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"Sharing To Be Better"

Well Control Incident – 8 ½” section

Summary of well incident

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Status prior to start drilling the 8 ½" potential reservoir hole section;

- 12 ¼" hole section was drilled with seepage losses throughout the section with 1.60 sg OBM.
- Hole angle c. 40 degs
- 9 5/8" casing was set and cemented at 2275 m.
- Casing shoe was set in a limestone stringer
- Casing was cemented with minor losses.

Summary of well incident

Incident Summary:

- 9 5/8" LOT 1.84 sg (expected LOT 1.95sg)
- Drilled 8 ½" hole with 1.65 sg MW. Noted with high ECD's, and unnoticed and unreported downhole losses.
- Non Ported float in BHA
- Influx was taken at 2320 m in Farsund Formation
- Attempt to circulate out influx and kill well conventionally with 1.75 sg MW without success due to significant - total downhole losses.
- Bullheaded 1.75 sg Kill MW down DP and Annulus to kill well.
- Well "unstable" therefore bullheaded cement to plug back and abandon well bore due to not being able to stabilize the well.

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DETAILS of INCIDENT

Well Schematic at Time of Incident

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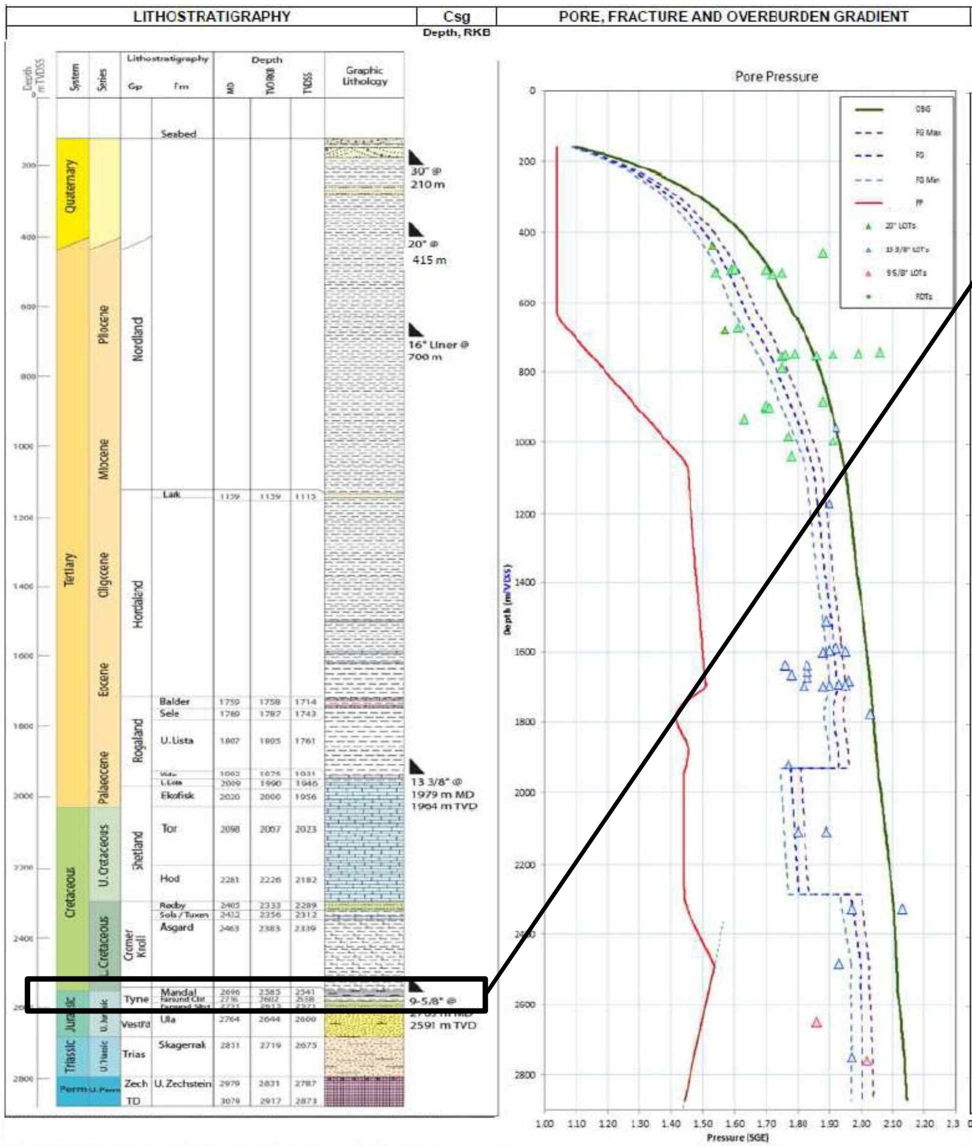

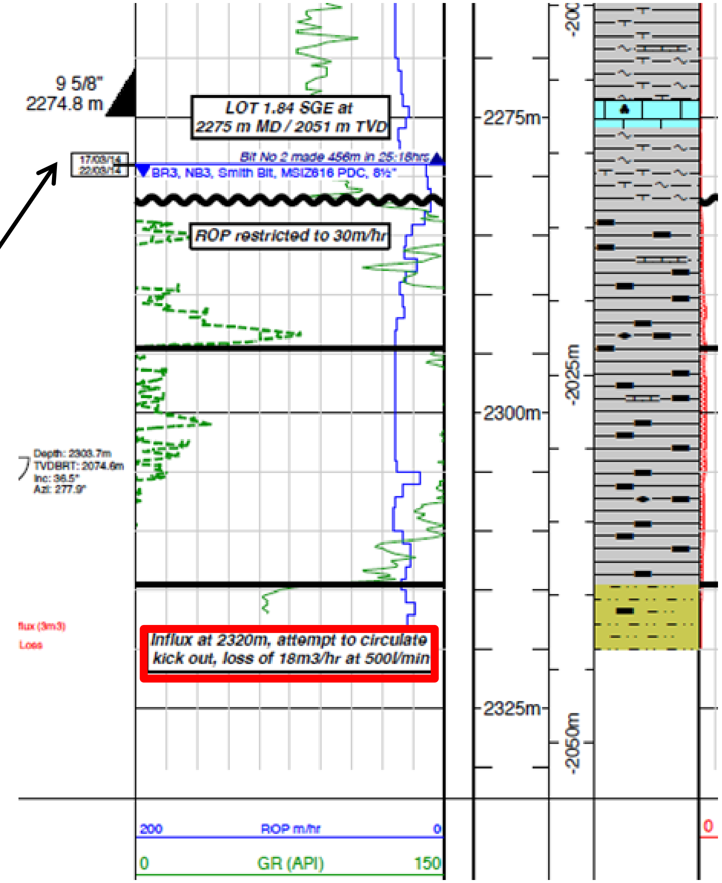

No. 1 Questions

1) What do you notice about the setting depth of the 9 5/8" Casing Shoe ?

2) Do you think this was known to the Drilling Team in advance ?

Well incident in 8 ½" hole section

- RIH with 8 ½" drilling assembly to drill out shoe track
  - LWD / MWD was tested OK while RIH.
  - MW in hole 1.60 sg OBM
  - Kick drill performed just above the float collar

- RIH and drilled shoe track.
  - Increased from 1.60 sg to 1.65 sg to allow for drilling into potential reservoir
  - LWD / MWD sending data OK
  - Performed LOT to 1.84 sg after drilling 3 m new hole and conditioning mud to even 1.65 sg
  - On first bottoms up observed shale shakers overflowing with mud, adjusted flow rate and continued drilling.

No. 2 Question

1) Do you think the losses over the shakers were known to all the offshore team at this time ?

Well incident in 8 ½" hole section

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- Drilled Ahead in 8 ½" hole section to potential top of reservoir
  - Drilled to 2291 m with continually high ECD's 1,87 – 1,90 sg

No. 3 Questions

1) What do you notice about the value of the ECD's ?
2) Do think there could be downhole losses at this time and why ?

  - Made connection and continued drilling down to 2320 m, observed a gas peak of 1,66 % from last connection. Circulated bottoms up to check for gas: 0,2 – 0,3 %

- Made connection at 2320 m MD (5 m into Farsund Siltstone) Observed Well Flowing and Shut in Well with Bit on bottom;
  - SICP: 26,5 bar, SIDPP: 15 bar, Gain: 800 ltr, MAASP: 36 bar,

No. 4 Question

1) What do you notice about the value of the SIDP

  - Kill mud weight: 1,75 sg (Pore Pressure 1,723 sg EMW + 2 point safety margin)

- Commenced well kill operation as per Drillers Method
  - Started circulating out influx with 30 SPM, ICP actual: 50 bar, only 35% returns, reduced rate to 25 SPM and then 20 SPM, attempting to reduce loss rate but losses ranged from 70 – 100%.

No. 5 Question

1) Why do think the losses were so great and circulation could not be established ?

Well incident in 8 ½" hole section

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- Shut in well due to high loss rate: pumped 33,6 m3 with 22,4 m3 lost to formation, SIDPP: 35 bar, SICP: 37 bar
- Reduced annular closing pressure to 500 psi and pulled bit 0,5 m off bottom. Re-applied 1200 psi annular closing pressure.

No. 6 Question

1) Why do you think the annular pressure was bled off and the DP stripped back 0.5 m ?

- Bled off DP from 35 bar to 6 bar, SCIP constant.
- Re-established SIDPP: at c. 15 bar by pumping with cement unit down DP and noting pressure change
- Re started circulating out influx using Drillers method with 10 SPM, DP: 45 bar, with only about 10% returns

No. 7 Question

1) Why do you think even after stripping back 0.5 m there was still so much losses ?

Well incident in 8 ½" hole section

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- Stopped pumping and shut in well; SIDPP: 37,2 bar, SICP: 37,7 bar
  - Total pumped: 46,5 m3 with total 33,9 m3 lost to formation
- Bled DP to down 6 bar. SICP stayed constant. Opened choke and bled 120 ltr from casing side. Casing pressure reduced to 32 bar. Closed choke and casing pressure built to 37.7 bar in few seconds.
- Re-established true SIDPP pumping from cement unit, SIDPP approx 15 bar

No. 8 Question

1) Why do you think the cement pump was used re establish a true SIDP pressure ?

- Well shut in. SICP stable at 37,7 bar. SIDPP stable at 15 bar.

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Well incident in 8 ½" hole section

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- Decided to use Bullheading method to kill the well.

No. 9 Question

1) Why do you think the decision was made to bullhead the well dead ?

- Bullhead 85 m3 1.75 sg OBM down drill string and annulus with 20 SPM Drill pipe, 40 SPM annulus

No. 10 Question

1) Why do you think there are 2 different pump rates for the annulus and DP ?

- Bled down annulus in stages from 9.8 bar to 7.0 bar.

- Open well and circulated well with loss free rate of 560 lpm to reduce gas cut mud (5-0 %).

- Not able to get a 100% stable well.

No. 11 Question

1) Why do you think the well was never stable after bull heading it dead with kill weight mud ?

- Decided to bullhead cement and plug back Open Hole with cement.

No. 12 Question

1) Why do you think the decision was made to bullhead cement into the well and plug back ?

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What do you consider to be the main areas of Learnings from this Incident ?

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Questions / Answers / Learnings

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No. 1 Questions

1) What do you notice about the setting depth of the 9 5/8" Casing Shoe ?

It should be observed that the shoe is set in a limestone stringer, which is not an ideal lithology to set a shoe in as it can fracture and induce losses in either the cementing operations or when drilling ahead

2) Do you think this was known to the Drilling Team in advance ?

No it was not, the Team would never have planned to knowingly set a casing shoe in a limestone stringer for the reason above.

Learning(s) :

1) *The original plan as noted in the drilling programme was for the 9 5/8" casing shoe to set in the claystone **below** this limestone stringer. The setting depth of the shoe was revised up to 2275 m for operational reasons relating to the latter P&A of the well. If this change of setting depth had been documented and risk assessed in a **Management of Change** document the casing shoe would not have been set at this depth which was coincidentally the depth of a limestone stringer.*

2) *Prior to running and cementing the 9 5/8" casing it was "know" to the Wellsite Geologist, Mud Logger and Ops Geologist that the shoe would be in the limestone stringer and they did not raise a "red flag" as they incorrectly assumed the Drilling Supervisor and the onshore Drilling Team were aware of this fact . **Never assume** that all members are fully aware of a given situation – always double check.*

No 2 questions

1) Do you think the losses over the shakers were known to the DSV at this time ?

Yes, but he was not advised of the estimate rate or volume or duration of these surface losses.

Learning(s) :

1) Never assume *that the DSV is aware of a given situation – always double check.*

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Questions / Answers / Learnings

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No. 3 Questions

1) What do you notice about the value of the ECD's ?

The ECD's noted are higher than the LOT achieved at the 9 5/8" shoe.

2) Do think there were indications of downhole losses ?

Yes , as the ECD's are higher than the LOT and the fact that the casing shoe is set in a limestone stringer it is highly probable that there were downhole losses at this time into this stringer.

Learning(s) :

*1) No downhole losses were noted or reported at this time as it was **assumed** that the ECD readings were incorrect as they were reading too high to be valid, and any losses noted were assumed to be on surface at the shakers.*

*Never **"assume"** that a reading is not correct until it is proven so - always double check and if you have to assume always assume the worst case ! – in this case that there was downhole losses.*

No. 4 Question

1) What do you notice about the value of the SIDP

The value is most likely incorrect due to the fact of having a non ported float valve in the BHA

No. 5 Question

1) Why do think the losses were so great and circulation could not be established ?

With the BOP's closed and circulating through the choke line across the choke applied sufficient back pressure to the annulus to induce losses down hole. The most probable location of the would be the 9 5/8" casing shoe that was set in a limestone stringer or the formation drilled into at TD.

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Questions / Answers / Learnings

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No. 6 Questions

1) Why do you think the annular pressure was bled off and the DP stripped back 0.5 m ?

The well was SI directly after a connection was made and the rig was prepared to start drilling ahead – ie the bit would have close to, or on bottom, when the well was SI. This could have resulted in the bit being "spudded" on bottom and instead of being able to circulate we could have been injecting into the formation when try to circulate.

Therefore to remove this uncertainty it was decide to pull the string back 0.5 m and to be able to do this the closing pressure on the annular had to be reduced, when the string had been pulled back the closing pressure was increased to its normal pressure to maintain a seal.

No. 7 Question

1) Why do you think even after stripping back 0.5 m there was still so much losses ?

The losses were not caused by the bit being on bottom and the most likely place for the losses is still either the casing shoe or the formation drilled into at TD.

No. 8 Question

1) Why do you think the cement pump was used reestablish a true SIDP pressure ?

The non ported float in the BHA means that pressure below it can not read accurately – the DP was lined up to the cement unit so that a controlled low speed pump rate could be used to pump up the pressure in the DP and when that pressure balanced the pressure below the float valve it would start to open so that a valid pressure could be obtained. Note : This is not a "guaranteed" method of getting an accurate SIDP but in situations like this it is worth trying.

Questions / Answers / Learnings

No. 9 Questions

1) Why do you think the decision was made to bullhead the well dead ?

Due to the uncertainty surrounding the SICP,SIDP and the Volume of the Influx the fluid type of the influx could not be accurately determined so therefore it had to be assumed to gas, and there was concern about a gas bubble migrating up the borehole. As a consequence of the losses making it impossible to circulate up influx, get the influx out of the well and to get kill weight mud into wellbore it was decided to bullhead kill MW into the well to kill the well.

No. 10 Question

1) Why do you think there are 2 different pump rates for the annulus and DP ?

Obviously the annular volume of fluid is much greater that the internal volume of the DP and in bull heading the objective is to get the kill mud at the bit at the same time so therefore there has to be a higher pump rate on the annulus side than the DP side..

No. 11 Question

1) Why do you think the well was never stable after bull heading it dead with kill weight mud ?

When bull heading a considerable volume of mud has to be injected into the formation in a relatively very short time – the formation has to some extent be over pressured and even "balloon" to take this volume is such a short time – dependent upon the permeability and porosity of the formations exposed it could take some time before the pressures equalized and the "ballooning" decreased. Therefore when the well was opened the well bore had not equalized and tried to do so by flowing back into the well making the well unstable.

No. 12 Question

1) Why do you think the decision was made to bullhead cement into the well and plug back ?

To be able to equalize the pressure in the wellbore fluid would have to been bleed off from it at surface and this carried a risk that if the influx fluid was gas then there was a risk that gas could have been brought back into the wellbore as part of the equalization process – this was considered as an unacceptable risk. Therefore the cement was pumped at this time

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What do you consider to be the main areas of Learnings from this Incident ?

The principle learnings from this incident are :-

1) ***Management of Change processes should be implement for what are considered even minor changes to the agreed programme so that the proposed changes are fully risk assessed.***

2) ***Volume Control is crucial at all times and should be carefully monitored and any deviations noted, explained and advised to all.***

3) ***"Assuming" everybody knows the same information is not a correct assumption – always double check.***

4) ***"Assuming" that tools are not working correctly if the information they give does fit with "expectations" - always assume the worst case until proven differently.***