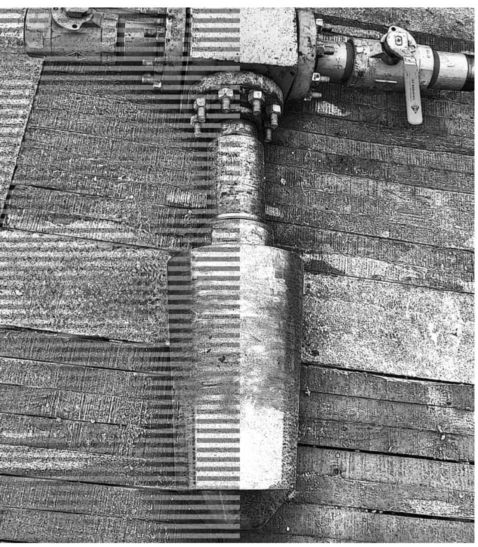
When Poor Integrity Leads to Blowout

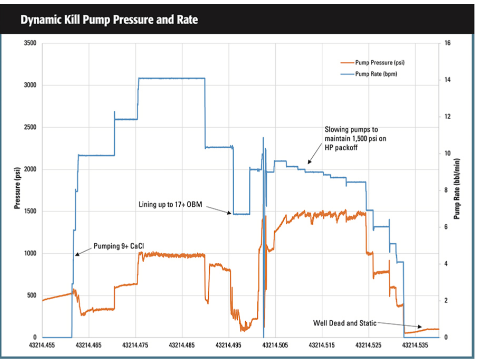
WILD WELL CONTROL

WELL CONTROL

JOB TYPE:
Blowout with Fire

LOCATION: Middle East





Dynamic Kill Pump Pressure and Rate

In April 2018, a production well in a mature field in the Middle East blew out gas from a known formation to a tortuous flow path of unknown sections of the compromised casing and packer via compromised tubing. Surface broaches from the production tubing and casing were observed as far as 300 m from the blowout well. Wild Well Control understood there was an uncontrolled flow of formation fluids due to the irregular and ever-changing surface tubing and production casing pressures. Furthermore, cathodic protection wells in the area were showing signs of gas and fluid production that were not in production intervals.

DIAGNOSING THE PROBLEM

Since the wellhead location was showing no signs of broaching or instability, wireline logs could be run and evaluated. A production spinner survey, temperature and tubing integrity log were performed. The production spinner survey demonstrated changing velocities as the log progressed to the bottom of the well. Usually, this is an indication of holes in the production tubing. The temperature log highlighted a significant cooling interval at ~2000 ft, indicating a large volume of gas expansion to the annulus and most likely outside of the production casing.

The tubing integrity log was performed, but results would take several days before they were available for evaluation. At the client's direction, an inflatable plug on CT was installed as deep as possible and set in an effort to block the flow, but this was unsuccessful. It is often difficult to place large bore components/plugs into flowing wells or to a depth where they are successful at stopping a flow.

As pressure built up in the thief reservoir, nearby cathodic protection wells began to flow oil, gas and water from a shallow, water-bearing formation. As they did, they were filled with cement. This process was initially successful at stopping the flow oil, gas and water from a shallow, water-bearing formation. As they did, the wells were filled with heavy cement. This process was initially successful at stopping the flow, but as pressures in the shallow reservoir were unable to relieve themselves, pressure continued to increase, and additional water and cathodic protection wells (up to 800 m away from the blowout well) continued to flow to relieve the pressure that was building.

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CS001

EXPERIENCE.
THE WILD WELL DIFFERENCE

REMEDIATION EFFORTS

Initial remediation efforts included pumping mud and brine from the surface to attempt a well kill, which was unsuccessful. It was determined that a hydraulic workover unit would have to be installed to pull the tubing as the well continued to flow and a new, uncompromised string of tubing could be installed and a dynamic kill performed.

Since the tubing was compromised, it was determined that BOPs would have to be installed that would allow the cutting and removal of the tubing from the well one or two joints at a time while maintaining pressure integrity on the well. A snubbing unit was mobilized from The Netherlands and additional BOPs were mobilized from the U.S. After the production tree was removed and the hanger was latched, a radial torch cutter on wireline was used to cut the production tubing above the inflatable plug (above the production packer). The hanger was pulled into the BOP stack, the tubing was cut with BOP shear rams and the hanger laid down. The tubing fish required milling within the BOP stack to allow latching the lower fish with an overshot. This development drastically increased the time line to cut and pull the tubing string from well.

CONTINGENCY PLANNING

Contingency planning included utilizing a relief well to intersect and perform a dynamic kill operation. The initial planning considered using an existing nearby wellbore for reentry and sidetracking operations. Satellite imaging showed that the area near the wellbore was increasing in height, making drilling a new well risky. Partners and teams were mobilized to engineer and plan sidetracking operations on an existing well to make an intercept and dynamic kill.

RESOLUTION

Additional broaches occurred and caught fire, increasing the incident visibility, requiring a rapid resolution. By the time the hanger was removed and laid down, the tubing integrity log was available for field personnel to review. The integrity log showed the location and size of the holes through the tubing string.

Wild Well Control suggested to the client that a dynamic kill was a feasible option through the open-ended tubing even though there were holes throughout the tubing string. A surface broach ignited that evening, and due to wind conditions, the location was shut down and required evacuation. After the location was secured, a dynamic kill through the damaged tubing string became the primary option to regain control of the well. Wild Well Control calculated fluid densities, pump rates and volumes required for a successful dynamic kill attempt. After the fluid was mobilized, a high-pressure pack-off was installed to the tubing fish in the BOP stack, and a dynamic kill through the tubing was simulated and successfully completed with 500 bbl of 9+ ppg NaCl brine followed by ~500 bbl of 17+ ppg OBM at a maximum rate 10 bpm. The well was topped up with 5 bbl of 9+NaCl brine before the pressure was observed indicating the well was full. The pressure was monitored for 30 minutes without any changes, confirming the well was dead.

SUBSEQUENT PLUG AND ABANDONMENT

After the well was confirmed dead, the tubing was pulled from the well and laid down conventionally, without the need to shear and lay down each joint. After laying down the final joints of tubing, the visual assessment indicated that the radial torch cut failed to cut the tubing, and the production packer was still attached to the tubing. This eliminated a separate trip to recover the packer. With the tubing and packer removed, a cement retainer was installed above the production perforations and in the well was secured with a cement plug.

CONCLUSION

Operators in mature fields experiencing well integrity problems in aging assets monitor tubing and casing pressures on a regular basis to determine when casing barrier envelope may have integrity issues. Having a clear insight into their well's integrity or lack thereof makes planning significantly easier. Wells that are not left unattended, or not monitored regularly, require significant diagnostic efforts to remediate. Wells flowing underground pose additional risk of broaching prior to ultimate resolution. This factor should always be planned for in the instance that a surface broach migrates to the well pad or around the wellhead itself.

Producing wells with compromised barriers and poor wellbore integrity present some of the most complex well control challenges. Loss of wellbore integrity above the depth where natural sediment strength is capable of containing reservoir induced pressure creates a situation where the kill operations must be implemented from the bottom of the well. However, uncontrolled downhole flows and mechanical tubular damage often makes re-entry difficult or impossible. Furthermore, broaching adds significant risk to personnel and assets during control operations. These situations, even on normally pressured producing wells, require extensive diagnostics and extraordinary means to safely resolve. Many of these difficult and costly events can be avoided via frequent monitoring to identify the first indications of wellbore integrity issues and acting immediately to isolate the problem well before an uncontrolled flow develops.