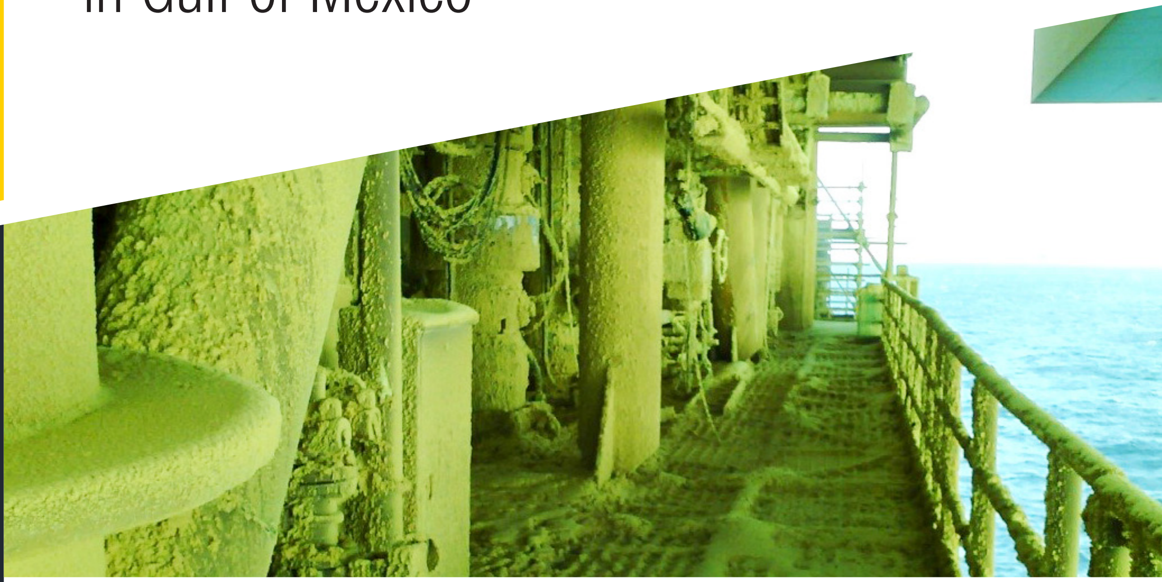
Floating Mud Cap Well Control in Gulf of Mexico

WELL CONTROL

JOB TYPE
Floating Mud Cap

LOCATION
Gulf of Mexico



Wild Well successfully deployed a “Floating Mud Cap Well Control” technique to assist in stabilizing and maintaining control during a well control event aboard a floating vessel drilling a deepwater well in the Gulf of Mexico.

INCIDENT SUMMARY

The following case history was developed from a well control event that occurred on a floating vessel while drilling a deepwater well. The well control event was complicated by a small window between formation fracture pressures and pore pressures (less than 1.4 ppg differential). As such, crews were challenged with maintaining constant bottom-hole pressures throughout well control circulation techniques without fracturing weaker formations. The well control team successfully used a “Floating Mud Cap Well Control” technique to assist in stabilizing and maintaining control during the well control event.

HEAVY DENSITY MUD CAP

The term “Mud Cap” has been used to describe a variety of well control and drilling techniques. For well control, Wild Well has defined “Heavy Density Mud Cap” (HDMC) as the spotting of heavier density fluids within the riser system to add additional hydrostatic pressure to the bottom of the well during well control events. Using common displacement techniques, a higher density fluid is circulated into the riser using a combination of the kill line and booster lines, which adds sufficient density to the fluid column to prevent taking a kick when the subsea BOPs are opened. This higher density fluid is allowed to “float” in the riser. The pipe is run or pulled from the well and the position of the cap must be calculated frequently.

CONSTRAINTS

HDMC is a way to maintain control of the well, which meets specific and unique requirements. HDMC may be used when:

- Kick has been taken.
- Hole is filled with oil-based mud or synthetic oil-based mud.
- There is a smaller kick size (less than 40 bbl).
- There is a small influx drive rate (less than 1 bpm).
- Placement of heavy density fluid into the riser can occur within a shorter time span
- When compared to circulating a hole volume.
- Placement of the high-density cap in the riser is preferred due to an inability to circulate the well without incurring losses.

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SPECIAL CIRCUMSTANCES

Formations normally encountered by deepwater wells represent zones of high permeability and porosity at varying normal and subnormal pore pressures. As such, these formations may contain smaller variances between their respective pore pressures and fracture gradients.

The Figure ** represents the predicted pore and formation pressures together with the actual pressures encountered. With an open-hole section of ~1,000 ft, the wellbore encountered two problematic zones. The upper zone would accept cuttings and annular fluids around an estimated bottom-hole pressure of 15.34 ppg. The lower kick zone would allow formation fluids to enter the wellbore if the estimated bottom-hole pressure fell below 15.2 ppg. Wild Well was contacted by a client operating in 5900 ft. of water with a 100 ft. air gap. The exploratory well was being drilled within a new deepwater lease with little areal control. Seven casing strings were installed, cemented and tested. Wellbore pressures could be contained within a four ram, 15,000 psi BOP stack outfitted with one 4 1/16 in. choke line, one 4 1/16 in. kill line and one 4 1/16 in. booster line. Geological surveys showed no potential for abnormal pressures. The well had been constructed with little or no problem.

Since most deepwater wells are extremely prolific, the crews had undergone rigorous training in identifying and shutting in the well at each drilling break. Equipment volumes had been identified and fingerprinted. A new hole section was drilled to interval TD at 21,000 ft. below mud line (31,200 ft. MD/27,000 ft. TVD) with a 15.2 ppg SOBM with no problems. During hole opening operations from 10 3/4 in. to 12 1/4 in., the drilling crews encountered a small amount of losses as the hole section was washed and reamed. After hole opening, the well was logged and BOPs were tested for six days. The hole remained stable during testing. Following BOP testing, the crews ran a hole-opening BHA to circulate and condition the hole prior to running casing. The hole-opening assembly was tripped into the well to 3700 ft. BML (9700 ft. MD/TVD). At this time, the crews observed improper fill-up. The well was shut-in with 137 psi SICP. A mud cap of 16.0 ppg was pumped into the riser and placed 500 ft above BOP. The mud cap was placed 500 ft above the BOP because the water depth was great enough to allow trip in hole (TIH) or pulling out of hole (POOH) without having to stop and close BOPs. From there, the crews would have to pump the slug up the riser before POOH or U-tube the slug down for TIH. The crews wanted to ensure the "slug" stayed above the BOP where it could be pumped out by using a closed BOP. If the slug was allowed to move below the BOP, the slug would increase in height, thereby increasing the overall hydrostatic pressure. The well was opened and the crews continued to run the hole opening assembly to 11,700 ft BML (17,700 ft MD). At this time, the riser was completely displaced with 15.2 ppg synthetic oil based mud (SOBM). After displacement, the well flowed back 15.6 bbl with shut-in casing pressure(SICP) of 200 psi. The kick was circulated on choke using the Driller's Method. The pump was staged down from slow pump rate (SPR) of 38 to 31 spm. Crews observed an additional eight bbl gain with SICP = 380 psi. Wild Well was contacted and asked to assist in well control activities.

SOLUTION

The plan put forth by the client was to replace the riser cap with 17.0 ppg SOBM and to stage in hole. Once on the bottom, plans included displacing the riser cap with lighter density SOBM and circulating and/or weighting up through choke as needed. Simulation Prior to departing for site, Wild Well performed a series of simulations, simulating a 24 bbl influx vs. a 100 bbl influx. The following example yielded that a 100 bbl swabbed influx would be needed to develop the 380 SICP as observed on the rig using submitted well geometry. Top of the influx for 100 bbl is at 29,600 ft, approximately 1100 ft off the bottom. Following are assumptions used in the model:

- Hole open size is 12 ¼ in. to TD without washout. The 19 ft between the 10 ⅝ in. under-reamer and the bit makes a difference of less than one bbl.
- Bit is currently at 11,700 ft BML (17,700 ft MD). The hole section below the bit is tricked in the model with a 0.2 in. tube from there to 21,000 ft BML TD (31,200 ft MD/27,000 ft TVD) of the well.
- Wellbore schematic is shown in Figure 2.
- Influx is dry gas from bottom 20 ft of the hole.
- Mud weight is 15.2/15.55 ppg SMW/ESD from simulation.
- Reservoir pressure is the same as static mud BHP at TD, which means the kick is a swabbed kick.

The simulations verified a large swab kick would be required to result in the 380 psi SICP (almost 10 times the volume reported that was swabbed). Wild Well believed that the SICP could be a combination of trapped circulating pressures, fluid differential pressures and swabbed pressures.

DATA GATHERING

Upon arriving on site, Wild Well personnel performed a review of all pertinent well control information, which has been summarized in Figures 2 - 3. Figure 2 shows the differences between predicted values and actual casing setting points. The last casing point of 11 7/8 ft set at 20,000 BML (26,000 ft MD/TVD) achieved a formation integrity test of 16.1 ppg. From there, the production hole was successfully drilled to TD using a 15.2 ppg SOBM with no problems. Only after the first hole opening run, did the well have partial lost circulation with a small kick of 15 bbl.

The team reviewed this information, and conducted flowback and SICP tests to determine rates of flow and subsequent pressure differentials. After conducting the tests, the wellbore was circulated, kick was removed and the mud was conditioned.

- Flowback averaged 60 bph with additional SICP of 60 psi. The smaller volumes represented a non-prolific producer in which a mud cap could be used to RIH to TD.
- When shut-in, the differential between the losses and kick was estimated to be 0.13 ppg (150 psi)
- The team theorized that a loss zone was located below shoe and above

kick zone for worst case analysis.

- Although the well was successfully TD'd with 15.2 ppg SOBM, fractures had been induced requiring a higher mud weight to kill the well (estimated 15.31 ppg or 150 psi more than originally drilled).
- The team estimated an additional 150 psi would be needed to mitigate potential kicks (estimated 15.44 ppg).
- Lost circulation material would be needed to assist in mitigating losses from induced fractures. As shown in the

PROCEDURE USED

- Review information.
- Perform volume calculations and ensure at least two hole volumes of fluid available.
- Develop mud cap receipts and volumes.
- Displace lost circulation material.
- Place appropriate mud cap for additional hydrostatic pressure while tripping.
- Open well, check for flow.
- Stage into hole, breaking circulation as needed.
- Once on bottom, close BOP and circulate out kick.
- Circulate and condition well (vary pump speeds as needed to keep losses to a minimum).
- Spot LCM pill on bottom.
- Pump riser cap for additional hydrostatic pressure while tripping.
- Displace choke line with kill fluid.
- Check for flow.
- Open BOP and check for flow.
- Circulate riser.
- Pump out of hole.
- Set packer and test BOPs.
- Set riser cap.
- Rig up and run liner.
- Cement same.