do you see any well control risks with the planned operations?
- Question 2: How would you displace 1.03 SG packer fluid into B-annulus?



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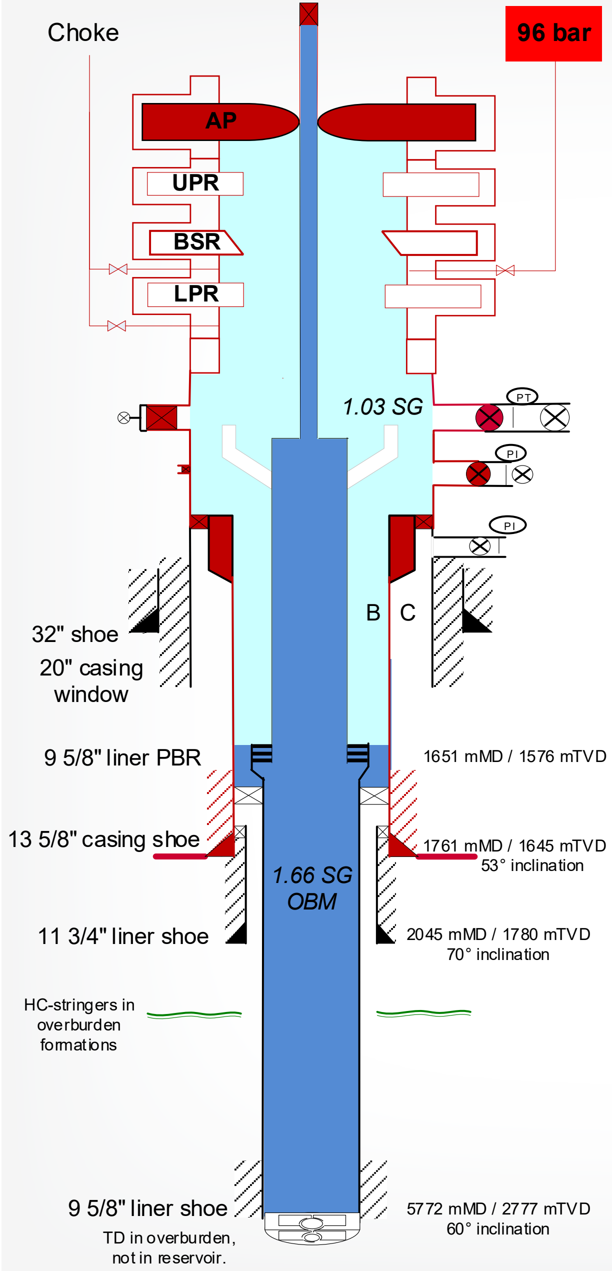
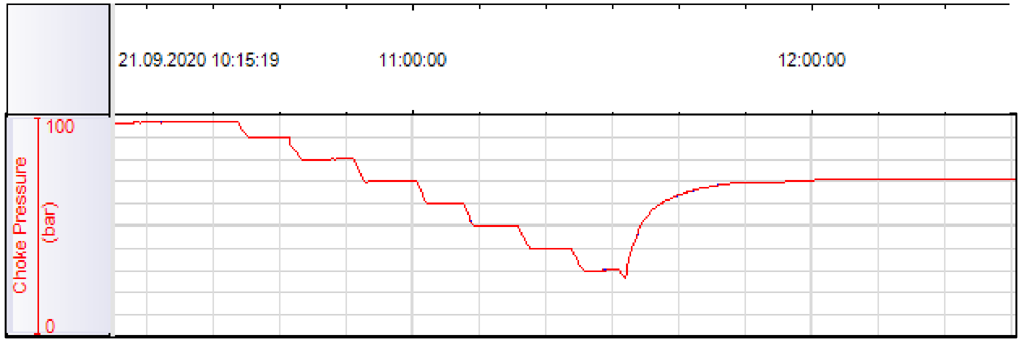
Displace B-annulus to packer fluid

- Ran 10 ¾" tieback to 1m above 9 5/8" liner PBR at 1651 mMD / 1576 mTVD
- Closed annular preventer on 5 7/8" landing string and displaced B-annulus to 1.03 SG packer fluid by reverse circulation down kill line with returns up drillstring to poorboy. Observed expected u-tube pressure on B-annulus.
- Question 3: What is the expected pressure on kill line after completed displacement, assuming ventilated pressure on drillstring?
- Stripped in, stung tieback seal stem into 9 5/8" PBR and landed tieback casing hanger. Applied pressure down drillstring to 50 bar, verified seal stem holding pressure.
- Bled off pressure on drillstring side, annulus pressure stabilized at 96 bar.
- Question 4: How would you proceed with the next step in the operation?

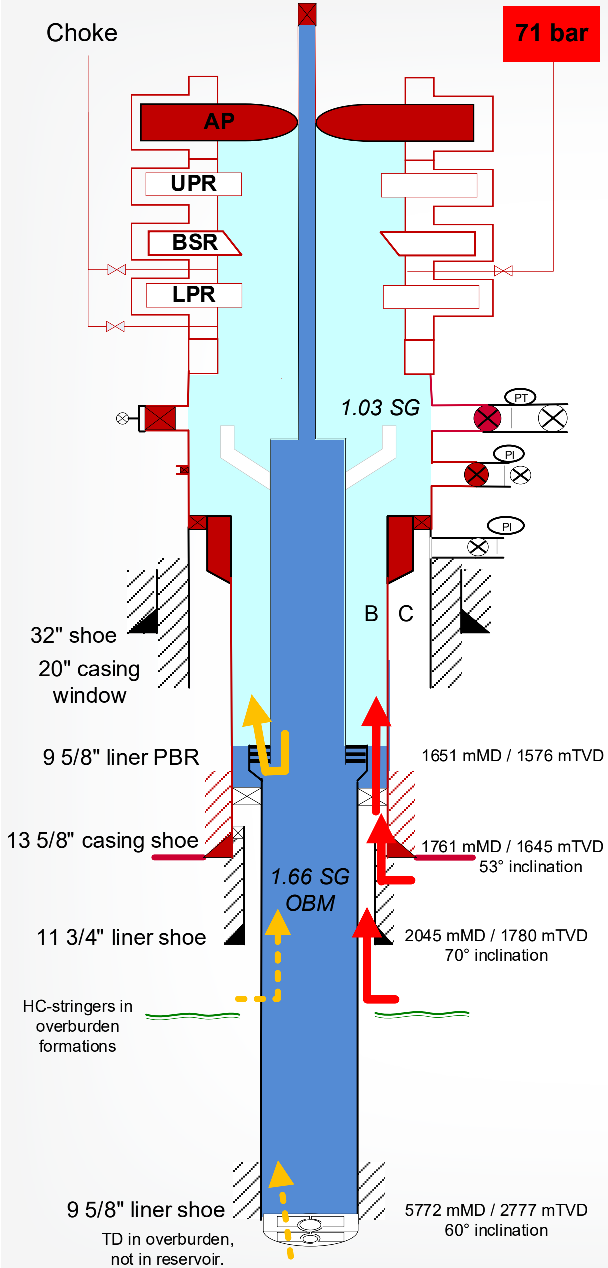


Inflow test

- NORSOK D-010: "Inflow testing is performed to verify the ability of the WBEs to withstand a pressure differential, e.g. when displacing the well to underbalanced fluid"
- Question 5: When B-annulus pressure is bled off, which WBEs (Well Barrier Elements) are taking over the primary barrier function towards overburden behind 9 5/8" liner?
- Performed controlled inflow test by bleeding down pressure in 10 bar steps. Verified stable pressure for 5 minutes between each step:

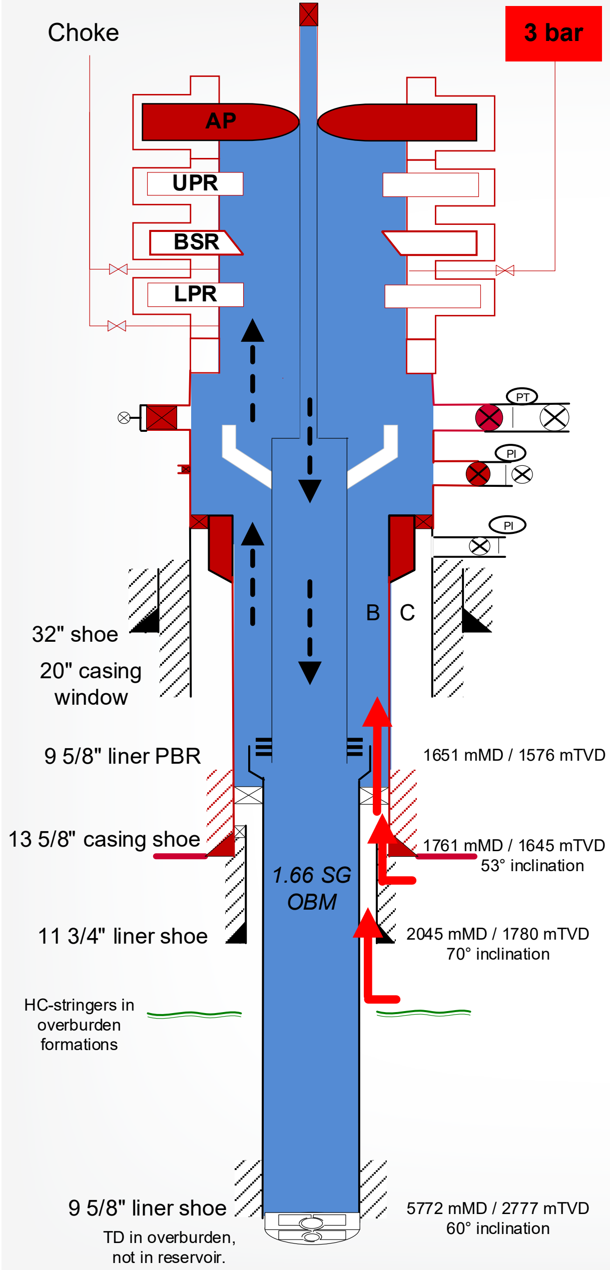


- Question 6: How do you interpret the inflow test?



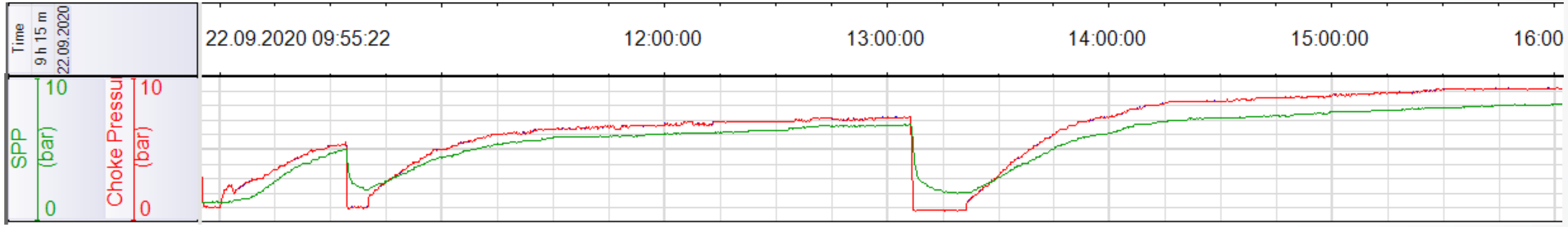
Inflow test positive – analysis

- At 26 bar, observed annulus pressure starting to increase, stabilizing at 71 bar after 20 minutes. No monitoring of drillstring pressure during inflow test.
- Potential leak paths:
  - (YELLOW): Tieback seal stem, due to u-tubing pressure or combined with leaking 9 5/8" liner or shoetrack
  - (RED): 9 5/8" liner hanger packer, due to formation pressure either from HC-stringers in 12 ¼" section or from behind 11 ¾" liner
- Evaluation:
  - Tieback seal stem previously tested to 50 bar, lower than differential pressure applied during inflow test. Opened IBOP and pressured up drillstring to re-test seal stem. Verified drillstring full and seal stem holding pressure.
  - 9 5/8" liner hanger packer exposed to "negative" pressure from overburden 12 ¼" formations for the first time -> most likely leakage point and source. (11 ¾" liner cement verified earlier by bond log)
- Question 7: How would you suggest handling this well control situation?

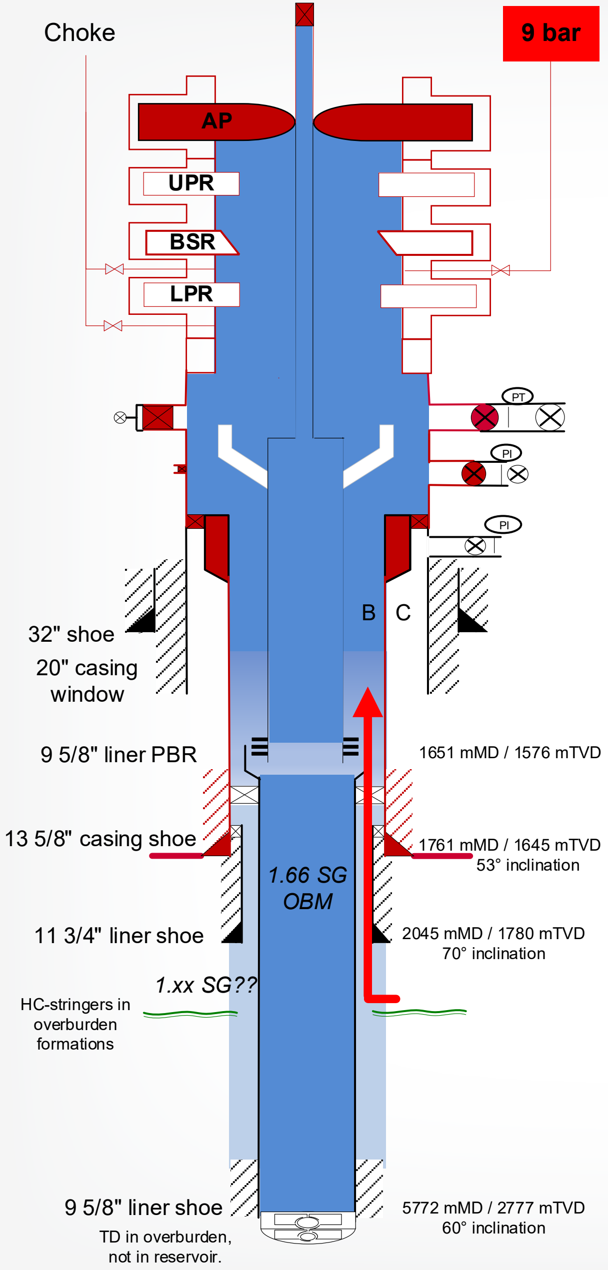


Well control

- Stripped out to lift seal stem out of PBR, and displaced B-annulus back to 1.66 SG OBM by circulating down drillstring and tieback, taking returns through choke.
  - At 1.4 x BU, observed max 1.3% gas after poorboy
- Circulated until even mud weight of 1.66 SG. Monitored pressure on annulus, stable at 3 bar. Opened annular preventer, no gas observed.
- Flow checked well. Observed steady increase in trip tank of 0.6 m3/hr. After 2 ½ hrs and 1.5 m3 gain in trip tank, closed annular preventer.
  - Observed slow increase in annulus pressure and drillstring pressure; bled down pressure couple of times to fingerprint well response



- Question 8: How do you interpret these observations? Why is the well not stable after displacing back to 1.66 SG mud?

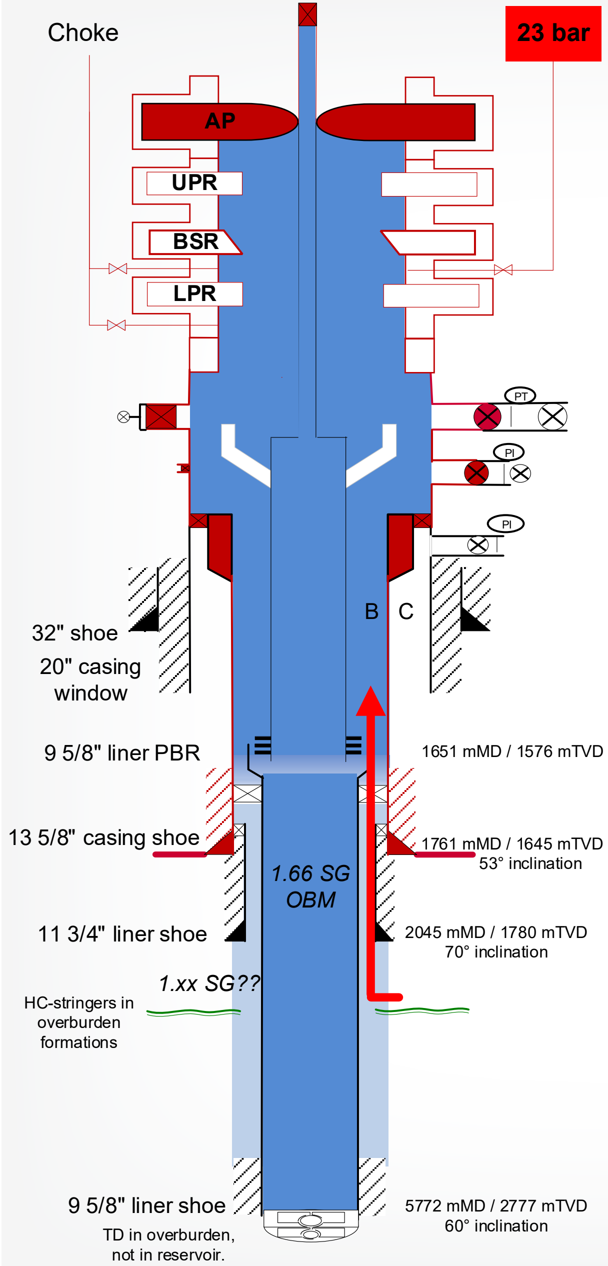


Well control – continued

- Circulated down drillstring and tieback with returns through fully open choke and poorboy. Observed gas in mud increasing after ½ BU, with max. 22% gas at BU.
  - MWout varying between 1.55 SG and 1.63 SG. Bled concentrate into active to increase MW towards 1.66 SG.

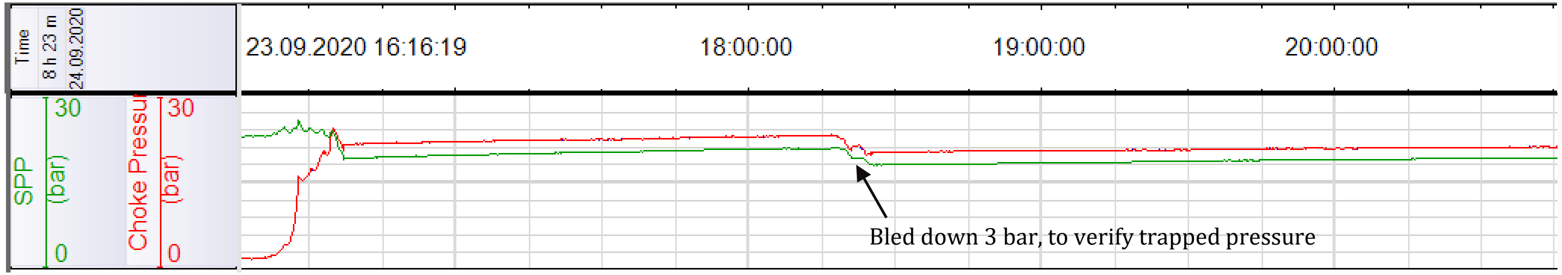
- **Conclusion**: mud leaking in from below 9 5/8" liner hanger packer, with reduced density due to hydrocarbons from 12 ¼" section – well not in overbalance with 1.66 SG mud at 9 5/8" liner hanger packer depth

- Question 9: What options do you see for handling this situation?



Well control – continued

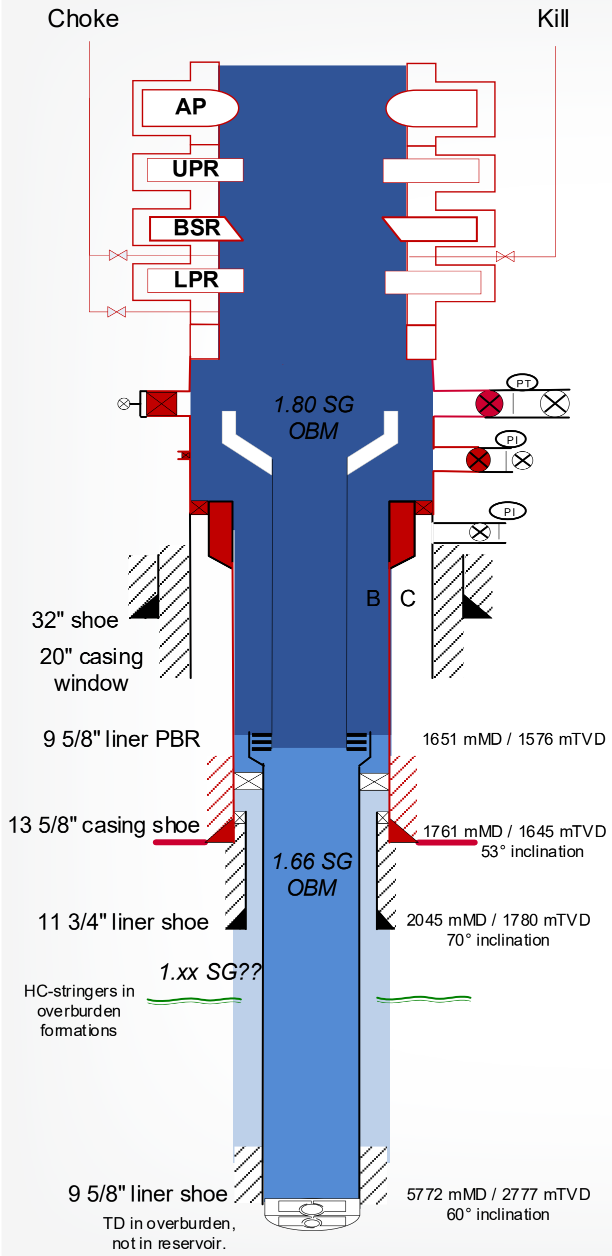
- Continued circulating through fully open choke and poorboy while increasing mud weight with concentrate. Slowly reduced gas level to 0.1% and stabilized MWout at 1.67+ SG. Experienced slight loss tendencies while circulating.
- Closed in well and observed pressure:



- Question 10: What possible causes are there for the increased shut-in pressure?

- Decided to circulate in heavier kill mud, to achieve positive differential pressure above 9 5/8" liner hanger packer and kill well
  - **Risk** -> Losses at 11 ¾" liner shoe

- Question 11: Can we somehow quantify this risk, prior to displacing to heavy mud?



Well control – resolved

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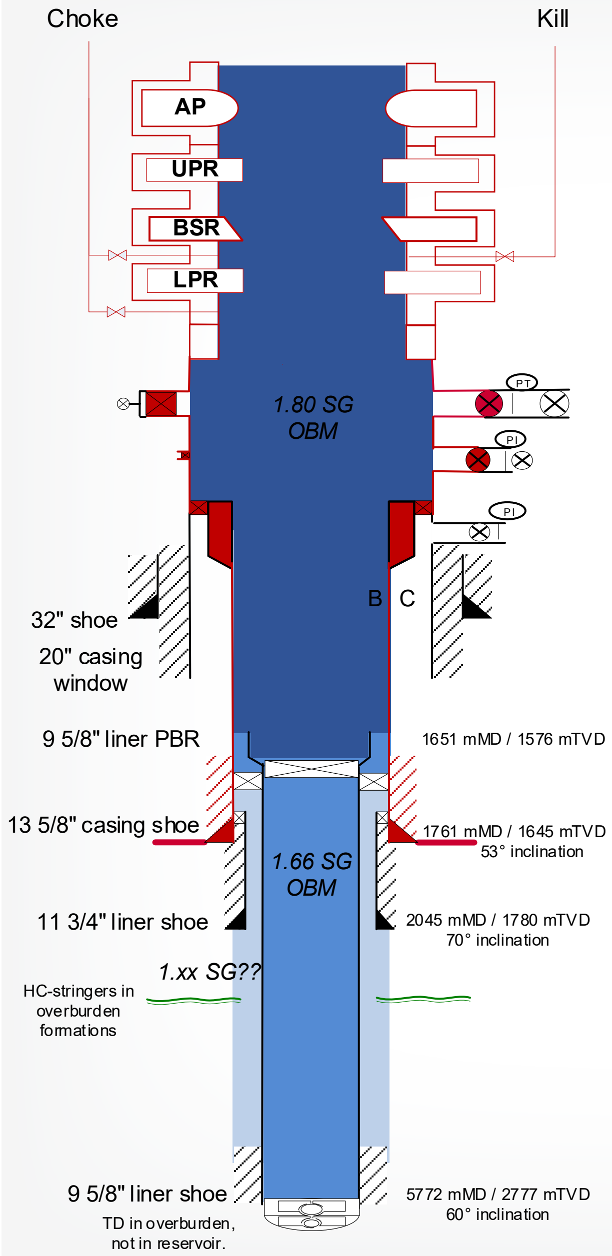
- Circulated another BU, no gas observed. Closed in well with additional backpressure on choke (29 bar) to confirm sufficient window for displacement to heavy 1.80 SG kill mud. No losses.

- Displaced well to 1.80 SG by reverse circulation down kill line and B-annulus with returns up tieback and drillstring, with constant bottom hole pressure
- Stripped in hole to sting into 9 5/8” PBR and landed tieback casing hanger in wellhead. Cross circulated through BOP and opened annular preventer.
- **Flow checked well stable**.
- Released and pulled out casing hanger running tool.

- Question 12: Discuss further options for this well. What would be your suggested plan of operations to improve the well’s barrier status?



Further operations

- RIH with 9 5/8” barrier plug and set same in top of 9 5/8” liner at 1670 mMD. Tested plug and conditioned mud until even 1.80 SG MWout.
- Pulled 10 ¾” tieback casing to surface. Inspected anchor and seal stem ok.

- RIH with polish mill, circulated BU, no gas. Polished 9 5/8” PBR.
- RIH with 13 5/8” plug, set plug above 9 5/8” PBR and leak tested 9 5/8” liner hanger packer and 9 5/8” plug ok. Tested 13 5/8” casing above plug ok.
- RIH with BSP (Bottom Set Packer), stinged into PBR, and leak tested to verify PBR status prior to re-running tieback. POOH with BSP.
- Ran and installed tieback casing, displaced B-annulus to packer fluid

- Question 13: Was this your preferred solution?

Conclusions & reflections

- Awareness of changing well barrier elements during operations, and verification of these
- Leak testing mechanical barriers with mud is no guarantee for good inflow test
- Inflow testing reflections:
    - Possible to perform inflow test prior to running tieback?
    - Increase test pressure of tieback seal-stem, to the expected u-tubing pressure after displacement of annulus
    - Apply positive DP pressure for observation during inflow test
- Required kill mud weight / awareness of kill point depth (with kill mud above packer and HC from deeper zones in 12 ¼” section below packer)
- Verify well integrity prior to displacement to 1.80 SG kill mud (concern with formation strength at 11 ¾” shoe)
- Understanding of flow potential in overburden