HPHT Wells – The Drilling Stand Conundrum

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A potential challenge associated with drilling High Pressure hole sections is that a well control event could require a pumping pressure greater than the rating of the rig's mud pumps. Under these circumstances a method is required to switch to a pump with a higher pressure rating – usually a Cementing Pump.

Historically, some operators have chosen to use a "Drilling Stand" or a "Drilling Single" when drilling HPHT sections using a Topdrive. This equipment is intended to facilitate the removal of the top drive and the installation of a circulating head connected to the High Pressure pump.

Drilling Stand

A Drilling Stand has a Full Opening Safety Valve (also known as a FOSV and to some as a Kelly Cock or IBOP) below each single of DP. This ensures that throughout the process of drilling down a stand it is always possible to pick off bottom and pull back a short distance to position a FOSV at the drillfloor. In theory, this can then be closed and the connection removed above it and a high pressure circulating head installed.

An operational disadvantage of this system is that the Drilling Stand has to remain at surface, so after drilling the stand a relatively complex and prolonged pipe handing process has to occur. The Drilling Stand has to be removed and stood back in the mast; a new stand of pipe made up to the string and run in hole and then the Drilling Stand reinstalled followed by the top drive prior to recommencing drilling.

Drilling Single

A Drilling Single avoids multiple pipe handling associated with a Drilling Stand. It can vary but, for example, might comprises a FOSV, 10ft DP pup, DP single and a second FOSV. This is connected below the topdrive and acts very similarly to a Kelly. Drilling is conducted using singles of drillpipe installed below the Drilling Single. This technique requires the ability to pick up singles of drillpipe and make them up to the Drilling Single while it is installed on the topdrive. It loses the benefits of drilling in stands and introduces multiple pump off events compared to drilling with stands.

The problem with FOSVs!

In addition to the operational inefficiencies mentioned above, the use of a drilling stand introduces more fundamental problems when drilling with a surface BOP. During a well control event, it is likely that one or more FOSVs will be either across the BOP or below the closed BOP element. A FOSV adds 1 to 2 feet of length to a drillpipe connection; complicating the space out, restricting which BOP elements can be closed around the drillpipe body and increasing the risk of an unshearable connection being located across the BOP or preventing the drillstring being hung off prior to shearing in an emergency. Furthermore, API Spec 16A only requires FOSVs to be able to withstand a minimum of 2000psi (138 bar) pressure from the outside and to have a temperature rating of 194 F (90 deg C). These conditions, particularly excess external pressure, is highly likely when circulating out a HP gas kick; especially when drilling with water-based mud. Do we really want to add the complication of gas entering the drillstring near surface during a well control operation?

These factors have led to Operators re-examining the requirement for a Drilling Stand or Drilling Single for HP hole sections; particularly for surface BOPs. To do this, more issues should be considered:

- What are the possible pumping pressure demands during a well control event?
- What is the standpipe manifold rating?
- Can the configuration of modern topdrives offer an alternative option?

- Can the configuration of the standpipe and cementing manifolds be adapted?

Severity of Pressures?

What pressure could potentially be seen at the standpipe manifold during a well control event? This clearly depends on the type of kick (encountered /drilling or induced / swab etc) and the location of the bit relative to the bottom of the hole.

Induced or swab kicks with the bit on or relatively close to bottom are usually associated with very limited Shut-In Drillipe Pressure. The standpipe pressure with therefore be largely determined by the circulating rate chosen to kill the well.

An encountered or drilling kick has the additional load on the standpipe of the kick intensity, the difference between the mud hydrostastic and the pore pressure in the kick zone. Ultimately the severity of this is limited by the shoe strength of the previous casing or liner shoe.

Providing no influx enters the drillstring during the kick and the integrity of the drillstring is maintained, it is unlikely that the maximum pumping pressure will approach the limits of a 7,500psi mud pump with small liners installed or perhaps even those of a 5,000psi mud pump. If, however, a significant amount of low density influx enters a drillstring during the shut in process or the drillstring parts near surface during the well kill (e.g. H2S embrittlement) then peak loads on the standpipe manifold and mud pumps could be potentially much higher and, indeed, exceed their rating. Consequently, procedures must exist to allow for a high pressure pump to be used.

Pump Ratings

The mud pump pressure rating is determined by the size of the liners installed in the pump. The maximum pumping pressure (using the smallest ID liners) usually matches the pressure rating of the standpipe manifold pipework, the jumper hose to the top drive and the top drive swivel. Historically this has been 5,000 psi (345 bar) but increasingly it is 7,500psi (517 bar) with the majority of new build 15,000psi rated rigs having the higher rating.

The maximum allowable standpipe pressure is, however, usually an agreed percentage of the setting of the pressure relief valve (pop off valve) installed in the discharge side of the mud pumps. This setting itself is also usually an agreed percentage of the pressure rating of the liners installed on the mud pumps. The combination of these factors could see the maximum standpipe pressure being 70-80% of pressure rating of the liners (and sometimes considerably less if “conservative” values of these two percentages are chosen). This selection process is commonly driven by both Drilling Contractor and Operator policies (as well as personal preference!)

Top Drives

The top drive has more than one pressure rating. The break in ratings is usually facilitated by the presence of two Full Opening Safety Valves with a pressure rating equal to the rig’s main Blow Out Preventers. These are located below the swivel. Above the Upper (remotely operated) FOSV, the pressure rating of the top drive matches the Standpipe manifold. The Lower FOSV is manually operated. A torque wrench is usually available on the Topdrive to allow the connection between the two FOSVs to be broken, regardless of the location of the Topdrive in the Mast.

Operational Alternatives

A key step in optimising HPHT Drilling Procedures is to realise that it is not necessarily required to take immediate action. It should be apparent that three different conditions are possible:

i. Pumping pressure is less than the maximum pumping pressure (fraction of mud pump relief valve setting)

ii. Pumping pressure exceeds (i) but is less than the pressure rating of the standpipe manifold etc.

iii. Pumping pressure exceeds the pressure rating of the standpipe manifold etc.

In case (i), the well can be killed through the topdrive using the mud pumps.

In case (ii) the well could be killed through the topdrive using the Cement pump providing the mud pumps are isolated and the cement unit is connected to the standpipe manifold

Only in case (iii) would it be necessary to isolate the standpipe manifold. This can be done instantly from the Driller's station by closing the remotely operated upper FOSV on the topdrive. Alternatively, if either a Drilling Stand or Drilling Single has been used, it can be done by closing the manual FOSV that should be located at drillfloor level.

In the case of a Subsea BOP, priorities can be different – notably if standard operating procedures call for the drillstring to be hung off prior to circulating out an influx. In this case, the decision to install a kill assembly may be taken at the start of a well kill rather than when pressures reach a critical point. This does not prevent, however, the well subsequently being killed using the mud pumps if the kill assembly is configured to allow pumping from both a Cement unit (via a pump in sub) or rig pumps (vertically through the kill assembly.)

How to Line up to the Cement Unit without a Drilling Stand or Single?

So…what are the options to install a kill assembly connected to the Cement Pump if it is not desirable to use a Drilling Stand or Drilling Single? A protocol risk-assessed by one Operator in the North Sea as being preferable to using a Drilling Stand with a surface BOP is:

a) Inflow test the float valve(s) routinely used in HPHT wells. If they hold pressure, break a DP connection at the drillfloor and immediately install a manual FOSV. Then install the HP circulating head.
b) If the float valves are not holding, close the Lower FOSV on the Topdrive, open the Upper IBOP and inflow test. If holding,. break the connection between the Lower and Upper IBOPS and install a crossover assembly to a circulating head.

While, in theory, deviating from a traditional two barrier philosophy, this risk was mitigated by a number of factors. The rig was fitted with a 7,500psi standpipe manifold and the pumps dressed with liners rated to the pump's nominal rating. Physical pop off valves were set to close to the pump rating , backed up by software pressure limits. To maximise the chance of the BHA float valves holding, two floats are used; a poppet type installed above a flapper type such that they have different failure modes - and a failure of the upper (poppet) type is unlikely to block or disable the lower (flapper) type. Both floats are replaced and redressed every time the BHA is pulled. The underlying premise is that the probability of needing to isolate the standpipe manifold is orders of magnitude lower than the circumstances that could see an external to internal leak in a FOSV positioned below the BOPs.

Conclusion

So…in conclusion…is a drilling stand required or preferred? I believe it depends on many factors – in order of significance;

- Surface / Subsea BOP?
- Standpipe Manifold pressure rating?
- Able to circulate fast enough using smallest pump liners?
- Risk of H2S?
- Pressure uncertainties - Exploration or drilling scenario?
- Cement unit connected to the Standpipe manifold

Should a risk assessment indicate a high probability of needing to use a Cement unit to kill the well when using a surface BOP then the use of a drilling single is probably preferable to a drilling stand. And don't forget the logistical and command and control challenges of killing the well from a Cement unit!!

About the Author

Steve Collard is a Chartered Engineer (MIMMM) with more than 30 years of experience in the Drilling Industry ranging from office based drilling engineer through wellsite drilling supervisor to specialist Well Engineering and Well Control consultancy and training. He has presented papers on Well Control at SPE and IADC conferences and has served as the technical author of several corporate Well Control and Casing Design standards and training manuals.

Steve pioneered the concept of "Drilling the Well on a Simulator", working closely with drilling simulator vendors, Operators and Drilling Contractors to produce realistic and relevant training environments where integrated rig teams can be exposed to well specific well control and other operational challenges, develop and then practise responses strategies. He continues to deliver lecturing and general consultancy in Casing Design and Advanced Well Control; specialising in Deepwater and HPHT Well Control training, coaching, rig team building and simulation.