



“Sharing to be better”

Total mud loss followed by kick from a semi-submersible drilling unit in “karstified carbonates”

Karst: “An area of irregular limestone in which erosion has produced fissures, sinkholes, underground streams, and caverns”.

Summary

- An appraisal well was drilled from a semi-submersible rig with a 5-ram subsea BOP
- Potential «karstified carbonates» were prognosed in the reservoir, however previous wells in similar formations in the area had been drilled without any major problems
- Minor losses had been experienced on some of the previous wells but these were easily cured with conventional LCM
- Severe losses could not be excluded
- A 9 5/8" casing had been set prior to drilling 8 1/2" hole into the expected reservoir
- During cutting of core no. 11, the bit dropped 2m and immediate severe mud loss followed by a kick was experienced
- The 2nd line onshore emergency response team was initially mobilized
- A Well Incident Team was established onshore
- The losses were cured and the well killed after 10 days

Geological risks

- Potential of mud loss when drilling karstified carbonates
- 3 wells with similar geology drilled earlier in the area
- Probability of "open caves" very low (caves most likely filled with sediments)
- Experience from previous wells that losses could be cured with traditional LCM pills of Calcium Carbonates
- Contingencies in place:
 - LCM pills and LCM materials on site
 - Large mud volumes on site and at the nearest base
 - Conventional cementing materials

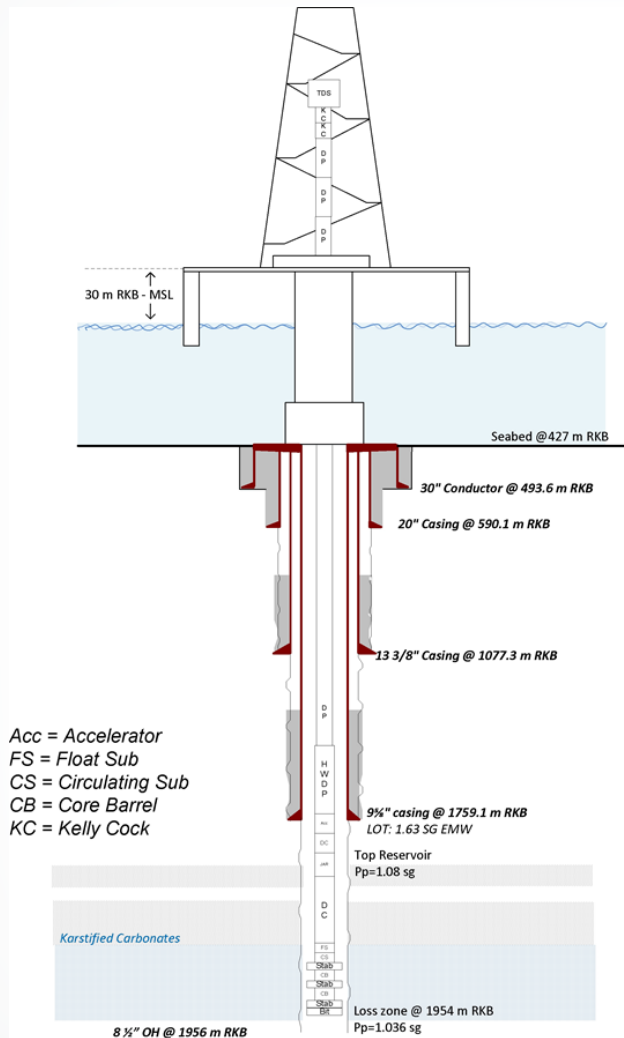


Sequence of operations

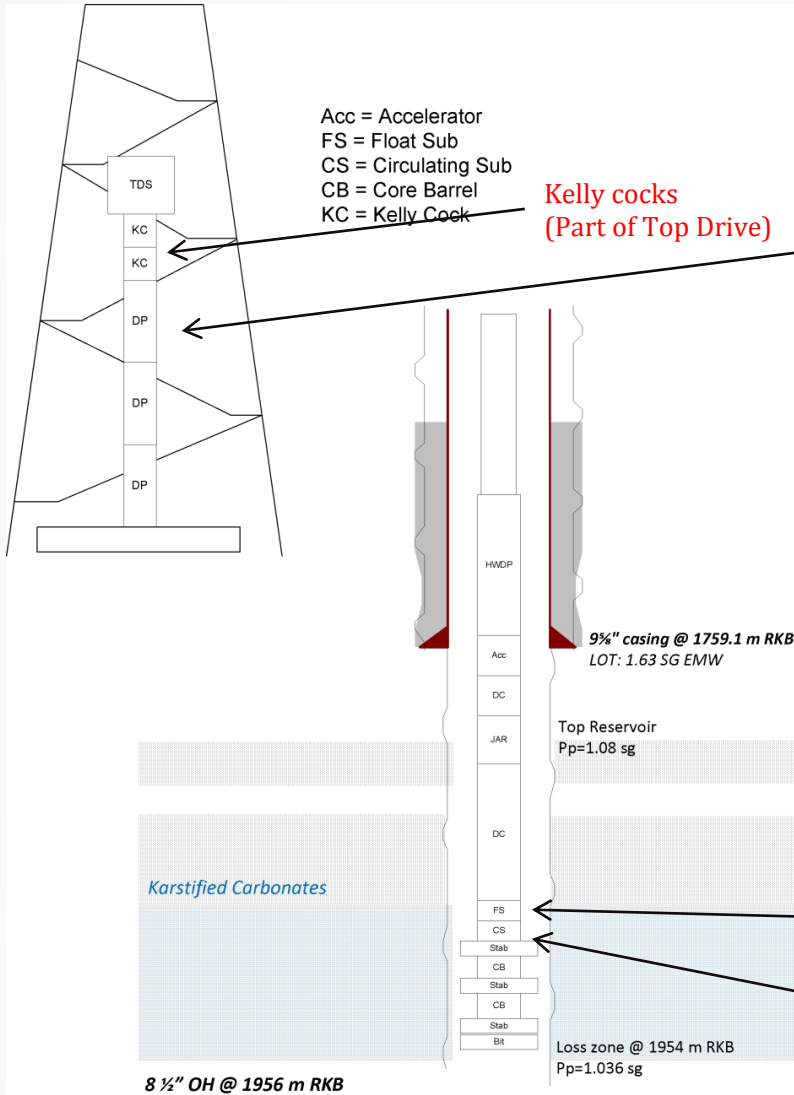
- Coring 8 1/2" hole at 1954 m RKB when corehead dropped 2m. Mud weight in use was 1.16 sg. Maximum estimated pore pressure was 1.08 sg at top reservoir
- Mud losses occurred immediately, approximately 60 m³/hr experienced in attempt to keep hole full with mud from trip tank
- Unable to cope with losses by filling mud from the trip tank

Question 1: What would you do?

Well status upon incident



- Started filling annulus with seawater via the trip tank
- While filling with seawater, pumped 13 m³ CaCO₃ LCM pill (350 kg/m³) and displaced down drillstring with 1.16 sg mud
- Still filling annulus with seawater. Meanwhile set slips, dropped ball and opened circulation sub (35 mm opening)
- Pumped a second LCM pill of 15 m³ down string while still filling annulus with seawater
- Well flowing back when full of seawater after 118 m³ seawater filled into annulus
- Closed in well on Middle Pipe Ram (MPR) (5-ram BOP with one Super Shear and one Shear/seal ram). Tool joint pulled up underneath MPR
- Observed annulus pressure increasing



Question 2: do you see any shortcomings with the top stand with pressure on Drill string and annulus?

Float leaking (non-ported flapper type)

Circulating sub opened

Observations and actions taken

- Annulus pressure increasing but observed a slower trend at around 80 bar
- Decided to bullhead annulus to seawater to keep pressure below 100 bar, MAASP against LOT with seawater. Procedure repeated several times
- Due to risk of hydrates, kill/choke lines were displaced to 50/50 MEG/Seawater after each bullheading of annulus
- Continued to bullhead LCM pills down drill string through circulating sub (35 mm port in circulation sub)
- Observed no effect of LCM pills with exception from a couple of positive trends seen towards end of displacement. LCM pills contained various size CaCO_3 , mica and nut plug of various sizes at 350 kg/m³ concentrations
- Observed the DP float was leaking after 6 LCM pills pumped down the drill string. Maximum observed pressure on drill pipe prior to pumping LCM was 25 bar
- Annulus pressure built back up after each bullheading. Bullheading of annulus was repeated when kill/choke pressure reached 80-100 bar
- **Question 3: Identify and discuss the risks that you see**

Well Incident Team established onshore

- A well incident team was established onshore consisting of:
 - Internal drilling and well control personnel
 - Internal well test engineer to assist in planning wireline pressure control operations, handling of hydrocarbons on surface upon well killing etc.
 - External service companies representing mud, cement and wireline operations
 - Well control and «ice plug» experts from Wild Well Control
 - Well control personnel from the drilling contractor
 - Rig planner from the drilling contractor
- Close cooperation between the daily operations team and the well incident team was established

Main Risks identified

- Diesel/bentonite squeeze turned down due to risk of plugging lines and drill string
- Avoid plugging drill string with LCM or cement
- Leaking DP float – should be in a position to rig up wireline (pressure controlled)
- Plugging of drill string and/or circulation sub
- How to drop sponge balls behind a cement job
- Pumping cement through Top Drive
- Stuck BHA after a cement job
- Risk of not being able to run wireline to cut drill string after a cement job and stuck BHA
- Risk of hydrates in BOP area with seawater and gas in annulus
- Avoid rigging up coiled tubing for solving the problem

Actions by the Well Incident Team

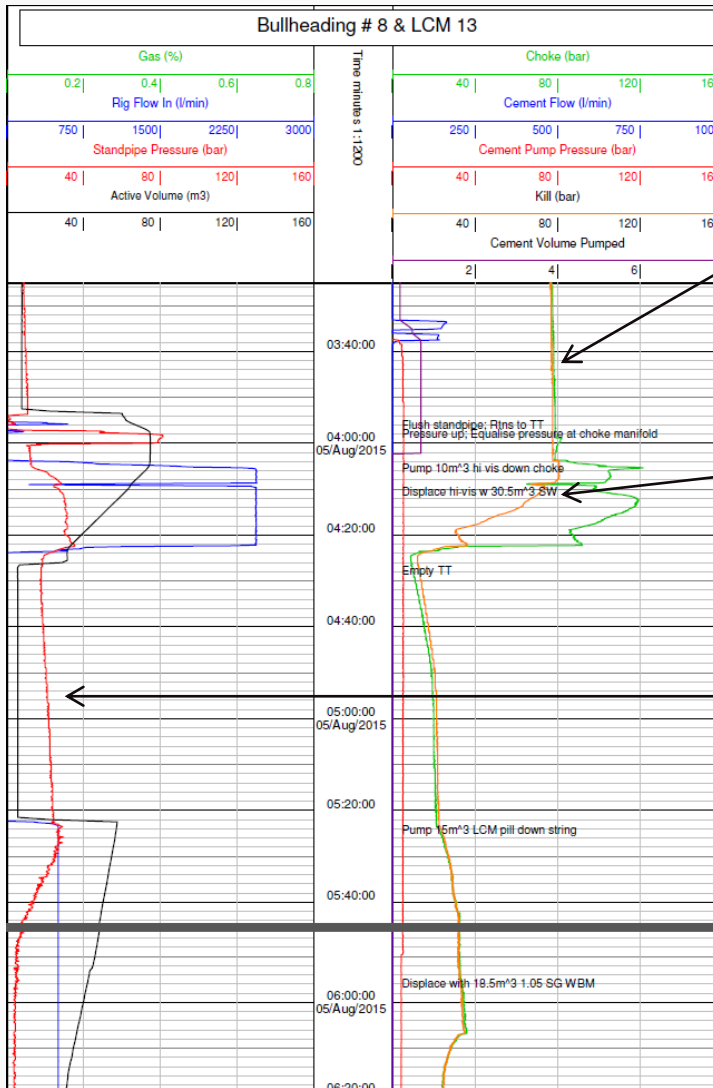
- The following plans were agreed at an early stage:
 - An intermediate goal was to remove the stand of DP above rotary to be in position for rigging up wireline pressure control equipment.
 - Cut the drill string such that cement would flow out of the pipe some 200 m above bottom of the well before pumping thixotropic cement
 - Prepared detailed plans for removing top stand based on pressure response and flow checks to be able to stab manual kelly valve on top of drill string (PS! Leaking DP float)
 - Back up procedure was to freeze an ice plug below the top stand. This method was never used due to uncertainties related to integrity of the drill pipe afterwards
 - Initiated mobilisation of wireline pressure control equipment, mono conductor, kelly valves, long bails, drill string severing tools and slop tanks for collecting oil on surface
 - Initiated mobilisation of chemicals for thixotropic cement, a slurry that gels up quickly at static conditions. Mobilised filterunit for pumping cement through Top Drive

- **Question 4: when removing top stand, in case of uncontrolled flow out of the drill string due to a leaking float, what do you see as contingency? And was it acceptable with a tool joint located underneath the MPR?**

Further actions

- Based on pressure response after bullheading of LCM down the drill string followed by a flowcheck, the top stand was removed, drill string secured with manual kelly valve and tool joint was hung off on top of MPR by stripping out
 - Note: problems were experienced when stripping tool joints out of annular preventer due to very high overpull. The stripping was done by exchanging closing of annulars and pipe rams
 - A physical shear test had been performed earlier during the rig intake process. The shear/seal rams were back-up for securing the well
- **Question 5: any issues with setting slips on a semi-sub with BOP closed?**
- The above procedure was repeated such that two more stands and one 2m long pup joint was removed from the drill string.
- The Lower Annular Preventer (at reduced closing pressure) was used as closing element when setting slips to allow the drillstring to move slightly due to rig heave. The rig heave was less than 0.5 m during the well incident
- The 2m pup joint (spaced out for coring) caused problems for optimal stick-up for wireline rig-up and at the same time hanging off drill string on the MPR
- **Lesson: when spacing out for a full stand of coring, make sure any pup joints are installed below the BOP**

Typical situation during the incident



Annulus pressure building up and levelled out around 80 bar, but still increasing

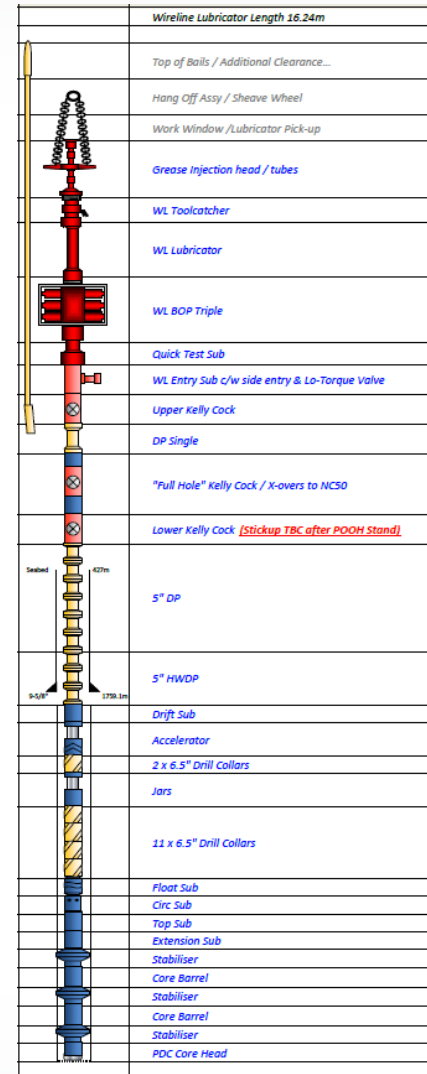
Bullheading annulus with hi-vis mud followed by seawater down Chokeline. Displaced kill/choke lines to 50/50 MEG/Seawater after bullheading

Drill string float (flapper type) leaking



Further actions

- The top stand plus two stands and a 2m pup joint was stripped out of the well
- Wireline pressure control equipment was installed and monoconductor cable rigged up
- The string was severed in the connection between the two upper 6.5" Drill Collars with a 2" JRC severing tool



Severed 6.5" DC



- The fish dropped downhole
- Length of fish left in hole: 145m
- Attempted to bullhead annulus after severing BHA – no go, hole was plugged
- The losses were then stopped 9 days after the incident and there was no need for pumping thixotropic cement
 - A total of 23 LCM pills and 18 bullheading operations of the annulus were performed
- Circulated out influx with Drillers method with 1.05 sg mud. Killed well with 1.12 sg and later displaced to 1.15 sg WBM.
- Plugged well with conventional cement plug and performed technical sidetrack to a shallower TD than the main bore

Lessons learned – karstified carbonates

- Always have circulation sub in BHA
- Use double float subs in BHA
- Consider using dart sub in drill string
- Use drilling stand with 3 manual kelly valves for easier rig-up of wireline
- Have equipment for wireline pressure control and drill string severing tools available at nearest base
- Have chemicals onboard the rig for pumping thixotropic cement etc.
- Depending on situation, strip out or cut drill string before pumping thixotropic cement to give some 200 m distance from the cement exit point to the loss zone
- If spacing out for coring, install pup joints such that they do not cause unfavorable stick-up for wireline rig-up

Volume pumped into the well

- Water based mud: 753 m³
- Hi-visc pills: 193 m³
- LCM: 340 m³
- Seawater: 618 m³
- MEG: 62 m³